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Navigating the crises in European energy:

Price Inflation, Marginal Cost Pricing, and principles for electricity market redesign in an era of low-carbon transition

UCL Institute for Sustainable Resources

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Michael Grubb

with Thomas Ferguson, Ana Musat, Serguey Maximov, Zaichun Zhang, James Price and Paul Drummond

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The energy crisis engulfing Europe is a crisis of both gas and electricity markets, with huge cost impacts on consumers across all European countries. In Britain, half of typical household energy expenditure arises from electricity. This paper examines how the cost of gas-powered generation feeds through to electricity bills, on the principle of marginal cost pricing, setting the price for most of the time though it accounts for only about 40% of GB generation. Combined with the steep decline in wind and solar costs over the past decade, this has resulted in an unprecedented degree of 'cost inversion' in the electricity system. We offer estimates of the increase of revenues across the wholesale market, and outline five principles for reform for addressing the combined challenges of energy costs and accelerating low-carbon transition.

Keywords: Electricity market design; energy crisis; marginal cost pricing; energy transition; energy poverty

Journal of Economic Literature (JEL) Classification Codes: L16; L51; L94; L98; Q4; Q28; Q58

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About this publication

This publication is released as Working Paper 3 in the UCL Institute for Sustainable Resources series Navigating the Energy-Climate Crises. It contains an Executive Summary for stakeholders interested in the policy-relevant findings of the underlying research.

Corresponding Author

Professor Michael Grubb, University College London Institute for Sustainable Resources
m.grubb@ucl.ac.uk, Central House, 14 Upper Woburn Place, London WC1H 0NN

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Navigating the Energy-Climate Crisis - Working paper series

A series of papers to inform debates in European countries about structural options for responding to the energy-climate crises, particularly concerning the electricity sector in the context of transitions towards more renewables-intensive systems.

Reflecting the urgency of the energy-climate crises, four Working Papers are planned for September and October 2022. Papers 1 and 2 provide technical research findings concerning, respectively, (1) the extent to which natural gas drives electricity prices, and (2) estimated flows of money across different types of generating technology and support systems in the British electricity system. Papers 3 and 4 analyse policy implications, concerning (3) some of the fundamental economic considerations for sustainable policy responses, and (4) specific design considerations for 'dual market' approaches, including proposals for a Green Power Pool.

For more information and to see the papers published so far visit the Navigating the Energy-Climate Crisis website.

Editor and Lead Researcher
Professor Michael Grubb
Professor of Energy and Climate Change, UCL Institute of Sustainable Resources.
Email: m.grubb@ucl.ac.uk. Twitter:@michaelgrubb9 @UCL_ISR

Executive Summary

Economies across Europe face unprecedented energy-economic challenges, with cost-of-living/inflation impacts which hold the prospect of turning into major social and political crises. In the UK, without any intervention, total household consumer expenditure on energy is set to rise from £64bn in 2021 to around £200bn – an *increase* exceeding defense and education expenditures combined. This is dominated by expenditure on electricity and gas, split (on average) roughly equally between the two. Energy costs are a prime factor driving general inflation in the UK to at least 10%, whilst poor households face cost-of-living increases of almost 20%.

The proximate causes – a Covid-recovery surge of global demand relative to supply in global gas markets, followed by the Russian invasion of Ukraine - are well known. In addition, the unprecedented heatwaves and drought across Europe – in line with the expected foothills of accelerating climate change - have curtailed output from nuclear and hydro sources, adding further pressure to electricity prices even aside from other more direct impacts of the extreme weather.

However, underlying these proximate causes is the generalized application in energy of an economic principle of marginal cost pricing, far beyond its appropriate limits. This principle - which in energy markets could be more precisely termed short-run-marginal-cost-on-all pricing - means that fossil fuels still predominantly set the wholesale price of electricity, which over the past eighteen months, has risen from around £50/MWh to around £200/MWh.[1] At the same time, European electricity systems are in the midst of a transition from the internationally traded commodity of fossil fuels, to mainly domestic assets – notably, renewable energy sources.

Aside from the cost and distributional consequences, such an approach to pricing is also demonstrably inappropriate for driving investment in non-fossil fuel assets; indeed, it is obscuring the growing success of a transition which has seen rapidly rising volumes of increasingly cheap renewable energy. The UK in 2013 initiated a system of long-term fixed-price ("CfD") contracts for renewables. The initial rounds combined cheaper onshore wind & solar with less mature & hence more expensive offshore & biomass energy, but the investment stimulated huge cost reductions particularly in offshore wind. The large offshore windfarms coming onstream this year cost around £70/MWh, and the subsequent contracts for offshore wind – agreed in 2019 and 2022 for delivery in the next few years – cost around £46/MWh and £38/MWh respectively.

The result is a striking 'cost inversion'. Such sources, based on contracts outside the market, offer power at under a quarter of current and projected wholesale electricity prices. They presage a future of predominantly non-fossil, asset-based electricity with entirely different economic (as well as environmental) characteristics. Aside from the proximate causes, navigating the crisis by exploiting this transition is the fundamental task facing policymakers.

In this context, we identify the following challenges and corresponding implications for policy:

1. *Short-run (in electricity, half-hourly) marginal-cost-pricing means that the most expensive operating sources set the electricity price for most of the time, and are an inappropriate basis*

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[1] Costs for wholesale markets are given in £/MWh. £10/MWh is equivalent to 1p/kWh, the unit typically used for domestic electricity prices; final consumer prices of course incur many additional costs for transmission, distribution, retail, and various other services for maintaining supplies.

for funding investment in long-lived assets which cost little to run. As demonstrated empirically in our first working paper (#1),[2] fossil fuels set the electricity price for most of the time, at levels which are now much higher than the energy cost of at least half the system (recent renewables and existing nuclear) – so the price of electricity is way above the average cost of generating it. The market design reflects largely static theories of 'optimal equilibrium' which neglect distribution, entry barriers, risk allocation and the evolving dynamics of the system.

This dependence on fossil fuels to set the wholesale price in practice introduces high volatility and uncertainty in the price that non-fossil investors would receive in the market, making it an extremely inefficient basis for funding large-scale renewables. Renewables investment in practice has mostly been funded *outside* the wholesale market, leading to large technology cost savings which only partially feed through to electricity prices. The result is an increasingly disjointed system, including ambiguity and confusion around many so-called 'green tariffs', but with prices to most consumers still mainly set by fossil fuels even as governments accelerate efforts to decarbonize electricity – a combination which itself its unsustainable.

Implication: the growing prevalence of lower-cost renewables, mostly on long-term contracts, is not an aberration but a fundamental feature: against the context of the energy price crisis, it offers an opportunity that could be seized by substantial changes in electricity market design which will anyway become unavoidable as the role of fossil fuel declines.

2. *The gap between wholesale electricity prices and average electricity generation costs is a structural problem with huge financial consequences.* We estimate that, if sold at day-ahead prices, revenues to British generators selling electricity into the British wholesale electricity market (excluding the renewables on fixed-price CfD contracts) would have approximately doubled from about £12.5 - £14 billion in 2019, to £28 - £30bn in 2021.[3] Based on price trends this year they are likely to nearly double again in 2022.

   Gas markets remain tight and volatile, but forward electricity contracts show prices rising even above the marginal cost of gas generation - reflecting the perceived risk of shortfalls and unstable piecemeal interventions. This enhances profits to all generators and further drives inflation. Expectations of high electricity prices also deter electrification of heating, transport and industry, which is a central plank of decarbonization and reducing dependence on fossil fuels.

Implication: structural solutions are required to separate the average price of electricity from the short-run marginal-gas cost and risk-based premium pricing of current wholesale markets.

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[2] "We find that before the energy crisis, gas set the electricity price in Britain for 84% of the time despite being only 40% of the generation, whilst non-fossil sources set the price under 1% of the time (imports from the continent held down the price for the remaining 15%); across Europe, on average fossil fuels set the price for two-thirds of the time whilst constituting only one third of the generation." UCL-ISR: NECC Working Paper #1, "The Role of Natural Gas in Electricity Price-Setting in Europe".

[3] Different data sources yield slightly different results. This estimate comprises only sources that participate in the GB balancing mechanism, and excludes those on fixed-price contracts which repay surplus. The actual figure accruing in recent periods could be lower to the extent that generators were still on fixed price Power Purchase Agreements. Our Working Paper NECC #2, *Where's the money going? Estimating electricity generator revenues in Great Britain*, will provide details of data sources and calculations for different technology / contract classes.

3. *Some consumer groups are much more vulnerable than others and the price increases in train have untenable distributional consequences.* Economic ideas of 'aggregate static efficiency' do not capture essential distributional dimensions of welfare and the realities of different circumstances. Moreover, whilst high gas prices are a global phenomenon, electricity price impacts across regions vary radically according to market design:
   - For industry, high wholesale prices across Europe risk making it impossible for electro-intensive, trade-exposed sectors to compete internationally. In the UK, proposals for industry support – effectively, government underwriting to a fund to spread bills over many years – have been rejected, and would not address the fundamental problem.
   - For households, without intervention, average UK domestic consumer bills are set to almost quadruple from pre-crisis levels. Whilst energy costs are a major factor in driving general inflation at around 10%, the poor face an almost 20% increase in their basic living costs, not remotely matched by increased welfare payments. For 'fuel poor' households, even reducing the electricity price to the average generation cost would bring limited help, as typically about half of the bill is from gas heating. Current financial support for the estimated 8 million such households totals just under £10bn - a level of support which is still inadequate, contentious in terms of tax implications, and hard to sustain.

Implication: Governments need to consider whether vulnerable groups – in both households and business – can or should be priority beneficiaries of the revolution in cheap clean electricity.

4. *Current approaches to contracting renewables, both public and private, are not durable for transition at scale.* Renewables are now clearly much cheaper than wholesale electricity, per unit. However, the variable nature of wind and solar requires backup and balancing to ensure reliable supplies, which whilst moderate in scale at present, may rise non-linearly as their contribution grows. Backup and balancing are system properties, but the fact that the renewables sector does not bear its share of these costs removes incentives for efficient location and choice of renewables and undermines the clarity and credibility of purely private sector renewable contracts and 'green tariff' offerings.

Implication: seizing the opportunity of low-cost renewables ultimately requires market structures which apportion backup and balancing costs appropriately and proportionately.

5. *Consumers are diverse and so are their emerging technology options – but multiple obstacles prevent consumers – both households and businesses - from exploiting the potential.* Smarter controls, emerging technologies and new electricity uses including storage at many scales could reduce dependence on fossil fuels, bring down overall costs, enhance flexibility and help consumers offset some of their energy bills. Electrification including heat pumps for heating, electric vehicles and many industrial processes, could introduce new sources of decentralized flexibility for helping to match the variability of wind and solar energy. Short-run marginal-cost pricing remains important as a dynamic signal "at the margin" of production and consumption (rather than being applied across all electricity), for efficient operation and to reward flexibility; but empowering consumers to respond to this requires reforms to drive investment in the required demand-side technologies and associated infrastructures.

Implication: Along with supporting infrastructure, pursuing the energy transition will require new policy approaches and institutional structures to engage consumers across all energy uses, so as to enhance investment in energy efficiency, innovation, and electrification with flexibility.

Overall, a strong role for public policy is inescapable given the ‘perfect storm’ facing our energy system. There is little evidence that public ownership is a better long-term solution, but it risks becoming the default if these problems are not tackled. The key is to recognize that whilst the emerging, non-fossil electricity system is both cleaner and cheaper, it is also fundamentally different. Exploiting the opportunities to escape the energy-climate crises will require fresh thinking: to combine asset finance with efficient dynamic operation of what is already becoming, by default a dual electricity system. Researchers have already identified multiple elements for achieving this, with at least three structural options for separating marginal from average costs in the system; our next report explores, in particular, options to harness ‘dual market’ approaches.

