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.

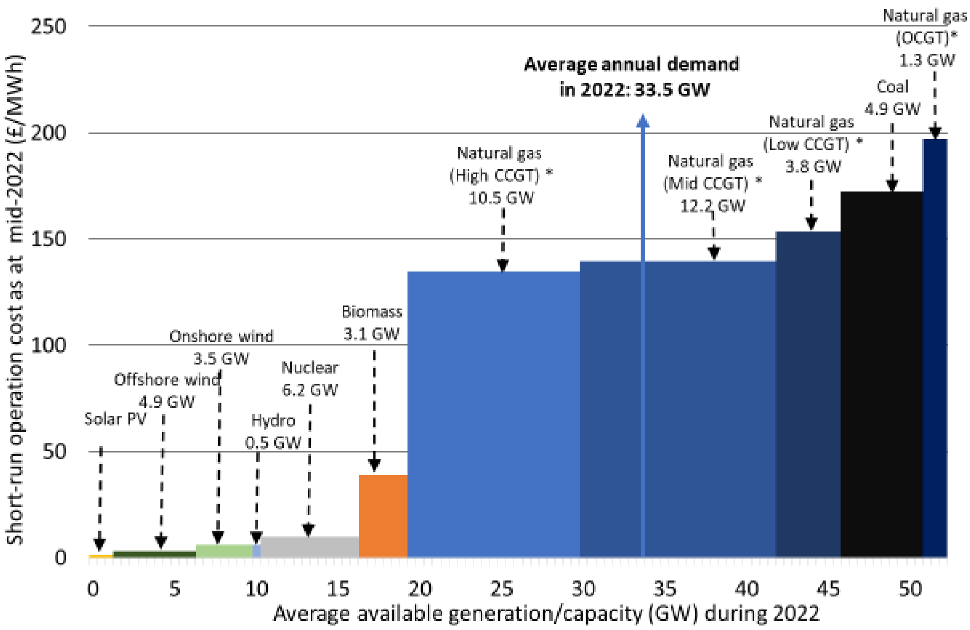
The ‘marginal cost curve’ is already split

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.