May 2023: ISSUE 136

THE OXFORD INSTITUTE FOR ENERGY STUDIES

forum

A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

ELECTRICITY MARKET DESIGN DURING THE ENERGY TRANSITION AND THE ENERGY CRISIS

INTRODUCTION

The topic of electricity market design has become highly contentious in recent times—particularly in Europe, where there has been a surge in wholesale electricity spot prices due to the exorbitant prices of natural gas. Many point to the market design's focus on setting a single market clearing price based on the costliest resource required to meet demand, frequently natural gas, as the root cause. Besides the current energy crisis and short-term problems, there is a growing concern amongst analysts that, with the current market design, the extensive adoption of zero-marginal-cost renewable electricity would force wholesale electricity prices down to levels that render new investments unprofitable. The long-term ramifications are now a crucial part of the ongoing conversation in many regions, such as the United Kingdom, where the government has introduced its Review of Electricity Market Arrangements (REMA) to address such concerns.

In a decarbonized, decentralized, and digitized energy system, electricity markets should aim to meet several key policy objectives. These include facilitating the integration of renewable energy sources and distributed energy resources, ensuring security of supply, promoting efficient investment in infrastructure, and enabling the transition to a low-carbon economy. However, there are concerns about whether energy-only wholesale markets, as supported by EU legislation, can efficiently meet these objectives. Incremental reforms, such as long-term contracts and more granular price signals, may help address some of these issues. However, there may also be a need for more structural reform to achieve decarbonization objectives in an efficient way, for instance the introduction of nodal pricing. The role of consumers and distributed energy resources will also be crucial in the new markets, and their involvement may require additional market design changes and indeed new, for instance, local markets. Ultimately, the incremental reform of electricity markets may help address the European energy crisis, but there are also alternative market designs to consider, each with its own strengths and weaknesses.

Given this background, the articles in this issue of the *Oxford Energy Forum* debate the topic of electricity market design and the ways in which the market should be reformed to meet the dual challenges of the short-term energy crisis and long-term decarbonization objectives.

Harvey and W. Hogan argue that the efficient design of an electricity market is physically constrained by certain assumptions. In their view, a clear understanding of the fundamentals of electricity markets is required in order to develop effective responses and ensure that temporary measures can transition into sustainable systems. The essential components of an economic dispatch, locational marginal prices, financial transmission rights, compatible forward markets, and hedging arrangements already exist and work in theory and practice. The authors assert that it is important to adopt a market design that works, and any transition should be consistent with long-term market design fundamentals. Ignoring these fundamentals, in the authors' view, would be the worst approach, as it may lead to disruptions in cost and reliability.

M. Hogan argues that the power grid has traditionally operated like a symphony orchestra, centrally directing supply-side resources to meet demand. However, there is a growing recognition of the need to tap into the flexibility of demand for affordable decarbonization and electrification. This will require the grid to function more like a jazz ensemble, with different players improvising in response to supply ebbs and flows. Encouraging flexible loads to consume electricity without regard for the timing of their consumption could result in inflated costs and lost opportunities. To ensure a harmonious interplay between flexible loads and variable supply, an effective market design is necessary. According to the author, the single pay-as-cleared, marginal-cost-pricing wholesale energy market paradigm is well suited to inform the decentralized coordination required.

Poudineh argues that electricity prices exhibit fat-tailed distribution, which means that extreme price spikes or drops could be more common than what would be expected under a normal distribution. This issue may exacerbate as deployment of variable and uncertain renewable generation increases in the electricity sector. According to the author, the increased volatility in energy markets due to fat-tailed distributions can have various impacts. It can lead to higher risk premiums, increased cost of capital, and discouragement of investment in low-carbon technologies. Also, consumers may face higher electricity bills during extreme events, and smaller players may face higher hedging costs to manage their exposure to electricity prices. Additionally, energy policies that rely on stable and predictable electricity prices may be less effective in a market with fat-tailed price distributions. The author argues that the design of the electricity market should consider the increased probability of extreme price events, not only by promoting risk management practices like hedging or insurance but also by implementing energy storage, demand response, and other flexible resources that are likely to have greater value in a market with fat-tailed price distributions.

Grubb argues for a more radical solution. He asserts that preserving short-run marginal cost pricing signals without applying them to all consumption is entirely feasible. The author proposes a ‘dual markets’ approach centred on a Green Power Pool (or multiple pools) of renewable generators. The pool operators or equivalent institutional structures incorporate the cost of renewables generation, calculated at the average contract price, reflecting the long-run marginal cost/contracted strike-price. Additionally, they purchase from the wholesale market when demand exceeds the available renewable energy, and that cost is passed on to the consumer, ideally on a real-time basis. Consequently, consumers contracting with the Green Power Pool pay the average cost of generation, comprising renewables and balancing purchases to ensure reliable supplies. Meanwhile, marginal short-run incentives for consumer flexibility can be maintained. The author considers different options for allocating Green Power Pool energy and makes the case for a social tariff that prioritizes the ´fuel poor´ based on ethical and political rationales.

In the context of Great Britain’s electricity market, Newbery, however, argues that radical reforms to the wholesale market are not necessary, but rather a continuation towards more competition is needed. In the author’s view, minor adjustments to contracts for difference (CfDs), feed-in tariffs, and Transmission Network Use of System tariffs could lead to more efficient location choices and market response. Long-term changes like introducing nodal pricing and an Independent Design Authority could also be considered, but they may take longer to implement. The role of the Low Carbon Contracts Company could be clarified, and levies on electricity should be reconsidered to avoid distorting the shift to low-carbon heating. Short-term fixes for the current energy price crisis should incentivize responses to high prices while providing support for a fixed number of kWh per month to domestic customers without overcompensating the wealthy.

Focusing on the Great Britain market, Gross states that the UK’s electoral schedule means that any major decisions on market reform will be made by the next government, so the priority for the REMA process currently should be to limit the damage to investor confidence that has already been caused. The debate around locational marginal pricing within REMA is becoming increasingly entrenched, but it is important to avoid it becoming a purely technical argument that is disconnected from discussions about household bills, energy independence, and green jobs. Realistic options for change may not be achievable until the middle of the next Parliament, so it is essential to have a clear focus on low-regret, cost-minimizing practical solutions that can be implemented in the short term and within the current regulatory framework.

Green, in the context of the electricity market in Great Britain, asserts that when the UK’s CfD programme was first developed, financiers and market participants insisted that contracts be held by a counterparty with an explicit government guarantee. This decision may have been influenced by the unfamiliar nature of the CfD program at the time. The author asks whether, now that it is well established, a more decentralized approach could be effective. He gives an example of renewable portfolio standards in the US to illustrate that it is feasible for retailers and generators to enter into a long-term fixed-price contract that covers both the electricity output and the renewable certificates, through either a portfolio standard or tradable certificate. According to the author, such a contract would have comparable economic impacts to the CfDs that are favoured by the European Commission and utilized in the UK.

In the context of the EU electricity market, Finon explores the long-term central trader model, which utilizes hedging contracts with low-carbon equipment to meet its objectives. He compares this approach to the central buyer model and argues that both models offer advantages—such as facilitating the transition towards carbon neutrality, and protecting consumers from extreme price volatility by linking retail prices with long-term costs while still allowing for short-term system optimization through the spot market. However, he argues, the central buyer model provides more consistency in achieving the second objective. Despite being in line with European market and competition regulations, the mandate given to a public company to purchase most of the wholesale power in the central buyer model makes it difficult for EU advocates of a free market to accept.

Focusing on the same market, Roques and Burger argue that the energy crisis tested the European internal market for gas and power, which has overall shown resilience and correctly signalled the scarcity of these resources. However, the emergency framework left room for interpretation by member states, resulting in varying national implementations and distortions. An expedited process for market reform is needed to supersede these interventions, with a consensus emerging on the need for a greater role for long-term contracting and consumer hedging. This may lead to hybrid markets combining short-term market mechanisms with planning and redistribution mechanisms. The heterogeneity of the European power market and political landscape may result in different national approaches, potentially leading to further distortions and fragmentation of the European power market.

In another article on the EU electricity market, Glachant argues that a reform of this market alone is not sufficient to deliver EU energy security, decarbonization, and electrification. According to the author, the entry into the era of hybrid electricity markets as part of the electricity market reform is a necessary but not sufficient condition for success. This is because achievement of these goals faces direct and indirect constraints such as grid and infrastructure adequacy, allocation of decision rights between the EU and member states, EU Central Bank monetary policy and member states' public budget financing, and existing international industry trading and manufacturing chains. Therefore, the EU energy landscape, post-market reform, will continue to require effort, attention, and coordination from public and private energy decision-makers.

Mountain analyses Australia's National Electricity Market (NEM) and presents thoughts on future changes. The author argues that that future debates on the development of the spot market in Australia should have more modest objectives, with the spot market being essential for price-based power system balancing and allocating the cost of imbalance to the participants that caused it. The focus should be on customers' freedom to choose their suppliers to discipline expenditure and spur innovation in the contemporary Australian context, where governments and their agents are becoming increasingly involved in determining investment and developing or procuring new production, transmission, and storage.

In an article on the same market, McConnell and MacGill argue that the June 2022 market suspensions in the Australian NEM were caused by market settings that were not suitable for the conditions that materialized. Prior to the suspension, governments and decision-makers had doubts about the ability of the market to deliver sufficient investment, and were already moving beyond the existing NEM frameworks and market structures. Since the suspension, there have been moves away from a laissez-faire market approach, with the federal government capping the domestic price of gas and coal prices and state-based policy initiatives developing. However, the results of formal market and institutional reform processes have been lacklustre. According to the authors, these developments reflect a loss of faith in the energy-only market design, and there is a need for better acknowledgment and reflection of these developments in Australia's energy rule-makers' and regulators' institutional and governance arrangements to ensure the energy transition is not delayed or derailed.

FUNDAMENTALS DEFINE THE CONSTRAINTS ON ELECTRICITY MARKET DESIGN

Scott M. Harvey and William W. Hogan

European electricity market design challenges arise from the confluence of the immediate disruptions associated with the war in Ukraine and the continuing pressures accompanying the move to a cleaner energy system. In addressing the immediate challenges there should be a clear understanding about the fundamental nature of electricity markets, both to craft transition responses and to ensure that temporary measures can and do transition into workable systems that can endure even in the face of large uncertainties. Discussions of electricity market reform, in the present European context but also in general, often make implicit assumptions that are highly consequential. An explicit and brief summary of critical fundamentals sets the stage for a discussion of the implications for the intended electricity market design that should be a goal to guide the transition.

Fundamentals

Electricity systems have special characteristics that constrain both physical operations and market mechanisms. The familiar features include the need for instantaneous balancing, the physical properties of power flows, and the many complications of security constraints to protect against persistent conditions that could lead to cascading failures. In addition, there are related institutional features that underlie the electricity market design. The key fundamentals employed here include the following:

- In a decentralized market, profit-seeking market participants have material discretion to participate through bidding or self-scheduling, as well as through investment decisions.
- Real-time markets require coordination through a system operator, and the system operator can accommodate a workable approximation of the complex multi-part supply offers and demand bids.
- The grid is not likely to be a copper plate without material transmission constraints, implying sometimes large differences in economic conditions across the grid. This will be more important, not less, with a resource mix that includes large quantities of intermittent resource capacity—particularly as such capacity is often sited some distance from centres of load.
- The product demanded by consumers is power delivered at their respective locations.

While not exhaustive, these seemingly innocuous conditions largely constrain the elements of efficient electricity market design. Added details of reliability contingency constraints, reliability unit commitments, ancillary services, policy constraints, emissions pricing, market power mitigation, price volatility, mandates for hedging, transmission planning and expansion, and so on are important and worthy of consideration. But these can be accommodated within a framework defined by the key fundamentals.

Implications for electricity market design

Profit-seeking market participants will anticipate the real-time settlements system when making forward commitments. As a result, efficient market design must begin with the real-time market. Forward market structure and prices should be made consistent with the real-time structure, and the reverse approach is fraught with the risk of unintended adverse consequences. Prices should support an efficient solution to keep incentives aligned with a social welfare objective.

In real time, productive economic efficiency requires economic dispatch. Given cost-reflective bidding, this can be provided by the system operator while managing the complex transmission flows largely by adjusting the dispatch of generation, load, and storage. Prices and related settlements exist to support this economic dispatch. Given the physical nature of power flows, these prices can differ materially across locations in explainable but sometimes counterintuitive ways. These are the conventional locational marginal prices (LMPs). The basic economic-dispatch-with-LMP is, relative to other market designs, the one that supports the efficient market outcome. Market monitors, market power mitigation designs, and merger policy can address the scope of opportunities for the exercise of market power or other forms of bid manipulation.

The real-time LMPs define both the settlement prices for locations and the point-to-point transmission charges for self-schedules. By contrast, point-to-point firm physical transmission rights for the capacity of the system cannot be defined or provided along with the economic dispatch, but a set of economically equivalent financial transmission rights can be made available. Together the real-time prices and financial transmission rights can support forward contracts between buyers and sellers at different locations.

Hence, efficient real-time markets can support forward markets, which largely consist of financial contracts. The principal observable physical actions before real time are for unit commitments (in part needed to anticipated real-time contingency constraints). But no energy is delivered in the forward market, and the real-time LMPs provide an efficient incentive for settling hedges structured as contracts for differences.

Real-time market power concerns can be addressed through ex ante regulatory interventions such as offer caps. This can mitigate real-time exercise of market power without undermining efficient incentives for the remaining participants in the markets.

Real-time energy markets require compatible designs for ancillary services, including operating reserves. These requirements can produce scarcity conditions which can influence real-time prices through operating reserve demand curves, which can be defined to reflect transmission system reliability criteria, raising prices under scarce conditions, creating incentives both to perform in real time and to invest in appropriate capacity going forward.

Carbon prices for emissions would be reflected in real-time dispatch offers and translate into marginal impacts in locational prices, without requiring any fictional tracing of power or emission flows through the transmission system. This focus on the problem, emissions, avoids the need for imperfect administrative identification of subsidies for imperfect substitutes such as renewables at a different location.

Efficient prices have been and would be volatile—perhaps more so in the future given the increasing proliferation of renewables generation in the system. In practice, the degree of future volatility will depend on many factors, including the development and operation of intertemporal storage, demand-side flexibility, and improved pricing designs for final customers, as well as the evolution of the resource mix and consumer demand patterns.

The presence of volatility does not much affect the basic wholesale market design, which could accommodate a wide range of pricing outcomes. However, price volatility would be important for final consumers, especially for residential and small consumers that are not able to reduce consumption in response to high prices.

In principle, the basic elements allow for forward hedges arranged on a voluntary basis. The voluntary nature, coupled with efficient real-time prices for settlement, would avoid many of the complications of regulation. However, there is an irreducible element of uncertainty, and long-term voluntary contracting opportunities may be difficult to obtain, and might be deemed as inadequate for certain customers.

The ubiquitous transmission constraints require recognition that mandatory hedging arrangements for these smaller customers, in fact for all users, must focus on delivered loads and prices. Hence contracts need not be for power at the generator's location, but could be at the final customer's meter. In practice the hedging arrangements could be organized through opt-out provisions of otherwise mandatory aggregation models, as have been successfully employed for delivered power with, for example, a three-year rolling price commitment.

Transmission expansion, with its strong interactions across many participants, would be through coordinated planning but with beneficiary-pays cost allocation that seeks to recover the costs of transmission enhancements from the cohort of participants that are deemed to benefit most from the upgrade.

This discussion of fundamentals is largely silent on the degree of penetration of renewables, or any of the particular cost structures of load and generation. These all affect the outcome of prices and quantities, but they do not impact the basic market design. Further, this design does not include 'capacity' markets as currently defined. Demonstrating both resource adequacy and capacity deliverability under stressed conditions has always been complex, and it has become far harder with a resource mix that includes large amounts of intermittent resources and many types of energy-limited resources. We don't know how to solve this problem through regulatory proceedings and rules. The best we can do is provide customers with market-based hedges for delivered power. The key customer-centric forward hedging contracts are not with generators based on their location and volume of production; the regulatory focus of hedging arrangements would be on the delivered price of power at the customer's location.

Conclusion

Under the basic assumptions made explicit here, there are sharp physical constraints on the design of an efficient electricity market. All of the main components of economic dispatch—LMPs, financial transmission rights, compatible forward markets, and hedging arrangements—already exist in various systems. Although no electricity market yet incorporates all of these features, all the elements work in theory and have been proven in practice and have the great strength of being both internally compatible and consistent with electricity system fundamentals both now and in the future. The best approach would be to adopt a workable market design. At a minimum, any transition should be as consistent as possible with anticipated long-term market design fundamentals. The worst approach would be to follow the common practice of dismissing the fundamentals and hope that the disconnect with reality won't be too disruptive to customers in terms of cost or reliability.

ELECTRICITY MARKET DESIGN IN THE NEW JAZZ AGE: THE DECENTRALIZED COORDINATION OF FLEXIBLE DEMAND IN A RENEWABLES-DOMINATED POWER SYSTEM

Michael Hogan

The power grid has traditionally been built and operated like a symphony orchestra, with a mix of supply-side resources centrally assembled and directed by the system operator to meet demand. There is now growing recognition of the need to tap into the latent flexibility of demand if we are to advance both electricity decarbonization and the electrification of energy services in an affordable manner. The value of doing so will lie predominantly in avoiding uneconomic investment in higher-cost supply-side alternatives.

The great majority of this low-cost, high-value potential will not lend itself to the old symphony orchestra model—the grid will need to function more like a jazz ensemble, with different players improvising in response as less 'directable' supply ebbs and flows. If flexible loads, especially large, inherently flexible new electrified end-uses like transport and heat, are encouraged to consume electricity without regard for the impact of the timing of their consumption on marginal costs, the result will be greatly inflated costs for all and significant lost opportunity. It is therefore necessary that any proposed market design be effective, day in and day out, in eliciting a harmonious interplay between flexible loads and variable supply. The single pay-as-cleared, marginal-cost-pricing wholesale energy market paradigm is uniquely well suited to inform the distributed, decentralized coordination required for this to happen.

Be careful what you wish for

The European energy crisis has prompted a surge in critical attention to electricity market design. There is nothing new about claims that the wholesale market design paradigm is unfit for purpose, and there are certainly issues to be addressed, but this latest eruption is especially poorly grounded. The pain caused by the crisis is all too real. But blaming the electricity market design for it is like blaming organic chemistry for climate change. The wholesale electricity market is simply telling us—all of us, not just policymakers—what we very much need to know: the cost, considering our current and future sources of primary energy, of extending our current level and patterns of consumption, or the savings to be had from consuming less and consuming differently. It is also telling us, in unmistakable terms, how urgent it is that we ween ourselves from our dependency on fossil fuels.

Mitigating the equity concerns posed by these very real costs is the purview of retail tariff regulation and social policy, not wholesale market design. The parallel electricity transformations currently underway—rapid expansion of variable supply and rapid electrification of energy services such as transport and heat—make access to that information for all who can act on it more vital to the future of energy than it has ever been.

In other words, any discussion of electricity market design must consider the central role flexible demand can and should play in mitigating the enormous investment challenge we face. Proposals to 'redesign the electricity market' come and go, sometimes intriguing, but they are nearly always focused on addressing the myriad challenges presented by these transitions with top-down, supply-side prescriptions (generation, transmission, distribution), including huge investments in marginal assets that will be little used. Very few address—or even acknowledge—the vital role to be played by an active and responsive demand side.

The importance of demand flexibility

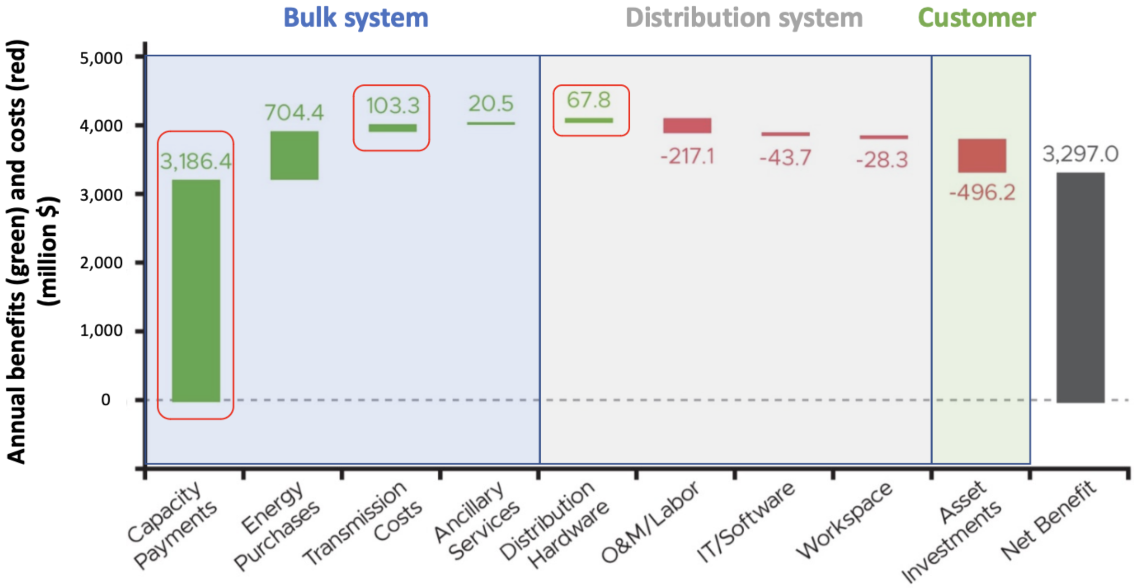
A recent study published by the Pacific Northwest National Laboratory (PNNL) offers a glimpse of the costs of a myopically supply-side approach, and the potential for flexible demand to substantially mitigate those costs.[1] The study modelled a stand-alone grid roughly the size of the Texas market under 'moderate' (15 per cent of annual energy) and 'high' (40 per cent of annual energy) variable resource penetration. It then compared wholesale system costs in each scenario under business as usual (no change in demand patterns) and with distributed customer-controlled load flexibility in response to supply variation.

Under the 'moderate' scenario, which excluded electric vehicle (EV) loads, the study found bill reductions of 10 per cent for all customers and 17 per cent for participating flexible customers. Savings were roughly 40 per cent greater in the 'high' scenario (which assumed 33 per cent penetration of EVs). The study did not examine the potential reductions in needed expansion of the distribution network, which typically represents roughly a third of retail bills. (This is being examined in a yet-to-be-published PNNL study.) Consider that medium-term targets for both renewables and electrification are already higher in many countries than the assumptions in the 'high' scenario.

The figure below (the 'moderate' scenario) shows that these cost reductions derive overwhelmingly from reductions in capital costs. This results from a combination of more conventional reductions in peak load of 9–15 per cent with more transformational reductions in daily load variation of 20–44 per cent, together significantly reducing the need for infrastructure investment (again, excluding potential savings in distribution network expansion). Whilst many system operators focus principally on post-gate-closure contingency services (which contribute less than 1 per cent of projected savings), the bulk of projected savings come from increased asset utilization due to pre-gate-closure flexibility in response to expected variations in system conditions.

[1] Reeve, H., Widergren, S., Pratt, R., Bhattarai, B., Hanif, S., Bender, S., Hardy, T., and Pelton, M. (2022), *The Distribution System Operator with Transactive Study*, Richland, WA: Pacific Northwest National Laboratory.

Figure 1: Potential cost savings from demand responding to prices, based on analysis of the amount and sources of economic benefit to consumers on a hypothetical Texas-sized grid from deploying flexible loads in response to system needs.



Note: Bars circled in red are investment cost savings. 'Capacity payments' is a proxy for generation investment. 'Distribution hardware' considers only substation upgrades. 'O&M' is operation and maintenance.

Source: Pacific Northwest National Laboratory.

A small share of these savings can be accessed by enabling demand participation in wholesale markets (energy, ancillary services, capacity) in competition with generation. However, most valuable daily demand flexibility cannot or will not participate directly in these markets.[2] As the PNNL study concludes, 'there is a need for a solution that integrates the coordination of demand flexibility into everyday grid operation, ensures it is automated, puts the customer in control of how much or little they participate, and fairly compensates them for the level of flexibility they provide to the grid.'[3]

Moving on, keeping up

Many—especially incumbent industry players—dismiss the idea of a responsive demand side based on the presumption that demand is nearly perfectly inelastic and cannot or should not be rationed with pricing. That presumption is increasingly anachronistic.