Introduction

“Electricity is Different”

- Walt Patterson (2007), in *Keeping the Lights On* (Chapter, *Electric Challenge*)

“No method of economic analysis can determine, scientifically, what to do about the gap between average and marginal cost”

- J.R.Nelson (1963), in *The American Economic Review*

1. Introduction

My title is plural, because we face interrelated crises. This paper outlines ways in which dealing with the energy crisis is intertwined with decarbonization, and why successfully navigating both requires tackling a third: a crisis of economic thinking and arrangements that are now inadequate for an energy sector in transition. The focus is upon electricity in Europe – the UK, European Union and related countries – though many of the themes are relevant to many countries, particularly those with competitive electricity markets.

Energy costs…

The first crisis looms particularly for every energy consumer in Europe (which is all of us, and many industries), impacting the cost of procuring energy and the price charged to consumers. In the UK, right up to end of 2020, the marker household energy price-cap set by the regulator Ofgem totaled just over £1000. By the end of 2021 it had doubled. As this paper goes to press, bills are projected to double again, with the cap from October set at £3549 / yr. with an increase to well over £4000 next Spring almost inevitable (Figure 1).

In absolute terms, those costs imply that household expenditure on electricity, gas and fuel over the next year, without support, would be in the region of £200bn - about 8% of GDP. This substantially exceeds combined expenditure on defense and education and makes energy the dominant driver of inflation.[4]

The huge surge echoes how the fossil fuel crisis is affecting energy bills across much of Europe and beyond without policy intervention. Its devastating impact, particularly on low-income households, has led to a mix of policy responses. In the UK, competing promises by candidates for the Conservative Party leadership to remove VAT and/or 'green levies' have been politically expedient but would slice only a few percent - respectively only the top sliver (VAT) or bottom sliver (green levies) - of bills as indicated in Chart 1,[5] and 'removal' may mean shifting those costs to general taxation or national debt. Hence these are more or less irrelevant - and potentially, even counterproductive - to mastering the underlying crisis driven by wholesale energy prices (the grey). In the UK, the more heavy-duty sticking plaster has comprised lump sum payments to households from the Treasury, touched upon in section 3.2.

[4] A useful summary, updated 26th August, is given by Carbon Brief at https://www.carbonbrief.org/analysis-why-uk-energy-bills-are-soaring-to-record-highs--and-how-to-cut-them/. Distributional impacts on consumers are summarized further in section 3.2 of this report.

[5] Green levies, which pay subsidies for older renewable energy projects in the UK, account for roughly 3% of the October 22 price cap level. Other levies go towards social policy objectives, paying for the 'warm home discount' that helps poorer pensioners with their bills, as well as the 'energy company obligation', which aims to tackle fuel poverty by insulating homes.

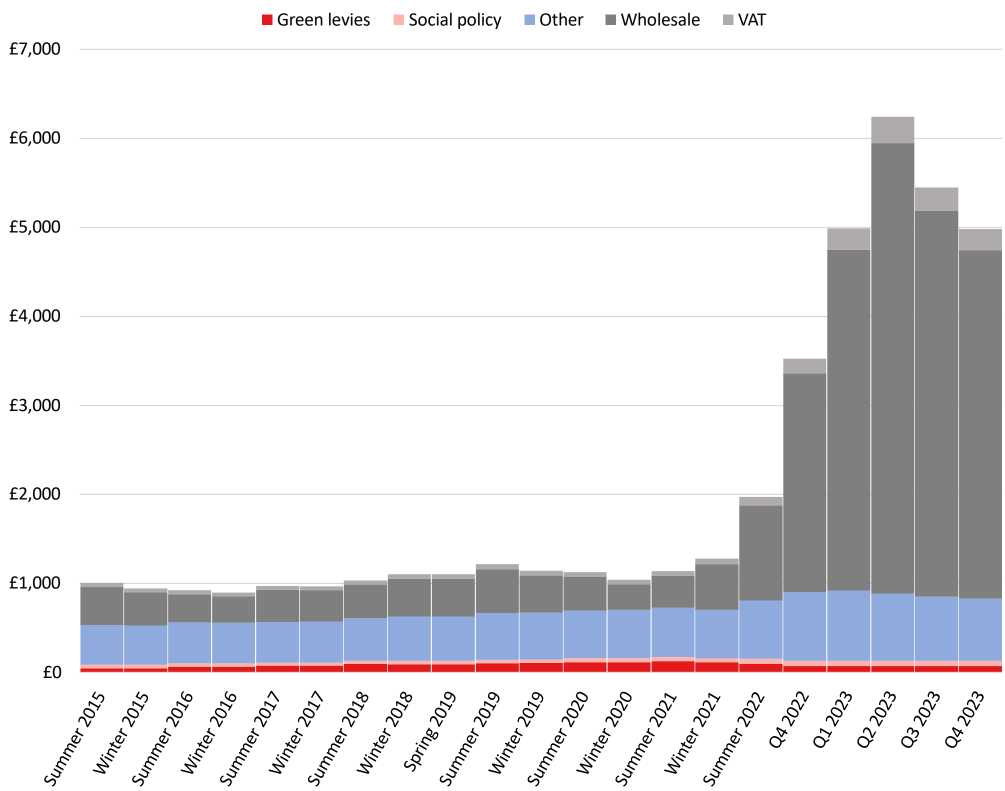

Figure 1: Typical UK household energy bills 2015-2023 Q1 based on price cap, and projections for rest of 2023

Notes: "Other" includes transmission, distribution, and retail costs. On average, the costs of a typical dual fuel bill are split roughly equally between gas and electricity.

Source: Redrawn from https://www.carbonbrief.org/analysis-why-uk-energy-bills-are-soaring-to-record-highs--and-how-to-cut-them/

Across Europe in addition to enhanced efforts on energy efficiency, there have been a diverse range of responses - some bold mixed with desperation, including absolute caps on gas prices and, in France, nationalization of the electricity company EdF. These piecemeal approaches are reversing the previously growing coherence of European energy policy, and could even threaten the EU's flagship Single Electricity Market.

… and Climate Change

The second crisis is climate change. It seems a twist of irony that in this year of energy crisis, heatwaves shattered temperature records. The UK recorded over 40C for the first time in history – some parts of southern and eastern Europe saw temperatures over 45C. Growing climate impacts in other parts of the world – especially hotter and poorer developing countries - have been even more devastating, most recently with the floods in Pakistan. Countries across the world must now grapple with the immediate impacts of climate change –including crop failures following droughts, damage to infrastructure from heatwaves, wildfires and flooding. Things will only get worse until emissions are drastically reduced, first and foremost by curtailing use of fossil fuels.

It makes no sense to use the present energy crisis as a reason to make worse the even bigger, more enduring crisis of climate change. Our response to the first must instead be a springboard to accelerate progress on climate change, in ways that also reduce dependence on volatile fossil fuel markets. The fact that low carbon electricity is now *much* cheaper than fossil-fuel based energy (see next section, and more generally, IPCC (2022)) signals a clear potential to do so.

Scope of this paper: rethinking some fundamentals of electricity markets

However, achieving this will require smarter thinking than yet displayed in either the UK or the EU, and in particular, to align necessarily urgent responses with the emerging opportunities of a longer-term transition. One underlying reason is that clear thought has been hampered by a simplistic interpretation of a common economic principle of 'marginal cost pricing', and the way it works in practice in electricity markets. At the heart of electricity economics across Europe is a short-run 'spot' market in which the 'marginal' generator – the most expensive operating plant required to meet the demand – sets the price for all in the spot market. This in turn becomes a reference point for most other contracts in the market.

In effect, a general economic idea of pricing 'at the margin', based on quite simple (and simplistic) economic ideas (see Box 1), has become translated into a more general structure of short-run-marginal-cost-on-all – a structure which also does not take into account the technological revolution under way in electricity systems.

As a primer for our work on redesigning electricity markets in a period of energy-climate crises, this paper sets out some fundamentals, explaining where the current operation of electricity price formation has led us, the deepening nature of the cost-inversion in electricity systems (i.e. renewables now being the cheapest form of generation), and some economic principles that could help guide options for short-run and longer-term reform.

It is impossible for this paper to cover all the important issues in electricity market design. An excellent comprehensive overview is provided by the UK government consultation document *Review of Electricity Market Arrangements* (BEIS, 2022). A major study by Energy Systems Catapult (Keay-Bright and Day, 2022) also covers a wide range of reform issues and options in UK electricity.

Most significantly, the paper does not attempt to cover in depth (a) issues of location, and associated charging for transmission, constraints and interconnectors; or (b) local and distributed electricity management. Locational incentives, for wholesale market operation, are well covered by literature and debates on locational marginal pricing or zonal pricing (e.g., (Newbery, 2021)). Design for efficient type and location of investment (insofar as it is recognized that short-run incentives do not adequately incentivize location of big generation) is thinner but emphasizes the need for coordinated system planning of generation and transmission, a 'system architect' function. Local and distributed electricity issues are well covered, amongst others, in research by the Exeter INOGOV program e.g., (Pownall, Soutar and Mitchell, 2021).

This paper focuses on the other underlying issues which are fundamental to a successful transition that can address the concerns of both the energy crisis, and decarbonization, particularly in relation to the current highly charged debates around the role of marginal cost pricing.

The analysis comprises two main sections. Section 2 outlines the principles, intended benefits, and evidence about the impact of marginal cost pricing in European electricity, and the consequent impact of gas costs on wholesale electricity prices and revenues. It then contrasts the current fossil fuel part of the system with emergent renewable energy systems and associated new technologies for electricity demand and system flexibility.

Section 3 then outlines for discussion four fundamentals relevant to effective reform, namely:

- Investment horizons and risk allocation

- Distribution and Welfare
- Innovation and transition for renewables-intensive systems, including variability
- Consumer differentiation and agency

The conclusion then outlines briefly a classification of major reform proposals that touch upon some of these issues.

2. Marginal Cost Pricing and cost inversion in European Electricity

2.1 Primer: the idea of marginal-cost-pricing

Box 1: Price formation in wholesale electricity markets

The way that primary energy costs set the wholesale price of electricity in competitive electricity markets, whilst complex in practice, is very close to the simple theory of marginal cost pricing. Conceptually, this stacks up generating units in order of increasing operational cost, with the cheapest-to-operate running first. This, which defines the 'merit order' of operation, is summarised with data for the British electricity system in Figure 2. The underlying market principle is that meeting the total electricity demand requires a price matching the cost of the most expensive operating plant required to do so – otherwise that plant wouldn't run.

In practice, generating plants bid a price at which they will generate electricity, and the market will only provide enough power ("clear") when the price brings on enough generation to do so. This is set by the operating cost of the most expensive unit required to meet the demand – known as the marginal plant - at any given time, *based on short-run operating costs*. Since these are short-run costs – with prices typically varying every half hour or hour – the core trading market is often known as a *spot market*. Since all generators have a reasonable idea of the likely state of the market when they bid, the price of electricity tends to approximate that 'marginal' cost – a private operator won't sell its electricity at a much lower price than it could get in the wholesale market.

After scheduling all non-fossil plants (solar, wind, hydro, nuclear), which are generally cheapest to run for most of the time across most of Europe, the needed additional generators are powered by fossil fuels – which consequently, set the price for all. All those other ('inframarginal') generators receive much more than their short-run operating costs.

The theory is that this extra revenue - 'inframarginal rents' – can then cover the capital cost of those non-fossil plants, which historically have been much more expensive to build - and if higher fossil fuel costs increase that marginal price, the scheme increases the incentive to build more such non-fossil fuel plants.

The idea can be extended to take account of locational issues, through 'locational marginal pricing' (LMP), or less specific 'zonal pricing'. These reflect the cost of transmission from generators to demand, including the cost when some generators have to be 'constrained off' due to insufficient transmission capacity – which also then signals the value of constructing new transmission capacity.

This approach has much to commend it in theory, most clearly in terms of "efficient dispatch" – to ensure that plants which cost least to run operate before more expensive ones - and in providing information about important constraints on the system, including when supply is tight.

