UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Designing efficient Renewable Electricity Support Schemes

EPRG Working Paper 2107

Cambridge Working Paper in Economics 2128

David Newbery

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 high resource 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, adjusted for regional variations in correlation with total renewable output. This yardstick CfD delivers efficient dispatch while assuring but limiting the total amount of subsidy and not over-compensating high resource sites. The revenue assurance, with a government-backed counterparty, allows high debt:equity, dramatically lowering the subsidy cost.

Keywords renewables support schemes, distortions, auctions, yardstick contracts,

JEL Classification D44, D62, D86, H23; H25, L94; Q28; Q42; Q48

Contact dmgn@cam.ac.uk
Publication March 2021

Designing an incentive-compatible efficient Renewable Electricity Support Scheme

David Newbery[1]
EPRG, University of Cambridge
19 March 2021

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 high resource 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, adjusted for regional variations in correlation with total renewable output. This yardstick CfD delivers efficient dispatch while assuring but limiting the total amount of subsidy and not over-compensating high resource sites. The revenue assurance, with a government-backed counterparty, allows high debt:equity, dramatically lowering the subsidy cost.

Keywords renewables support schemes, distortions, auctions, yardstick contracts

1. Introduction

Faced with a net-zero carbon target by 2050, the electricity industry will have to reach near zero emissions far sooner. A large part of that ambition requires a substantial increase in variable renewable electricity (VRE, primarily wind and solar PV). For reasons of market and policy failures discussed below, VRE will benefit from support. If this substantial investment in renewable electricity is to be delivered at least cost, support schemes need drastic redesign. Existing renewable electricity support schemes reflect past compromises to reconcile often conflicting objectives and to disentangle past unintended consequences of faulty policies.[2] While existing RE enjoys contractual commitments can continue to be honoured, their inefficient form can be replaced by quite different efficient policies without undermining policy commitment. Indeed, efficient policies are more credible as there would be no need to subsequently change them, encouraging, not dissuading investors.

This article proposes an incentive-compatible efficient contract that can be auctioned to deliver least cost decarbonisation while maintaining control over the amount of support. It starts by identifying the market failures that require correction and from that considers how best to address them. It follows the standard public economics approach combined with

[1] I am indebted to David Reiner and Iain Staffell for helpful comments.

[2] See e.g. Bunn and Yusupov (2015), Klobasa et al. (2013), Nock and Baker (2017). One obvious conflict is between the EU Emissions Trading Scheme fixing a cap on the number of emission allowances, and the subsequent Renewables Directive that increased renewable targets without reducing the cap commensurately. The unintended result was the additional renewables had zero impact on EU emissions.

mechanism design that is relatively uncommon in energy policy.[3] One reason for this reluctance to follow this logic is that governments are reluctant to internalise externalities by corrective taxes or subsidies and instead prefer targets. These targets need to be justified by many reasons in the hope of finding political support: environmental protection, energy security and job creation, many of which would not stand close economic scrutiny (Borenstein, 2012). That often leads writers to concentrate on the extent to which the targets have been met or the justifications satisfied, without enquiring into the underlying reasons for intervention.[4]

Efficiency is neatly captured by the requirements of the EU *Clean Energy Package* (DIRECTIVE (EU) 2018/2001, §19):

> Electricity from renewable sources should be deployed at the lowest possible cost to consumers and taxpayers. When designing support schemes and when allocating support, Member States should seek to minimise the overall system cost of deployment along the decarbonisation pathway towards the objective of a low-carbon economy by the year 2050. Market-based mechanisms, such as tendering procedures, have been demonstrated to reduce support cost effectively in competitive markets in many circumstances.

The *Clean Energy Package* requirements provide good principles that should guide the design of Renewable Electricity Support Schemes (RESS) in any jurisdiction. It also, arguably, removes on of the main impediments to efficient RESS design by dropping the obligation for each Member State to meet a specified renewable energy share. Such obligations drive countries to designs that stress RE output, not capacity, that are the root cause of most of the distortions discussed here. By replacing that requirement by a stress on designing routes to net-zero, combined with the dramatic improvement in the commercial viability of unsupported VRE, it opens the way to revisit the main causes of market failure affecting VRE, and stresses the role of markets, and hence, indirectly, market failures. Boute (2012, p72) notes that the Russian Ministry of Energy announced in 2012 that the national renewable energy target should be based on installed capacity, not energy, in line with the approach here.

The lesson that well-designed auctions can dramatically reduce the cost of procuring renewable electricity compared to administratively fixing the strike price has been demonstrated by the dramatic reductions in clearing prices (Newbery, 2016a), most notably in successive auctions for off-shore wind in the North Sea (Grubb and Newbery, 2018). This article designs a contract to auction to deliver Variable Renewable Electricity (VRE) at the lowest possible *social* cost to consumers and taxpayers, including external costs and benefits.

There is a tension between accelerating investment in renewable electricity (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 can lead to excessive public cost and rapid cancellation of the scheme, or in some cases,

[3] Notable exceptions include Huntingdon et al. (2017), Barquin et al.(2017) and Andor and Voss (2016).

[4] Thus Ragowitz and Steinhilber (2014) measure the speed of meeting the targets as their measure of efficacy that they contrast with efficiency, of achieving the target at least cost. Most government and EU reports concentrate on efficacy.

to retrospective withdrawal, notably in Spain (CEER, 2018). Quantity-based schemes, such as green certificates, can place excessive risk on developers, leading either to under-delivery or over-compensation, as an early article by Finon (2006) argued. The solution is simple but took surprisingly long to rediscover[5] – auction either a fixed volume or a fixed sum of funds to secure the least cost solution that meets the capacity target or fits the budget.

