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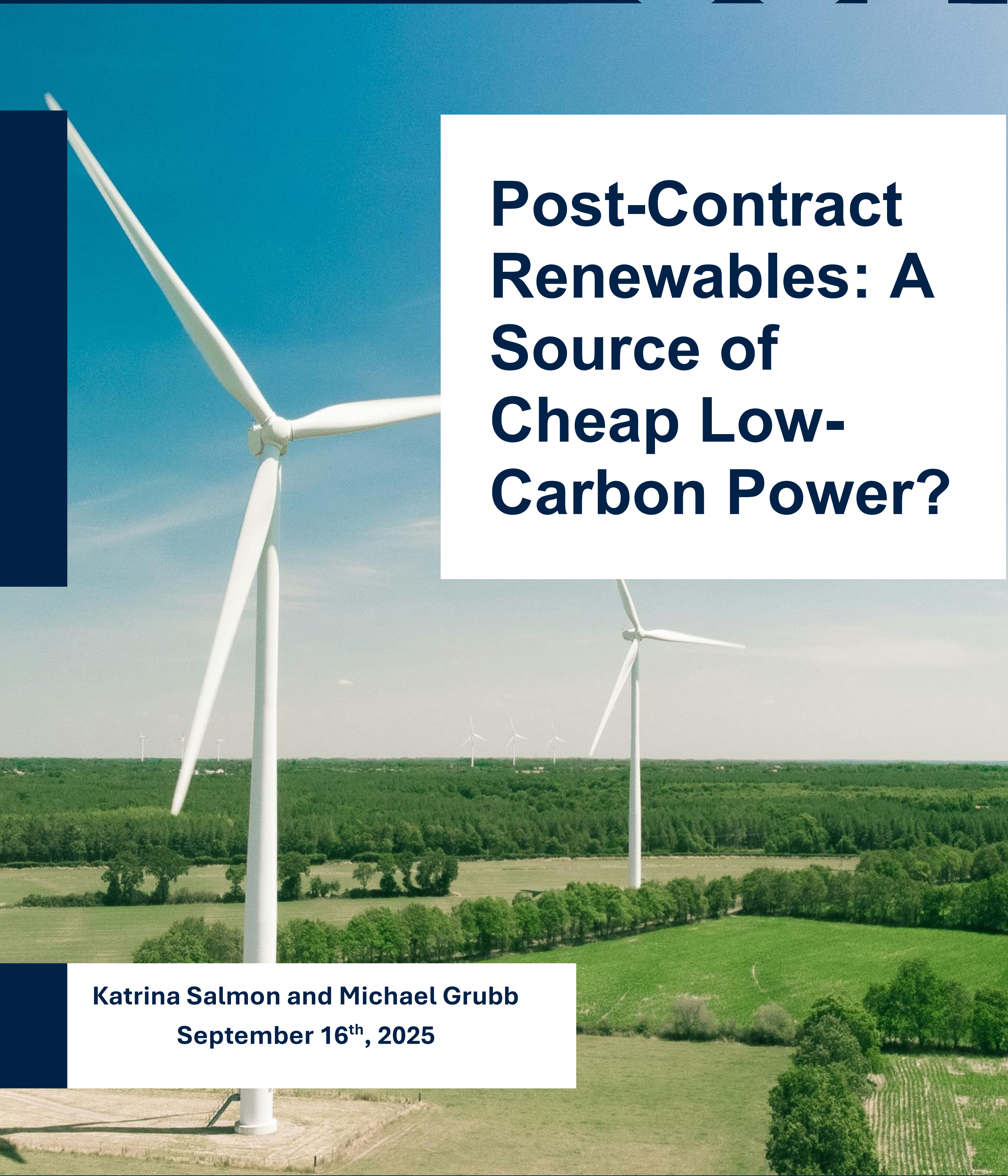
Post-Contract Renewables: A Source of Cheap Low-Carbon Power?