However, it rests on many assumptions which are often glossed over. If demand cannot respond to short-run prices it is a recipe for volatility. It typically assumes that very short-run prices can drive efficient long-term investment, and that entry for new cheaper technologies is easy and quick - neither is true in electricity (see also section 3.1 and note 18). Also underpinning it is an assumption of sufficient competition between different units to ensure the cheapest does operate – whilst the participants know that anything which lessens the entry or output of cheaper plants will raise the marginal cost, and hence the revenues to all generators (a core reason for extensive monitoring mechanisms to try and detect market manipulation by large companies).

Moreover, the focus on ideas of 'static aggregate efficiency' often leads to neglect of crucial distributional concerns, as highlighted by the energy crisis, and other limitations of marginal pricing as a *primary mechanism* to accelerate transformation away from fossil fuels, as explained in section 3.

One common myth is that huge profits simply reflect monopolies dominating in uncompetitive markets. In electricity, if anything, almost the reverse is true in the short run. Increases in electricity prices have been particularly dramatic in competitive electricity markets, because they respond rapidly and with few constraints to the principle of marginal cost pricing (Box 1).

Underlying the economic theory of marginal cost pricing (MCP) is an idea of equilibrium – a long-run stable situation, with pricing providing market incentives to move towards such a state, as outlined in Box 1. MCP is indeed a very important incentive to operate existing systems efficiently. It ensures that the cheapest-to-operate plants are used as much as possible, with more expensive ones only called on when needed. The theory is that such pricing is efficient, including the lead incentive to construct new, low cost plants, which can use their operating profits to recoup the cost-of-capital and which (it is assumed) are much more expensive to build than fossil fuel plants.

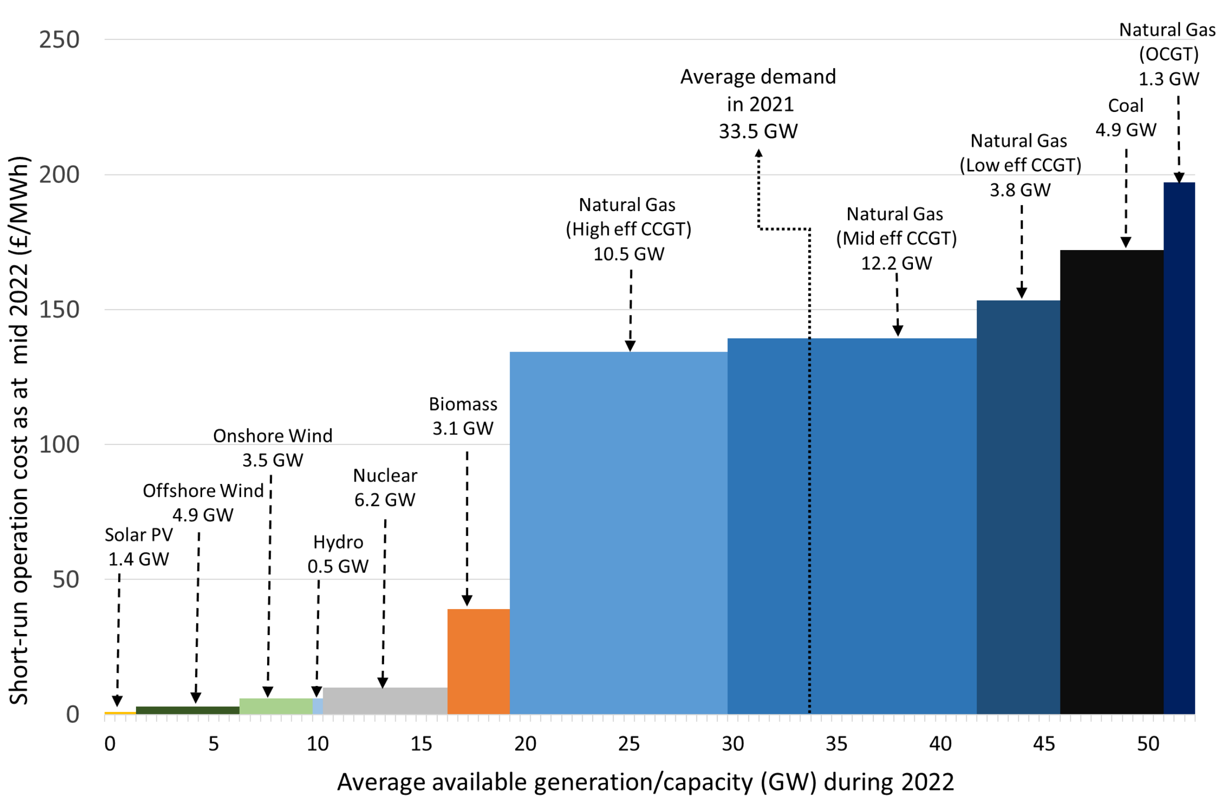

Figure 2: Merit-order of electricity generation in Great Britain in mid-2022.

Notes: Based on approximate short-run marginal costs in mid-2022. Capacity values given are based on average availability and capacity factors of each technology. Costs are the sum of variable O&M, fuel, and carbon costs (as applicable). Installed capacity per technology from DUKES 5.11, costs of fuels from DUKES 3.2.1, O&M costs from BEIS, carbon cost assumed at 80 £/tCO2, Capacity factors from DUKES 6.3 and availability factors for thermal generation assumed at 0.9.[6]

[6] https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020. DUKES is the Digest of UK Energy Statistics.

Figure 2, which shows the GB[7] generating stock and operating costs, stacked up in order as at mid-2022, illustrates the practical implication. Expressed in term of power, the average annual demand of 33.5 GW far exceeds the average available output of low-carbon electricity sources, so gas plants are essential to meet demand for almost all the year – and, consequently, set the wholesale price, then at around £150/MWh. In theory, the operating profits for all the non-fossil plants, to the left in the Figure, are intended to cover their higher investment cost (Box 1).

2.2 Some consequences of marginal-cost-on-all pricing

Despite many positive dimensions, in terms of the wider and longer-term economics of the system however, the textbook idea of marginal cost pricing poorly captures implications of the instability of fossil fuel markets, or many realities of investment and innovation required, particularly for emerging technologies and new players. This is partly because the principle is usually assumed to apply across all electricity, as a 'homogenous product' – 'energy-only' markets, in which the same short-run marginal cost is applied to all.

The case for this as the *overall* best approach implicitly assumes that the principal difference between generating plants is the balance of capital vs operation costs in producing an identical single commodity – electricity – and, crucially, that markets can strike the best balance between capital investment and operational costs. It also largely ignores the perspectives of energy consumers, with diverse needs, vulnerabilities, interests and actual or potential capabilities; and assumes away concerns about distributional impacts. We examine these and other key dimensions in section 3.

It is the consumer impact that has catapulted the energy crisis to the political frontline whereas technical analysts have tended to focus more on the other dimensions. For marginal pricing implies that the 'marginal' generator – the most expensive to run at any given point in time – sets the wholesale price of all electricity. A recent empirical study of electricity price-setting in Europe confirms the implications. [8] Table 1 summarizes results for the most recent year studied across 9 major European countries (for other years and other countries, see the source paper).

[7] When discussing the economics and operation of the electricity market itself, the focus is on Great Britain, where the system is governed by a single electricity market; the system in Northern Ireland is subject to different rules as it is integrated physically and operationally with the Irish electricity system.

[8] UCL-ISR NECC Working Paper 1: Behnam Zakeri*, Iain Staffell, Paul E. Dodds, Michael Grubb, Paul Ekins, Jaakko Jääskeläinen, Samuel Cross, Kristo Helin, Giorgio Castagneto Gissey (2022), 'Energy Transitions in Europe – Role of Natural Gas in Electricity Prices'. Preprint available at SSRN: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=%204170906

Table 1: Percentage of time for which electricity prices were set by different sources in 9 major European countries (2019)

Country	Fossil fuel	Non-fossil	Imports
Germany (DE)	91%	7%	2%
Denmark (DK)	25%	13%	62%
Spain (ES)	89%	6%	5%
France (FR)	7%	93%	0%
Ireland (IE)[a]	61%	1%	38%
Italy (IT)	86%	11%	3%
Greece (GR)	77%	0%	23%
Portugal (PT)	87%	13%	0%
United Kingdom (UK)	84%	1%	15%

Source: (Zakeri *et al.*, 2022)*, Table 2*

In most of those countries (excepting France, Denmark and Ireland), although non-fossil sources and (for some) electricity imports accounted for over half the generation, fossil fuel generators set the price for more than 75% of the time. In the UK, natural gas accounted for around 40% of generation but set the price for 84% of the time and imports kept the price down for almost all the rest (15%). Non-fossil sources set the price less than 1% of the time, though they generated about half of the GB's electricity in that year (wind and solar being about 25%).[9]

[9] Non-fossil generation in Great Britain in 2021 totaled just over 50% of generation, comprising wind 19.4%, solar 3.6%, nuclear 13.8%, biomass 12%, Hydro 1.6%, plus 7.4% imports from interconnectors which were primarily from nuclear power in France.

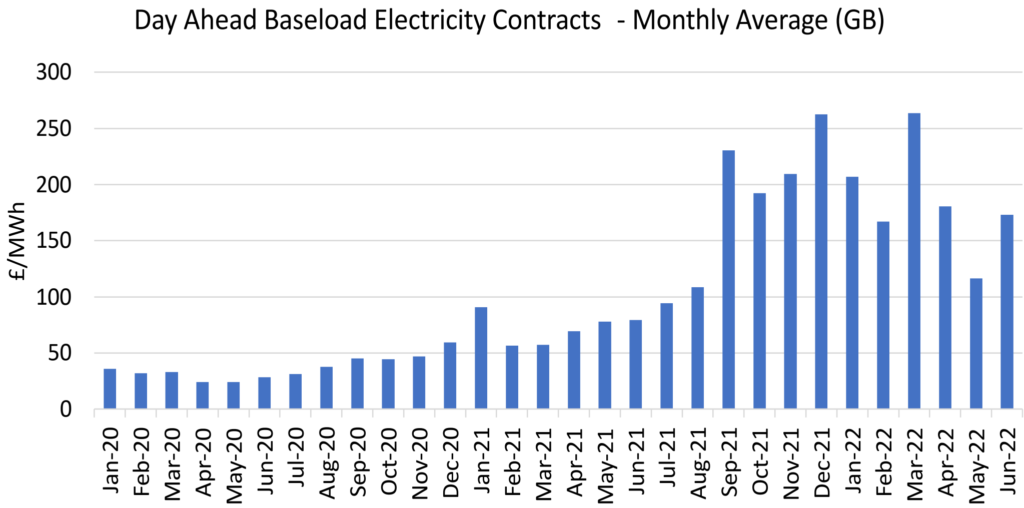

Figure *3*: GB Wholesale electricity prices (day-ahead) from January 2020 to June 22

Source: Ofgem: https://www.ofgem.gov.uk/wholesale-market-indicators

Consequently, after several years of relatively stability, the wholesale price of electricity across Europe has followed the price of fossil fuels, and in Britain, specifically, natural gas. The result, shown in Figure 3, is that wholesale electricity prices over the past year have gyrated around £200/MWh – four times the level typical through to 2020. Given the combined impact of increases in direct fossil fuels (particularly gas for heating), along with this impact on electricity prices, it should be no surprise that crisis in the fossil fuel markets is generating a wider inflationary and cost-of-living crisis.

Along with this arise concerns about 'windfall profits'. The profits of fossil fuel producers have surged to extraordinary levels – with BP and Shell between them reporting overall profits totaling around £30bn in the first half of 2022.

Less transparent and more complex are developments in electricity. The price paid to generators in the wholesale market has increased dramatically – driven by the roughly quadrupling cost of the fossil fuel generators on the right-hand side of Figure 2. However, the cost of generation for low-carbon and other 'inframarginal' generators – notably, those on the left-hand side of Figure 2 - has not changed. Some of those generators are selling on fixed price contracts, but the profits to those which sell into the wholesale market have mushroomed. In section 3.2 we summarize our analysis of the impact on revenues in the wholesale electricity market.

