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Separating electricity from gas prices through Green Power Pools: Design options and evolution

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ABSTRACT

This paper develops a detailed proposal for an efficient way to channel the value of large-scale renewables, which have become much cheaper than gas-driven wholesale electricity prices, to consumers at 'cost-plus' prices. This would reduce the fiscal pressure on governments for market-wide subsidies and offer more stable support for consumers most in need. We detail how this

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‘green power pool’ approach could interact with the wholesale market to ensure firm power, also bringing transparency to the cost of balancing the variable renewables output, and maintaining incentives for efficient supply and demand responses. We illustrate the approach with reference to the cost and volume trajectories of UK renewables backed by government CfDs, targeted initially to particular consumer groups, as a first step in a wider transition towards direct consumer access to cheap renewables.

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1. Introduction

"An unkind critic of economics once said that economists have two great insights: *markets work*; and *markets fail*.

An unkind critic of politics once added that economics was thus a step ahead of both the political left and the political right, each of which accepts only one of these insights …"

- Richard G. Lipsey, *An Introduction to Positive Economics* (Fifth Edition, 1979, p.417)

Across much of the world, the cost of fossil fuels has surged in the aftermath of Covid and the war in Ukraine. Across Europe, unprecedented gas prices also largely drive the price of electricity. At the same time, the cost of renewables has gone down and down, whilst volumes are growing. But consumers are not seeing the benefit of this dramatic 'cost inversion' in electricity production. Electricity markets need reforms to develop market structures that work for both producers and consumers in these new conditions.

This paper builds directly on our previous (NECC #3) publication, which set out some of the underlying challenges concerning: : Price Inflation, Marginal Cost Pricing, and principles for electricity market redesign in an era of low-carbon transition.[1] It aims to contribute to urgent debate in the UK and across Europe about responding to the energy crisis, specifically in relation to the electricity sector. It identifies opportunities for response that arise from – and can contribute to – the ongoing transitions towards renewable electricity generation. The focus is on the UK, with reference also to the European context, but the underlying issues around electricity market design, in a world of volatile fossil fuels alongside cheap, large-scale renewables, are in principle relevant globally.

The enquiry has three fundamental motivations. First is the energy crisis itself, including its potentially devastating impacts on poor households and energy-intensive industry, and the strain this places on our economies and societies. Whilst the crisis is first and foremost about gas, it is in electricity that the most obvious opportunities arise. There has been significant 'cost inversion' – previously expensive renewables becoming far cheaper, and now much below the high cost of gas-based generation, which has continued to set the electricity price - as mapped out in NECC #3's discussion of marginal cost pricing.

Second, the combined energy and climate crises underline the urgency of accelerating the transition to cleaner energy sources. However, the regulatory framework that has launched the renewables revolution, and is transforming the power sector, is not adequate to ensure appropriate range and scale of investment needed for the next stage of transition to a renewables-based system. In particular, a system transitioning to variable solar and wind energy

[1] Grubb, M, Ferguson, T, Musat, A, Maximov, S, Zhang, Z, Price, J and Drummond, P (2022) *Navigating the crises in European energy: Price Inflation, Marginal Cost Pricing, and principles for electricity market redesign in an era of low-carbon transition*, Available at: https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/ucl_isr_necc_wp3_with_cover_final_050922.pdf

will increasingly require diversity and efficient complementary 'balancing' of variable renewables with other sources when needed, and a large expansion of transmission capacity. Mechanisms to define these needs and their costs to the system are not transparently reflected in the current framework.

Third, the current electricity wholesale market is not well designed to engage other actors, sectors and consumers in the dynamics of low carbon transition. The short-run-marginal-cost-on-all basis of current design reflects an age of centralized generation based on the commodity economics of fossil fuels, which is not appropriate for a system increasingly dominated by the economics of asset investments (in this case, renewables and other non-fossil sources, enhanced transmission, etc.). Further, the current design fails to involve consumers as active participants with agency in engaging, contributing to, and ultimately benefiting from the transition.

Electricity reform is a wide and complex area, with many dimensions and contributions as described in NECC #3. This paper focuses upon key market reform options that seek to support simultaneously efficient financing for large-scale renewables, and their potential contribution to the interests of electricity consumers, including business and households. It touches upon locational issues but does not delve specifically into issues of locational (nodal and zonal) pricing, localized generation and 'prosumers', or distributed systems management.

Following Section 2, which outlines 'where we are and where we are heading', Section 3 briefly summarizes some 'visions' for long-term reform. These provide relevant background for Sections 4-5, which detail design options for a 'green power pool' derived from the success of current structures for funding cheap renewables, and Section 6 which outlines options for other renewables and related evolution for electricity market reforms in Great Britain.[2]

2. Where we are and where we are going

Where are we?

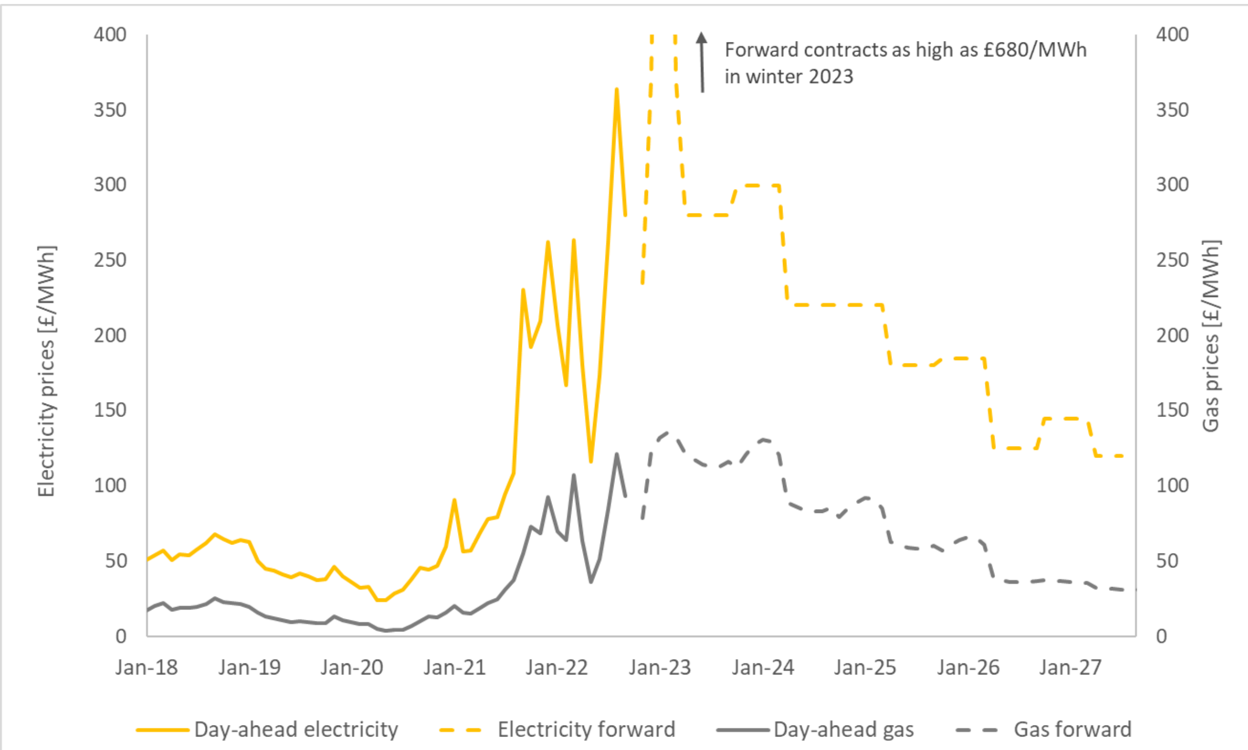
In the decade before the COVID pandemic struck , wholesale electricity prices in Great Britain averaged around £50/MWh, with variations rarely exceeding £10/MWh. They dropped briefly as demand fell during the COVID 'lockdown' measures in 2020, but recovered by the end of the year. However, prices have since rocketed, averaging nearly £200/MWh across 2022 so far, and peaking at above £350/MWh (see Figure 1). A similar trend has been experienced across Europe. Such a crippling rise in electricity prices is fundamentally linked to a rise in gas prices – a combined result of increased demand for gas as the continent emerged from COVID restrictions, and decreasing supply from Russia following the war with Ukraine (along with lower hydro and nuclear output in 2022).

Fluctuations in electricity prices are so closely linked to those of gas due to the design of wholesale electricity markets in GB and across Europe. Indeed, short-run-marginal-cost-on-all pricing means gas power plants are overwhelmingly operating 'at the margin' of the system

[2] Great Britain has an integrated electricity market, covering England, Scotland and Wales. Northern Ireland, while part of the UK, shares an electricity system and market with the Republic of Ireland.

required to ensure sufficient generation (the marginal plant). In 2019, gas plants set the electricity price in GB 84% of the time, despite providing just 45% of generation, meaning electricity prices are often well above the average cost of generation. Currently, this implies potentially very large windfall profits for those generators not on long-term, fixed-price contracts and with very low marginal costs (e.g., renewables and nuclear), operating in the day-ahead markets in particular. See our previous papers, NECC #1 and #3, for more detailed explanation and discussion of existing electricity market design in the UK and Europe, and its consequences.

Such a rise in gas and electricity prices has led to an energy crisis in Europe, with a risk of profound economic and social consequences. Governments across the continent have introduced a range of emergency measures to tackle this crisis (see below). However, even with these



measures, European consumers will still be facing a 'winter of discontent', with prices in many countries likely to be far higher than just two years ago (winter 20/21).

Figure 1: Electricity and gas wholesale price trends in Great Britain.

Sources: Ofgem (historical: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators, *and BW (forward prices:* https://www.businesswisesolutions.co.uk/energy-market-snapshot/, accessed Nov 22*)*

…and where we are heading: the next two years

Figure 1 illustrates the extraordinary scale of gas and electricity price increases in Great Britain, along with available data on 'forward prices' - contracted prices for future delivery, which indicates market expectations and hedging positions over the next four years. Markets expect prices to come down – but only gradually; electricity wholesale prices are expected to remain in the range £100-£200/kWh, compared to around £50/kWh typical in the previous decade.

In the EU, the main measures proposed to tackle high prices involve mechanisms for capping gas prices, taxes on windfall profits, and a fixed revenue cap on inframarginal electricity generators – largely renewable and nuclear (proposed at €180/MWh).