Certainly, some loads are less elastic than others, and some end uses are more suited to adopting and responding to dynamic pricing than others. But the fact is that the 'value of lost load' (VoLL) for many end-use services, especially large new transport and heat loads, varies widely across time and location. Whilst the VoLL to interrupt lighting may be quite high, the VoLL to interrupt EV charging and shift it to a different time is usually very low. Indeed, at, say, 02:00 it is, in nearly all cases, effectively zero. Even across a more traditional suite of end uses, the potential for end users to respond is quite significant.[4]

The presumption also ignores the rapidly decreasing cost, increasing ease, and increasing value of bidirectional demand flexibility as we expand reliance on variable, capital-intensive and low-variable-cost production. Finally, it ignores clear evidence that flexible loads will, in fact, respond to pricing if it fully values the real-time flexibility they can provide, and that they can sustain that responsiveness indefinitely.

[2] Hogan, M. (2022), *Tapping the Mother Lode: Employing Price-Responsive Demand to Reduce the Investment Challenge*, Reston, VA: Energy Systems Integration Group, Retail Pricing Task Force.
[3] Reeve et al., (2022), *The Distribution System Operator*, Executive Summary page 3
[4] See, for example, Alstone, P., Potter, J., Piette, M.A., Schwartz, P., Berger, M., Dunn, L., Smith, S., Sohn, M., Aghajanzadeh, A., Stensson, S., Szinai, J., and Walter, T. (2017), *2025 California Demand Response Potential Study—Final Report on Phase 2 Results*, Berkeley, CA: Lawrence Berkeley National Laboratory.

One recent demonstration of this new flexible demand reality is National Grid ESO's (Electricity System Operator's) CrowdFlex project.[5] Moving from flat tariffs to a set of time-of-use retail pricing offerings for a large sample of Octopus Energy and Ohme customers over a six-month trial elicited load shifting away from high-price hours to low-price hours of 19–23 per cent among EV-owning customers and 12 per cent among non-EV-owning customers. Those levels of responsiveness persisted unabated for the duration of the trial. A more traditional option was also trialled with a large sample of customers, requiring customers to enrol in advance for a one-time increase or decrease in demand over a two-hour period of ESO's choosing. This elicited a much larger response—a downturn of 41 per cent (non-EV owners) to 59 per cent (EV owners) and an upturn of 131 per cent (non-EV) to 617 per cent (EV)—but one that is unlikely to be sustainable over any significant number of events. (The upturn results point to the potential for flexible demand not only to reduce peak prices, but to lift market clearing prices during periods of high renewable production, an important part of a much longer response to the highly contingent claims about the impact low-variable-cost resources will have on prices under the current market design paradigm.)

A noteworthy aspect of the CrowdFlex results is the difference they illustrate between a traditional conception of demand flexibility—a centrally directed imitation of a supply resource, which for reasons both administrative and behavioural is highly limited in application—and the conception of demand flexibility that will be most valuable to a decarbonizing and electrifying energy system—a highly decentralized, price-driven behavioural change by consumers acting independently, most likely via automation or via an energy service provider, on a daily basis over an extended period of time. The difference in results may reflect that on any given day the customer loads responding to time-of-use pricing form a shifting subset of those responding to a one-off event, with the combination of diversity and agency contributing to a lower but sustainable and still very significant shift in the pattern of demand.

There is long experience and a level of comfort in some regions with the former model of command-and-control demand flexibility. In contrast, the electricity industry has traditionally dismissed the potential for the latter model of decentralized, repeatable shifts in load curves by customers happy to be regularly flexible if the price is right. Initiatives like CrowdFlex are demonstrating just how out-of-date this traditional viewpoint is. In doing so, they shine a bright light on the necessary (though not sufficient) role of an underlying wholesale market price that reflects real short-term variation in the marginal cost of consuming electricity.[6] Lest one be tempted to fall back on tired evasions like customers being uninterested in watching their meter or in being directly exposed to wholesale prices, projects like CrowdFlex and many others showcase the innovation taking place in offering consumers flexible energy management services that are convenient and financially compelling.

The deeply ingrained supply-side bias that leads to discounting of distributed demand flexibility in resource planning is one of several contextual factors that create hidden barriers to a more active demand side, turning scepticism into a self-fulfilling prophecy.[7] Others include out-of-market 'capacity remuneration mechanisms' that over-procure the supply-side resources capable of participating in them by implicitly valuing marginal capacity at levels many times higher than the value available to energy market participants. These contextual barriers are addressable if the goal is to make the current market paradigm fit for the future. In contrast, top-down, supply-side-focused market redesign proposals are only likely to exacerbate and further institutionalize these impediments to an affordable energy system transformation.

A simple illustration

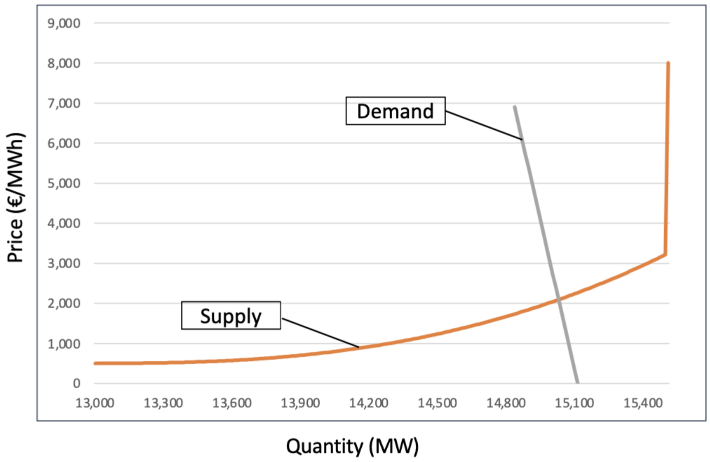
Consider a simplified example of the social welfare implications of neglecting development of distributed demand flexibility and the short-term wholesale market pricing needed to inform it. The figures below depict a hypothetical system during a given pricing interval, under two sets of assumptions. In this example the demand for energy has risen beyond the point where the demand for reserves can be met by re-dispatch and is approaching the point at which the system operator would choose to curtail firm load to maintain a minimum safe reserve level.

The first figure includes the familiar depiction of demand as nearly completely inelastic. It also depicts a supply curve that does not fully incorporate the opportunity cost of being short of the desired level of reserves. The second figure improves both curves; in this figure, the demand curve reflects the fact that while demand is relatively inelastic across a lower range of prices, the higher the price rises, the more elastic demand becomes. The supply curve in this figure reflects an administrative intervention

[5] *CrowdFlex—Phase 1 Report*, 2021, Gallows Hill, Warwick, UK: National Grid ESO.
[6] For an extended treatment of barriers and remedies, see Yule-Bennett, S., and Sunderland, L. (2022), 'The joy of flex: Embracing household demand-side flexibility as a power system resource for Europe', Montpelier, Vermont: Regulatory Assistance Project.
[7] For a more detailed discussion of contextual barriers, see Hogan (2022), *Tapping the Mother Lode*.

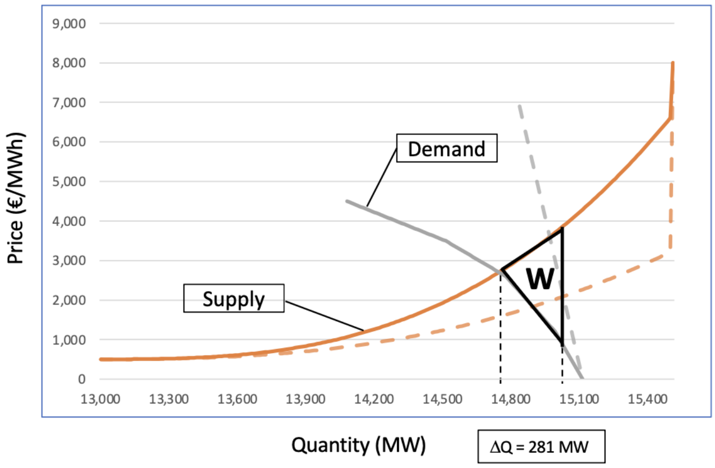
(co-optimization of energy and reserves and/or an administrative reserve shortage price adder) to ensure the market price reflects the full marginal cost of energy, including both the marginal generator's variable cost of production and the opportunity cost of further reducing reserve levels. As a result, the market clears at a lower level of demand, at a higher clearing price, and with a gain in social welfare during this one interval of €387,780. The gain, of course, is the result of not consuming more electricity in this interval at a cost increasingly exceeding its value.

Figure 2: Conventional supply and demand curves, with nearly complete demand inelasticity and supply that does not fully account for the opportunity cost of a reserve shortfall



Source: Regulatory Assistance Project.

Figure 3: Supply and demand curves reflecting demand elasticity that increases with price and supply that reflects the contribution of the opportunity cost of a reserve shortage to marginal cost



Source: Regulatory Assistance Project.

Note: The dotted line curves show the original, unimproved supply and demand curves; the area inside the triangle W represents the gain in social welfare resulting from the correction. The black dotted lines denote the original market-clearing quantity (right) and the improved market-clearing quantity (left).

Again, a very truncated version of this effect can be obtained with more traditional command-and-control peak-shaving programs, but these capture none of the value of daily flexibility, nor do they capture any of the value of the obverse elasticity of demand to very *low* prices.

Conclusion

An engaged and responsive demand side is crucial to the affordability—and thus the political sustainability—of the dual transitions to decarbonization and electrification. The potential savings are predominantly in avoiding uneconomic capital investment, and those savings are accessible via distributed, customer-driven interaction between flexible loads and the needs of a system increasingly reliant on variable supply. It is a transition from a legacy power grid run like a symphony orchestra to a 21st century grid functioning more like a jazz ensemble. The single pay-as-cleared, marginal-cost-pricing wholesale energy market provides the essential information needed to make beautiful music.

Whilst this article addresses specifically the imperative of flexible demand in market design, a brief word is needed regarding concerns about driving low-carbon investment. There is no validity to claims that growth of renewables must lead to the inability of spot market prices to support investment. (The subject of this article is an important part of the rebuttal of those arguments.) Nonetheless, significant improvement in spot market price formation is possible and necessary. Investment also relies on access to a range of forward risk management tools. These would normally emerge as a natural extension of buyer and seller incentives in response to legitimate need for new investment (which can be shaped by policy). Yet there are valid concerns that various factors have conspired to impede that normal market function.

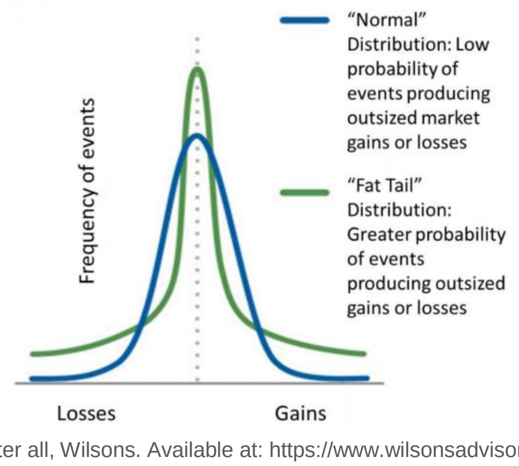
Whilst capacity remuneration mechanisms have proven especially problematic, several promising ideas have been brought forward about measures to encourage a more robust forward contracting environment.[8] Such measures, together with improved price formation, a focus on the demand side, and well-designed social policy, are fully capable of ensuring adequate investment in low-carbon supply, whilst also avoiding an unnecessary extended investment hiatus.

EXTREME MOVEMENTS OF ELECTRICITY PRICES: WHAT DO THEY MEAN FOR MARKET DESIGN?

Rahmat Poudineh

Electricity prices can fluctuate due to a variety of factors, including changes in demand, weather events, and supply disruptions. If prices follow a normal distribution, extreme electricity prices will become rare events because under such distribution approximately 99.7 per cent of observations lie within three standard deviations from the mean. However, there is an argument that electricity prices exhibit fat-tailed distribution.[9] A fat-tailed distribution is a probability distribution that has a higher-than-normal probability of extreme events, which means that extreme price spikes or drops could be more common than what would be expected under a normal distribution.

Figure 1: Normal versus fat-tailed distribution



Source: Straight talk: It's a fat-tailed world after all, Wilsons. Available at: https://www.wilsonsadvisory.com.au/news/straight-talk-its-a-fat-tailed-world-after (Accessed: April 23, 2023).

To understand this better, let's consider a simple example of daily electricity prices for a year, assuming that they are normally distributed with a mean of $100 and a standard deviation of $10. Let's also assume a fat-tailed distribution of electricity prices

[8] See for example Schlecht, I., Hirth, L., and Maurer, C. (2022), *Financial Wind CfDs*, Kiel and Hamburg: ZBW–Leibniz Information Centre for Economics.

[9] I am indebted to Farhad Billimoria for discussion about this issue.

that has the same mean and variance but a higher tailedness (say a Student's t-distribution with 3 degrees of freedom). If we compare the likelihood of extreme (greater than two standard deviations) price movements under the two distributions, we can see that the probability of extreme electricity price movements is 64 per cent higher under a fat-tailed distribution than under a normal distribution.

Furthermore, in a fat-tailed distribution, the tail probabilities decay more slowly than in a normal distribution. This means that the probability of extreme price spikes or drops remains relatively high even as the distance from the mean increases. For example, if we look at the probability of an electricity price movement greater than 10 standard deviations, it is effectively zero for normal distribution (7.6×10^{-24}, to be exact) but around 0.36 per cent for fat-tailed distribution. Although this looks like a small chance, in practical terms this means that if we were to observe electricity prices for a long enough period of time (say 10 years), we would expect to see extreme price movements that exceed 10 standard deviations more than 13 times.

Indeed, this is not just an argument. Several studies have looked at the statistical properties of electricity prices, and some have found evidence of fat-tailed behaviour.[10] Although some argue that the observed price behaviour can be explained by other statistical distributions or could be a result of measurement error or other data quality issues, fat-tailed behaviour of electricity prices is likely to be consistent with the characteristics of a complex and dynamic system such as that of the power sector for the following reasons.[11]

Firstly, the demand for electricity is relatively inelastic, meaning that consumers need a certain amount of electricity to meet their needs and are generally unable or unwilling to reduce their consumption significantly in response to price increases. This can result in a situation where even a small increase in demand can lead to a significant increase in prices.

Secondly, electricity cannot be easily stored on a large scale yet, meaning that supply must be constantly adjusted to meet demand in real time. When demand increases, it can be difficult for generators to quickly ramp up production, leading to a situation where prices may increase significantly in response to even a small increase in demand. The opposite is also true when demand declines or there is overgeneration.

Thirdly, the electricity market operates on a marginal pricing system, which means that the price for electricity is set by the last unit of electricity that is dispatched to meet demand. This can lead to situations where a small change in supply or demand for any reason can result in a large change in price, as the price is determined by the cost of the most expensive unit of electricity dispatched.

Fourthly, in many places, the power sector still relies heavily on natural gas, coal, or oil. This can result in a situation where a small change in fuel costs can have a disproportionate effect on electricity prices.

One might be tempted to say that the essence of this issue (if proved to exist) is the marginal cost pricing, and thus, if we move away from it to an alternative model, the issue of extreme price movements will be resolved. Apart from the fact that there is no efficient alternative (at least with respect to short-term efficiency), removing the efficient price signal is likely to change the problem from extreme price movement to extreme frequency of demand-and-supply imbalance. In an efficient market, price movements are the way to keep supply and demand in balance, which is of critical importance in the electricity sector. Therefore, if we do away with efficient pricing, we might encounter another even more complex problem.

Given this background, there are multiple implications of a having a fat-tailed probability distribution for electricity prices.

1. Due to the increased volatility of fat-tailed distributions, market participants may require higher risk premiums to compensate for the higher risk of extreme price events. This can increase the cost of capital and can discourage investment in low-carbon technologies that rely on market price for cost recovery. This can slow down the transition towards a low-carbon energy system, which requires significant investments in new renewable energy capacity.
2. Consumers are exposed to the risk of price spikes during extreme events, which can lead to higher electricity bills. It can also make further penetration of electric vehicles and heat pumps more difficult.

[10] See for example Byström, H.N.E. (2005), 'Extreme value theory and extremely large electricity price changes', *International Review of Economics & Finance* 14(1):41–55, https://doi.org/10.1016/s1059-0560(03)00032-7.
[11] To avoid confusion, this analysis does not include normal price fluctuations in the electricity market, which are not necessarily problematic. Indeed, fluctuations in prices can serve as valuable signals for both investment and operational purposes, particularly as the energy system adapts to incorporate renewable sources that are subject to variability. Thus, this article only focuses on extreme price movements.

3. Electricity market participants may face higher hedging costs to manage their exposure to electricity prices. This can create challenges for smaller market participants, who may not have the same resources to manage their risk as larger players.
4. The higher volatility of fat-tailed distributions can create challenges for energy policy. For example, policies that rely on stable and predictable electricity prices, such as energy-efficiency programmes, may be less effective in a market with fat-tailed price distributions. A significant drop in electricity prices, for example, makes it more difficult to justify the upfront costs of energy-efficient appliances or building upgrades.
5. Market design needs to account for the higher likelihood of extreme price events—not just by encouraging the use of risk management strategies such as hedging or insurance, but also through the deployment of energy storage, demand response, and other flexible resources, which are likely to be more valuable in a market with fat-tailed price distributions.

While the use of risk management strategies such as hedging or insurance and the deployment of flexible resources are complementary approaches to managing the risks associated with fat-tailed electricity prices, there are also fundamental differences between these two. Hedging and insurance are designed to provide financial protection against extreme price movements, but they do not directly affect the underlying supply and demand dynamics in the electricity market. However, energy storage and flexible resources can reduce the likelihood of extreme price movements by reducing peak demand and increasing supply during periods of high prices. By reducing the need for expensive peaking power plants, these resources can help to dampen price spikes and increase the overall stability of the electricity market.

There also other issues to consider in relation to application of risk management instruments to address fat-tailed distribution. It is often not easy to hedge effectively against extreme electricity price movements because these events are quite rare and difficult to predict. Furthermore, the instruments available for hedging may not be well suited for such events. For example, many hedging instruments, such as futures or options contracts, are designed to mitigate risk over a relatively short time horizon, typically up to a few years. However, extreme price movements can occur over much longer time periods, making it difficult to effectively hedge against them using these instruments.

Additionally, under such price movements the risk of default is higher, because if prices move against a party who has committed to a long-term contract, they may be unable to meet their contractual obligations. Also, extreme price movements may be correlated with other risks, such as credit or liquidity risk, which can make it even more challenging to effectively hedge against them. For example, during periods of extreme price volatility, liquidity in the market may dry up, making it more difficult to execute trades or unwind positions. Finally, over-hedging can also be a problem itself. If a large number of market participants are using hedging or insurance strategies to protect against price volatility, this may increase the likelihood of extreme price movements because there are fewer market participants available to respond to changing supply and demand conditions.

These all point to the important role of energy storage and demand-side flexibility resources to address price spikes and drops in the future power system. The increase in the share of intermittent renewable energy resources is likely to increase the probability of having fat-tailed price distribution. This is because wind and solar are subject to variability and uncertainty, which can create challenges for balancing supply and demand in real time if traditional thermal resources are phased out before energy storage or other flexibility resources become widely available. When there is an over-supply of renewable energy, prices can fall to zero or even below, and when there is an under-supply, prices can spike to very high levels. The fact that both supply and demand will be weather related will exacerbate this issue.

There are various types of energy storage, but not all of them are helpful in the context of this problem. If we are facing the risk of significant electricity price increases or decreases for a long period of time in an unknown future, the most suitable energy storage technologies would be those that are capable of providing large-scale long-duration storage, with the ability to store energy for days, weeks, or even months. Chemical energy storages, such as hydrogen or its derivatives like ammonia, are among the candidates. This involves, for example, using excess electricity to produce hydrogen through electrolysis, which can then be stored and used to generate electricity later through gas turbines. There are also other options such as compressed air, thermal energy storage, and pumped hydro.

The key issue, however, is electricity market design. Long-duration storage technologies face a unique challenge due to three interrelated factors. Firstly, these technologies require a substantial amount of capital investment. Secondly, there is often a prolonged gap between the decision to invest and the completion of the project. Finally, there are limited, if any, long-term revenue streams available to support investment decisions. Long-duration storage assets cycle infrequently, which means the necessary spread between the purchase and sale prices becomes significantly greater for their economics to make sense. As a result, although short-duration storage (such as batteries) has experienced growth, the capacity for long-duration storage has not increased. It is uncertain whether the current electricity market design will be able to provide long-duration storage technologies.

Specifically, investing in hydrogen storage entails two main risks related to demand and pricing. The first risk is insufficient demand, meaning that there may not be a strong enough need for hydrogen storage after the investment has been made. The second risk is a low price for utilizing the storage facility, where the cost of accessing hydrogen storage may not be high enough to justify the investment. This can occur for various reasons, such as competition among different types of hydrogen storage or advancements in technology. These two risks contribute to uncertainty in revenue, which may diminish over time as the hydrogen economy expands. Nonetheless, this uncertainty must be managed through an appropriate business model, which may require government support.

Demand-slide flexibility, however, is more challenging to encourage. While demand for electricity plays a critical role in determining prices in wholesale electricity markets, it typically does not participate directly in these markets. This is partly related to physical characteristics of demand, which is largely a function of consumer behaviour and thus cannot be easily controlled or adjusted in real time. It is also partly related to regulatory and market barriers. Small-scale consumers may have limited ability to participate in the wholesale electricity market directly. This is why their participation is indirect, either through demand response programs conducted by aggregators or through retail electricity providers, who purchase electricity on their behalf.

An electricity market that is designed to enable demand-side flexibility typically includes several specifications and market mechanisms to incentivize and facilitate the participation of demand-side resources. One important feature is that electricity prices should be set dynamically based on real-time system conditions, which can incentivize consumers to reduce their electricity consumption during periods of high prices. This can be achieved through time-of-use tariffs, critical peak pricing, or real-time pricing. However, reconciling dynamic pricing with the desire of consumers for simple fixed tariffs can be a challenging task. Consumers typically prefer fixed tariffs because they are easy to understand and budget for. Dynamic pricing, on the other hand, can be confusing and unpredictable, making it harder for consumers to manage their energy bills.

Apart from the fact that consumers need to be educated about how dynamic pricing works and how they can benefit from it, technology and automation are likely to play an important role in facilitating roll-out of efficient pricing. Smart devices, such as smart thermostats or appliances, can help consumers participate in dynamic pricing programs more easily. These devices are designed to automatically adjust their energy usage based on the current pricing, without requiring any action from the consumer. Overall, a two-sided electricity market requires sophisticated technical infrastructure and systems to enable real-time interaction between supply and demand. This needs significant investment in software and hardware, as well as a high level of coordination between market participants.

We should also not underestimate the role of long-term demand-side flexibility, which refers to changes in energy usage that require longer planning and implementation times, such as adopting energy-efficient technologies or upgrading building insulation. These measures can reduce energy consumption over the long term and provide greater flexibility in energy usage patterns. Governments can set minimum energy efficiency standards for appliances and equipment, such as light bulbs, refrigerators, and air conditioners, to reduce energy consumption. However, beyond that, energy efficiency should be integrated as a product in the electricity market.

A competitive auction mechanism to procure ‘negawatts’ could encourage the development of new markets for energy efficiency, which could in turn support the implementation of larger-scale projects and a rebate for demand reduction. Also, energy efficiency certificates can be traded as a way for energy suppliers or other market participants to meet their energy efficiency targets or obligations. A market could also be established at the network level to trade spare grid capacity, enabling customers to sell their excess capacity back to the network. This market would be based on the premise that customers can implement energy efficiency measures more quickly and cheaply than the network operator can reinforce the network, and network needs would be tendered accordingly.

Finally, while markets can play an important role in addressing extreme events, they may not be sufficient to fully address the challenges posed by these events. In some cases, government intervention may be necessary to ensure that the electricity system is prepared for and can respond effectively to extreme events. How to balance the roles of government and market in responding to extreme movements in electricity prices is a challenging question, especially when such events threaten the reliability of the electricity supply or create significant financial hardship for consumers. Ultimately the most effective approach will depend on the specific circumstances of each situation and will require careful consideration of the costs and benefits of different policy options and a willingness to adapt to changing market conditions.

DISENTANGLING THE DEBATE ON ELECTRICITY MARKET (RE)DESIGN AND 'SPLIT MARKETS'

Michael Grubb

Introduction

'Marginal cost pricing is good; "split markets" are therefore bad.' That statement might caricature one side of a vibrant debate on European electricity. The fact that there is a debate—and a sometimes heated one—itself suggests a need to look more closely, if we are to make headway.