Gas itself accounts for less than half the total generation. To some degree, gas generators themselves have benefited – the more efficient ones gain profits when the less efficient (and more costly ones) are setting the price, and gas has at times made additional revenues from higher 'imbalance' payments in the volatile market, but others selling into the wholesale market, and not on fixed price contracts, benefit the most.

The crisis is not over – far from it. Electricity generators need to contract their gas supplies ahead, to be confident they can generate when required. Figure 4 shows the unprecedented trends in GB wholesale gas prices from well below 50 p/therm (even lower during Covid in 2020), to over 500 p/therm in summer 2022. The futures market climbs even higher, maintaining at over 700 p/therm throughout 2023 before softening in 2024. Forward gas prices are very volatile, reflecting nervous and uncertain markets and numerous deep uncertainties about whether emergency supplies arrive in time (and at what cost), the progress of the Ukraine war, and prospects for European and global demand in the face of sky-high prices, among many other factors. They change on an almost daily basis. But even out to 2026, the market expectation across Europe is that gas will remain several times more expensive than the cheap gas previously enjoyed by consumers (Figure 4).[10]

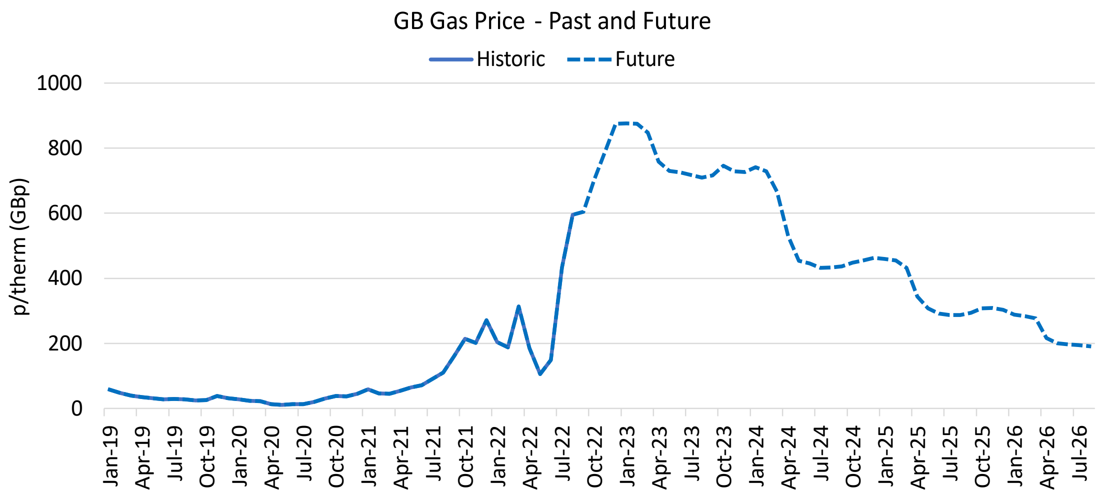

Figure 4: Wholesale gas prices in Britain (NPB), historical 2019 to July 2022, and forward contract prices to 2026 (at end Aug 2022).

Source: *Compiled by authors with historical data from Ofgem (to June 2022) and Trading Economics https://tradingeconomics.com/commodity/eu-natural-gas (for July and August 2022), with forward contracts data from Platts European Gas Daily (Volume 27 / Issue 166 / August 30, 2022).*

To ensure generation, electricity generators have to bid for gas, at prices set by the gas market. Moreover, forward prices in *electricity* markets suggest that electricity buyers, nervous about possible generation shortfalls and future prospects, are now paying a substantial premium above even projected gas generation costs.[11] This is attributed to general nervousness exacerbated by a 2022 shortfall in nuclear and hydro generation due to the extreme weather conditions. If these electricity costs come to be reflected across the full market, the price crisis in electricity has barely begun.

Many producers are ‘winning’, with the inevitable cost to energy consumers. None of the factors noted necessarily undermine the value of marginal cost pricing for ensuring efficient and effective *operation* of the system – with some important caveats, including periods where market risk perceptions start to drive the electricity price way above even gas costs.

[10] Over summer 2022 European gas prices rose above UK prices, as Germany and others bid to secure enough gas to fill up their storage capacity (which the UK lacks) for winter. In general, UK and continental prices tend to be closely coupled.

[11] The industry indication is known as the ‘clean spark spread’ (CCS) which expresses the extent to which electricity prices exceed the cost of gas-powered generation (including, comparison of forward gas with forward electricity contracts) – a measure of the profitability of gas generation. Normally the gap is small. In recent months, the forward CCS has “exploded”, especially for the coming winter – most notably in France, but also in other European countries: in Britain, in August the CCS for the coming winter was reported as over €200/MWh (https://timera-energy.com/europes-power-crisis-overtaking-gas-crisis/ - Figure 2)

In normal conditions and earlier times, particularly when fossil fuels were cheap, the price-setting role of fossil fuels was hardly problematic. Renewables were a moderate part of generation in most countries, and along with nuclear, mainly state-backed.[12] The life-cycle costs of renewables were relatively high, and many were supported outside the wholesale market, though large installations sold power into it. Marginal-cost-on-all pricing, combined with such renewable supports, may have been a sufficient approach in this previous era. The time-and-place signals derived from short-run wholesale markets, particularly alongside locational or zonal pricing, provide some real incentives to operate the system efficiently - even more so with more variable inputs from renewables. In regions like Europe with an adequate carbon price, it also minimizes emissions from existing plants.

Marginal cost pricing in such a system may still be (some) economists' dream, but it has turned into a politician's – or even businessman's – nightmare: depending on the vagaries of fossil fuel prices and risk perceptions, it makes capital-intensive investment expensive and risky in case the future price collapses, whilst at other times creates sky-high prices and windfall profits.

2.3 Cost inversion

I use the term 'cost inversion' in two, closely interrelated ways: the dramatic fall in the cost of renewables compared to prior assumptions and the net effect on the economics of electricity systems. From modest and expensive beginnings, recent years have witnessed a revolution in new renewable energy sources – both the volumes deployed, and corresponding cost reductions. The most recent IPCC report (IPCC, 2022 Chapter 6) charts the large global average reductions in the life-cycle generating costs even since 2015 of solar PV (-56%), wind (-45%), batteries (-64%), and others.

[12] Nuclear was also a modest share except in a few countries where nuclear+hydro dominated generation and set the price most of the time, as in France, much of it having been constructed with state-backing to help cover the construction costs and risks.

Box 2: The transition in UK renewable energy policy: from Renewable Obligation Certificates (ROCs) to fixed price contracts (CfDs)

In the UK , the renewables transition is reflected in the policies and contracts supporting renewables. Back in 2000, fossil fuels were very cheap and renewables expensive. Very small-scale generators (e.g. household PV, small farm installations) could receive fixed electricity prices (feed-in-tariffs). However to deliver its initial goal of getting 10% of electricity from renewables by 2010, the government set obligations on suppliers to procure renewable energy, realised through 'Renewable Obligation Certificates' (ROCs). These renewable energy generators sold electricity into the wholesale market, whilst the selling the associated ROCs added about £50/MWh on average to this.

This led to a rapid growth of renewable energy capacity, from very small beginnings. By 2010, the costs of onshore renewables had come down substantially and fossil fuel prices were already higher, and the new coalition government embarked on reform. This culminated with Electricity Market Reform in 2013, which established a different system, 'Contracts for Difference' (CfDs) on the electricity price, which effectively guarantee a fixed price for electricity generated over the first fifteen years of operation (for large-scale renewables): the government allocated first contracts in 2014, and in early 2015 moved to competitive auctions to secure large-scale renewables at least cost.

The ROCs system overlapped with this for some sources, and was finally closed in 2017. To encourage investment, the ROCs contracts were set for 20 years – so the last ones could, in principle, continue to sell ROCs until 2037.

Now, renewables are a rapidly rising part of many generating systems across Europe and elsewhere. Resources are ubiquitous and costs have plummeted. In the UK, the declining cost and the new system for contracting renewables led to rapid growth in the amount of renewables, and an even more dramatic decline in costs, particularly for offshore wind. Over successive rounds, the contracted cost of new offshore wind capacity fell (in 2021 currency), from about £170/MWh, to under £50/MWh, whilst the capacity and generation has grown exponentially (Figure 5).

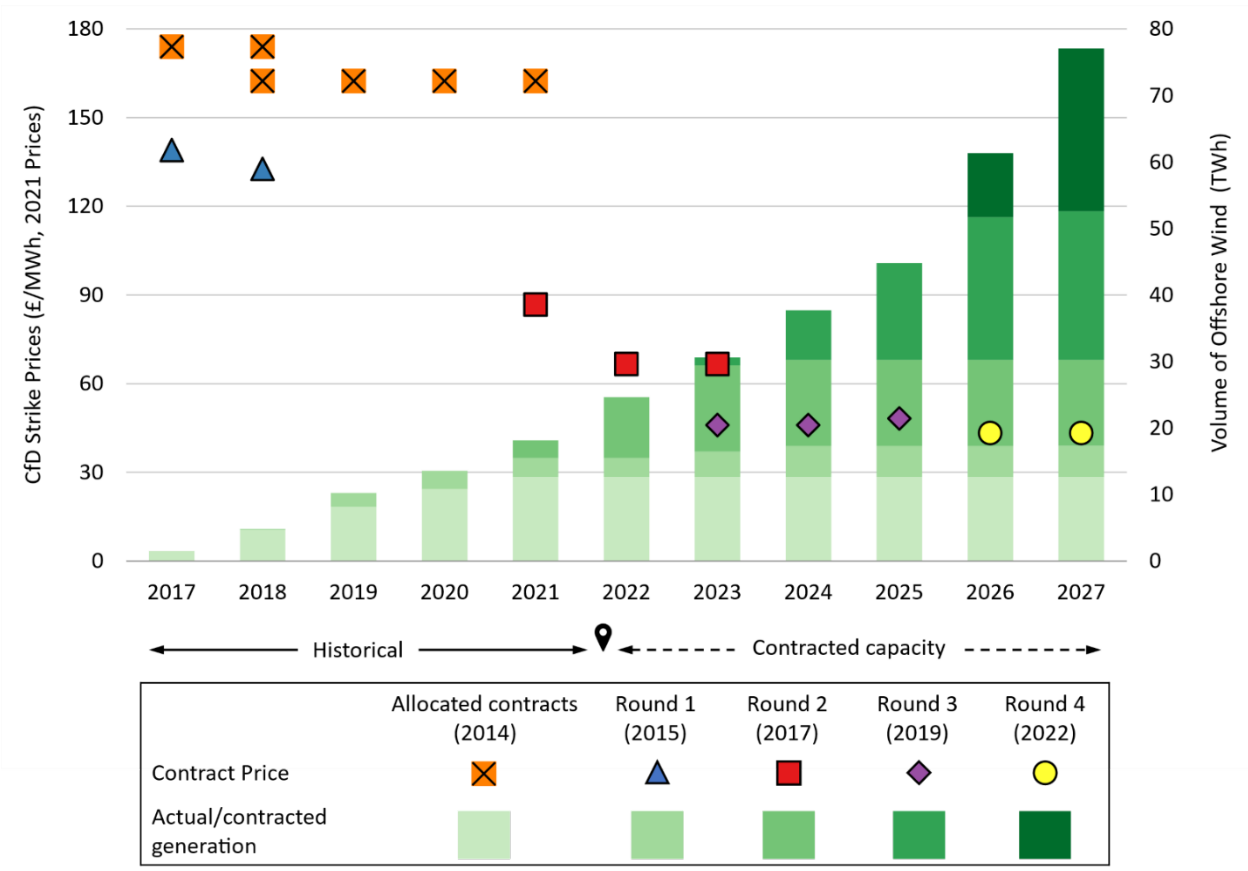

Figure 5: Offshore wind Contracts for Difference (CfD) Strike Prices, and historic and projected annual generation,

Source: Authors, with data from the Low Carbon Contracts Company (LCCC).