In the UK, the government first announced the Energy Bills Support Scheme, providing a £400 discount to all households in GB across winter 22/23, with targeted additional payments for those in receipt of certain benefits. Subsequently, the Energy Price Guarantee sets caps on household electricity and gas unit retail prices, corresponding to an *average* dual-fuel bill cap of £2,500 per year for two years from October 2022. This has since been reduced to six months, to April 2023). This is still far more than double the typical annual bill across the previous decade. Prices to non-domestic consumers are capped at around half the level faced by households, with a review after three months (January 2023), with an option to extend support for 'vulnerable businesses' thereafter. These measures to cap electricity prices in general, come at great cost to the public purse (the UK's original Energy Price Guarantee may have cost up to £140 billion[3]), and present a range of political and other challenges and risks.

In the EU, tensions over the levels of price caps, national applications, trade, and (re)distribution of associated revenues are already flashpoints. An overwhelming issue for much of Europe emerged when Germany announced a plan to subsidize not just consumers but producer fuel prices. If implemented, this would directly undercut the 'level playing field' principle for industrial production across the EU single market.

Most importantly, these measures scarcely address the underlying dynamics and electricity market structures that facilitated this crisis. In July 2022, the UK government launched its Review of Electricity Market Arrangements (REMA); which aims to explore options to ensure that the electricity market in Great Britain is "fit for the purpose of maintaining energy security and affordability for consumers as the electricity sector decarbonizes." The process suggests any reforms to the existing market would only begin from the mid-2020s. However, the likely cost to the UK Treasury of the measures already proposed will likely accelerate this timeframe and allow consideration of more radical options than may previously have been thought feasible.

2025/6 and beyond

Although projecting energy prices too far into the future is fraught with uncertainty, early data suggests that wholesale electricity prices in Great Britain may remain far above historical averages well into the second half of the decade (Figure 1). At the same time, electricity systems across Europe are undergoing a rapid transition. Across the EU and UK, non-fossil sources already amount to almost two-thirds of generation and are projected to rise to over 80% before 2030. Table 1 summarises data from published sources on projections for both the UK and EU; Figure 2 illustrates an updated projection for the EU, reflecting the accelerated policies to move

[3] See Miller, G (2022) *Energy Price Guarantee - Counting the Costs*, Available at: https://www.cornwall-insight.com/energy-price-guarantee-counting-the-costs/

away from gas, and suggests that over half of all electricity generated could be from variable renewables – i.e., wind and solar – from under a quarter today.

Table 1: Current (2021) and projected contributions to electricity generation in TWh/year

		Non-fossil fuels			Fossil fuels
		Wind & solar	Hydro & Biomass	Nuclear	
EU + Norway*	2020/21	542	667	684	991
	2026/27	1020	669	568	794
	2030	1225	669	519	710
UK	2020/21	89	46	50	127
	2026/27	194		35	73
	2030	235		43	46

* Norway included due to its interconnection to the UK and its relevance in the total hydro power in the European interconnected system. Sources:[4]

[4] Sources: For the EU, the 2020 generation was obtained from Eurostat (https://ec.europa.eu/eurostat/databrowser/view/nrg_bal_peh/default/table?lang=en) and the hydro generation from Norway was added according to https://energifaktanorge.no/en/norsk-energiforsyning/kraftproduksjon/. The projected generation for 2030 is according to the EU reference scenario 2020 (https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en) and the contribution of Norwegian hydro generation was increased proportionally to the expected installed capacity growth as per https://iea.blob.core.windows.net/assets/de28c6a6-8240-41d9-9082-a5dd65d9f3eb/NORWAY2022.pdf. The values for 2026 were obtained by interpolating linearly between 2020 and 2030.
For the UK, the 2020 generation was obtained from BEIS (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1032260/UK_Energy_in_Brief_2021.pdf).The 2026 and 2030 generation are according to the NetZero Strategy Baseline (https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021 Annex J

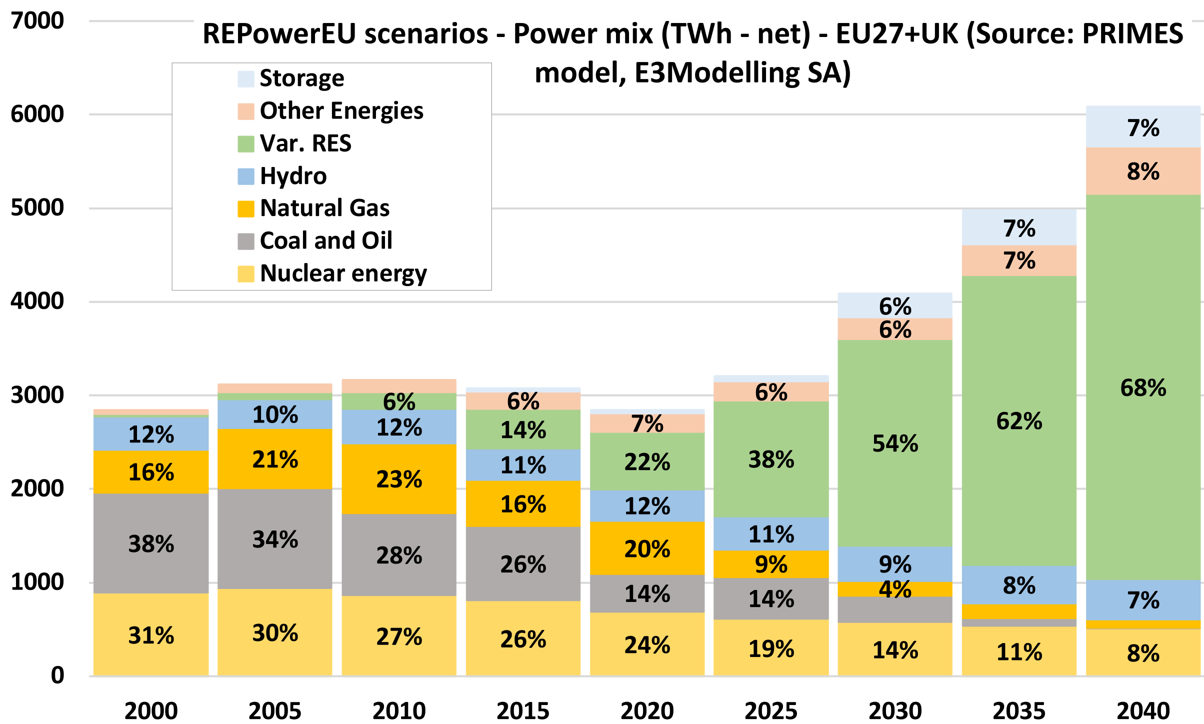


Figure 3: Current (2021) and projected contributions to electricity generation in TWh/year.

Source: E3Modelling SA, Athens

The costs of renewable generation have fallen dramatically over the last decade or so. Even before the crisis, new renewable contracts were at costs comparable to gas generation. Although there are uncertainties surrounding the specifics of future developments (including rising interest rates, perceived political risks and supply chain dynamics), the average cost of renewables – particularly wind and solar - will continue to decline. This means that **the cost inversion between renewables and traditional fossil fuel generation sources is likely to be a sustained, rather than transitional, reality**.

However, for the rapid transition to renewables to continue, changes in electricity market design and supporting infrastructure will be needed. Otherwise, rapidly growing periods of demand and supply imbalance, transmission constraints, and electricity price 'cannibalisation', would impede the transition.[5] Renewable energy expansion has been substantially driven by government-backed contracts 'outside' the wholesale market, but concerns are likely to grow around the role of direct government contracting potentially expanding to roughly half of all generation.

[5] The process by which renewable generators progressively reduce wholesale electricity prices through with their near-zero marginal costs, such that they depress their own revenue with increasing deployment and generation.

This paper focuses on the potential electricity market structures that could both tackle the fundamental dynamics that have led to the current electricity price crisis, and that can support a continued and efficient transition to a system dominated by renewable sources.

3. Strategic visions and proposals

The many long-term visions for low carbon electricity systems fall into two main types. The first type has a particular focus on centralised generation technologies and large-scale storage: with various views and scenarios for nuclear, wind and solar, carbon capture, global grids, and green hydrogen. The second places emphasis on high efficiency, localised systems with distributed generation, batteries, and electric vehicles (EVs) plugged into the system with smart controls, providing ‘flexibility’ in electricity demand. These also tend to emphasise more demand-side social, and governance/participatory dimensions, including a significant role for highly engaged ‘prosumers’.

These visions are not mutually exclusive. Whatever the potential for localized distributed generation, it seems likely that heavy industry and cities, in particular, will continue to need access to large-scale generation through transmission grids, whilst all will benefit from flexibility.

There would doubtless continue to be a role for a wholesale electricity market, or similar mechanism designed principally to incentivize cost-efficient use of existing generation capacity.[6] However as explained in NECC #3, the growth of renewables and their big cost reductions have largely involved incentive structures and processes *outside* the wholesale market.

Very few studies tackle the question of what combination of regulatory and market structures might be needed to help turn the various future visions into reality. Those that have, in part, start from the underlying observation stated in NECC #3: that the transition, to a large degree, will involve shifting from the vagaries of fuel-based international commodity markets to something which better supports investment in assets, many of which then cost little to run – ‘infrastructure electricity’, by Patterson (2007). Most emerging proposals share a common theme: the restructuring of electricity markets (plural) according to the financial and temporal structures of different generation sources.

Some bold analysts propose a complete split between two electricity markets. An ‘on demand’ market,[7] based upon energy stored in fossil fuels and potentially biomass, uranium, or (for hydro) large reservoirs. Said market would likely be similar to current wholesale markets, with correspondingly variable prices based on short-run costs. An entirely separate market would offer ‘as available’ electricity, e.g., from wind and solar, on long-run assured prices (i.e., semi-fixed prices, with small variance), reflecting the average cost of those sources, rather than

[6] ‘Wholesale market’ is a general term for electricity generation sales and purchases, often centered on (generation) offers and (purchase) bid on a ‘day ahead’ market, but which can include trades on other many other timescales from intra-day to forward trades from months to a few years ahead.
[7] Keay, M. and Robinson, D. (2017). ‘Market design for a decarbonized electricity market: the “two market” approach’, in Rossetto, N. (ed.), Design the Electricity Market(s) of the Future, proceedings from the Eurelectric-Florence School of Regulation Conference

marginal costs of the wholesale market. Consumers can get cheap power by contracting with the 'as available' market, which they can support with (likely more expensive) firm power with a parallel contract from the 'on demand' market. In such designs, intermediate suppliers could play a role, by bundling the components into a single contract for households, for example.

An alternative proposal focuses on detailed conceptual design for a combination of long-run fixed-price (> 10 years) private bilateral Power Purchase Agreements (PPAs) between individual generators and offtakers, designed for renewables, and interacting with a short-run variable price market.[8] In principle there is no obstacle to the private sector continuing to develop and expand such an approach building upon the existing PPA market and contractual designs. However, a key drawback to the more widespread application of such contracts appears to be their fearful complexity (see Section 6).

