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Designing an incentive-compatible efficient Renewable Electricity Support Scheme

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Keywords renewables support schemes, distortions, auctions, yardstick contracts

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Designing an incentive-compatible efficient Renewable Electricity Support Scheme

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Abstract

Most existing renewables support schemes distort location and dispatch decisions. Many impose unnecessary risk on developers, increasing support costs. Efficient policy sets the right carbon price, supports capacity not output, and ensures efficient dispatch and location. The EU bans priority dispatch and requires market-based bidding, but does not address the underlying problem that payment is conditional on generation, amplifying incentives to locate in windy/sunny sites. This article identifies the various distortions and proposes an auctioned contract to address location and dispatch distortions: a financial Premium Contract for Difference (PCfD) with hourly contracted volume proportional to local renewable output/MW, with a life specified in MWh/MW, reflecting regional differences in correlation with wholesale prices. This yardstick PCfD delivers efficient dispatch, assures but limits the total subsidy while not over-rewarding windy/sunny sites. The revenue assurance allows high debt: equity, dramatically lowering the subsidy cost.

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1. Introduction

Faced with an economy-wide net-zero carbon target by 2050, the electricity industry will have to reach near zero emissions far sooner. That requires a massive increase in variable renewable electricity (VRE, primarily wind and solar PV).[3] The UK expects a more than doubling of renewable electricity (RE) between 2019 and 2030, requiring a volume of new contracts equal to all past support schemes (National Grid, 2021). Delivering that investment at least cost will require a drastic redesign of support schemes and contracts. This article proposes an efficient contract that addresses past market and policy distortions.

Existing support schemes reflect past compromises to reconcile often conflicting objectives and to disentangle past unintended consequences of faulty policies (Bunn and Yusupov, 2015; Klobasa et al., 2013; Nock and Baker, 2017). Thus the EU Emissions Trading Scheme fixed a cap on emissions, but the subsequent *20-20-20 Renewables Directive* increased renewable targets without reducing the cap commensurately. The unintended result was the additional renewables had zero impact on EU emissions. Reforming VRE support design yet again might worry policy makers concerned at investor confidence. In fact it would increase confidence to offer more efficient new contracts while honouring existing RE

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[3] A list of abbreviations is given after the references.

contracts. Efficient policies are more credible as there is no need to change them, reducing investor risk and increasing their willingness to invest.

There has been a tension between accelerating investment in RE and providing unnecessarily generous payments that risk excessive public cost. Price support schemes like Feed-in-Tariffs (FiTs) that set the price and allow all entrants to claim these FiTs have often led to excessive public cost and rapid closure, or in some cases to retrospective withdrawal (e.g. in Spain, see CEER, 2018). Quantity-based schemes, such as green certificates, can place excessive risk on developers, leading either to under-delivery or over-compensation (Finon, 2006). The solution is simple but took surprisingly long to rediscover, given that the first UK RE support schemes in the 1990s involved auctions (Mitchell, 2000). Well-designed auctions can dramatically reduce the cost of procuring RE compared to administratively fixing the strike price. Newbery (2016a) showed that the first GB auction after the 2011 *Energy Act* dramatically reduced contract prices, while successive auctions for off-shore wind in the North Sea more than halved prices (Grubb and Newbery, 2018; CEER, 2020). The auction can either fix the volume or the funds available to deliver the least cost solution that meets the capacity target or fits the budget.

This article proposes an efficient contract that can be auctioned to deliver least cost decarbonisation while maintaining control over the amount of support. BEIS (2021) provides comments to a consultation on current GB Renewable Electricity Support Schemes (RESS), which identifies some of the key issues to address. The *Clean Energy Package* requirements provide good principles to guide the design of RESS, but avoids drawing out the design implications. It stresses the role of markets, but that requires policy makers to identify and address the market failures facing decarbonisation. The next section identifies the market failures that justify intervention, Section 3 sets out the criteria for efficient support schemes. Section 4 lists the types of support schemes, briefly reviews the relevant literature and provides evidence on their prevalence. Section 5 identifies the distortions of existing schemes to highlight the ways in which they can be overcome. Section 6 then proposes a contract design that avoids these distortions and addresses the market failures. Section 7 concludes.

2. Market failures justifying renewables support

The two main arguments for supporting VRE are that their deployment drives down future costs (their learning benefit) and they face risks (particularly policy and market redesign risks) that are hard to hedge with existing futures and contract markets. Future investment in flexible fossil back-up generation and storage also face increased future risks that will also require careful market design and contracts but that is left to be dealt with elsewhere. Competing fossil investment will be over-subsidized unless it faces the right carbon price. World Bank (2019) argued that the 2020 Paris target-consistent price was at least US$40–80/t$CO_2$. At least in the EU and UK, carbon prices facing electricity were over €50 ($60)/tonne by June 2021, within this range. Most other countries impose far lower carbon prices. If it is politically difficult to raise carbon prices, then a second-best policy might be to subsidize all technologies (and notably VRE) in proportion to the carbon they abate (Newbery, 2018a).

The learning externality depends on the cumulative installed capacity, not current output, of VRE. The learning benefit derives from R&D, design and production economies of scale, all driven by demand for deployment, and not from the output the technology produces once installed.[4] (Investors will demand reliable and suitably durable plant, provided they face undistorted price signals.) Thus for each doubling of installation of solar PV units, future unit costs fall by about 20%, and have done for 40 years (ITRPV, 2016; Frauenhofer, 2016; Rubin et al., 2015). Similarly, doubling on-shore wind farm capacity appears to lower future unit costs by 12% (IRENA, 2019). Andor and Voss (2016), drawing on Newbery (2012), demonstrate that if the only externality facing renewables is a learning spill-over, there is no case for subsidizing output. Similarly, Özdemir et al. (2020) find that capacity, not output, support is the least-cost route to future RE output and carbon targets.

Previous EU policy has specified target shares of renewable energy for each Member State. That encouraged inefficient output support (Meus et al., 2021), without questioning the underlying reasons for intervention. Fortunately, the EU *Clean Energy Package* has dropped the Member State RE requirement, emphasising instead decarbonisation at "the lowest possible cost to consumers and taxpayers" using "(M)arket-based mechanisms, such as tendering procedures" (Directive (EU) 2018/2001 §19). As such the barrier to directing support on the source of the learning externality, installation rather than output, has now been removed.

The second market/policy failure in an industry prone to unpredictable policy interventions is missing futures and insurance markets (Newbery, 2016b). Without suitable long-term risk hedging contracts, investors face risky future revenues that significantly impact the cost of capital. Newbery (2016a, p1325) showed that replacing Renewable Obligation Certificates that paid a market-determined premium on a volatile wholesale price by a guaranteed fixed price lowered the cost of capital by 3.3% real. The implied saving on projected generation investment of £75 billion up to 2020 (DECC, 2011) would be £2.5 billion per year by 2020, continuing for 15 years. CEER (2020) shows the remarkable improvements achieved by tendering in the EU in coverage and downward pressure on prices since their 2018 report.

There are also specific problems in determining the capacity credit of VRE and addressing potentially excess entry that might distort free unsubsidized VRE entry (Newbery, 2020). Such distortions can be simultaneously overcome by auctions for the efficient volume of entry.

3. Criteria for efficient contract design

Least system cost requires that new VRE is the right technology in the right location and is dispatched efficiently. Location decisions depend on both the form of support and locational signals delivered either through nodal pricing (LMP) or spatially varied network system charges, which will also have to be set correctly (as discussed below). If these locational signals were correct, and if all externalities were internalised in efficient prices and investors could hedge on adequate futures and insurance markets, then the market prices would guide efficient choices. Although these conditions do not hold, they are a useful reference for correcting market failures. The central problem of RESS design is to confront VRE with efficient market prices while at the same time providing the necessary subsidy (if

[4] quantified in Newbery (2018b; 2020a).

any) to deliver the right volume of VRE and, more important, hedging future market price risk. VRE costs have fallen to the point in many countries (including GB) with adequate carbon prices that they appear to require no subsidy. However, the UK Government, in its Report *Enabling a High Renewables, Net Zero Electricity System: Call for Evidence; Government response* reported that "Most respondents felt there was not a viable route to market for renewable projects based principally on future wholesale market prices. Primarily, this was because the wholesale market is not deemed investable by investors due to future price risk, price volatility, the likelihood of more frequent occurrences of price cannibalisation, and the lack of mitigations to protect investors from these risks. …the current CfD design exacerbates the issues of price volatility and price cannibalisation. This is because projects are insulated from market signals and this becomes a barrier to the deployment of renewable projects without government support. … increasing exposure of renewable projects to market signals would add to the cost of financing renewable projects." (BEIS, 2021, pp8-9).