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Cover image: Thomas Reaubourg

Key Points

- Alongside expanding investment, UK renewables policy needs to pay attention to the opportunities and challenges associated with older renewables coming to the end of their investment support contracts.
- In theory these generators could offer an ongoing stream of cheap power based on assets for which the initial investment has been paid off, but the reality is likely to be more complex and varied between sites, technology, vintages, and regions.
- The issue is urgent (with 5.5GW of renewables coming off contract in 2027) and strategically important, with another 5 GW by 2031 and rising to over 30GW cumulatively by 2037 (excluding the large Drax biomass plant; see footnote 1).
- Almost half the capacity coming off contract in 2027 is in Scotland, dominated by early wind farms, with some complexities arising from transmission distances. Most of the rest is in England, divided almost equally between wind and fuelled technologies, with smaller capacities in Wales (10%) and Northern Ireland (4%).
- The economics of post-contract operation for these generators are complicated by ongoing maintenance costs for ageing assets, charges for continued access to transmission (plus sometimes planning permission or land rights), and large uncertainties in the revenues that generators might earn in the wholesale market, particularly as the volume of competition from newer, supported renewables grows.
- The Government is committed to offering CfDs to support full-scale 'repowering' of old onshore wind sites (replacement with new, usually bigger, turbines). The initial take-up will be limited by many factors, probably to a few hundred MW of existing capacity in this year's CfD auction. The design of such auctions needs careful consideration, in particular to aid 'price discovery' of the actual costs of repowering old sites.
- Other options include (i) enhanced use of power-purchase agreements (PPAs), perhaps with electro-intensive industries; (ii) a government-backed cap-and-floor on revenues; and (iii) varied options for 'Green Power Pool' arrangements to facilitate more direct consumer access to this growing renewable capacity.
- All these options require further exploration, not least because they could signal and test potential pathways towards evolution of a renewables-led, asset-based power system beyond direct government investment support. Structures which enhance revenue certainty could also tempt additional renewables capacity to transfer early from their current contracts, presenting an opportunity to reduce end-consumer costs.

Introduction

As the UK devotes significant attention to decarbonising its power sector, most of the policy debate has focussed on how to expand funding and capacity. Today's efforts build upon decades of investment in renewable generation sources, yet to date, little attention in the public and policy debate has been paid to the prospects for, and increasing age of, some of our oldest generators – and the challenges and opportunities involved.

The debate in the UK seems significantly lagging behind the planning in Germany and Denmark, where investment in renewable generation (most notably onshore wind power) started even earlier and policymakers began considering the future of their oldest wind sites in the mid 2000s. For the UK, the need to address these generators is urgent.

The UK now faces a situation where many of our oldest renewable generators will soon exit government-backed renewables support schemes (5.5 GW of capacity in 2027, rising to 10.6 GW by 2031). In principle, this exit could provide an opportunity for consumers to benefit from the low-carbon generators they have supported for decades. Having already repaid their upfront investment costs, there seems to be little reason these generators could not continue operating once they exit their support schemes. Yet, in practice, it is unclear how feasible continued operation may be, particularly in a market structure where other renewables are supported by forms of revenue support.

This briefing paper outlines the scale and timing of generation exiting the Renewables Obligation (RO), Contracts for Difference (CfD), and Feed-in-Tariff (FiT) schemes. Starting with the quantities and characteristics of these generators, it explores whether they are likely to be able to operate on 'merchant' terms in the wholesale electricity market, whether there is any closure risk, and the potential to significantly expand capacity on these sites by upgrading the installed infrastructure ('repowering'). Finally, we indicate potential policy options that merit further consideration.

Timeline of Capacity Exits

The first generators coming off contract are those supported by the Renewables Obligation (RO) scheme, while the majority of CfD and Feed-in-Tariff (FiT) capacity will receive support through the late 2030s. Figure 1 shows overall projections, based on contract type, excluding the large Drax biomass plant.[1] Given the dominance of the RO on the exits over the coming years, the rest of this Briefing Paper focuses on these generators.

[1] The Lynemouth biomass Power Station (0.4 GW) is expected to exit the CfD in 2027 as the government moves to supporting biomass with carbon capture, utilisation, and storage (BECCS). Drax, which is covered partly by the RO and partly by the CfD is expected to transition to a specially-designed CfD through 2031. Given this unique arrangement, we have excluded Drax from all datasets in this briefing.