Notes: 'Allocated Contracts' were the prompt start contracts directly allocated by government in 2014, while subsequent rounds were subject to competitive auctions. Years in parentheses are years the allocation/auction rounds took place; the graph places the corresponding symbols in the year the projects generate at the contracted volumes (typically, 3-5 years after contract for large offshore). Round 4 generation assumes three awarded contracts begin generating in 2026 (Inch Cape P1, EA3 P1, Moray West) and two begin in 2027 (Norfolk Boreas, Hornsea P3), with average capacity factors of 40%.

This has opened up a huge new energy resource. By 2021, wind and solar already generated about a quarter of the UK's electricity, divided between solar (12.1 TWh), onshore wind (29.2 TWh), and offshore wind (35.5 TWh); about half the offshore wind in that year was under CfD contracts. These volumes compare with current total electricity generation of around 320TWh/yr. Between 2022 and 2027, CfDs already awarded to new offshore wind capacity are expected to add an additional 59 TWh per year, at an average contracted generating cost of under £50/MWh.

The result is a spectacular cost inversion. A decade ago renewables at scale, whilst cheap to run, were overall more expensive and required direct subsidy. But even *before* the energy crisis, wind and solar were competitive with fossil fuel generation, given appropriate financing structures (section 3.1). In the midst of the energy crisis, the latest (Round 4) fixed-price contracts for PV and wind energy – both onshore and onshore - were struck at costs/MWh under a quarter of the cost of the prevailing wholesale electricity price.

Since the largest resources (wind and solar) are intrinsically variable, fossil fuel plants will retain a crucial role for backup and balancing of the system for many years, but with a rapidly declining share of generation – which as noted, is already under half the total across most of Europe, and in the UK – but which still largely sets the price.

In an era of the fossil fuel crisis and fuel poverty, with heightened imperative to accelerate clean energy investment and higher carbon prices, it is high time for a fresh look at the fundamentals of how to (re)design our electricity systems.

2.4 The emerging electricity system

Two key features of the emerging electricity sources and systems underline the need for fresh thinking.

The first is that the change from fossil fuels to renewables represents a step-change – a radical discontinuity – in economic (and environmental) structure. Economically, to a large degree, it is a move from commodity-based to asset-based economics. Of course, big fossil fuel plants cost a lot to build, but the overall long-run economics are still dominated by the cost of fossil fuels to power them. The economics of renewables, by contrast, are dominated by the capital investment – the sun or wind are essentially free thereafter, and operating costs are modest and mainly fixed. It is the initial big lumpy asset that matters, not the cost of fuel.

The gap between the two systems is highlighted by the gulf between the economics of gas (low investment, expensive to run) and renewables (high investment, extremely cheap to run) –as illustrated in Figure 2. There is little way for finance to shift smoothly from one to another. Also, there is little continuity in emissions. In operation, fossil fuel generation emits copious amounts of CO_2, whilst non-fossil sources emit none.

All this is challenging for policy, not least because traditional economic theories and tools work best in context of continuity, not step-change – to shift money at the margin, by changing relative prices.

To underline the point, it is worth reflecting on analogies. Road building is not financed by charging every car a usage fee for access to the road. Nor does the construction sector gain its revenues by everyone paying a fee for every hour they occupy their homes or offices. Neither offers a strong analogy, but they demonstrate that the principle of marginal cost pricing, driven purely by consumer consumption of the product, has obvious limitations when it comes to what is largely asset finance.[13]

[13] The road-building analogy in particular is limited by the fact that roads in economic terms are in general 'public and non-excludable goods.' In operational terms however, transport does offer a good theoretical analogy to marginal cost pricing (with thanks to David Shipworth, UCL):

"A group of you leave a football match and all need to get to the train station to catch the same train. Some get on the local bus that costs £2 each - but you can't all fit. Some get Uber minivans that cost £5 each - but again there aren't enough. Some get taxis at £10 each. The last couple have to persuade a guy to drive you there and this costs £20 each. You all get to the station on time.

With the way the electricity market works everybody would have to pay the highest cost (£20 each) rather than the actual cost. Given who got what mode of transport is a lottery this is equal (everybody pays the same) - but expensive - and the bus driver makes a huge profit. In the electricity system we *have* to 'clear the market' (get everybody to the station on time) - and we don't expect the most expensive generator (driver) to operate at a loss - so we pay everybody the cost of the last and most expensive provider."

Second, the challenge of the energy transition extends way beyond the specifics of fossil fuels vs renewables investment. The 'new electricity system' is different in multiple ways beyond the finance-capital and environmental structures. As summarized in Table 2, the differences span other aspects of generation (notably, 'on demand' availability, vs renewables variability 'as available'), the importance of storage, location, the role of demand and consumers, and the potential scale of the transmission system – as well as other, less prominent dimensions of system operation.

The veteran energy analyst Walt Patterson coined the term *infrastructure electricity* to underline just how different this new kind of electricity system could be – electricity that does not require fuel, but assets to convert natural energy flows into flows of electrons to meet human needs, at multiple scales (Patterson, 2007).

Table 2: The many dimensions of difference between fossil fuel and emerging electricity systems

	Fossil-fuel based	New electricity system
Generation – output and economics	Baseload + flexible	Variable, inflexible
	Costs dominated by fuel & other operating costs	Capital intensive – costs dominated by capital
	At the margin, price-setting Differentiated prices reflecting variable costs	In wholesale markets, renewables price taker
Generation – scale, location and timescale	Economies of scale – large centralized plants, primarily powered using internationally traded commodities.	Economies of location – very varied scales from household PV and farms, to offshore, and through interconnectors to neighboring markets.
	Construction: years to a decade or more.	Construction: generally, a few months (more localized) to a few years (offshore, interconnectors).
Electricity Storage	Limited, except for hydro-based systems	Vital, with a range of technologies & timescales – dedicated batteries, connected electricity vehicles, thermal with combined heat-and-power, hydrogen etc.
Demand	Variable	Variable; offset against localized / storage Seasonal variations, amplified with heat pumps
	Inflexible	Growing flexibility, smart controls
	Mostly fixed tariffs	Differentiated / time-of-use tariffs
Transmission	One-way, from gen to consumers,	Two/multi-way
	Bulk	Peak needs

Other services	System inertia, frequency control etc. largely inbuilt in the rotating mass of large power stations	System inertia, frequency control etc. – need for separate service markets / incentives to balance supply and demand capabilities

2.5 Generic implications

The important implication is that we cannot usefully think of renewables and decarbonization as simply involving a cleaner version of the current system, which is more or less expensive. The emerging system is fundamentally different.

The need for fresh thinking about electricity markets has in fact been recognized by analysts for many years.[14] With a rapidly rising share of renewables, falling costs of installation and accelerated change in related technologies and business models, it is overdue. In the UK, reforms in 2012-2014 were a major step forward in terms of accelerating progress in renewables themselves, but renewable energy will soon be at a scale for which the system was never designed. The energy crisis gives impetus towards a new phase of reform.

For economists, the compelling logic of marginal-cost-on-all pricing needs to be set against the economic "general theory of the second best".[15] As taught in all economic schools (but often then forgotten), this demonstrates that if an economic system already differs from the theoretical ideal of a perfect, optimizing, welfare-maximizing market – as is inevitable in reality - it cannot be automatically assumed that the normal economic policy prescriptions will necessarily improve things. So, for example, if markets are for some reason inherently short-term or risk-averse, maximizing competition will result in inadequate investment or investment biased towards conventional technologies – amplified further, if private investors do not face or adequately factor in future environmental costs and damages. If severe distributional impacts are not addressed, approaches which raise prices may reduce overall welfare, even if they reflect actual marginal costs.

Similarly, inertia and vested interests in maintaining the current system matter. Companies do not want to write-off fossil fuel assets if they can possibly avoid it. Systems with capital-intensive, long-lived assets – whether fossil fuel or renewables – also have high entry costs: radically new ventures are expensive and risky, which is why the renewables revolution only occurred on the

[14] For example: 'Electricity markets in the EU were initially designed under the assumption of supply-side competition among thermal generators; renewable generation was either residual or, in the case of hydropower plants, largely amortized. It is illogical to expect that design to be fit [for purpose] under a completely different set of assumptions … When (re)thinking about energy markets it is not enough to look for ideas that are merely wrong; we need to look for troubled ideas that block progress by inspiring devotion out of proportion to their historical achievements.' Jorge Vasconcelos, 'The energy transition from the European perspective,' in Vicente López-Ibot Mayor (ed), 2017, *Clean energy law and regulation,* Wiley, Simmonds & Hill Publishing.

[15] (Lipsey and Lancaster, 1956). The theory states that in real-world circumstances, beset by multiple characteristics that deviate from economic theory of 'first best' markets, it cannot be automatically assumed that policies which would be optimal in a 'first best' model will necessarily improve things in reality – one has to assess policies against the realities of prevailing conditions.

back of strong government support, at initially high cost. Adequate access to the system may also hinge upon transmission, which new entrants cannot control, so coordination is required. If incumbent companies have market power, they may not only seek ways to raise the marginal cost of the system, so as to secure higher revenues, but resist more fundamental changes.

As noted in a classic economic textbook, regarding the relationship between government and industry and the British approach to competition policy, in the light of 'second best' realities, "a pragmatic approach has much to recommend it".[16] An effective, pragmatic approach to reforming electricity markets needs to incorporate the realities outlined in the next section.

3. Some key principles for new electricity market arrangements

3.1 Investment horizons and risk allocation: the myth of market neutrality

Energy is a long-term business, nested increasingly in short-term financial drivers. Historically, most electricity infrastructure – the big coal, hydro and nuclear stations, and transmission – were built mostly by state-owned and directed companies.[17] Privatization and the establishment of short-term electricity markets (hereafter, 'spot markets' for simplicity) mostly drew upon these investments, plus gas plants which are relatively cheap and quick to build (most of which, indeed, relied upon gas bought from gas production and transmission systems that were mostly funded either by state-backed investments or long term, oil-linked contracts).

Economic theorists often argue that markets 'should' generate long-term contracts to help hedge against risks. Countries differ in the extent to which long-term contracts and hedging instruments have arisen in practice (in the UK, few extend beyond a couple of years), but nowhere has the private sector on its own created such instruments with time horizons remotely adequate to cover investment risks on the timescales of large renewables (let alone, nuclear).

As one of the world's leading energy economists notes, economists generally accept the need to correct for the market failures of inadequately priced emissions (through a carbon price), and the public benefits of technology learning-by-doing (though supports for emerging technology), but another key 'market failure' (amongst others) that seems poorly understood is the lack of sufficiently distant futures and insurance markets.[18] The persistent absence of adequate long-term financial instruments to support investment cannot be simply assumed away with "should".

The problems with existing market practices do not stop here. A peculiar feature of electricity markets is that *the cheapest operating plants face the greatest net-revenue risks*, if they depend on spot markets for revenues. This arises directly from the structure of marginal cost pricing: the higher the operating costs, the more likely it is to be setting the price when generating. Specifically, because fossil fuel plants generally set the electricity price, they are largely self-hedged against

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[16] Lipsey and Harbury (1st Edition 1988, p.219); Lipsey and Harbury, 1992

[17] Oil has been different, owing to the huge profits available, which have enabled both State-Owned Enterprises and the private "Oil Majors" to take big risks for huge long-term gains – enabling them also to develop a specialized financial system to support such ventures.