Conversely, while the proposal for fully split markets is simple in conception, it is such a radical departure that it may be seen more as a potential final destination for zero-carbon systems rather than an option for near-term implementation.[9] Nonetheless, some major companies, including BT in the UK and Google globally, have themselves have embarked on the quest for a genuinely "24/7" carbon-free electricity compact.[10]

Our scope

As stated, our focus is on policy options relating to larger-scale generation, providing power directly to industrial and (through suppliers) other consumers, interacting with the existing wholesale market as a source of balancing and backup for variable generators.[11] We refer to this as a 'dual market' structure: distinct arrangements for a new structure appropriate to the very different characteristics of renewables, but interacting directly with the existing wholesale market.

In this context, and that of the current European energy crisis, the most specific proposal for harnessing the opportunity of existing low-cost renewables, with least disruption to the Single Electricity Market, is the Greek proposal put forward in July 2022.[12] This would require non-fossil fuel generators with very low marginal costs to offer *volumes* to the day-ahead market, rather than price-based bids. The Market Operator would then clear the market in the usual way,

[8] Pierpoint, B. (2020). *A Market Mechanism for Long-Term Energy Contracts to Support Electricity System Decarbonisation*, Available at: https://media.rff.org/documents/pierpont-long-term-electricity-markets-paper-dec-2020-final.pdf

[9] A fully split market is a radical step that appears difficult as a near-term approach because of the contractual complexity, low level of informed consumer engagement at present, and extent of intermediaries and investment required in flexibility and local storage that may be required to assure firm power for consumers. It could however be a logical outcome, for example, if small-scale storage options improve radically over the coming years, along with increasingly sophisticated consumers and intermediaries to manage 'firming' of renewable energy.

[10] https://www.bt.com/bt-plc/assets/documents/digital-impact-and-sustainability/our-approach/our-policies-and-reports/bt-carbon-reduction-plan.pdf; and https://gocarbonfree247.com/

[11] Implicitly, "larger scale" in this context refers to generators likely to connect at the level of national transmission rather than local distribution, principally generators of a few tens of MW capacity or larger.

[12] For outline of the Greek proposal see https://data.consilium.europa.eu/doc/document/ST-11398-2022-INIT/en/pdf

after taking into account the output offers from these generators, which would be paid at fixed prices rather than the marginal clearing price.

In one way or another, this is the obvious economic principle upon which to operate day-ahead competitive electricity markets as the volume of renewables on fixed-price contracts grows. In terms of the underlying economics, it is a logical *operational* cornerstone for 'dual market' proposals, but in itself does not address a range of other issues addressed in this paper.[13]

A Green Power Pool – a thumbnail sketch

Varied proposals hold potential to address the increasing gulf between the average and marginal cost of electricity generation. Those noted above, however do not directly address questions of possible targeting, and differ in the extent to which they do (or in principle could) address the final two of our suggested guiding principles - appropriately (and transparently) apportioning backup and balancing costs, and consumer engagement.

In 2018, in the context of work examining the drivers behind the high electricity prices faced by UK industry compared to key European competitors, we published a proposal.**Error! Bookmark not defined.** It presented an approach which could involve targeting access to a 'green power pool' of cheap renewables, made available to industrial consumers who faced the greatest competitiveness pressures. Given the huge degree of cost inversion now evident in the EU and UK electricity systems, the proposal developed in this paper explores in more depth, ways in which consumers could access these growing pools of increasingly cheap electricity, whilst preserving security of supply and, enhancing low carbon investment and efficient operation of the system.

The central proposition involves aggregating the output of groups of low carbon generators on fixed-price contracts through what may be termed a 'green power pool'. This would offer the electricity directly to offtakers rather than indirectly through the wholesale market and its marginal pricing structures.

Figure 3 shows estimates of the volume available from different low-carbon sources in receipt of government support in Great Britain in 2023, and projections to 2027/8. The latter indicates that if all CfDs so far contracted were combined with generation currently supported by Renewable Obligations, the total (over 150TWh/yr) would, within five years, amount to about half UK electricity generation.[14] The volume from the four auctioned CfD rounds to date is growing fast and by 2027/28 would amount to about a quarter of current total UK generation.

[13] The Greek proposal does not engage significantly with the issue of whether or how the day-ahead market offers adequate incentives to invest, or direct consumer access (beyond existing Power Purchase Agreements). It focuses upon the operation of a dynamic wholesale market alongside significant volumes of existing plant on fixed price contracts.

[14] Complications in this data include that only about half the RO generation reported by Ofgem participates in the national balancing mechanism, as indicated; Much of the rest may connect at distribution level, and some may be for own use, making it unclear how much might be available to participate in a national 'green power pool.'

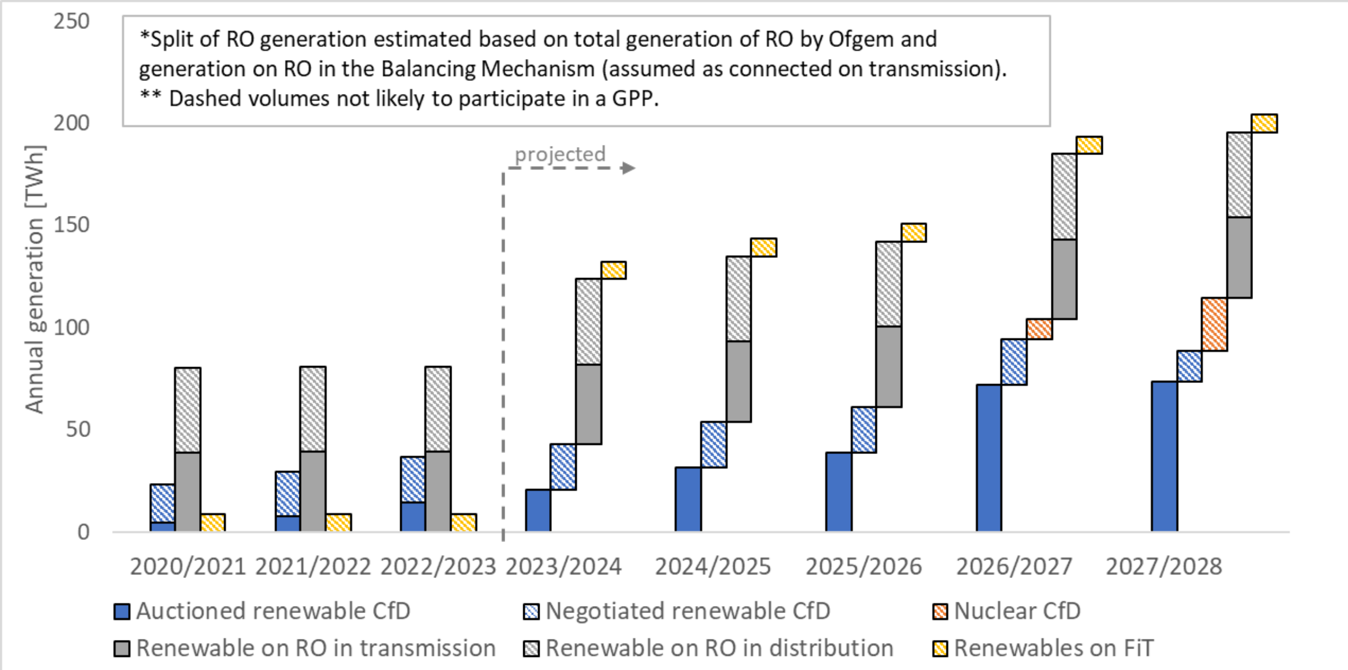


Figure 4: Renewable energy and other CfD derived generation in UK, expected 2023 and projected 2027/28.

Source: Produced by the authors based on LCCC's projected generation and the RO annual report 2020 - 2021. For comparison, total UK generation in 2021 was 308TWh (UK Energy in Brief, 2022).

We explore potential terms of access, and how the pool can offer 'firm' power to its customers through interactions with the wholesale market, which in other respects would continue structurally unchanged. Because the two markets would be linked in this way, we refer to this as a proposal for 'dual' rather than 'split' markets.

Our proposal is not inconsistent with key dimensions of the proposals outlined above, and more detailed implementation questions can be informed by insights from them.

However, major changes in market structures do not spontaneously arise – least of all in closely regulated markets like electricity. The long-run issue is not the complexity of a new market design fit for the future – today's electricity markets would also appear fearfully complex compared to half a century ago. Rather, the main question is how or even whether a new design could evolve from the present system, and the present mix of private and government-backed contracts.

In general, market systems build upon opportunities, and evolve in the light of experience. Our major focus in this paper is upon key options, feasible in the context of the energy crisis, which could accelerate the transition in the right direction.

4. A CfD-derived Green Power Pool: targeting supply

Several key features of an emerging electricity system 'fit for the future' are already evident. Given the asset nature of renewables (high capital but low operational costs), the value of investment security in the form of long-term contracts has been amply demonstrated by the success of fixed-price feed-in-tariffs and contracts-for-difference (CfD). Our previous working paper (NECC #3) explained the theoretical reasons why this is appropriate for such asset investments: they are not only long-term (like much else in the energy system), but also carry all the price risks of 'inframarginal' generation in wholesale electricity markets, which means that the wholesale market is intrinsically tilted against non-fossil fuel investments. Even aside from the sheer scale of investment and innovation, empirical analysis has shown, unequivocally, the extent to which long-term contracts have lowered the cost of capital, saving billions of pounds.[15]

In effect, these contracts are an important step towards structural reconfiguration of the electricity system and a 'dual markets' approach, the first of the guiding principles we suggest in NECC #3 (reproduced in Box ES-1). However, they are only partial since they involve an indirect, purely financial contract (see Box 1). When the CfD-based generation is cheaper, the CfDs also begin to address the second guiding principle of separating the average cost of electricity from the fossil fuel-driven marginal cost of generation, by recycling most of the excess revenues back to suppliers and ultimately consumers.[16] These represent a step on the journey towards market structures more appropriate to renewables.

It would be possible to continue to rapidly expand renewables using these existing mechanisms. An outstanding challenge in the context of the energy crisis is the higher-than-average revenues generated for non-fossil sources supported by other means. Such sources include renewables supported by feed-in premiums in much of the EU, and the Renewables Obligation (RO) mechanism in Great Britain and Northern Ireland. [17] On 12th October 2022, the UK government announced that it plans to cap revenues from such sources, as adopted earlier in guidance by the EU – an awkward, emergency fix to what may be better addressed as a structural problem.[18] These approaches do not address our three other potential guiding principles – hence the search for better options.