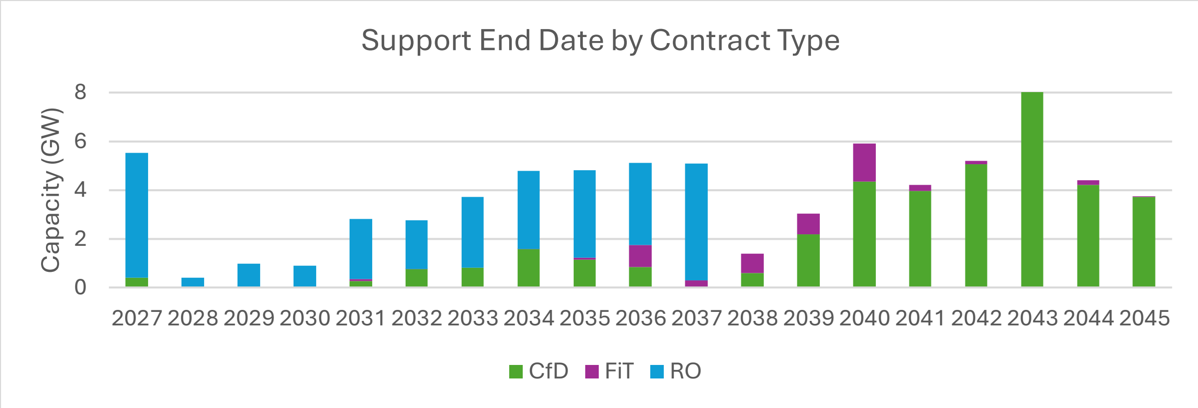

Figure 1: Timeline of Support Contract Exits by Scheme[2]

Expiry Timeline of Renewables Obligation Support

The RO scheme provides subsidy payments (paid by electricity consumers) on top of any revenue earned by the generators (Figure 2). Open to new entrants from 2002-2017, the scheme covers some 35 GW of renewable capacity (compared to the UK's current total renewable capacity of 61 GW) of varying age and type. The RO also includes generators built originally under the Non-Fossil Fuel Obligation (NFFO) scheme (1992-1998). These oldest generators (some of whom have now received 25+ years of support), along with those built between 2002 and 2007, will exit the scheme in 2027.

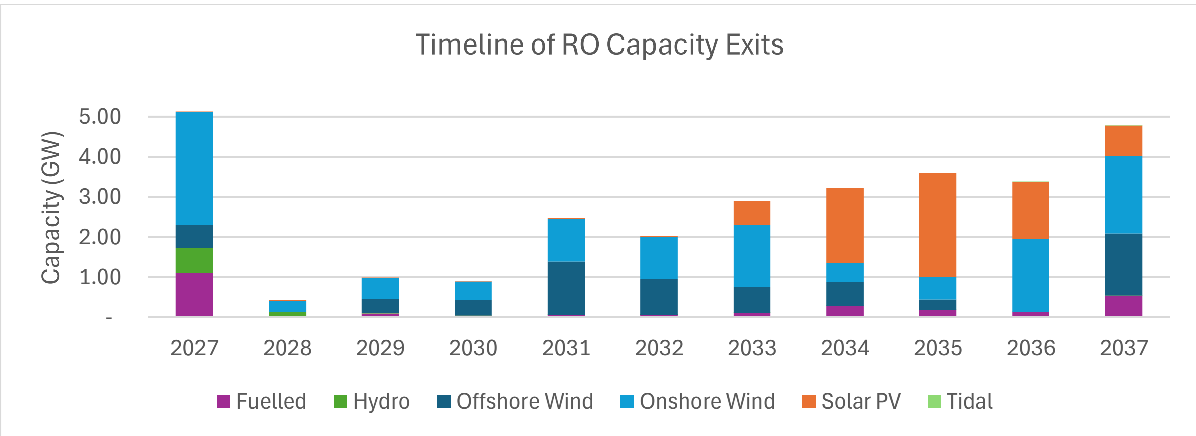

Figure 2: Timeline of RO Exits by Capacity Type[3]

The generators supported by the RO vary significantly by location, both over the lifetime of the scheme (Figure 3) and in the capacity exiting in 2027 (Figure 4).

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[2] The CfD figures include all projects that have been successfully awarded a CfD. Consequently, since some projects have not yet started operating, any dates beyond 2041 are indicative based on current deployment timelines.

[3] For legibility, all technologies with an input fuel (including biomass and sewage gas) have been combined into a single category, 'Fuelled.' The full range of technologies covered by this term is defined by DESNZ.