[18] Indeed, Newbery (2017) – a recent President of the International Association for Energy Economics - takes it further: "One might conclude that energy-only markets … should signal the profitability of adequate new investment, provided all the other security services are adequately remunerated … This might be plausible if all investment decisions were taken on commercial grounds … that prices were not capped, that the policy environment were predictable and stable, and that either a liquid forward market existed for a reasonable fraction of the proposed plant life (i.e., twenty-plus years ahead of the final investment decision) or credible long-term power purchase agreements could be signed with creditworthy counterparties. Unfortunately, hardly any of these conditions hold."

the risk of future fossil fuel and carbon price variations: higher fossil fuel or carbon prices will increase their inputs costs but also increase the electricity price they receive, and *vice versa.*

Renewable energy or nuclear generation largely have their costs fixed by the capital investment (and debt repayments). If their revenues depend on the electricity wholesale market, the paradox is that they, not fossil fuel investments, face the risks of the uncertain fossil fuel and carbon prices, as long as fossil fuels set the price. Hence such markets -— even if they were backed with available futures and insurance contracts - are inherently tilted against non-fossil sources.

Even if some renewable generators that are not on fixed price contracts are enjoying record revenues at present, marginal-cost-on-all pricing carries an additional paradoxical risk for investment. At times when there is enough renewables output to not need fossil generation, the price received collapses - 'cannibalizing' revenues whenever renewables can meet the full demand, which on the logic of marginal cost pricing, drives the spot market close to zero (or even negative).[19] Ironically, therefore, greater stated renewables ambition could, if not backed by appropriate policy or market structures, actually deter renewables investment, by making future zero prices potentially more likely.

In the UK, recognizing the strategic benefits of renewables at a time when they were more expensive, and during an extended period of low fossil fuel prices, in 2000 the government created a system of Renewables Obligation Certificates. In effect (see Box 2 above) this added a subsidy, amounting to around £50/MWh (5p/kWh), to the price that renewables could receive in the wholesale market. It increased the rewards to offset the risks.

As noted (Box 2), recognizing the value of reducing revenue risk itself, as well as feed-in-tariffs to support small generators, the government subsequently introduced the contracts-for-difference (CfDs) to guarantee fixed payments per MWh for large-scale renewables generators.[20]

Economic sceptics of such approaches complain that such contracts do not remove risk, but just shift it on to governments. This neglects two critical points. First, a good economic principle is that risks should be borne by those creating them or otherwise best able to predict, control or bear them. The vagaries of very high or very low electricity prices – driven partly by the geopolitics of fossil fuel markets and the politics of carbon price design, as well as regulatory decisions – have clearly, far more to do with government than renewable energy investors. Second, along with the shifting of risks, underwriting by a AAA-rated government of course reduces the cost of finance. Combined with auctions, the result, as estimated by (Newbery, 2018), was an approximately 3 percentage point reduction in the rate of return sought by investors in large-scale renewables – in itself potentially saving billions of pounds on the overall cost of the clean energy transition in Britain.

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[19] When the output from cheap-to-operate sources selling into the wholesale market exceeds the demand, it becomes the price-setter and the price drops precipitously. If they are subsidized or have a fixed guaranteed effective price (e.g. with FiTS and CfDs), at such times they can bid in negative prices to ensure they still get their subsidy or fixed revenue per unit output. Adding more renewables increases the frequency with which this will occur – and in a marginal-cost-on-all market, all renewables (unless on fixed price contracts) thus lose revenue. This 'cannibalization' also has the paradoxical consequence that a more ambitious government goal for renewables, if not matched by appropriate policy, could actually deter renewables investment.

[20] For an account of the development of the UK's Electricity Market Reform and emerging lessons, see M. Grubb and D. Newbery (2018), Reforming Electricity Markets for the Transition: Emerging Lessons from the UK's Bold Experiment, MIT / EPRG, https://www.eprg.group.cam.ac.uk/eprg-working-paper-1817/; with subsequent academic paper published as (Grubb and Newbery, 2018).

Such government involvement does carry its own risks, but market reforms should take great care before dispensing with the benefits of long-term fixed-price contracts for capital investment. Particularly when they now yield clean electricity at a fraction of the now-crippling cost of wholesale electricity.

3.2 Distribution and Welfare: marginal-costs-on-all and ameliorative measures

The gravity of the energy crisis, in terms of its impact on bills paid by many millions of households, is starkly clear from Figure 1, which as noted, reflects that at the time of writing, the typical UK household bill is projected to exceed well over £4000/yr. next year (divided roughly equally between the impact on gas for heating, and electricity prices). This will take many millions of households well above most benchmarks of 'fuel poverty' - almost half of UK households earn less than £30,000 (2021 median household income).

Industries, especially electro-intensive industries exposed to international competition, are also highly vulnerable. Large companies can, and many have, negotiated special contracts, but are still under huge pressure from the general rise in wholesale prices, especially electro-intensive industries exposed to international competition. For example, in many Asian countries, governments still set the price of electricity, in principle based on average generation costs. In practice, this can yield precisely the opposite problem to that faced in Europe: the South Korean government, for example, with an upcoming election, resisted pressures to raises prices as the gas price rose, leading the national energy company (KEPCO) to lose $6.5bn just in the first quarter of 2022 and to struggle to survive financially. But Korean manufacturing industry gains a huge competitive advantage over European companies.

Finally, of course, energy price rises have adverse macroeconomic consequences. These include inflation, and other short-run macro-economic impacts on near-term GDP, since they cut directly into current consumer expenditure on other items, rather than corporate or shareholder profits (which are less likely to be injected back into the economy at least in the near term (eg. Weizsäcker and Krämer, 2021)).

Faced with this, governments have three basic choices, which can be broadly termed *Laissez Faire, Relief/redistribution,* and (at least for electricity) *Reform.*

a) Laissez Faire

One is to do as little as politically viable – *laissez faire* - and make a few symbolic changes to ease the pressures a little (as noted in the Introduction, the proposals in the UK to remove VAT, or suspend / move green levies, are themselves quite trivial compared to the scale of the challenge). The underlying argument is that price signals are important and that markets always involve winners and losers – and that the market will ultimately 'self-correct' in time if left alone. On the generation side, those selling into the wholesale market had to live through long periods of relatively low prices, and the unexpectedly-high profits now being made by non-fossil generators create an incentive to build more – the classic argument for marginal cost pricing. On the demand side, high consumer prices increase incentives to be efficient, and more frugal, in their energy use.

Set against this are obvious contrary arguments. Whilst energy prices are important drivers of overall national energy consumption levels in the long-run[21], most households have limited capacity to react in the short term.[22] Indeed, the poorer consumers are those least likely to be able to invest in efficiency improvements, and are far more likely to be renting poor quality, inefficient accommodation, about which they can do very little anyway.

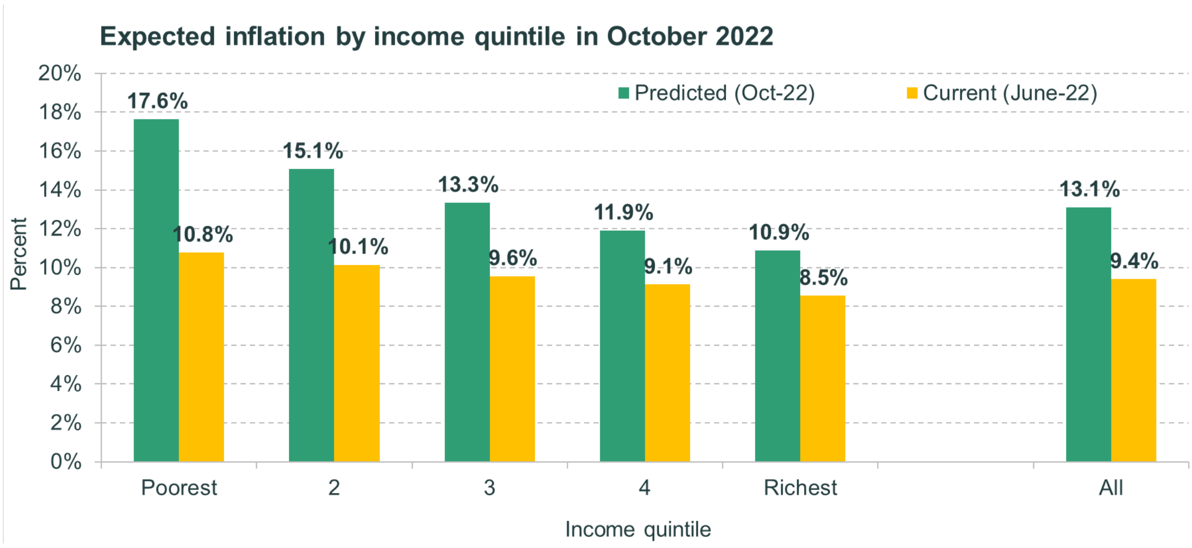
The impacts on inflation and poorer consumers are the current overwhelming concern. For the UK, two publications during August 2022 underline the scale of the challenge. Energy prices are generally acknowledged to be regressive – they hurt poor people more. Analysis by the Institute for Fiscal Studies (Johnson *et al.*, 2022) expresses the impact in terms of inflation on the normal household basket of goods for different groups; against a background of general inflation now projected at over 11%, the study estimates that the poorest 20% of households (bottom quintile) will face an overall cost increase of 18% during FY 2022-23, compared to the previous year (Figure 6a).

The idea that it is at least 'economically efficient' to let marginal costs drive prices for all is itself erroneous, according to the norms of standard welfare economics, if there are no compensating measures and efficiency is defined in terms of collective welfare (see box 3).

[21] M. Grubb et al (June 2017), Minus 1: Empirics, theory and implications of the 'Bashmakov-Newbery Range of Energy Expenditure', Final report to INET: https://www.ucl.ac.uk/bartlett/sustainable/publications/2018/apr/exploration-energy-cost-ranges-limits-and-adjustment-process

[22] The economic measure being 'elasticity', which for gas consumption is estimated at between 0.1 – 0.28: a gas price rise of 10% induces only 1 – 2.8% gas saving https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/532539/Annex_D_Gas_price_elasticities.pdf. See also https://www.cornwall-insight.com/short-term-energy-market-interventions/#.Yw9MoG91jho.twitter

(a) Distribution of expected inflation, by income quintile (Source: Johnson *et al.*, 2022)



(b) Distribution of expected household energy bills after £400 rebate, compared to 2019-20 levels, as % of expenditure by income decile. (Source: Brewer *et al.*, 2022)

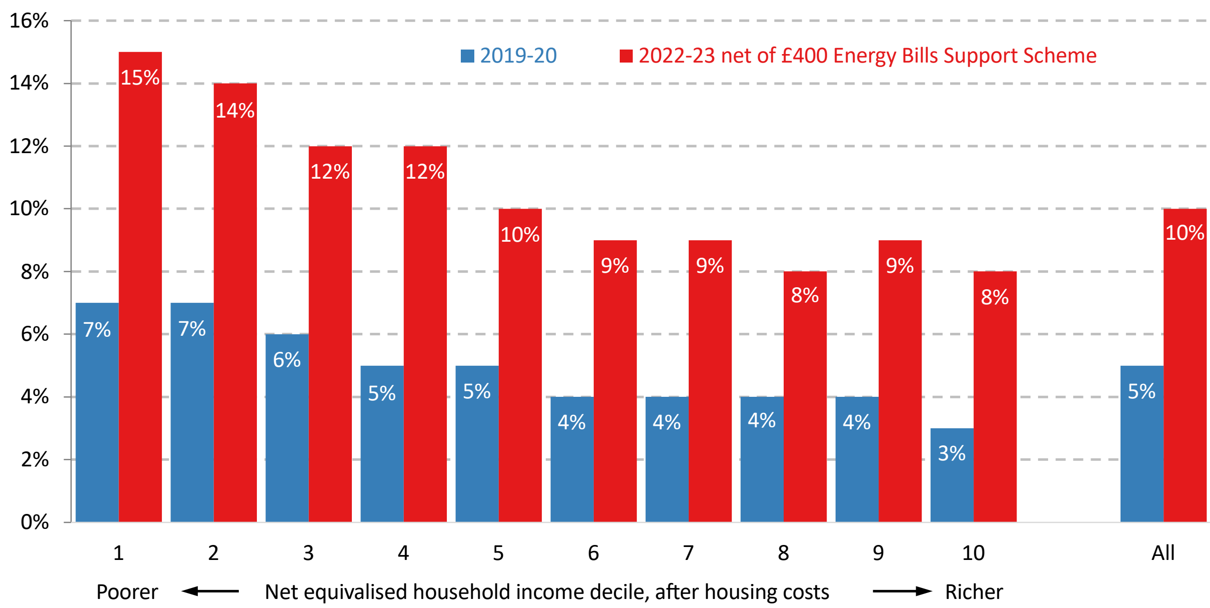


Figure 6: Distributional impact of the energy crisis on UK households

Box 3: Welfare, utility and regressive prices: some basic observations

Based on the observation that most people want more income, economics relates income to welfare, typically equated with 'utility'. It is however widely accepted that personal utility is not simply proportional to disposable income – i.e. a given amount of money benefits poor people much more than it would benefit the very rich.

