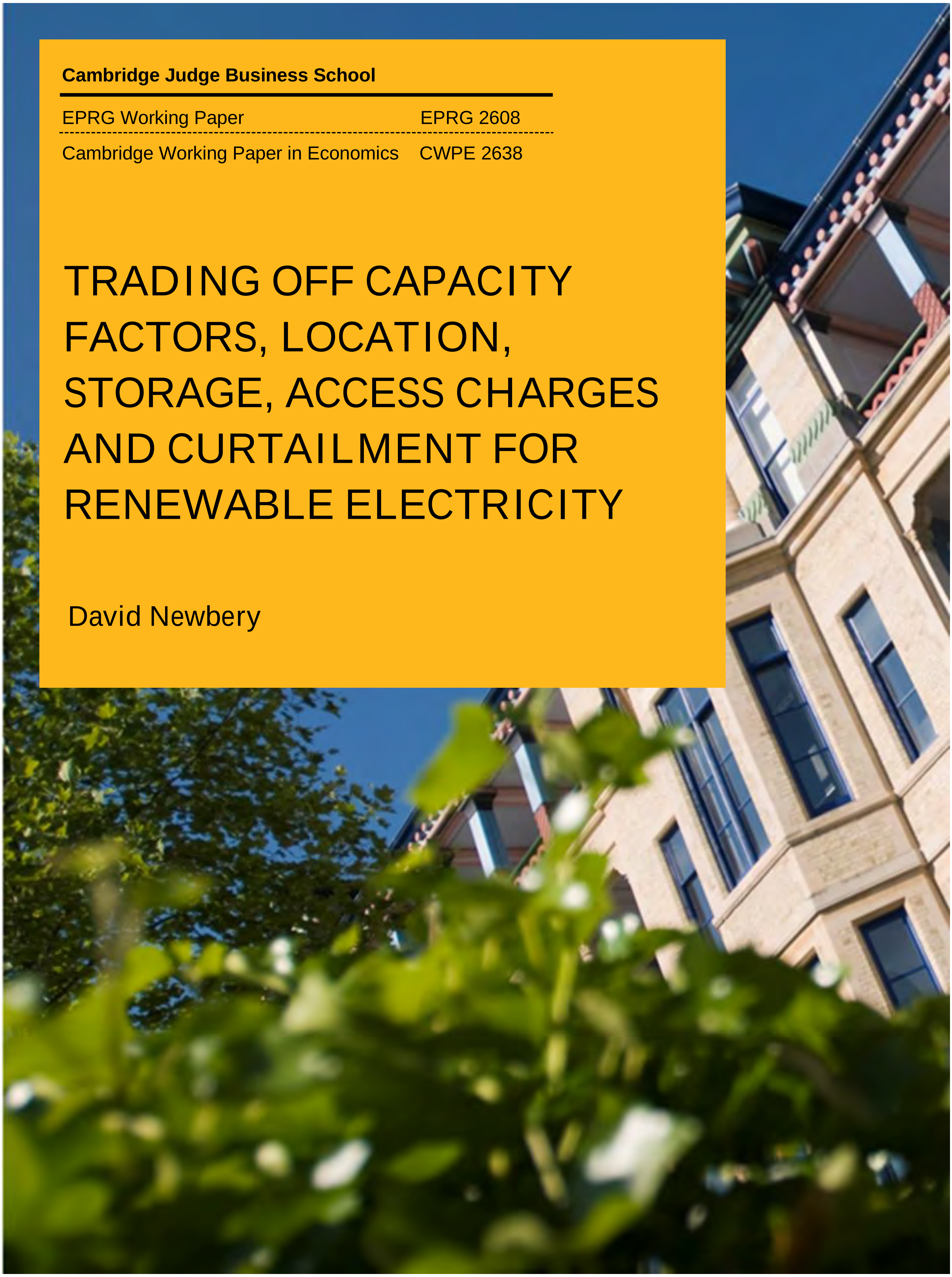

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TRADING OFF CAPACITY FACTORS, LOCATION, STORAGE, ACCESS CHARGES AND CURTAILMENT FOR RENEWABLE ELECTRICITY

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Abstract : Variable renewable electricity (VRE) is typically located far from load centres. As marginal curtailment is 3+ times average curtailment, unless transmission is expanded commensurately, VRE curtailment will rise rapidly. This article develops a novel closed-form solution to give formulae for the efficient balance of transmission expansion, renewables capacity and voluntary curtailment in a simplified model where VRE is distant from load. Given equilibrium in demand centres, the solutions are independent of market prices, depending only on cost and technology parameters. If local grid-connected storage covers most of its cost, co-located storage increases its profit for onshore wind and lowers optimal export capacity. The model is calibrated for on-shore British wind. Overhead lines, if built sufficiently rapidly, have little effect on desirable levels of curtailment/congestion for Scottish wind, but for Britain's proposed undersea links high costs increase efficient curtailment to the point where further Scottish wind expansion becomes unprofitable.

Keywords : Transmission constraints, access regimes, variable renewable electricity, storage, curtailment, zonal pricing

JEL Classification : H23; L94; Q28; Q42; Q48

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Trading off capacity factors, location, storage, access charges and curtailment for renewable electricity

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May 11, 2026

Abstract

Variable renewable electricity (VRE) is typically located far from load centres. As marginal curtailment is 3+ times average curtailment, unless transmission is expanded commensurately, VRE curtailment will rise rapidly. This article develops a novel closed-form solution to give formulae for the efficient balance of transmission expansion, renewables capacity and voluntary curtailment in a simplified model where VRE is distant from load. Given equilibrium in demand centres, the solutions are independent of market prices, depending only on cost and technology parameters. The model is calibrated for on-shore British wind. Overhead lines, if built sufficiently rapidly, have little effect on desirable levels of curtailment/congestion for Scottish wind, but for Britain's proposed undersea links high costs increase efficient curtailment to the point where further Scottish wind expansion becomes unprofitable.

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1 Introduction

As Variable Renewable Electricity (VRE, on- and off-shore wind, solar PV)[1] increases its penetration, it typically encounters two distinct obstacles. The first and most immediate is that as VRE is typically located in very different places to existing generators, the transmission systems will be unable to absorb more than modest levels of VRE before hitting transmission constraints. These may be relaxed by building more transmission but only at considerable extra cost. With the standard firm grid access agreements (under which any plant constrained off the system is compensated), constraint costs may rise rapidly until transmission is expanded. In Britain "Thermal constraint costs have increased by 64% in 2024/25, totalling £1.7bn.[2] This follows a large increase in thermal constraint volumes, rising 81% year-on-year to 13.5TWh. ... We expect this trend to continue over the 2020s as new generation connections in constrained regions outpace network build, ..." (NESO, 2025a). Constraint costs are thus a spatial problem.

