Efficient Renewable Electricity Support: Designing an Incentive-compatible 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, 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 Contract for Difference (CfD) with hourly contracted volume proportional to local renewable output/MW, with a life specified in MWh/MW, with long-term transmission contracts based on predicted output-weighted actual or simulated nodal prices. This yardstick CfD delivers efficient dispatch. It assures but limits the total subsidy. It does not over-pay for windy/sunny sites. The revenue assurance allows high debt:equity, dramatically lowering the subsidy cost.

Keywords: Renewables support schemes, Distortions, Auctions, Yardstick contracts

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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).[1] The UK expects a doubling of renewable electricity (RE) between 2019 and 2030, requiring a volume of new contracts equal to all past support schemes (National Grid, 2020). 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 about investor confidence. In fact, it would increase confidence to offer more efficient new

1. A list of abbreviations is given after the references.

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contracts while honouring existing RE 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. The *Clean Energy Package* requirements provide good principles to guide the design of Renewable Electricity Support Schemes (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 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/tCO_2. At least in the EU and UK, carbon prices facing electricity were over €90 (\$95)/tonne for December 2022 (in May 2022), above 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.[2] (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, dou-

2. Quantified in Newbery (2018b; 2020a).

bling 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 both on the form of support and the design of connection and use of network system charges, which will also have to be set correctly (as discussed below). 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 generator to face and respond to the efficient locational spot 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, 2020; 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 AND THEIR LIMITATIONS

There is an extensive literature providing details on the various policies that have been implemented in different countries,[3] 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.[4] 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,

3. 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.

4. 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.

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).[5] 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 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 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

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

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 installed capacity, not as a fraction of the installation cost, but setting it at the right level is not simple. Capacity subsidies can be a payment per MW determined by a capacity auction, but would need to be unconditional on market prices or remaining reserves to suit VRE. As such they are directed to address the learning externality, but not, without further parameters, the riskiness of future wholesale prices. 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 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 for 24 hours, sometimes for 4-hr periods for a month or longer). 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 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),[6] 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 system costs of the windy compared to the central location are €25,000/MWyr. 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.

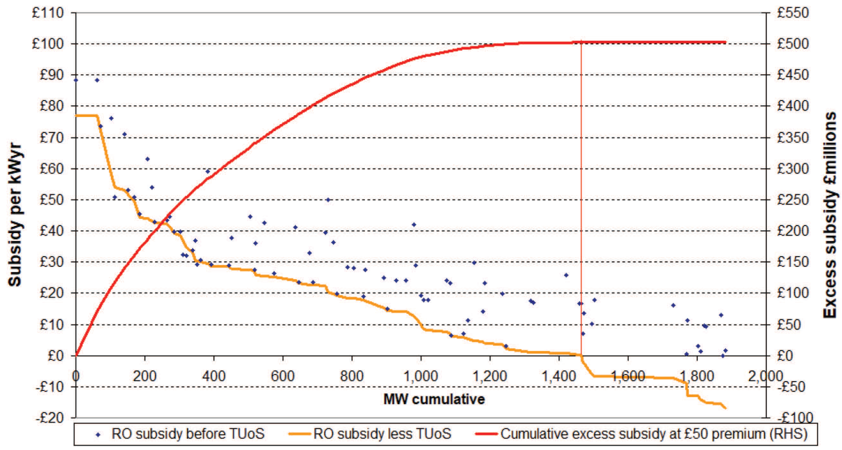
Under the RESS, however, the windy location will earn net revenue of €80 x 2,500 - €25,000/MWyr = €175,000/MWyr and the central location will earn €80 x 2,000 = €160,000/MWyr, an advantage of €15,000/MWyr. The developer will prefer the windy location, leading to an inefficient location decision. (See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

