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De-linking power from gas prices: a closer look

As the government steps in to ‘de-link’ power to protect Britain from energy price shocks, Regen asks whether the proposed changes to the Electricity Generation Levy and a new Wholesale CfD are likely to have a significant impact on consumer bills and what other design options should be considered.

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Will ‘de-linking’ really drive down bills and/or protect consumers from future price shocks?

Regen put out a very quick response to the government’s announcement of plans to “de-link” gas prices from the electricity wholesale market (published 21 April 2026). In this slightly longer paper, we take a closer look at the government’s plans and ask whether they will actually reduce bills or provide value to consumers. We also look at some of the design options and potential unintended consequences of changes to the EGL windfall tax and extension of the CfD scheme to legacy assets.

The paper's conclusion is that, while these are pragmatic policy changes that could provide a degree of protection for consumers against future price shocks, they are not a panacea for lowering consumer bills in the near term. They also require careful, detailed design and implementation to ensure value for money and to avoid further market distortion.

Recap of the government’s delinking proposals

The government’s plans do not amount to a decoupling of gas power prices in the wholesale market or make direct changes to the way marginal prices are set. As we have already commented, that would have required a major market redesign for which there is no durable ‘split-the-market’ proposal. It would also have created significant market distortions, leading to the loss of important price signals and market inefficiency that would have quickly outweighed the claimed benefits.

Instead, the government has opted for a more practical approach that doesn’t split the wholesale market but seeks to unlink generator revenue from rising wholesale prices, transferring a portion of that revenue to consumers. The two key measures are:

- 1) **Extending and deepening the Electricity Generator Levy** (a windfall revenue tax), which will now run beyond 2028 with an increased marginal revenue tax rate of 55% for earnings above £82 per MWh, effective from 1 July. This would apply to non-CfD renewables and legacy nuclear plants.
- 2) **Introducing a new ‘Wholesale Contract for Difference’ (WCfD)** that would offer legacy generators a fixed ‘strike’ price contract with the first WCfD allocation in 2027.

As we noted in our initial response, these two measures are complementary – a carrot and stick approach – that seeks to both prevent generators from making excess profits in the short term while encouraging (maybe forcing?) them onto a long-term contract that would also provide a hedge for consumers in the event of future wholesale price rises.

Whether this constitutes a good deal for consumers would all depend on the WCfD strike price and the details of the scheme. Done well, CfDs do offer a means to transfer value from generators to consumers, but this only works if the contract allocation process is competitive, and generators have an incentive to offer a low price (lower than the prevailing wholesale price forecast) to avoid market price risk and, in the case of new generation, a means to reduce their cost of capital. Both measures make sense and, although they won't necessarily reduce bills if wholesale prices are low, they could provide a safety net that would protect consumers during periods of very high wholesale prices in the future.

However, although CfDs have worked to secure investment in new generation, it is not certain that a WCfD, offered to legacy assets that are already built and potentially coming towards the end of their operational life, will provide the same level of value transfer to consumers. A worst-case scenario is that a poorly designed scheme with an inappropriate strike price could lock future consumers into higher-cost energy. This could be the case, given that future wholesale power prices are expected to fall, even if the strike price looks good value at the time of contract award.

The extension of CfDs to legacy assets could also have secondary impacts in the wholesale market, including impacts on the liquidity (volume) available for forward trading and PPAs. More capacity under CfDs could change the dynamics of short-term trading, especially during periods of oversupply (economic curtailment) and negative prices.

Will the WCfD deliver significant value to consumers?

A CfD can be an effective solution to address the problem of renewables earning inframarginal rents in a 'gas sets the price' market while still supporting new investment. Participation in a CfD scheme means that generators are prepared to give up some of their upside revenue during high price periods in exchange for a more stable and enduring revenue stream. The scheme also provides consumers with greater price certainty, serving as a hedge against future price rises.

A WCfD, aimed at legacy generators, would not decouple the market; CfD-backed generators still trade in the market at prevailing prices, although their trading behaviour may be affected. It does, however, 'de-link' the revenue earned by renewable generators from the short-term market price and can therefore be a means to transfer value to consumers.

We need, however, to be careful how we define value. A CfD does not necessarily guarantee lower electricity prices. It could be price-neutral or even slightly negative and still add value because it provides insurance against very high wholesale prices, especially price shocks. As the Office for Budget Responsibility has identified, price shocks are, in many ways, more destructive for consumers, businesses and the economy than stable but slightly elevated energy prices.