The second obstacle arises at high VRE penetration as a result of high peak: average VRE output ratios – 3-4:1 for wind, 4-10:1 for PV. High average VRE outputs imply very high peak outputs. VRE lacks the inertia of the spinning turbines of conventional plant. Inertia is needed to keep frequency within narrow limits for system stability, and as inertia falls, the rate of change of frequency to fluctuations in demand or supply rises to threaten system stability or system collapse. This imposes a limit set by the maximum acceptable share of System Non-Synchronous Penetration (SNSP, i.e. the fraction of demand met by VRE). In 2020, the Single Electricity Market of the island of Ireland (SEM) had to dispatch down 12.1% of wind output, 6.2% because of transmission constraints and 5.9% curtailed because of system-wide constraints (Eirgrid/Soni, 2023). SEM (2024) defines and differentiates between constraints and curtailment. This paper contrasts voluntary curtailment chosen by the VRE owner with System Operator mandated actions in the balancing or real-time market designed to manage transmission constraints or to maintain system stability. It is therefore focused on the spatial rather than the system problem. This terminology is further clarified below.

VRE enjoys higher potential capacity factors in areas often far from load centres and with little local demand. Most countries initially ignored this spatial disparity, as at low VRE penetration the existing networks may have had adequate capacity to absorb the VRE regardless of location. Perhaps as a result, and perhaps driven by the desire to increase VRE capacity to meet

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[1] Abbreviations: BESS: Battery Electrical Storage System; CfD: Contract-for-Difference; G-TNUoS: Generator's Transmission Network Use of System (charge); f.o.c.: first order condition; HVDC: high voltage direct currentt; OHL: overhead line; PCF: potential capacity factor; TEC: Transmission Entry Capacity; REZ: Renewable Energy Zone; VRE: variable renewable electricity.

[2] and up from £0.7 bn in 2019/20 before the price spike of the energy crisis (author's additon).

targets, such as the various EU and UK renewables targets for 2020[3],[4] and 2030,[5] most countries paid little attention to where new VRE investment might or should locate. Britain's *Clean Power 2030 Action Plan*'s "expectations for the 2030 capacities of key technologies at national and regional level ... means 43-50 GW of offshore wind, 27-29 GW of onshore wind, and 45-47 GW of solar power, . . . " (HMG, 2024, p10). While accepting that this would require massive transmission expansion, there was little initial discussion on how best to achieve a low-carbon electricity system at least cost by integrating transmission planning and VRE location. The newly created public National Energy System Operator (NESO) was charged in 2025 to draw up spatial infrastructure plans and develop instruments to deliver a least cost (generation and transmission) expansion plan. The relevant Government department launched a consultation on how best to achieve this in Spring 2026.[6]

This article addresses just such problems and proposes solutions. It considers the problem facing the NESO charged with developing Strategic Spatial Energy Plans[7] to guide the location of new VRE, planning the cost-effective transmission system to deliver power from these new developments, and setting Generation-Transmission Network Use of System (G-TNUoS) charges to guide VRE developers to choose appropriate locations and Transmission Entry Capacity (TEC) to minimize total system cost. If G-TNUoS charges are set correctly, the decentralized solution will be the same as the planned solution, so the model assumes a single optimizer making all choices. It examines the trade-off between locating VRE in high resource areas and the cost of the extra transmission required to deliver that power to load centres. It demonstrates that provided VRE developers are confronted with an efficient *marginal* G-TNUoS contract (£/kW per year for e.g. 20 years) then developers will choose an efficient level of TEC and a corresponding level of curtailment.

This has the strong implication that the GB method for setting G-TNUoS in different locations needs radical reform – easily introduced without legislation as TNUoS charges are reset each year under a mandate to provide efficient guidance to new investors. The second major finding is that the recent and dramatic fall in the cost of grid-scale Li-On battery electric storage systems (BESS) makes co-locating BESS behind the grid connection point potentially desirable in giving access to otherwise zero-value surplus electricity. Provided local grid-connected BESS

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[3] 20 20 by 2020: Europe's climate change opportunity, COM(2008)30 final at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52008DC0030

[4] https://publications.parliament.uk/pa/ld200708/ldselect/ldeucom/175/175.pdf

[5] https://commission.europa.eu/energy-climate-change-environment/overall-targets-and-reporting/2030-targets_en

[6] https://www.gov.uk/government/publications/reformed-national-pricing-rnp-delivery-plan/reformed-national-pricing-rnp-delivery-plan-accessible-webpage#chapter-2-siting-and-investment-levers

[7] https://www.neso.energy/what-we-do/strategic-planning/strategic-spatial-energy-planning-ssep

is also profitable there is an additional benefit in allowing a lower TEC and a delayed injection of the now larger surplus.

Its novel contribution lies in the way the economics of distant VRE and co-located BESS are modelled. Rather than a conventional unit commitment and dispatch model of the whole electricity system with all its transmission constraints (as in Chyong and Newbery, 2025) it examines deviations from an electricity market in equilibrium with a single VRE, on-shore wind. It models the system as two zones: the Southern zone is in equilibrium with windfarms just covering costs. That condition allows the Southern price when wind is generating to be defined by its annualized cost. Given transmission costs from the Northern zone (the zone of interest), correlations of Northern and Southern wind and transmission loss factors, that gives the Northern competitive wind price into the transmission system. Similarly, on the assumption that auctions for BESS capacity support grid-connected entry in the North, the economics of co-located BESS can be simply compared with local grid-connected BESS. These simplifications allow the construction and algebraic solution of a very simple model that allows the trade-off between wind capacity and chosen TEC capacity to be explored for varying marginal transmission expansion costs. It also allows a simple test of whether co-locating BESS is a substitute for TEC.

The urgency of these reforms can be illustrated from recent Scottish experience of wind curtailment. The ten most curtailed British wind farms, all in Scotland, accounting for 9.5% of total potential output, were all curtailed more than 40% of the time.[8] Scotland is rich in wind resource, has a small demand compared to England, and has severely constrained connections to England at the Scottish border. The UK Government has approved a number of subsea HVDC links to bring Scottish power south of the border, but these are considerably more costly than onshore overhead lines. At present the G-TNUoS charge are intended to approximate the Long-Run Marginal Cost (LRMC) of expanding by overhead lines (OHL). For delivering power from central Scotland to the load centres in the Midlands by OHL is $£31,242$ MW^{-1}yr^{-1}as explained in more detail below. The most expensive and hence marginal off-shore Scotland-England Greenlink (SEG2) would cost $£131,700$ MW^{-1}yr^{-1} or four times as much to deliver to load centres.