There is an extensive literature providing details on the various policies that have been implemented in different countries,[6] analyses of their impacts, and proposals for improvements (which, however, mainly fall short of the proposal in this article).[7] Rather than repeat surveys of that literature, this article first identifies the market failures that require correction. 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. If renewables displace carbon and carbon is under-priced, and if it is not possible to set the correct price for carbon, then a second-best policy might be to subsidize low-carbon generation such as renewables (Newbery, 2018a).

The EU also argues for investment, rather than output support as it "has the advantage that operating costs are in principle not affected. Moreover, it is a one-off measure which does not need to be readjusted at a later stage due to developments in technology or markets to avoid overcompensation." (EC, 2013 §3.1.5.) In the past, however, the EU chose output targets for renewable energy in its various Directives. Unsurprisingly, Member States therefore chose output subsidies to meet these targets at least cost (Meus et al., 2021). The latest Directive, however, does not allocate renewable energy target shares to individual Member States, but instead concentrates on decarbonisation, so subsidies to output are no longer necessarily implied.

This article follows other economic criticisms in supporting the changed emphasis in the latest EU policy as the least cost way of reaching net-zero. Özdemir et al. (2020) demonstrate this by comparing output and capacity support as the least-cost route to future RE output and carbon targets.

The starting point of this analysis is to assume that carbon is correctly priced as there is an appropriate and directed instrument to address that externality. At least in the EU, the carbon price is now approaching the correct level – the EUA price in March 2021 was US$48/tonne, while World Bank (2019) argued that the 2020 Paris target-consistent price was at least US$40–80/t$CO_2$. Learning externalities are the remaining motive for VRE support,[8] sometimes described as taking account of dynamic, rather than just static efficiency. There are other relevant market failures that afflict liberalised electricity markets, of which

[5] The first RESS in the UK was an RE auction to allocate funds from the Fossil Fuel Obligation originally designed to finance nuclear decommissioning after the electricity industry was restructured for privatization (Mitchell, 2000).

[6] The Council of European Energy Regulators, CEER, provides periodic *Status Reviews* (of renewables support schemes) e.g. CEER (2018). 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.

[7] 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.

[8] quantified in Newbery (2018b; 2020)

the most important in an industry prone to unpredictable policy interventions are missing futures and insurance markets (Newbery, 2016b). There are specific problems in determining the capacity credit of VRE and pricing curtailment that might distort free unsubsidized RE entry (Newbery, 2020). Such distortions are overcome by auctioning a suitably designed contract.

2. Criteria for designing renewable support schemes

Least system cost requires that new VRE locates optimally and is dispatched optimally. Least cost to consumers includes the (excess)[9] cost of any subsidies to persuade VRE of the commercial case to enter. 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.[10] 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 in a separate auction to off-shore wind, and the most immature technologies like wave and tidal stream have their own RESS auction. For auctions to work well, bidders need clarity on the future market design, future carbon prices and system rules or Grid Codes (including differential locational transmission charges) that will prevail over a reasonable fraction of the life of the investment, probably for 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.

VRE has another important characteristic in that its peak output is a considerable multiple of its average output. For wind this might be 3:1 (more if the average capacity factor is below 33%) and for solar PV in Northern climes, more like 10:1. At even moderate levels of VRE penetration there will be surplus output even allowing for export and storage. This excess will need to be curtailed, requiring a decision on whether, and if so how, it should be compensated when curtailed. This will also impact the cost to consumers and taxpayers. It also makes priority dispatch a potentially costly solution to encouraging VRE, and the EU has now banned priority dispatch for new VRE. An efficient RESS should encourage VRE to choose not to generate if the value of its output is less than its avoidable cost. As a partial remedy, some systems require that VRE only make non-negative offers.

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 1 shows the ratio of the revenue/MW secured locating a wind farm

[9] Above the social optimum, although as a global public good, learning externalities should largely be financed from general taxation.

[10] del Río (2017) draws lessons on best practice in auction design from around the world, and argues for clearly announcing a sequence of successive auctions to guide the development of a supply chain, and full information disclosure, with suitable penalties for non-investment, price ceilings and efficient administrative procedures.

at representative UK regional sites (defined by UKNUTS-2) compared to the UK average. This is calculated from the invaluable hourly dataset compiled by Iain Staffell,[11] selling at simulated DAM prices for 2005-11 (from Green and Vasilakos, 2010) that account for the market impact of a high level of wind penetration. Table 1 shows the considerable but stable variation in the value of wind across locations and the relatively smaller variation over time (relative to the UK average for that year). As an example the wind output locating in K3 (Cornwall) had a correlation with the UK average of R^2 = 40% over this period. Thus wind resources are systematically different in different locations, and this needs to be taken into account in designing supports that target capacity rather than output.

Table 1 Ratio of regional annual average wind revenue/MW to the UK average, 2005-11

	UKH1	UKJ4	UKK3	UKK4	UKM2	UKM3	UKM5	UKM6	UKN0	average	SD
2005	113.4%	92.3%	121.3%	97.1%	72.9%	80.4%	77.6%	75.4%	91.3%	91.3%	17.0%
2006	113.1%	93.7%	117.1%	94.6%	73.2%	79.8%	75.7%	77.3%	92.2%	90.8%	16.0%
2007	113.7%	93.2%	120.2%	97.5%	72.8%	79.2%	75.9%	74.1%	90.0%	90.7%	17.3%
2008	109.9%	89.1%	119.2%	93.9%	75.2%	83.7%	75.8%	76.7%	93.4%	90.8%	15.4%
2009	117.5%	95.7%	122.7%	92.4%	71.9%	77.4%	81.6%	75.7%	86.5%	91.3%	18.1%
2010	112.7%	89.4%	117.6%	94.5%	74.1%	80.8%	78.5%	79.4%	92.8%	91.1%	15.3%
2011	112.7%	89.4%	117.6%	94.5%	74.1%	80.8%	78.5%	79.4%	92.8%	91.1%	15.3%
average	113.3%	91.8%	119.4%	94.9%	73.5%	80.3%	77.7%	76.9%	91.3%	91.0%	16.3%
SD	2.2%	2.6%	2.1%	1.8%	1.1%	1.9%	2.1%	2.0%	2.4%	0.3%	

Sources: https://www.renewables.ninja/country_downloads/GB/ninja_wind_country_GB_current_merra-2_nuts-2_corrected.csv, Green and Vasilakos (2010)

H1 is East Anglia; J4 is Kent; K3 is Cornwall; M2 is East Scotland; M3 is SW Scotland; M5 is Aberdeen; M6 NW Scotland, NO is N. Ireland; all peripheral locations with the highest wind in NW Scotland.[12]

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). 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).