Nevertheless, for the ordinary consumer or business energy user struggling with energy bills, the measure of success or failure of the WCfD is likely to be whether the CfD strike price is

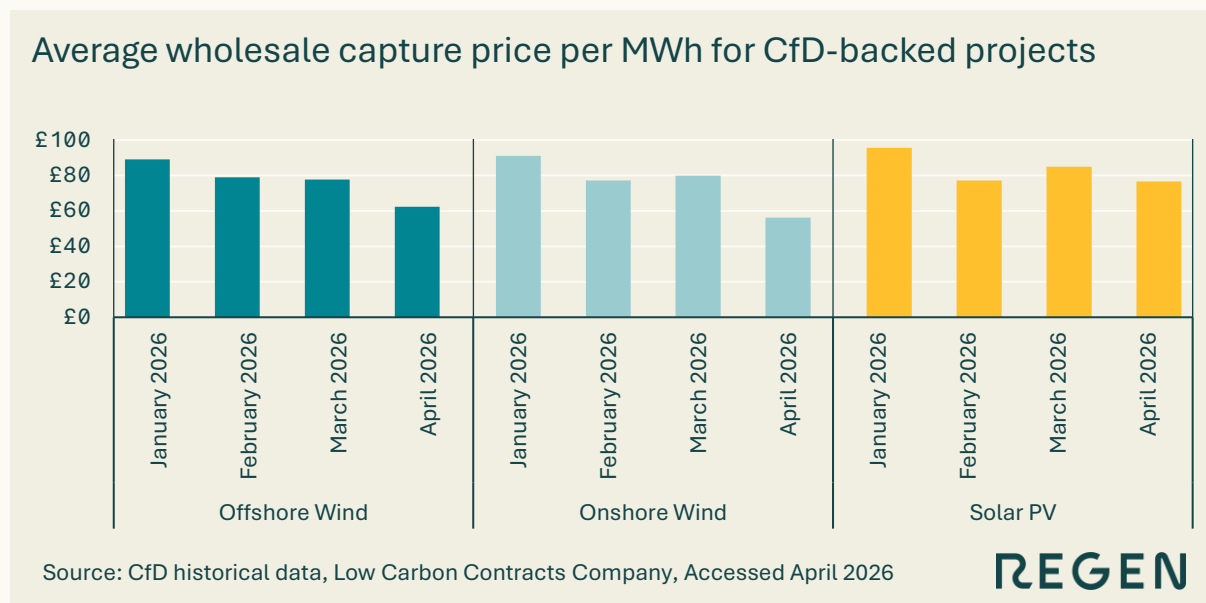
considered good value relative to the prevailing wholesale price. This is even more true of the WCfD (barring repowering) since there is no added value from the capital investment, technology development, jobs and supply chain benefits as there is for new construction projects.

What we can say is that if the negotiated or auctioned strike price is low enough, the CfD mechanism can transfer value to the consumer. We can see this already. When wholesale prices are high, the lower-cost CfDs negotiated for onshore wind, solar energy and the later offshore wind projects directly benefit consumers through the two-way payback mechanism.

We saw the payback benefit very clearly during the 2022/23 Energy Crisis, as we had sustained periods when wholesale prices were well above the CfD strike prices for most generators.

It is harder to discern the same payback effects in the current energy crisis because:

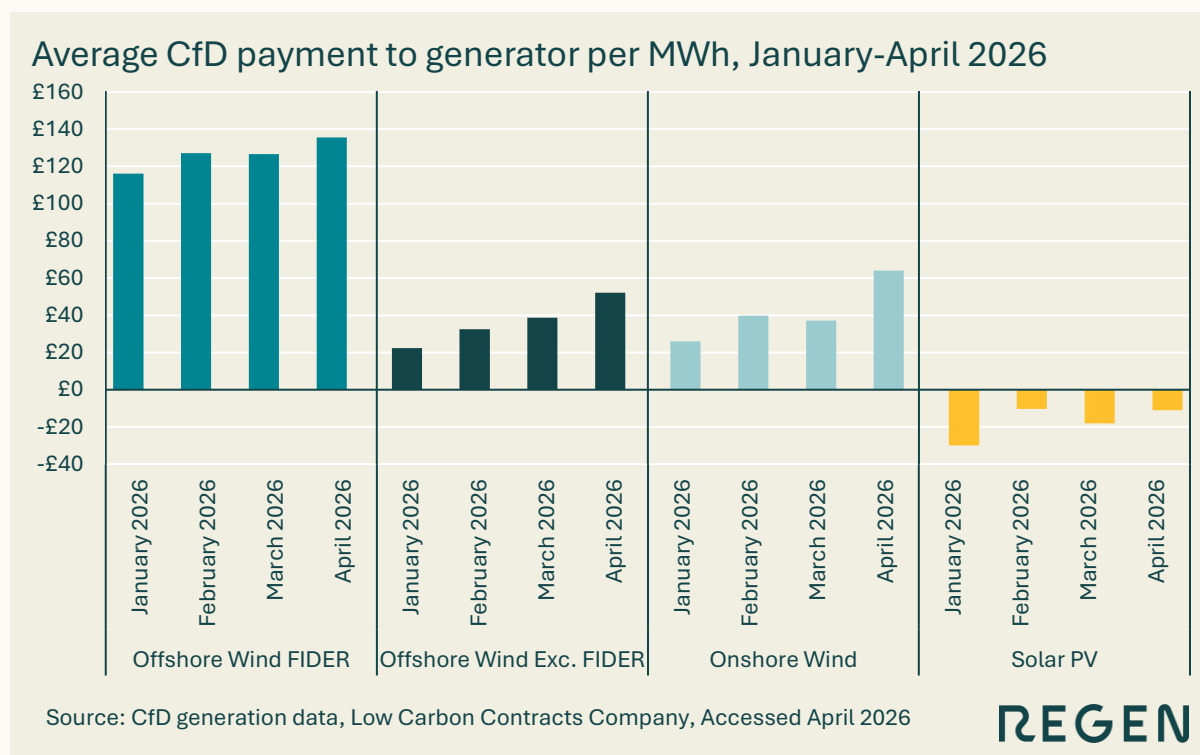
- a) **Wholesale capture prices for renewables have not (yet) increased significantly due to the Iran conflict.** This is another indicator that something is changing in the market – when renewable volumes are high (wind is blowing and the sun is shining) wholesale prices fall, irrespective of higher gas prices. The renewable price effect is outweighing the marginal price increases from higher gas prices.