The policy maker will set the design format of the efficient contract to give the right signals to locate and operate and which reduces risk to lower the cost of capital. Once the contract has been designed, the required revenue can be determined by a well-designed sequence of auctions (see del Río, 2017 on lessons for good auction design). Auctions are the best way to deliver least cost procurement, with the added advantage of allowing control over the volumes of RE or cost of the RESS.

Operation or dispatch decisions require the operator to face and respond to the efficient spot and location price for electricity. Within a technology class (PV, wind) the right design choice depends on selling all its services (including ancillary services like ramping down) at their efficient value (Meus, 2021). Thus the choice of height, blade diameter and controllability of wind-turbines can be distorted by inefficient price signals, while the orientation of PV panels should maximise value, not output (Borenstein, 2005).

Different technologies justify different levels of support (as they have different learning rates). Auctions for different technologies can be run in parallel – in Britain more mature technologies like on-shore wind and solar PV are allocated a separate "pot" (of money) to off-shore wind. The most immature technologies like wave and tidal stream have their own pot. For auctions to work well, bidders need clarity on the future policies that may impact their contract value such as changes in Grid Codes or balancing rules. They need reliable predictions of (or comparable duration contracts for) differential locational use-of-network charges over a reasonable fraction of the life of the investment, or at least 10 years.

The main future sources of renewable electricity are wind and solar PV. They have high capital costs but low running costs. Variable running costs for PV are zero, while for wind they are modest at €5-12/MWh (BEIS, 2020c; NREL, 2018). It follows that the major cost of VRE is the cost of financing the investment – the weighted average cost of capital, WACC. The more predictable and certain are the costs and revenue streams after the final investment decision, the higher the share of debt: equity and the lower the WACC. That requires reducing risk efficiently, as the lack of sufficiently distant futures markets removes the option of hedging such risks on the market.

4. Types of support schemes and their limitations

There is an extensive literature providing details on the various policies that have been implemented in different countries,[5] analyses of their impacts, and proposals for improvements. Meus et al. (2021) provides a useful summary of papers analysing different support schemes, and a comparison between leading forms of RESS. Neuhoff et al. (2018) argues that falling renewables costs argues for a reappraisal of their various merits and drawbacks. A few papers start by identifying the market failures in need of correction (Huntingdon et al., 2017; Barquin et al., 2017; Andor and Voss, 2016) but many measure success by their consistency with earlier EU volume targets. Ragowitz and Steinhilber (2014) measure the speed of meeting the targets as their measure of efficacy, which they contrast with efficiency, of achieving the target at least cost. Most government and EU reports concentrate on efficacy.

RESS can be price-based, quantity-based, investment-based, or capacity-based. Klobasa et al. (2013) distinguish five kinds of price-based RESS and one quantity-based or quota scheme, in which the government sets a specified share of renewables in final consumption, and RE producers are issued certificates per MWh injected (green or Renewable Obligation certificates, ROCs). Meus et al. (2021) widen this list to include investment-based and capacity-based subsidies.[6] Quantity-based schemes have a price determined by demand and supply of certificates, which may be capped by a penalty price, paid by retailers failing to meet their share, with the revenue recycled back to enhance the value of the certificates, as in the UK Renewable Obligation (RO) scheme. The certificate value is a premium on the market price. Meus et al. (2021) ignore quantity-based schemes but include support to investment (i.e. subsidies that lower the installed cost) and subsidies per MW of capacity.

Price-based schemes such as Feed-in Tariffs (FiTs) can pay a fixed price over the contract period, or it may vary by time-of-day and/or season. For VRE the payments are on metered output, often (until recently prohibited by the EU Commission) with priority access to the grid (and hence no need to find a buyer). Premium FiTs (PFiTs) or Feed-in Premium (FiP) schemes pay a premium on the market price. The premium may be fixed, or sliding, in which the premium makes up the difference between a reference price and a strike price, and again is paid on metered output. A sliding FiP may be a one-sided option as in Germany, or in the British CfD with FiT, a two-sided obligation, reducing the upside cost to consumers (Onifade, 2016). Producers need to sell output on the market or to an off-taker (usually under a Power Purchase Agreement).[7] Where ROs or green certificates are priced by demand from retailers, that demand share may follow a pre-announced rising level, or be increased if the

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[5] The Council of European Energy Regulators, CEER, provides periodic *Status Reviews* (of renewables support schemes) e.g. CEER (2018, 2021). The Congressional Research Service (2013) provides a detailed briefing on EU wind and solar electricity policies. See also the extensive references in Abrell et al., (2019). Ragwitz and Steinhilber (2012) provide a useful survey up to 2012.

[6] The concept of subsidy used in this paper is broad. The annual CEER Reports (e.g. CEER, 2018; 2020) explains the concept in some detail.

[7] Marketing costs might be €3/MWh, while PPAs are at a discount to expected sales value.

certificate price falls below some level, or, and less predictably, if there is pressure to increase demand to reach renewables targets (Wyrobek et al., 2021).

Table 1 gives a break-down of the type and extent of different forms of RESS in the EU in 2013 from CEER (similarly detailed breakdowns do not appear in later CEER reports). Later reports (CEER, 2020) show an increase in FiPs from six CEER member countries in 2014 – 2015 to 17 in 2019. By 2019 19 CEER member countries had at least one FiT scheme in place and only five countries had Green Certificates, with the UK phasing out its scheme. However, as most RESS contracts last between 10-30 years, the data from 2013 still casts a long shadow.

Table 1 EU support costs by type of support, 2013

Type of support	RESS costs (€ m.)	share total support	GWh	share GWh	Cost per MWh
Call for tender	€ 10.3	0%	219	0%	€ 47
FIP	€ 11,010.8	31%	79,099	27%	€ 139
FIT	€ 19,357.6	54%	147,908	50%	€ 131
Green Certificates	€ 5,196.1	15%	66,966	23%	€ 78
Investment grant	€ 1.0	0%	48	0%	€ 21
total	€ 35,575.7	100%	294,240		€ 121

Source: CEER (2015)

Note: limitations of coverage and details of measurement and weightings are given in the source. For support systems with FiTs, the level of subsidy is calculated by subtracting the average wholesale electricity price from the paid-out tariff.

Table 2 gives the breakdown for 2013 and 2019 by technology, showing the remarkable growth in off-shore wind and the fall in support costs for PV. (The rise in off-shore wind costs reflects the massive entry of later countries with initially higher support levels.) CEER (2021, table 16) gives support costs for new installations in 2018 and their support prices for 2019. The data coverage is unfortunately very sparse, but for the small number of countries reporting, 70% of the installed PV capacity enjoyed support at less than €50/MWh and for on-shore wind 50% of 2018 new capacity enjoyed support of less than €21/MWh and 65% less than €40/MWh.

Table 2 EU support costs by technology, 2013 and 2019

technology	RESS costs (€ m.)	share total support	GWh	share GWh	Cost €/MWh
PV 2013	€ 23,128	66%	72,352	25%	€ 320
PV 2019	€ 43,254	57%	190,256	35%	€ 227
Wind - onshore 2013	€ 9,993	28%	196,453	67%	€ 51
Wind - onshore 2019	€ 13,917	12%	291,455	53%	€ 48
Wind - offshore 2013	€ 2,153	6%	25,434	9%	€ 85
Wind - offshore 2019	€ 8,200	31%	67,882	12%	€ 121

Source: CEER (2021)

Note: See source for coverage and data limitations. The cost/MWh is the output-weighted support price by reporting country.

Briefly, FiTs address the problem of excessive risk, but at the expense of insulating the producer from market signals. FiPs and Green certificates do signal market prices, but at the cost of higher risk. However, both suffer from the inefficiency caused by making subsidy contingent on delivery, distorting both location and operating decisions, as discussed in the next section.

Capacity-based schemes have, as Huntingdon et al. (2017, p479) noted, the advantage of paying on expected, not actual performance, making wholesale electricity market prices guide decisions, provided their RESS design is appropriate. Boute (2012) notes that the Russian RE capacity payment was contingent on reliable delivery and hence quite inappropriate for VRE. Investment subsidies may take the form of a possibly generous tax rebate or a straight subsidy as a fraction of the installation cost. Overgenerous tax breaks have been criticized for encouraging investment in cheap unreliable designs, notably in California (Cox et al., 1991) and India (Arora et al., 2010, §3.3). Poor subsidy design can lead to cheap but inefficient choices, as claimed to be the case in the Netherlands (Meus et al., 2021).