To be clear, the European Single Electricity Market has done a great job at what it was most fundamentally designed to do—reflect, on a short-run basis, the cost of bringing on generation to meet demand at a specific time, anywhere across Europe. This author is not aware of anyone proposing to completely replace it.

Therein lie the fundamental issues. It is short run—very short run. And the price in that market, received by all generators selling into it, feeds through almost all electricity consumption. To be specific, it is a short-run, marginal-cost-on-all market. That is the first clarification required.

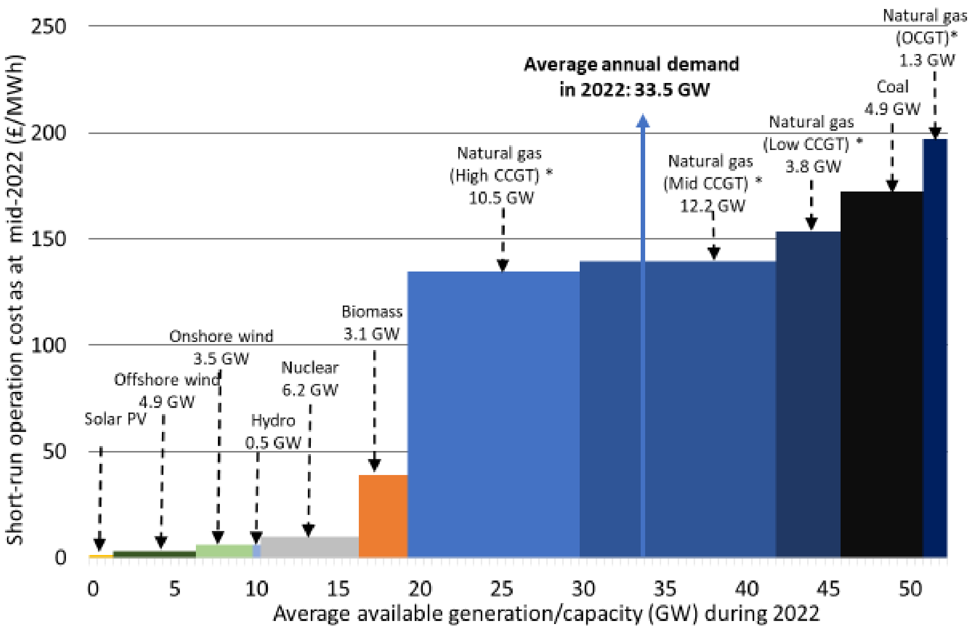
The 'marginal cost curve' is already split

The second is to recognize that most electricity systems are actually already split in terms of generation investments. No UK nuclear stations have been funded through 'the market'. The remarkable expansion of renewable energy, and its cost reductions, have been almost entirely financed through additional mechanisms to support investment. Some of these have indeed been, in effect, an add-on subsidy—premium feed-in tariffs (FiTs) or the UK's Renewables Obligation Scheme. But the most efficient have been those that provide long-term price security—fixed FiTs or contracts for difference (CfDs)—especially where competitive auctions are used.

Moreover, these generators have low or almost no marginal operating costs. The figure below shows the GB electricity 'merit order' structure (ranking based on generators' short-run operating costs per unit output: vertical axis) plotted against their average annual output (for renewables) or available capacity (for thermal plant) in 2022 (horizontal axis). The striking feature is that, aside from biomass, it is not remotely continuous: compared to the average demand (33.5GW), the system was split almost evenly between plants that cost very little to run and gas generation. The market structure, of course, meant that gas set the price. Econometric studies indeed show that in 2021, gas set the price 98 per cent of the time in the UK despite being only 40 per cent of generation.[12] Therein lay the great energy 'winter of discontent', and the reorientation of the UK Review of Electricity Market Arrangements towards a wider range of fundamental questions.

[12] Zakeri, B., Staffell, I., Dodds, P. E., Grubb, M., Ekins, P., Jääskeläinen, J., Cross, S., Helin, K., and Castagneto Gissey, G. (23 July 2022), 'Energy transitions in Europe—role of natural gas in electricity prices', SSRN, https://ssrn.com/abstract= 4170906.

Figure 1: Merit order of electricity generation in Great Britain in mid-2022



* CCGT = Combined Cycle Gas Turbines (respectively high, mid and low efficiency); OCGT = Open Cycle Gas Turbines. Different colours indicate different energy resources

Source: Grubb, M. (2022), Navigating the Crises in European Energy: Price Inflation, Marginal Cost Pricing, and Principles for Electricity Market Redesign in an Era of Low-Carbon Transition, https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/ucl_isr_necc_wp3_with_cover_final_050922.pdf.

Notes: The figure is based on approximate short-run marginal costs in mid-2022. Capacity values given are based on the average availability and capacity factors of each technology. Costs are the sum of variable Operation &Maintenance, fuel, and carbon costs (as applicable), with data from UK government.[13]

So it will help to drop the rhetoric and concentrate on the substantive questions. Do we want short-run marginal prices applied to all generation and all consumption, or do we differentiate—and if so, why and how? And, if investment structures reflect long-run marginal costs, do we want these to relate to consumer pricing—and if so, how?

Return to fundamentals

The questions above refer to what we want, not efficiency, because efficiency has many meanings and can be delivered in many ways. J. R. Nelson noted 60 years ago in the *American Economic Review* that 'no method of economic analysis can determine, scientifically, what to do about the gap between average and marginal cost'[14]—which, in practice, can be read as the gap between long-run and short-run marginal cost. And efficiency has become synonymous with Pareto efficiency, which essentially is blind to distribution: people can die from high winter energy prices and economics can still call the energy market Pareto-efficient. Ordinary human beings, and politicians, would not—a lesson underlined yet again by the energy crisis, and responses to it, which at one point threatened the 'single electricity market' itself, and even the political fabric of the European Union.

There are two intellectual debates, with two obvious links between them—links which become all the more important in the face of an accelerated transition towards renewables.

[13] Digest of UK Energy Statistics – Data Tables https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1135950/DUKES_2022.pdf: Installed capacity per technology (thermal) DUKES 5.11, costs of fuels from DUKES 3.2.1, Operation & Maintenance costs from BEIS, carbon cost assumed at 80 £/tCO2, capacity factors from DUKES 6.3. Availability factors for thermal generation assumed at 0.9 (https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020).

[14] Nelson, J. R. (1963), 'Practical applications of marginal cost pricing in the public utility field', *American Economic Review*, 52(3), 474–481, https://www.jstor.org/stable/1823888#metadata_info_tab_contents.

The first is that least-cost should imply capital efficiency for the huge investments required. The simplistic economic theory that high infra-marginal rents should attract adequate investment, supported by long-run hedging, is the worst kind of theory. It fails in terms of all the empirical evidence, it embodies the dubious assumptions that there are no significant barriers to entry and that incumbents have no market power, and it neglects the more sophisticated recognition that efficiency is also about efficient allocation of risks. Most fundamentally, many of the risks facing low-carbon investments arise from political risks—the geopolitics of fossil fuel prices and political choices around carbon pricing, interconnector investments, capacity markets, planning rules, etc.—all of them potentially subject to policy cycles.

It is not obvious that hedge funds, offering investor protection against these policy, political and geopolitical uncertainties, should be amongst the major beneficiaries of the energy transition. If governments today want efficient investment in goods which mix public and private benefits (like low-carbon investment), it is eminently sensible for them to underwrite many of those risks through contracts rather than expecting markets to do so. The EU debate has talked up the potential of private sector Power Purchase Agreements, which indeed have an important role to play. But the fact that the EU debate is now considering government underwriting of counterparties for Power Purchase Agreements illustrates the limits, and intellectual contortions, of expecting markets to deliver the required scale of public goods investment, or to do so efficiently—particularly for low-carbon sources for which cost-of-capital is paramount.

The future is coming fast

Consequently, in economic terms the gap between short-run and long-run marginal costs will only increase, certainly in volume terms. Few seem to fully grasp the scale of what is coming. In both the UK and the EU, non-fossil generation is expected to account for more than 75 per cent of generation by 2030—*within seven years*. The currently fossil-fuel-price-setting marginal cost curve element of the figure above is not only migrating rapidly to the right, it is on a trajectory to phase-out, in the sense of reflecting the operational costs of fossil fuel generation. The rhetorical question for electricity markets as currently conceived is, therefore, for how long can the disappearing fossil fuel tail continue to wag the dog of a renewables-based electricity system?

The question is rhetorical in the sense that efficient dynamic scheduling of the dispatchable on-demand plants will become even more important, not less. Around half the projected generation (again, in both Britain and the EU) by 2030 will be variable—wind and solar. A short-run wholesale market is needed more than ever, but it has to adapt to accommodate the maturing of the adolescent renewables. Over time, its' composition should transition from fossil fuels to flexible 'on demand' low carbon generation and grid-connected storage – but that cannot happen overnight.

For such a system, therefore, and especially during the coming decade of transition, the big question surrounds the 'short-run-marginal-pricing … *on all*'. It already does not apply to all generators—for which there is minimal loss of operational efficiency, since those on FiTs or two-way CfDs are mostly variable and non-dispatchable 'must run'. A great deal of angst has been expressed about the problems that would arise if short-run-marginal-pricing signals were lost to consumers. One—inadequate—answer could be to note that some types of consumers/consumptions in fact have little flexibility to respond anyway.

Green power pools combined with operational consumer price signals

A 'dual markets' approach based on a Green Power Pool (GPP), or indeed pools, of renewable generators can feed through the cost of renewables generation (at the average contract price, i.e. reflecting the long-run marginal cost/contracted strike-price), supplemented by purchases from the wholesale market when demand exceeds the available renewable energy. The result is that consumers pay overall the average cost of the generation—a combination of the renewables plus balancing purchases to ensure reliable supplies. The marginal price required to ensure reliability is added to the consumer bill, but only for consumption above the volume of renewables available. To maximise efficiency, where feasible this would be passed through on a real-time basis, creating short-run incentives for consumer flexibility.[15]

[15] For details of design and associated contract structures, see Grubb, M., Drummond, P., and Maximov, S. (2022), *Separating Electricity from Gas Prices through Green Power Pools: Design Options and Evolution*, Navigating the Energy-Climate Crises Working Paper #4, https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/navigating_the_energy-climate_crises_working_paper_4_-_green_power_pool_v2-2_final.pdf

Indeed, the full incentive structures usually associated with the wholesale market alone can be preserved, to the extent that the 'retail system' (large consuming organizations and suppliers linking through to households and smaller consumers) can develop to handle two-tier pricing contracts. Those contracts would have a volume associated with the 'as available' renewables generation, plus full incentive to develop flexibility to reduce reliance on the 'on demand' wholesale/fossil fuel market, especially when spot prices in the latter are high.

Consumer access to a green power pool with assured prices – who could benefit and how?

The key remaining issue, then, is how consumers should benefit from such a GPP and dual market structure—in terms of access to electricity equivalent to the GPP renewables generation, in each hour, at an assured price derived from the renewables contract prices (obviously with add-ons for network and other expenses). There are essentially three options.

1. The electricity at this price could be made available to all suppliers, in proportion to their overall customer base. The obvious challenge would then be how to ensure that suppliers do pass on the costs appropriately. Paradoxically, if suppliers adopt marginal cost pricing logic in their sales, they, not consumers, would end up taking the inframarginal rents—much in the way that generators made big profits from free emission allowances in the EU Emissions Trading Scheme whilst selling at marginal prices. So some element of price regulation would seem necessary.
2. The cost and volume of the GPP could be used to set the base block of household 'rising block' tariffs—a new take on an old idea of enabling everyone, including the poorest, to access a certain amount of electricity at affordable prices. The normal rationale is a broad equity argument grounded in the presumption that richer people consume more electricity. In this case, a base supply at the GPP assured price would, more broadly, have the effect of reducing the exposure of all consumers to price volatility associated with fossil fuels.
3. The beneficiaries of a GPP could be prioritized, particularly in a period of high fossil fuel costs and transition away from them, in terms of specific consumer groups. This amounts to a form of social tariff. There are many variants of proposals for social tariffs, most involving fiscal subsidies to identified 'fuel poor' groups, based on ethical and political rationales. These generally have to face the realities of relying on direct public finance, in the hands of treasuries—with the consequent risks that treasuries may remove such support at any budget, or (in contrast) that once established, politicians may chase votes by promising ever wider and more generous social tariffs, leading to general energy subsidies with all the known problems these generate.

The core difference, therefore, would be that a social tariff derived from a GPP would operate independently of the Treasury and be self-constrained by the volume of available renewable energy. It would provide a degree of price assurance to a targeted group of consumers, whilst the inevitable pressures to expand would become directly tied to the objective of accelerating the volume of renewables for purposes of decarbonizing the electricity system. Ethically, an additional argument would be that since the subsidies required to launch renewables at scale were funded through a fixed (and hence regressive) consumer charge, there is a clear ethical logic for saying that poorer consumers should be the first to benefit from the resulting revolution in the cost of renewables.

Establishing a GPP (or more than one) would not be a trivial step, but nor need it involve massive disruption. A GPP associated with renewables on CfDs has the advantage of linking it to a pool of renewables of known price (declining sharply) and volume (rising rapidly), for which existing government underwriting gives a prima facie case for government to determine how the economic benefits should be fed through to consumers. In the UK—given that fact, and the existence of associated institutions (like the Low Carbon Contracts Company, the government-backed counterparty to CfDs)—a CfD-derived GPP could be established quite rapidly, with varied options as to how much it affects electricity market trading itself as opposed to primarily financial rewiring.

Aside from the details of different design and implementation options, the aim remains the same: to start connecting consumers more directly to the predictable cost of renewables—the main body of our future electricity system—rather than having all consumption tied to the declining and likely volatile tail of fossil fuel costs.

REFORMING ELECTRICITY MARKETS FOR HIGH RENEWABLE PENETRATION

David Newbery

The UK government's Review of Electricity Market Arrangements (REMA) consultation is a response to the government's 2021 objective of decarbonizing the UK's electricity system by 2035, with ambitious targets to be met by 2030. It made the following case for review:

> We do NOT consider that existing market arrangements are likely to deliver our ambition for a decarbonised and secure electricity system by 2035 at *least possible cost* to consumers, and put us on a pathway to a (sic) meet our 2050 net zero target. We therefore conclude that there is a strong case for change.[16] (emphasis added)

The main argument of this note is that quite modest changes can be made very quickly to deliver most of the required changes to the market design. It is also desirable to consider and start the process of making more radical changes that will make the electricity market better suited to longer-term challenges, but there is no need to scrap most of the current features of the market while making these more radical changes. The central point is that much, perhaps all, of the required improvements can be made by careful modifications of long-term contracts, with both National Grid and with those for renewable electricity auctioned by the UK government.

Since the consultation was launched, the urgency of dealing with the current energy crisis has prompted calls for immediate and more radical changes. This note concludes with policy recommendations that would address the current energy crisis without disturbing the longer-run market and institutional design arrangements.

The key features of the present market arrangements worth keeping are

- the use of (and timetable for) auctions for renewable energy, which to date have been remarkably successful in driving down delivery costs, but need to increase delivery,
- the predictable payment stream the auction delivers, enabling secure low-cost finance (mainly bonds) and hence lowering the delivered cost of electricity,
- a capacity auction to procure adequate de-rated capacity for security of supply,
- continued refinements to the pricing and procurement of ancillary services for reliability and flexibility,
- a locational cost-reflective generation transmission tariff methodology, and
- retention of real-time prices set at the marginal cost of acquiring power.

Modest changes to the design of the contract for difference with feed-in tariff (CfD with FiT) (described below) for variable renewable electricity (VRE), i.e. wind and photovoltaic (PV), can address some of the flaws in existing contracts and make holders more market responsive. Network charges can also be easily adjusted to improve investment location signals. Both reforms could (and should) be introduced before the next round of renewables auctions. The following sections set out these reforms in more detail.

The size of the decarbonization challenge

The size of the challenge of decarbonizing electricity by 2035 is clear:

> Our scenarios indicate that around 300 GW of capacity could be needed by 2035, up from around 100 GW today. That means that over 10 GW of new capacity is required on average each year until 2035, against an historical average of 5–6 GW.[17]

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[16] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements, 43.
[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1098100/review-electricity-market-arrangements.pdf p27

More granular detail is provided in the April 2022 British Energy Security Strategy.[18] The latest auction for renewable electricity ran on 7 July 2022,[19] and secured 10.8 GW to be commissioned over many future years. These commissioning volumes can be compared with the target rate of expansion from the National Grid's Future Energy Scenarios,[20] and suggest that unless future auctions deliver substantially more capacity and/or auctioned volumes are commissioned more quickly, the 2030 targets will be substantially missed. The largest volume procured was for offshore wind (which takes considerably longer to commission), but total procurement is running at about half the rate needed to meet the 2030 targets.[21]

While Scotland procured onshore wind, England and Wales ignored this low-cost renewable resource,[22] reflecting the current government's hostility to onshore wind. The Climate Change Committee recommends that the UK should more than double its onshore wind capacity from 14.2 GW now to 29 GW by the end of the decade. That implies an urgency in overcoming political and local opposition to onshore wind as soon as possible.

Reforming the CfD with FiT for renewable electricity

Under the current CfD with FiT, a successful bidder receives the clearing strike price s £/MWh on metered output for 15 years from commissioning. Thus in the July 2022 auction, onshore Scottish wind received a strike price of £$_{2012}$42.47 = £$_{2022}$53.94/MWh, considerably below the 2022 wholesale price. The developer is responsible for selling output in the market (or to an off-taker) and receives (or pays, if negative) $m_h(s - p_h)$ where m_h is metered output in hour h, and p_h is the reference (day-ahead) wholesale price in that hour.

This contract has a number of disadvantages. First, there is no incentive for the developer to respond to real-time market prices, for example by offering to reduce output to assist in balancing, or to hold some capacity back to offer flexibility services, either of which might be more valuable to the system than the day-ahead price suggests. There is also an incentive to generate when prices are below the avoidable cost of generating, as the strike price will be higher than this. Worse, it can encourage production when the real-time price falls to or below zero, risking that a dispatchable plant might close down and start up at considerable cost, when the economic cost of suspending output from VRE is at or near zero.

The CfD with FiT can be revised easily to avoid these problems by copying the format of conventional CfDs. A standard CfD is a purely financial contract that pays the strike price s on an agreed volume, M, regardless of whether producing or not. The generator decides to generate solely guided by the spot price as the CfD pays $(s - p)M$ when the market price is p, and the generator makes profit $(s - p)M + (p - c)y$ if producing y when the avoidable cost c is below the market price, and if $p < c$, does not produce, and avoids making a loss $(p - c)y$ by setting $y = 0$, just receiving $(s - p)M$.

The solution is to make the VRE contract payable not on metered output, but on day-ahead forecast output of that technology at that location. The developer would designate a preferred forecasting agency to provide day-ahead hourly forecasts of the capacity factor θ_{rh} for its own technology (using power curves and weather forecasts) at its location r in hour h. The generator would secure a yardstick contract in the periodic renewable auction at the strike price s for capacity K. The proposed yardstick CfD (YCfD) would pay $(s - p_{rh})\theta_{rh}K$ when the spot price is p_{rh} (in hour h, location r). (In the absence of nodal pricing, $p_{rh} = p_h$. Nodal pricing, also known as locational marginal pricing, LMP, is one of the more radical solutions and would take some years to implement.)

There is another potentially undesirable feature of the fixed-length (15 years) CfD with FiT. To an approximation, the capital cost of VRE is independent of location, and so over a fixed number of remunerated MWh the present discounted value of revenue will be almost independent of location and hence more closely aligned with the capital cost. (Higher capacity factors will deliver that number of MWh more rapidly and hence will have a slightly higher present discounted value.) If the lowest capacity factor

[18] Department for Business, Energy & Industrial Strategy (2022), *British Energy Security Strategy*, https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy.
[19] See https://www.gov.uk/government/news/biggest-renewables-auction-accelerates-move-away-from-fossil-fuels.
[20] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[21] FES, 2022 at https://www.nationalgrideso.com/future-energy/future-energy-scenarios. The calculations are based on the Consumer Transformation scenario, which does not hit the Department for Business, Energy & Industrial Strategy off-shore wind target until 2035. (Only the ambitious Leading the Way scenario achieves that.) The target capacities are only given for 2030. The implied annual increments are based on projected output but smoothed.
[22] The UK Department for Business, Energy & Industrial Strategy (2022, *British Energy Security Strategy*) admits that on-shore wind is the cheapest renewable electricity.

sets the clearing price, and if the contract is for a fixed number of years, higher-capacity-factor VRE farms will earn higher revenues and hence higher (infra-marginal) rent. If instead the contract were for a fixed number of MWh/MW of capacity (i.e. for a fixed number of full operating hours, e.g. 40,000) then the advantage of the higher capacity factor would be much reduced, reducing infra-marginal rents and hence the cost of the auction.

Contracts signed under the Renewable Obligation (RO) scheme that continued until about 2017 added (and continue to add) about £50/MWh to the wholesale price, thus over-rewarding development of high-capacity-factor VRE in distant onshore windy locations (such as the west coast of Scotland). This would still be a problem if the CfD with FiT contract length were specified in years when the support price is above the expected output-weighted wholesale price (as it is likely to be when VRE begins to saturate demand).

There are two additional challenges that VRE contracts must handle—how to deal with and pay for curtailment and local congestion. Curtailment arises as an inevitable consequence of high VRE penetration levels, as peak-to-average-output ratios are 3–4:1 for wind and 9–11:1 for PV. As VRE penetration increases, they will produce more than demand in many hours. The REMA consultation found that by 2035 prices could be driven to zero 50 per cent of the time as a result of surplus (spilled) VRE.[23] When VRE is in country-wide surplus (after exporting when neighbouring countries are not saturated, and injecting into storage until full), the efficient wholesale price should fall to the avoidable cost of the marginal curtailed generator (zero for PV, £4–10/MWh for wind).[24] YCfD holders would still receive the excess of the strike price over the (low) day-ahead market price on their (high) forecast output, but would choose not to generate if the real-time price falls below their avoidable cost—in effect, they would self-curtail. If they were instructed to curtail, they would still receive the contract payment *less* their avoidable cost (to be specified in the YCfD contract), as their contribution to their (capped) capital finance cost, the recovery of which ensures a low finance cost.

Congestion arises because the network has limited capacity and cannot export the output from specific locations. With nodal pricing this is not a problem, as the effect would be the same curtailment, but under the current zonal pricing the day-ahead price might be quite high, and if VRE is constrained off under the YCfD it would only receive a smaller amount (or might even have to pay back). The simplest solution under zonal pricing would be to pay the lost profit, as with existing constraint payments needed for conventional CfDs. The ‘full operating hours’ during this period would in both cases be the forecast output per MW, relevant for an output-defined contract (and a further argument for that contract form).

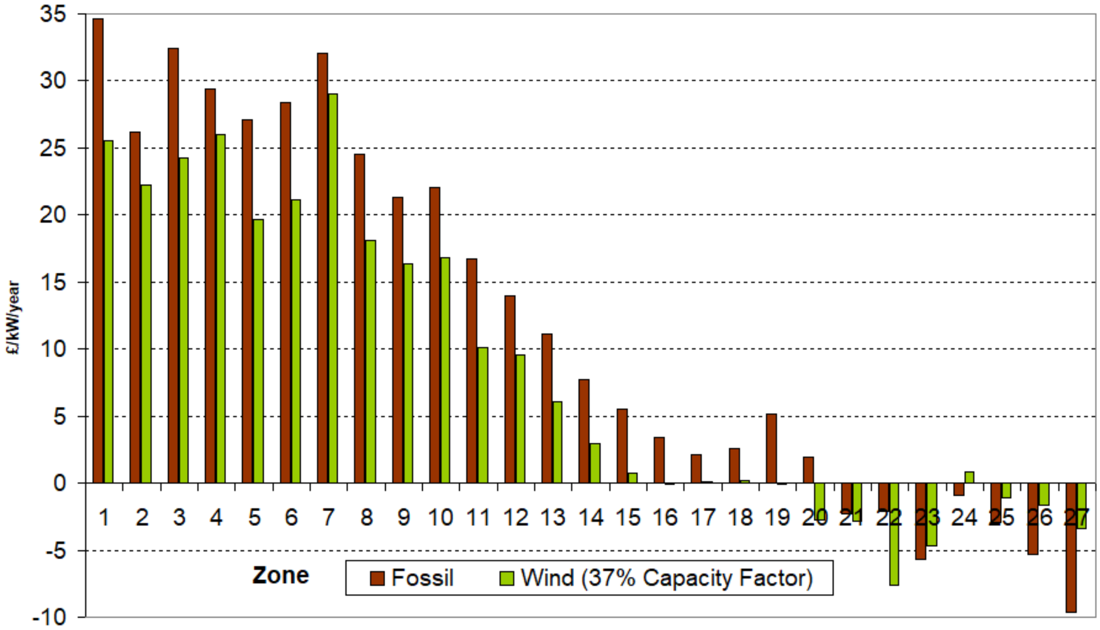
The combined result of these two changes would be a YCfD (the REMA consultation called these ‘deemed’ CfDs) that would pay $(s - p_{rh})\theta_{rh}K$ when the spot price is p_{rh} (in hour h, location r) for the first N MWh/MW (i.e. full output hours), where p_{rh} indicates that if at some date nodal pricing is introduced the contract would not need changing.