- b) **The CfD scheme is still burdened with the very high strike prices that were agreed back in 2013 for the ‘Investment Contract’ or FIDER projects.** These offshore wind and biomass projects received high CfD contract prices to cover upfront innovation, investment and higher costs associated with first-mover projects.

With inflation indexation, the offshore wind FIDER projects now have an average strike price of around £205 per MWh, well above the current wholesale prices, resulting in CfD payments to generators of over £120 per MWh. In 2025, the offshore wind FIDER projects cost c. £1.5 billion in CfD payments – around 37% of CfD payments made to all wind and solar. The FIDER projects will remain on their CfD contracts until the early 2030s. This cost burden could be moved to general taxation, the logic being that higher FIDER CfDs were awarded to support the UK’s industrial strategy – technology innovation, infrastructure and supply chain benefits.

If we isolate solar PV, however, which did not get high CfD awards for early investment, we can see the CfD payback in action. On average, so far this year, CfD-backed solar projects have been paying back £17 for each MWh of solar generated. Offshore and onshore wind CfD contracts placed after AR1 also have significantly lower strike prices. As these newer projects are commissioned and begin generating, the overall cost of the CfD scheme per unit of energy will decrease.



So what are the lessons for policymakers considering an extended WCfD for legacy generators?

The first lesson, obviously, is that the CfD strike price needs to be extremely competitive. We do not know what negotiations took place behind the FIDER contracts for offshore wind, biomass conversion and dedicated biomass, but these contracts have placed a cost burden on consumers, with strike prices far higher than those in subsequent CfD contracts set via competitive auction. We would therefore hope to see the WCfD strike price below the current wholesale price and below the equivalent long-term PPA prices available in the market.

The second lesson contains the kernel of some good news. When renewable generation volume is high, or even around average, the downward impact on wholesale prices is beginning to outweigh the marginal price-setting influence of gas. This trend of lower or stable wholesale capture prices for renewables, even as gas prices rise, has been noted by several recent studies, including Baringa's review of the impact of the removal of the Carbon Price Support Scheme and Ember Energy and Modos's analysis of gas price-setting periods.^{1 2}

Why are renewable wholesale capture prices not rising in line with gas prices?

It's not fully clear how the market is responding to higher renewable penetration, but two things seem to be happening when renewable volumes are high. Firstly, gas is less often the marginal price setter, being replaced by storage, interconnectors and sometimes renewable energy. The second, more important, effect is that, even if gas is the marginal price setter, there is more competition among gas generators, less price gouging and more instances where lower-cost gas generators set the marginal price. This competition and merit-order effect is one factor contributing to the lower wholesale prices we've seen so far, despite the rise in gas prices. Interconnectors and storage are also playing a supporting role in reducing price volatility.

However, there is a caveat to this more optimistic analysis: gas prices during the war on Iran have not risen as high as the €350 per MWh peak we saw briefly in 2022 when Russia invaded Ukraine. Other factors may be contributing to lower wholesale costs in this crisis compared to that one, including the availability of French nuclear power. It is also probable that the

¹ Figures from the 2022/23 energy crisis suggested that gas assets may set the day-ahead price in 85-90% or more of price periods. More recently, Modos has completed an analysis using a marginal cost estimate for a low-cost CCGT plant as a proxy threshold to estimate when gas plants are the marginal generator. Their snapshot analysis suggests that the periods in which gas set the price may have fallen from over 90% of periods in March 2022 to around 67% in March 2024/25. If this analysis reflects a broader trend it may indicate that GB wholesale market, like Spain, is becoming less dependent on the position of gas in the merit order.