[11] License: https://creativecommons.org/licenses/by-nc/4.0/ - Reference: https://doi.org/10.1016/j.energy.2019.08.068

[12] A map of the regions can be found at https://upload.wikimedia.org/wikipedia/commons/thumb/f/f7/NUTS_2_statistical_regions_of_the_United_Kingdom_2015_map.svg/1920px-NUTS_2_statistical_regions_of_the_United_Kingdom_2015_map.svg.png

To demonstrate the importance of this, Table 2 shows the ratio of the revenue/MWh[13] secured locating a wind farm at representative UK regional sites compared to the UK average. Table 2 shows the remarkably small variation in the unit value of wind across locations and the even smaller variation over time (relative to the UK average for that year).

Table 2 Ratio of regional annual average wind revenue/MWh to the UK average, 2005-11

	UKH1	UKJ4	UKK3	UKK4	UKM2	UKM3	UKM5	UKM6	UKN0	average	SD
2005	101.0%	101.9%	101.9%	100.2%	98.8%	98.6%	100.7%	101.1%	100.0%	100.5%	1.2%
2006	100.1%	99.4%	100.5%	99.7%	100.1%	99.9%	101.6%	99.8%	99.5%	100.1%	0.7%
2007	100.8%	101.4%	100.9%	101.3%	97.5%	98.8%	99.1%	98.9%	102.3%	100.1%	1.6%
2008	100.7%	102.5%	101.6%	101.3%	97.9%	98.5%	98.0%	97.7%	99.8%	99.8%	1.8%
2009	100.3%	101.4%	100.6%	100.0%	99.6%	99.9%	100.8%	101.3%	100.5%	100.5%	0.6%
2010	100.0%	100.2%	100.9%	100.8%	100.1%	99.8%	100.6%	99.9%	99.6%	100.2%	0.5%
2011	100.1%	100.3%	100.4%	99.9%	99.8%	99.9%	100.1%	100.1%	100.1%	100.1%	0.2%
average	100.4%	101.0%	101.0%	100.5%	99.1%	99.3%	100.1%	99.8%	100.2%	100.2%	0.7%
SD	0.4%	1.1%	0.6%	0.7%	1.1%	0.7%	1.2%	1.2%	2.4%	0.3%	

Sources: as Table 1

This article identifies distortions caused by existing RESS and proposes a new contract that guides efficient location decisions and delivers efficient dispatch. 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. An efficient RESS should balance the desirability of achieving this against the desirability of reducing risk to lower the WACC.

3. Types of support schemes and their distortions

RESS can be price-based, quantity-based, investment-based, capacity-based, or even regulated. 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. 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 RO scheme. The certificate value is a premium on the market price, and as such it is arguably a mixture of a price and quantity instrument. 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

[13] Table 2 measures the variation in the unit value of wind caused by a mismatch of output with prices. As wind penetration increases this variation should increase, so the modest variation here is an understatement of a high VRE penetration future.

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, 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).[14] 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).

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 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). Capacity subsidies can be a payment per MW determined by a capacity auction (typically with an obligation to be available in stress periods, and hence relatively risky for VRE), or unconditional (usually over a set number of years). As such they are directed to address the learning externality, but poor subsidy design can lead to cheap but inefficient choices, as claimed to be the case in the Netherlands (Meus et al., 2021). The choice of technology (type of wind turbine, such as height, blade length, and even spacing) could therefore be distorted by inappropriate RESS. 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.

The last type of RESS is the Regulatory Asset Based (RAB) model, (although there are few examples of the latter for VRE, as they are more appropriate for long-lived projects such as nuclear power, tidal barrages and hydro-electric dams, see e.g. Newbery et al., 2019). Simshauser (2021) gives an interesting model for Renewable Energy Zones, which can be either regulated or merchant. Such zones deal with the problem that massive VRE entry on a weak transmission system can lead to considerable inefficiency and mistaken investment decisions, unless the transmission investment and VRE location are coordinated and jointly financed – that is, the VRE jointly pays the additional transmission investment. A RAB model is likely to be cheaper, but subject to regulatory delays, while merchant investment can respond more rapidly, and the extra financing cost might be offset by the shorter route to market.

Under the RAB model, the regulator defines the RAB as the allowed cumulative investment, determines a depreciation schedule and an allowed WACC on the RAB, agrees any future investment plans, decides on the allowable operating costs, and sets a strike price

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

to recover the return on the RAB, its depreciation and the operating costs, for a fixed period (typically 5 years), before resetting these parameters at the next price control. Depreciation schedule implicitly defines the duration of the contract (if for a simple project, rather than a portfolio). Regulated asset schemes will not be considered further here.

3.1. *Distortions from making payment contingent on delivery*

Almost all existing price and quantity-based schemes suffer from the problem that the subsidized price determining the revenue (on average above the market price) is only paid if the VRE generates, and so the strike subsidized price, not the market price, 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 introduced by the *Energy Act 2013* (HoC, 2013) that replaced the previous PFiT (with RO certificates). 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, and where the reference price is the spot market price. The generator makes its output decision looking purely at avoidable costs and potential revenues. If it is unprofitable 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 $(s - p).M$. If the generator had to produce to receive its CfD payment it would receive the smaller amount $(s - c).M$ per hour. 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 inflexible plant to avoid costly shut-downs and restarts. 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 offer price if $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 be subject to a number of distortionary incentives in the choice of technology. Good choices would adapt to local conditions and choose system-friendly or advanced designs that can offer ancillary services but at higher cost (Meus, 2021). They would 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),[15] and would not over-favour high resource areas (discussed immediately below).