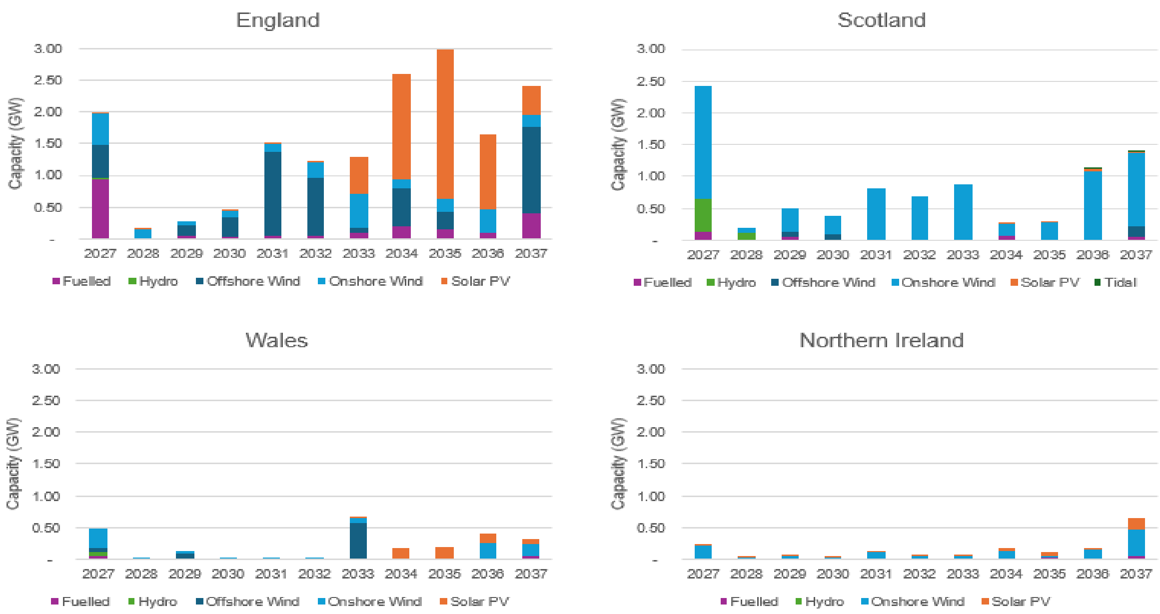

Figure 3: RO Exits by Country Over Scheme Lifetime

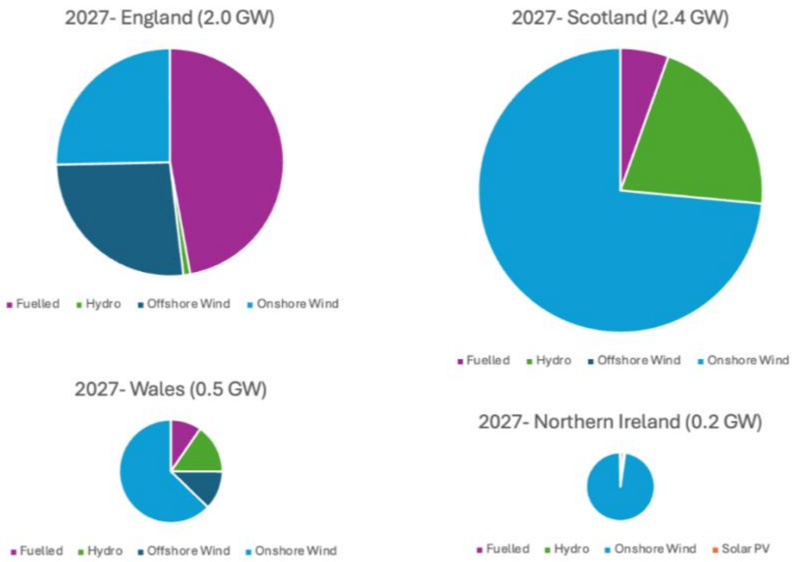

Figure 4: 2027 Capacity Exits by Country and Technology

Of the 5.1 GW exiting the scheme in 2027, 39% of this capacity is in England, while 47% is in Scotland. The English capacity is split almost equally between fuelled technologies and wind, while the Scottish capacity is dominated by onshore wind. Wales and Northern Ireland together make up the remaining 14%, most of which is onshore wind capacity.