² Analysis from Ember Energy: [Clean Power Fortifies Britain Against Gas Price Shocks, April 2026](#)

structural increase in prices we've seen since the Russian invasion of Ukraine already reflects a premium for expected higher volatility, and so the price already had some uplift 'baked in'.³

Policymakers considering a CfD scheme need to understand this change in market dynamics. When we look at high-renewable countries like Spain, the marginal price-setting issue is far less prominent. If policymakers believe that setting a WCfD will help to reduce periods of high prices, they need to consider that when renewables are generating, the wholesale price will very likely be lower anyway, and when they are not generating, the benefit of a CfD-based hedge is less because the volume generated is lower.

A poor outcome for consumers would be to set a strike price at such a point that:

- When renewables are at a high volume, wholesale prices are, in any case, low, but we then make high CfD payments to generators
- When renewables volumes are low, wholesale prices still spike, but CfD payments back from renewables are less because there is less generation volume to pay back.

This new market dynamic challenges the narrative that, because gas sets the price, wholesale prices must necessarily be high nearly all the time. This is no longer true. Or at least, it is no longer true for the range of gas price increases we have seen so far due to the Iran conflict.

It's tentative – if gas prices shot up to post-Ukraine war levels and stayed higher for longer, the gas price effect could become dominant again – and a WcFD would be of value. However, there is growing evidence that the clean power strategy is beginning to work. Here in the UK and across Europe, renewable energy is pushing down wholesale costs, reducing the impact of gas price volatility and reducing gas and LNG import dependency.⁴ This improvement in outlook does, however, challenge the case for a CfD that is not linked to an increase in (or repowering of) generation capacity.

Electricity Generator Levy... not such a big stick – at least, not yet

In our response to the government's announcement regarding the EGL we highlighted the need for any windfall tax to be targeted and proportionate. The government may have good cause to recoup excess, exceptional profits made by any producer at the expense of consumers, but should ensure that taxes do not claw back legitimate earnings, which would then have a bigger impact on the market and risk future investment.

No producer likes a windfall tax, but the original EGL design (as amended in 2023 to exclude new investments) was broadly accepted by the industry as a necessary evil. Its key features were a reasonable threshold revenue rate (currently £82 per MWh), a de minimis and capacity

³ See Kate Mulvany, Cornwall Insight: [When is a price shock not a shock.](#)

⁴ Regen discusses the risk of UK's LNG dependency and the need for demand reduction in our recent paper: <https://www.regen.co.uk/insights/could-expanding-north-sea-gas-production-cut-gb-energy-bills>

allowance for small generators and a marginal revenue tax rate (45%) that allowed some revenue upside for generators. As Regen said at the time, it was a better design than some windfall taxes we saw in Europe. Although its term, running to 2028, was longer than the anticipated period of high energy prices.

The revised EGL will feature a higher marginal tax rate at 55% and an extended term beyond 2028. We do not know for how long the new tax will be extended, but investors must be thinking that it is likely to remain for some time and could become a permanent feature.

Will the EGL materially benefit consumers?

In point of fact, the revenue from the EGL and the oil and gas Energy Profits Levy (EPL) goes to the Treasury as a form of corporation tax, not directly to consumers. Many stakeholders, including Regen, have suggested that the tax be redirected to explicitly reduce consumer bills, perhaps by further lowering the environmental levy charges. The Treasury has always been reluctant to earmark (hypothesize) taxes for particular purposes, and it seems unlikely it will change its approach now. It could also argue that it's already supporting consumers at taxpayers' expense by shifting levies onto general taxation.

Nevertheless, it is important, from a communication and transparency perspective that there is clarity about the payments and contributions made by the industry, as well as about subsidy support. A similar point could be made about the lack of transparency in areas such as network charges, CfD payments, RAB contributions and cap-and-floor schemes.

It also relates to the lack of transparency on how policy interventions will actually affect consumer bills. A recent example is the claim that the benefits of removing Carbon Price Support (CPS) will offset the cost burden on general consumers to pay for 25% reductions in electricity bills for British Industrial Competitiveness Scheme (BICS) companies. Offsetting one benefit against another cost without any counterfactual is bound to raise suspicions.

Putting aside the question of transparency and whether funds go to the Treasury or the consumer, the key question is whether the EGL will actually raise significant tax receipts, which could then, in theory, reduce consumer bills. The answer, to a large extent, depends on what happens in the wholesale market. If prices rise above the threshold and stay high for longer, the windfall tax kicks in. If prices fall back, the tax take will be less. So a relatively low tax return is not necessarily a bad thing if it reflects falling prices. The EGL is still doing its job as a sentinel against excess profit; an insurance against surging prices.