Figure 1 illustrates another inefficiency of fixed length contracts. It shows the average capacity (or load) factor (CF) since installation for wind farms of above 1.4 MW installed after 1/1/15 in England and 1/1/16 in Scotland (to give comparable numbers for each nation). If they had been auctioned for a fixed number of MWh/MW (i.e. for 15 years at a 25% CF or just under 33,000 full operating hours), and if the marginal wind farm had bid for a ROC price (or a FiP) of £50/MWh and cleared at a CF of 25%, then the rising line shows the cumulative excess subsidy paid out to infra-marginal wind farms. For the 1,900 MW that would have been accepted, the excess subsidy amounts to £500 ($620) million (undiscounted over the number of subsidised full operating hours). Note that GB already signals location for windfarms through its Transmission Network Use of System (TNUoS) charges which vary with the windfarm's annual average capacity factor. This charge eliminates a considerable proportion of the excess rent.[7]

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.

6. E.g. by angling solar PV panels to maximize value not insolation.
7. Without the TNUoS charge the excess subsidy could have been as high as $3.7 billion

Figure 1: Subsidy and cumulative excess subsidy



Note: premium £50/MWh, England 2015–20 and Scotland 2016–20. TNUoS charges from National Grid ESO (2021a) adjusted for individual capacity factors
Source: Renewable Energy Foundation at https://www.ref.org.uk/generators/index.php

5.1.1 Transmission pricing, transmission constraints and re-dispatch

Location choices are also guided by spatially varying connection and use-of-system charges. 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 (or Financial Transmission Rights, FTRs) 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. However, most studies show high net benefits from a move to LMP.[8] Eicke and Schittekatte (2022) discuss and reject most of the arguments against LMP and show that most studies show that the payback from a move to LMP could be as little as one year. The UK Government is actively considering a change to LMP (Energy Systems Catapult, 2021) and that considerably simplifies the contract design proposed below.

The main advantage of LMP is that it avoids the need for redispatching to relieve congestion constraints, and instead the LMPs calculated day-ahead can be rapidly updated (the typical frequency is at 5 minute intervals close to dispatch). The main driver of the move to LMPs in the UK is the estimate that the cost of redispatch to manage congestion will rise from about £500 million/yr now to between £1bn and £2.5bn/year at a maximum, before more transmission investment reduces congestion (National Grid ESO, 2021b).

If excessive transmission investment is to be avoided, generation needs better locational signals. Transmission Network Use-of-System (TNUoS) charges need to be made location-specific as in GB (but rare in the EU). Efficient locational decisions require long-term predictability of the annual network cost. The GB TSO, National Grid, publishes zonal charges that now in part depend on annual average capacity factors (CF) of the generation connected. Thus for 80% CF fossil generation the range across GB in 2020–21 is £44/kWyear (from £34.6 to -£9.6/kWyr) while for wind

8. Neuhoff and Boyd (2011) and others cited in Eicke and Schittekatte (2022) suggest benefits of 1–3% of turnover.

with a 30% CF the range is £36/kWyr.[9] Figure 1 shows that the inclusion of locational TNUoS makes a considerable difference to the rent earned by windfarms.

However, while moving in the right direction, the charges are only based on the average annual CF at each location regardless of technology and can be changed for all generators annually. The fact that different technologies operate at different hours of the day and seasons of the year will affect the output-weighted LMPs that could diverge between technologies. Changing transmission charges annually adds unnecessary risk, given that generators cannot relocate if charges change and TSOs receive risk-free regulated revenue. Instead what are in effect deep connection charges should take the form of long-term contracts—FTRs—with a tenor comparable to other long-term capacity and renewables contracts. The TSO is best-placed to compute the likely future evolution of estimated hourly LMPs for each type/technology considering entry. The annual averages then determine the long-term contract price, to be fixed on entry, but recomputed for subsequent entrants. This decouples the need for stability in the annually set TNUoS charges that restrict the speed of response to the evolving transition. As a long-term right, the FTR at that node would be transferable directly for the same technology, but with side payments to the TSO for different technologies.

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. Without LMPs. 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. In the absence of LMPs, transmission constraints have to be addressed in the balancing market (at increasing cost as shown above for GB). 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)). However, it would be far cheaper to move to LMPs as quickly as possible, before large volumes of VRE enters the system.