The generators supported by the RO also vary in age. Most of the 2027 capacity exits will comprise generators built in the early 2000s to take advantage of RO payments, but 35% of these generators are older (including a small amount of hydropower from the 1950s). Many of these generators have continued to operate far beyond their originally intended/expected duration, especially the onshore wind farms, which were originally planned to operate for only 20-25 years.

It is consequently likely that many generators may be *physically* able to operate beyond their exit from the RO scheme. Questions remain, however, about whether and how they may do so, and the market or contractual structures under which they may continue to generate.

Costs, Options and Revenues for Post-Contract Operation in Wholesale Market

At this point, we will turn to the challenges facing onshore wind, given this technology's dominance in the coming RO scheme exits. An initial presumption might be that wind turbines cost very little to operate, given that they convert "free energy" (the wind) into useful electricity to sell on the GB market. If this were all, one would expect them to continue operating after the contracts supporting their construction (i.e. the RO) expire. In fact, NESO's Clean Power 2030 (CP30) modelling assumes all post-contract generators will continue operating "without additional support" at least through 2030.

In practice, three factors complicate this picture: the intrinsic 'running cost' of continued *operation* (including maintenance and incremental/component replacement); other (mostly fixed) costs required for the 'licence to operate;' and revenue uncertainties associated with generation dependent purely upon market sales (primarily the wholesale market), typically known as the 'merchant tail' of operation after the initial support contracts expire.

i) 'Intrinsic' running costs (e.g. maintenance, component replacements)

In general, one would expect the cost of operating such a 'free fuel' technology to be relatively small during the planned equipment lifetime, albeit with some variation between sites. As turbines age, however, it is natural to expect maintenance costs to rise, perhaps with increasing need to replace some worn components.

One international study of extending wind turbines beyond their initial operating life suggests maintenance costs for turbines rise rapidly as they age. Many generators sign warranty/maintenance agreements with their turbine manufacturer for the first 15 years of operation. Past this point, the turbine owner is responsible for ongoing maintenance. For many of the oldest generators, it will become increasingly challenging to find replacement parts as manufacturers no longer support these older turbines. There is evidence some owners have begun cannibalising their own turbines (i.e. closing some turbines and using parts to keep others going), to enable the continued operation of at least part of the remaining farm.

There will come a point beyond which manufacturers simply cannot find the necessary parts for repairs or turbine foundations begin to crack, and the site is no longer viable or safe to operate. At this point, generators may consider 'repowering' their site by replacing all the old turbines, as discussed in more detail below. Despite four consultation rounds[4]

[4] 2020 Net Zero Power Consultation, 2022 CfD Reforms Consultation, 2024 AR7 Consultation, 2025 AR7 Consultation

by the Department for Energy Security and Net Zero (DESNZ) mentioning this topic, we have found almost no data on ongoing maintenance costs and the point at which these might exceed revenue.

i) Other costs to continue operating

Continuing to operate a wind farm will involve other costs concerning licences, connections etc. (that might be termed 'extrinsic', for externally required costs).

Many onshore wind sites, especially in England, only have planning permission and leaseholds for 25 years, a threshold many RO generators are approaching. Thus, it will be necessary to extend their planning permission. While this process is simpler than an initial application, it will require owner confidence in the site's longevity and profitability.

Particularly for generators in Scotland, however, probably the largest extrinsic cost would be Transmission Network Use of System (TNUoS) charges. TNUoS charges cover the costs of the high-voltage power lines that transmit electricity from power stations to local distribution networks. For generators, these take the form of fixed annual payments related to the generators' capacity connections.

As has been explored in DESNZ's REMA consultations, TNUoS charges vary dramatically by region, and are perceived as "volatile and hard to predict,"[5] though projections out to 2030 have been published by NESO.[6] For generators in regions where TNUoS charges are low (and potentially even negative-mainly the South of England), this could become a revenue stream, but for those with very high TNUoS charges (primarily Scotland), they could make continued operation uneconomic.

Conversely, however, if operators close generation sites, they will be responsible for decommissioning the sites and returning them to their original state.[7] It is not clear that turbines' salvage value would cover the full costs of decommissioning.

ii) Revenue Expectations

Perhaps the greatest uncertainty, however, is not about the potential operating costs, but these generators' revenue. Especially for Scottish generators, the transmission system's capacity to transport this power to the UK's primary demand centres in England will become increasingly important. As illustrated in Figure 5, Scottish demand is currently only around 22 TWh annually (which equates to an annual average demand of 4 GW) and in the National Electricity System Operator's (NESO) forecasts is not set to rise above 9 GW even by 2040.