[15] See Blyth et al (2021), *Risk and investment in electricity markets*, https://ukerc.ac.uk/publications/zero-carbon-electricity/

[16] In relation to renewables on these or similar 'fixed price' contracts, the Greek proposal provides a financially more direct route for incorporating the output of fixed-price renewables into the wholesale market, with similar outcomes for consumers.

[17] Despite its closure to all new entrants in 2017, the 20-year contracts of the Renewables Obligation continues to guarantee a subsidy to many renewable generators in addition to the price received for selling their electricity on the open market.

[18] One option in discussion in the UK is to bring RO-backed generation (and maybe existing nuclear) onto state-backed, fixed-price contracts, akin to CfDs. This would imply state-backed price guarantees assuming an ever-greater role in the electricity system; just this, combined with the contracts already committed under the 4th CfD auction round, would imply about half UK generation within 5 years being on such state-backed fixed price contracts (Figure 3.)

Box 1 – Financial flows under the Contracts-for-Difference (CfD) mechanism

A CfD is a private law contract between a low-carbon electricity generator and the UK government-owned Low Carbon Contracts Company (LCCC), based around a fixed 'strike price' determined for 15 years. In physical terms generators offer power into the wholesale market, hence the contracts determine payments for the difference between the market price, formalised through a variable Market Reference Price (MRP), and the strike price for each individual contract.

Whenever the strike price exceeds the MRP – i.e. the fixed price exceeds the wholesale market price - the LCCC pays the generator the difference. Conversely, when the MRP exceeds the strike price, the generator pays the LCCC the difference.

Payments to generators from the LCCC are funded by a statutory levy on all UK-based electricity suppliers (the Supplier Obligation Levy). This levy comprises two main components: an 'Interim Levy Rate (ILR), determined for each quarter in advance, based on projected net costs and eligible volume supplied, and a Total Reserve Amount (TRA), a quarterly lump sum paid to ensure the LCCC is able to make payments if costs are higher than expected. Suppliers also pay an Operation Cost Levy, to fund LCCC administrative costs.

For quarters in which generators are expected to make net payments to the LCCC, the Supplier Obligation Levy (ILR and TRA) may be set at – but not below – zero. This has been the case since April 2022, as wholesale prices have greatly exceeded strike prices. When they are due, net payments to suppliers are made as part of an end-of-quarter reconciliation process. Due to concerns that suppliers might not pass on these payments to their customers, in June 2022, Ofgem decided to amend their 'default tariff price cap' to ensure that household consumers on the default tariffs benefited from these repayments.

Technically, therefore, CfDs are not quite fixed-price contracts: they are contracts which, after a series of short-run transactions, either (a) involve a 'top-up' payment to generators funded from charges added to the bills of most consumers (excluding some industries), or (b), for CfDs which are cheaper than the wholesale price in a given period, refunds of the excess generator income, some months later, to consumers who are on (price-capped) default tariffs.

Targeting support: rationales and basic options

Due to the energy crisis, the need to help consumers with soaring bills has become paramount across all European countries. The responses have been varied, as outlined in NECC #3 (and above) – but they have also been problematic.

Some approaches involve helping all consumers, either with direct financial payments, or blanket measures to subsidize electricity prices. Direct and undifferentiated financial payments involve large direct government expenditure, do not reduce the inflationary pressure of rising energy prices, and do not contribute to reform of the electricity market structures that have exacerbated the crisis.

To reduce inflationary impacts, governments can in principle reduce electricity prices with various mechanisms. The 'Iberian exception' has legislated caps on gas prices used for power generation.[19] Others involve paying the difference between wholesale and capped retail prices. However, such general subsidies to electricity prices have multiple drawbacks. Aside from muting everyone's incentive to save energy, the greatest beneficiaries are those who consume the most (typically, richer people), and the bill is huge, with major distorting effects and no longer-term benefits. The German government seems to be backing away from its proposal for a €200bn subsidy; in the UK, the financial liabilities from the retail energy price cap introduced in September 2022 – unfunded, and alongside tax cuts - were a dominant factor in the financial turmoil and fall of the UK Prime Minister Liz Truss just a few weeks later.

The alternative is to target support to those who need it most. All approaches to targeting involve political choices, drawing on consideration of which groups should benefit and why. Two priority groups stand out for exceptional political, economic and welfare concerns:

- **Vulnerable industries** whose competitiveness is directly threatened by substantial differentials in electricity prices compared to their international counterparts

- **'Fuel poor' domestic consumers** already targeted for previous government supports, or otherwise defined for this purpose.

Of course, many other groups could stake a claim for support with electricity prices and bills. With fiscal targeting, how many consumers can be supported will be determined by the cost of such support; the scope for targeting through a 'green power pool' depends on the availability of and access to cheap renewables. We illustrate volumes below, which suggests scope to expand beyond these groups, and potentially far beyond if some or all the of renewables currently supported by ROs were brought into such a pool, as discussed in section 6.

Vulnerable industries

Electro-intensive industry in Europe was already hard-pressed to compete, but the energy crisis makes the situation untenable for some, due in part to the price-regulated nature of electricity markets in many other countries (e.g., as noted in NECC #3 for South Korea). A theoretical case for intervention resides in the economic 'theory of second best'.[20] Letting many such industries close and migrate in response to the energy crisis is neither good economics, nor feasible politics, nor would it contribute to global decarbonization – indeed, potentially the reverse.

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[19] https://www.euronews.com/my-europe/2022/04/26/brussels-agrees-to-iberian-exception-allowing-spain-and-portugal-to-cap-electricity-prices

[20] The economic case resides in the economics of living in a 'second best' world, where goods are traded between countries which treat commodities differently. This, indeed, was the foundational arena for the economic theory of second-best. Many countries, especially in Asia, still regulate electricity end-use prices at levels which are now very low compared to countries with short-run-marginal-cost-on-all pricing.

Practical and legal problems may differ according to the means of support. The option of fiscal targeting – direct subsidies – to directly support an industry's' international competitiveness, runs counter to the underlying principles of world trade and comparative advantage. Specifically, to prevent a global race-to-the-bottom, the WTO Agreement on Subsidies and Countervailing Measures (SCM rules) allows other countries to impose countervailing duties on a country that tries to directly subsidize its exports, if harm can be demonstrated. Current approaches – in which some governments are capping generator profits (EU) or subsidizing end-use electricity prices for industry (in the UK at least, as declared for the winter 22/23) – might be defended as temporary, exceptional measures – but may still risk countervailing duties by other countries, especially if extended; this remains to be seen.[21]

In Great Britain, one potential definition of priority industries could be those already eligible for compensation for the indirect costs of the UK Emissions Trading Scheme (UK ETS) and Carbon Price Floor applied to electricity generation. This group used between 3 to 4 TWh of electricity in 2021, close to 15% of the electricity generated under CfDs that year. An alternative definition could consider the industries that are eligible for the Energy Intensive Industries Exemption Scheme, which are a larger group, and in 2021 accounted for 9.9 TWh of electricity demand, 45% of the electricity produced under CfDs.[22]

The potential legal benefits of a targeted green power pool for vulnerable industries should be explored. The essential argument in NECC #3 is that renewable electricity is different in multiple ways to conventional generation – including its global environmental benefits and economic characteristics. Making such electricity preferentially available to electro-intensive industries based on prices genuinely reflecting its production cost thus should be legitimate under EU and/or WTO rules.[23] Targeting renewable electricity at internationally trade-exposed industries may indeed be the only way to reduce their electricity costs without risk of retaliatory duties, whilst helping heavy industrial sectors electrify and decarbonize their operations in line with the Paris Agreement.

'Fuel poor' households

The case for targeting cheap renewable electricity to vulnerable households is more straightforward in principle, as the state has a right (many would say in the current circumstances, a duty) to help.

Aside from the noted expense of simply capping the general price of retail electricity (in Great Britain, at levels about twice the price of the previous decade) many welfare groups argue that this is still inadequate to protect the poorest, and disproportionally benefits the rich. Multiple

[21] Compensating duties may be blocked by EU law, though subsidies may be allowed in case of emergencies – however defined.
[22] Author-derived estimates
[23] If these generators were moved to direct long-term contracts at their strike price (so technically no longer on CfDs, but genuine fixed price contracts), it would be hard to argue that they were being subsidized, if there were no actual payments from government (indeed, government underwriting itself is not the same as a subsidy; it is not uncommon for governments to establish export credit guarantees). There could be complications arising from the historical background of these contracts, but the fact that recent CfDs have been paying back handsomely to the government would make it hard to sustain an argument that they have benefited overall from historical subsidy.

studies are emerging with proposals on how to better target support to the most vulnerable[24], but are yet to meaningfully engage with the question of *how* to deliver support – whether by giving those consumers money, or somehow giving them preferential access to cheaper electricity.

Compared to direct government payments, one rationale for giving them access to a CfD-derived pool of renewable electricity is that it would provide more stable and predictable support, far less subject to the repeated changes of government budgetary politics.

The obvious route to deliver CfD-derived electricity to such vulnerable consumers would be for suppliers to create special-purpose vehicles to purchase and market such power to the identified customer groups. The framework for these special-purpose vehicles would of course have to be regulated, to prevent them profiting by on-selling to higher-price markets. The 20% of lowest income households consumed close to 13.5 TWh in 2021.[25]

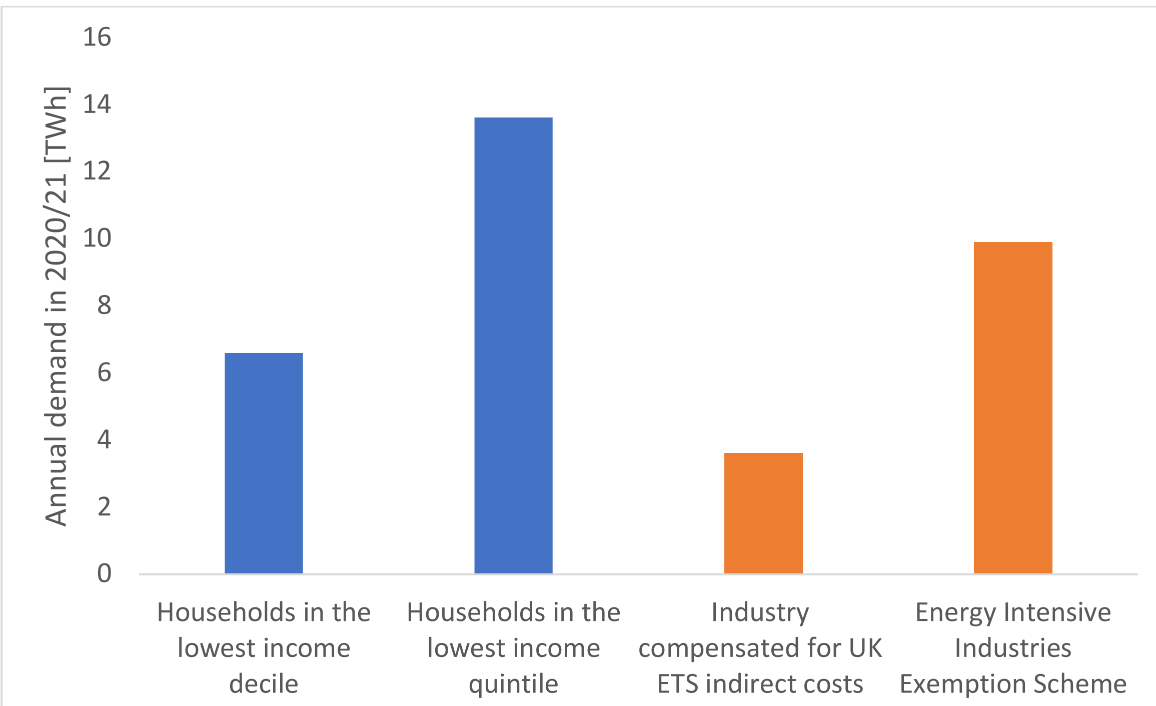

Figure 5: Estimates of electricity consumption of various 'vulnerable customers'

Source: For households see[25], for industry see[22].