9. To put these numbers in perspective, the first GB capacity auction has cleared at £20/kWyr.

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, at least if the market price falls 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). Developers will need to know how or whether curtailed VRE would be compensated, which will depend on the form of contract considered below. The simplest solution to deal with rapidly escalating curtailment[10] is to offer connection contracts that specify last-in first to be curtailed, so that existing VRE can reasonably predict their position in the curtailment queue. The efficient market price with system-wide curtailment should be close to zero or even negative (to keep inflexible plant from shutting down). That makes it unprofitable for VRE to offer to supply and will voluntarily self-curtail, providing, as in the contract set out below, generators decide whether or not to produce based on the market, not subsidized price. The contract set out below also ensures that the financial penalty for curtailment is just the present value of enjoying future support *less* the present support (hence very small).

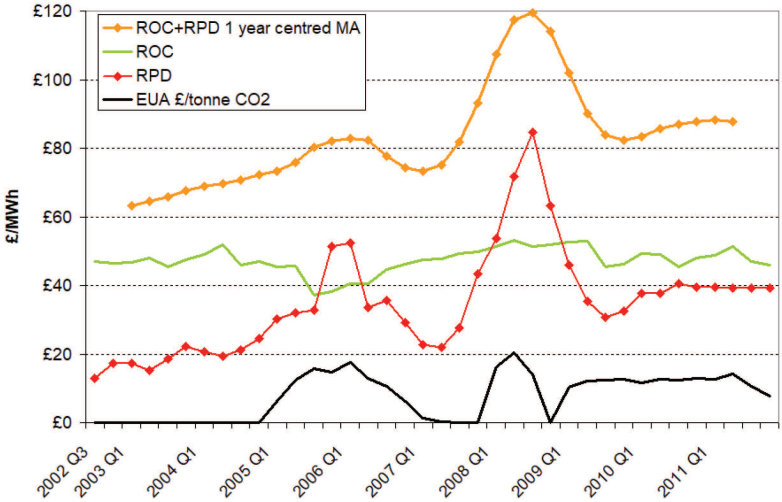
5.2 Excessive costs from unhedgable risk

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 obligation.

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, 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 Renewable Obligation Certificate (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.

10. The marginal curtailment can be 3–4 times average curtailment (Newbery, 2020b).

Figure 2: UK wholesale (RPD), EUA and 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. Newbery (2012, Fig. 2) showed that UK forward prices for delivery in 2010 of electricity, gas and coal costs (including the EU carbon price) moved in lock-step over the period in which forward markets quoted prices for annual 2010 contracts, again chosen to cover 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).

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, Table 3 shows the average modelled wind capacity factors (CF) in various UK regions (defined by UKNUTS-2) from MERRA-2 wind data.[11]

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 UKF3 averaged from 2010–19 is 43.4%/33.5% = 129.4% 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 2010–2019 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) zero. The implications of this can be very roughly estimated for the average wind year 2018, but projecting forward to the expected capacities in 2026. With the projected export capacity for GB in that year (10GW), 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 hours of projected wind curtailment and scaling up the remaining prices to give an average annual price of €70 ($83)/MWh for all other hours. (Neither the choice of year for prices nor scaling has much impact on the results).

11. 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 (2020) 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.