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[5] Potential reforms to TNUoS charges under DESNZ's REMA programme create additional uncertainty about the future of transmission charges.

[6] For example, wind generators in Northern and Western Scotland pay the highest tariffs, reflecting the typically long transmission distance to demand; typically over £25/kW/year at present, projected to rise to £35 - £45/kW/yr by 2030 to pay for the projected rapid build-out of transmission capacity.

[7] There are some sites for which this was not made a requirement, creating the risk of abandonment.

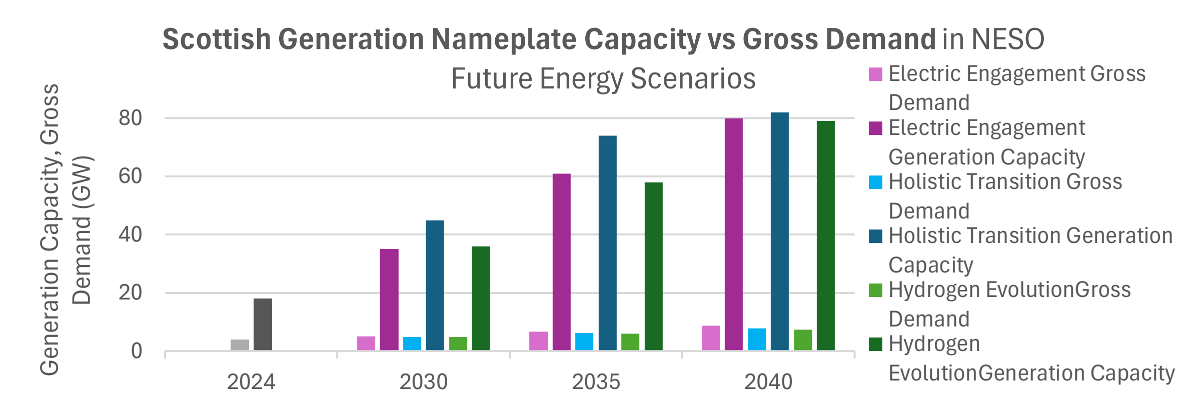

Figure 5: NESO Scottish Gross Demand vs Generation Capacity

Transporting all this electricity will strain the transmission system; at times when the power offered in the national market exceeds export capacity, generators in Scotland are paid to reduce their output (curtailment) while generators in England are paid to turn on. NESO forecasts the costs of managing this imbalance (constraint costs) to rise from £3 bn in 2024 to £8 bn in 2030. Given this demand/generation imbalance and the scale of expected constraint payments, a growing proportion of revenue for wind generators in Scotland could be curtailment payments, requiring consumers to pay for power no one can use. This could (perversely) keep merchant generators operating, but it delivers little value to electricity consumers.

One indication of the challenge facing policymakers is that adding too much new wind generation in Scotland could reduce the use of existing wind farms. Our earlier research has highlighted a rapidly growing frequency of 'potential surplus' generation – combined nuclear, wind and PV exceeding demand - at the national level, but without taking account of transmission constraints or flexibility (storage, interconnections). Some additional preliminary research at our Centre, using a model which accounts for different zones and transmission constraints, suggests that 1 GW of additional offshore wind in Scotland, *over and above* existing projections for 2030, could find half its annual output curtailed, due to combinations of national surplus and/or transmission constraints.[8]

The revenue implications for market prices and post-contract operation are complex. Generators only receive constraint payments when their bids are accepted in the 'national merit order' as being needed to meet demand: NESO dispatches generation starting with the lowest price bids, ascending until supply matches demand. Since renewable generators are cheaper than thermal generators, as renewable capacity expands and these generators can satisfy national demand, the difference in bid prices between renewable generators will become increasingly important for determining which generators are needed in each hour.

[8] Preliminary runs with the Antares model, using the projections of NESO's 2021 'Leading the Way' scenario, including projected transmission and storage. Storage helps generators better utilise existing transmission, by storing their output for use at times when more transmission capacity is available.