Reforming transmission pricing

If there is to be a single auction clearing strike price, s, for each technology category, then it will be important to give the right locational guidance for the investment decision, and that requires simple changes to Transmission Network Use of System (TNUoS) charges. These charges should be set to guide investors to the locations that minimize total system cost (generation and transmission). At present any generator connected to the transmission system pays a zonal TNUoS charge.

[23] see figure 5, p38 of the REMA Consultation at https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[24] Department for Business, Energy & Industrial Strategy (2020), *Electricity Generation Costs 2020*, https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020; National Renewable Energy Laboratory (2018), *Offshore Wind Energy International Comparative Analysis*, Technical Report NREL/TP-6A20-71558, https://doi.org/10.2172/1483473.

Figure 1: Transmission network use of system charges 2021-2022



Note: zones run broadly northeast to southwest, from zone 1 in north Scotland to zone 27 in Cornwall. Negative charges imply payment to the generator if generating in peak (Triad) hours.[25]

Source: National Grid Electricity System Operator (2022), Final TNUoS Tariffs for 2022/23, https://www.nationalgrideso.com/document/235056/download.

The figure above shows the variation in TNUoS charges across Great Britain for base-load and a 37 per cent capacity factor wind generator. The TNUoS charges are set by National Grid's Investment Cost Related Pricing methodology, set out in Section 14.14.6 of the Connection and Use of System Code:[26]

> The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

This is correct in theory, but the actual charges suffer from two serious faults. First, the charges to all users are changed annually to reflect changing demands on the network, even to existing plant that cannot relocate. Major TNUoS changes each year are discouraged as they would undermine the predictability of future grid charges and increase investor uncertainty. Within each price control period of five years there is considerable stability and predictability. However, the rapid rate of VRE expansion will lead to local congestion, and TNUoS charges will need to change to steer entrants away from export-constrained zones, making lifetime charges uncertain.

The second problem is that Investment Cost Related Pricing assumes that the network can be immediately and incrementally resized to optimize system costs. In practice, network enhancements take many years to deliver, and for that reason (and inherent lumpiness) are initially over-sized to be suitable for a reasonably long term (the present grid was largely completed in the 1960s). In sum, at any date network charges are unlikely to give the right entry signals.

[25] Triad hours are the three half-hours of highest system demand separated by 10 days used to set demand charges
[26] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc

The solution is simple, and already applies to the charges set by Offshore Transmission Owners for using the transmission from the offshore wind farm to the onshore connection point. These charges are set for a period of 20 years. The solution is to offer 15- or 20-year contracts at a fixed cost at each node on the onshore network, adjusted as in the preceding figure (which contrasts fossil baseload and wind) to reflect the different demands different types of plants make of the system. These contracts could be adjusted each year for the next round of entrants without affecting existing contract holders (who, after all, cannot relocate once they have invested).

The developers of mature VRE (like onshore wind, PV, and increasingly offshore wind) would now know on entering the auction almost exactly what their predicted revenue and costs would be over the life of the contract, on the back of which cheap bond finance should be readily secured.

Addressing the current energy crisis

Many commentators have argued against marginal cost pricing and suggested more or less abandoning the current market design completely.[27] Their appealing argument is that VRE and nuclear power have very low marginal (and in some cases lower average) cost than the price set by the marginal carbon-inclusive gas and coal plant, and that the considerable infra-marginal rents they earn should be passed on to consumers through the ‘as available’ market, leaving the dispatchable power to be bought on a separate market to make up any shortfall.

This two-market solution is quite unnecessary, certainly for any future new nuclear power financed by the Regulatory Asset Base (RAB) and for all existing CfD with FiT contracts, whose counterparty, the Low Carbon Credit Company, already receives the difference between the wholesale and strike price. As more new entrants are covered by long-term contracts, any infra-marginal rents will become available to the public sector automatically. A sensible new market design can be simply characterized as one with competition *for* the market (via auctioned long-term contracts) followed by competition *in* the market (with marginal pricing).

The infra-marginal rents can be passed back to consumers via equivalent long-term contracts, adopting a stepped tariff of the kind long in use in e.g. California, which increases the tariff above a baseline.[28] At the next re-setting of the tariff (presumably on 1 April 2024), the government could announce that the first 200 kWh/month (or 2,400 kWh/year) would be at the low capped rate, but that all consumption above that rate would be at wholesale-related rates. The regulator might also cap this additional rate based on forward contract prices as with the previous capped system, but one might equally argue that retailers could compete to offer better marginal rates (subject to close scrutiny of their financial ability to make such offers, based on their collateral and contract positions). Alternatively, or in addition, those with heat pumps could be offered a low-carbon contract, perhaps subject to being locally dispatched.

Retaining marginal pricing is critical for incentivizing efficient energy dispatch and use, notably for time-of-use pricing, which will be attractive to some (larger) consumers with schedulable load. The aim of good market design is to provide good hedges to reduce risk and cost while preserving short-term market signals. This is already the case through the CfD market for large loads, and can be extended to cover the rest of the market with some creative contract design.

Whether it is legal or feasible to impose new and closer-to-average-cost contracts on existing but initially subsidized generators is unclear, at least to this author. The current buy-out price for the 2022–2023 obligation period is £52.88 per RO certificate,[29] which is added to the current very high wholesale price for renewables holding RO contracts (before 2017 but continuing in some cases to the 2030s). As a first step, if legal, the RO certificate market price could be driven to zero by removing the obligation for suppliers to buy RO certificates. More generally, as the excess of RO contracts over the original cost of the VRE is publicly paid for, one might argue that they are no longer in the public interest and should be referred to the Competitions and

[27] E.g. Grubb, M. G. (2022), *Navigating the Crises in European Energy: Price Inflation, Marginal Cost Pricing, and Principles for Electricity Market Redesign in an Era of Low-Carbon Transition*, https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/ucl_isr_necc_wp3_with_cover_final_050922.pdf; Keay, M., and Robinson, D. (2017), *Market Design for a Decarbonised Electricity Market: the ‘Two Market’ Approach*, Oxford Institute for Energy Studies, https://www.oxfordenergy.org/publications/market-design-for-a-decarbonised-electricity-market-the-two-market-approach/; Keay-Bright, S., and Day, G. (2022), *Rethinking Electricity Markets—EMR2.0: a New Phase of Innovation-Friendly and Consumer-Focused Electricity Market Design Reform*, https://es.catapult.org.uk/report/rethinking-electricity-markets-the-case-for-emr-2/.

[28] E.g. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-1.pdf.

[29] https://www.ofgem.gov.uk/publications/renewables-obligation-ro-buy-out-price-mutualisation-threshold-and-mutualisation-ceilings-2022-23.

Market Authority to be reset. Price controls for regulated assets (like the grid) are long-term contracts subject to inspection and re-setting if no longer in the public interest at each price control date. All nuclear stations are held by EDF, who wishes to sign an RAB contract for Sizewell C. Perhaps they could be persuaded to accept similar RAB contracts for existing plant.

A second step would be to abolish the Carbon Price Support that adds £18/tonne CO_2 to the UK Emissions Trading System price, and replace it with a carbon price tax that rises at a predetermined (carbon-target-consistent) rate, providing more stability and predictability to its future level. The current Carbon Price Support again gives unjustified infra-marginal rent to all low-carbon generation without CfDs with FiTs (including biomass).

The final, and perhaps only legal, solution is a windfall tax on all RO certificate-issuing companies, and perhaps also on existing (and largely amortized) nuclear assets.

Summary

There is no need for some of the more radical reforms suggested to the current wholesale market, merely a continuation of the direction of travel towards more competition *for* the market followed by competition *in* the market. Minor adjustments to the CfDs with FiTs and TNUoS tariffs could achieve most of the immediately available gains of more efficient location choices and more market response. Longer-term desirable changes to introduce nodal pricing and perhaps an Independent Design Authority (to proactively coordinate transmission and generation locations) could be set in motion, as they will take longer to deliver. The role of the Low Carbon Credit Company could be usefully clarified, and the balance and level of levies on electricity reconsidered—particularly as gas is exempt, distorting the shift to low-carbon heating. Short-term fixes to address the current energy price crisis should ideally preserve incentives at the margin to respond to high prices while providing support for a fixed number of kWh per month (or year) to domestic customers without overcompensating the wealthy.

ARGUING OVER THE FUNDAMENTALS OF MARKET REFORM IS UNDERMINING INVESTMENT AND IMPEDING THE ENERGY TRANSITION

Robert Gross

In July 2022 the then UK Department for Business, Energy and Industrial Strategy (BEIS) opened a public consultation on prospective reforms to the wholesale electricity market for Great Britain. (The focus on Great Britain rather than the UK reflects the fact that the island of Ireland operates an integrated all-Ireland grid, with different market and regulatory arrangements.) The consultation was announced in the British Energy Security Strategy, launched in April 2022 as part of the government's response to unprecedented energy price rises.[30]

However, the consultation known as REMA—the Review of Electricity Market Arrangements—had been long planned and pre-dated the crisis, originating in a 2020 *Energy White Paper* that instigated a review of the future of renewable support schemes.[31] This was described in incrementalist terms, with the white paper referring to an 'evolution of the electricity market [which] will seek a balance between options for further reform of the market with maintaining the success of the CfD.'[32] The CfD (contract for difference) is the UK's principal support scheme for low-carbon energy, and offers a long-run fixed price contract to eligible generators.[33]

It is instructive to recall the context in which that original consultation was launched, and its scope. In the run-up to 2021's UK Presidency of the United Nations Climate Change Conference (COP26), and in a period of low energy prices where policies were focused on post-Covid economic stimulus,[34] the energy white paper included new targets for offshore wind, retail market

[30] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1098100/review-electricity-market-arrangements.pdf.
[31] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf.
[32] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf, page 47.
[33] https://www.lowcarboncontracts.uk/contracts-for-difference-cfd.
[34] https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution.

proposals aimed at encouraging switching, and new funding for carbon capture and storage, hydrogen, and floating offshore wind.[35] A major focus was green jobs. It paid little attention to wholesale market design. Indeed, a principal theme was how successful existing schemes had been at expanding renewables whilst reducing their costs. The associated consultation document hinted at the possibility of more radical changes, but it also included a section asking about how the CfD scheme could do more to promote industry and growth in disadvantaged regions.[36] This suggested that whilst radical changes might be mooted, they were not being taken particularly seriously.

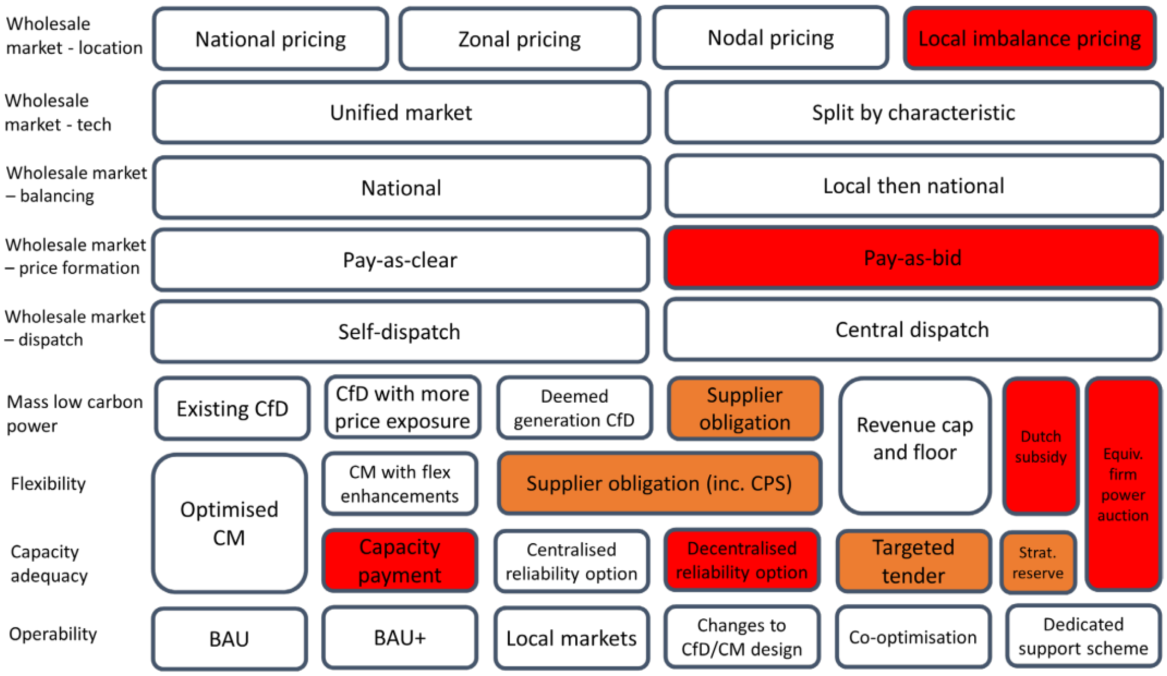
Back in 2020 this commentator expected minor changes, certainly in the short or medium term, and a strong focus on incremental improvement aimed at delivering policy goals. The government had just placed offshore wind at the heart of a 'green industrial revolution' and set a target to quadruple its installed capacity in just 10 years.[37] It seemed self-evident that above all else officials would not want to undermine the investment needed to mobilize on the order of £60 billion in new investment. It would not have been surprising if the entire REMA process was confined to relatively minor adjustments with a largely successful support regime, known as electricity market reform, brought into being in 2013.[38]

The policies created through electricity market reform have been associated with significant reductions in the prices paid for renewables, ongoing expansion of renewables, development of a new nuclear power station, falling CO_2 emissions, and healthy capacity margin (a widely used, if simplistic, measure of power system reliability). A cap-and-floor scheme introduced in 2014 helped to secure new interconnections to mainland Europe,[39] and a range of new service contracts created by the Electricity System Operator (National Grid ESO) have seen the emergence of around 2.5 GW of grid-connected batteries.[40]

Despite the gradualist language of the original consultation, the 2020 call for evidence on renewable support schemes grew into 2022's wide-ranging review (REMA). This considers more than 30 options for electricity market/incentive reform, many of which are profound and far reaching, requiring fundamental changes to the operation of the wholesale market. The figure below reproduces BEIS's representation of all the options discussed in the REMA consultation document. In March 2023 the new Department for Energy Security and Net Zero published its summary of responses to the REMA consultation, to which 225 groups and individuals responded. In its response, the Department only ruled out six options. Despite a majority of responses being against zonal or nodal locational marginal pricing (LMP), these remain under consideration, as do a wide range of changes to the CfDs, so-called split markets, and a move from self-dispatch (market arrangements in place since 2002 in Britain based upon bilateral contracts between generators and suppliers) to centralized despatch (single buyer model).[41]

[35] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf.
[36] https://www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence.
[37] https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution.
[38] https://www.legislation.gov.uk/ukpga/2013/32/contents/enacted.
[39] https://www.ofgem.gov.uk/sites/default/files/2021-09/Regime%20Handbook.pdf.
[40] https://www.nationalgrideso.com/document/157791/download.
[41] https://fsr.eui.eu/regulatory-models-in-the-power-sector/.

Figure 1: Options for renewables support discussed in REMA (red represents options discounted as of March 2023 orange items are partially included)



Note: CM: Capacity Market, BAU and BAU+ refer to 'Business as Usual'

Source: Department for Energy Security and Net Zero (2023), *Review of Electricity Market Arrangements*, p. 9, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1140189/review_of_electricity_market_arrangements_summary_of_responses.pdf.

The decision space: open-minded but unrealistic?

In some respects, it is welcome that the officials managing the REMA process have been open-minded. This allows a wide range of prospective changes to the electricity market to be debated. The issues REMA seeks to tackle are significant: current policies do not provide enough support for investment in new sources of flexibility such as longer-duration storage, and network constraints are impeding progress and creating inefficiencies, whilst the presence of large volumes of renewables creates a phenomenon known as price cannibalization.[42] The unprecedented rise in gas prices has also led to increasing emphasis on the potential for a renewables-dominated power system to offer lower and more stable prices, if only the gas-to-power wholesale power price link, described by one former UK prime minister as 'ludicrous',[43] could be broken.

The problem is that it is difficult to square a wide-ranging and largely open review of all imaginable power market redesign options with high-level political commitments to an unprecedented increase in the installed capacity of renewables in an equally unprecedented short time. The documentation around REMA has stressed the importance of maintaining investor confidence and avoiding an investment hiatus.[44] Government has committed to maintain forthcoming CfD allocation rounds. However, as yet no timeline has been attached to the potential implementation of any of the options that would require fundamental changes to the design of the wholesale market. This is at odds with the desire to maintain investor confidence. Prospective investors now do not have a clear view of whether market design changes will be implemented during the investment horizon of future projects entering the development phase now.

The debate about market design is also taking place in a wider context in which the entire energy system is in a state of transition. In its contribution to the first BEIS consultation, UK Energy Research Centre (UKERC) described this as a

[42] https://imperialcollegelondon.app.box.com/s/028irer6xb67qodf7ll991ul1wfbcshp.
[43] https://www.edie.net/boris-johnson-planning-energy-market-shake-up-to-end-ludicrous-electricity-prices-for-homes-and-businesses/.
[44] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1098100/review-electricity-market-arrangements.pdf.

conflagration of 'non-equilibrium risks[45]'. These pertain to systems that are in a state of flux, shifting to substantially different infrastructure for supply and different patterns of demand, with many of these changes driven by policy, and very little historical pricing information to inform future investments.[46]

The UK has a tradition of grandfathering investment and avoiding retroactive rule changes, but the complex interactions between incentives, wholesale market design changes, management of constraints, and other factors mean that REMA is already creating considerable policy risk for future investments. The simplest way to minimize this would be for officials to delineate a timeline during which the more far-reaching changes are off the table. This would also introduce a welcome dose of realism into the deliberations, since changes that require primary legislation will require years to even begin to implement.

The case for an incremental approach

For at least the next 10 years the non-equilibrium risks are substantial. They are unavoidable if we are to get substantially onto a trajectory towards zero-carbon electricity during the 2030s, meet stated policy goals such as the target of 50 GW for offshore wind, deploy 600,000 heat pumps per year, and phase out petrol cars.[47] The policy-dependency of many of these risks makes them potentially unsuitable to be wholly managed by the private sector. The rate of electrification of heat and transport will be largely policy-driven and determines overall demand for electricity. Likewise, support for carbon capture, use, and storage and nuclear and other low-carbon generation options affects overall supply, whilst the build-out of flexibility options such as hydrogen and interconnectors determines price behaviour in markets. Progress with electricity network upgrades will affect constraints, hence price formation if we move to locational marginal pricing.

In 2021 UKERC undertook analysis of market price risk for a hypothetical offshore wind project developer, looking out to 2035 with a range of scenarios for energy system development based upon the Future Energy Scenarios provided by National Grid ESO. The analysis found a wide range of prospective wholesale market price formation outcomes, with substantial implications for curtailment and price capture by individual wind operators, driven largely by the availability of flexibility and overall volume of wind and solar generation on the system. The analysis concluded that, from a developer perspective, the presence of such risks in the absence of the revenue stability provided by a CfD would add up to 6 percentage points to risk-adjusted rate of return. It also found that each 1 per cent addition to the required rate of return for the offshore wind fleet envisaged in 2035 is roughly equivalent to a £1 billion per year addition to overall system costs.[48]

The early stages of the transition are perhaps the most uncertain. To tackle the transition over the next 8–15 years, a pragmatic approach would be to continue to commit to CfDs, which could be incrementally modified to introduce enhanced incentives for flexible operation or to reflect locational factors. UKERC has also mooted the possibility of widening the scope of CfDs to include legacy plants.[49] Work could take place in parallel on whether a new form of market is needed to facilitate the continuation of low-carbon investment over the long term. This could be phased in as we get nearer to a new equilibrium situation (perhaps late 2030s) and it becomes clearer what the characteristics of this new system are. An approach that sustains the CfD for the foreseeable future appears to be the direction of travel for REMA, as the government has largely ruled out the main alternative, a low-carbon obligation on suppliers (note that this is marked as orange in the figure above, reflecting the government view that obligations on suppliers could complement evolved CfDs).

Similarly, whatever the theoretical advantages of moving to LMP, it isn't possible without also moving to central dispatch in the wholesale market overall, a major change to market design that would need primary legislation. This would need to be part of the legislative programme for the next government, hence not even entering the parliamentary process until after the general election, expected in 2024, and then taking several years (assuming it is a high enough political priority for a new government to command parliamentary time). LMP has become the most hotly contested aspect of REMA—vehemently opposed by developers and generators, the Scottish government, and others, but advocated enthusiastically by some commentators, and prominently supported by National Grid ESO.[50]

[45] https://ukerc.ac.uk/publications/beis-rema/
[46] https://ukerc.ac.uk/publications/beis-call-for-evidence-enabling-a-high-renewable-net-zero-electricity-system/.
[47] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future#:~:text=The%20energy%20white%20paper%20builds,net%2Dzero%20emissions%20by%202050.
[48] https://ukerc.ac.uk/publications/zero-carbon-electricity/.
[49] https://ukerc.ac.uk/publications/can-renewables-help-keep-bills-down/.
[50] https://www.scottishrenewables.com/assets/000/002/442/SR_response_call_for_input_on_LMP__FINAL_original.pdf?1655998834; https://www.gov.scot/publications/onshore-wind-policy-statement-2022/pages/9/; https://www.nationalgrideso.com/news/new-eso-report-finds-electricity-market-reform-critical-delivery-future-system-affordable.

Apart from the time it would take to implement and political opposition, the main arguments against LMP centre on the prospective impact on generation investment risk. This is because for any prospective future generator, location-specific prices would be contingent on progress with network upgrades, whether other developers build schemes in the same location, and whether new demands/sources of flexibility also locate in the same part of the network. All these factors are outside the control of individual investors and therefore introduce uncertainty. This translates into additional risk, increasing cost of capital and hence directly increasing generation costs and consumer bills. It is possible that CfDs could be used to insulate generators from some of these risks, but that would at least partially negate the benefits of moving to LMP. Developers would also be subject to increased volume risk, because if central despatch is used to manage constraints prior to gate closure, the likelihood of being constrained off increases.

A detailed discussion of the pros and cons of LMP has been provided by colleagues at the University of Strathclyde, who point out many of the pitfalls associated with moving to central dispatch and caution against the overly simplistic idea that it represents 'the answer' to managing network constraints.[51] Analysis by energy consultants Afry has also pointed out that whilst a single buyer could help manage locational constraints, it is less able to accommodate dispatch of flexible resources.[52] Given the political sensitivities, complexities, and limitations associated with LMP, the uncategorical advocacy of National Grid ESO is difficult to understand. Whilst it may make sense for National Grid as a private actor responsible for network operation and still part of a group that appears unable to build network capacity quickly enough, the ESO is to transition to a non-profit Future System Operator with wide-ranging strategic responsibilities.[53] It is to be hoped that these responsibilities will require the Future System Operator to take a more transparent and even-handed approach in future.

A thorough discussion of LMP is beyond the scope of this paper. However, since it simply cannot be introduced quickly, it would appear pragmatic to be explicit that it is off the table for at least the duration of this decade and move on to consider alternative options for constraint management (not least overcoming barriers to the network upgrades that are fundamental to the energy transition).

Market design and the role of government in the energy transition

The alternative to an incrementalist approach is simple enough. It would be to accept that an investment hiatus is inevitable and give up on the aspiration to decarbonize electricity by 2035, and on political commitments such as the 50 GW target for offshore wind. Such an approach would give getting the fundamentals of market redesign right a higher priority than trying to meet the 6th Carbon Budget, creating jobs in offshore wind, or accelerating the transition away from reliance on expensive foreign gas described in the British Energy Security Strategy.