[24] E.g., Brewer et al (2022) *A chilling crisis: Policy options to deal with soaring energy prices*, Resolution Foundation.

[25] Author calculations based on the average weekly electricity expenditure of households by disposable income decile, Office for National Statistics (2022) (https://www.ons.gov.uk/file?uri=/peoplepopulationandcommunity/personalandhouseholdfinances/expenditure/datasets/familyspendingworkbook1detailedexpenditureandtrends/fye2021/workbook1detailedexpenditureandtrends1.xlsx). For reference, in England in 2020 approximately 45% of households in the lowest income quintile were deemed "fuel poor", concentrating roughly 70% of total fuel poor households, according to BEIS (https://www.gov.uk/government/statistics/fuel-poverty-detailed-tables-2022).

Figure 4 summarises some initial estimates of the volume of demand from different definitions of these categories, which demonstrates that the amount of electricity generated from CfD-supported generators (Figure 3) *already* exceeds the likely demand of these groups.

Options for targeting

Targeting support for those who really need it is far more cost-effective – but more complex. In the UK context there are broadly three options to help target specific groups, however identified:

- **Direct financial payments**, which may or may not be funded by 'windfall' taxes

- **Recycling of the financial surplus from CfD contracts**, when wholesale prices exceed strike prices (see Box 1), targeted to specific priority groups rather than returned to supply companies

- **Direct targeting of CfD (or other) fixed-price generation contracts** to priority consumer groups, charged at or near strike prices (plus associated network and other costs).

After discussing the possible role of a 'green power pool' in targeting support to consumers, Table 1summarizes some pros and cons of these different approaches.

A CfD-derived green power pool: issues in targeting

The electricity procured through CfDs can be considered as a potential pool of electricity, already cheaper than current wholesale prices and with a sharply declining cost across successive contract allocation 'rounds', illustrated by the declining cost of offshore wind contracts as discussed in NECC #3 (Figure 5).[26] The fact that the government has a direct stake in CfD contracts makes the question of what happens with this cheap electricity a topic of legitimate public interest. Further, the government stake could make it both simpler and quicker to implement changes. Combined with the fact that both costs and volumes are known (including for some years hence), this a natural first focus for considering some practicalities of a Green Power Pool.

[26] The gap is striking: over the period 2022-2025, the volume of output from offshore wind will double, to over 40TWh/yr, supported by round 2 and 3 CfDs at prices averaging around £50/TWh (in 2021£) – 5.0p/kWh. The weighted average of all auctioned CfD prices by 2026/2027 (Figure 5) is 56 £/MWh, whilst the forward contracted data for that year (Figure 1) is 125-145£/MWh. The latter also coincides with wholesale price forecasts by the analysis Cornwall Energy, which projects around 130-140 £/MWh for that period (https://www.cornwall-insight.com/press/energy-prices-to-remain-significantly-above-average-up-to-2030-and-beyond/).
Whilst wholesale and retail costs of course cannot be directly compared, the corresponding end-use cost would be less than the UK retail electricity price cap announced in September 2022: "The average unit price for dual fuel customers paying by direct debit will be limited to 34.0p/kWh…", with a cap on industrial electricity prices at half this level. 100 £/MWh [the standard units for wholesale] is mathematically equivalent to 10 p/kWh [the standard units for retail], before add-on costs (footnote 29).

Figure 6 presents the actual and projected volume-weighted average strike price for electricity produced by generators with CfD contracts. Based on auctioned CfDs only[27] the weighted-average strike price – dominated by offshore wind – is already below £100/MWh, and declining, remaining far below the forward electricity prices presented in Figure 1. If and as future CfD contracts (post-Round 4) are awarded, and their generation brought online, weighted average prices are likely to decrease further, offering substantially cheaper power to final consumers.[28]

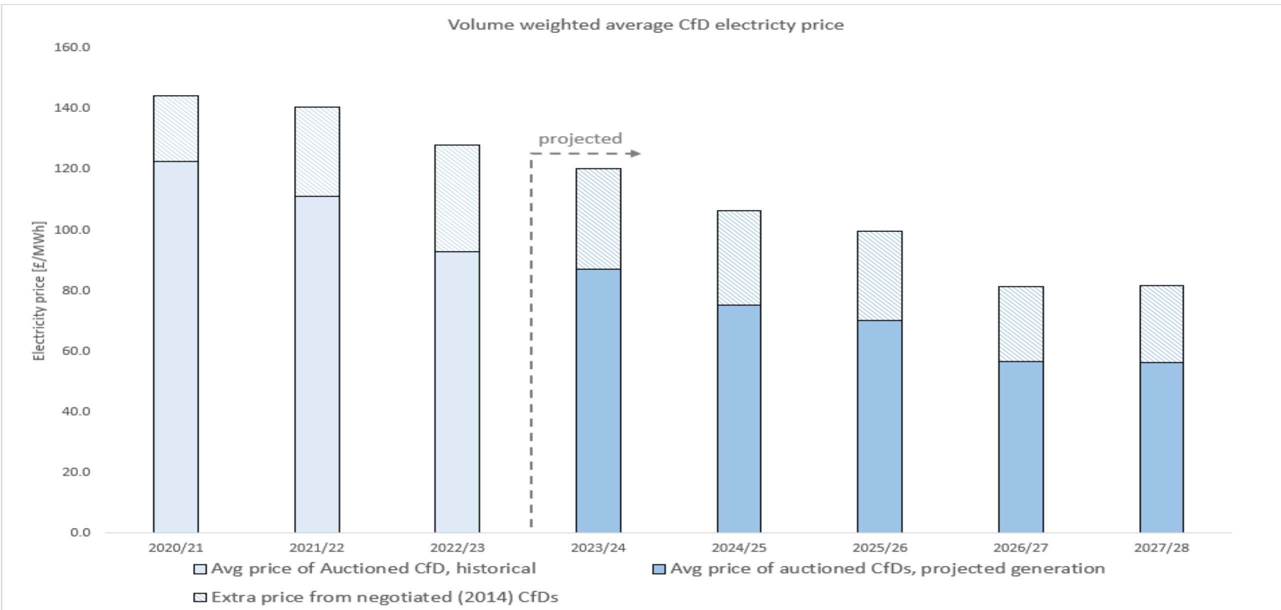

Figure 6: Average wholesale prices of electricity produced by existing and contracted CfDs.

Source: Produced by the authors based on LCCC's forecasted generation (Figure 4), and Ofgem price cap.[28]

At present, the surplus revenue from generators selling into the wholesale market is ultimately returned to electricity suppliers, in proportion to their eligible sales. They are expected to pass on said revenue in the form of savings to consumer bills, as discussed in Box 1.

Could this electricity instead be made preferentially and directly available to particular consumer groups, at costs related to the generator strike prices? This has potential benefits of a structural approach to helping those in most urgent need, along with the complexities of any targeting.[29]

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[27] i.e. if the more expensive 'negotiated' (pre-Round 1) contracts are not included. As well as expensive initial offshore wind contracts, the negotiated CfDs awarded in 2014 included significant volumes of biomass and the Hinkley Point C nuclear reactor; the subsequent auctioned CfDs are dominated by wind and some solar.

[28] The total add-on costs (beyond the wholesale price) for estimating retail prices are substantial, but complex. Based on the last Ofgem 'standard tariff' price cap before COVID, add-on costs amounted to almost 15 p/kWh. Network costs were the largest single component of this, followed closely by policy costs, and then a variety of operating costs and overhead allowances. Under a GPP, the policy costs relating to renewable energy supports (which by 2020 dominated the total policy costs) would become redundant.

[29] Choices of who should benefit would be politically loaded, the boundaries would be difficult, and implementation, complex. Though many of these drawbacks also apply to targeting of fiscal supports to low-income groups, the idea of targeting cheap electricity directly instead is novel and contentious. Economists might add that it would be inefficient compared to letting the market compete for low-cost electricity, but this is, at best, highly debatable. As outlined in NECC #3 (Box 3), this depends on assumptions about how one defines efficiency and measures welfare,

An additional central reason to consider targeting such generation is that if contracts to access this pool of cheap electricity were offered openly and competitively to consumers, market forces would simply drive the price up – probably to or near the wider market price for electricity – largely defeating any distributional purpose. To gain distributional benefits, the price would in the first instance have to be regulated and access restricted (through terms of franchise to suppliers) to benefit the most vulnerable.

Targeting: a summary of options

As noted, a decision whether to target CfD-derived cheap electricity directly – and if so to which consumer group(s) – is clearly a political decision, not a technical one. But the present market design makes it impossible to do so. There is a clear case to work out options to give governments the ability to target this cheap electricity if they wish.

As observed, any targeting is also administratively complex. Many other researchers have written on options for targeting fiscal measures, primarily for poorer households (there is less academic attention to targeting in industry, though it can occupy huge attention for governments when there are credible risks of major closures). Targeting cheap electricity would be novel, which likely raises the complexity. The question we address is how it could be done; and for politicians to judge whether, compared to the alternatives, the complexities are justified by the benefits. Table 2 summarises some of the pros and cons of different options for *implementing* targeted support.

whether and how the state collects and redistributes windfall profits - the assertion largely ignores issues not only of distribution, but 'second-best' economic theory.