Despite their relatively low operational costs, post-contract generators will likely sit close to the end of the merit order for their respective technologies because they are not able to bid as low as generators who benefit from support schemes. This will become more severe if and as there are more frequent, non-positive wholesale electricity prices. This could substantially reduce revenues to post-contract generators operating in the wholesale market, unless they can utilise (or build) storage, so as to increase economic use of their output.

Barriers to Repowering Onshore Wind

In addition to continuing to operate existing turbines, onshore wind developers also have the option to repower existing sites, meaning the original turbines are removed and replaced with new ones. These new turbines are generally larger, and fewer are required to replace (or expand) the farm's output. Repowering would seem to be a lifeline for some generators, and it could bring significant benefits to the power system. The oldest generators are sited in the windiest onshore areas, and on average across Europe, repowering of old wind farms triples individual wind farm output. Decades of data on wind trends can also help de-risk financing for repowering. Not only could significant repowering contribute to meeting CP30 targets (insofar as it involves a net capacity addition), but these sites generally face less public opposition from local communities.

During the RO scheme, 19 projects were repowered as they were able to reapply for the scheme at their new capacity. Since the closure of this program in 2017, seemingly only one project has been repowered. With generators benefitting from generous subsidies, there has been little incentive to sacrifice this revenue support even for an increase in farm capacity.

However, considerable uncertainty remains about the actual costs of repowering. NESO has suggested repowering could be delivered "relatively cheaply," while DESNZ's consultation rounds on the topic suggested the costs of repowering were similar to those for newly-developed onshore wind. One factor is that entirely new planning consent is needed when repowering, plus transmission capacity must be upgraded if the capacity of the wind farm increases. Changes to how onshore wind is built since original development make repowering an extensive endeavour, adding to the scale of upfront costs.

Given the expected similarities between the costs of new-build and repowered projects, DESNZ has committed to enabling repowered onshore wind projects to apply for a new 20-year CfD, starting in the Allocation Round this fall (AR7). Open only to projects larger than 5 MW, generators must have reached the end of their operational life (25 years) before the repowered project begins operating, meaning projects exiting the RO between 2027-29 will be eligible in this initial round. This first repowering auction could set a precedent for repowering other technologies through the CfD scheme, thus we explore some lingering auction uncertainties in the final section.

We estimate that no more than 0.85 GW will be *eligible* for repowering in AR7 (Figure 6); the reality could be much lower.[9] The remaining 5.5 GW exiting the RO scheme between 2027-29 consists of onshore wind too young to participate in AR7 and ineligible technologies (like biomass and sewage gas).

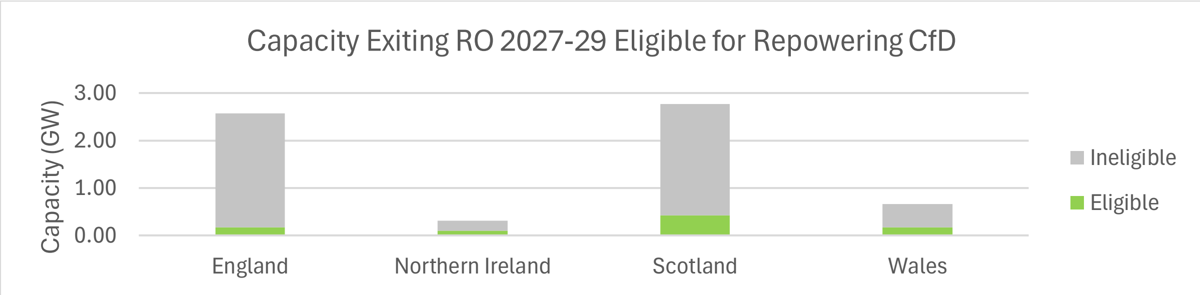

Figure 6: Eligibility for AR7 Repowering Compared with Generation Exiting RO Scheme

Implications for Continued Operation: New Structures Needed?

Merchant Operation: What about Power Purchase Agreements (PPAs?)

Given the challenge of merchant operation, Purchase Power Agreements (PPAs), particularly with major companies (Corporate PPAs 'CPPAs'), may help alleviate some risks. There are a range of possible CPPA designs, the aim of which is to provide long-term price certainty, to both generators and buyers.