Back in 2010 Oxford Institute for Energy Studies fellows Phil Wright and Ian Rutledge published a book titled *UK Energy Policy and the End of Market Fundamentalism*.[54] This turned out to be highly prescient of forthcoming changes to the UK electricity market, given the much more directed approach to security of supply and low-carbon energy ushered in through the 2013 Energy Act.[55] Yet within the small community that debates the details of electricity market design, 'market fundamentalism' still appears to hold some currency. For some academic economists, and some non-academic advocates, the debate still seems to focus on the desirability of a Platonically idealized, energy-only, nodal-priced market. It is surprising how deeply engrained this view is amongst energy market economists, including those inside government and associated agencies. The view of some still seems to be that if only we could get the prices right, remove distortions, and avoid the desires of governments to pick winners, an optimized market-based solution would emerge. Politically, this does not appear to be a particularly plausible approach to an energy crisis in which every household in the country is having their energy bills subsidized by the state. It also appears to hugely overstate the capacity of private-sector actors to navigate a transition in which all the moving parts of the energy system are changing at once.

[51] https://www.strath.ac.uk/whystrathclyde/news/2023/researchersadvisecautiononrushingtoadoptlocationalmarginalpricingofelectricity/.
[52] https://afry.com/sites/default/files/2022-10/afry_review_of_market_design_in_gb_-_summary_report_final_v200.pdf.
[53] https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-future-system-operator.
[54] Rutledge, I., Wright, P., and Boardman, B., Oxford Institute for Energy Studies (2010), *UK Energy Policy and the End of Market Fundamentalism*. Oxford: Oxford University Press.
[55] https://www.legislation.gov.uk/ukpga/2013/32/contents/enacted.

Given the electoral timeline in the UK, any significant decisions about market reform will be made by the next government. In the meantime, the imperative for the REMA process should be to limit the damage to investor confidence that is already being done. The battle lines in REMA are becoming deeply entrenched, particularly over LMP. It must not become a technocratic argument far removed from the debate about household bills, energy independence, and green jobs that cannot possibly deliver realistic options for change until the middle of the next Parliament. There is no high-level political driver behind REMA's debates. Politicians are rightly focused on shorter-term concerns. The clearest signal REMA can send this side of the election is that all of the fundamental (or fundamentalist) market reforms are off the agenda for at least a decade. It should focus instead on low-regrets, cost-minimizing, problem-solving actions within the current regulatory environment that can be taken now.

CONTRACTING FOR RENEWABLE ENERGY: RETURN OF THE SINGLE BUYER?

Richard Green

Most low-carbon generators have a very stable cost structure; the events of the last 18 months make it clear that gas-fired generators do not. A market design that is well suited for one type, therefore, may produce revenues that alternate between inadequate and excessive for the other. British Energy, the UK's nuclear generator, needed a government rescue after a period of low electricity prices in the early 2000s, while many politicians have recently suggested that wind and solar generators are making too much money from power prices driven up by the high gas prices resulting from Putin's war.

There are three broad models for organizing the electricity industry. Traditionally, much of the industry was vertically integrated (at least between most of the generation and transmission in each area) and regulated or publicly owned. From the 1990s onwards (with Chile pioneering part of the model a decade earlier), wholesale markets were established in some countries and US states, with competition between generators intended to keep prices at the right level. The key point is that prices are set every day, responding to the balance between supply and demand, although many transactions have been hedged in advance with physical or financial contracts. A third possibility is the single buyer model, where the operation and revenues of independent generators are determined by the terms of their long-term contracts. The single buyer runs 'competition *for* the market', while there needs to be effective competition *in* the wholesale market for that model to work effectively.

When EU-wide restructuring was first mandated, a version of the single buyer model was allowed, but with features that made it effectively equivalent to wholesale competition, and it was not adopted anywhere. Similarly, those US states that have liberalized their electric utilities have also followed the wholesale competition model (without necessarily allowing the retail consumers choice, which is also required in most EU countries). It has been widely adopted elsewhere, as a way to introduce private investment into what is often a mainly state-owned industry.

Support for renewables

While there may be hundreds of different mechanisms supporting renewable generators around the world, we could perhaps group them into four classes in terms of their effect on the generator's revenues.

1. The *feed-in tariff* offers a fixed price to all eligible generators; if this price is too attractive, it may have to be cut or the number of generators allowed to sign up may need to be limited to control the cost of the scheme. Retrospective price cuts for existing generators should be avoided, although sudden reductions may feel almost as bad for the owners of projects under development.
2. While a generator's per-kWh revenues should be fixed (or follow a predictable formula) under a feed-in tariff, a *feed-in premium* combines a smaller fixed element with the market price. The Federal Production Tax Credit offered to renewable generators in the US is effectively a feed-in premium scheme. The premium element is (or should be) predictable, the market price less so.
3. A third group of schemes combines two revenue streams that are, at least in principle, *market based*. The canonical example is the tradable green certificate, where the supply of certificates from generators relative to the number that must be surrendered (typically by retailers) determines their price. That might be capped by the possibility of paying a buy-out charge or given a floor if the government (or its agent) commits to buying surplus certificates.

4. Finally, *auction* schemes promise fixed prices at a level determined by competition between would-be generators. These could be linked to physical contracts where the generator's output is effectively pre-sold, or the auction could set the strike price in a contract for differences (CfD). The generator still has to sell its output in the market (or via another contract), but also receives or pays back the difference between the strike price and a reference price, some measure of the market price. This should have the effect of fixing the generator's overall revenues, subject to any basis risk between the reference price and the amount actually received for its sales. Note that if there are limits on the amount that can be paid (in either direction) via the CfD, the scheme may end up as a fixed premium over (or under!) the market price.

Auctions and feed-in tariffs offer the greatest degree of revenue protection, followed by fixed-premium schemes, with market-determined premiums creating the greatest uncertainty over future revenues. Given that the return on capital is a large component of the average cost of nuclear, wind, and solar power, there are significant benefits to minimizing that cost. In March 2023, the European Commission proposed that all future support to renewable generators should be based on CfDs, and that if their strike prices are below the market price of electricity, the surplus should be returned to consumers. This is a mechanism that should reduce price risk on both sides of the market. However, auction schemes differ from the other support mechanisms in that the policymaker (or their representative) needs to make an explicit decision on how much capacity to buy. This goes against one of the main motives for electricity liberalization.

Why did we liberalize?

It is wise to be suspicious of any single-cause explanation of a policy choice, and the motives for liberalization will have varied between countries, time periods, and proponents. Nonetheless, one of the motivations for breaking up the UK's Central Electricity Generating Board was its poor record on investment, ordering too much capacity and building it too slowly (and hence expensively). The argument for privatization and liberalization is that a state-owned monopoly is under little pressure to control its costs, whereas the managers of a private company in a competitive market should know that they can only satisfy their shareholders if they make the right decisions.

Experience has proved this view slightly simplistic—many capital-intensive industries suffer from periods of over-capacity following an over-enthusiastic herd response to high prices, and companies with market power face weaker incentives to operate efficiently. Nonetheless, free entry and the fact that companies can learn from others' experiences do offer the prospect of valuable innovation. In the late 1980s, the Central Electricity Generating Board was planning to build a series of large coal-fired power stations; an entrant chose to develop a combined-cycle gas turbine instead, and the rest of the industry rapidly followed suit. In energy retailing, the entrant retailer Octopus has developed a software platform, Kraken, that is also used by several other companies (in the UK and abroad) to serve over 25 million customers.

Some European countries have held auctions for offshore wind in which the project has already been specified. Environmental and grid connection studies can be carried out before the auction, reducing risk to the developer and allowing a shorter period between the auction and the start of construction. In contrast, the UK auctions of the 1990s were for developer-proposed schemes which could be put forward at such an early stage that many of the winners subsequently failed to obtain planning permission to build their schemes. There is a trade-off between increasing competition in an auction by making it easy to enter and ensuring that enough preparation has been done to ensure that the competing projects can actually be built, and those UK auctions got this trade-off wrong. However, while the auction can be designed to allow some flexibility in what gets proposed, someone still must decide how much capacity to auction, and of what type. The amounts may only be finalized once the bids are in, but they must still be decided.

The issue is wider than the choice of which renewable generators to support. Several European countries, and some of the US markets, have auction-based capacity markets to ensure that sufficient capacity is available at peak times. The intra-annual variation in wind and solar load factors means that backup generation or electricity storage will be needed to ensure demand is met (unless it becomes *very* flexible). Their inter-annual variation is likely to imply that these generators' annual revenues from short-term market prices are volatile, raising their cost of capital unless other revenue streams, such as from capacity markets, are available. Those capacity markets could also have a CfD-style approach, returning revenue in years when market prices would have been more than sufficient (the so-called reliability options design). The European Commission's recent package includes recommendations for member states to support electricity storage, including through auctions. This raises the prospect that almost every large scheme helping to meet electricity demand has entered the market through some kind of auction.

Could contracts be decentralized?

When the UK's CfD scheme was designed, market participants and their financiers insisted that the contracts were held by a counterparty with an explicit government guarantee. Given that renewable generation costs were higher, and electricity prices lower, than today, generators expected to receive money from the contracts. The fact that all electricity retailers were required to collect this money and pass it on to the counterparty was not sufficiently reassuring, and a state-owned company was duly established to give the greatest possible security. In part, this may have been due to the unfamiliar nature of the CfD scheme, so could a more decentralized approach work now that it is well established?

Could the combination of retail competition and decentralized contracting be a problem? Around 20 UK energy retailers have gone bankrupt in 2021-2 because they failed to hedge their wholesale purchases well enough. Long-term wholesale hedges can be unattractive for a company in a sufficiently competitive retail market if retailers are forced to follow short-term reductions in wholesale prices or lose customers to unhedged competitors. Against a static background, this might not be a problem if all retailers were required to have similar contracts in place, but if renewable costs continue to fall, retailers with a portfolio of older schemes could find themselves 'out of the money'. Smaller retailers could also be at a disadvantage when negotiating contracts, unless some collective arrangement was available.

It is worth looking across the Atlantic. While federal tax credits support renewable generation in the US, many states also have renewables portfolio standards or mandates, with retailers required to procure a proportion of their sales from qualifying generators. These are decentralized schemes, with the retailers often showing compliance by surrendering a certificate for each MWh of renewable output. This approaches the tradable green certificate schemes discussed above. While those give the generator the market price plus a variable premium set in a separate market, it is also possible (with either tradable certificates or a portfolio standard) for retailer and generator to sign a long-term, fixed-price contract to cover both the electricity output and the renewable certificates. That contract would have similar economic effects to the CfDs favoured by the European Commission and in the UK.

Not every US state leaves the contracting to its retailers. Rhode Island requires distribution companies to contract with renewable generators and sell the certificates to retailers, while New York has centralized procurement by the state's Energy Research and Development Agency, but these seem to be exceptions. Some of these retailer counterparties are monopolies, but others operate in competitive markets. Some are part of larger groups (including the incumbent investor-owned utilities with a substantial asset base of generation, transmission, and distribution), but they need not be. Is the additional revenue from the fixed-premium federal production tax credit the factor that makes the overall policy financeable? How does the cost of capital for renewable generators compare with levels on the other side of the Atlantic?

This *Forum* exists to spark debate on energy issues. People who want a competitive solution to the future of the European electricity industry could perhaps explore the US approach and ask how it could be modified for European conditions. Others will be comfortable with the idea of a single buyer following its vision of an efficient low-carbon electricity industry and using auctions to minimize procurement costs.

THE CENTRAL TRADER MODEL: A SOLUTION TO STRENGTHEN THE LOW-CARBON TRANSITION AND TO PROTECT CONSUMERS IN THE EUROPEAN UNION

Dominique Finon

The long-lasting crisis in electricity markets calls for a debate on the real effects of competition in the European Union's (EU's) electricity market, whose design is based on hourly wholesale markets. This arrangement presents a triple drawback: first, giving prices aligned with the fuel cost of marginal producers, which never reflect the complete cost of any generation technologies; second, causing price volatility, which makes long-term anticipation of the net present value of an investment an impossible challenge; and third, exposing suppliers and consumers to episodes of very high prices due to the volatility of fossil gas prices. It removes any role for market prices as long-term signals for investment in production, as proven by the experience of the last 15 years in Europe, where very few investments in non-RES (non-renewable energy sources) techniques have been made through the market.

It follows that this market model is unable to fulfil the promise of lowering power prices by competition pressure. It is not able to create incentives to make suppliers hedge their risks, which could help to protect their customers. It is also deficient in facing the long-term challenges of security of supply as well as of decarbonization. The price signal sent by this hourly market is ineffective for investing in equipment lasting 30, 60, or 100 years, as is the case for low-carbon equipment (RES, nuclear, combined cycle gas turbine with carbon capture, hydraulic, and now storage). It is also inefficient for triggering investment in peaking units, which could not recover their investment cost by relying on scarcity rent during uncertain price spikes, as well as investment in flexibility sources relying on arbitrage revenues.

The present market design has already been modified in the EU to meet these two objectives, but only partially, as this was in conflict with the Commission's market formalism in the matter of competition and state aids limitation. If standardized long-term schemes that guarantee revenues—feed-in tariffs, premiums, and contracts for differences (CfDs)—have been allowed for variable RES (VRE) equipment, but not for other low-carbon techniques, it is because of the strong political preference they enjoy, which ignores all rationality.

The problem remains entirely open for the rest of the power mix: renewal of dispatchable equipment for security of supply, non-RES low-carbon techniques (nuclear, gas with carbon capture and sequestration), flexibility sources (storage, etc.) and network development—all areas whose importance grows with large-scale deployment of VRE developed out of the market. In other words, the previous arrangements are not sufficient to move towards secured and decarbonized systems with large share of VREs, which require the generalization of de-risking arrangements to every technique and coherent development by planning.

Another way of organizing the market could pursue three objectives:

1. sharing the risks of investing in new equipment through revenue guarantee contracts,
2. hedging market risks for suppliers in order to ensure consumer protection with quite stable retail prices aligned with long-term costs,
3. maintaining hourly markets to ensure short-term coordination inside the system and between systems, for which they are remarkably efficient.

Proposed by France and Spain for reforming the EU electricity market design, the model of long-term central trader, based on the generalization of hedging contracts with low-carbon equipment, meets these objectives. It has inspired the new project of regulation on electricity markets which has been proposed on March 2023 by the Commission.

In the following, the main characteristics of this model are presented, which allow the first two objectives to be met in a more or less effective way. In a second step, we present a possible improvement (which is not included in the French and Spanish proposals) that would allow to achieve the objective of consumer protection more reliably by helping the stability of selling prices. For this purpose, the model could be usefully completed by the assignment of another function of intermediation to the central trader, to purchase on the spot market every low-carbon MWh related to CfD contractors, and to resell them to suppliers.[56] Indeed, this makes it possible to guarantee that low-carbon MWh are sold to suppliers (and then to consumers) at prices aligned with the weighted average long-term cost of the low-carbon system.

Generalizing hedging contracts for all new equipment

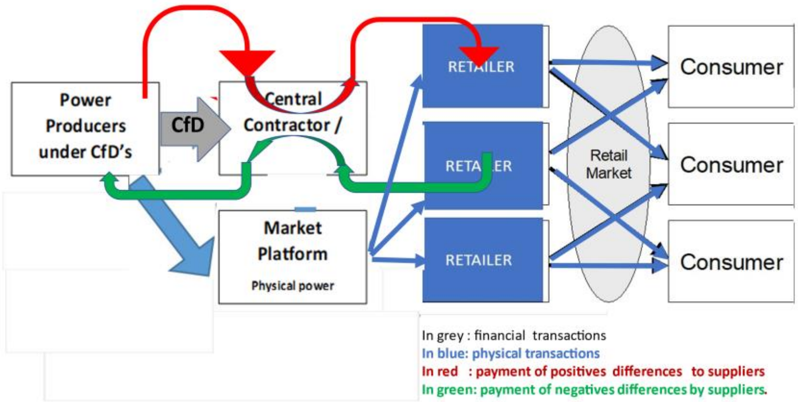
The first character is the establishment of long-term financial contracts (with maturity of 15 to 30 years) between developers of new low-carbon equipment for market risk coverage and a public commercial entity. This one should be created in order to commit in CfDs with each new low-carbon generator that wishes to hedge its risks by contracting with a credible public authority (see below). The latter disburses or receives the difference between the hourly market price and the contract's reference price (strike price), depending on whether the former is below or above the latter. This type of contract leads to a stable revenue stream, which fits quite well with the cost structure of low-carbon equipment with low or zero variable costs.

For new large equipment in capital-intensive technologies with long lead times, such as nuclear and carbon capture & sequestration, CfDs will be established by negotiation. For new RES equipment (wind power, photovoltaic solar, refurbished

[56] See Finon, D., and E. Beeker, E. (December 2022), *The Long Term Central Buyer Model*, CEEM policy paper. Chair on European Electricity Markets (CEEM), Paris Dauphine University

hydro), long-term contracts will be made by auctions, which will be opened regularly and select contractors on the price they request. They will be specialized by types of renewable sources, given the differences in loads and services they procure. In order to incentivize entry through the auction scheme, the government should commit to auction for capacities aligned with their RES objectives, through a pre-established calendar.

Figure 1: The central trader model: financial flows on differences



In order to be in conformity with the EU market rules, CfDs should not be mandatory for low-carbon developers. For entrants, participation in the RES auctions is voluntary. Indeed developers choose between a CfD scheme and entering into a power purchase agreement (PPA) at a fixed price with private counterparts. That said, apart from the motive of distrust vis-à-vis any state interventions, it is difficult to find an advantage in hedging long-term risks by a PPA for either a VRE developer or a large buyer. On the side of the RES producer, there is the risk of his counterpart, an industrial consumer, defaulting on the contract in case of bankruptcy or delocalization. On the side of this counterpart (which is assumed to be interested in purchasing green electricity at a stable price over the long term), it faces the challenge of being exposed to both price risk and volume risk for the additional sourcing it needs for its complementary supply. The high transaction costs of the hedging solutions can be demotivating.

Capacity contracts with flexibility and backup resources

Development of flexibility resources (such as fast-ramping gas turbines, battery systems, pumped storage, and hydro lakes refurbishment) which require high capital expenditure is facing too high uncertainties about their likely income. Their operations, and so their revenues on energy and ancillary services markets, are conditioned by the variability of the supply–demand equilibria coming from the generation side (with VRE productions) and the demand side (winter or summer peaks). No equipment can be made profitable on the basis of its revenues on balancing and ancillary services markets and on the energy market by various intertemporal arbitrages. These revenues are so volatile, and so uncertain over the long recovery period, that it is necessary to hedge investments through specific long-term contracts of capacity remuneration with incentives to availability.

This hedging could be assumed by the implementation of a capacity remuneration mechanism based on auctioned forward capacity contracts. With auctioning organized by technologies, competition for the contracts will drive down the prices to the producer's fixed costs (annuity covering the capital cost), and fixed operating costs. Each flexibility source will recover its fuel costs through revenues on the spot market.

Hedging main market risks for suppliers

In a system with dominating low-carbon generation, the public entity which contracts CfDs with producers is also able to hedge price risks for suppliers for the major part of their sourcing. This is possible as soon as the CfD system is extended to all existing low-carbon plants (as the French and Spanish governments have proposed in their statements on electricity market reforms). Indeed, it makes it possible to recover infra-marginal rents from each low-carbon plant in times of gas price spikes, and transfer them to consumers. (A corollary benefit would be to bring the remuneration of existing assets into line with that of new assets.) The CfDs with existing assets will be shorter term (from one to eight years for those with refurbishment). They could be awarded by auction, unless the government prefers to regulate each strike price at a level that covers the depreciation annuity and operating costs. (The auction could be a pay-as-bid auction to avoid undue rents.)

Hedging suppliers' risks in order to protect consumers is justified by the lack of incentives for suppliers to hedge their own risks. But this does not mean that all their risks will be hedged. A minor part of their wholesale procurement on the spot market corresponds to the MWh produced by the complementary system to the VRE system for flexibility and backup. Consequently, as they are not hedged against price risks for the corresponding quantity, suppliers will transfer these risks to their customers by their price and services offers. They will be encouraged to diversify their offers away from guaranteed prices over several months. This could be done with dynamic pricing, as well as with modulated offers with some load shaving during short price spikes. Thus consumers will adapt their behaviour in periods of high spot prices

Finally, these two-way transfers between low-carbon producers and suppliers, which allow mutual risks hedging, provide rather stable retail prices which reflect the average costs of low-carbon plants covered by CfDs, that is, the long-term cost of the low-carbon mix.

To guarantee producer–consumer transfers

To manage long-term contracts and their price differences with spot prices, a government should set up a public company to manage the two-way financial transfers between consumers (represented by suppliers) and low-carbon power producers committed in CfDs. The referential model of such a company is the Low Carbon Contracts Company established in the UK for this purpose.

The aim is to give credibility to public contracts in symmetrical commitments to give back 'differences' to producers when spot prices are below strike prices, and conversely to reallocate infra-marginal rents to suppliers and consumers during episodes of gas price spikes (rather than to keep these rents for the public budget). In the first situation, compensations to producers are financed by suppliers who pay a flexible tax calculated by the company from the balance of differences over a certain time-frame (week, month, or quarter) between the strike price and spot price for each CfD. Conversely, when the wholesale price is higher than the strike price, repayments from producers to suppliers are established by the public company in each time frame in proportion to their market share.

Member states' control over their long-term choices

Member states that adopt this central trader model aim in fact to lead their own electricity and energy policy, providing that their decarbonization commitment to the EU is respected. The choice of power mix is a matter of national sovereignty allowed under Article 194-2 of the TFUE (Treaty on the Functioning of the European Union). The overall coherence of the system will be set by a public planning body endowed with important competences in modelling complex systems for developing an optimization approach to investment decisions. It will be responsible for the programming of the generation mix, including flexibility sources and grid development at different scales (national, regional, and local) in order to establish the calendar of successive auctions for RES development and others.

The long-term plan will be defined according to the energy policy objectives set by the government in the light of (supposedly) impartial advice from the planning body legitimated by its modelling capability. It will develop a sliding program for the development (and closure) of production capacities. This approach is radically different from the present EU political practice of piling up targets (such as RES share and energy efficiency) based on political criteria, without any economic rationality, thanks to CO_2 emissions reduction goals.

This central trader model has a good chance of becoming an option for member states to choose in the next regulation (or directive), even if Germany is opposed to this change. The Commission has recognized that this model would be compatible with European rules and so easily implementable, while it considers it 'a sustainable solution for recovering rents from "infra-marginal" producers (i.e. the low-carbon producers) and reallocating them to consumers, via transfer to suppliers for compensation'.[57]

From the central trader to the central buyer

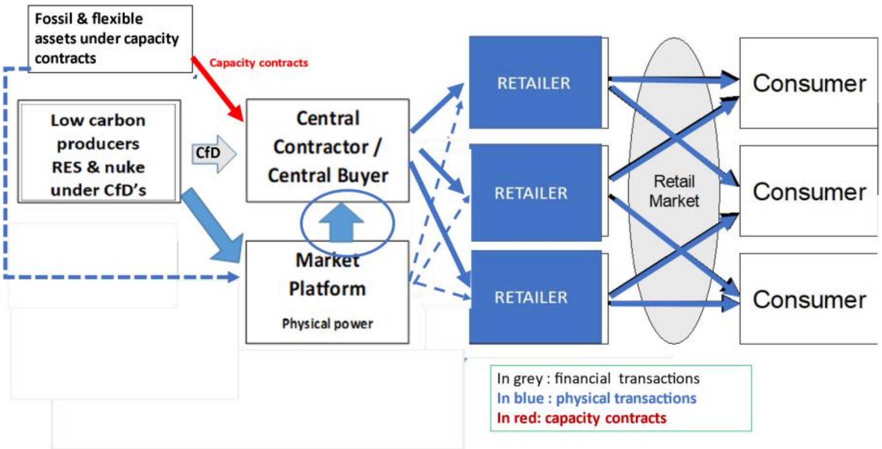
In the central trader model, the two-way transfer between low-carbon producers and suppliers is supposed to provide rather stable retail prices that would reflect the long-term cost of the low-carbon mix. But in fact there is no guarantee that, once suppliers receive their compensations during high-price episodes, they will adjust their price offers to their different types of

[57] EU Commission, 'Non-paper: policy options to mitigate the impact of natural gas prices on electricity bills', November 2022.

customers accordingly, because imperfect competition does not provide incentive to do it. In any case, there is no incentive for them to adjust their price offers on an equivalent basis between different consumers. So it is interesting to consider another model in which alignment of retail prices with long-term costs of low-carbon production would be much more accurate.