	Direct payments	CfD indirect	Direct – Targeted Green Power Pool
Description	*Government direct payments to priority groups*	*Focus CfD recycling payments to priority groups*	*Give priority groups access to cheaper electricity through a Green Power Pool*
Complexity of initial implementation	**Low** (for households), if based upon existing benefit systems	**Medium*** (more complex for industrial consumers)	**Medium to High** depending upon contract complexity
Stability of mechanism	**Low** contingent upon general budgetary decision-making	**Medium** consumers (or their suppliers) pay wholesale prices, later receive compensation	**High** Long-term contracts with assured prices reflecting cost of CfD contracts
Predictability of benefit to targeted group (assuming policy stability)	**High**	**Medium** Level uncertain and payment timing misaligned to high cost periods	**High** Assured price component has low variability
Predictability of liability (assuming policy stability)	**Medium** Depends on government decisions in relation to evolution of energy prices	**Low but transitional** Degree depends on underlying energy price volatility	**High** Generator prices fixed; consumer assured price has low range
Transparency in system costs for balancing renewables variability	**Low / Medium**** No change	**Low / Medium**** No change	**High** (assuming implemented with GPP balancing from wholesale market)
Contribution to development of low-carbon system	No change	No change	**High** (depending on contract design)
Wider economic and legal risks	Potential WTO challenges for industrial support; government bears cost; potentially inflationary	Unclear WTO compatibility for industry support; no cost to government; not inflationary	Likely WTO compatible; no cost to government **If based on CfDs only**: Not inflationary **If RO generators brought into GPP**: potentially deflationary, depending on strike prices & time horizon

Table 2 - Comparison of different targeting approaches

** Targeting recycling of CfD revenues introduces new complexities as the current mechanism is based on a common cap to the tariff (see box 1)*
*** Current system involves 'constraint payments' and Capacity Market, but does not transparently identify other costs associated with providing 'firm power' complementary to variable renewables output*

As noted in our earlier report (note *iv*) almost all governments in Europe (including the UK) have long had policies to differentiate electricity prices to a limited degree, notably between households and industry in general, and for some trade-exposed industry groups. More general targeting is necessarily a transitional measure, to help particular groups in conditions of extreme prices and inequality. Yet in a different form, targeting is also used to stimulate transitions to better technologies – support either on the supply side (as with large-scale wind energy), or demand-side (as with heat pumps) – or often, both (as with electric vehicles).

As is clear from Table 2, creating a distinct channel to visibly connect ever-cheaper renewables to cheaper consumer electricity prices, such as through a green power pool, thus has a range of potential strategic benefits compared to other options for targeting support for energy costs. It does however require a plausible route of expansion, so that over time, explicit targeting can be dropped, enabling consumers to choose between standard contracts, and the emerging direct 'efficient route to market' for clean renewables.

We return to this in section 6. First, we use the key example of a CfD-derived pool to illustrate mechanisms for dealing with the variability of renewables.

5. A CfD-derived Green Power Pool: balancing variable renewables

In principle, the idea of a green power pool selling electricity to consumers through long term contracts derived from CfDs, is independent from whether the output is targeted, or available as another product open to all consumers in the general electricity market.

However deployed, given that much of the CfD-derived power would be variable output from wind and solar, complementary 'as required' sources (including storage) would be necessary, which may be purchased from the wholesale market (at various time horizons). We refer to this as 'GPP-balancing', to provide security of supply to consumers.[30]

Figure 6 summarizes the overarching structure of a Green Power Pool, and its relationship to generators, the wholesale market, and consumers. The following sections detail how the pricing relationships would work.

[30] Note, the term 'balancing' is also used for the short-term 'balancing market' in the half-hourly market, to provide intra-day adjustments to deal with fluctuations from predicted demand and generation.

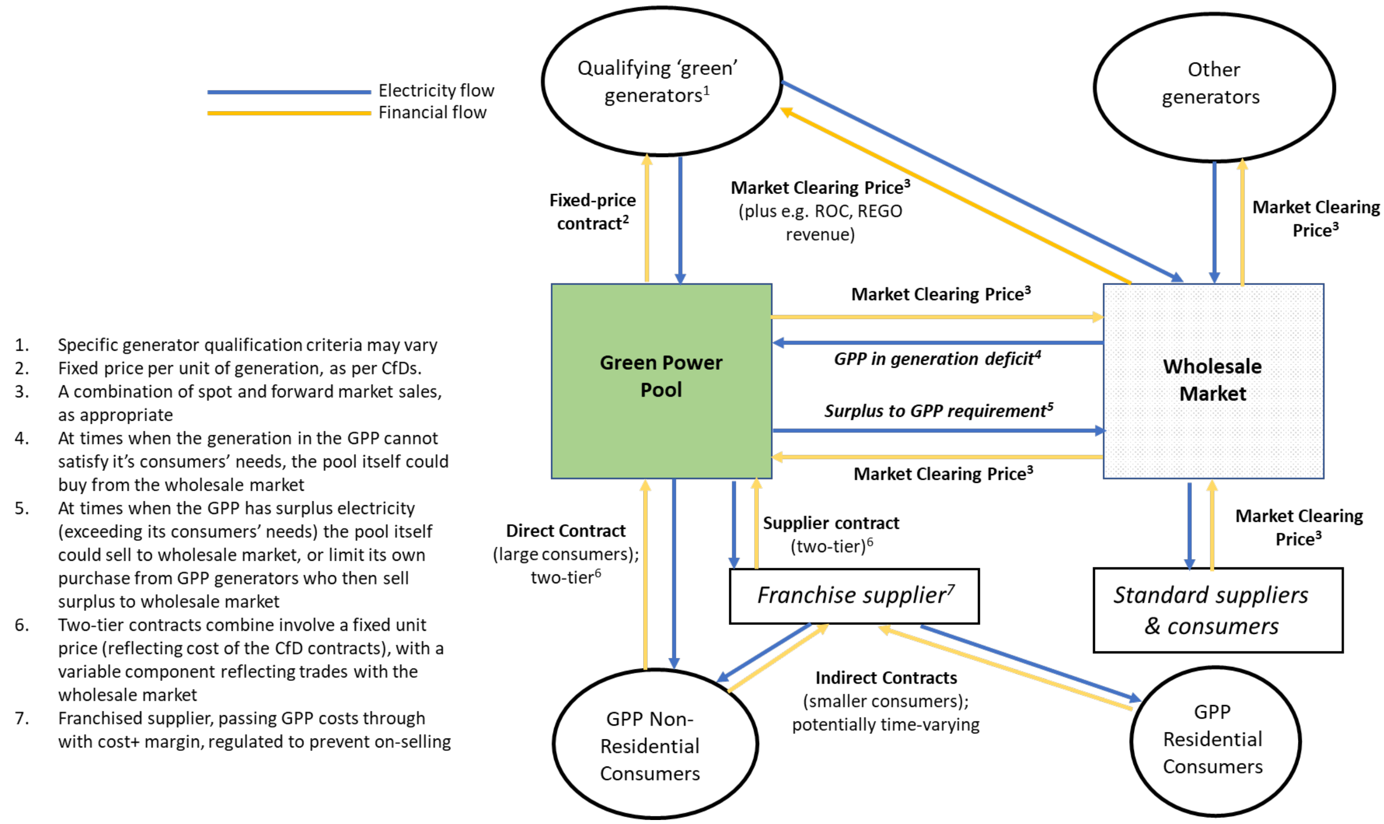

Figure 7: *Basic structure of the Green Power Pool operation*

Economic principles and caveats

Our fourth guiding principle is that systems appropriate for high levels of renewables require market structures which allocate balancing costs appropriately and proportionately:

- *Proportionately* implies that if there is a distinct market for renewables, that market should bear the costs required to maintain reliable supplies to its customers. This would also have the benefit of transparency, since the scale of actual balancing costs remains a topic of considerable confusion and contention, and muddies public understanding of the real costs of renewables;

- *Appropriately* means taking account of the purposes and incentive implications of the 'cost-reflective' pricing, so that price signals have maximum value in incentivizing a least-cost system.

Green Power Pool: a simplified approach

The simplest starting point would be for GPP consumers to pay an 'assured price' for the electricity they consume from pool generators. This price would reflect the output-weighted average strike price (£/MWh) of the capacity generated in any given period. The price would thus vary as the relative contribution of the different renewables changed, but within a relatively small range. We use the term 'assured price' (rather than fixed) because it reflects the contracted costs both of real-time generation, and an evolving mix of generators over a longer time horizon. Indeed, whilst individual generator costs are fixed (in real terms) by the strike price, the average portfolio cost declines as the newer, cheaper renewable generators come online, as shown in Figure 4.

Surplus GPP generation. For periods in which the GPP is in surplus (i.e. generation exceeded demand), the excess supply could be exported to the wholesale market, which economically can occur in various ways. The two following options would preserve the pros and cons of consumers paying an assured price - if the surplus generation were sold either:

- on the same basis as CfDs, through offers into the wholesale market, and cost differentials recovered through contracts with the Low Carbon Contracts Company as at present; or
- as proposed by Greece as a relatively simple fix to reduce costs and windfall profits in the EU power market – for renewables to provide any power to the wholesale market on a volume basis, at a fixed price. This could be done bilaterally for each generator – or the pool itself would export to the wholesale market at the generation-weighted average strike price of its generators.[31]

This relatively simple approach means not gaining the benefits that might flow from a fuller economic incentive approach – one which reflects ways in which a GPP might pass the costs and value of sales at the wholesale price through to its customers and generators, as outlined below.

Insufficient GPP generation. At other hours, the pool generation would be insufficient to meet pool demand, and additional power must be bought from the wholesale market and passed on to consumers, who would need to pay the associated cost. For final consumers without smart meters, the simplest approach would be to reflect this in the rates for this marginal consumption, at whatever time-granularity they can manage.[32] However, given that most suppliers already buy based on half-hourly pricing, it would be reasonable for any supplier licensed to sell green power pool electricity to deal with half-hourly prices.

[31] The Greek volume-based approach would involve generators (or the GPP) notifying the wholesale System Operator of its projected surplus generation, to be paid at the generators' (or GPP weighted-average) strike price.
[32] Adding to the base price of electricity, notified at whatever notice period was deemed appropriate – daily or weekly to reflect forecasts, or monthly or quarterly to reflect seasonally-adjusted expected outputs of renewables relative to demand.

A next step in 'cost reflectivity' would be for the cost to be specified in a two-tier pricing structure. This would reflect separately the generation available from the Pool (at the 'assured price'), plus the additional cost of GPP-balancing purchases from the wholesale market. In economic terms this is preferable so that suppliers and consumers see the real *marginal* cost of increasing consumption. This requires identifying the *proportionate consumption* of suppliers/consumers that would be paid at the assured price, with the remainder reflecting the wholesale market cost. This gives a price signal which properly reflects the cost of increasing or reducing electricity demand in the Pool – the marginal price, at any given point in time. If fed through to their consumers, this would give suppliers the ideal incentive to flex their demand or utilize localized storage (choosing when to charge and potentially discharge EVs, for example).[33] This approach is summarized in Table 3.