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

3.2. Locational distortions arising from fixed contract length

Most VRE are offered a contract specified in years from commissioning, whether the contract is set administratively or auctioned, and whether it is a FiT, a CfD with FiT, or a 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 centres) 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). The social value of the electricity produced at the windy location is €40/MWh x 2,500 hrs = €100,000/MWyr and of the central location is €40 x 2,000 = €80,000/MWyr. Suppose that the extra system costs of the windy compared to the central location are €25,000/MWyr, then from a system cost perspective it is better to locate centrally.

Under the RESS, however, the windy location will earn €80 x 2,500 = €200,000/MWyr and the central location will earn €80 x 2,000 = €160,000/MWyr, an advantage of €40,000/MWyr, more than sufficient to pay the extra grid charge of €25,000/MWyr, so the developer will prefer the windy location, leading to an inefficient location decision. (See also Huntingdon et al., 2017, §2.)

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 when dealing with hedging risk.

3.3. *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). 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. With falling RE costs, this overcompensates 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% 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). Figure 1 shows the variability of the two elements, lower for the ROC price as they are underwritten to some extent by a pre-

announced expanding demand in line with forecast VRE supply.

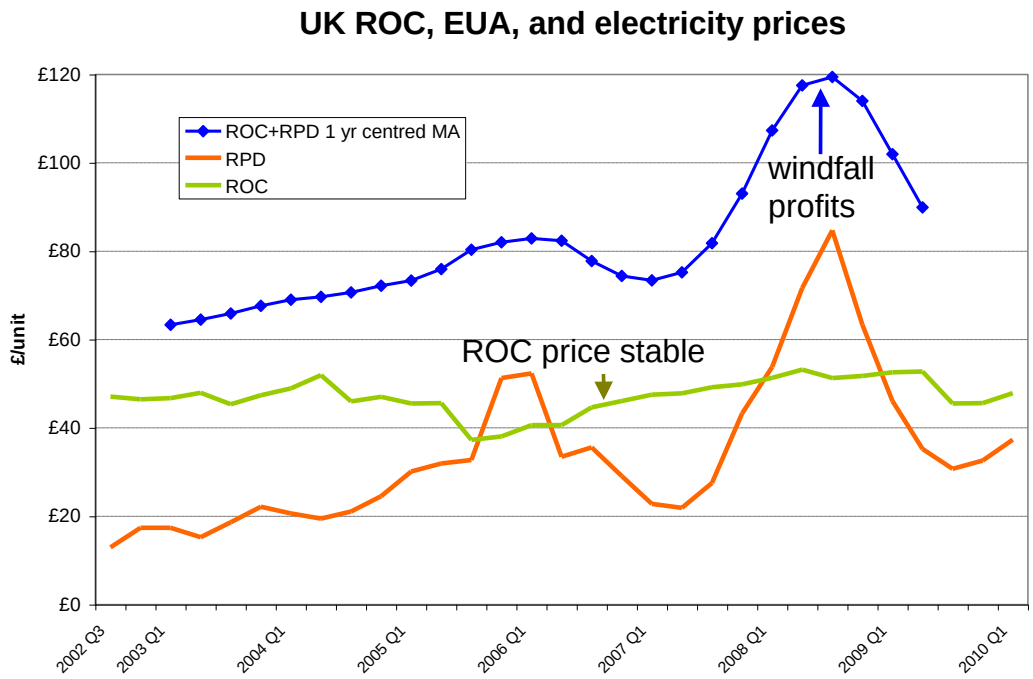

Figure 1 UK wholesale prices (RPD) and the Renewable Obligation Certificate (ROC) prices
Source: UKRPD and Ofgem

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 it 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 short answer 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 2 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 2020 contracts. The fossil generation profit (difference between electricity price and fuel cost) is considerably more stable than the electricity price that is the major determinant of VRE 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).