In practice, attempting to design all major policies to improve distribution would be both impossibly complex and practically contentious, because it would dilute economic incentives – benefits rewarding hard work and skills - and set policies in conflict with the efficiency that markets often provide. Much economic reasoning therefore sidesteps issues of distribution (to a degree that others often find surprising or objectionable), arguing that distributional issues should not concern costs, but focus mainly on realised income - as addressed by taxation policies, to be decided politically, and implemented by the Treasury.

This neat separation of price implications of energy policy from distributional equity concerns has its limits, both theoretically and in practice. In the case of the energy crisis, it is clear that high energy prices have massive distributional consequences, in terms of the impact on net disposable income for poorer households. Any reasonable calculation demonstrates that, beyond a certain point of higher energy prices combined with large profits to cheaper producers, marginal-cost-on-all prices substantially reduces overall welfare compared to policies which give cheaper energy to those most in need of it.

The devil of course lies in the detail of whether and how this can be done, and in practice, who and what defines those most deserving of access to cheaper electricity.

Obviously stronger energy efficiency measures could help to ameliorate energy bills, particularly in relation to heating, but beyond a few modest 'quick wins', for example in terms of boiler settings, achieving scale takes time. In the UK, the pace of investments to improve household energy efficiency largely collapsed after policy changes in 2012. [23] The scale of improvements within the scope of principles declared by the present government is limited, and anyway would need to be sustained over extended periods.

b) Relief and redistribution

The second option is crude, but conceptually simply: the Treasury can redistribute money. This has been the principal response to date. At the time of going to press (late August 2022), a mostly one-off package of support had been developed in the UK, with a total value close to £25bn.[24]

The biggest single item is fixed payments of £400 per household, to rich and poor alike, (including double home-owners). The Resolution Foundation (Brewer *et al.*, 2022) finds that, *after* taking account of the £400 off all energy bills already committed by the government, the bottom quintile (first two sets of columns in Figure 6b) will on average be spending 14-15% of their disposable

[23] Investment in energy efficiency in the UK collapsed in the past decade (CCC, 2022; see Figure 4.6). The UK Energy Security Strategy of April 2022 contained the curious assertion (for an official government document) that "The British people are no-nonsense pragmatists who can make decisions based on the information", as a primary reason why the government does not support stronger measures, beyond mostly pre-existing government grants, to improve energy efficiency in the notoriously inefficient UK buildings stock.

[24] Specifically (from (Johnson *et al.*, 2022): £400 to all households labeled as an "energy discount" that will be subtracted from energy bills. £150 for all households in council tax bands A-D (around 80% of households). £650 for any family on means-tested benefits. £300 for pensioners. £150 for those on a disability benefit.

income (after housing costs) on energy – more than twice pre-crisis (2019-20) levels and almost twice the percentage in rich households. A flat-rate solution alleviates overall pressure, but on its own does little to ameliorate how unfairly the burden falls.

Consequently, the other big item is £650 for any family on means tested benefits, plus some payments based on Council tax bands, disability benefits, and for pensioners. To help fund this huge package, an estimated £5bn/yr. is to be raised from a windfall tax on oil and gas companies, given their level of profits from high energy prices, as noted previously.

To be effective, such debt/tax-and-redistribute will need to be repeated every year for several years. As yet, there is little or no direct alignment of relief with levels of actual energy consumption, which the Resolution Foundation study suggests to be an essential need, if complex, to prevent costs ballooning even further.

c) Reform

The third kind of approach would be to try and tackle the problem of short-run-marginal-cost-pricing-on-all in the energy system itself, at least in electricity. In our concluding section, we touch on options which are presented in more depth in our subsequent report.

One element of this, of course, comes back to the structure amongst generators, given that half the generating capacity has not had any increase in costs. Specifically, nuclear, and renewables supported by Renewable Obligation Certificates - both of which have enjoyed significant state support - are now gaining ‘supernormal’ revenue.

By matching the hourly generation of all plants against the wholesale day-ahead prices, we were able to estimate the change in overall electricity revenues to GB generators participating in the main UK (“balancing”) electricity market. As detailed in our NECC Working Paper 2, *Where’s the money going?*, we estimate that, if sold at day-ahead prices, revenues to British generators selling electricity into the British wholesale electricity market (excluding the renewables on fixed-price CfD contracts) would have approximately doubled from about £12.5 - £14 billion in 2019, to £28 - £30bn in 2021.[25] Based on price trends this year they are likely to nearly double again in 2022, and potentially go even higher next year.

Actual revenues to date could be less to the extent that generators were locked in to forward contracts with suppliers or industrial consumers at lower prices (though some of these are themselves are linked to spot prices). Over time, the price in most such contracts is likely to converge towards the spot or general gas-and-electricity forward contract prices. Whether or not such price levels maintain, increase further, or decline, will of course depend heavily on the trend in natural gas prices, and the extent to which past and projected gas prices have been built into forward contracts.[26] The trends at the time of publication are hardly reassuring in this regard, as seen from the most recent data on gas prices (Figure 4).

[25] Different data sources yield slightly different results. This estimate comprises only sources that participate in the GB balancing mechanism, and excludes those on fixed-price contracts which repay surplus. The actual figure accruing in recent periods could be lower to the extent that generators were still on fixed price Power Purchase Agreements. Our Working Paper NECC #2, *Where’s the money going? Estimating electricity generator revenues in Great Britain*, will provide details of data sources and calculations for different technology / contract classes.

[26] Note that the timing of revenue and profits to generators is different from the timing of household bills displayed in Figure 1. There is always a lag between changes in gas prices, to wholesale prices, through to changes in consumer bills, and even more so for the data in Figure 1 which is calculated from changes to the Ofgem price cap.

Our estimates are gross revenues; the overall cost base including gas has also risen of course. About 40% of GB electricity generation in 2021 was from gas generators, and the price rise reflects the impact of their cost increase, 'at the margin'. Some of the more efficient gas generators will have made significant gains (their costs rose less than those of the marginal, older and less efficient generators that often set the price), but – excepting those on long-term fixed price contracts (FiTs and CfDs) - most of the balance of increased revenue accrued to non-fossil generators whose costs hardly changed.

One option would be to try and implement a windfall tax on electricity, though this has drawbacks and difficulties even beyond their imposition on oil and gas producers, for which there are precedents and a pre-existing ring-fenced tax structure could be utilized. Let's rewrite this sentence; two thoughts here Even for these, the tax would be only prospective, for the next 3 years after announcement – not imposed retrospectively. The contractual structures and tracing in electricity are (even) more complex due in part to the half-hourly settling of electricity markets and wide diversity of contracts and players, including small players. The complexities would be magnified even more should the government contemplate anything retrospective due to multiple bankruptcies of many small supply companies, which could not afford to buy the electricity they had already promised to sell to customers.

An alternate is then to consider looking inside the structure of the electricity system itself, and existing supports. The generators on CfDs are already paying back to suppliers' revenues they get above their fixed price, albeit with complexities and lags. One 'quick-win', suggested and supported by many in the renewables and energy industry, could be to hold a fixed-price auction for output from existing nuclear and the renewables currently on ROCs (Gross, MacIver and Blyth, 2022) – tempting them into the security of a long-term CfD fixed price contract, through which they would also start to pay current surplus back to energy suppliers to help hold down bills.[27]

More radical restructuring of how we operate our electricity systems would move further away from the philosophy of marginal-cost-on-all pricing, with at least two main approaches, discussed in our conclusion, which form the focus of the next paper in our series, on 'dual market' approaches.

First however two other important considerations require attention if reform measures are to align well with the strategic needs of a decarbonizing electricity system.

3.3 Location and variability: developing efficient incentives for investment and innovation

The electricity system is in a state of major transition, based on innovation – and this should inform another dimension of reform. The remarkable development of wind and solar indicates at least four key elements which underline that successful innovation is about far more than just government R&D. For wind energy, it comprised (Jennings *et al.*, 2020):

- Research & Development combining government and private sector, across many different dimensions of technology (resource mapping, blades, materials, foundations, control systems etc.)
- Learning-by-doing through successive generations and scales of technology

[27] See https://ukerc.ac.uk/publications/can-renewables-help-keep-bills-down/: the authors estimate the savings could range between £5bn/yr. and £22bn/yr. depending on assumptions. Technically, the CfD system does not separate participating generators from the wholesale market, but it requires them repay most of surplus revenues obtained from wholesale prices above the agreed level. In late August, the trade bodies Energy UK and Renewables UK issued supportive statements for this option.

- Economies-of-scale from larger turbines and more extensively developed supply chains
- Declining finance costs as the finance sector became more familiar with the technology and its reliability, and more confident in both the companies and the stability of the government policy, in general and specifics of the CfD instruments in particular.

The result of this sustained effort, including the most recent CfD auction, was illustrated in Figure 5. It shows that innovation involves periods of experimentation, building of niche markets and industries to scale, and overcoming many obstacles often arising from incumbent interests, institutional and regulatory structures.[28]

Future energy innovation will need to be about *systems* overall, including incentives for the kinds of innovation needed. One key factor arises from the variability of wind and solar. At contributions up to 20% or so of UK electricity supply, these were easily absorbed into the existing system; the best estimates of backup and balancing costs conclude these add at most £10/MWh to the cost of renewables generation at present (Heptonstall and Gross, 2020). As their contribution grows however, the scale of backup and balancing required will grow, non-linearly. The associated cost will depend on the balance and location of wind and solar, at different scales in the system, and also the extent of 'flexibility' in the system – most obviously, storage of various durations and locations, and in efficient transmission. The government REMA consultation identifies this as an important challenge, with some options identified (e.g. in Newbery, 2021).

As with the reduction in the cost of offshore wind and its supply chains, continuing innovation will require the right mix of government support and market incentives, which at present are weak. The fixed-price nature of CfD contracts gives no incentives for efficient choice or location; both the structure of CfDs, and the planning and political resistance to hosting renewable infrastructure in England, tends to lead to concentrated, remote locations, amplifying the variability of the overall renewables output and the need for transmission.

Equally important, the theoretical value of storage and other relevant technologies is not sufficiently matched by any major entity that has a strong interest in promoting them. Generators in general do not: fossil fuels benefit directly from higher demand (and, like traders, tend to benefit from volatility), nor do renewable generators in general (and particularly, those on fixed price contracts). The System Operator has incentives to lower the cost of short-run balancing,[29] but overall the incentives are not well placed.[30] Interconnection also helps to manage variability and increases the value of renewables.

The question of how efficiently to motivate greater flexibility – including transparency and allocation of costs for backup and balancing - is a third important principle to be considered in market reform. During the 2020s, the variability in output from wind and solar will become a dominant source of variability in the net load served by traditional electricity sources. As the renewables sector

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[28] For a major and recent overview of the issues and literature, including case studies, see e.g. Grubb M. *et al,* (2021).

[29] https://www.elexon.co.uk/article/bsc-insight-increasing-costs-for-balancing-the-gb-system. In some cases, National Grid or distribution companies may want to promote flexibility, to reduce the need for investment in new transmission and distribution, but that is hardly a core business need.