In the central buyer model, the public company also has an intermediation function. It is assigned to purchase each hour on the spot market the quantity of MWh corresponding to the total low-carbon production covered by the CfDs, to the extent technically possible. This position allows it to resell these MWh to the suppliers by correcting each hourly price by the differences between spot prices and the strike price of each CfD for which it is the counterpart of a low-carbon producer. This allows the company to define resale prices to suppliers by alignment with the weighted average cost of low-carbon production by nuclear and VRE each hour. Having in hand the long-term cost of each low-carbon producer, the public company is in a position to hedge market risks for suppliers' sourcing in a more effective way than in the central trader model.

Figure 2: The central buyer model



Suppliers (as eventually very large consumers) could procure well-calibrated power blocks (base, mid-base, peak, etc.) from the public company on an hourly basis and in forward contracts. These blocks could be sold with posted prices aligned with the weighted average costs of the low-carbon mix. Their definition would have to be transparent along with pricing principles defined by the regulator, in order to avoid market power exercise by the public company. A market alternative for their sourcing is auctioning for the acquisition of different blocks (in open descending auctions, with a start price higher than the posted price). In parallel, as said before, the suppliers have to complement their sourcing by purchases on the spot market. This is a more flexible way of finding the benefits that market splitting proposals have sought.

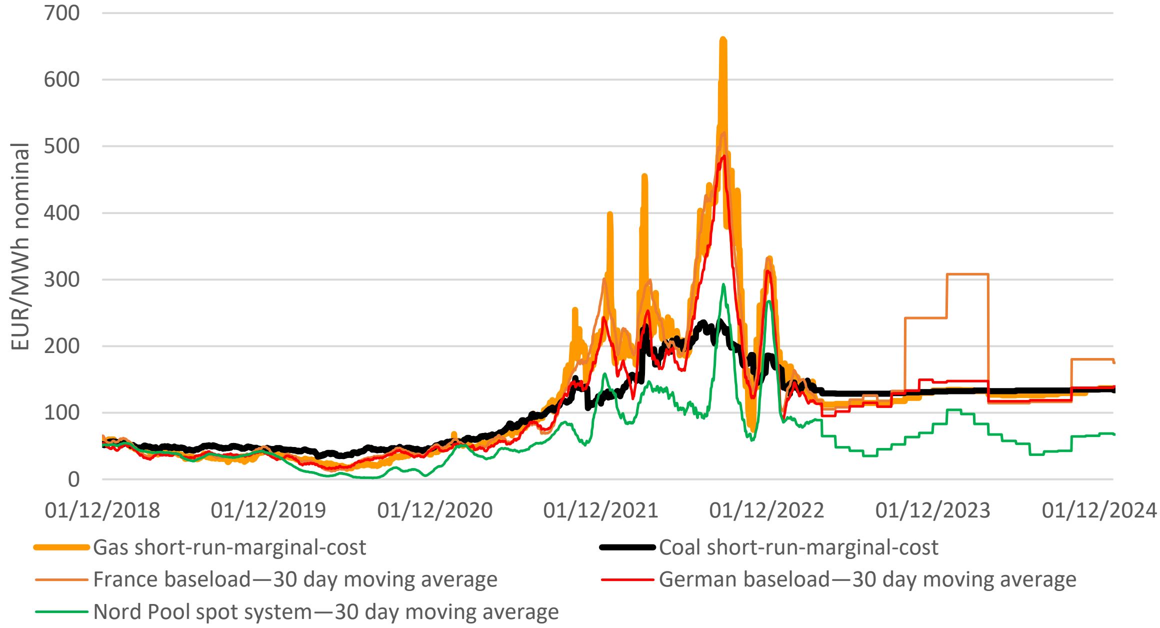
To sum up, these two models present a solution to ease transition towards carbon neutrality, and to protect consumers from extreme price volatility by coupling retail prices with long-term costs, while preserving short-term optimization of the system through the spot market. The central buyer model offers more efficiency to reach the second objective. There is no real incompatibility between this model and the European rules in matters of market and competition. That said, in the central buyer model, the mandate to purchase the bulk of wholesale power which is given to the public company makes this model much more difficult to accept by the EU defenders of the market at any price.

POLICY INTERVENTIONS IN EUROPEAN ELECTRICITY MARKETS IN RESPONSE TO THE ENERGY CRISIS: WHAT WILL THEIR LEGACY BE?

Fabien Roques and Anton Burger

The dramatic increase in wholesale power prices in 2021 and 2022 represents the first major stress test for European wholesale markets, which had seen stable prices over the past decade. During the crisis, the market did signal the scarcity of gas and power, showcasing its resilience. The increase in wholesale power prices across Europe was mostly driven by gas prices, with the increase of CO_2 prices having a smaller impact. As shown in the figure below, baseload prices started to increase in 2021 and rose dramatically in the beginning of 2022. The increase in wholesale prices differed across countries, depending on the generation mix and interconnection with other markets. Some of the bidding zones in the Nordic market, for instance, were less affected by the rising gas prices due to electricity generation relying more on hydropower and in some countries on nuclear. France saw high scarcity prices, mainly due to the low availability of its nuclear reactors and hydropower.

Figure 1: Daily power price and short-run marginal costs

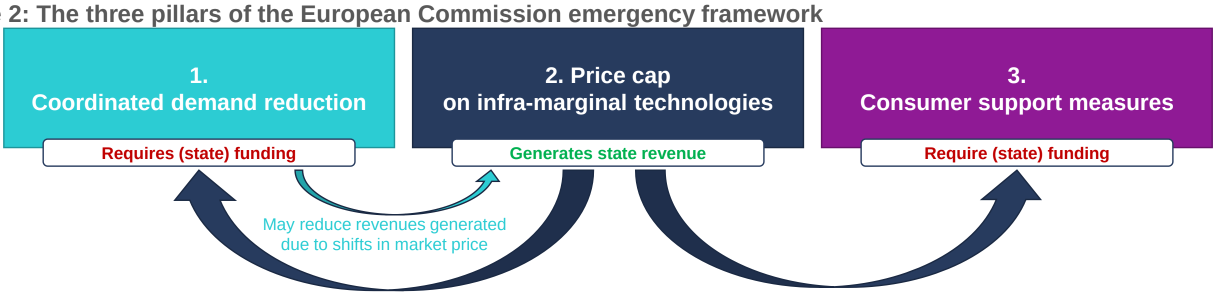


Source: Compass Lexecon analysis based on EnergyMarketPrice (2023), *Data Hub Energy Prices,* https://www.energymarketprice.com/home/.

As a consequence of this wholesale power price increase, there were a multitude of market interventions in Europe focussing on both retail and wholesale markets. The European Commission introduced an emergency framework for national market interventions and state aid approval based on three key pillars in September 2022.[58] This framework is exceptional in its nature, with a phase-out of the measures initially anticipated in March 2023, which was, however extendable based on the 'general situation of electricity supply and electricity prices' (and has actually been extended).[59] The figure below illustrates the underlying logic of the emergency framework.

[58] European Commission (2022, September 9), *Proposal for a Council Regulation on an Emergency Intervention to Address High Energy Prices*, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022PC0473&from=EN.
[59] European Commission (2022), *Proposal for a Council Regulation*, 39–40.

Figure 2: The three pillars of the European Commission emergency framework



Source: European Commission (2022, September 9), *Proposal for a Council Regulation on an Emergency Intervention to Address High Energy Prices*, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022PC0473&from=EN.

The first measure aims at a coordinated demand reduction, with the aim of reducing peak demand by 5 per cent. The second measure, a price cap on infra-marginal technologies, is supposed to generate the necessary revenue for the other measures. The third measure is support for customers, to help with rising living costs. This article discusses first the retail interventions and then the wholesale market interventions that were introduced in various European countries in 2022.

Interventions in retail markets

With rising wholesale market prices, end customer prices, and with them political pressure, rose quickly in all European markets. As a result, most countries introduced regulatory measures in retail markets in one form or another. While there were many ideas, and just as many titles for those schemes being floated around, the retail market measures by and large fell into four categories:

- direct subsidies, which basically mean direct transfers to customers,
- reductions in energy taxes or VAT,
- decreases of (or exemptions from) network tariffs, and
- retail price regulation.

The text below discusses the patterns that emerged from these measures, and what they mean from an economic point of view.

- **Direct subsidies** were introduced in 25 out of 28 European countries, and came mainly in the form of lump-sum payments. The advantages of direct subsidies are that they avoid direct market interference by use of the welfare system and that they use lump-sum payments instead of subsidizing energy consumption itself, which would only increase energy demand. However, as prices rose further during the summer of 2022, some countries started to doubt that those measures would suffice, in particular because direct subsidies have the disadvantage that they typically do not reduce (and may even increase) inflationary pressures.
- **Reductions in energy taxes or VAT** were introduced in 26 out of 28 countries. From an economic perspective, a reduction in energy taxes may have the disadvantage that energy demand increases, given the assumption that the tax was initially set in an efficient way in order to internalize external effects.
- **Reductions of or exemptions from network tariffs** were introduced in nine out of 28 countries.
- **Retail price regulation** was introduced in 16 out of 28 countries. Price regulation can lead to distortions when tariffs are not cost reflective, and in some cases (e.g. tariffs below actual costs) could create the risk of increasing energy demand beyond an efficient level. The way in which retail regulation measures were introduced or reformed in the different member states varied widely, and was driven by the institutional setups in the various countries. For example, in the UK, the already existing price cap was amended, whilst some countries which no longer had regulated tariffs, such as Germany and Austria, reintroduced regulated (subsidized) tariffs.

Figure 3: Overview of retail policy measures in Europe

	Austria	Belgium	Bulgaria	Croatia	Cyprus	Czech Republic	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy	Latvia	Lithuania	Luxembourg	Malta	Netherlands	Poland	Portugal	Romania	Slovenia	Slovakia	Spain	Sweden	United Kingdom
Direct subsidy for energy costs	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•		•	•	•	•	•		•	•	•
Reduced energy tax/ VAT	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•		•	•	•	•	•	•	•	•	•
Decrease/ exemption from network tariffs	•							•			•				•	•						•			•	•		•
Retail price regulation	•		•			•	•	•		•	•		•					•	•	•	•		•		•	•		•
Wholesale price regulation										•									•				•			•		
Windfall profits tax/regulation			•										•		•						•		•			•		•

Source: Sgaravatti, G., Tagliapietra, S., Trasi, C., and Zachmann, G. (2023, March 24), *National Fiscal Policy Response to the Energy Crisis,* Bruegel, https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices.

Interventions in wholesale markets

Interventions focussed initially on retail markets to protect consumers from what was anticipated to be a short-lived shock. But the rising costs of such measures, combined with inflationary pressures, led a number of policymakers across Europe to turn to wholesale market interventions during the course of 2022. The objective of these interventions was to reduce wholesale prices (it was also stated that the aim was to decouple wholesale prices from gas prices), but also to help finance demand reduction measures and the aforementioned support schemes for consumer relief. The perception of high infra-marginal rents (i.e. margins of electricity generators with low marginal costs in times of high electricity prices) also attracted political attention, and different countries proposed different types of interventions to capture and redistribute some of the profits from generators to consumers.

The text below provides a brief overview of the discussions around wholesale market interventions during 2022. It then describes the EU guidelines for the introduction of an infra-marginal price cap, and the ways in which these measures have been introduced in different countries, highlighting substantial differences.

The different types of wholesale market measures

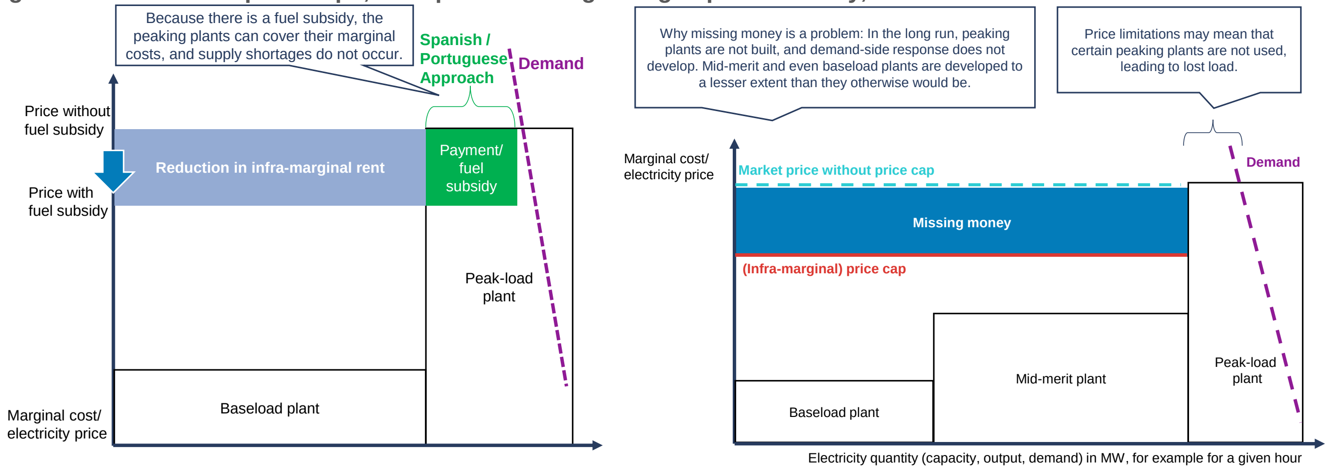
There were many suggested short-term wholesale market measures, which can be divided into four main categories from least to most interventionist:

- a windfall tax,
- a price cap,
- a fuel subsidy for fossil generators, and
- a market split by technology.

A common issue with the different measures mentioned below is that they change market rules retroactively (that is, after investments are made on the basis of these market rules), and it is possible that this will lead to legal actions on the ground that it is a violation of investors' reasonably formed expectations.

A windfall tax (also called an infra-marginal cap) was implemented in some countries; this caps the revenues of generators with lower marginal costs than those of peaking plants after the market has cleared. Because a windfall tax should in theory not interfere with market clearing, it does not have most of the drawbacks listed for a price-cap below (as shown in the right part of the figure below).

Figure 4: The effect of price caps, the Spanish/Portuguese gas price subsidy, and the EU windfall tax



A price cap was proposed in European and national discussions, in particular regarding the maximum price on some of the trading platforms. While price caps reduce infra-marginal rents and thereby wholesale prices as well as retail prices, they also create a number of economic distortions. To put it briefly, the market price loses the ability to correctly signal the scarcity and value of electricity, as price caps

- undermine the profitability of peaking plants and storage, which ultimately may lead these resources to exit the market (something that happened in Australia over the summer 2022 and led to a market suspension);[60]
- reduce the incentive for demand to economize on consumption and/or provide demand-side response;
- distort electricity trade flows, by creating an artificial export—from countries that have an artificially low price because of the price cap, to neighbouring countries;
- undermine investment in generation, storage, and demand-side response; and
- lower the incentive to innovate.

A fuel subsidy for fossil generators: Spain and Portugal implemented a policy measure that could be described as a further developed form of a price cap. Gas and coal plants receive a so-called fuel price cap, which means that the fuel they use for electricity production is subsidized. Therefore, they are not allowed to set a price beyond a certain threshold (there was no formal limit to what generators could bid, but a limitation of fuel prices). The left part of the figure above illustrates this quasi price cap. While this measure has most of the properties of a price cap otherwise, it does not create the risk of plants higher up in the merit order leaving the market, because they receive a fuel subsidy (depicted by the green rectangle) which keeps them generating, even with the quasi price cap being below their marginal costs.

A market split by technology: The most interventionist measure in discussion was the proposed split of the wholesale electricity market by technology (called the Greek proposal). The idea was to create a separate market for low-variable-cost technologies. Low-cost technologies would bid for contracts for difference (CfDs) in a form of competition *for* the market. But the electricity of those technologies would not be sold at the 'normal' market. This proposal had the drawback that low-cost technologies would not have been exposed to market prices, which would have made their dispatch likely less efficient.

In practice, policy ambitions to intervene in the wholesale market were faced with the reality that the European electricity market, through the electricity price, coordinates the dispatch of a very large number of generators, storage operators, suppliers, imports and exports, and large electricity users, almost in real time and all over Europe. As such, interventions directly interfering with electricity price setting were limited to a few countries, although many of the policies implemented have an indirect distortive effect on the market. Since the issue that policymakers wanted to address is largely a distributional problem, other policy levers could have been used which would have been less distortive, such as general fiscal and redistribution policies, not necessarily limited to the energy sector.

[60] Australian Energy Market Operator (2022, June 24), 'AEMO lifts market suspension', https://aemo.com.au/newsroom/media-release/aemo-lifts-market-suspension#:~:text=On%20Wednesday%2015%20June%202022,supply%20of%20electricity%20for%20consumers.

Implementation of the infra-marginal cap

Given the different options discussed across the member states, and the potential for distortions, the European Commission tried to provide a common framework for exceptional interventions during the crisis. The council reached an agreement on 14 September 2022 to allow countries to introduce an infra-marginal price cap that is applied ex-post, which is essentially a windfall tax,[61] as well as demand-reduction measures, direct consumer support, and a solidarity contribution.

With regard to the infra-marginal price cap, the Commission suggested that revenues above €180/MWh could be taxed at a 90 per cent rate to retain incentives for efficient behaviour on the market.[62] Recognizing that not all electricity is sold on the spot market, the Commission suggested that forward market transactions and long-term contracts for renewable plants—'green PPAs' (power purchase agreements) should be taken into account.[63] However, the wording of the agreement left ample room for interpretation, such that different approaches in implementing the cap could be anticipated—for instance to differentiate between technologies, exceed or undercut the cap, only partially apply the cap, exempt certain energy sources from the cap, or not apply the cap consistently across different markets (such as excluding the balancing market).

In practice the national implementations of the infra-marginal revenue cap differ widely, often undercutting the set cap of €180/MWh. Differences occurred in particular with regards to whether the tax was set retroactively or only prospectively, the level of the price cap, which end date was set, and whether the tax above the threshold was actually set at 100 per cent or at 90 per cent. The table below gives an overview based on public information available as of March 2023.

Figure 5: National implementations of the European Commission's infra-marginal price cap/windfall profits tax

Country	Measures implemented	Dates of implementation	Effective retroactively?
Spain	Gas price cap is €40/MWh, increasing in €5 increments to €70/MWh.	June 2022 – May 2023	No
Austria	40% of oil and gas revenues are taxed if they exceed the 2018–2021 average by 20%. 90% of infra-marginal generators' revenue above €140/MWh with a capacity above 1 MW is taxed.	July 2022 – end of 2023	Yes
Italy	There is a one-time power, gas, and oil tax on 50% of 2022 revenues if they exceed the 2018–2021 average by 10%.	1 December 2022 – 30 June 2023	Yes
Bulgaria	The price cap for renewables is €179/MWh.	December 2022 – June 2023	Yes
Romania	The windfall power tax on revenues of more than €92/MWh for generators of more than 10 MW is 100%. The same applies for revenues above €180/MWh for biomass fuels or waste plants. Infra-marginal technologies have individual calculations (~€130/MWh).	April 2022 – March 2023	Yes

[61] European Commission (2022), *Proposal for a Council Regulation.*
[62] European Commission (2022), *Proposal for a Council Regulation*, 7.
[63] European Commission (2022), *Proposal for a Council Regulation*, 8.

Country	Measures implemented	Dates of implementation	Effective retroactively?
Slovakia	Technology-dependent power price caps are €100/MWh for waste; €120/MWh for solar; €180/MWh for nuclear, hydro, and wind; and €230/MWh for coal. There is also a 90% tax on power producers' earnings above the cap.	December 2022 – December 2023	No
France	Revenues are capped at €90/MWh for nuclear, €100/MWh for wind and solar, €175/MWh for the combustion of biogas, and €145/MWh for the thermal treatment of waste.	N/A	Yes
Germany	Revenues are capped at €130/MWh for offshore wind and nuclear, €60/MWh for lignite (plus EU ETS costs) for most of the units, and €82/MWh (plus EU ETS costs) for lignite plants coming back from the reserve.	Until June 2023 (possible extension until April 2024)	Yes

Source: CL analysis based on multiple sources.64 ETS = Emissions Trading System.

To conclude, the national implementations of the infra-marginal price cap and related taxation measures show a very wide variety, with very different price levels across the EU, often below €180/MWh. This creates distortions in the merit order across borders as generators pass through these costs to some extent in their bids. Moreover, there is uncertainty as to the duration of these extraordinary measures. Going forward, it remains indeed to be seen if member states will phase out windfall profits taxes as planned by the Commission by the end of 2023.

What is the legacy effect of these policy interventions?

Whilst it is too early to assess the effect of these temporary interventions in the market, the crisis has triggered a debate on a structural reform of the European electricity market. The European Commission launched a consultation early 2023 which led to a set of market reform proposal.[65] The stated objective of the reform is threefold: to enhance the deployment of renewables, to protect customers from the volatility of short-term market prices, and to boost the EU's industrial competitiveness while deploying clean energy sources. The proposal for reform consists of two communications, one proposing to amend the

[64] Bulgarian Photovoltaic Association (2023, January 3), 'Implementation of the measures of Council Regulation (EU) 2022/1854 of 6 October 2022 on the ceiling of the revenues of electricity producers', https://www.bpva.org/actual/prilagane-na-merkite-na-reglament-es-20221854-na-saveta-ot-6-oktomvri-2022-g-za-tavan-na-prihodite-na-proizvoditelite-na-elektricheska-energiya; Bulgarian Photovoltaic Association (2023, January 13), 'The CM determined the market revenue cap for RES producers without a contract for compensation with premiums', https://www.bpva.org/en/actual/the-cm-determined-the-market-revenue-cap-for-res-producers-without-a-contract-for-compensation-with-premiums-the-ess-fund-published-the-declaration-form; Bundeskanzleramt Österreich (2022, December 29), *Bundesgesetzblatt Österreich—Bundesgesetz über den Energiekrisenbeitrag-Strom,* Rechtsinformationssystem des Bundes, https://www.ris.bka.gv.at/Dokumente/BgblAuth/BGBLA_2022_I_220/BGBLA_2022_I_220.pdfsig; Heller, F. (2023, January 11), 'Spain wants to extend Iberian derogation, proposes EU electricity market revamp', Euractiv, https://www.euractiv.com/section/politics/news/spain-wants-to-extend-iberian-derogation-proposes-eu-electricity-market-revamp/; Hudec, M. (2022, November 16), 'Slovak government to cap electricity, gas prices for municipalities', Euractiv, https://www.euractiv.com/section/politics/news/slovak-government-to-cap-electricity-gas-prices-for-municipalities/; Jimenez, P. H. (2022, October 6), 'Analysis of the Iberian singularity (last 3 months) versus other regulatory mechanisms', Haya Energy Solutions, https://hayaenergy.com/analysis-of-the-iberian-singularity-last-3-months-versus-other-regulatory-mechanisms/; Kopac, J. (2022, September 21), 'How Romania's 'windfall tax' risks unravelling the EU electricity market', Euractiv, https://www.euractiv.com/section/electricity/opinion/how-romanias-windfall-tax-risks-unravelling-the-eu-electricity-market/; Reuters (2022, December 8), 'Factbox: windfall tax mechanisms on energy compensation', https://www.reuters.com/business/energy/windfall-tax-mechanisms-energy-companies-across-europe-2022-12-08/; Reuters (2023, January 31), 'Slovakia sets price caps on power plants by type of fuel', https://www.reuters.com/business/energy/slovakia-sets-price-caps-power-plants-by-type-fuel-2023-01-31/; Senato della Repubblica (2023, March 26), 'Bilanco di previsione dello Stato per L#anno finanziario 2023 e bilancio pluriennale per il triennio 2023–2025', https://www.senato.it/leg/19/BGT/Schede/FascicoloSchedeDDL/ebook/56372.pdf; Sgaravatti, G., Tagliapietra, S., Trasi, C., and Zachmann, G. (2023, March 24), 'National fiscal policy response to the energy crisis', Bruegel, https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices; *The Slovak Spectator* (2023, January 13), 'State will compensate businesses for rising energy costs', https://spectator.sme.sk/c/23113489/state-will-compensate-businesses-for-rising-energy-costs.html.

[65] European Commission (2023, March 14), *Reform of Electricity Market Design—Commission Staff Working Document,* https://energy.ec.europa.eu/staff-working-document-reform-electricity-market-design_en.

Electricity Market Design Rules and the other to amend the Wholesale Energy Market Integrity and Transparency Regulation to improve the Union's protection against wholesale market manipulation.