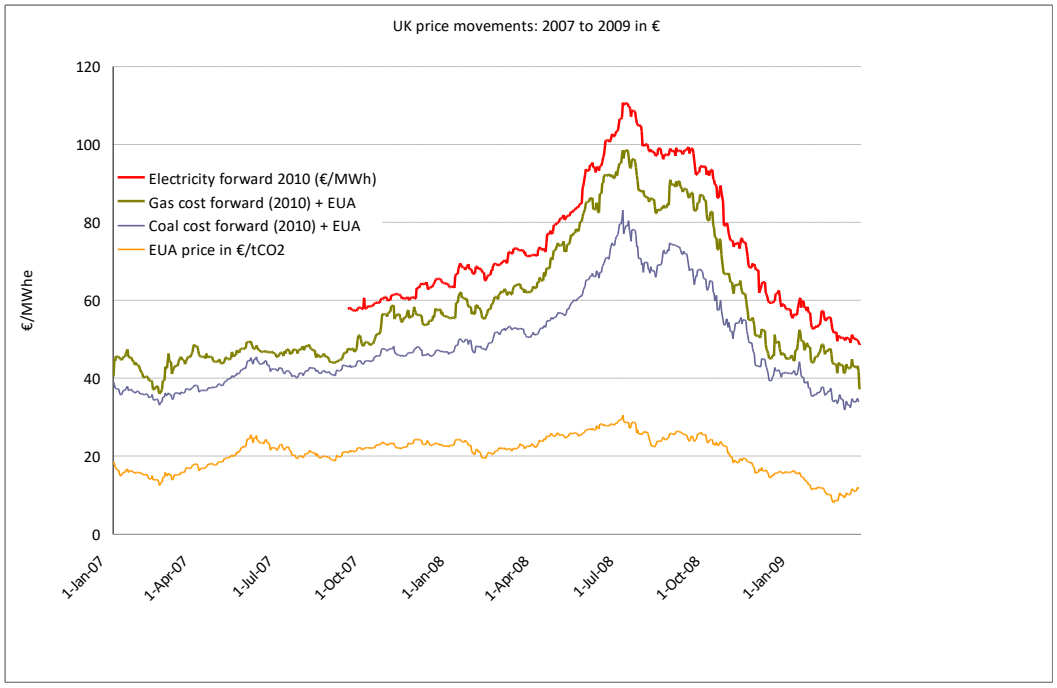

Figure 2 Forward prices for UK base-load 2010 contracts
Source: Bloomberg

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 set at e.g. the monthly average of the Day-ahead hourly prices, which will be below high prices that risk the VRE having to make payments. A sliding FiP or CfD with FiT would stabilise the revenue of the VRE (at $s - p^*$) where p^* is the (averaged and more stable) reference price. 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.

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).

4. Avoiding RESS distortions by an incentive-compatible volume 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 in detail in Brunekreeft et al. (2005) and surveyed 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 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 congestion and the need to redispatch to resolve the constraint, but instead of calling for a redesign of the support scheme, 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 affecting operating costs are in principle not affected but does spell out how this support is best delivered, 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 again does not address the distortions identified here. IEA's *20 Renewable Energy Policy Recommendations* is more concerned with distortions from fossil fuel subsidies[16] but has a section on RE in which it argues to "Recognize (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 do have this property, if properly defined to ensure that the right technology is installed. Boute (2012) noted that they were favoured in Russia, but there treated in the same way as other capacity procured to deliver the reliability standard. However, by themselves, they still leave market risk with the capacity holder, with the same disadvantages noted above of the lack of suitable hedges. To preserve the hedging advantages while providing incentives for efficient dispatch, the alternative is to make its contracted output M_h in hour h equal to $\theta_{rh}K$, where K is its capacity, θ_{rh} is the average capacity factor for wind in region r in hour h. This could be based on the best relevant wind forecast, which, given that the wind farm has to sell in the market (or its agent has to sell on its behalf) would be the likely amount sold in any case. The following proposition demonstrates that the wind farm will be dispatched (and constrained down) efficiently.[17]

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

Proposition 1. A yardstick CfD which pays $(s - p_h)\theta_{rh}K$ in hour h in region 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 average capacity factor for wind in region r in hour h.

Proof. Efficiency requires that the wind farm (subscript w) will offer at its avoidable cost, c, in the day-ahead auction and into the balancing market for constrained down actions. Suppose that $p_h > c$ and the wind farm offers $C >$ c. If $C > p_h$, then the wind farm will not generate and will receive $(s - p_h)\theta_{rh}K$, compared to receiving $(s - p_h)\theta_{rh}K + (p_h - c)\theta_{wh}K$, where $\theta_{wh}K$ is the day-ahead forecast output of the wind farm and thus the offer into the wholesale day-ahead market. Provided $\theta_{rh} - \theta_{wh}$ is small (which is equivalent to choosing an appropriate sized and located region r) the first term is larger, and similarly if $C < c > p_h > C$ there is a risk of generating and losing $(c - p_h)\theta_{wh}K$. Bidding according to the true avoidable cost is a dominant strategy, at least for a price-taking generator.

Conclusion 1 A yardstick CfD for VRE in which the volume contracted each hour is proportional to the area-wide 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 ancillary services

While this contract may make little difference for congestion management (at least if there are sufficient conventional plant able to reduce output) and given that a zero lower bound of acceptable bids is a simpler solution, the proposition will be more useful in combination with other minor changes to contract design when it comes to the more important location distortions.

However, while this contract (or a zero bid constraint) addresses the problem if VRE needs to sell in the wholesale market (as with PFiTs and as required in future under the EU *Clean Energy Package*) it does not deal with simple legacy FiTs, which guarantee payment on injection. As FiTs are usually linked to priority dispatch, that means unless curtailed they will always supply and could drive the market price below zero. As noted, this evident distortion has been addressed in the *Clean Energy Package* that disallows priority dispatch for new RESS contracts. It is open for regulators to offer those with priority dispatch contracts an adequately attractive alternative contract that overcomes this limitation where it is causing serious distortions. As there are 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.

4.1 Constraints and Curtailment

As VRE has a high ratio of peak to average power, and as penetration increases, so transmission constraints and system-wide curtailment will become necessary. Local transmission constraints require generation behind the constraint to reduce output 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).

Constraints are normally addressed by non-energy balancing actions, in which generators indicate how much they will accept to be constrained down, and under the *Clean Energy Package* Regulation 2019/943 (Art 13.1) new controllable renewables are to be treated in the same way as conventional generation:

> The redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria. It shall be open to all generation technologies, all energy storage and all demand response, including those located in other Member States unless technically not feasible.

Redispatched units are to be financially compensated, and the normal practice is for this to be their lost profit, which is signalled by their bid to decrease output. For an unsubsidized generator if the market price is p and its avoidable cost is c, they should be happy to be paid $p - c$ per MWh for their output to be reduced, although they may bid a sum exceeding p and risk not being constrained.[18] The problem with subsidized generation is that their lost profit may be distorted by the subsidy, and may lead to an inefficient choice of units to constrain down, as discussed above. If, as seems sensible for many reasons, VRE is prohibited from negative bids, compensation would be limited to their strike price (or the premium plus market price), and is equivalent to the standard practice of offering firm connection rights to all generation. In congested areas offering non-firm connection offers to new entrants until cost-effective reinforcement relaxes the export constraint would remove the need to compensate those entrants, and would provide a good locational signal. This is consistent with REGULATION (EU) 2019/943 Art 13(7):

> Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that

[18] They may argue that the cost of restoring output after a reduction is considerable, or they may have other commitments (e.g. to deliver heat as well as electricity), or they may believe they can exploit their market power if there are few other alternatives open to the System Operator. Normally there will be rules limiting the exercise of market power.

have accepted a connection agreement under which there is no guarantee of firm delivery of energy.