Table 3: Regional annual average modelled wind capacity factors, 2010–19

year	UKF3*	UKG3	UKH3*	UKK3*	UKL1*	UKL2	UKM5*	UKN0*	UK Total
1980–2009	44.7%	17.2%	42.2%	40.8%	42.1%	23.8%	27.1%	32.2%	34.9%
2010	39.2%	13.2%	38.3%	35.2%	33.9%	17.6%	23.5%	25.2%	29.0%
2011	45.2%	17.4%	42.9%	41.1%	42.3%	24.5%	27.5%	32.5%	35.1%
2012	43.3%	16.0%	41.4%	39.8%	39.8%	21.9%	25.0%	29.4%	32.7%
2013	44.2%	16.8%	41.9%	41.0%	41.6%	23.2%	26.4%	31.9%	34.8%
2014	43.7%	16.9%	41.0%	39.4%	40.7%	23.2%	25.6%	29.6%	33.6%
2015	46.2%	19.0%	45.2%	44.1%	43.9%	26.2%	28.8%	33.9%	37.0%
2016	41.6%	15.1%	40.9%	38.7%	38.4%	21.0%	24.3%	29.0%	32.0%
2017	45.2%	16.5%	41.2%	40.8%	42.2%	22.8%	27.5%	30.9%	34.7%
2018	42.6%	16.0%	40.0%	39.1%	39.7%	22.2%	25.7%	30.7%	33.3%
2019	42.9%	15.8%	41.0%	41.0%	40.3%	21.9%	25.1%	29.9%	33.2%
average 2010–19	43.4%	16.3%	41.4%	40.0%	40.3%	22.5%	25.9%	30.3%	33.5%
as ratio to total	129.4%	48.5%	123.3%	119.3%	120.0%	66.9%	77.3%	90.3%	
SD yrly	2.0%	1.5%	1.8%	2.3%	2.7%	2.3%	1.6%	2.4%	2.2%
R^2 CF on total	71.5%	67.5%	50.5%	38.8%	82.3%	71.9%	58.8%	63.4%	
Hourly value €/MW	€20.06	€7.43	€18.74	€18.40	€18.74	€10.33	€12.26	€14.60	€15.76
as ratio	127.3%	47.1%	118.9%	116.7%	119.0%	65.6%	77.8%	92.7%	
Hrly TNUoS €/MW	€ 0.01	-€0.02	€ 0.09	-€0.50	-€0.41	€0.00	€2.98	n.a.	€1.10
€/MWh (w/TNUoS)	€46.19	€ 45.70	€45.05	€47.25	€47.51	€45.93	€35.82	*€48.20*	€43.77

Source: https://www.renewables.ninja/country_downloads/GB/ninja_wind_country_GB_current_merra-2_nuts-2_corrected.csv. F3: Lincolnshire*, G3: W Midlands; H3: Essex*; K3: Cornwall*; L1: W Wales*, L2: E Wales; M5 is NE Scotland*, NO; N. Ireland*; where * indicates coastal. 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 last section of the table. The average revenue per hour is shown in €/hr per MW of capacity, also as a ratio to the UK total, and immediately below that the locational TNUoS (for 2021) also in €/hr per MW of capacity. These are remarkably low except for Cornwall and NE Scotland (at the extremes of the transmission system). The last line gives the net (of TNUoS charges) revenue per full MWh, the result of dividing the net revenue/hr by the CF. It reveals that the revenue per full operating hour is fairly stable (SD over these NUTS-2 regions is €3.71/MWh, considerably lower across all NUTS-2 regions) so the variation is mainly driven by variations in CF, not in their correlation with the overall wind total (at projected 2026 penetration levels, which will considerably increase in later years). 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 to the on-line working paper (Newbery, 2021) 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). The coastal locations (shown starred) mostly have higher than average CFs (except curiously for Scotland and N Ireland) while the inland locations (no stars) have lower CFs. 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. These limitations were avoided by examining actual windfarm performance in Figure 1.

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%, but 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).

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. 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 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 (with the exception of well-designed incentive-compatible capacity subsidies that are benchmarked for the technology). In an efficient market, the real-time price of electricity should fall to the avoidable cost of marginal VRE or possibly below to keep flexible plant running for system stability. That should signal voluntary curtailment by VRE suppliers if they face the correct signals. LMPs address congestion constraints, but in their absence, offering firm or non-firm connections provide a partial solution. Long-term spatial and technology differentiated network contracts (FTRs in the case of LMPs) are a preferable long-term location signal. An efficient RESS should balance the desirability of achieving all these against the desirability of reducing risk to lower the WACC.