An efficient capacity subsidy would be an efficient fixed amount per MW of installed capacity, not as a fraction of the installation cost, but setting it at the right level is not simple.[8] Özdemir et al. (2020) compare capacity and energy subsidies against the now abandoned EU requirement to deliver a RE output target, showing that allowing sufficient time to reap learning benefits can reduce the costs of achieving even a (future) output target.

5. Distortions caused by existing price and quantity support schemes

Almost all existing price and quantity-based schemes create distortions because the subsidized or strike price determining the revenue (on average above the market price) is only paid if the VRE generates. Hence it is the subsidized strike price, not the market price, that guides location and dispatch decisions. The contrast with hedging instruments used for conventional generation is most clearly seen with the British Contract-for Difference (CfD) with FiT (*Energy Act 2013* at HoC, 2013).

A normal CfD specifies an amount, M, (MW), a strike price, s, and a reference market price, p. The generator receives (or pays, if negative) $(s - p).M$ per hour (usually 24 hours, sometimes for 4-hr periods). As such the CfD is a purely financial contract that requires transfers between the parties regardless of whether the generator produces or not. The generator makes its output decision looking purely at avoidable costs and potential revenues. If it is uneconomic to produce, the spot price p must be below the avoidable cost, c. It must also be below the strike price s so the generator receives $(s - p).M$ per hour. If the generator had to produce to receive its CfD payment it would receive the smaller amount $(s - c).M$. It thus avoids losing $c - p$ per MWh. Generators with and without CfDs will all be dispatched efficiently, based on the merit order of avoidable cost.

Under the CfD with FiT in which the reference price is the spot price, the generator only receives the (above market) strike price if it generates, even though its avoidable cost may be higher than the market price, which may have been driven to very low or even

[8] The amount of subsidy depends on the range of beneficiaries considered – whether it is those in the country, the EU (mediated through targets) or the whole world (e.g. through participation in *Mission Innovation* – see http://mission-innovation.net/

negative levels to allow VRE to collect some subsidy. This could lead to an inefficient dispatch, exacerbated by priority dispatch. The inefficiency can be partly allayed by not allowing VRE to bid negative prices (in New Zealand the minimum acceptable VRE offer price is $0.01/MWh). While the avoidable cost of PV is zero, the avoidable cost of wind is positive (perhaps €5-10/MWh). The problem remains with a simple FiT that pays the strike price only if the VRE generator produces (or is available and is curtailed or constrained-off by the System Operator, in which case the generator is paid not to produce, normally at the strike price).

Unless generators make decisions based on market rather than strike prices they will also be subject to a number of distortionary incentives in the choice of technology. Good choices would adapt to local conditions and choose system-friendly designs that can offer ancillary services but at higher cost (Meus, 2021). They should choose sites uncorrelated with other VRE output to avoid producing at times of depressed prices (Elberg and Hagspiel, 2015; Grothe and Müsgens, 2013; Huntingdon et al., 2017),[9] and would not over-favour high resource areas (discussed immediately below).

5.1 Locational distortions

Most VRE developers are offered a contract specified in years from commissioning, whether the contract is set administratively or auctioned, and whether it is a FiT, CfD with FiT, FiP or PFiT. As the contract strike price is above the average market price (or the premium is positive), there is an additional incentive to locate in high wind or sunny locations, rather than locations that deliver the VRE at least system cost (of the investment and transmission). A simple example illustrates the problem, set out in Newbery (2012, p79). Suppose there is a windy but distant location with on average 2,500 full operating hours per year and a less windy but central location (close to demand) with 2,000 full operating hours. Suppose the average wholesale price is €40/MWh and the RESS provides a premium of €40/MWh on the market price (or the FiT has a strike price of €80/MWh). Suppose also that the extra transmission costs of the windy compared to the central location are €25,000/MWyr (or equivalently that the annual average discount on the nodal price compared to the centre is this amount). The *net economic* value of the electricity produced at the windy location is €40/MWh x 2,500 hrs - €25,000/MWyr = €75,000/MWyr and of the central location is €40 x 2,000 = €80,000/MWyr. From a system cost perspective it is better to locate centrally.

Under the RESS, however, the windy location will earn net revenue of €80 x 2,500 - €25,000/MWyr = €175,000/MWyr and the central location will earn €80 x 2,000 = €160,000/MWyr, an advantage of €15,000/MWyr. The developer will prefer the windy location, leading to an inefficient location decision. (See also Huntingdon et al., 2017, §2.)

Figure 1 illustrates this for GB. It shows the excess Renewable Obligation Certificates (ROC) amounts paid to wind farms with a higher rolling capacity factor (RCF) than 25%, on the assumption that such a wind farm would just break even with a ROC price of £50/MWh paid (in addition to the wholesale electricity price) for 15 years, that is for 25% x 8,760 x 15 = 32,850 hours. The "excess subsidy" is then this ROC value of £50/MWh for the RCF *less* the marginal 25% needed to induce entry. The amount is shown per kW of capacity per year

[9] E.g. by angling solar PV panels to maximize value not insolation.

before and after deducting the latest transmission charges (2021/22 year).[10] The ROC excess subsidy before transmission charges are the diamonds, those after as the continuous line.

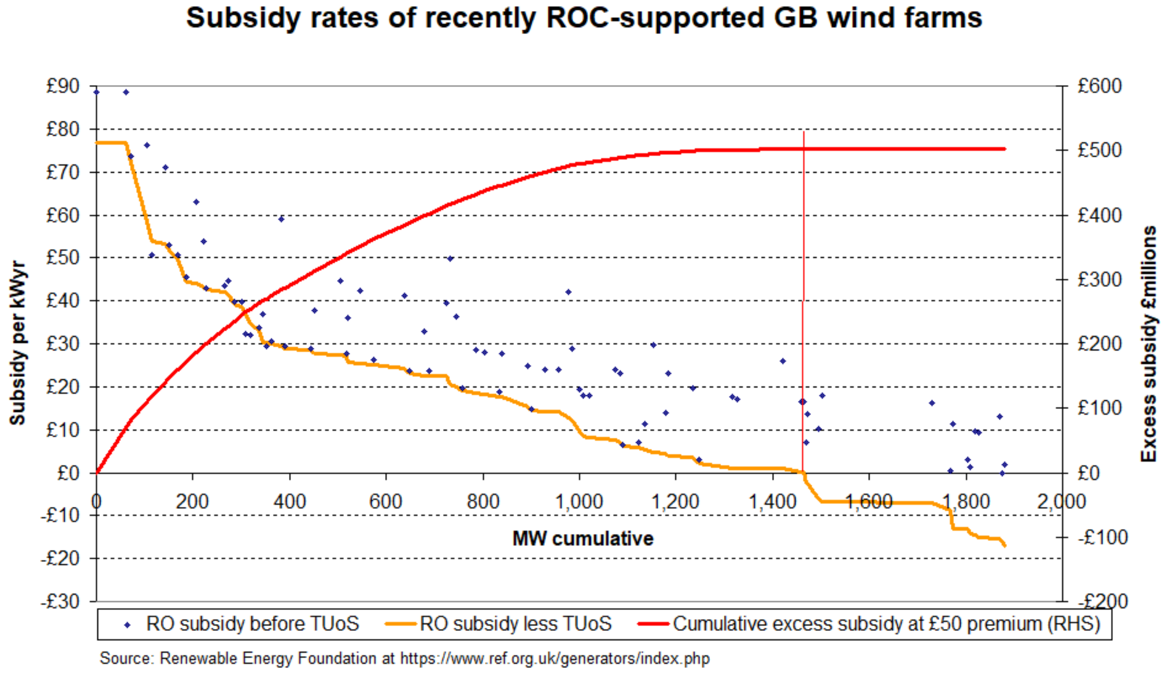

Figure 1 Subsidy rates and cumulative excess subsidy paid at ROC price of £50/MWh, England 2015-20 and Scotland 2016-20.
Sources: Renewable Energy Foundation at https://www.ref.org.uk/generators/index.php , National Grid ESO (2021)

The total excess subsidy (*not* the total ROC subsidy) paid to each wind farm is then the excess ROC payment times the capacity for 15 years, and the cumulative excess subsidy is the sum of all the wind farms for which the ROC payment is sufficient to cover the transmission charges (so only up to the vertical cut-off line). The assumption here is that this excess is inframarginal rent that could be avoided with a better contract. Some wind farms that have more than 25% RCF become uneconomic because of the high transmission charge, but might be happy to enter and earn the wholesale price with the ROC – here they are assumed not to enter. Transmission charges are clearly important, in some cases driving revenue below the assumed entry cost, but in some other cases the transmission charges are negative (that is, generation is paid if generating in winter peak periods). While transmission charges have a considerable impact on net revenues they not enough to counterbalance the advantage of windy locations.