Based on a preliminary analysis of these proposals and of the policy debate around the market reform agenda, there are two areas of discussion that represent a significant evolution from earlier policies:

- One focuses on consumer protection and active engagement in hedging, through a range of measures. Many of the measures related to the retail market that the Commission suggested in its March 2023 proposal reflect the recent experience of an energy price crises and the need to provide better opportunities for consumers to actively hedge. The Commission suggests, for instance, the following concrete measures: customers should have the right to have a fixed-price contract for at least a year; regulators should have the power to require that part of the demand of a supplier be met through PPAs; member states must have a supplier of last resort; and customers should have access to regulated retail prices in the case of a crisis.
- The other aims to support investment through long-term contracts. The Commission puts forward a number of measures to foster long-term contracts with private or public counterparties in the form of PPAs or CfDs. Two-sided CfDs, where renewable generators are guaranteed a certain minimum price for their output, appear to be a potential way forward to reduce risks for both investors and consumers, as producers are guaranteed a minimum level of remuneration but also have to pay back revenues in excess of the guaranteed price. There are a number of interesting finer points around the ideal incentive design of two-sided CfDs (market premium models, carbon CfDs, etc.), but discussing those would go beyond the scope of this paper.

Conclusion

The energy crisis has been the first stress test of the common European internal market for gas and power. Overall, the market has shown resilience, and has done what it was supposed to do—it correctly signalled the scarcity of gas and power until about September 2022, and the reduction in scarcity of gas and power after that. As such, the existence of a liquid and competitive short-term electricity and gas market in Europe seems to have been an asset.

The European Commission emergency framework left a lot of room for interpretation by member states, and it is obvious that national implementations vary wildly, giving rise to a number of distortions. This, combined with the uncertainty on their removal by the end of 2023, gives new urgency to the need for a structural reform of the market, which has become needed to supersede these interventions, which risk becoming permanent otherwise.

Whilst it is too early to identify the long-term legacy of the crisis and policy interventions, a consensus seems to emerge on the need to complete the existing EU energy market with a greater role for long-term contracting and greater opportunities for consumers to hedge.[66] This is likely to lead to hybrid markets, which are mixed 'liberalized markets with state intervention and long-term contracts', combining both short-term market mechanisms and planning and redistribution mechanisms.[67]

Moreover, whilst the European Commission proposals suggest a number of key areas for a common approach for reform, it is the view of the authors of this paper that given the heterogeneity of the European power market and political landscape, we will likely see different approaches on national levels on some of those key issues, creating a risk of further distortions and potentially fragmentation of the European power market.

[66] Eurelectric, Compass Lexecon (2023, March 29), *Electricity Market Design: Fit for Net Zero—Policy Recommendations,* https://www.eurelectric.org/publications/electricity-market-design-fit-for-net-zero-policy-recommendations/.

[67] Roques, F. (2021), 'The evolution of the European model for electricity markets', in G.-J.-P. (eds), *Handbook on Electricity Markets, Edited by Jean-Michel Glachant, Paul L. Joskow and Michael Pollitt,* 308–328, at 327; Roques, F., and Finon, D. (2017, February 20), 'Adapting electricity markets to decarbonisation and security of supply', *Energy Policy* 105: 584-596, http://dx.doi.org/10.1016/j.enpol.2017.02.035.

REFORMING THE EU INTERNAL ELECTRICITY MARKET WILL NOT SUFFICE TO DELIVER EU AIMS

Jean-Michel Glachant

We need to wonder if a reform of the EU internal electricity market would suffice to deliver EU energy security, decarbonization, and electrification. Regrettably, this is not the case. Let us be frank: this market reform, this entry into an era of 'hybrid electricity markets', is a condition for success but only a necessary condition, not a sufficient one. Why? Let us consider four other conditions for success to make this point clearer. Decarbonization and electrification face (1) other direct constraints, such as adequacy of grids and infrastructure; (2) indirect constraints, such as the allocation of decision rights between the EU level and the member states; and other types of constraints, both external and internal to the energy field, such as (3) the EU Central Bank monetary policy and member states' public budget financing and (4) existing international trading and manufacturing chains.

It is therefore equally true to say that the existing EU market reform does not change all the fundamentals in the European energy policy, and that the EU energy landscape, post market reform, will require more effort, more attention, and more coordination from public and private energy decision-makers.

Direct constraints: adequacy of grids and infrastructure

When decarbonization and electrification trends displace the technology frontier to wind farms, photovoltaic (PV) panels, heat pumps, and electric vehicles, the reality of electricity flows must still deal with the reality of grids and system operation. The four countries leading the EU's offshore expansion are targeting 65 GW in their northern seas in 2030 (more than France's existing nuclear fleet) and 300 GW in 2050 (2.2 times France's total generation set). Where are the transmission lines to move all of this? Will the corresponding enormous power flows only be canalized among these northern maritime countries, or will they also feed many other EU countries—and in the latter case, with which lines, interconnections, or corridors? How can citizens in the Benelux be persuaded to accept construction of power lines that pass through their countries to supply power to Italy, Austria, and perhaps elsewhere? How should the grid in the North Sea and beyond be financed?

The same can be said of offshore wind, solar PV, and distribution grids. For example, the European vision of the solar future expressed in RePowerEU in May 2022 is 320 GW of PV by 2025 and 600 GW by 2030. Are there distribution grids ready to connect and manage this supply? One can also consider heat pumps and electric vehicles in the future. The EU would like to double its number of heat pumps to 10 million in 2027. Are the distribution grids ready for this? The Dutch distribution grids are already quite congested, and the Belgian grids are starting to be. And what would 'being ready' mean?

In the past, flow constraints in distribution grids were considered a given, and grids had to be adapted to overcome them in a 'fix and forget' manner. Today, research shows that new investments in distribution grids can vary by 40–50 per cent if the users of the grid behave differently and become proactive. How can users be incentivized to adapt and react to the reality of grid constraints, peaks, congestion, and investment costs? Should it be by creating new markets, local markets, new grid usage rules, or new connection agreements, or by giving grid managers new grid congestion management rights?

This reasoning could be extended to other assets and investments needed to secure and operate the grids—such as large storage, demand response, and other balancing reserves—to deliver security and resilience of electricity systems by 2030 and 2050.

Indirect constraints: allocation of decision rights between the EU level and member states

A comprehensive reform of the EU internal electricity market is likely to have three pillars: long-term contracts for price hedging, long-term contracts for energy delivery, and long-term contracts for capacity building. Aside from market reform, another key condition for the success of Europe's energy transition aims is related to grids and infrastructure adequacy.

Frankness and realism immediately show that, in each of these four key areas, the member states and not the EU have the core decision-making rights. The EU mainly intervenes via the numerous European grid codes for flows operation, and the coordination of power exchanges and transmission system operators through 'market coupling'. It is somewhat paradoxical that an ideal reform of the internal electricity market would reinforce so deeply the role of public authorities in each country but would not consider at all how to better coordinate the new European web of long-term contracts. Regarding the elementary microeconomics of collective action, one might say that the EU as a whole will face a consistent 'moral hazard' issue. Each country will directly combine the way it wants to handle its four key areas of decision-making; but many core results will affect Europe as a whole and only appear at the EU level: for example, dependence on imported fossil fuels, sensitivity to fossil price shocks, sharing of new decarbonized assets through interconnection and market coupling, and resilience against new types of energy shocks created by worsening climate change.

Certainly, we already have some European tools addressing some similar issues: the studies made by the European Network of Transmission System Operators – Electricity ENTSOE (the 10-year network development plan and the adequacy study), the financing granted to Projects of Common Interest through the EU network policy, and the National Energy & Climate Plans (and the corresponding regulation of Energy Union governance). However, all these tools suffer from two main limits: they were conceived to work within the former internal electricity market framework, and they are all quite deeply entrenched in their respective silos. A new system of European governance has to be carefully thought through and practically implemented to reach the level of coordination that the EU will need to successfully accelerate its decarbonization and deepen its electrification. The challenges that European industry and the European economy will face in the new world geopolitics in the three decades up to 2050 do not allow us to make many mistakes or lack cohesion.

Constraints external to the energy sector: EU Central Bank monetary policy and member states' public budgets

Unfortunately, the success of Europe's market reform aims also faces hard constraints external to the energy sector, which means that one cannot expect much benevolence and leniency there. Among these are the EU Central Bank's monetary policy and the member states' public budgets.

EU monetary policy should have stayed outside our review, because the European Central Bank's leaders are openly addressing climate change, and have put it in their general policy framework, which is remarkable. But the current inflationary wave has created a much more urgent priority for them. The Bank is no longer willing to sustain the 'easy money' policy that it had adopted for a long time, and a tightening of monetary and financial policy is the new normal. This may last for a long time, as the Bank is not willing to impose a rapid and brutal tightening of policy but rather prefers a significant but softer and longer hardening. It is not obvious that this softer tone will not depress companies' and households' willingness to invest. How will the EU then accelerate its investments in both decarbonization and electrification?

The size and speed of investment flows are not the only concern here. Most decarbonization investments are in capital-intensive options with low variable costs (such as wind, solar, storage assets, and building refurbishments). The total cost of these actions is then strongly impacted by rises in interest rates. Even if interest rates stay under the current inflation trend, the total cost of many decarbonization actions is jumping today and will push up the European price for decarbonization.

The second part of this monetary and financial lock is member states' public budgets. In 2021, member states enjoyed €750 billion more funding at the EU level, as the post-Covid extraordinary recovery instrument supplemented the ordinary European budget of €1,000 billion for 2021–2027, but things have tightened since. More than €700 billion was spent in 2021–2022 by EU governments only to feed current energy and fossil fuel consumption, and this crisis is expected to last through 2023 and 2024. The cost of the Commission's RePowerEU plan, if implemented by the member states, was evaluated in May 2022 at €300 billion. The cost of addressing the lack of Russian gas in 2023 has been put by the Internal Energy Agency at €100 billion. While the prospects for growth in the EU are seen as very slim if not negative, where will governments find the financing to accelerate decarbonization and electrification? Of course, the macroeconomics of such energy transition investments and expenses are good for economic growth, as was demonstrated in an Oxford 2020 study with Stiglitz and Stern, but where can the initial financing be found?

Furthermore, financing the acceleration of the energy transition at the member state level not only competes with more redistributive expenses that governments might prefer in an atmosphere of energy crisis, but might also have to compete with other types of macroeconomic stimuli. The new understanding of 'green macroeconomics' is less rosy than that of 2019–2020. Many decarbonization and electrification actions require investments today to obtain the same amount of services as yesterday. These investments do not increase industry productivity or consumption satisfaction. They 'only' reduce an externality: climate change. This means that the effort to invest de facto reduces the available amount of 'market wealth' that can be redistributed. It is literally an effort.

The new 'sobriety' wording gives some of that meaning. When starting this effort, we have to be sober with appropriable wealth and promises of consumption. This is a difficulty not yet factored into the 'fair and green growth' policy that the EU has made popular since 2019. Of course, citizens and decision-makers will find ways of absorbing this new approach and giving it a sense, for example as a duty to build a sustainable future for future generations or as pride in constructing or reconstructing sustainable industry and a sustainable economy in the EU, responding to the strong geopolitical turmoil that we face until 2050. All of this is doable, sensible, and positive, but it has to be done—the sooner the better.

Constraints internal to the energy sector: existing international trade and manufacturing chains

It is more and more understood in the EU that the worldwide global economy is fragmenting, and that new geopolitics and geo-economics have come or are coming, with a still undefined shape and a new set of rules but a clearly different direction to 20 years ago at the birth of this century. It is pointless here to wonder why, but we need to ask ourselves what the possible consequences are for the success of the current European market reform aims.

The first obvious consequence concerns European energy security. For 10 years (1994–2004) the European Commission president, José Manuel Barroso, was unconvinced that Russia and its leaders could be fully trusted. An immense majority of other European leaders, business leaders, and presumably public opinion thought the opposite. As Jean Monnet (the 'founding father of Europe') used to say, doing business appeases tensions and if you do not become friends you might at least become partners respecting a few basic rules for a peaceful neighbourhood. This actually worked well between France, Benelux, and their former enemies Germany and Italy, but finally not with the core of the former USSR: Russia. Therefore, the EU and Russia are divorcing. As Russia was our first supplier of oil, coal, and gas, this divorce is economically and financially traumatic. Together, as the EU, we have not decided to replace our dependence on Russia with exactly the same dependence on other countries. We will instead try to accelerate our independence from fossil fuels by accelerating decarbonization and electrification. Our decarbonization has for the moment several pillars, the biggest being renewables (e.g. hydro, wind, solar, geothermal, biomass, and biogas) and another being low-carbon options like nuclear or fossil fuels with Carbon Capture and Storage. In addition, our electrification (for example with heat pumps and electric vehicles) is conceived as expanding our decarbonization beyond today's uses of electricity. We also know that electricity will not be a universal vector for all energy uses, and we are preparing a green low-carbon hydrogen sector (with methanol and ammonia) for heavy transport as a part of maritime and air traffic plus parts of industrial processes. How much clean hydrogen the EU will import and from where remains an open question.

A less obvious but equally important factor is other industrial chains, notably ones centred on manufacturing. Will the EU keep quietly importing solar panels, wind turbines or key components of wind turbines, heat pumps, and other equipment from remote foreign countries? If we really want to accelerate our decarbonization and strengthen it as a component of our energy security, shouldn't we build an entire European manufacturing chain for these supplies? We have already realized that we need to Europeanize the manufacturing of electrical batteries for our coming wave of electric vehicles. What else should we see similarly?

As 'green manufacturing chains' are fed at their roots by many 'green critical materials' like lithium, cobalt, and rare earths, how should the EU organize the basic supply of these key strategic components? Are we going to open mining activities for those materials in Europe? There is enough lithium for batteries in Europe, but it is so difficult to get a permit… Or is it better to import a maximum to avoid public opposition?

The EU is discovering what dependence is in a deglobalizing world and what alternative options are doable, with their pluses and minuses. We have to build a minimum base of European sovereignty to be sure to be able to achieve our core strategic aims. It is doubtful that we can do it separately in each of our 27 countries. We shall do it in some kind of European sovereign cooperation: to be explored, tested, and then duly implemented. Having a reformed electricity markets helps, but does not deliver all the steel for that armour.

Conclusion

A new market configuration combining long-term contract arrangements and short-term central markets is not a surprise discovered during the European crisis. Leading electricity researchers at the Massachusetts Institute of Technology arrived at the same conclusion when studying the main consequences of the push for decarbonization in the US. Both the US and the EU are entering a new era of hybrid electricity markets combining private and public dimensions. What the EU adds to this general finding is a need to build strongly independent European energy security when accelerating the decarbonization push and the electrification pull.

Left alone, the reform of the EU internal electricity market cannot guarantee the success of the core European aims.

AUSTRALIA’S SPOT ELECTRICITY MARKET: REFLECTIONS AND PROSPECTS

Bruce Mountain

Australia’s National Electricity Market (NEM), which is actually five regional markets covering its southern and eastern states only, is 25 years old this year. It is seen in Australia as a success of ‘cooperative federalism’ (the states have the constitutional obligation to supply electricity, and so the NEM could not be created without their agreement).

Before it was created, Australia’s Industry Commission said it would increase national income more than any of the other microeconomic reforms pursued by the Hawke-Keating governments. A review a decade after its creation concluded that ‘Australia is respected internationally for its past reforms in energy with these reforms producing one of the most competitive and efficient energy sectors in the world.’[68]

Among the Group of 20 large economies, the NEM has the highest per-capita coal and the lowest per-capita gas generation, but also by far the highest per-capita solar and amongst the highest wind. Coal has been contracting gradually and soon is expected to contract quickly as a source of electricity, to be replaced by the wind and sun. Policymakers are pursuing renewable expansion at a rate that will see production dominated (more than 80 per cent) by variable renewable sources within a decade. Consequently, electricity market design in general, and arrangements for the provision of reliable supply in particular, have received considerable attention over the last five years.

This article describes the NEM, summarizes its context, philosophy, and developments, and presents thoughts on future changes.

Description

The NEM is a mandatory (for generators bigger than 30 MW) centrally settled energy-only single-price constrained-optimization five-minute multiregional electricity pool. Compared to short-term (spot) electricity exchanges elsewhere, it is most similar to the original England and Wales Pool.

Its main differences compared to that pool are that it is a multiregional market (the regions corresponding to the state boundaries), ancillary services markets (for frequency control and rapid response) are co-optimized with the main energy market, and the clearing price is based on a constrained optimization. Formally, the clearing price is the offer of the most expensive generator at each regional reference node (i.e. each state’s capital city). Unlike in England and Wales, before the creation of the NEM there was not a system of price calculation that could be easily adapted to accommodate offers from generators.

Like the spot market in New Zealand and until recently Texas, the NEM is an energy-only market (though various reliability measures also exist). Compared to spot markets in other countries, the NEM has the highest market price cap ($15,200/MWh), noting however that the New Zealand market does not have a cap. The NEM also has a cumulative price cap (based on rolling average prices).

Market prices hit the cap frequently (typically for hundreds of five-minute dispatch intervals each year), and cumulative price caps have applied, albeit not frequently. Spot prices in the NEM are the most volatile of all electricity markets that we know of (in some regions in some years, average annual prices would halve if the prices in the 72 highest-priced half-hourly settlement periods were excluded).

The NEM’s spot market exists in a context of very high vertical (generation–retail) integration. In Tasmania almost all retail supply comes from a government-owned supplier. In Queensland, government-owned generators and retailers supply most electricity. In South Australia, Victoria and New South Wales, the three largest retail suppliers (all privately owned) also own or control most of the generation whose production they sell, and between them they meet at least 60 per cent of the demand in each regional market. Only a small share (less than 5 per cent) of load and customers are served by retailers who do not also own generation.

[68] Scales, B., Carmody, G., Swift, D., & Rattray, A. (2007). *Energy Reform, The way forward for Australia* (Issue January). Page iii. https://www.energy.gov.au/sites/default/files/energy-reform-way-forward-aust-final-report-exec-summary-2007_0.pdf

In this context it is no surprise that financial contracts (mostly swaps but also caps) to hedge volatile spot market exposure play a limited role. Only in New South Wales and Victoria is there a liquid market for contracts, and even then liquidity drops quickly for contracts more than 12 months ahead. Contracts exchanged on the Australian Stock Exchange are largely unchanged over the 25 years of the NEM.

On the demand side, there is very little direct participation in the spot market by customers. Retailers that have offered customers exposure to spot prices have found very few takers, and only a small amount of large customer demand is exposed to spot prices.

A description of the wholesale market can't ignore developments in distributed energy, which is not traded in wholesale markets. In fact, the largest single source of renewable electricity supply in the NEM (about 15 per cent of total end-customer demand) is to be found on the market's 3.4 million customers' roofs (about one in three dwellings or one in two detached dwellings) and also businesses that have installed rooftop photovoltaics. It is these customers, not utilities, that have invested more capital in electricity production, and that have added more capacity than any other, since the creation of the NEM.

As the large privately owned utilities close their coal generators, it might be that they will turn to their customers to host the production (rooftop solar) and storage (behind-the-meter batteries) that they will use to supply those customers, and in part their neighbours.

Context, philosophy, and outcomes

Unlike in Britain, the spot market in the NEM was not shaped by pre-existing software and systems (the GOAL scheduling and dispatch system) that could be easily adapted to the provision of offers from generators to replace marginal costs. In the NEM, a clean slate, the opportunity to have watched successful developments elsewhere (notably in England and Wales), and perhaps also the fervour of the newly converted for the promises made in the spot market literature,[69] resulted in a spot market that perhaps attempted to more rigorously implement marginal cost orthodoxy than in the England and Wales Pool. This can be seen in various important details: gate closure 30 minutes before dispatch, unlimited generator re-bidding, five-minute dispatch, a constrained-optimization price calculation, and co-optimization of ancillary and energy markets.

Many of the engineers and economists who were actively involved in the development of the spot market went on to occupy senior administrative positions in government and in energy market institutions in the supervision of the market they had created. For many years these engineers and economists defended the spot markets against attempts to introduce capacity payment schemes (ever-higher spot market price caps were invariably decided to be a preferable solution to possible capacity shortfalls). In fact the only significant market design change that the institutions have accepted over the history of the NEM has been to shorten the settlement period from 30 minutes to five minutes.

The energy market institutions also actively opposed policies such as renewable obligations schemes that provide income in addition to that which generators obtain through the mandatory spot market.

Despite institutional opposition to capacity mechanisms, a decentralized reliability obligation scheme was implemented in 2020. This obliges retailers to enter financial contracts to cover their retail supplies if reliability limits are triggered. Evidently it was not trusted by ministers: no sooner had the ink dried on this new obligation than ministers instructed the institutions to advise on market design changes to promote reliable supply.

The pursuit of marginal cost orthodoxy by officials and the energy market institutions might be contrasted with the evident scepticism, by investors and governments, of the spot market as a source of adequate income to motivate investment. With a few exceptions, almost all of the additional large-scale generation developed since the start of the NEM is either owned by governments, contracted by governments (through contracts for differences), or spurred on by policy support (such as mandatory renewable obligation certificates).

[69] For example, one study—Caramanis, F. C., Bohn, R. E., and Schweppes, F.C. (1982), 'Optimal spot pricing: practice and theory', *IEEE Transactions on Power Apparatus and Systems*, 101(9): 3239—concluded that optimal spot prices would deliver higher customer and producer profits, less frequent blackouts, better capacity utilization, and greater social welfare than any other prices.

Over the history of the NEM, the focus of policy support has evolved. From the start until 2004 the development of coal generation in Queensland was supported by policy through government-owned development, that would not otherwise have occurred. Gas generation policy support, mainly in Queensland (through obligation schemes), followed until 2010. From 2002 in a small way and from 2010 in a big way, renewable generation has also been the focus of support (initially through obligation schemes and now increasingly also through contracts for difference with state governments as the counterparties). Since 2017, electricity storage has also become a focus of policy support (through government ownership and government contracting).

Most recently, the government of Victoria, the state which led privatization in the 1990s, has committed to re-establish the State Electricity Commission to develop renewable generation and storage. The Labour opposition in New South Wales (the state that had only by 2016 fully privatized its generation and retail supply) has adopted a similar policy to be contested in forthcoming elections.

Looking ahead

The preceding text contrasted the different market design preferences of the energy market institutions on the one hand, and investors and governments on the other. The former have reacted to criticism of the market by recommending ‘more market’ or less restricted markets. The latter have increasingly preferred to incentivize new investment by providing income or absorbing risks outside the electricity market and most recently through direct government development and ownership of new capacity. How might this be explained? Three possibilities arise:

First, governments have adopted policies to reduce emissions but have refused to include emission costs into electricity markets. By implication, policy support outside the electricity market is unavoidable if emission reductions are to be achieved.

Second, locational access charges have proved impossible to implement. This is no surprise considering the vested interests in the electricity sector (coal generators insisted that their preferential access should be grandfathered). In addition, turning the ‘social licence’ and environmental impact of new transmission into dollar-per-MWh charges is intractable. Consequently differences in locational constraints are being reflected in ministerial decisions—such as policies for the development of offshore wind—rather than electricity market prices.

Finally, the study cited earlier warned that spot prices were the best possible prices, but only if transaction costs were ignored.[70] Evidently these transaction costs are significant (emission and locational costs just mentioned are amongst many others that have proved to be difficult to price in spot markets) and can not be ignored.

How might the Australian market design debate evolve from this point? Shortly before the end of 2022, ministers agreed to arrangements to directly procure energy storage from non-fossil-fuel sources through competitive tenders, against the advice of the energy market institutions but with the support of investors in new renewable capacity and storage. Most recently, ministers have rejected proposals to introduce locational spot prices, again against the advice of the institutions but with the support of investors in new capacity.

These ministerial decisions seem to have brought to an end what had become an intractable debate over the preceding five years, on the redesign of wholesale electricity markets. There now seems to be little enthusiasm in Australia for the sort of wide-ranging debate that the Department for Business, Energy and Industrial Strategy’s Review of Electricity Markets kicked off in Britain in July 2022.

It might be suggested that these decisions reflect a much-diminished role for spot markets in Australia’s electricity future. But, as the early description sets out, customers have shown little enthusiasm for direct participation in the spot market, and producers have not relied on it to compensate new investments. From this perspective, perhaps the recent ministerial decisions reflect a realistic assessment of how things actually are, rather than how energy market institutions have long wished them to be.

Perhaps future debate on the development of the spot market will be more constructive and tractable if more modest outcomes are expected of the market. In particular, the spot market would seem to be essential for price-based power system balancing and to allocate the cost of imbalance to those participants that caused it. Is it realistic to expect it to do much more than this?

[70] Caramanis, Bohn, and Schweppes, ‘Optimal spot pricing: practice and theory’.