6. DESIGNING EFFICIENT RESS CONTACTS

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 detail 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[12] 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 in hour h equal to $\theta_{rh}K$, where θ_{rh} is the forecast capacity factor for the VRE at location r in hour h. The windfarm could designate her preferred forecast that would provide data to the counterparty company. The wind forecast would be translated through power curves to expected output of the model of turbine contracted. As the wind (or PV) farm has to sell all its output in the market at or shortly after the time of the forecast, M_h is close to the amount sold, and so is an excellent hedge. The following proposition demonstrates that the wind farm will be dispatched (and constrained down) efficiently.[13]

> *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 forecast capacity factor at location r in hour h, s is the strike price and p_{rh} is the relevant wholesale price. The last-price auction would pre-specify the way in which θ_{rh} is determined, and 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 (subscript v) will offer at its avoidable cost, c, in the day-ahead auction and into the balancing market for constrained down actions. First 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 $\theta_{rh}K$ at $C >$ c. If $C > p_{rh}$, then the VRE will not generate and will receive $(s–p_{rh})\theta_{rh}K$, compared to receiving $(s–c)\theta_{rh}K$ if truthfully revealing c. The second term is larger, providing an incentive to truthfully reveal avoidable costs as c. Similarly, if $c > p_h > C$ there is a risk of generating and losing $(c–p_h)\theta_{rh}K$. 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 VRE-specific output/MW encourages efficient bidding for dispatch while preserving stable revenue streams needed for low-cost finance.

A similar 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

12. Such as the 15% subsidy to electricity and gas in the UK resulting from preferential VAT rates.
13. This contact design is also closely related to the incentive effects of benchmarking on a regulated firm's performance (Shleifer, 1985).

a pre-determined number of years to ensure adequate performance. Huntingdon et al. (2017, p479) builds on the 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. A chosen local 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 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 benefits from LMP (hence p_{rh}) for congestion management, failing which a zero lower bound for acceptable VRE bids into the wholesale market would give similar results. (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 (the Low Carbon Contracts Company)[14] 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.[15] 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 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 front-end loads repayments. 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).

The second locational distortion is blunting the incentive to locate in areas and/or choose designs (e.g. optimized to local wind speeds) that minimise correlations with the same generic category (wind, PV). This is logically addressed under LMP with a long-term FTR, failing which

14. see https://www.lowcarboncontracts.uk/
15. Steinhilber (2016) notes that this specification is used in China.

with a long-term contract for the Transmission Network Use-of-System (TNUoS) charge based on predicted output-weighted (shadow) LMPs. Assuming that developers face efficient long-term TNUoS contract charge or pay for long-term LMP FTRs, this locational distortion can be addressed by extending Proposition 1 in a natural way (with the same proof):

> *Proposition 2*. A yardstick CfD that pays $(s–p_{rh})\theta_{rh}K$ in hour h at location r for a period limited to T hours, where T satisfies ${}_{h=1}\Sigma^{T}\, \theta_{vh} = N$, where θ_{vh} is metered output at location r, regardless of whether generating or not, will ensure efficient dispatch and constraint management and efficient location, providing it is offered with a transmission contract set at efficient future output-weighted LMPs.

The absence of locational transmission charges and a country-wide uniform wholesale price would encourage VRE to locate where the resource delivers in higher priced hours (when the system is not saturated with wind or PV), but this requires a suitable hedge. The same idea of finding a suitable yardstick suggests the following (second-best) contract (valid for auctions before transmission pricing is corrected to include suitable locational signals). Instead of setting the yardstick volume at the local average output (which provides a perfect hedge if the VRE matches that average), instead set the yardstick volume at the system-wide average. This introduces basis risk, which may be modest, but rewards areas with a low correlation with the system average, and hence a lower correlation with low-priced hours.