The volume contract set out below is attractive in that if the connection agreement is non-firm, the VRE will be almost completely compensated by future equivalent revenue, which should be reflected in lower bids in the auction, even if curtailment does not provide immediate compensation.

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). Curtailed VRE would need assured compensation, which will depend on the form of contract, as considered below.

4.2 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) that may also have higher system costs, is simply addressed. It 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).[19] 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 and better reflects technical progress lowering future VRE costs. 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 (or one set 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 main remaining problem is that almost completely hedging output risk with the yardstick CfD of Proposition 1 does not address the second locational distortion, of 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). Paying the market price when actually generating would encourage locating where the resource delivers in higher priced hours (when the system is not saturated with wind or PV), but this requires a suitable hedge.

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

The idea here is to preserve the market price signal to locate while both hedging the market price risk and relating the subsidy to capacity, not output. One solution is again to make use of reference locations as before. Consider wind, and suppose the system average wind output per MW in hour h is θ_{Sh} when the system average price is p_h, so that the system average wind revenue is $\sum_h \theta_{Sh} p_h$/MW in that period (month, season, year). The corresponding revenue for a representative wind farm in region r is $\sum_h \theta_{rh} p_h$/MW. If in addition to the previously determined CfD revenue, the wind farm received (or paid if negative) the period sum $\sum_h (\theta_{rh} - \theta_{Sh}) p_h$/MW then the incentive to locate where most valuable is restored, once the total number of full operating hours is limited. Settlement would be after the data were collected and validated (much as happens in daily auction markets to determine the wholesale price) and could be paid monthly in arrears.

This can be combined with the yardstick CfD of Proposition 1, together with a volume limited number of full operating hours, either in total, e.g. 30,000MWh/MW, or for sub-periods of several years, e.g. 9,000MWh/MW over 5 years, up to 15 years in total. 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.

Proposition 2. Setting the strike price s in the yardstick CfD as defined in Proposition 1 but adding (or subtracting if negative) the period sum $\sum_h (\theta_{rh} - \theta_{Sh}) p_h$/MW (where θ_{Sh} is the system-wide capacity factor, θ_{rh} is the capacity factor in local region r, and p_h is the hourly wholesale price) for a limited number of full operating hours, would induce efficient location while providing strong revenue assurance.

Proof. The strike price and revenue paid do not depend on generator w's actual hourly output, $\theta_{wh}K$, but are correlated with it, providing a partial hedge, and encouraging a location that maximizes $\sum_h (\theta_{rh} - \theta_{Sh}) p_h$ less transmission charges. The volume limit removes the incentive to locate solely because of high capacity factors, while preserving the incentive to locate where there is low correlation with the system average.

The quality of the hedge could be tested using the very useful UKNUTS-2 hourly dataset illustrated in Tables 1 and 2, but the variation is rather small, so the Appendix provides an exaggerated example to make the case. This volume-defined contract 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 subsidy payments.

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.

For locations where export limits are likely to lead to persistent constraints, the auction contract should be quite clear that the connection agreement is non-firm. 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 contract could be further defined 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.

5 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. Many support schemes impose unnecessary risk on developers, leading to more costly finance and higher 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) and 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 proportional (and roughly equal) to the technology-specific area output per MW capacity, with a life specified in MWh/MW capacity (e.g. 30,000 full operating hours). If the strike price in the CfD is set by the difference between the average wind/PV revenue per MWh and the spot price, this yardstick volume-limited CfD preserves the same efficient dispatch incentives of normal CfDs widely used by conventional generators, while assuring but limiting the total amount of subsidy, and still providing 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. The revenue assurance, which will need a government-backed counterparty, enables investment to be financed largely by cheap debt, dramatically lowering the subsidy cost.

References

Jan Abrell, J., S. Rausch, C. Streitberger, 2019. The economics of renewable energy support. *Journal of Public Economics* 176, 94–117 (probably not useful except for references)

Andor, M. and A. Voss, 2016. Optimal renewable-energy promotion: Capacity subsidies vs. generation subsidies. *Resource and Energy Economics* 45, 144–158

Arora, D., Busche, S., Cowlin, S., Engelmeier, T., Jaritz, H., Milbrandt, A., Wang, S., 2010. Indian Renewable Energy Status Report: Background Report for DIREC 2010. NREL/TP-6A20-48948

Barquín, J., P. Rodilla, R. Cossent, C. Batlle. 2017. Obtaining best value for money in res auctions: a capacity-based with an embedded menu of contracts approach. Working Paper IIT-17-177A https://repositorio.comillas.edu/jspui/handle/11531/23913

Borenstein, S., 2012. The Private and Public Economics of Renewable Electricity Generation. *Journal of Economic Perspectives*, 26 (1): 67-92. https://doi.org/10.1257/jep.26.1.67

Boute, A., 2012. Promoting renewable energy through capacity markets: an analysis of the Russian support scheme. *Energy Policy* 46, 68–77. https://doi.org/10.1016/j.enpol.2012.03.026 .

Bunn, D. and Yusupov, T. 2015. The Progressive Inefficiency of Replacing Renewable Obligation Certificates with Contracts-for-Differences in the UK Electricity Market. Energy Policy 82 (July): 298–309. https://doi.org/10.1016/j.enpol.2015.01.002 .