[30] https://www.nationalgrideso.com/industry-information/charging/balancing-services-use-system-bsuos-charges explains how short-run balancing costs are spread across generators, suppliers and DNOs via BSUoS. See also the ESC report Keay-Bright and Day (2022).

matures, it needs to bear its share of the overall backup and balancing costs.[31] One feature of our proposals for "dual markets"[32] would be for the renewables sector overall to become responsible for its share of associated backup and balancing costs, so that, in partnership with government, it has a strong incentive to support investment and innovation to minimize these costs.

3.4 Consumer differentiation and agency: whose challenge?

Electrons are all the same, but electricity purchases are not; nor are electricity consumers. Until very recently, most literature and debate on electricity market design was focused almost entirely on generation, networks, and retail competition - as if all consumers were the same, their interests and capabilities were identical, and few cared about anything other than price (along with some aspects of quality of service).

That, obviously, is wrong. Electricity consumers span not only a huge diversity of households, but many different sectors, which obviously have very different characteristics – for a breakdown, see Figure 76. These differ not only in sensitivity to price, but scale, timing, flexibility, capacity to engage in complex contracts, interest in other factors (such as environmental – with many companies now signed up to "100% renewables"), and much besides.

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[31] A proposal from Prof Dieter Helm (Helm, 2017) that renewable generators should pay for the backup of their plants could (depending on whether it could be designed to include demand-side response) create a strong push for flexibility, but it would be a very inefficient and expensive way of doing so – in part because it would parcel out to numerous individual plants what is a collective need to balance output of renewables overall. Efficient backup and balancing is a system property, with enormous inefficiencies if parceled out to individual generators. A trivial example: we do not build capacity to ensure that every household could securely turn on all kettles (not to mention other appliances) at the same time. For renewables, both capacity backup and dynamic balancing costs are substantially reduced by geographical dispersion (e.g., as a wind system crosses the country) and even more by technological variety (wind + solar + ….), even more so if there is significant storage. Helm's proposal also does not clarify whether the level of 'backup' should be average output, average winter output, or peak capacity, of a wind farm – because there is no logical answer (except, the latter would be grossly inefficient). It is an excellent principle that backup and balancing costs should be both transparent, and ultimately paid for in the cost chain from variable power sources to consumers of that power - but only if the different variable inputs are aggregated, with backup and balancing recognized as a collective system property, with costs proportionately allocated.

[32] M.Grubb and P. Drummond (2018)

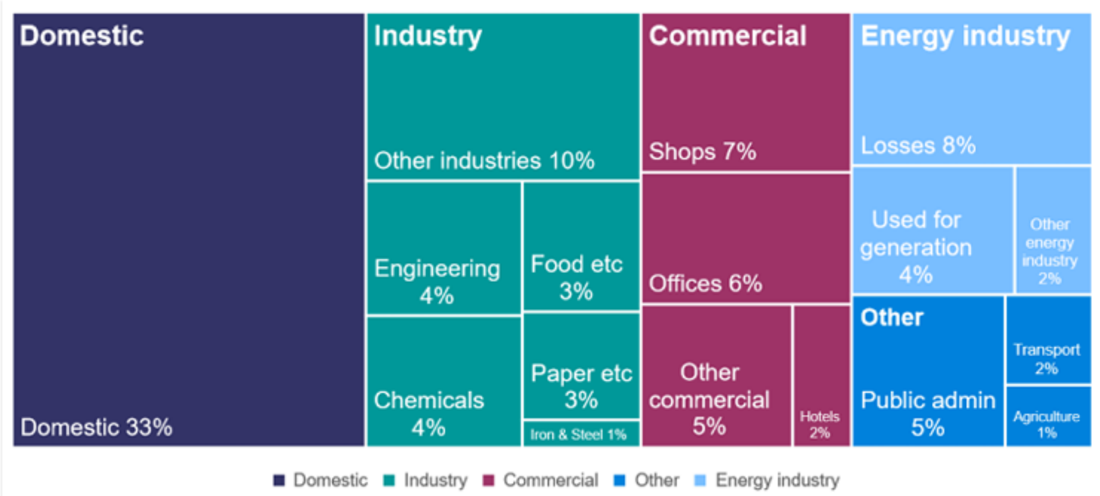

Figure 7: Distribution of electricity demand between different sectors

Source: Digest of UK Energy Statistics (2022), Chapter 5 (Figure 5.2): https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Nor is assuming all electricity consumers are the same a helpful simplification for at least three reasons that are growing in importance. One is the distributional impacts of energy pricing just discussed: some consumers – businesses as well as households – are far more vulnerable than others. Second is the growing need for flexibility in the system, to help strike the best balance between the variable output of primary renewables,[33] various demand-side flexibilities and capabilities, and storage. Third is that moving away from fossils will involve substantial electrification of new uses, which more directly and obviously involve consumer choices – including electric vehicles and heating (e.g. heat pumps).

In addition, significant numbers of consumers – again, both domestic and commercial - have expressed the value they attach to tackling climate change by buying electricity through 'green tariffs'. Most have been surprised, puzzled, and disappointed by the fact in the energy crisis, their electricity prices have gone up almost as much as others', especially when their tariffs were declared "100% renewable". Without delving into details (the situation does vary between different green suppliers), the main reason is the way that cheap, renewable energy at present remains inextricably mixed up with the rest of the system.

An extensive report by the Energy Systems Catapult (Keay-Bright and Day, 2022) lists "consumer focus" as the first of five challenges to be addressed by market reform. It observes:

> *Radically improving consumer propositions across the sector is critical to making low carbon choices more attractive for consumers and unlocking system benefits (particularly through greater demand side flexibility) that will ultimately reduce costs for all consumers.*

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[33] Primary renewables are those which depend directly on natural energy flows like wind, solar and tidal energy. Other renewables include biomass and hydro, which because the energy is stored (in wood or water) are generally much less variable in output.

[Energy Systems Catapult's] work with consumers highlights the current challenges that many consumers face in getting what they need from energy services, and the potential for substantial improvement. Consumers currently face undifferentiated offerings based on supply of electricity and pass through of costs (including levies, network charges, VAT), with few suppliers offering rewards for flexibility through time-varying tariffs or service-based packages.

Consumer satisfaction in the energy sector is relatively low compared to other sectors …"

The ESC report goes on to note that much future electricity demand growth will come from sources that are intrinsically flexible (which applies to electrification of industry, as well as consumer uses like EVs and heat pumps, which bring some built-in storage capacity). This is potentially very valuable for creating an efficient system with a high share of renewables, with one estimate that such demand-side flexibility would save around £7bn/yr. *(OVO Energy and Imperial College London, 2018),* along with significant additional savings from reducing the need for grid reinforcement in distribution *(Energy Technologies Institute, 2019).*

Consequently, the report concludes that *"Major innovation in new demand-side business models, exploiting data and digitalization, could deliver win-win outcomes for the power system and all consumers",* but that *"Attractive consumer offerings, however, will be key to unlocking flexibility…"*

In theory, since there is substantial value in flexibility, the private sector could offer more sophisticated contracts to deliver this. Some do, but as noted, the offerings remain very limited. Since large swings of electricity demand have always imposed significant costs on the system (and by 2020 the UK already had 25% of its electricity from variable renewables), the first question is – as with the absence of adequate private long-term contracts - why have they not emerged at scale?

Without going into detail, there are various possible reasons but they all likely combine both demand and supply factors. First, since consumer-based flexibility is complex there are transaction costs if people have to actively respond to price changes. Automation (e.g., programming for pre-set responses of smart appliances) offers an alternative but may involve some technological capacity or investment in control systems – as well as overcoming human inertia for people used to plain vanilla electricity at a given price. Regulatory protection could be important, similar to that around complex financial products, to provide assurance.

The energy crisis is forcing everyone to think more about energy consumers. The chance to engage them better in solutions which could also help to build a cleaner, cheaper and more secure energy future should not be missed.

4. Conclusions

This paper has argued that successfully navigating the combined crises of energy and climate change requires understanding the unique characteristics of the electricity system, and the markets for electricity that we have created. The foundation of an effective response should be recognition that, in electricity at least, the crisis is a structural one. European countries, including the UK, already get more than half their electricity from non-fossil sources, and that proportion is set to grow rapidly, in this decade and beyond. Yet the core electricity market remains based around fossil fuels.

In electricity, the crisis has therefore exposed, not created, the fact that overall electricity prices cannot sensibly continue to be set on the basis of short-run-marginal-cost-on-all pricing, in which gas sets the price in wholly disproportionate ways. The fact that new renewables in particular cost a small fraction of the electricity wholesale price underlines the potential opportunity, if reforms can effectively support and accelerate the transition already under way. Against that backdrop, the paper has identified at least four key challenges and associated principles, of which the first two are closely intertwined:

- The transition is from a commodity-based towards an asset-based system, with strong implications for appropriate types of markets and finance; more specifically, short-run commodity-based pricing (an energy-only market) is an extremely inefficient way to finance assets that are capital intensive but very cheap to run.
- Distributional impacts – between producers and consumers, and amongst different consumer groups - matter hugely; governments cannot ignore the large gap between marginal and average costs in the system, and need to consider options for targeting help for the most vulnerable.

In principle, the energy cost burden can be alleviated either through relief / redistribution, or through reform; and each comes with the same philosophical and practical choice, whether to help all consumers equally, or to prioritize support for the most vulnerable. Relief and redistribution, as in the current emergency packages, is the only credible option for this winter, but policy needs urgently to engage options which involve reform.

Part of the answer is already at hand. Across Europe, the majority of renewable generation has been based upon fixed price contracts in some form. In the UK and several other countries, the Contracts-for-Difference have been very effective for renewables and will pay back to suppliers most of what are now surplus revenues, helping to dampen the gap between marginal wholesale and average costs on the system. Some direct private contracts (Power Purchasing Agreements) also help address these two challenges, for the participants involved.

In the EU, several countries called for reform as the crisis developed and in July, Greece proposed a systematic way to integrate non-fossil sources into the existing wholesale market in ways to bring the electricity price down to average rather than marginal cost. [34] Other EU countries including Germany are now actively pursuing the options.[35] Such options have not yet featured in current UK political debates about responding to the energy crisis.

Structural reforms should also take account of other strategic challenges to be navigated in the electricity transition, notably:

- As the renewables / non-fossil part of the system grows further, it should increasingly bear the costs of backup and balancing (including locational dimensions) currently provided by the rest of the system;

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[34] The proposal is for a power market design in order to decouple electricity prices from soaring gas prices. Information note from the Greek delegation in view of the Extraordinary Transport, Telecommunications and Energy Council on 26 July 2022. ENER 266: Ref 11398/22. The essence of the proposal is that sources with long-term contracts should offer volumes into the market and their fixed prices, rather than bid competitively towards the system marginal cost; only after taking these volumes would the market operator take bids from fossil fuel 'on demand' sources. The combined market would then be selling on the average price of the two. In the US, some proposals are emerging which acknowledge the key role of cheap long-term contracts and ways to integrate them into wholesale markets. These and others, including proposals to fully split the markets as in (Keay and Robinson, 2017), will be reviewed in our subsequent report.

[35] https://www.euractiv.com/section/electricity/news/berlin-brussels-join-calls-for-fundamental-reform-of-eu-power-market/

- Consumers – both private and business – are very diverse, their interests and options matter, and policies should aim to engage consumers much more actively in the system, giving them real options for contributing to and benefiting from the transition under way.

Few proposals address all of these challenges together. Options which could offer consumers more direct access to cheap renewables, properly structured, may offer new ways to achieve these multiple objectives (e.g. the ‘dual-market’ proposals by Keay and Robinson (2017) or by Grubb and Drummond (2018)). As yet, the distributional and welfare dimensions that are dominating the politics of the energy crisis have as yet barely touched upon the opportunities afforded by the energy transition, and *vice versa*.

Crises are also opportunities for reform. Our next paper in this series will consider in more depth dual-market approaches, which may hold the greatest promise for both tackling distributional concerns of the energy crisis, whilst developing the fundamental requirements for new market structures appropriate to the emerging world of low-carbon electricity.

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[See footnotes for weblinks to shorter commentaries and data relating to energy crisis]

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