Before the current energy crisis, the annual EGL tax revenue was expected to fall from around £1.8 billion in 2023/24 and £0.7 billion in 2024/25 to maybe half a billion in 2025/26. The rise in prices since the end of February should slightly increase the 2025/26 forecast.

The power price forecasts for 2026/27 suggest that average wholesale prices will remain above the £82 MWh threshold for much of the year, even if the war on Iran is resolved. With the new marginal rate of 55% kicking in from 1 July this would suggest that 2026/27 will produce a

significantly higher EGL tax return. Beyond 2027, barring future price shocks, average wholesale prices are expected to fall again, with central projections in the range of £70-80 per MWh, at or below the tax threshold.

As well as the sensitivity to wholesale prices, the EGL revenue take is highly dependent on how companies are structured and how electricity is traded. When it was first introduced in 2023, the forecast was that it could raise up to £14 billion by 2028. This was viewed as highly optimistic, and the actual outturn has been far less. The main reason the tax take has been low is that wholesale prices have fallen below the tax threshold; a secondary reason is that the EGL only targets the revenue of generation companies. In reality, many generators sell their energy to offtakers and intermediary traders via long-term contracts and forward trades, not at the marginal price point. It is often these traders and intermediaries who are selling energy in the short-term market and can arbitrage against very high marginal prices. The picture is further complicated by the presence of vertically integrated companies that both generate and trade, by the co-location of storage assets and by the higher volume of power that is exported via interconnectors to neighbouring markets.

It is possible that a simple EGL, targeting revenue at the point of generation rather than across the whole value chain, may be encouraging trading activities that get around the EGL. Whether the government has the appetite to go further in search of excess profits among power traders, and risk piling more uncertainty and complexity into the market, remains to be seen.

Will the revised EGL spook investors?

The flip side of a windfall tax is that, if it is viewed as a revenue grab, it might discourage investment in future generation or the repowering of current assets.

So far, the response (in public) from investors and generators has been muted. Several large generators and trade bodies offered supporting quotes for the government's press release. Another indicator is that the share price of some larger asset owners, which had fallen sharply on speculation that the Treasury and DESNZ were preparing a radical market overhaul, rose again as the specifics of the delinking proposal were published. It could have been a lot worse, seems to be the general market response.

A 10% rise in the marginal tax rate still leaves some revenue upside. Some may argue that it could have been higher. It should be remembered, however, that this is a revenue tax; there is also a corporation (profit) tax to be applied on top. Keeping the threshold at which the tax kicks in at £82 per MWh, and linked to CPI, also maintains the primary purpose as an excess profit tax rather than a grab for legitimate revenues. Importantly, the tax does not apply to new investments, although the dates from which the new EGL might apply have yet to be defined.

So the short-term response has been neutral. In the long term, however, any increase in windfall taxes will likely focus investors' minds. The fact that the tax no longer has an end date – we only know it is 'beyond 2028' – will probably send a message that it is very likely here to stay. It will certainly reinforce the current market sentiment that the CfD, or some other revenue

support contract, is the only viable route to market. That could have long-term consequences if, at some point in the future, the government would like to see projects being built based purely on market prices and merchant risk.

Will the EGL uplift be enough to encourage uptake of the WCfD?

We have already discussed that the WCfD strike price needs to be low enough to ensure good value for consumers. However, a voluntary WCfD scheme also needs to be attractive enough to attract sufficient capacity to participate. We don't know whether the government has a WCfD capacity target, but given the volume of legacy generation currently outside the CfD, it would need to target 3-10 GW to make a material difference.

So will generators be interested in a fixed price contract?

In general, generation asset owners will be interested in any discussion of securing longer-term revenue. The risk of market volatility and price cannibalisation, resulting in lower capture rates for generators, is very real and increasing. As already discussed, renewable capture prices in short-term markets are already showing signs of cannibalisation when generation is high.

They will also be cognisant that a future government may have more hostile intentions towards renewable generation, and will have goodwill towards a government that pursues a positive energy investment strategy. So there will be a willingness to support the Clean Power Plan.⁵

However, on the evidence we have seen, a modest increase in the EGL marginal rate is unlikely to significantly change the fiduciary calculations of company managers on behalf of their shareholders. They will consider any WCfD contract offer against the present value of earnings that could be made operating on merchant prices with whatever alternative hedging arrangements they could make, including the use of long-term PPA contracts.

As an example of an alternative long-term contract, RWE has now entered into long-term PPA agreements to provide energy to Network Rail.⁶

We might ask if it matters whether generators enter into long-term PPA or CfD contracts. Both could provide price hedging for consumers, and in REMA and other policy consultations, the government has expressed a desire to expand and support the corporate PPA market.