If the RO payment had been made for a fixed number of full operating hours (e.g. for the 32,850 hours of the assumed marginal wind farm above) and if it had been set in an

[10] These are shown for wind farms of above 1.4 MW installed between 2015-20 in England and 2016-20 in Scotland (to give comparable numbers for each nation) for those with a rolling capacity factor of 25% and above. They are calculated as the rolling capacity factor less 25% (e.g. 30% - 25% = 5%) x 8,760 (hrs per year) x £50/MWh (average ROC value), divided by 1,000 (to translate to £/kWyr).

auction with the assumed marginal wind farm setting the value at £50/MWh, then most of this excess would have been eliminated. The most subsidised wind farm in Figure 1 would have received its subsidy over 8.3 years instead of 15 years, which at a real discount rate of 8% would yield a 26% higher present value than the marginal entrant (at 3% the increase would be only 10%).

While it is desirable to restrict the total subsidy paid, it is also desirable to signal that VRE should locate where its correlation with system-VRE is lower, and this will need to be taken into account below when dealing with hedging risk.

5.1.1. *Transmission pricing, transmission constraints and re-dispatch*

Location choices are also guided by spatially varying connection and use-of-system charges as figure 1 showed. If these are not set efficiently, then all new entrants, not just VRE, may locate inefficiently. Practice varies widely within the EU and across the world. Locational Marginal Prices (LMP), as set out in the US Standard Market Design and implemented widely in the US, if set efficiently (and if market power is mitigated) are the gold standard. They are best suited to dispatch decisions, and need long-term transmission congestion contracts to provide good investment locational signals. LM pricing has been repeatedly ruled out in the EU, partly to encourage market depth and liquidity, and partly as the systems cost of change are deemed high compared to the benefits. Instead annual use-of-system charges need to be made location-specific as in GB (but rare in the EU). The range of annual charges for GB wind transmission charges ranged from -£7.5/kWyr to +£29.5/kWyr (a range of £37/kWyr, comparable to many of the excess subsidy rates shown in Figure 1).

Efficient locational decisions require long-term predictability of the annual network cost. In the past the GB TSO, National Grid, published zonal indicative charges assuming that all new entry would be conventional base-load plant displacing less efficient older plant. In the energy transition, different technologies will operate at different hours of the day and seasons of the year and impose differential location costs and values on the system. In National Grid ESO (2021) intermittent generation has part of its spatial grid charges proportional to the recent RCF. The TSO is best-placed to compute the likely future evolution of estimated hourly LMPs for VREs allowing for their hourly output profile in each zone. The annual averages then determine the long-term contract price, to be fixed on entry for a reasonable period (e.g. 15-25 years). The contract could be either firm (with compensation for non-availability of the network) or non-firm (but with a guaranteed minimum level of availability).[11] The right of delivery at that node would be transferable directly for the same technology, but with side payments to the TSO for different technologies. At present most transmission charges are set annually adding unnecessary risk, given that generators cannot relocate if charges change and TSOs receive risk-free regulated revenue. This long-term transmission contract has the advantage that future zonal contracts can be re-estimated in the light of future scenarios without having to worry about thwarting past expectations that guided now irreversible entry decisions.

[11] As successfully introduced on GB distribution networks, see https://www.ofgem.gov.uk/publications/flexible-plug-plays-successful-delivery-reward-application

As VRE has a high ratio of peak to average power, and as penetration increases, so transmission constraint management and system-wide curtailment will become necessary. Local transmission constraints require generation behind the constraint to reduce output (be constrained off) and to be replaced by increased generation elsewhere. System-wide curtailment is necessary when there is more VRE than the system can absorb while maintaining stability. In the island of Ireland in 2019 4% of VRE was constrained off and 3.7% was curtailed (Eirgrid, 2020). Curtailment is discussed in the next section. Transmission constraints are normally addressed in the balancing market. Generators indicate how much they will accept to be constrained down and replaced by other generators that indicate how much they need to be paid to increase output. Under the *Clean Energy Package* Regulation 2019/943 (Art 13.1), new controllable-down renewables are to be treated in the same way as conventional generation with suitable compensation for deviating from their planned production. Normal practice is to pay their lost profit, best indicated in a last-price balancing auction. For an unsubsidized generator if the market price is p and it bids its avoidable cost c, it would be paid its foregone profit $p - c$ to reduce output. (If the constraint is predictable it may be tempted to bid below avoidable cost to increase profit, a ruse that competent market monitors should ban and detect.)

The problem with subsidized generation is that their lost profit may be distorted by the subsidy. If they only receive a subsidy if dispatched, and if the subsidy is y above the spot price, p, they may be willing to make a negative bid of $-(y - c)$, which can lead to an inefficient choice of units to constrain down (e.g. less flexible plant that is costly to close and re-start). An efficient support scheme will avoid this. One relatively simple solution is to prohibit VRE from negative bids while allowing conventional generation to make negative offers to avoid having to shut down and expensively re-start.

Potential entrants in congested areas can be offered non-firm connection offers until cost-effective reinforcement relaxes the export constraint. That removes the need to compensate those entrants, and provides a good signal to avoid locating where the network is weak and reinforcement costly (as under Regulation (EU) 2019/943 Art 13(7)).

5.1.2 Curtailment

In contrast to redispatch to deal with constraints, the extent of curtailment will depend on the size of the system (small islands will experience highly correlated VRE output that will be attenuated across Continental synchronised systems), its flexibility, size of interconnection and its storage capacity (MarEI, 2020). However, beyond some level of penetration the cost of avoiding curtailment will exceed its value, and curtailment will become necessary. VRE with efficient yardstick contracts should choose to self-curtail, as the market price should fall to the avoidable cost of the only remaining generation capable of reducing output (VRE, as all other units are at their minimum levels to ensure system stability). The efficient yardstick contract also ensures that the financial penalty for curtailment is just the present value of enjoying future support *less* the present support (hence small).

5.2. *Excessive costs from unhedgable risk*

The European Commission has been enthusiastic about PFiTs rather than FiTs as "they oblige renewable energy producers to find a seller for their production on the market and make sure that market signals reach the renewable energy operators through varying degrees of market exposure" (EC, 2013, 3.1.3). As noted above, by 2019 19 CEER countries had adopted FiPs. Later the EC recognised that a sliding FIP has "the disadvantage of partly shielding the beneficiary from price signals, but from the investor perspective this may be precisely what allows the investment to take place at a reasonable cost of capital." Neuhoff et al. (2017) point out that the normal sliding FiP is a one-sided option, allowing the generator to be paid the strike price if the market price is below the strike price, but paying the market price if above. This one-sided option has an additional uncertain value which risks overcompensating RE, and is better replaced by the UK CfD with FiT that is a two-sided.

The key lesson from the PFiTs, and especially under the UK RO scheme, compared with FiTs was that the WACC needed to persuade entrants was considerably higher (May and Neuhoff, 2021), perhaps 3.3% real higher (Newbery, 2016). The uncertainty can be broken down into two parts, exposure to market price risk, which is common to all generators (at least, if they are not vertically integrated into retailing), and risk about the future level of subsidies. The value of ROCs and green certificates depend on future demand and supply, and are hard to predict (and might even be cancelled as happened in Spain, or rendered valueless if the market is flooded or the obligation on retailers removed). Figure 2 shows the variability of the two elements for a particular period that experienced a sharp rise in annual wholesale prices. The variability of the ROC price is lower than the wholesale price as they are underwritten to some extent by a pre-announced expanding demand in line with forecast VRE supply.