[33] The place of consumers here could of course be taken by their suppliers, who would be best placed to judge the extent to which such a two-tier pricing structure could be practically and meaningfully passed on to different types of consumers. In relation to long-term contracts, more sophisticated approaches could involve finer-grained time periods to determine 'typical' consumption levels at different times, from seasonal right down to hourly granularity, as in the industrial dual-market proposal by Pierpoint (2020) – see Footnote 8

Table 3: Physical and consumer cost states Green Power Pool – Simplified consumer cost model

GPP State	Physical flows and payments with wholesale market	Consumer costs (simplified model)
Pool generation is ***surplus*** to Pool demand	Pool/generators sell surplus power to wholesale market	Pool consumers pay the 'assured price' for all their electricity consumption
Pool generation is ***insufficient*** to meet Pool demand	Pool buys additional power from the wholesale market to meet demand	Additional costs passed through to pool consumers, applied to demand exceeding their 'proportionate' share of Pool supply, as either • a changing unit price as the volume of purchase required by the pool grows, or • "two-tier" pricing, i.e., with the proportionate power at the assured price, additional power charged at the wholesale market price (if suppliers have capacity for such contracts)

Note also that introducing the notion of an entity's *proportionate demand* – the proportion that can be procured from the Green Power Pool –also opens the possibility for the franchised GPP suppliers to be responsible for procuring the additional power required from the wholesale market. The 'Pool' would then need no direct financial trades with the wholesale market itself beyond potentially selling surplus power, which might also give greater scope for supplier innovations regarding GPP-balancing.

To determine the final 'GPP retail price' the consumer would pay, network charges and any other applicable taxes and levies would be added to the assured and flexible price element of supply. Which taxes and levies that currently apply to different electricity consumers in Great Britain, and which might continue to apply to GPP consumers, is beyond the scope of this paper. However, as many taxes and levies applied (other than VAT) are mechanisms for recovering the cost of legacy renewables deployment and social programs, an argument could be made that none should be applicable to GPP consumers, at least in the first instance when the consumer base is focused on vulnerable consumers. However, if legacy renewables (i.e. those receiving ROCs) were moved to another arrangement, this major levy element would be removed for all consumers.

Physical and economic states

To get maximum economic benefits – for both the system, and consumers from the Green Power Pool - when consumers use less power, they could also benefit from the potential additional revenues of sales to the wholesale market. In purely economic language, overall efficiency implies that consumers should experience the marginal costs and benefits of their marginal consumption, at all levels. Green Power Pool contracts should enable precisely those benefits, without them paying the system marginal price on all their consumption.

To consider more carefully the potential physical and economic states of the system, for exposition it is useful to consider the Green Power Pool initially as a single integrated actor, with no internal constraints e.g., from transmission. Further it is useful to consider the underlying economic characteristics of generators in the Pool, and how these relate to important debates around the structure of future CfD contracts. The underlying characteristic of most renewables output (particularly wind and solar, which would dominate the Pool's generation portfolio) is that due to very low variable costs, they would generate at maximum capacity when possible, whether or not anyone demands it.

The exception could arise if the entire electricity system has an overall surplus of renewables and 'must run' plants. In that case it is simplest to consider that the Pool would bid power to the wholesale market at a floor price (which may be zero – the state of 'cannibalization') and some pool generators may be directed or paid to cease generation.[34] In summary, there are three possible physical states and associated economic flows, as indicated in Table 4.

Table 4: Physical states and economic conditions of the green power pool – full-incentive model

Increasing renewables output relative to demand

Physical state	Physical flows	Economic flows (full-incentive model)*
Insufficient pool generation to meet pool demand	Pool imports from wholesale market	Additional costs passed through to consumers, applied to demand exceeding their 'proportionate' share of renewables generation
Sufficient pool generation to meet pool demand, so some surplus	GPP / generators exports to wholesale market	*Simplified*: GPP suppliers / consumers receive assured price *Fully cost-reflective:* GPP suppliers / consumers see variable price for 'proportionate' share of GPP *surplus***: • If wholesale price exceeds the pool average strike price, increasing demand incurs higher than Pool price (e.g. reward for reducing demand or generating from local storage) • If wholesale price below pool average strike price, lower marginal price (eg. incentive to fill storage)
Renewable and 'must run' generation in country exceeds national demand + exports	GPP / generators export to wholesale market above a 'floor price'*** and may reduce some generation	Alongside above structure for consumers, generators would normally receive fixed price with contract structures derived directly from existing CfD strike prices. Existing and planned treatment of generators in extreme conditions of overall surplus generation, when generators are constrained off, would apply unchanged.

** This model would require sophisticated infrastructure for consumers to respond to a variety of pricing structures, and more complete attention to generation incentives under different conditions. For a simplified model, see Table 3 and footnote.*
*** Proportionate share of GPP surplus is distinct from proportionate share of GPP generation/demand, as defined above.*
****Floor price in practice defined by CfD terms. CfD Round 4 contracts have implicit floor price of zero.*

[34] Which generators, on which terms, would be determined by the specific structure of existing and future CfD contracts, which for the present is beyond our core focus. There are several options for reforming CfD contracts to improve economic incentives where relevant, whilst minimizing any increase in revenue uncertainties which would drive up the cost of capital. If properly designed, these could, for example, involve a structure in which sources like biomass would be the first to cease generation in case of an overall surplus, and – if nuclear stations operate with a CfD – they would be incentivized to turn down generation to the extent manageable.

To bring this together, Figure 7 shows a flow diagram for key dimensions of how consumer contracts in a Green Power Pool could work in a semi-simplified way.

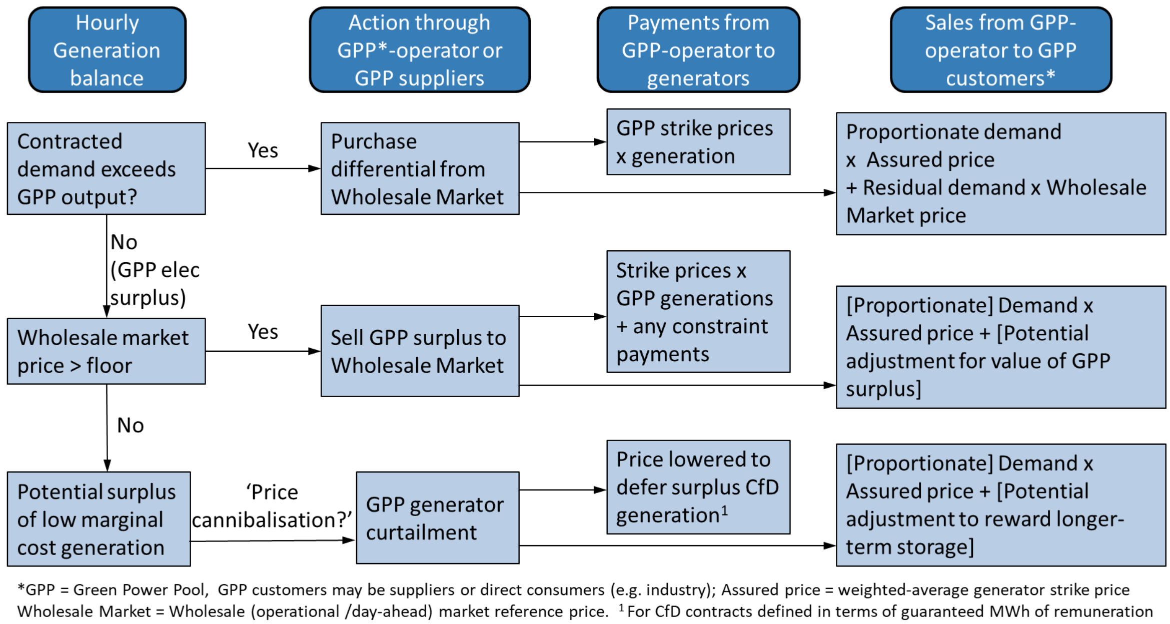

Figure 8: Flow chart of main operational conditions for a Green Power Pool (simplified consumer prices)

Implications for consumers outside a GPP

If the GPP is to be targeted, then by necessity most consumers will not be eligible to receive electricity from it – at least in its initial years. Although these consumers may be considered less 'vulnerable', the potential impact of a 'dual market' on these consumers should be considered.

In principle, from a static perspective, it is not clear that moving renewable generators with CfD contracts from the wholesale market would have a material effect on wholesale electricity prices. Both electricity supply to and demand from the wholesale market would be reduced, and on aggregate, the merit order, and total supply and demand would remain effectively unchanged. Suppliers in the wholesale market would be unable to forward-hedge using CfD-based generators. However, due to the structure of the CfDs (see Box 1), these generators are already strongly incentivized to sell their power at no less than day-ahead hourly spot price, should they wish to receive revenue equivalent to their strike price. Final retail prices, however, may increase if non-GPP suppliers (and ultimately, consumers) receive fewer payments from CfD generators and the LCCC, if wholesale prices remain above average strike prices. Conversely, they are not liable for payments to these generators should the situation reverse.

A key question surrounds the fate of RO-based generators (see Section 6). Should these generators be moved to a fixed-price contract under the GPP, opposing pressures are again put upon the wholesale price, as suppliers would lose the ability to hedge with low-marginal cost renewables (inflationary pressure), but the GPP consumer pool may expand, taking demand out of the wholesale market (depressive pressure). However, RO policy costs would be removed from the retail prices for non-GPP consumers.

Complications emerge when considering the direct and dynamic interaction between the GPP and the wholesale market, as described in the previous section. Surplus GPP power would be sold to the wholesale market. At existing levels of renewable generation and marginal costs of fossil fuel generation, this would reduce wholesale prices. However, over time, as the relative supply to and demand from the GPP and wholesale markets change, along with changing GPP generation contact and fossil fuel prices, the effect becomes less clear (although, weighted-average GPP generation prices are likely to be approximate pre-crisis wholesale prices by 2026/27, if negotiated CfD contract generators are excluded – see Figure 4. Further analysis is required to examine this interaction and its potential effects.

6. Consumer engagement, expansion, and options for long-term contracts markets

Our fifth 'guiding principle' concerns consumer engagement, for the reasons set out in NECC #3. Almost every assessment finds many demand-side measures on energy efficiency that can reduce overall system costs, and rapidly growing potential for flexibility, which also becomes increasingly valuable as the contribution of variable renewables grows. Yet despite over a decade of efforts and exhortation, consumer engagement remains very limited (NECC #3, section 3.3). This section outlines whether, and if so in what forms, direct consumer access to renewables, through the national electricity system, may help.