Brunekreeft, G., Neuhoff, K. and Newbery, D., 2005. Electricity transmission: an overview of the current debate, *Utilities Policy*, 13 (2), June, 73-94. http://www.sciencedirect.com/science/journal/09571787/13/2

CEER, 2018. *Status Review of Renewable Support Schemes in Europe for 2016 and 2017*, Ref: C18-SD-63-03

Congressional Research Service, 2013. *European Union Wind and Solar Electricity Policies: Overview and Considerations*, CRS 7-5700, R43176 at www.crs.gov

Cox, A., C. Blumstein and R. Gilbert, 1991. Wind Power in California: a Case Study of Targeted Tax Subsidies, ch 9 in Gilbert, R., (ed.) *Regulatory Choices: A Perspective on Developments in Energy Policy*, University Of California Press, Berkeley at https://publishing.cdlib.org/ucpressebooks/view?docId=ft838nb559&chunk.id=d0e27822&toc.id=d0e27822&brand=ucpress

del Río, P., 2017. Designing auctions for renewable electricity support. Best practices from around the world, *Energy for Sustainable Development*, 41, 1-13.

EC, 2013. *European Commission guidance for the design of renewables support schemes*, SWD(2013) 439 final

Eicke, A., T. Khanna and L. Hirth, 2020. Locational investment signals in electricity markets - How to steer the siting of new generation capacity? *The Energy Journal*, 41 (6), 281-304.

Eirgrid, 2020. *Annual Renewable Energy Constraint and Curtailment Report 2019*. At www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2019-V1.2.pdf

Elberg, C., Hagspiel, S., 2015. Spatial dependencies of wind power and interrelations with spot price dynamics. *Eur. J. Oper. Res*. 241, 260–272. https://doi.org/10.1016/j.ejor.2014.08.026 .

HoC, 2013. *Energy Act 2013*, 2013.c.32, at http://www.legislation.gov.uk/ukpga/2013/32/contents/enacted/data.htm

Finon, D., 2006. The social efficiency of instruments for the promotion of renewable energies in the liberalised power industry. *Annals of Public and Cooperative Economics*, 77(3): 309-43. https://doi.org/10.1111/j.1467-8292.2006.00308.x

Green, R. and Vasilakos, N. 2010. Market Behaviour with Large Amounts of Intermittent Generation. *Energy Policy* 38 (7): 3211–20. https://doi.org/10.1016/j.enpol.2009.07.038

Grubb, M. and D. Newbery, 2018. UK Electricity Market Reform and the Energy Transition: Emerging Lessons. *The Energy Journal* 39(6) 1-24. https://doi.org/10.5547/01956574.39.6.mgru

Grothe, O. and Müsgens, F., 2013. The influence of spatial effects on wind power revenues under direct marketing rules. *Energy Policy* 58, 237–247.

Hirth, L., 2018. What cause the drop in European electricity prices? A factor decomposition analysis. *The Energy Journal*, 19(1), 132-157 https://doi.org/10.1016/j.enpol.2013.03.004 .

Höckner, J., S. Voswinkel and C. Weber, 2020. Market distortions in flexibility markets caused by renewable subsidies – The case for side payments, *Energy Policy*, 137, 111135, 1-13, at https://doi.org/10.1016/j.enpol.2019.111135

Höfer, T. and R Madlener, 2021. Locational (In)Efficiency of Renewable Energy Feed-In Into the Electricity Grid: A Spatial Regression Analysis, *The Energy Journal* 42(1), 171-95. https://doi.org/10.5547/01956574.42.1.thof

Huntington, S., P. Rodilla, I. Herrero and C. Batlle, 2017. Revisiting support policies for RES-E adulthood: Towards market compatible schemes. *Energy Policy*, 104, 474-83. http://dx.doi.org/10.1016/j.enpol.2017.01.006

IEA, 2018. *20 Renewable Energy Policy Recommendations*, IEA, Paris at https://www.iea.org/reports/20-renewable-energy-policy-recommendations

Klobasa, M. J. Winkler, F. Sensfuss, and M. Ragwitz, 2013. Market Integration of Renewable Electricity Generation – the German Market Premium Model, *Energy & Environment*, 24(1/2), 127-146

MarEI, 2020. *Our Zero E-Mission Future*, at https://eaireland.com/our-zero-e-mission-future-report-published-today/

Meus, J., S. De Vits, N. S'heeren, E. Delarue, S. Proost, 2021. Renewable electricity support in perfect markets: Economic incentives under diverse subsidy instruments, *Energy Economics* 94 105066, 1-18, at https://doi.org/10.1016/j.eneco.2020.105066

Mitchell, C., 2000. The England and Wales Non-Fossil Fuel Obligation: History and Lessons, *Annu. Rev. Energy Environ*. 25: 285–312.

Neuhoff, K., May, N., Richstein, J.C., 2018. Renewable energy policy in the age of falling technology costs. DIW Discussion Papers, No. 1746. At https://www.diw.de/documents/publikationen/73/diw_01.c.594384.de/dp1746.pdf

Newbery, D., 2012. Reforming competitive electricity markets to meet environmental targets. *Econ. Energy Environ. Policy* 1 (1), 69–82.

Newbery, D.M. (2016a). "Towards a green energy economy? The EU Energy Union's transition to a low-carbon zero subsidy electricity system—lessons from the UK's Electricity Market Reform." *Applied Energy* 179: 1321–1330. https://doi.org/10.1016/j.apenergy.2016.01.046

Newbery, D.M. 2016b. Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors, *Energy Policy*, 94, 401–410. http://dx.doi.org/10.1016/j.enpol.2015.10.028

Newbery, D., 2018a. Polices for decarbonizing a liberalized power sector, *Economics: the Open-Access, Open-Assessment E-Journal*,12 (2018-40). http://dx.doi.org/10.5018/economics-ejournal.ja.2018-40

Newbery, D., 2018b. Evaluating the case for supporting renewable electricity, *Energy Policy*, 120, 684–696. https://doi.org/10.1016/j.enpol.2018.05.029

Newbery, D., 2020. Club goods and a tragedy of the commons: the Clean Energy Package and wind curtailment, EPRG WP 2036 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-2036

Newbery, D., M. Pollitt, D. Reiner and S. Taylor, 2019. Financing low-carbon generation in the UK: The hybrid RAB model, EPRG WP 1926 at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2019/07/1926-Text_REV.pdf

Newbery, D., M.G. Pollitt, R.A. Ritz, W. Strielkowski, 2018. Market design for a high-renewables European electricity system, *Renewable & Sustainable Energy Reviews*, 91, 695-707; https://doi.org/10.1016/j.rser.2018.04.025

Nock, D. and E. Baker, 2017. Unintended consequences of Northern Ireland's renewables obligation policy, *The Electricity Journal*, 30, 47-54.