1.1 Terminology: constraints and curtailment

When the System Operator orders generators to reduce output to maintain feasible dispatch this is described as constraining-off. If in contrast generators choose to contract for Transmission Entry Capacity, TEC, below maximum potential output, and as a result have to scale back any excess, this is (voluntary) curtailment – the subject of this paper. The reason for limiting TEC

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[8] See https://windtable.co.uk/

is that at least in Great Britain, TEC is paid on maximum injection, and it may be commercially attractive to buy a lower TEC and waste some output. This seems to be the case for some offshore wind farms that have to pay the Offshore Transmission Operator for the contracted link to shore. It is also an attractive option for connecting to the lower voltage distribution network, which has deep connection charges, i.e. the cost of reinforcing the network to accept the chosen TEC. The Distribution Network Owner may offer a firm connection (guaranteed access) at a high deep connection charge, or a non-firm connection at a much lower charge, with a guarantee of no more than some share of uncompensated curtailment (e.g. 5%). Where the developer accepts TEC of less than maximum potential output, the resulting surplus will be described as curtailment (as it is voluntary, not mandated constraint management or congestion).

The rest of the paper first briefly reviews the relevant literature, then sets out a simple algebraic model to investigate the trade-off between TEC and (voluntary) curtailment. This is followed by calibrating the models for Britain, showing the critical role of efficient transmission charges, and the value of co-locating BESS. The final section pulls together the conclusions and policy implications.

2 Literature review

It is frequently the case that VRE has higher potential capacity factors (PCFs) in areas often poorly served by the transmission system that was designed to serve load centres from fossil and nuclear generation. Yasuda et al. (2022, figs. 3-7), updating Bird et al. (2016), demonstrate in a series of graphs that without transmission expansion, curtailment rises rapidly in Europe, the US and China. While some regions (Texas, China, and initially at least, Italy) have reduced constraint costs by expanding transmission, most countries/regions have experienced rising constraints and curtailment. Newbery (2021, 2023a) showed that marginal curtailment rates were typically 3+ times average curtailment rates as typically reported. This has considerable implications for the long-run marginal cost of investing in VRE in constrained regions (Newbery, 2025).

Fell et al. (2021) note that US utilities have been investing heavily in transmission to deliver VRE in sparsely populated areas with good VRE resources to load centres. Rana et al. (2025) develop a guide for efficiently locating VRE by representing transmission constraints through nodal prices, illustrated for Texas, demonstrating considerable potential cost savings. However, as noted below, nodal pricing is likely to be an imperfect measure of the trade-off between transmission investment and VRE location.

More directly in line with this article, Eicke et al. (2020) argue that considerable system cost savings can be achieved by providing better locational guidance to VRE to balance higher potential output against higher transmission costs. They provide a comparative review of locational investment signals from deep connection charges (CAISO, France, Mexico, PJM, Sweden, and Norway), to nodal prices, locational grid charges such as those applied in GB, and a number of others. They note that most suffer from various drawbacks, particularly their future unpredictability that raises entry costs. They note that nodal pricing, while theoretically efficient (with perfect foresight, no lumpiness or market power) in practice is unable to recover more than 20-30% of transmission costs (Pérez Arriaga et al. 1995) making nodal markets a poor guide to efficient location (quite apart from their future unpredictability). Similarly, Grimm et al. (2016) demonstrate the importance of locational signals in a stylized model of an energy-only liberalized market with conventional generation and show that zonal pricing (market splitting) only partly reduces the inefficiency of location decisions.

Deep connection charges might seem better designed as they are predictable, and should reflect the cost of the incremental capacity required. However, if there is lumpiness then a fair charge should make allowance for future entry. This is often difficult and can act as a barrier to VRE entry. Britain has deep connection charges for connecting to the distribution networks, with the important option of paying less but accepting some level of uncompensated curtailment. The transmission network has shallow but quite highly spatially differentiated charges and only offers firm connection (up to the chosen entry capacity, with self-curtailment above that level).

Merchant Renewable Energy Zones (REZs), in which VRE developers pay for the extra transmission link, can solve some of these problems and have been remarkably successful in Australia (McDonald, 2023; Simshauser, 2021, 2022; Simshauser and Newbery, 2023). As to efficient management of curtailment, Newbery and Biggar (2024) show that in a merchant REZ it is efficient to not reward VRE when curtailed and to share access to the export capacity pro-rata (so that all face average curtailment). If transmission cannot be expanded for a significant period then entrants should face marginal curtailment until export capacity is expanded, e.g. by curtailing in the order last-in first curtailed. This has been proposed for the island of Ireland by Eirgrid (2022), which offers a non-firm connection until the link is reinforced or after five years, whichever is sooner.

Qi et al. (2015) note that co-locating storage with a REZ allows a trade-off between storage and transmission capacity. However, its marginal value decreases rapidly as it is primarily useful in managing short-term fluctuations in output and thus allowing VRE higher peak output for a given export capacity. Simshauser (2025) computes efficient co-located storage in REZs. Wu et al. (2023) similarly develops a stochastic model to find the level of storage that minimizes system costs. The rapid deployment of co-located Li-On batteries with grid-scale isolated PV farms attest to their importance, and on-shore isolated wind farms in Scotland are contemplating similar co-located batteries. It is therefore important to explore their potential for reducing TEC and economising on transmission investment.

Savelli et al. (2022) point out that locational transmission charges with firm access do not address congestion issues and argue for modifying CfDs to address such system costs. Joos and Staffell (2018) make similar points. These should be addressed with efficient signals for curtailment that do not over-reward locating in congested zones, and this can be achieved by efficient forward-looking long-term G-TNUoS contracts as described below.

2.1 Location signals and transmission charges

Britain, unlike most EU Member States, has a number of potentially effective signals to guide location. The annual Transmission Network Use of System charges for Generators (G-TNUoS) are locationally differentiated and intended to reflect the long-run marginal cost (LRMC) of connecting the generator to load. Thus a windfarm connected in Argyll in Scotland (a windy location) would pay £24.30/kWyr. while one connected in the Midlands and East Anglia would be paid £0.10/kWyr. if delivering in winter peak hours (otherwise zero). At the assumed 38% load or capacity factor (CF) the difference between the two translates to £7.26/MWh, a substantial incentive to locate wind farms in low charge zones instead of zones distant from demand. To put this figure into context, the Feb. 2026 Auction Round 7a cleared at £72.24/MWh for onshore wind.[9] A wind farm in Argyll would earn a gross income of £64.98/MWh, compared to the full £72.24/MWh in East Anglia fCF windfarm there. The Argyll windfarm would need to have a 37.8% capacity factor to earn the same gross income as a 34% CF East Anglian wind farm (in 2030) and so would be competitive at these G-TNUoS charges. The impacts of charging the forward-looking *marginal* transmission cost is explored below.