In the contemporary Australian context in which governments and their agents are becoming ever more involved in determining investment and developing or procuring new production, transmission, and storage, it would be helpful to pay more attention to how customers' freedom to choose their suppliers can be used to discipline expenditure and spur innovation.

WHEN A CLIMATE CRISIS MEETS AN ENERGY CRISIS—LESSONS FROM THE AUSTRALIAN NATIONAL ELECTRICITY MARKET

Dylan McConnell and Iain MacGill

Australia is one of the world's largest coal and liquefied natural gas (LNG) exporters, and has a power system dominated by fossil fuels. It was also an early and enthusiastic adopter of electricity market restructuring. While it remains one of the world's most emissions-intensive electricity sectors, the Australian National Electricity Market (NEM) has also seen some of the world's highest growth in wind and solar generation.[71]

In June 2022, the NEM was subject to an unprecedented market suspension that lasted nine days. This occurred against a backdrop of extremely high electricity prices, a largely uncoordinated energy transition, and long-running discussions on significantly reforming the structure of the market itself. This paper briefly outlines the experience of the NEM during the unfolding energy transition and the energy crisis, with a view to illuminating useful lessons and insights into the more general questions of market design and energy transition facing electricity industries around the world.

The Australian National Electricity Market

The NEM is the power system that connects the eastern states of Australia. It delivers power to approximately 10 million customers, and supplies approximately 80 per cent of Australia's electricity consumption,[72] across one of the longest grids in the world. Each year roughly 200 TWh of energy is generated across the NEM, predominately from approximately 300 large centralized generation facilities. Peak demand is around 35 GW, and the installed capacity (including distributed rooftop solar generation) is approximately 70 GW.

As of calendar year 2022, coal generation still dominated the energy mix, contributing 58 per cent of supply.[73] However an impressive expansion of wind and solar has seen renewable energy providing an ever-increasing contribution. Renewable generation contributed 35 per cent over 2022, and almost 43 per cent in Q4 of 2022.[74]

Prior to the 1990s, the electricity sector was owned and operated by vertically integrated state-based utility commissions, which were established by acts of state governments. As in some other parts of the world, Australia began restructuring the electricity sector in the 1990s, motivated by the efficiency and productivity gains promised by the introduction of competition.[75] An intricate national framework for energy markets was established, which emerged from a need to unify disparate state approaches and responsibilities.[76]

These reforms centred on the introduction of a regional wholesale spot market, to introduce competition in the wholesale electricity sector and decentralize operational and investment decisions—ideally to private firms, or failing that, to competitively driven state-owned corporations. A competitive wholesale spot market is still central to the current design of the NEM. The market is an energy-only gross pool market, with all electricity supply offered into a central regional five-minute spot market operated by the Australian Energy Market Operator. The NEM is one of the more pure implementations of an energy-only market and the principles of marginal cost pricing. There is currently no formal or explicit capacity market, and market revenue is primarily based only on energy delivered.

[71] Ember (2022), *Global Electricity Review 2022*, https://ember-climate.org/insights/research/global-electricity-review-2022/.
[72] Australian Energy Regulator (2022), *State of the Energy Market 2022*, Melbourne, Australia: AER, https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2022.
[73] OpenNEM (2023), *OpenNEM—An Open Platform for National Electricity Market Data*, https://opennem.org.au.
[74] OpenNEM (2023), *OpenNEM—An Open Platform for National Electricity Market Data, https://opennem.org.au*; Australian Energy Market Operator (2023), 'Quarterly energy dynamics Q4 2022', Melbourne, Australia: AEMO, https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q4-2022.pdf.
[75] For further details on the restructuring, see Haines, F., and McConnell, D. (2016), 'Environmental norms and electricity supply: an analysis of normative change and household solar PV in Australia', *Environmental Sociology* 2(2), https://doi.org/10.1080/23251042.2016.1155690.
[76] Kallies, A. (2021), 'The Australian energy transition as a federalism challenge: (un)cooperative energy federalism?' *Transnational Environmental Law* 10(2): 211–235, https://doi.org/10.1017/S204710252000045X.

In theory, of course, generation is typically offered into the market at the short-run cost of production. This results in optimal electricity pricing, both maximizing profit for the generator and simultaneously minimizing total system costs. This short-run marginal cost is generally sensitive to and dominated by fuel costs. In practice, generator offers also reflect unit commitment needs, derivative contract positions and, typically, some opportunistic high price bids for additional generation near their rated capacity.

Prices also rise to extreme values during periods where reserves are scarce, as is necessary in energy-only markets. Such scarcity pricing is intended to play a key role in signalling the need for new investment in generation capacity. The high prices, or the risk of them, is critical to driving short- and longer-term derivative contracting that supports operational scheduling and investment.

In practice, questions remain about the suitability of this approach. Indeed, the debates about the resource adequacy implications of energy-market design can be traced back decades[77]. These doubts are even greater when facing the need to rapidly drive profound increases in clean generation investment. Whether or not the NEM will (or in fact has) driven sufficient capacity to ensure resource adequacy continues to be the subject of debate in Australia.[78] While the NEM has seen considerable generation investment over its now 23 years of operation, it can be difficult to separate purely market-driven investment from the impacts of external policy-setting, including renewable energy targets, carbon pricing, and even state government ownership of some large participants.

In the NEM, wholesale prices are currently capped at AUD15,500/MWh. For comparison, annual volume weighted prices were typically historically AUD50–100/MWh. Some mechanisms exist to protect participants from prolonged extreme pricing. One such mechanism inadvertently contributed to the crisis and market suspensions, which is discussed further in the next section.

These features all contributed to the unprecedented crisis and market suspension in 2022. A system with generation and pricing still dominated by traded commodities was susceptible to international price shocks. Scarcity pricing resulting from unexpected generator unavailability and inadequate capacity contributed to extreme pricing. A key protection measure acted to exacerbate existing dynamics and worsen the situation. In isolation, the existing market design may well have persevered without significant problems. The combination proved too challenging, however, ultimately resulting in the temporary suspension of the market.

The makings of a crisis

The NEM pre-2022

In addition to facilitating the efficient dispatch of electricity in real time and ensuring system demands are met at lowest cost, the spot market was intended to provide price signals to market participants to drive investments. This function was questionable and debated prior to the crisis and has arguably been further eroded since. There were signs of stress in the NEM well before 2022.

An extraordinary rise in wholesale electricity prices from 2016, alongside a black system event in South Australia, sharpened political interest in and focus on the electricity sector. The system black and high electricity prices triggered multiple reviews and inquiries, most notably a review from the competition regulator and the chief scientist.[79] The linking of the Australian east coast gas market to international LNG markets through export facilities that came on line in 2016, and unexpected coal plant exits, were certainly factors.[80] A lack of flexible dispatchable generation investment to match these exits as well as growing renewable deployment were also argued to be key factors. These triggered several processes to reform the market to ensure it was fit for purpose. Most notably, these reforms included a proposal that essentially introduced a formal capacity market to the NEM.

[77] For example, see Cramton, P., & Stoft, S. (2006). The Convergence of Market Designs for Adequate Generating Capacity. White Paper for the Electricity Oversight Board. Center for Energy and Environmental Policy Research, MIT, Cambridge, MA. http://hdl.handle.net/1903/7056 and Cramton, P. (2017). Electricity market design. Oxford Review of Economic Policy, 33(4), 589–612. https://doi.org/10.1093/oxrep/grx041

[78] Energy Security Board (2022), 'Capacity mechanism high-level discussion paper', https://www.energy.gov.au/sites/default/files/2022-06/Capacity%20mechanism%20high-level%20design%20consultation%20paper.pdf.

[79] Australian Competition and Consumer Commission (2018), *Retail Electricity Pricing Inquiry—Final Report,* 06/18_1361, Canberra, Australia: ACCC; Finkel, A. (2017), *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia, https://www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market.

[80] McConnell, D., and Sandiford, M. (2020), 'Impacts of LNG export and market power on Australian electricity market dynamics, 2016–2019', *Current Sustainable/Renewable Energy Reports*, November, https://doi.org/10.1007/s40518-020-00164-2.

However, frustrated governments (both state and federal) increasingly and simultaneously took matters into their own hands. In the immediate aftermath to the system black, the South Australian government significantly reinserted itself into the energy supply system, after years of their energy generation asset being fully privatised. This ultimately included direct support for a big battery energy storage system (the largest in the world at the time), and a state-owned gas peaking plant, among other actions.[81] The state government also legislated to give the state's energy minister powers to direct the market. Shortly afterwards, the federal government announced and initiated the development of a 2 GW pumped hydro scheme (called Snowy 2.0). This was progressed via a government-owned entity (Snowy Hydro), which drew on equity from the state.

Since then, direct involvement from various governments of all persuasions has only increased, including other states passing legislation which allows them to work around and beyond the existing NEM frameworks and market structures. This includes the ambitious New South Wales (NSW) Electricity Infrastructure Act,[82] which allows the NSW government to use long-term energy service agreements to underpin 12 GW of new renewable generation across three new Renewable Energy Zones. Victoria also introduced its own legislation, and its own renewable energy target (50 per cent by 2030)[83] and auctions to support that target. Through the government-owned Snowy Hydro, the previous federal government also later supported the construction of a new 750 MW gas turbine in NSW.[84]

A new federal government was also elected on the promise to significantly modernize the electricity grid, through a $20 billion 're-wiring the nation' fund.[85] The details of this program are not fully finalized. However, it is expected that concessional financing will expedite the development of transmission infrastructure separately from or parallel to the existing arrangements funding transmission (and the checks and balances that entails).

In the lead-up to the market suspension, it was clear that both politicians and market institutions were not confident in the ability of the current market arrangements to deliver the necessary new investment. Processes were underway to significantly reform the market, but governments and other decision-makers had largely already made up their minds and were involving themselves more directly and purposefully in the provision of power once again.

Immediate lead-up to the crisis

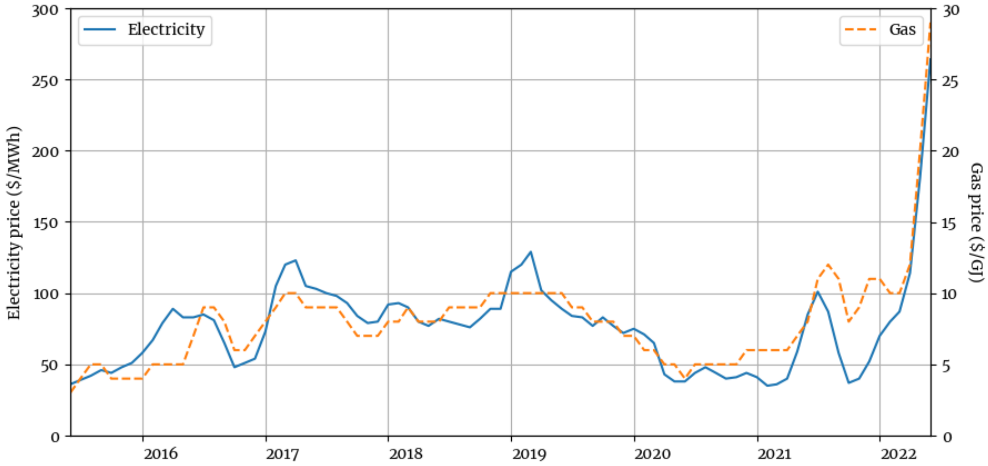
In early 2022, the war in Ukraine and the associated international turmoil sent both coal and gas prices to record levels, creating a global energy crisis. Australia was in no way isolated from these effects, with its domestic markets—particularly the gas market—strongly linked to international markets and pricing. Even where NEM participants have longer-term coal and gas contracts, some may have been able to reroute these towards exports rather than using locally.[86]

Gas prices across the eastern seaboard states surged to over five times historical averages. This alone would have been sufficient to drive significant increases in prices in the Australian electricity market. While gas generation contributes a relatively modest share to annual electricity supply (6–9 per cent in recent years), it has a considerable impact on price setting in the market.[87] The relationship between electricity prices and gas prices can be seen in the figure below.

[81] Government of South Australia (2017), *Our Energy Plan South Australian Power for South Australians*, https://webarchive.nla.gov.au/awa/20170314004323/http://ourenergyplan.sa.gov.au/.
[82] New South Wales Legislative Council (2020), *Electricity Infrastructure Investment Act 2020*, https://legislation.nsw.gov.au/view/html/inforce/current/act-2020-044.
[83] Victorian Government (1 February 2023), 'Victorian renewable energy and storage targets', https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[84] Australian Government (19 May 2021), 'New gas power plant for Hunter Valley', https://www.energy.gov.au/news-media/news/new-gas-power-plant-hunter-valley.
[85] Parliamentary Budget Office (2022), 'Powering Australia—rewiring the nation—Australian Labor Party', https://www.aph.gov.au/-/media/0E6625101815437D8D883CB3DC6C515F.ashx.
[86] McConnell, D., & Sandiford, M. (2020). Impacts of LNG Export and Market Power on Australian Electricity Market Dynamics, 2016–2019. Current Sustainable/Renewable Energy Reports. https://doi.org/10.1007/s40518-020-00164-2
[87] McConnell, D., & Sandiford, M. (2020). Impacts of LNG Export and Market Power on Australian Electricity Market Dynamics, 2016–2019. Current Sustainable/Renewable Energy Reports. https://doi.org/10.1007/s40518-020-00164-2

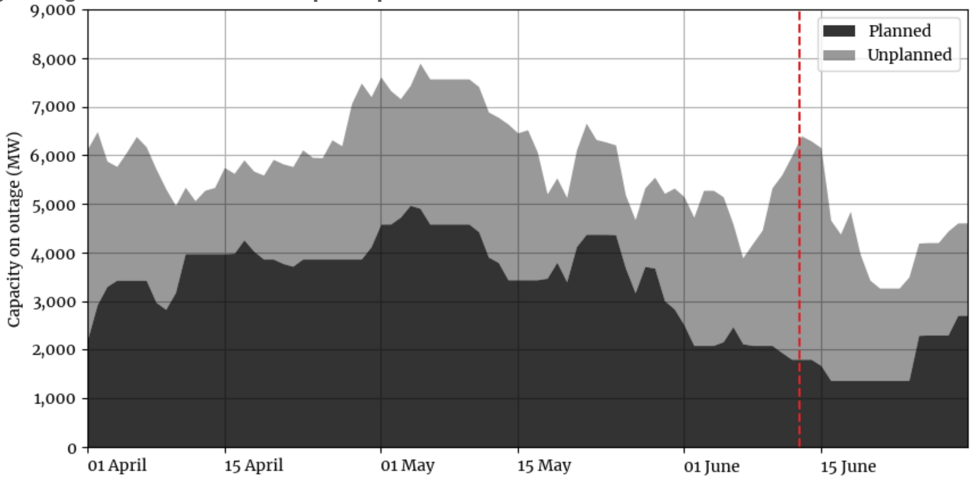
Figure 1: Gas and electricity prices in Australia, 2016–2022



Source: Australian Energy Market Operator (2022), *Quarterly Energy Dynamics Q2 2022*, Melbourne, Australia: AEMO, https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf.

The high gas (and coal) prices combined unfavourably with some planned and unplanned coal outages. Both NSW and Queensland had relatively high levels of planned outages at the black coal plants in 2022. Unplanned outages peaked in the period leading up to market suspension at 4.6 GW out of total installed capacity of 22 GW.[88]

Figure 2: Planned and unplanned coal outages during the lead-up to the 2022 market suspension; the dashed red line indicates the beginning of the administered price period



Source: Australian Energy Market Operator (2022), *Quarterly Energy Dynamics Q2 2022*, Melbourne, Australia: AEMO, https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf.

Combined with a relatively cold winter, these conditions and the market design drove spot and forward prices to high levels, placing some energy customers under a great deal of financial pressure. Several small electricity retailers also went into voluntary administration during this period. The impact of these wholesale prices is still flowing through to energy consumers today.[89]

[88] Australian Energy Market Operator (2022), 'Quarterly energy dynamics Q2 2022', Melbourne, Australia: AEMO, https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf.
[89] Australian Energy Regulator (2023), 'Draft determination—default market offer prices 2023–24', https://www.aer.gov.au/retail-markets/guidelines-reviews/default-market-offer-prices-2023%E2%80%9324/draft-decision.

Price caps and unintended consequences

The high market price cap in energy-only markets represents a significant financial risk to market participants. Prolonged periods of pricing at the market price cap would generate windfall profits for some generators, well above the appropriate recovery of fixed costs, while bankrupting retailers or other large energy consumers.

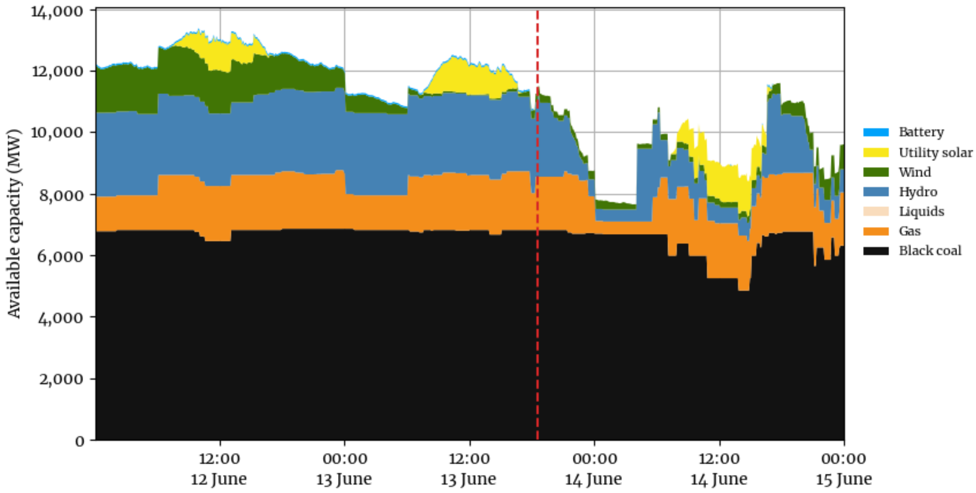
To limit this risk, policymakers had decided early in the NEM design process to place a cap on market revenues equivalent to 7.5 hours of pricing at the market price cap during extreme periods.[90] This protection is implemented via the 'cumulative price', which is calculated as the rolling sum of prices over a period of a week. Once this sum exceeds a threshold (equivalent to the market price cap applied for 7.5 hours), administered pricing is applied. Administered pricing was set at $300/MWh. This level was considered sufficient to allow all generators to at least recover their short-run marginal costs.

These arrangements were deemed to allow sufficient incentives and signals for financing new capacity while protecting consumers and other participants from onerous risks and costs. Significant recovery of fixed cost could occur at 7.5 hours at the market price cap (currently $15,500/MWh), and beyond that short run costs could still be recovered, and generators would still have incentives to generate.

These market settings were initially established over two decades previously and were ill-equipped for the conditions that materialized in June 2022. The high marginal cost of generation due to the coal and gas price rally had significant impacts on this arrangement. Firstly, the high underlying marginal cost meant that the cumulative price was already a high level, even without scarcity pricing. Phrased alternatively, significantly less than the 7.5 hours of pricing at the market price cap was required for the threshold to be hit.

Secondly, and perhaps more significantly, the administered pricing was well below the marginal cost of thermal generation at export gas and coal prices. As such, some generators were in fact not able to recover their short-run marginal cost, as was envisaged in the initial design of this scheme, or were responding to the opportunity cost related to export opportunities. The consequence is that there is a disincentive for generators to offer their capacity to the market and continue generating. As administered pricing was applied, this is exactly what happened. Generators withdrew capacity, which further exacerbated the supply shortfall and pushed prices up and to the market price cap for longer.

Figure 3: Declining availability of generation in NSW following the imposition of an administered price cap of $300/MWh during the lead-up to the 2022 market suspension; the dashed red line indicates the beginning of the administered price period



Source: Australian Energy Market Operator (2022), *Quarterly Energy Dynamics Q2 2022*, Melbourne, Australia: AEMO, https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf.

[90] Australian Competition and Consumer Commission. (2000). 'Applications for Authorisation: VoLL, Capacity Mechanisms and Price Floor. Australian Competition and Consumer Commission.' https://www.accc.gov.au/system/files/public-registers/documents/D03%2B38328.pdf

In order to manage the dispatch process, the Australian Energy Market Operator began to issue dispatch instructions to withdrawn generation via their directions powers.[91] There were several complications associated with this. It was unclear how much capacity was actually unavailable rather than just bid as unavailable, and the dispatch engine was unable to find feasible solutions without violating constraints. The uncapped prices also remained at the market price cap, meaning that the cumulative price simply climbed ever higher with no prospect of it falling below the threshold.

After several days of administered pricing, the operator took the unprecedented step of suspending the entire market. The market-based dispatch process was essentially replaced with manual central decision-making by the market operator. The suspension was lifted nine days later, a point after which the cumulative price fell below the threshold, and the scheduling function of the market could resume, albeit at still high prices by historical standards.

Discussion and conclusions

The penultimate cause of the June 2022 market suspensions was arguably the presence of dated market settings that were not suitable for the conditions that materialized. The Australian NEM is hardly alone in this regard, given the electricity market turmoil seen elsewhere in the world. However it is the case that at least one of the conditions that materialized, namely insufficient supply, is very likely reflective of longer-term underlying challenges. It's clear that prior to the suspension, governments and other decision-makers had doubts about the ability of the market to deliver sufficient investment and were already moving beyond the existing NEM frameworks and market structures. Indeed, the more than 33 GW renewable capacity added to the NEM over the past 15 years—which has been the vast majority of new capacity—has largely been underwritten by 'out of electricity market' policy drivers.[92]

Since the market suspension and wider energy price crisis, we have seen further moves away from a laissez-faire market approach. The federal government (with support from the states) moved to cap the domestic price of both gas and coal late in 2022, illustrating the political intractability of high domestic prices, particularly while coal and gas exporters reap record profits.

The political difficulty of potentially high and volatile energy prices—essential for a functional and complete energy-only market—does not sit well with the significant investment that the energy transition demands.

State-based policy initiatives have also continued to develop. The Victorian government was re-elected in late 2022 with a commitment to re-introduce the State Electricity Commission of Victoria (or at least a new state-owner participant in the Victorian region of the electricity market), alongside significant commitments to support an offshore wind industry. The Queensland government recently announced a new $62 billion jobs and energy plan that would see the state reach 80 per cent renewable energy by 2035, which would remain majority owned by the people of Queensland.[93] A newly elected NSW government has just committed to a new state-owned entity, the Energy Security Corporation of NSW, and the potential re-nationalization of a coal plant has not been ruled out[94].

Meanwhile, the results of processes to formally reform the market and institutions have been lacklustre. After almost five years of development and consultations led by the Energy Security Board (formed specifically to address perceived gaps in governance after the South Australian blackout), the plan to introduce a formal capacity mechanism has been terminated. This has been replaced by a yet-to-be-designed mechanism that would see the federal government underwrite new capacity, potentially through reverse auctions. In its annual report, the Energy Security Board has acknowledged that recent events have set back the development of open and competitive markets.[95]

[91] Australian Energy Market Operator (2022), 'NEM market suspension and operational challenges in June 2022', Melbourne, Australia: AEMO, https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

[92] Nelson, T., Nolan, T., and Gilmore, J. (2022), 'What's next for the Renewable Energy Target—resolving Australia's integration of energy and climate change policy?', *Australian Journal of Agricultural and Resource Economics* 66(1): 136–163, https://doi.org/10.1111/1467-8489.12457.

[93] Queensland Government (2022), *Queensland Energy and Jobs Plan*, https://www.epw.qld.gov.au/__data/assets/pdf_file/0031/32989/queensland-energy-and-jobs-plan-overview.pdf.

[94] Hutchinson, S. (2023). 'NSW Labor floats buying back Eraring power station'. Australian Financial Review. https://www.afr.com/politics/nsw-labor-floats-buying-back-eraring-power-station-20230306-p5cpot

[95] Energy Security Board (2022), *Health of the National Electricity Market 2022*, https://esb-post2025-market-design.aemc.gov.au/health-of-the-nem.

Implicitly, these developments reflect a loss of faith in, if not outright rejection of, the energy market design. Irrespective of the theoretical appeal of the design, and the potential risks of moving away from this approach, Australian governments and decision-makers have seemingly made up their minds. The increasing role of out-of-market government action, or even risk of action, in turn undermines truly market-driven responses. Such developments need to be better acknowledged by Australia's energy rule-makers and regulators, and reflected in its institutional and governance arrangements, to ensure that the Australian energy transition is not delayed or even derailed over the coming decade and beyond.

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The views expressed here are those of the authors. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its members nor the position of the present or previous employer, or funding body, of any of the authors.

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