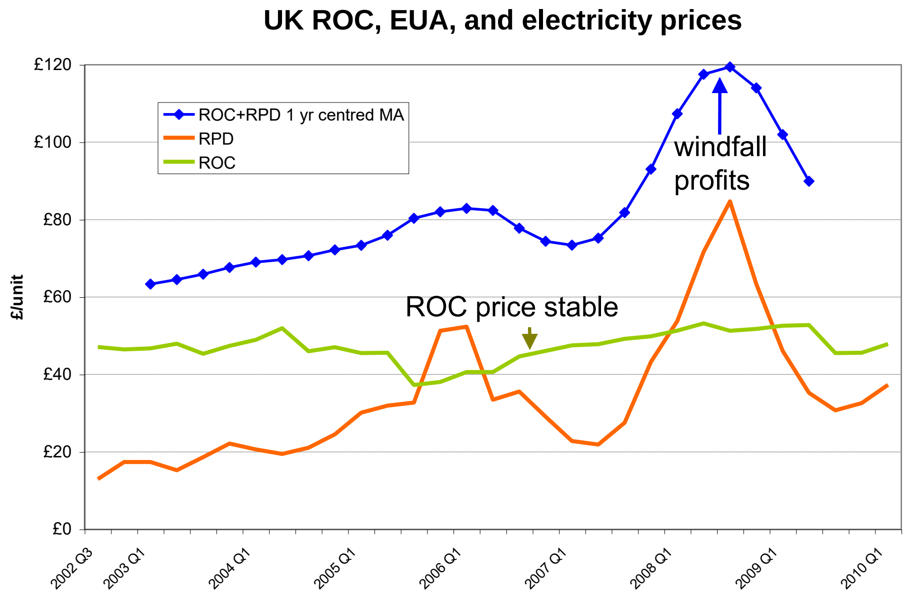

Figure 2 UK wholesale prices (RPD) and the Renewable Obligation Certificate (ROC) prices
Source: UKRPD and Ofgem

This double jeopardy explains why the UK replaced the RO scheme with CfDs with FiTs. The risk arising from the variability of the RO price of the premium can be addressed by fixing the premium, which is problematic if the premium is administratively set and slow to adapt to changing market and cost conditions. Faced with the excessive payments as VRE costs fell, some countries (Germany) specified a rate of decrease of the premium (or in that case the strike price), but the simplest solution is to hold periodic auctions to determine the market clearing premium (or indeed strike price).

The normal argument for confronting all generators, conventional and VRE, with market risks is that it creates a so-called level playing field, placing risk upon those best able to manage it (through, in particular, hedging arrangements or Power Purchase Agreements, PPAs). The counter-argument is that VRE faces rather different market risks than fossil generation. In markets with a modest share of VRE, fossil generators set the market-clearing price most of the time. They are naturally hedged as wholesale prices follow fuel prices (Roques et al., 2008), while zero-carbon generation will be exposed to the very considerable fuel price risk. Figure 3 shows UK forward prices for electricity, gas and coal costs (including the EU carbon price) in lock-step for delivery in 2010 over the period in which forward markets quoted prices for annual 2010 contracts (again the period is chosen to include the price spike in 2009). The fossil generation profit (difference between electricity forward price and forward fuel cost) is considerably more stable than the forward electricity price that is the major determinant of VRE contracted profit.

Arguably, VRE producers could also hedge in the fuel markets, but only for a limited future period, although they can (and do) sell under a long-term contract to an integrated utility better placed to hedge (including a hedge against lower prices caused by high VRE penetration).

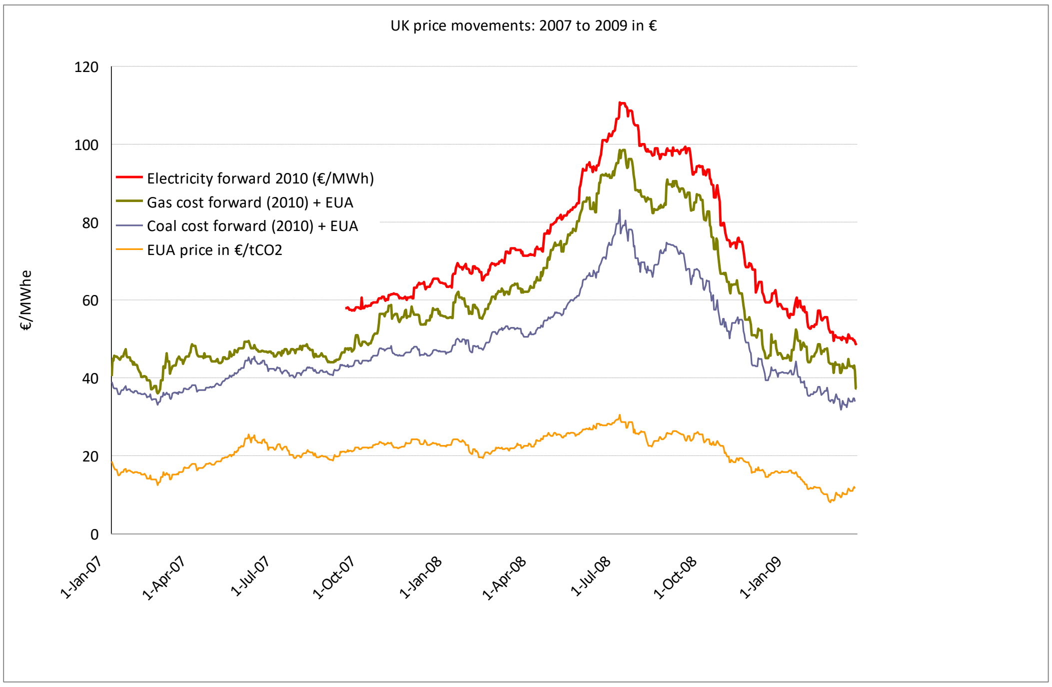

Figure 3 Forward prices for UK base-load 2010 contracts
Source: Bloomberg

So why not offer conventional CfDs to VRE in the RESS with contracted output M set equal to the θK, where K is its capacity, and θ is its capacity factor (i.e. the fraction of its average output to that if it delivered *K* MWh each hour)? With a purely financial CfD, generators would choose not to generate if the market price falls below avoidable cost. If the wind or sun were strong, it would only be partly compensated, and would sell the surplus at the market price (likely depressed by high wind and/or sun). In addition, VRE cannot choose to generate its contracted amount if the resource (wind or sun) is not sufficiently strong, and under a conventional CfD the VRE would be liable to lose $(s - p)M$ or even, if p is high, to pay $(p - s).M$. That is the obvious reason why the CfD is on metered, not contracted, output.

The reference price p could be subject to an upper bound, effectively a one-sided CfD like the Reliability Option used in some capacity markets. The VRE remains exposed when its output is below the contracted amount, even if the exposure is limited by the cap, while selling any surplus is likely to be at below average prices as the surplus depresses prices. Unless prevented, the VRE will still be willing to offer to generate at any spot price above $c - (s - p)$, which could be quite large and negative. Again, this can be avoided by ensuring a minimum offer price and removing priority dispatch. Such modifications mitigate, but do not remove, the underlying distortion that the subsidy is contingent on delivery.

The only long-term hedging open to VRE is to sign a PPA with a fossil generator (or retailer), as they may value the hedge against the downward pressure on wholesale prices caused by massive VRE entry (amply demonstrated for Europe by Hirth, 2018). Bunn and Yusupov (2015) argue that this is a reason for retaining PFiTs (specifically the RO scheme) rather than moving to fixed strike prices, and that argument may have increasing force as the share of VRE begins to dominate price determination. After the 2011 market reform in Britain, the shift to fixing the strike price (or delinking it from major movements in the wholesale price) clearly lowered financing costs, as argued above (Newbery, 2016a).

5.3. *Spatial variability*

Finally, VRE has not only temporal, but also spatial variability, which in turn has two dimensions. The first is that output per MW varies considerably spatially. To demonstrate the importance of this, the top part of Table 3 shows the average modelled wind capacity factors (CF) in various UK regions (defined by UKNUTS-2).[12]

The last 10 years are averaged and can be compared with the average over 1980-2009 shown in the top row. The average is also expressed as a ratio to the UK total. (Thus the ratio for UKD1 averaged from 2010-19 is 45.7%/33.5% = 136% as shown.) The Standard Deviation (SD) shown is of the *annual* average regional CFs over the 10 yearly averages. Below that is the correlation coefficient (R^2) of the regional *hourly* CFs on the UK, computed by correlating the hourly CFs from 1980-2019 on that for the UK total. The correlation coefficients measure the extent to which the revenue earned in each region will be driven by the UK total wind, which in turn will, when curtailed, drive the efficient price to (or near)

[12] The data were downloaded from the source indicated and appear to be corrected (Staffell and Pfenniger, 2016) for known biases. The CFs would appear to be for a modern 2,000 MW turbine with a hub height of 80 m, which would deliver a higher CF than the existing wind fleet. Thus while the source gives the average UK CF over these 10 years as 33.5%, BEIS (2020a) gives the UK on-shore 10yr average as 26.4% or about 80% of that in Table 1 (SD 2% over the 10 years). However, the modelled regional variation should be similar to the actual regional variation.

zero. The implications of this can be very roughly estimated for the average wind year 2018, but projecting forward to the later 2020s. Allowing for exports when the Continent is not saturated, it is possible to make a rough estimate of curtailed wind in that year as explained in Newbery (2020b). The day-ahead prices for GB in 2018 are then adjusted by assigning a zero price to hours of projected wind curtailment and scaling up the remaining prices to give an average annual price of £56.90 ($79)/MWh for all hours. (This is the BEIS 2020b baseline forecast average wholesale electricity price for 2025. Neither the choice of year for prices nor scaling has much impact on the results.)