The snap verdict is that, taken in isolation, the 10% EGL uplift won't force generators into a WCfD, but there may also be another discussion under way. The modest increase in marginal tax rate may be just the first round of a longer negotiation between the government and generation investors. The 10% uplift announced could be just establishing the principle that the

⁵ [Reforms Energy Plans Could Cause Truss Style Chaos Guardian May 26](#)

⁶ [April 2026 – RWE Gwynt y Môr Offshore Wind Farm will begin powering Network Rail's offices, stations, and depots from 1 April 2027](#)

government is prepared to use fiscal policies to keep profits in check and to protect consumers, and to remind generators that if it really wants to turn the screw to compel generators into a long-term contract, it has the means to do so.

Could the WCfD be adapted to persuade generators to offer greater value to consumers?

The main attraction of a CfD for generators is that it enables them to secure lower-cost finance for new construction. Unless it is adapted in some way, that element is missing from a legacy WCfD.

The WCfD could also entail a key disadvantage for legacy projects. In order to benefit from the revenue security hedge provided by the WCfD, generators would be compelled to trade in the day-ahead market – the same market in which the contract reference price is set. That probably means giving up or renegotiating the indexation of any long-term PPA contracts that they may already have in place. Swapping a PPA hedge for the WCfD strike price hedge.

But that also means that, under the terms of current CfDs, the generator will be exposed to an increased negative price risk during times of oversupply and economic curtailment, which are becoming more frequent. If negative prices occur, the generator faces a loss of their CfD top-up payment. By not trading in forward markets, they may also face a greater risk of volume curtailment. Some may prefer to stick with a long-term PPA with a guaranteed offtake.

Turning up the dial on the EGL might force generators into a long-term WCfD contract, but it would be a high-risk strategy, especially at a time when the government needs investors to invest billions into the UK's energy infrastructure, and also to keep an ageing nuclear fleet running for longer.

A better, or complementary, approach would be to look at how the WCfD could create value for both generators and consumers. Developing win-win outcomes will require a detailed design and impact assessment. These are not easy solutions to implement, but here are a couple of options that could be explored:

1) Changing the basis of the reference price

One avenue to explore would be to increase the level of price and volume revenue security by, for example, changing the basis of the WCfD reference price from a day-ahead index price to a basket of trades across differing timeframes. This approach is being developed in Europe, where it is being promoted as a better solution. It allows the generator greater flexibility to sell power in forward markets and benefits consumers by increasing liquidity in these markets, countering one of the key liquidity disadvantages of the current CfD design.

Depending on how contracts are defined, it could also reduce the impact of negative price periods for WCfD holders. That would make the WCfD more attractive and reduce strike prices.

2) Designing the WCfD to support repowering

Repowering is both an opportunity and a challenge for the power sector. Regen [recently looked at this aspect of the market](#) and concluded that many projects (mainly onshore wind) could be repowered and increase capacity over the coming decade. The future of repowering, however, is uncertain, with projects facing many barriers not dissimilar to those faced by new projects.⁷

One specific barrier is the reintroduction of development risks (planning, grid connections, etc), managing a cash flow hiatus between decommissioning and reconstruction, and the need to raise finance again. Without support, it is more likely that projects will be decommissioned.

A WCfD that spans support for legacy and repowered assets would be attractive and may help developers to raise finance. It may also help to secure planning and grid connections. The complexity, however, could be that the hybrid legacy/new asset WCfD may need to have a more complex contract and possibly two strike prices, for legacy generation and repower generation.

3) Designing the WCfD to support storage colocation

Another area to explore would be whether the WCfD could support storage colocation. At present, although the CfD scheme allows for co-located assets, CfD holders have no incentive to arbitrage against wholesale prices since CfD payments are made against the metered generation output.

It might require a more complex CfD design, and some measures to prevent gaming, but it would certainly be worth looking at how fully integrated co-location will be supported.

What unintended downsides could the expansion of the WCfD scheme bring?

If the government manages to land on a WCfD strike price that is good value for consumers and, whether by carrot or stick, secures enough capacity into a WCfD contract, the scheme could be declared a success.

There are, however, a number of secondary issues that relate to how the WCfD, and CfD expansion in general, could affect liquidity, pricing and market behaviour. Some of these issues have already been considered under the Review of Electricity Market Arrangements.

⁷ For more analysis see [Regen 2026 Repowering : A Second Wind](#)

Liquidity in forward markets

As already noted, the current CfD design and method of reference price setting encourage CfD holders to participate in the day-ahead exchange markets. This has already caused concern that CfD volumes are not then available to trade in forward markets, including for corporate and utility PPAs. Expansion of CfDs to legacy assets could further reduce forward market liquidity and is likely to lead to the rescinding or redesign of some existing PPA contracts.

In a sense, through the CfD and WCfD, the government is taking out a forward hedge on behalf of UK consumers, and this is replacing or crowding out forward trades that could be made by corporations and utilities in the market.