A common challenge is that individual renewable generators' output is variable. To provide consistent power output to the buyer, the operator must either install adequate storage or commit to buying/selling from the wholesale market (at market prices) to regulate output. This increases the complexity and cost of signing a CPPA, and the pool of credit-worthy counterparties is limited.

CfDs for Repowering: Key Considerations

As DESNZ proposes to allow repowered sites to access 20-year CfDs, ensuring the design of the mechanism does not provide unnecessary support is important. The option of a separate auction for repowering could face problems of low liquidity especially if there are relatively few bidders. Given also that DESNZ (and renewables developers) believe repowering costs are similar to new-build, the proposal is to include repowered projects in the same auction with new onshore wind and solar.

As CfD auctions are pay-as-clear, if new windfarms set the auction price, it will not be clear how expensive repowering projects truly are, and they might be 'overcompensated.' To reduce this risk, DESNZ could consider – even within a single auction - having a separate clearing price for repowering bids or defining a separate budget for repowered sites overall. Either option could leave some generators on merchant terms, which would test the risk of closure. An additional risk is that if the auction results simply report the

[9] This figure has been calculated using Ofgem's 'commissioning date' of a project as its launch date and comparing the capacity exiting the RO scheme between 2027-29 and the amount of onshore wind older than 25 years by the end of 2029.

winning gross capacity, there will not be a clear indication of the true *net* capacity addition to the system.

Regardless of the precise auction design, CfDs were intended for discrete build/no build capacity decisions. It remains unclear if this is truly the best mechanism to support the more complicated range of potential options for post-contract generators. The current CfD design also provides few incentives for flexible operation (certainly, in relation to transmission constraints), so such an approach might ultimately simply exacerbate growing system challenges.

Alternative Forms of Support

Given the limitations of merchant operation and lingering questions about CfDs for repowering at scale, at least two alternative market designs could be explored to alleviate the challenges explored above.

Cap-And-Floor Design

The first is a cap-and-floor on revenues, similar to that used for interconnectors and being designed for long duration energy storage. When wholesale prices dip below the floor, generators receive a subsidy, but they pay back any profits when prices exceed the ceiling. Depending on the structure, this mechanism could incentivise flexible operation (unlike the CfD). Interconnectors have never required floor payments, demonstrating the usefulness of this mechanism if designed appropriately. It is not entirely clear, however, whether this structure would be suitable for post-contract generators or how precisely the cap and floor levels would be set.

Green Power Pool (GPP)

The second approach could be some form of Green Power Pool (GPP). The intention of the GPP is to facilitate more efficient consumer access to renewables, at a price related to the generators' long-run average cost, rather than exposing them to the volatility of a gas-based power system. Conceptually it has much in common with fixed-price PPAs (many PPAs, in fact, involve wholesale-market-linked prices), but a key benefit compared to most PPAs would be aggregating output from different renewable sites (in a region or more widely), providing a more consistent power output. In this way, a GPP could be thought of as an aggregate pool of CPPAs, reducing many of the administrative and balancing needs of individual bilateral CPPAs. This mechanism could be targeted at specific user groups such as the fuel poor or heavy industry.

A GPP – or other options to enhance price stability (or predictability) compared to wholesale - could be combined with UKERC's 'Pot-Zero' concept, giving RO generators the option to exit the RO early, in exchange for longer sustained revenues at a more predictable price. This could also sustain technologies that are not eligible for repowering CfDs or simply see significant risk in even temporary merchant operation.

While a GPP was considered by DESNZ during its REMA programme, it was rejected partly on the grounds it has not before been tested in the real world, and a perception (if maybe misplaced) that it could inject uncertainties for new generation, driving up the investor risks and hence price of CfD auctions. Further work is required to understand how the concept could be adapted to support post-RO or post-CfD generators, and to consider many outstanding questions including, for example, the scope (of generators and consumers), how prices would be set or negotiated in relation to wholesale price expectations, and many aspects of institutional design.

Remaining Uncertainties & Next Steps

There remain significant uncertainties about the economics of post-contract operation, including the pros and cons of supporting repowering through various possible mechanisms. Our ongoing research aims to explore these topics, as well as the potential for CPPAs, a cap-and-floor, or GPP options to support continued operation. If you have insights or would like to contribute to this research, please contact us at katrina.salmon@ucl.ac.uk.