Table 3 Regional annual average MERRA-2 modelled wind capacity factors, 2010-19

year	UKD1	UKF3	UKG3*	UKH2*	UKJ2	UKK3	UKM2	UKN0	UK
1980-2009	47.7%	44.7%	17.2%	24.3%	24.4%	40.8%	26.2%	32.2%	34.9%
2010	38.8%	39.2%	13.2%	19.9%	21.1%	35.2%	20.8%	25.2%	29.0%
2011	47.2%	45.2%	17.4%	24.6%	24.3%	41.1%	26.0%	32.5%	35.1%
2012	44.6%	43.3%	16.0%	23.4%	23.8%	39.8%	23.6%	29.4%	32.7%
2013	47.6%	44.2%	16.8%	23.8%	24.3%	41.0%	26.9%	31.9%	34.8%
2014	46.1%	43.7%	16.9%	23.8%	23.5%	39.4%	24.8%	29.6%	33.6%
2015	49.1%	46.2%	19.0%	26.9%	27.0%	44.1%	28.9%	33.9%	37.0%
2016	43.9%	41.6%	15.1%	22.6%	23.5%	38.7%	23.5%	29.0%	32.0%
2017	48.1%	45.2%	16.5%	23.7%	23.4%	40.8%	26.3%	30.9%	34.7%
2018	45.5%	42.6%	16.0%	22.7%	23.0%	39.1%	25.2%	30.7%	33.3%
2019	46.3%	42.9%	15.8%	23.2%	23.7%	41.0%	24.6%	29.9%	33.2%
avg 10-19	45.7%	43.4%	16.3%	23.5%	23.8%	40.0%	25.1%	30.3%	33.5%
as ratio	136%	129%	49%	70%	71%	119%	75%	90%	
SD yrly	2.9%	2.0%	1.5%	1.7%	1.4%	2.3%	2.2%	2.4%	2.2%
R^2 CF on total	83%	72%	68%	62%	45%	39%	76%	63%	
sim. £'000/MWyr	£224	£85	£108	£112	£183	£190	£116	£119	£99
sim. £/MWh	£56.3	£56.1	£56.1	£56.2	£55.8	£56.3	£56.9	£56.7	£56.3
diff. £/MWh	-£0.05	-£0.26	-£0.18	-£0.04	-£0.55	£0.02	£0.56	£0.39	£0.00
R^2 Rev on total	95%	90%	84%	82%	75%	75%	89%	86%	100%

https://www.renewables.ninja/country_downloads/GB/ninja_wind_country_GB_current_merra-2_nuts-2_corrected.csv, D1: Cumbria; F3: Lincolnshire; G3: W Midlands*; H2: Beds & Herts*; J2: Surrey/Sussex; K3: Cornwall; M2: E Scotland; NO: N. Ireland; where * indicates inland. See https://ec.europa.eu/eurostat/statistics-explained/images/2/27/NUTS_2_regions_in_the_European_Union_%28EU-27%29_and_statistical_regions_at_level_2_in_the_EFTA_and_candidate_countries.png

The results are shown in the lowest section of the table. The average revenue per year per MW of capacity shows substantial variation, from £85,000/MWyr in F3 (Lincolnshire, E coast) to £224,000/MWyr in Cumbria (NW England). The average revenue per MWh is shown in £/MWh, and in the line below, its deviation from the UK total wind revenue per MWh. It reveals that the revenue per full operating hour is remarkably stable (SD over all 40 NUTS-2 regions is £0.23/MWh). At least in this (simulated) near future the differential value per MWh produced does not vary much across the country. Part of the reason might be that solar PV and on-shore wind are negatively correlated (in 2018 R^2 = -21%), while on and off-shore wind are highly correlated (78%). As VRE penetration rises differences are likely to increase, although as solar PV is expected to grow as fast as wind, the effect will be muted. In countries with a dominance of one type of VRE regional differences are likely to be more important. The Appendix provides an exaggerated example of differential regional values.

The Table shows the considerable but stable variation in the strength of wind across representative locations and the relatively smaller variation over time (relative to the UK average for that year). This considerable variation in CFs means that revenue per MW per year is almost as variable as CFs, so if contracts are defined in years, not MWh, there is a large differential in regional VRE profitability. Inland locations (shown starred) have lower than average CFs while the remaining coastal regions (no stars) have higher CFs, notably in the West. The regions are large and within each there are likely to be considerable variations, and as noted, the CFs are calculated for a modern large on-shore turbine. The actual windfarm performance shown in Figure 1 is rather lower.

The second important feature of locational variation is that the correlation in output decreases with distance between wind farms (Elberg and Hagspiel, 2015; Wolak, 2016). Thus the hourly correlation between Northern Ireland and NE Scotland (i.e. moving in the NE direction of the prevailing UK wind) is 39%.[13]

Wind and solar PV farms have lower value if their output is highly correlated with the system average VRE output, as they will tend to generate when prices are depressed by excess wind/sun. In the Government consultation the need for *market* (not subsidized) price signals includes "altering the location of sites, specifically to avoid a correlation of generation with similar technology types." Exposure to real-time prices has additional value, hence the "focus should be on ensuring CfD generators can take part in balancing services" (BEIS, 2021, p12).

Ideally, new entrants should locate where their output is least correlated with total VRE output, other factors being equal (capacity factor, transmission costs, network constraints). In efficient competitive markets this will be signalled by wholesale prices, even more strongly by zonal or locational marginal prices that better reflect instantaneous transmission costs (Eicke et al., 2020). For at least GB, and for curtailment, not network constraints, the hedging benefit of locational diversity appears modest, but is discussed further in the next section.

5.4. *Implications for correcting these distortions*

The previous sections have identified distortions caused by most existing RESS. In an efficient market, the real-time price of electricity should fall to the avoidable cost of marginal VRE when it is in surplus. That should signal voluntary curtailment by VRE suppliers if they face the correct signals. LMPs with suitable congestion contracts could address congestion constraints, but in their absence, offering firm or non-firm connections provide a partial

[13] This doubles to 79% if NE Scotland is lagged 4 hours on NI as the prevailing wind is from the SW. Similarly, moving from the far SW (K3: Cornwall) NE to East Anglia (F1, not shown) the hourly correlation rises from 32% to 81% when lagged 4 hours (all correlations using hourly wind data from 1980-2009).

solution. Long-term spatial and technology differentiated network contracts, in which the expected cost of compensation for constraint payments are included, are a preferable long-term location signal. The challenge in designing an efficient RESS is to use market prices to signal location and operation while giving developers a long-term hedge against the very variability of prices needed to achieve efficient operation and dispatch.

6. Avoiding RESS distortions by an incentive-compatible yardstick premium CfD

In what follows we assume that carbon is properly priced, that wholesale markets are workably competitive (as they are at least in Britain), and that grid charges for connection and use are correctly set, as discussed above. (For more on network pricing see Brunekreeft et al. (2005) and the survey in Eicke et al. (2020).) A CfD with FiT reduces market risk and that should lower the finance cost. Auctions discover the lowest premium able to attract investors. But the distortions remain if the generator only receives the (above market) strike price if it generates, and if its duration is time, not volume, limited. The solution proposed here addresses each of these drawbacks.

The first requirement is to ensure that VRE always bids its avoidable cost and hence ensures efficient dispatch. Höckner et al. (2020) recognise this is a problem in the German market when addressing the need to redispatch to resolve the congestion constraint. Instead of calling for a redesign of the support scheme, they argue for side payments to offset the distortion of treating the support price, not the market price, as the opportunity cost. Höfer and Madlener (2021) quantify the resulting constraint costs. EC (2013, §3.1.5) accepts that investment rather than output support avoids the incentive to distort offer prices. However, it does not spell out how to design the investment support, nor does it argue against the various support schemes widely deployed except insofar as they distort competition and trade. The most recent *Renewable Energy Directive* ((EU) 2018/2001) rules out priority dispatch and argues for market-based mechanisms, but fails to address the distortions identified here. IEA's *20 Renewable Energy Policy Recommendations* is more concerned with distortions from fossil fuel subsidies[14] but has a section on RE in which it argues to "(R)ecognize (e.g. through differentiated tariff levels) the different locational, time and technological value of the renewable power plants and decentralised installations (IEA, 2018, recommendation 12).