The main problems with these G-TNUoS tariffs is first, that the calculation assumes that the network can be annually resized using the existing way-leves to carry any extra current from the connection point to load, second, they can be and are changed annually, and third, that in order to retain some predictability, charges are only changed incrementally. At any moment the charges are likely to imperfectly reflect the actual forward looking LRMC, fail to address problems of lumpiness in expanding capacity, fail to reflect the long wait to deliver upgrades (median time 14 years) and are hard to predict for the future life of any new entrant.

Some of these problems can be addressed with minimal disturbance to the existing codes and regulations. Specifically, the main problem with changing the tariffs is that it is a zero-sum game for incumbents, and the logical solution is to leave all existing G-TNUoS charges

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[9] https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf

unchanged (indexed to the price level), but to offer new entrants forward-looking long-term (e.g. 20-year) contracts that give efficient locational signals. Any shortfall in the regulated revenue can be collected from the load tariffs, which are reset every year. Cost-reflectivity is a primary requirement of regulation so all that is needed in addition to the existing annual publication is to publish charges for new connections.

The potential implications of confronting new connections in Scotland with efficient G-TNUoS charges should not be underestimated. At present new Scottish windfarms are typically curtailed up to 50% of their potential output, but are granted firm access to an already heavily congested network. The proposed (but still inadequate) solution is to build offshore DC links to south of the main (B-6) constraint between Scotland and England. The cost of these links with their onward OHL links to load centres is shown in Table 1 below, and compared to existing charges, range from $4.2 - 7.8$ times as costly as current charges based on overhead lines, and these are the relevant marginal costs to confront developers. The implications for basing future G-TNUoS charges on forward looking marginal expansion costs are considered below, and suggest the importance of using way-leaves for the existing overhead lines to allow additional parallel overhead lines to expand capacity.

The question of the access rights is solved by the VRE determining the amount of firm capacity the developer is willing to pay for (see the more extensive discussion see Newbery and Biggar, 2024). In the model below new entrants will be required to pay for their desired firm Transmission Entry Capacity (TEC, their export capability) under a long-term contract at the marginal cost of providing that capacity. Any excess production above TEC will be (voluntarily) curtailed without compensation, and any contracts secured in auctions will be limited to their TEC volume. A further desirable requirement would be to only grant firm access at the requested TEC once the connections are able to absorb the incremental output, and until then the connections would be non-firm, i.e. with no compensation for curtailment. That would send a powerful location signal to connect only where and when there is adequate grid capacity.

3 The model

This section describes a simplified model of congestion problems created by more distant locations (from demand centres) enjoying higher on-shore wind capacity factors,[10] but requiring more costly transmission links to deliver that power. This is the case in Great Britain where Scotland has high wind and Cornwall has both good wind and high solar PV, but both are far from load centres in the Midlands and South East. The simplest model has two nodes - one (North,

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[10] Wind is the preferred VRE in Scotland, but in other countries the VRE could be PV or a combination of wind and PV, as in Queensland, Australia (Simshauser and Newbery, 2024).

subscript n) a distant isolated large wind farm connected to the transmssion system (assumed expandable at some cost), the other, in the South (subscript s) – near load centres and with a lower wind resource. The potential output of a wind farm with capacity V in hour y in the North is $\phi_n(y)V$, served by a dedicated transmission link with Transmission Entry Capacity (TEC) K and length d.[11] The annualized unit cost of wind capacity (including any fixed O&M costs) is r £MW^{-1}yr.$^{-1}$, avoidable costs are assumed zero, and the annualized cost of the line is c £MW^{-1}km^{-1}yr^{-1} (constant returns to scale). The total cost of locating and delivering power is $rV + cdK$ £/yr. The efficient size of the line (and TEC) will be such that for some of the time the potential exportable surplus $\phi_n V$ will exceed the TEC, K, and will be curtailed. It is convenient to order hours of wind production such that the capacity factor $\phi(y)$ is decreasing in y as in figure 1. The curtailment function $k(V, K, y)$ will be similarly ranked so that is decreasing in y up to y^* (the point at which the TEC constraint no longer binds and all potential wind output can be accepted) so that

$$k(V, K, y) = Max\{\phi_n(y)V - K, 0\}, \quad k(V, K, y^*) = 0. \tag{1}$$

Total curtailment is $\int_0^{y^*} k(V, K, y)dy$, so delivered output is $Y = V\int_0^1 \phi_n(y)dy - \int_0^{y^*} k(V, K, y)dy$. The social value of investments in and to the REZ is

$$W = p\left(V\int_0^1 \phi_n(y)dy - \int_0^{y^*} k(V, K, y)dy\right) - rV - cdK, \tag{2}$$

where p is the wind output-weighted sales price in the North.

Outside the REZ all market failures are assumed away or internalized, so that the expected market price for wind in the North, p, is efficient and correctly measures social value. Wind in the South is unconstrained by transmission. In equilibrium during the hours that Southern wind generates, wind capacity expands to drive excess profits to zero. The factor ρ allows for a possible mismatch between the price at which Southern wind breaks even, any difference in the correlation of wind in the North and the South, and marginal transmission losses from the North, which reduce the value of Northern injections.[12]

$$\begin{aligned} \rho p \int_0^1 \phi_s(y)dy &\equiv \rho p \theta_s = r, \text{ so} \\ p &= r/\rho\theta_s, \end{aligned} \tag{3}$$

where for convenience $\int_0^1 \phi_j(y)dy \equiv \theta_j$, $j = n, s$, the potential capacity factor ($\phi_s = 34\%$ in the South in 2030). This sets the relevant (output-weighted) price p in the North. As y is measured

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[11] A list of variables and parameters is given in Appendix C.

[12] Marginal transmission losses from Zone 1 (Scotland) to load centres in the Midlands reduce the effective price in the North by a factor 0.922, or, as modelled here, amplify the relative Southern price by a factor $\rho = 1.085$ (e.g. Oxera, 2003, Table 2).

in fractions of the year, output will be measured in MWyears of 8,760 MWhr, and while p is equal to 8,760 times the average price/MWh, equation (3) is in suitable units.