Consumer engagement in a CfD-derived Green Power Pool

Many dimensions of consumer flexibility – shifting the time of consumption – from periods of high marginal cost (e.g., low wind and solar, high national demand) to periods of low marginal cost (plentiful renewables, low national demand). Following Keay and Robinson (2017)[7], generation sources with a high degree of flexibility – such as fossil fuels, biomass and large hydro – would naturally remain part of the established 'on demand' wholesale market.

To the extent that prices from that market are passed through 'at the margin' to consumers participating in a renewables-dominated long-term contracts market, in the ways described above, they would face similar incentives and scope to profit from flexibility. One key difference is that the conditions for responding to such incentives could be set out in the context of a long-term contract. Those consumers on two-tier contracts would have high visibility of the difference between the immediate cost of wholesale electricity and underlying cost of power from the green power pool to inform their response. In some bilateral designs for long-term contracts, large suppliers and electricity-intensive industries might also see clear incentive to fund cheap renewables.

In practice, a targeted green power pool, based upon CfD-derived renewables, may have limited scope for this: supplies would be pre-determined, and the primary motivation for any prioritized targeting is likely to be helping vulnerable households and industries.[35]

Overall, a green power pool derived purely from current CfDs and targeted to a few priority 'most-in-need' groups has obvious limitations as a long-term solution for the large expansion of renewables envisaged. Expanding the scope would involve opening up the idea of direct consumer access to pooled renewables more widely. For this there are two broad approaches.

Expanding a Green Power Pool to other existing renewable capacity

An important challenge for any targeted pool would be which groups should have priority access. As noted, in the UK the overall output from CfD-backed generators already exceeds the average demand of the two most obvious priority groups. Beyond this, other consumer groups could include, for example:

- those business and private consumers who are already signed up to 'green tariffs'
- consumers who are contributing to reducing fossil fuel dependence by electrification, which could include some industrial or commercial electrification, as well as for example households adopting electric vehicles and heat pumps.

In the UK in 2021, roughly 9 million households were on green tariffs – about a third of all households. If their household consumption approximates the national average, households on green tariffs account for around 36TWh/yr.[36] The current green tariffs vary in their exact definition, but most of the generation associated with them derives from renewables supported by the Renewables Obligations. Because of the very large profits now being made by some RO generators (see NECC #2, *forthcoming*) – itself a symptom of the extent to which the current market design is inappropriate for renewables – there is active discussion about moving these generators on to long-term contracts. Clearly it would be unreasonable if those who signed up to green tariffs – many of whom paid over-the-odds for clean energy at the time – were excluded.

The second group indicated - consumers who are moving away from fossil fuel dependence by electrifying their transport and/or heating - are other obvious candidates. Currently, the scale of demand for electric vehicles and heat pumps is modest, but there are two obvious reasons why they should also be part of an expanded GPP: (1) they contribute to reducing emissions and dependence on fossil fuels, and (2) they bring a degree of valuable flexibility to complement the variable output of renewables in a GPP. For these consumers in particular, two-tier tariffs would provide valuable incentives.

[35] One possibility to explore in this context is whether access to such relative cheaper electricity supplies could or should be accompanied by support for basic measures to enhance energy efficiency, and smart meters. In the private rental sector, which is notorious for its energy inefficiency – an obstacle arises that many tenants may be relatively short-stay and uninterested in longer-term arrangements. Future research could explore possibilities for cheap energy contracts struck with property owners, who could then pass the assured retail energy prices on to successive tenants as part of their rental offer.

[36] https://www.gov.uk/government/news/government-to-tighten-rules-to-stop-greenwashing-of-electricity-tariffs

These and other groups may have quite a distinct demographic from the most vulnerable consumers. If considered purely in terms of vulnerability and equity, there would be little case for them to have prioritized access to cheap electricity. However, in terms of contributing to efficient decarbonization and development of the smart and flexible electricity system of the future, they are core. They also drive the early deployment of technologies that are important for the future, stimulating learning, cost reductions and development of supply chains, to the benefit of wider society.

Should the GPP include such consumers, generation capacity would need to expand beyond current CfDs. Conversely, should the base of CfDs be expanded by bringing in the generation currently supported by RO, the consumer base of the GPP would need expansion to match. The data on low carbon generation (Figure 3) makes it plain that the scope for expansion even within the next few years is large, reaching perhaps 150TWh/yr (even excluding the higher-cost negotiated CfDs).

A steppingstone to an open, private sector-based pool of long-term contracts?

Whilst the output of a CfD-derived Green Power Pool may initially need to be targeted to particular groups for the reasons laid out, this does not only complicate design - it also precludes or mutes what could be one of the greatest advantages of providing direct consumer access to low-cost but variable renewables – harnessing the combined powers of private sector innovation and diverse consumer demand.

For expanded access over time, it becomes important to think beyond a targeted Green Power Pool based on government-backed CfD contracts, towards a different but complementary focus – the existing market of private sector Power Purchase Agreements. There is a vibrant and expanding market for PPAs, with growing demand from companies keen to procure zero carbon power, including energy intensive industries desperate to find ways to escape the trappings of the wholesale electricity market.

A full treatment is beyond the scope of this paper, but the following points stand out.

First, innovation is central to a low-carbon low-cost future energy system, and the PPA market is vibrant with innovation, particularly in terms of its consumer offerings and use of smart control technologies. Most involve some degree of supplementing renewables output from the wholesale market to deal with variability, though in 2021 a new initiative was launched between major companies (like Google) and some governments to establish genuine, all-hours carbon free electricity contracts – the '24/7 carbon free energy compact'.[37] A rapidly growing and evolving PPA market could thus in principle help to bring huge levels of private investment into new renewables without government involvement.

Second, a non-trivial proportion of renewable PPAs have not stimulated 'additionality' in renewables deployment. Some PPAs are with generators that were financed and constructed with the knowledge that they would receive government support (e.g. under the RO or CfD

[37] https://24-7cfe.com/about/

contract), with the presence of PPA contracts (actual or expected) likely to be a secondary issue. Other PPAs are supported by guarantees of origin - 'Renewable Energy Guarantees of Origin' (REGOs) in the UK. These renewable PPAs are largely accounting contracts, with suppliers purchasing REGOs on the open market, divorced from the renewable generation against which they were originally issued. Whilst the system is now adequately monitored to prevent double-counting, only some PPAs really finance any additional investment in renewables. The contract lengths and forms vary considerably, with some linked to wholesale prices or with adjustment clauses. The cost of such PPAs have also risen sharply. Given the profitability of the wholesale market, buyers are reportedly finding it difficult to persuade new renewables to sign up to PPAs.

Third, PPAs generally comprise individual bilateral contracts between generators and consuming business or suppliers. The administrative costs of negotiating such contracts – particularly given the potential complexity of balancing provisions - have been considerable, though there has been significant progress in standardizing some of the legal dimensions, as established in Europe through the European Federation of Energy Traders, which in 2019 launched a standardized renewable PPA contract.[38] These can significantly reduce transaction costs and legal risks associated with PPAs, but almost inevitably, do little to standardize actual contractual terms around time horizons and treatment of balancing, let alone price. The EFET standard offers a structure including a schedule of *n* periods, of unspecified duration. The rest remains to be negotiated between the two parties.

This unavoidably means that the finance associated with PPA contracts reflects some element of counterparty risks – the risk faced by either party, should the other fail to deliver, for whatever reason – along with potentially complex and somewhat expensive elements to cover 'firming' provisions (with complementary generation from other sources) for contracts based on variable renewables.

In principle there are two approaches to reduce such costs. One is aggregation: for intermediaries to try and aggregate different PPA buyers and and/or generators into a larger pool. The other would be if it were possible to try and standardize key terms of such contracts sufficiently to enable them to be tradeable. This would substantially reduce the risks involved in signing such a PPA, since if either the generator or the offtaker failed (a risk revealed dramatically by the scale of supply company failures in the energy crisis), the contract would be available for other parties with a minimum of complexity.

There are of course obstacles. One is the tension in designing PPAs which match the time horizons desired by renewable investors with the timescales over which most buyers are willing to commit. This complexity is magnified by the challenge of balancing variable sources.[39]

The other potential obstacle to both these routes – aggregation, and tradability – is coordination. We have had open competitive electricity markets in Europe for over two decades. The private

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[38]https://www.efet.org/files/documents/EFET%20Power%20Purchase%20Agreement%20Full%20Version%202019%20-%2004.11.2021.pdf

[39] The design proposed by Pierpoint (see Footnote 8) for standardized contracts based on projected typical load shapes for various renewables, over at least 10-year contract horizons, is the most advanced proposal the authors have seen. Pierpoint also underlines the large benefits that could accrue from such standardization enabling pooling and tradability of such PPAs.

markets have not yet solved the problem of coordination, suggesting a classic economic case of coordination failure (though, the presence of many government-backed schemes also complicates matters). The private sector can be very effective at optimizing operations within a given market structure; and can also "compete for markets". It is much harder for the private sector on its own to create a largely new market structure – which is what would be implied here.

The PPA market continues to develop and is making a growing contribution. In addition to underwriting risks to help accelerate the pace of large-scale renewables deployment where required, governments could explore options for working directly with business to co-design PPA contracts that could engage consumer companies – suppliers and businesses seeking to procure renewables on fixed prices over reasonable timescales. As a starting point, one option may be to consider whether such contracts could form a basis for moving generators off the current RO/feed-in premium contracts, to something more sustainable for all.

It is unclear whether direct government efforts to coordinate or standardize PPA contracts more generally would help or not – but at the very least, the example of, and lessons from, building demand-side contracts to a publicly-backed 'green power pool' should offer useful examples, and lessons. In the long run, the result could be a structure of contracts which are genuinely tradeable. In essence, they might take the form of 'electricity bonds' – a tradeable contract which promises to deliver a fixed price of electricity over a fixed time horizon.

That, however, is for future exploration. The immediate opportunity, in a time of severe energy crisis, is to explore and enhance ways in which at least some consumers can better gain direct access to the rapidly expanding pool of cheap renewable energy. And, thereby, help also increase transparency, and over time bring to bear the power of enhanced consumer engagement to help accelerate the energy transition.

The government *Review of Electricity Market Arrangements* is prompted by recognition that moving away from fossil fuels, towards a system with a far greater contribution from variable renewables, means that the current system – built upon the economic characteristics of fossil fuels - is not fit for purpose. An enduring solution to the energy crisis cannot be to preserve that system, overlaid with a financial patchwork of emergency fiscal transfers and government-mandated revenue limits. The approach developed here does not claim to solve all the problems at once, but offers an important step in a more promising direction.