Capacity subsidies avoid distorting dispatch decisions but only if properly designed. A fixed technology-specific subsidy per MW (determined in an auction) directly addresses the learning subsidy but unaided fails to hedge future market risk. Boute (2012) noted that investment support was favoured in Russia for RE, but was treated in the same way as controllable capacity procured to deliver the reliability standard. Again, that fails to hedge market risk and further amplifies delivery risk. The required hedge to provide incentives for efficient dispatch must be independent of the dispatch decision, but set at the time of the investment decision when future output is not known.

The solution is to find a yardstick highly correlated with predicted hourly output but independent of the actual output. If K is the VRE capacity, make the contracted output $M_h = \theta_{rh}K$ in hour h, where θ_{rh} is the reference capacity factor for wind at that location chosen by the developer. This could be the best relevant wind forecast, or the measured wind speed at

[14] Such as the 15% subsidy to electricity and gas in the UK resulting from preferential VAT rates.

or near the VRE location (both translated through power curves to expected output, if necessary scaled to the model of turbine contracted). As the wind (or PV) farm will likely sell its forecast output in the day-ahead market, M_h should be close to the amount sold, and so an excellent hedge. The resulting yardstick CfD pays $(s - p_{rh})\theta_{rh}K$ in hour h at location r regardless of whether generating or not, where s is the strike price set at auction and p_{rh} is the spot wholesale price in hour h at location r (with nodal pricing, otherwise p_h).The following proposition demonstrates that the wind farm will be dispatched (and curtailed) efficiently.[15]

Proposition 1. A yardstick CfD that pays $(s - p_{rh})\theta_{rh}K$ in hour h at location r regardless of whether generating or not will ensure efficient dispatch and constraint management. In the formula K is its capacity, θ_{rh} is the reference capacity factor at location r in hour h (chosen by the developer, probably derived from the local day-ahead wind forecast) s is the strike price and p_{rh} is the relevant wholesale price. The last-price auction would pre-specify the duration of the contract. The auction would determine the strike price payable to all successful bidders for each technology succeeding in the auction.

Proof. Efficiency requires that the VRE will offer at its avoidable cost, c, in the day-ahead auction and into the balancing market for up to its predicted output. That requires truth-telling to be the VRE's dominant strategy. Note that the subsidy element $(s - p_{rh})\theta_{rh}K$ is independent of the VRE's supply offer to the market. Suppose that $p_{rh} > c$ and the VRE offers to supply at $C >$ c. If $C > p_{rh} > c$, then the VRE will not generate and will lose $(s - p_{rh})\theta_{rh}K + (p_{rh} - c)\theta_{rh}K$, where $\theta_{rh}K$ would be the day-ahead forecast output by the VRE. Unless $p_{rh} > s$ both terms are positive, providing an incentive to truthfully reveal avoidable costs as c. Similarly, if $C < c > p_{rh} > C$ there is a risk of generating and losing $(c - p_{rh})\theta_{vh}K$. Bidding according to the true avoidable cost is a dominant strategy for a competitive generator unable to influence the market price.

Conclusion 1 A yardstick CfD for VRE in which the volume contracted each hour is proportional to the forecast local VRE-specific output/MW encourages efficient bidding for dispatch while preserving stable revenue streams needed for low-cost finance.

The same idea has been proposed in Spain. Barquín et al. (2017) cites the Spanish Royal Decree 413/2014 that adjusted the required capacity support by a standard production for each technology (e.g. 1,600 hours/year for PV and 2,100 hours/year for wind). This would need to be paid for a pre-determined number of years to ensure adequate performance. Huntingdon et al. (2017, p479) builds on this idea of a reference plant to provide the benchmark, arguing that it encourages developers to try and beat the benchmark plant, which would therefore have to be updated, and might risk local saturation. An area-wide wind forecast would seem to have advantages in being ex-ante, not ex-post, and hence able to encourage other aspects of efficient dispatch, such as providing balancing (down) and other

[15] This contact design is also closely related to the incentive effects of benchmarking on a regulated firm's performance (Shleifer, 1985).

ancillary services. Solar forecasts are also available at a very local level, and like wind forecasts could be automatically updated if VRE agents wished to adjust their positions in intra-day markets (if this makes a material difference).

This contract may make little difference for congestion management (at least if there are sufficient conventional plant able to reduce output) if there is a zero lower bound for acceptable VRE bids into the wholesale market. (Market exposure is required for new investment under the EU *Clean Energy Package*.) Its main value is to combine it with other changes to address the more important location distortions discussed below. That leaves the problem of legacy contracts that guarantee payment on injection. As they also enjoy priority dispatch, unless curtailed they will always supply and could drive the market price below zero to receive at least some subsidy. Regulators could offer those with priority dispatch an adequately attractive alternative contract where it causes serious distortions. If there are adequate efficiency gains to be reaped, it is possible to offer a new contract that makes both parties better off.

The UK Government had to set up a Government-owned CfD Counterparty to reassure investors that their revenue under the CfD with FiT contracts was guaranteed by a credible counterparty. Contracts also need to specify that the payments would not be taxed or limited by future Government interventions. The same would be required for this yardstick CfD to provide credible and bankable revenue assurance.

6.1. Locational distortions

The yardstick contract addresses the problem of providing hedging while preserving spot market incentives, but by itself if does not remove the two forms of locational distortion. The first, of over-rewarding high resource areas (as illustrated in Table 1 and figure 1), can be avoided by limiting the length of the contract not by time but by the number of full operating hours (e.g. 30,000 MWh/MW capacity, as in Newbery et al., 2018) and this would be specified in the pre-auction information pack.[16] That way the undiscounted total subsidy paid would be independent of location, although the discounted sum would be slightly higher in windy locations. Thus if the subsidy is indexed and the real discount rate is 3.5%, the central location (of the example in §5.1) would be worth 5% less than the windy location. If the subsidy is not indexed, and the discount rate is 6% nominal, then the extra value of the windy location is 8%, still not appreciable. Not indexing seems preferable as it accelerates to loan repayment. In addition, commercial finance and certainly the tax system are almost entirely nominal, further arguing for not index linking.

An alternative that avoids deferring compensation to the end of the contract is to set an annual limit on full operating hours (perhaps averaged over 2-5 years to handle annual variability). This is similar to the Spanish Royal Decree 413/2014 that was designed to pay the capacity support by a number of full operating hours per year (e.g. 2,100 hours for wind, Barquín et al., 2017).

While the yardstick CfD induces VRE to respond to spot market prices, as it stands it does not signal long-run differences in the wholesale value per MWh of different locations. Paying the market price would encourage locating where the resource delivers in higher

[16] Steinhilber (2016) notes that this specification is used in China.

priced hours (when the system is not saturated with wind or PV), but this requires a suitable hedge against the fear that developers have of future cannibalization or other threats to market prices. The solution is to start from a regional VRE-output weighted average revenue/MWh that would be the expected revenue of "subsidy free" VRE (as reported in the lower part of Table 3, e.g. £56.25/MWh in UKD1). The periodic auction would then determine the premium f £/MWh to add to the regional base value, $b_r = \mathrm{E}\theta_{rh}P_h/\mathrm{E}\theta_{rh}$ where the expectation E is on the future forecast prices and the time period is comparable to debt tenors (10-15 years). The regional strike price would be $s_r = f + b_r$. The formula for the yardstick premium CfD would be $(s_r - p_h).\theta_{rh}$, where the capacity factor, θ_{rh} (CF, MWh/MW) in that hour is forecast (by the contract counterparty) and p_h is the hourly wholesale price, as above.

The contract counterparty would be responsible for publishing forward-looking (up to 25 years ahead) wholesale *hourly* prices that with the existing regional CFs would provide the pre-announced regional base prices. Such forecasts are already prepared and periodically updated (e.g. BEIS, 2020b). At each auction these would be updated but held constant for the life of each yardstick contract, hence adapting to expected changes in market development without negating the expectations of existing contract holders.

Proposition 2. A yardstick premium CfD that pays $(s_r - p_{rh})\theta_{rh}K$ in hour h at location r for a period limited to T hours, where T satisfies $_{h=1}\sum^{T} \theta_{rh}* = N$, and $s_r = f + b_r$ with $b_r = \mathrm{E}(\theta_{rh}P_{rh}/\theta_{rh})$ regardless of whether generating or not, will ensure efficient dispatch and constraint management and efficient location. In the formula K is its capacity, θ_{rh} is the developer's day-ahead forecast capacity factor in region r in hour h, $\theta_{rh}*$ is the actual metered capacity factor for the wind farm, N is the predetermined contract length in full operating hours, f is the premium set at auction, p_{rh} is the relevant wholesale price and P_{rh} is the forecast hourly price, both at location r over the next decade. Again the auction information pack would announce regional base values, b_r, the number of full operating hours, N, while the auction would determine the premium, f.