For the piece-wise linear approximation to the VRE duration schedule in Figure 2

$$\phi(y) = Max((1-ay),(1-y)/a), \quad a > 1. \tag{4}$$

Equation (1) becomes, from Appendix A,

$$k(V,K,y) = V - K - aVy, \ y \leq y^* = \frac{V-K}{aV}. \tag{5}$$

Curtailment, C, and total output, Y, are

$$\begin{aligned} C &= \int_0^{y^*} k(V,K,y)dy \\ &= \{(V-K)y^* - \frac{1}{2}aVy^{*2}\}, \\ &= V(\frac{(1-K/V)^2}{2a}). && (6) \\ Y &= V\theta_n - C = V(\theta_n - \frac{(1-K/V)^2}{2a}. && (7) \end{aligned}$$

Total welfare from investing in transmission and wind in the North is, after substituting for the price, $p = r/\rho\theta_s$, and output from (7)

$$W = \frac{rV}{\rho\theta_s}(\theta_n - \frac{(1-K/V)^2}{2a}) - rV - cdK. \tag{8}$$

Consider the problem facing the National Energy System Operator, NESO, charged with developing Strategic Spatial Energy Plans to guide the location of new wind farms, planning the cost-effective transmission system to deliver power from these new developments, and setting Generation-Transmission Network Use of System (G-TNUoS) charges to guide wind farm developers to choose appropriate locations and TEC to minimize total system cost. If G-TNUoS charges are set correctly, the decentralized solution will be the same as the planned solution. When considering expanding wind capacity, V, in the North it is necessary to check whether it would be worth expanding transmission to export the additional power. The first order condition, f.o.c., for choosing K is

$$\begin{aligned} \frac{\partial W}{\partial K} &= 0 = \frac{r}{\rho\theta_s}(\frac{1-x}{a}) - cd, \\ K/V &\equiv x = 1 - ac\rho d\theta_s/r = 1 - ab\theta_s, && (9) \end{aligned}$$

where $b \equiv cd\rho/r$ is the key cost ratio and $x \equiv K/V$. This demonstrates that higher transmission costs, cd, reduce TEC, while higher wind costs, r, increase TEC, K, as wind is more costly to waste. For a positive value of K and hence a viable wind investment, $cd < r/(a\rho\theta_s)$, which limits the transmission cost that can be incurred to deliver wind to demand centres. For profitable investment given the transmission cost, $W \geq 0$, which from (8) and (9) requires

$$\frac{\theta_n}{\theta_s} \geq (b+\rho) - \frac{ab^2\theta_s}{2}, \tag{10}$$

which is a stringent condition on the relationship of b and θ_n/θ_s. Alternatively, the right hand side of (10) can be interpreted as the breakeven capacity factor for a Northern windfarm. If investment is viable, it will be curtailed a fraction $y^* = b\theta_s$ of the year (from (9) and (5)), while the average capacity factor, ACF, after curtailment will be from (6)

$$\begin{aligned} Y/V &= \theta_n - \frac{(1-x)^2}{2a}, && (11) \\ \text{ACF} &= Y/V = \theta_n - ab^2\theta_s^2/2. && (12) \end{aligned}$$

3.1 Qualifications for convex duration curves

Figure 1 suggests that the wind duration curve is convex, also illustrated by the falling values for the slope a. If so, then the volume of curtailed wind for any level of TEC will be underestimated by the linear approximation. This might suggest that the opportunity cost of reducing TEC will be understated but the f.o.c. (9) trades off at the margin, at which the slope a will be almost constant, not varying with K. The implication is that TEC may be correctly calculated but the ACF may be higher than that given in (12). The discrepancy will increase as the cost of TEC increases.

3.2 Calibration

The annualized cost of on-shore wind farms projecting forward to 2030 is taken from BEIS (2023) data, uprated to 2023 prices, $r = £152,240$ MW^{-1}yr^{-1}(see Table 1). Estimating the cost per MWkm of transmission lines in a meshed AC network is not straightforward. G-TNUoS charge differences between zones are in principle the long-run marginal cost (LRMC) of expanding that line to allow an addition MW injection in the entry zone to be delivered to load in the exit zone. New lines have considerable economies of scale and connecting any two nodes will impact flows on many other lines. In addition, different types of generation impose different load patterns on the network, and as a result charges for intermittent generation like wind with a lower capacity factor (CF) than conventional baseload generation normally pays a lower share of the total cost. Thus a Scottish windfarm with a 45% CF pays on average 64% of the full (100% CF) charge (but with considerable variations across the region), while a baseload generator with a 90% CF pays 95% of the full charge. With these caveats in mind, G-TNUoS charge differences over long distances (above 500 km) from Scotland to the Midlands range from £$42-48$ MW^{-1}km^{-1}yr.$^{-1}$ and so moderately constant. Before accepting the published G-TNUoS charges it is important to check that they are reasonably consistent with the recent evidence published by Mott MacDonald (2024) and other estimates from recent lines.

The proposed short (58km, 4 GW) Cross Border Connection is projected to cost £54 MW^{-1}km^{-1}yr^{-1}(National Grid, 2025). Mott MacDonald (2024) gives figures for a comparable line (4 GW, 38km) of £50.8 MW^{-1}km^{-1}yr^{-1} and for a relatively short (5 GW, 113km) line at £32.32 MW^{-1}km^{-1}yr.$^{-1}$ and only £21.56 MW^{-1}km^{-1}yr.$^{-1}$ for one of 7.5 GW. For lower capacity costs are higher, and for longer lines, lower. To summarize, the G-TNUoS charges seem a reasonable estimate of the average annual costs of existing overhead lines (OHL).

The G-TNUoS charge for a 38% CF windfarm in Argyll is 75% of the full charge, which from Table 1 is 75% of £$32,200$ MW^{-1}yr.$^{-1}$ = £$24,150$ MW^{-1}yr.$^{-1}$ = £7.27/MWh. To put this figure into context, the Feb. 2026 Auction Round 7a cleared at £72.24/MWh for onshore wind.[13] This windfarm in Argyll would have the same gross income (after G-TNUoS charge) as a 34% CF windfarm in East Anglia (for which the charge is almost zero) if it had a CF of 37.8% (before considering voluntary curtailment, considered below).

However, congestion and curtailment is now so serious in Scotland that a number of subsea HVDC links are either commissioned (the Western Bootstrap, WB, commissioned 2017) or under construction (the two 2 GW Scotland-England Green Links (SEGL 1,2). Their annuitized cost for delivering power over the links can be calculated from their capital cost, adding an annual O&M taken as 20% of that value (from Mott MacDonald, 2024). The cost of WB to zone 10 is £$41,750$ MW^{-1}yr.$^{-1}$ to which is added G-TNUoS from zone 10 to zone 18 of £$21,960$ MW^{-1}yr.$^{-1}$(see Table 1). Similarly, the cost of SEGL1 from Torness in Southeast Scotland to Co. Durham is estimated at £$75,750$ MW^{-1}yr.$^{-1}$+ G-TNUoS of £$7,750$ MW^{-1}yr.$^{-1}$. The cost of SEGL2 from Peterhead in Scotland to the Drax Power Station in Yorkshire, and then South is projected to cost £$130,290$ + £$1,080$ MW^{-1}yr.$^{-1}$. Finally, the Scottish islands of Orkney and Shetland have been highly attractive to wind farms because of their high potential capacity factors (PCFs) – 43% and 50% respectively. The resulting total costs of moving power at 100% CF from Scotland to the load centre (taken as zone 18, Midlands and East Anglia) is shown in Table 1.