NREL, 2018. *Offshore Wind Energy International Comparative Analysis*. Technical Report NREL/TP-6A20-71558 at https://doi.org/10.2172/1483473

Onifade, T. 2016. Hybrid renewable energy support policy in the power sector: The contracts for difference and capacity market case study. *Energy Policy* 95, 390-401

Özdemir, Ö., Hobbs, B., van Hout, M., Koutstaal, P., 2020. Capacity vs Energy Subsidies for Renewables: Benefits and Costs for the 2030 EU Power Market. *Energy Policy* 137 111166. https://doi.org/10.1016/j.enpol.2019.111166

Ragwitz, M. and S. Steinhilber, 2014. Effectiveness and efficiency of support schemes for electricity from renewable energy sources, *WIREs Energy Environ*, 3:213 – 229. https://doi.org/10.1002/wene.85

Roques, F.A., D. M. Newbery and W. J. Nuttall. 2008. Fuel mix diversification incentives in liberalized electricity markets: a Mean-Variance Portfolio Theory Approach. *Energy Economics* Vol 30/4, 1831-1849; https://doi.org/10.1016/j.eneco.2007.11.008

Shleifer, A., 1985. A Theory of Yardstick Competition. *The RAND Journal of Economics*, 16(3), 319-327. Retrieved March 1, 2021, from http://www.jstor.org/stable/2555560

Simshauser, P., 2021. Renewable Energy Zones in Australia's National Electricity Market, EPRG WP 2103 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-2103/ .

Steinhilber S., 2016. *Onshore wind concession auctions in China: instruments and lessons learnt*. AURES Report D4.1-CN, March.

Wolak, F., 2016. Level versus Variability Trade-offs in Wind and Solar Generation Investments: The Case of California, at https://web.stanford.edu/group/fwolak/cgi-bin/?q=node/3

Wyrobek, J., Ł. Popławski, and M. Dzikuć, 2021. Analysis of Financial Problems of Wind Farms in Poland, *Energies*, 14(5), 1239; https://doi.org/10.3390/en14051239

Appendix Testing the hedging properties of the volume-limited yardstick CfD

Table A1 demonstrates the claims of Propositions 1 and 2. The strike price *s* is £60/MWh, the system average is *S*, the reference region is *r*, and the wind farm is *w*. The price is *p* and the capacity factor at *w* is a slight disturbance from the region average. The wind farm has a contracted output in each hour of region *r*, and sells is actual output at the wholesale price, *p* so its revenue is made up of the CfD revenue *(s-p)*r*, its market sales value (shown in the column *w*p*) and periodically (here at the end of the year) the locational adjustment of £1,120, which is the difference over the whole contract period of the revenue at the reference region, £1,960 less the system average revenue, £840. The contract period is the same number of MWh, 42/MW, but the contract length in time is 15 years for the system average but only 11.7 years in region r with higher wind on average (and a very low correlation with the system average – compare cols *S* and *r*).

Table 1

			Output MWh/MW				revenue at market prices/MW				CfD/MW	total revenue/MW	
	p/MWh	*(s-p) /MWh*	*S*	*r*	*w*	*r-S*	*S*p*	*r*p*	*w*p*	*(r-S)*p*	*(s-p)*r*	*r*	*w*
	£70	-£10	0	0.8	0.75	0.8	£0.0	£56.0	£52.5	£56.0	-£8.0	£48.0	£44.5
	£60	£0	0.1	0.7	0.75	0.6	£6.0	£42.0	£45.0	£36.0	£0.0	£42.0	£45.0
	£50	£10	0.2	0.6	0.55	0.4	£10.0	£30.0	£27.5	£20.0	£6.0	£36.0	£33.5
	£40	£20	0.3	0.5	0.55	0.2	£12.0	£20.0	£22.0	£8.0	£10.0	£30.0	£32.0
	£30	£30	0.4	0.4	0.35	0	£12.0	£12.0	£10.5	£0.0	£12.0	£24.0	£22.5
	£20	£40	0.5	0.3	0.35	-0.2	£10.0	£6.0	£7.0	-£4.0	£12.0	£18.0	£19.0
	£10	£50	0.6	0.2	0.15	-0.4	£6.0	£2.0	£1.5	-£4.0	£10.0	£12.0	£11.5
	£0	£60	0.7	0.1	0.15	-0.6	£0.0	£0.0	£0.0	£0.0	£6.0	£6.0	£6.0
average	£35	£25	0.35	0.45	0.45	0.1	£7.0	£21.0	£20.8	£14.0	£6.0	£27.0	£26.8
per MWh							£20.0	£46.7	£46.1	£140.0		£60.0	£59.4
Total			2.8	3.6	3.6	0.8	£56.0	£168.0	£166.0	£112.0	£48.0	£216.0	£214.0
total MWh per contract			42	42	42								
length of contract			15.0	11.7	11.7		15.0	11.7	11.7				
revenue over contract							£840	£1,960	£1,937			£2,520	£2,497
plus locational differential												**£3,640**	**£3,617**
locational differential								£1,120	£1,097			£1,120	£1,120

Note: *s* = £60/MWh

Note that the wind farm earns slightly less than the representative regional farm, but the locational differential is (by design) the same as at the regional level.