Proof. The strike price and revenue paid do not depend on generator v's actual hourly output, $\theta_{rh}*K$, inducing truth-telling bids. The limit of full operating hours removes the incentive to locate solely because of high capacity factors. If the VRE is perfectly hedged (i.e. the realised CF is the forecast CF), the VRE will receive $s_r = f + b_r$, which over the year will yield the unsubsidized regional revenue plus the premium. The premium is the same everywhere and paid for the same number of MWh, so location is guided efficiently as though by wholesale prices for the actual pattern of output. As all the contract elements are independent of VRE output decisions they also guide efficient dispatch.

This volume-defined premium contract is particularly advantageous in handling self-curtailment when prices fall below avoidable cost, in that there would be little loss (in present value terms) of not generating, as that would not impact total (undiscounted) subsidy payments. After the end of the contract the VRE could be offered annual contracts at a fair market strike price (b_r, regionally adjusted), or multi-annual contracts if the developer wishes to upgrade at a cost above some specified threshold level. The particular appeal of this auction design is that it can automatically deal with the transition to "subsidy free" VRE.

Successive auctions should reveal falling premia, which could even go negative, reflecting the value of the hedge compared to risking volatile wholesale prices. At the end of the contract one-year Premium CfDs can be offered, again with regional strike prices. The contract should be made contingent on the future possible introduction of nodal pricing; before than $p_{rh} = p_h$.

Conclusion 2 To discourage RESS from distorting location decisions and market prices, negative offers should be prohibited and the length of the contract should be specified in numbers of full operating hours (MWh/MW capacity). If the yardstick is based on the predicted profile of market revenues developers will be encouraged to locate where correlations with total wind output are lower, while the almost perfect (developer-preferred) hedge provides revenue assurance.

This contract deals with curtailment while network pricing is left to address congestion and locational loss factors. For locations where export limits are likely to lead to persistent constraints, the auction contract should be quite clear that the terms of the connection agreement as published by the TSO may be non-firm in designated zones for a period until planned reinforcement is delivered. When combined with volume-limited contracts compensation would take the form of deferred revenue. While this is slightly worse than immediate compensation it avoids the problem of defining the avoidable cost to determine the lost profit. For firm connections that problem can perhaps best be avoided by specifying a minimum acceptable bid for the technology type of VRE, perhaps pitched slightly above the technology-specific avoidable cost to encourage self-curtailment and deferred payment under the volume-limited contract.

The connection agreement could be further refined by making constraining-down for congestion management first-in last out, rather than as in most schemes, equi-proportional reductions. The defence of this discriminatory scheme is that at each auction, bidders can estimate the current level of congestion, and may base their bids on assuming that this rate will continue. Further entry is likely to exacerbate constraint management until reinforcement arrives. Simshauser (2021) gives graphic evidence that poor foresight of future constraints (in this case, taking the form of increasing transmission loss factors) can lead to inefficient location decisions and financially costly outcomes that will feed back into future RESS auction bids.

7. Conclusion and policy implications

Most existing renewables support schemes distort location and dispatch decisions, of which by far the more significant are locational distortions, as these persist for the life of the investment. These distortions are higher the larger is the subsidy element, which Table 2 shows remain high in many countries. Even when VRE no longer needs subsidy, it will continue to benefit from the risk-reduction of long-term contracts. VRE reaching the end of their support contract will similarly benefit from annual or multi-annual contracts to hedge risk. The contract described above continues to be relevant in both cases. Directing efficient locational choices changes with falling VRE costs and increased penetration. The distortion of over-rewarding distant sites gives way to the need to direct new investment to areas that avoid or mitigate both local congestion and system-wide saturation, where the contract described above remains effective and can accommodate any later move to LMP.

Many support schemes impose unnecessary risk on developers, leading to costlier finance and higher than required support payments. Provided carbon is properly priced, the efficient form of support should be to capacity, not output (except insofar as ensuring that the installation is capable of an efficient operating life). It should also preserve an efficient merit order against conventional generation. The EU's *Clean Energy Package* goes some way to addressing some of the dispatch distortions by banning priority dispatch and requiring market-based bidding for redispatch, but does not address the underlying problem of making payment of the subsidy conditional on generation. That amplifies the incentive to locate in higher system cost sites with a higher resource (wind or sun). It resulted in massive induced (and probably unnecessary) transmission investments in some jurisdictions, such as the undersea DC cables to bring wind from Scotland to England.

This article identifies the source of the distortions and proposes a novel contract to address both location and dispatch distortions. It argues for a purely financial Premium Contract-for-Difference (CfD) in which the contracted volume in any hour is proportional (and roughly equal) to the technology-specific local output per MW capacity, with a life specified in MWh/MW capacity (e.g. 30,000 full operating hours) and the local base price based on forecasts of future wholesale prices weighted by the pattern of local output. The auction determines a premium to add to the base price (zero for "subsidy free" VRE), which is paid equally per MWh to all winners for the same number of MWh. The local base price provides the incentive to locate in sites with a low correlation with average wind/PV output, while the MWh limit avoids incentives to locate solely because of a high resource. The revenue assurance, which will need a government-backed counterparty, enables investment to be financed largely by cheap debt, dramatically lowering the subsidy cost.

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Abbreviations

CfD: Contract for Difference
DAM: Day-ahead market
DC: Direct current
EUA: EU Allowance (to emit 1 tonne CO_2)
FiP: Feed-in premium
FiT: Feed-in Tariff
LMP Locational Marginal Price
MC: marginal cost (= variable cost)
PFiT: Premium Feed-in Tariff
PV: solar photo-voltaic
RE: Renewable electricity (or energy)
RESS: Renewable electricity support schemes
RO(C): Renewable obligation (certificate)
SEM: Single electricity market of the island of Ireland
TSO: Transmission System Operator
VRE: variable renewable electricity
WACC: weighted average cost of capital

Appendix Illustrative regional premia

Table A1 shows a stylized country in which the CFs in two regions have the same average CF but very different hourly patterns. Region A has only a 47% correlation with the country (All), while region B has a 94% correlation. The prices are ranked, with the last five periods corresponding to saturation (high CFs).

Table A1 Capacity factors and revenues for a stylized model with premium £42/MWh

	Regions and			wholesale	Revenue per MW		
period	A	B	All	price /MWh	A	B	All
1	10%	0%	0%	£300	£8.07	£0.00	£0.00
2	20%	0%	5%	£300	£16.13	£0.00	£3.00
3	30%	10%	10%	£40	£24.20	£5.55	£6.00
4	40%	15%	15%	£40	£32.27	£8.33	£9.00
5	40%	30%	20%	£40	£32.27	£16.66	£12.00
6	35%	20%	25%	£40	£28.23	£11.10	£15.00
7	50%	30%	30%	£40	£40.34	£16.66	£18.00
8	50%	20%	35%	£40	£40.34	£11.10	£21.00
9	30%	30%	40%	£30	£24.20	£16.66	£24.00
10	20%	40%	45%	£30	£16.13	£22.21	£27.00
11	15%	50%	50%	£0	£12.10	£27.76	£30.00
12	25%	40%	55%	£0	£20.17	£22.21	£33.00
13	50%	70%	60%	£0	£40.34	£38.86	£36.00
14	50%	80%	65%	£0	£40.34	£44.42	£39.00
15	60%	90%	70%	£0	£48.40	£49.97	£42.00
Average	35%	35%	35%	£60	£28.23	£19.43	£21.00
CF R^2 on All	47%	94%					
£/MW	£13.53	£4.73	£6.30		£28.23	£19.43	£21.00
b_r £/MWh	£38.67	£13.52	£18.00		£80.67	£55.52	£60.00
f £/MWh	£42.00	£42.00	£42.00				
s_r £/MWh	£80.67	£55.52	£60.00				

The revenues per MW and MWh (= £/MW/CF) are therefore very different, with region A more valuable at market prices than B. The regional base revenue is shown as b_r £/MWh to which the auctioned premium of f = £42/MWh is added to give the strike price $s_r = b_r + f$ in the last line. The right hand block shows the resulting revenue per MWh under the contract if the hedge is perfect. Note that for the country (All) the VRE is "subsidy free" but VRE is encouraged to locate at A (low correlation with the rest) and discouraged from B.