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[13] https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf

Table 1 Data and abbreviations

Item	symbol	cost per year
Wind	r	£$152,240$ MW^{-1}yr^{-1}
G-TNUoS zone 10 to 18	cd	£$21,960$ MW^{-1}yr^{-1}
G-TNUoS to zone 18	cd	£$32,200$ MW^{-1}yr^{-1}
WB to zone 18	cd	£$63,710$ MW^{-1}yr^{-1}
SEGL1 to zone 18	cd	£$83,500$ MW^{-1}yr^{-1}
SEGL2 to zone 18	cd	£$131,370$ MW^{-1}yr^{-1}
Orkney-Scotland	*	£$21,000$ MW^{-1}yr^{-1}
Shetland-Scotland	*	£$92,000$ MW^{-1}yr^{-1}

Note: * Delivery to Scotland, to which add the cost from Scotland to zone 18

Figure 1 shows the output duration curve for two windfarms in Scotland, Kelburn and Crosbie, both in Argyll west of Glasgow and both with CF of 40.3%. At this CF windfarms would be charged 70% of G-TNUoS and this is the factor used to adjust the cost figures in Table 1. Figure 1 shows they have very similar duration curves, with values for $a = 1/68\% = 1.47$, and for the upper extreme, $a' = 1/47\% = 2.13$. The cost of an onshore (OHL) expansion to deliver wind from Scotland is 70% of £$32,200$ MW^{-1}yr^{-1} so $cd =$ £$22,540$. With a North/South price scaling factor $\rho = 1.085$ the value of $b \equiv cd\rho/r = 0.16$. Consider the case of an Argyll windfarm with $\theta_n = 40\%$ and a reference Southern windfarm with $\theta_s = 30\%$, so that $\theta_n/\theta_s = 1.333$. The value of $b + \rho = 1.245$ and, with the more challenging lower value of $a = 1.47$, $ab^2\theta_s/2 = 0.006$, so the windfarm would satisfy (10) and be profitable. If $\theta_s = 30\%$, $b\theta_s = 4.8\% = y^*$, the fraction of the year voluntarily constrained. The peak value of voluntary curtailment is $a'b\theta_s = 10.2\%$ and the lower value is $ab\theta_s = 7.1\%$. Figure 1 shows that the relevant slope consistent with the estimated curtailment is $a' = 2.13$ so TEC is 89.8% of capacity. The ACF from (6) is $Y/V = \theta_n - \frac{1}{2}a(b\theta_s)^2 = 40.3\% - 1.065 * (4.8\%)^2 = 40.298\%$, a negligible decrease in delivered CF. The reason for the small loss is readily seen from Figure 1, as only the tip of the duration curve is removed, a small fraction of the entire area. The slight fall in effective CF implies that the Argyll windfarm is now competitive with a windfarm in East Anglia with a CF of 36.7%, comfortably above its assumed CF of 34%, and so competitive.

If the only way of serving new windfarms is by offshore links, the value of b varies from 0.32, 0.42, to 0.66 (for WB, SEGL1 and SEGL 2), so curtailed a fraction of the year $y^* = b\theta_s = 10.8\%$ (WB) to 22.3% (SEGL2). The profitability condition is now tougher. With the WB and $a = 1.47$, $b + \rho = 1.405$ and $ab^2\theta_s/2 = 0.023$, so $\theta_n/\theta_s > 1.38$ or $\theta_n > 41.5\%$ to be viable. With a value of a' the original windfarm is viable, but the higher value a' applies to high ratios of K/V. Even at the lower level of a, TEC varies from $K/V = 1 - ab\theta_s = 77\%$ to 67.2% of capacity, so the profitability condition is likely more stringent, and more so with the more expensive Green

Links. If we ignore the profit constraint, the ACF ranges from 39.1% to 33.1% (SEGL2), still a reasonable effective CF. Again the impact is modest as the area removed is small, even if the fraction of the year curtailed can be as high as 22.3% (using SEGL2). The non-linearity of the duration curve in Figure 1 becomes significant at higher levels of curtailment, as the area defined by the linear approximation becomes increasingly less than the actual area under the duration curve. Applying the theoretical value of K/V to the hourly ranked output gives a curtailment fraction of 19.5% (less than the theoretical estimate of 22.3%) and an ACF of 30%, confirming that curtailment is underestimated.

However, the profit constraint is potentially important for subsea links. Table 2 collects terms from the right hand side of (10) and applies them to the case where $\theta_s = 30\%$ to find the minimum value of θ_n to be profitable with the two values a and a'. With onshore transmission Northern windfarms look profitable at quite modest capacity factors but subsea links immediately put them at risk – Crosbie would not be viable if charged the marginal transmission cost involving subsea links.

Table 2 Critical capacity factors for profitable Northern windfarms

Link	$b+\rho$	$ab^2\theta_s/2$	$a'b^2\theta_s/2$	θ_n at a	θ_n at a'
TNUoS	1.245	0.006	0.008	34.2%	34.1%
WB	1.405	0.023	0.033	41.5%	41.2%
SEGL1	1.505	0.039	0.056	44%	43.5%
SEGL2	1.1745	0.096	0.139	49.5%	48.2%

The ACF ranges from 39.1% to 33.1% (SEGL2), still a reasonable effective CF. Again the impact is modest as the area removed is small, even if the fraction of the year curtailed can be as high as 22.3% (using SEGL2). The non-linearity of the duration curve in Figure 1 becomes significant at higher levels of curtailment, as the area defined by the linear approximation becomes increasingly less than the actual area under the duration curve. Applying the theoretical value of K/V to the hourly ranked output gives a curtailment fraction of 19.5% (less than the theoretical estimate of 22.3%) and an ACF of 30%, confirming that curtailment is underestimated.

The more important impact of moving to subsea connections is that the forward looking G-TNUoS charge increases to 70% of $\pounds 131,370$ MW^{-1}yr^{-1} = $\pounds 92,000$ MW^{-1}yr^{-1}. That would be equivalent to £28.64/MWh for SEGL2 using the higher, theoretical ACF, but at the modelled ACF of 33.1% a higher £31.83/MWh (and £35/MWh at the measured ACF of 30%). Windfarms in Argyll would need to bid $\pounds 72.24 + \pounds 35 = \pounds 107.24$/MWh to be competitive in against an East Anglia 34% CF windfarms bidding the AR7a price of £72.24 (if paying for SEGL2). As such they would struggle to compete with windfarms closer to load centres, making both the windfarm and the subsea links unattractive. Unless new OHLs can be built (in parallel to existing lines, using the same wayleaves) Scottish wind expansion would not seem system-cost effective.