As discussed, one way to mitigate this would be to change the basis of the market reference price. In other EU energy markets, policymakers are considering changing the reference price-setting methodology to one based on a basket of trades over different time periods. This would introduce more complexity and could reintroduce some element of market price risk; it would, however, promote more diverse trading behaviour and forward liquidity. It may also offer other advantages regarding negative pricing.

Economic curtailment and negative pricing

Several papers have highlighted the increasing prevalence of negative price periods. These occur when the price of power in specific markets – usually in day-ahead exchanges and intraday trading – goes negative.

While the market itself continues to function, and indeed it could be argued that a negative price is a useful and valid signal, they do have some unintended consequences.

The first consequence is that CfD contracts with a negative price rule, which includes most GB contracts after AR2, would lose their CfD uplift payment.⁸ This rule was introduced to comply with EU guidelines that revenue support schemes should not subsidise ‘excess’ generation.

This could have a number of impacts:

- a) Expecting an increase in negative price periods, any generator considering a WCfD will need to consider the loss of CfD payments at times when they are very likely to be generating at high volume. This will then push up the WCfD strike price at which they are prepared to invest. We have already seen this impact in the CfD AR7 auctions.

⁸ There are currently differing CfD negative price rules in place; no rule, a 6 hour rule and a signal period rule.

- b) CfD generators collectively have an incentive to bid into the day-ahead market at price zero or above, and hope that the market clears at a positive price. Individual generators, however, have an incentive to bid at a lower price to ensure that their full volume is cleared. There are no CfD payments if there is no volume generated. WCfD holders with an RO may, however, have even greater reason to bid negatively. This could create a new degree of market uncertainty and instability which again may add to revenue risk.
- c) Even if the day-ahead market clears at zero, meaning that CfD payments will apply, it's very likely that during periods of oversupply there will be economic curtailment. In other words, some generators will not have sold their full volume in the day ahead market. This could come about because they have withheld volume from the market, to keep prices positive, or as a result of tie-break rules applied in the exchange market in order to force the market to clear.
- d) If a generator has unsold volume at day-ahead, but the CfD market reference price is zero or positive, they will then have an incentive to sell additional volume in the intraday markets, and over interconnectors, even if this is at a negative price. So the negative price shifts from the day-ahead to the intra-day market. Is this a problem?
- e) Generators with the highest CfD will have the greatest incentive to bid negative and may even trade volume with CfD holders with a lower CfD strike price. This could mean that consumers end up paying more to make CfD payments to higher strike-price generators. In other words, the market rearranges itself to maximise the CfD payments, sharing that value between market participants but at the expense of consumers.
- f) Some generators may even be tempted to take an imbalance position in the balancing mechanism. Generating more than they have sold to obtain a CfD payment and willing to sell their energy in the BM at the system, or cash-out, price. This, plus the unpredictability of trading activity, could increase system costs.

The scenario described above is not certain and will be subject to how market behaviour changes in a period of economic curtailment. Our colleague Dr Simon Gill has looked at the implications of economic curtailment in more detail.⁹

⁹ [Economic Curtailment Understanding its Scale and Impact Dr S. Gill 2025](#)

In several respects, the market still works in the sense that it still clears, and from a demand/flexibility perspective, appropriate signals are given. The issues, however, relate to:

- An increased level of investment risk – leading to higher costs
- The potential that trading between generators increases the overall cost for consumers
- That market behaviour increases volatility in intraday trading, and the balancing mechanism, which in turn increases the challenge and cost of system operation.

The negative price issue is not unique to the WCfD, but it does highlight that widening the use of CfDs to legacy assets, with the current design of reference prices and negative price rules, could further exacerbate an existing problem.

The policy response to negative pricing is complex. The REMA team looked at this in the context of a switch to deemed/capability CfDs, but this option has not progressed. Part of the challenge of dealing with this issue stems from the media coverage of energy market issues. A deemed CfD solution, even if it were the most cost-effective, would invite headlines that we are ‘paying generators for not generating’. Officials are therefore reluctant to progress these solutions.

Conclusion

If the two de-linking measures have a modest impact, policymakers must take actions across a range of measures to reduce electricity costs in the near term.

The two measures announced – a windfall tax increase (EGL) and an offer to shift legacy generators onto a long-term contract – are a pragmatic but limited response to the risk of rising power prices as a result of the conflict in Iran and the risk of future energy price shocks.

A competitive and well-designed WCfD could provide a hedge against future price increases, but neither measure is a panacea, nor will they necessarily reduce power costs in the short term. The WCfD carries the risk of being overpriced or, more likely, of the government and officials failing to agree on a price, leading to very low uptake.

Even if they did result in a modest reduction in wholesale costs, much of the current bill increase stems from non-commodity costs, including the cost of making up for years of underinvestment in our electricity infrastructure and preparing the power networks for a future increase in energy demand for heat and transport.