To see how this works in the absence of any network charges if this change is applied to the 2018 regional wind averages (NUTS-2 level) then the range of changes to the average subsidy (the UK-wide CF times the strike price less the wholesale price, $\Sigma_h (s–p_h)\theta_{UKh}$/MW), which would be added to the wholesale value at site r, $\Sigma_h \theta_{rh} {*} p_h$/MW, is from -£6.12/MWh at UKD1 (with CF 45.1%) to +£8.66/MWh at UKG3 (with CF 16%). These extreme adjustments correspond (negatively) to the extremes in CF. The largest negative correction is in the region most highly correlated with the UK system wide CF (R^2 = 84%), and the largest positive correction has a lower correlation (R^2 = 63%), but not the lowest, which is UKK3 (at 43%). Table 3 shows that these charges are considerably larger than the 2021 TNUoS charges, which thus undervalue the wind-relevant locational elements.

The problem with this simple approach is that the hourly quality of the hedge is quite poor—the average SD of CFs across regions is 13% (+/– 5%). However, as the purpose of this locational signal is for investment, not dispatch, its benefits can be achieved by adding or subtracting the annual (or multi-annual) amount per MW of capacity, leaving the contract of Proposition 1 otherwise unchanged, while also limiting the contract to a fixed number of full operating hours e.g. 30,000MWh/MW. This removes the incentive to locate in regions of high resource while retaining the incentive to locate where the local resource has a lower correlation with the country average, while preserving an almost perfect output hedge but retaining the incentive to respond to spot prices.

> *Proposition 3*. A yardstick CfD that pays $(s–p_h)\theta_{rh}K + a_hK$ in hour h at location r for a period limited to T hours, where T satisfies ${}_{h=1}\Sigma^{T}\, \theta_{vh} = N$, and $a_h = {}_{h=1}\Sigma^{H}\, (\theta_{Sh}–\theta_{rh})p_h/H$, 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 forecast capacity factor at location r for hour h, θ_{vh} is the actual metered output in hour h per MW at the VRE site, θ_{Sh} is the system average capacity factor, H is the number of hours or settlement periods per year, N is the predetermined contract length in full operating hours, s is the strike price and p_h is the relevant wholesale price. Again the auction information pack would announce the method to determine (and perhaps the actual values of) the parame-

ters (the θ's) and the number of full operating hours, while the auction would determine the strike price, s.

Proof. The strike price and revenue paid do not depend on generator v's actual hourly output, $\theta_{vh}K$, inducing truth-telling bids. The limit of full operating hours removes the incentive to locate solely because of high capacity factors, while the term a_h guides efficient location decisions and is beyond the influence of the VRE developer.

Both volume-defined contracts combined with the efficient yardstick contract would be 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 fair market price, or multi-annual contracts if the developer wishes to upgrade at a cost above some specified threshold level.

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). This can be combined with a yardstick VRE to provide revenue assurance and guide location to areas of low correlation with the system average revenue.

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. 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 curtailment first-in last out, rather than as in most schemes, equi-proportional curtailment. The defence of this discriminatory curtailment scheme is that at each auction, bidders can estimate the current level of curtailment, and may base their bids on assuming that this rate will continue. Further entry is likely to exacerbate curtailment 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 becomes increasingly important with increased VRE 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 and system-wide saturation, where the contract described above has the key features to be effective.

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 has 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 Contract for Difference (CfD) in which the contracted volume in any hour is equal to the developer's hourly forecast output per MW capacity, with a life specified in MWh/MW capacity (e.g. 30,000 full operating hours) and the strike price in the CfD set by auction. Combined with comparable length contracts for transmission rights, either (ideally) a Financial Transmission Right on forecast output-weighted LMPs, or the equivalent Transmission charge computed on shadow LMPs (as is partly done with the GB TNUoS charges), the contract will deliver the correct locational and dispatch signals, solving problems of congestion management and curtailment.

Failing a move to LMPs and/or locational transmission charges, a second best surrogate is to add an annual regionally-specific capacity payment per MW. That can provide incentives to locate in sites with a low correlation with average wind/PV output, while avoiding incentives to locate solely because of a high resource, but with some additional short-run volatility in revenues. 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
TNUoS: Transmission Network Use of System (charges)
TSO: Transmission System Operator
VRE: variable renewable electricity
WACC: weighted average cost of capital