4 Storage

Isolated REZ's frequently co-locate a battery electrical storage system (BESS) to reduce demands on export capacity (TEC) and curtailment as well as offering price arbitrage opportunities (Simshauser, 2025). Thus the planned Crosbie wind farm in Ayrshire, Scotland has 80 MW of onshore wind and 50 MW BESS.[14] The attraction of co-locating BESS has increased both as the cost of grid-scale BESS has fallen and as BESS is increasingly successful in winning capacity agreements in the annual GB capacity auctions: "Another large increase in this year's T-4 Auction was battery storage, which was 75.4% up on last year's T-4, from 1,016MW to 1,782MW. Overall, storage rose by 18.9% ..."[15] The NESO auction site notes that these are the derated values, and the total new-build BESS capacity was $6,083$ MW, storage $17,077$ MWh. The average duration of 2.8 hours would be derated to 29.4% of its capacity (and hold a capacity contract with that value).

The benefits of co-location have been recognized in the recent European Commission guidance 10.12.2025 C(2025) 8479: "A good practice, especially for the development of hybrid installations, is to allow beneficiaries of a supported power-generating installation to invest in behind the meter flexibility solutions, such as batteries, thus allowing the beneficiary to save grid connection fees for the asset behind the meter and potentially contributing to the reduction of grid congestion."[16] The question addressed in this section is whether batteries can indeed substitute for TEC. That in turn depends on whether grid-connected rather than co-located batteries would be viable at the point of entry of the windfarm.

Co-locating BESS has a potential competitive advantage over local grid-connected BESS when bidding for capacity agreements. They can access zero-cost otherwise curtailed VRE, store it and export it in the same high value hours as local grid-connected BESS, because North-South export constraints will be non-binding in low Scottish VRE output hours. This assumes that in Scotland wind outputs in different locations are reasonably highly correlated. Taking hourly capacity factors at the NUTS-2 level for the regions of Scotland over the period 2005-2011 the regional correlations with the all Scotland average range from $93\% - 97\%$.[17] On the reasonable assumption that high price hours will be low VRE hours this condition is satisfied. The second

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[14] https://crosbiewindfarm.co.uk/

[15] https://www.lowcarboncontracts.uk/insights/overview-of-the-latest-capacity-market-auction-results/

[16] https://energy.ec.europa.eu/document/download/62b688e2-fe5c-42f2-80c0-f577ee325b0b_en?filename=C_2025_8479_1_EN at Box 4

[17] https://www.renewables.ninja/

potential advantage of co-locating BESS with wind farms is that excess wind can be stored allowing a lower choice of TEC, reducing annual grid costs. This is the claim explored below.

The first benefit is easily calculated and clearly positive. If BESS of size B and duration h hours is co-located but TEC unchanged at K^*, some fraction $\beta^*$of previous curtailment, C^* in (6), can be stored for later sale at the considerably higher price, γp.[18] Its value will be $\gamma\eta p\beta^* C^*$, where η is the round trip efficiency of the BESS (e.g. 90%). For comparison, a locally grid-connected BESS would be able to buy $\eta\beta^* C^*$ at the wind-sales price p and make net revenue $(\gamma p - p)\eta\beta C^*$, so the net benefit of co-location is just

$$\Delta W_1 = p\eta\beta^* C^* > 0. \tag{13}$$

The second potential benefit is that the BESS may allow a lower TEC, $K = K^* + \Delta K$, $\Delta K < 0$, but at the cost of increasing remaining curtailment. Suppose that at the margin a fraction β of the surplus can be stored when TEC is reduced by $-\Delta K$. The net benefit from reduced TEC is $cd(-\Delta K) > 0$, but curtailment increases by $\Delta C(1-\beta) > 0$. Immediate sales change by $p\Delta Y < 0$, but $\beta\Delta C$ is stored for later sale at a net benefit of $p\eta\beta\Delta C > 0$. The sum of these TEC related changes is

$$\Delta W_2 = cd(-\Delta K) + p\Delta Y + p\eta\beta\Delta C. \tag{14}$$

The first two terms of (14) cancel as they together make the first order condition for choosing K, and by the envelope theorem remain negligible for small deviations from the optimum K^*. The last term is positive. Formally, from (6) $\Delta C = b\theta_s(-\Delta K)$ and from (7) $\Delta Y = -b\theta_s(-\Delta K)$, so, substituting for $cd = rb/\rho$ and $p = r/(\rho\theta_s)$

$$\begin{aligned} \rho\Delta W_2 &= rb(-\Delta K) - rb(-\Delta K) + rb\eta\beta(-\Delta K), \\ \frac{\rho\Delta W_2}{rb(-\Delta K)} &= 1 - 1 + \eta\beta > 0. \end{aligned}$$

This confirms that BESS, in addition to giving access to some surplus and therefore free wind (ΔW_1) also allow some reduction in TEC, although simulations discussed in Appendix B suggest that this is very modest. Note that β is not the total fraction of wind that can be injected into the BESS, but the maginal fraction for a small decrease in TEC, which will likely be when lengthy periods of stronger wind occur and for which the modest storage capacity will rapidly become saturated, so β will be small.

Proposition 1 *The optimal level of TEC for VRE is slightly reduced by co-locating BESS provided the co-located BESS is itself profitable..*

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[18] The average ratio of the top to bottom deciles of day-ahead prices in GB from 2011-2018 is 2.32 and in the SEM (arguably a better proxy for a high wind region like Scotland) is 3.29. These give suggested values for γ.

This confirms EC's guidance, but at least for wind with its high serial correlation and hence rapid BESS saturation, the gains are likely modest. The reason for the very modest impact of BESS on TEC is that the average length of periods of surplus wind is high, so that any plausible BESS capable of winning a capacity contracts will have too little storage capacity to absorb the surplus for more than a few hours, after which it has no impact on curtailment. Put another way, increasing TEC is more effective than increasing storage. Figure A1 illustrates this, showing the average number of periods (defined as total hours of surplus wind for the given TEC divided by the duration, h, above which the duration counts – i.e. if n is the number of periods on the y-axis, nh is the total number of hours in such periods). Thus if $h = 2$, there are 876 hours of surplus wind in periods lasting at least 2 hours, with therefore $876/2 = 438$ such periods. The economics of co-locating BESS with solar PV may be considerably stronger, as the strong diurnal element and the short time between peak PV and peak residual demand makes daily cycling attractive and hence a stronger ability to substitute BESS for TEC. The proposition assumes that the extra revenue in (13) is sufficient to offset any handicap in locating BESS at that connection point rather than is some other available and profitable location. If so its capacity and duration can be determined numerically for particular examples. The capacity, B, should be less than TEC, K, as total storage can be increased by increasing hours of storage, h, up to the limit suggested by competing grid-connected BESS. Using the Crosbie hourly data the benefit (13) is insensitive to the components of Bh, and as extending life is a cheaper way of delivering storage, choosing the maximum economic h would seem sensible. If this is $h = 2$, then the proposed value of $B = 50$ MW is at a level beyond which benefits increase with Bh very slowly.