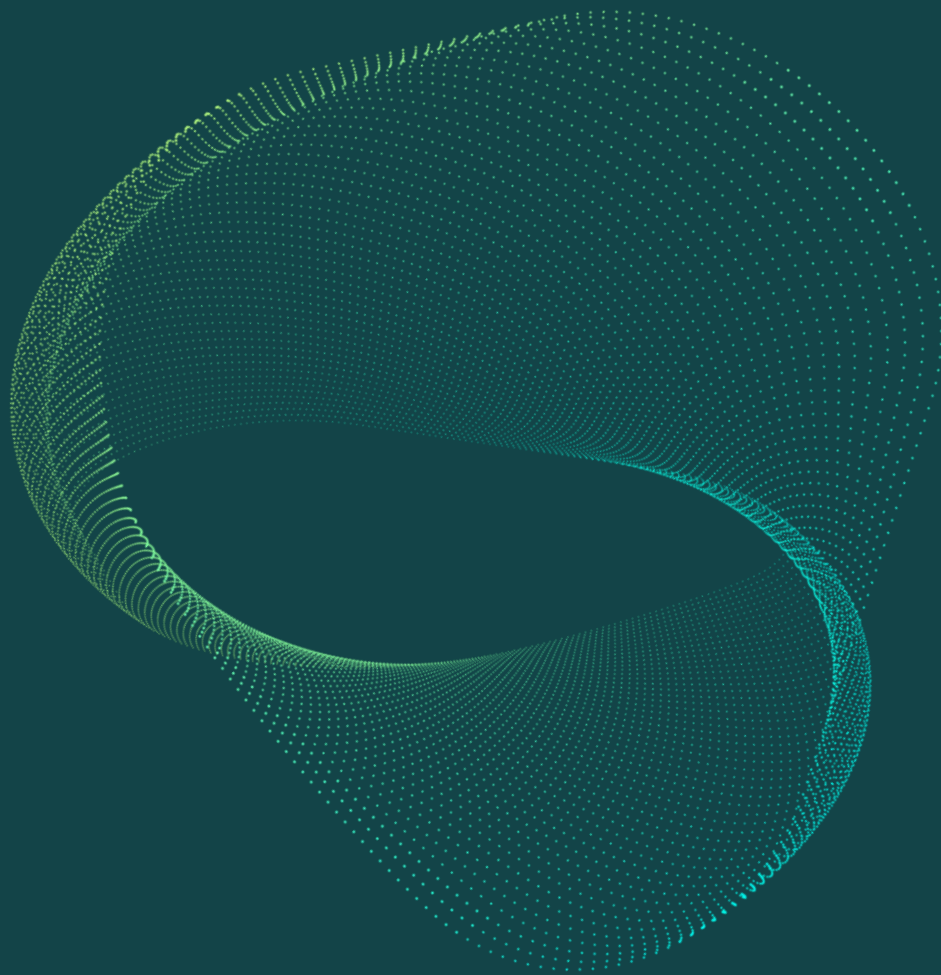
There is a way forward to low-cost, low-carbon and secure energy. That lies in the rapid electrification of energy demand and the production of renewable energy using the UK's natural resources, supported by energy storage, demand flexibility and interconnection to neighbouring markets, underpinned by a smarter, digitised energy system, to deliver power to consumers at the lowest cost.

We are beginning to see the early shoots of that energy future, and the fact that power prices have not jumped as high as they might have done given the rise in gas prices is a positive, albeit tentative, sign that something is beginning to change. The transition to clean power, however, is a long-term strategy with upfront investment that won't materially reduce consumer bills until the mid-2030s. By then, we expect electricity demand to more than double as its use extends to heat, transport and industrial processes, bringing economies of scale across the power system, lowering unit costs and enabling more flexible, efficient energy demand applications.

The next decade will, however, be difficult, as we bear the cost of investing in new network infrastructure alongside nuclear and renewable generation, while we remain dependent on fossil fuels and continue to face constraints that are impacting bills now. Naturally, there will be strident calls to reduce electricity costs for consumers today, especially when those costs are themselves a barrier to the transition.

As we have seen, there are no easy answers or quick fixes to reduce bills – no single lever that can be pulled. There are, however, a lot of actions and policies that can be taken to minimise bill increases: aligning network investment with changing demand, ensuring that markets remain competitive, driving down constraint costs, improving and automating control room functions, harnessing the value of flexibility, making better use of digital data and AI and, wherever possible, shifting costs and levies from consumer bills. Some of these actions have been captured with the proposed Reformed National Pricing programme; others are within the business-as-usual functions of NESO and Ofgem to deliver. All require proper governance and accountability, and must be delivered at pace.

In our next series of insight papers, we will look more closely at the proposed cost-reduction measures under the Reformed National Pricing and constraint cost reduction programme.



Regen
Bradninch Court,
Castle St,
Exeter
EX4 3PL

01392 494 399
www.regen.co.uk

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