5 Conclusion and policy implications

Efficient location signals are critical to guiding investment location decisions for VRE, as they will likely require additional transmission investment. This implies that new entrants should be offered their choice of the amount of firm entry capacity but only when the capacity can be delivered (or accept a non-firm agreement until capacity is available). The connection contract would be long-term (comparable to the life of the VRE or the length of any contract it secures) at the marginal cost of expanding the required transmission. If it is impossible for some (doubtful) reason to build onshoreand only subsea links are feasible, the marginal cost will include their very much higher cost (in some cases eight or more times as much as onshore). Any surplus above export capacity (TEC) would be voluntarily curtailed without compensation, thus ensuring an efficient choice by the developer, as is also the case for multiple entrants into an isolated REZ (Newbery and Biggar, 2024). Most countries have connection arrangements that are considerably more favourable to VRE than this and will over-encourage locating VRE in ways that increase total system costs and might amplify the case for co-located BESS as a second-best solution. The high marginal cost of expanding transmission by subsea links seriously compromises the economics of distant (Scottish) windfarms compared to those in favourable uncongested locations and strongly argues for revisiting their logic.

Free entry of storage behind the export injection point will be efficient provided it can access surplus (otherwise curtailed) VRE at zero cost and would otherwise be economic at that part of the grid. It can provide a modest reduction in TEC for wind, more for solar PV. Co-locating wind in congested regions is further disadvantaged with zonal pricing, as the high correlation of wind output across a region at high penetration levels will mean very low grid prices for grid-connected BESS when wind is curtailed.

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Appendix A Linearizing curtailment functions

The general symmetric VRE duration schedule in figure 2 is

$$\phi_y = Max((1-ay),(1-y)/a), \quad a>1.$$

The ratio of peak to average output is $1+a$. Figure 2 also shows the export capacity $K=\phi V_0$ at C, with the linear curtailment function AB and total curtailment the triangle ABC. (Note the algebra below can be replaced by simple geometric calculations.) The curtailment function is

$$\begin{aligned}
k(V,y) &= \phi_y V - K = V(1-ay) - K, \ y \le y^*, \\
V_0 &= V(1-ay^*) = K, \ \text{ if } y^* < 1/(1+a), \\
y^* &= (1-V_0/V)/a, \ \ dy^*/dV = V_0/(aV^2), \\
k(V,y) &= aV(y^*-y) = V - V_0 - aVy, \ \ y \le y^*.
\end{aligned}$$

Average curtailment is

$$\text{AC} = \frac{aV}{V}\int_0^{y^*}(y^*-y)dy = \frac{a}{2}(y^*)^2 = \frac{(V-V_0)^2}{2aV^2}.$$

Marginal curtailment is

$$\begin{aligned}
\int_0^{y^*}\frac{dk}{dV} &= \int_0^{y^*}\left(\frac{\partial k}{\partial V} + \frac{\partial k}{\partial y^*}\frac{dy^*}{\partial V}\right)dy, \\
&= \int_0^{y^*}\left(a(y^*-y) + aV.\frac{1}{a}\frac{V_0}{V^2}\right)dy, \\
\text{MC} &= \frac{a}{2}(y^*)^2 + \frac{V_0}{V}y^* = \frac{V^2-V_0^2}{2aV^2}.
\end{aligned}$$

The ratio of MC/AC is

$$\begin{aligned}
\text{MC/AC} &= \frac{V^2-V_0^2}{(V-V_0)^2}, \\
&= \frac{V+V_0}{V-V_0},
\end{aligned}$$

as in the second case above.

In addition

$$\begin{aligned}
\frac{1}{V}\int_0^{y^*}\phi_y dy &= \int_0^{y^*}(1-ay)dy \\
&= y^*(1-\frac{1}{2}ay^*) \\
&= y^*(\frac{V+V_0}{2V}).
\end{aligned}$$

Appendix B Wind and Storage

Curtailment is driven by winds higher than TEC, which may last for an hour or two (the majority of cases) but may be considerably longer. Figure A1 illustrates this showing the total time experienced by different periods of excess wind. Thus episodes of length $h = 2$ hours occur over the year n_h times, giving a total contribution to curtailment of $n_h.h$ hours. From figure A1, if TEC is 80% of wind capacity, $K/V = 80\%$, there are 100 episodes lasting no more than 2 hours giving 200 hours of curtailment, but only 10 episodes lasting no more than 5 hours giving 50 hours of curtailment. Consequently the graph of curtailment is far from sequential, each point may be separated from the next by many hours. This affects storage, as injections will occur when there is surplus but only so long as there is room in the BESS. With 2 hours storage this will cover a reasonable number of episodes, but for longer episodes the BESS will saturate.

Figure A2 shows this for an extreme case (and likely to be unprofitabe) of such costly TEC (using SEGL 2) that K is 67.2% of $V = 80$ MW $= 53.76$ MW. where the percentage of surplus that can be injected for later sale rises from about 10% for very high wind cases (at its maximum $78.44 - 53.76 = 24.68$ MW) to about 47% when wind only slightly exceeds TEC. High wind events are often of many hours duration and rapidly fill BESS leading to a low average BESS use. Lower wind speeds are more common, where its variability means short periods slightly above TEC and longer periods below TEC, allowing more extensive use of BESS. The shaded area is the fraction of potential surplus that can be injected when TEC is lowered from 53.76 MW to 50 MW, in this case about 48%. The conclusion to be drawn is that for the windfarm to be profitable when facing the marginal transmission cost, that cost must be low enough, in which case TEC will be a high fraction of capacity, and periods of excess wind will be infrequent and storage might be moderately attractive, but cumulatively short in total duration (figure A1). BESS profits will in such cases rely mostly on their local grid-connected counterpart profits, and only modestly on co-located benefits.

Appendix C Variables and Parameters

Choice Variables:

V: Wind capacity MW;

K: transmission export capacity, MW;

B: BESS capacity, MW;

h: hours storage duration

Relationships

$x \equiv K/V$;

Parameters:

θ_n, θ_s: PCF in North, South, 36% – 40%, 34%,

a: slope of curtailment schedule (Scotland, Crosbie) 1.47, 2.13 (inverse of percentage of year)

Other parameters:

d: tranmsision line length;

p: wind-output weighted price in North

ρ: Loss factor and price difference adjustments 1.085

γ: γp is the value of 1 MWh injected into a BESS 3

Costs

cd: cost per MW per year of line of length d

r: cost per MW per year of a windfarm

$b = cd\rho/r$: the key transmission cost ratio

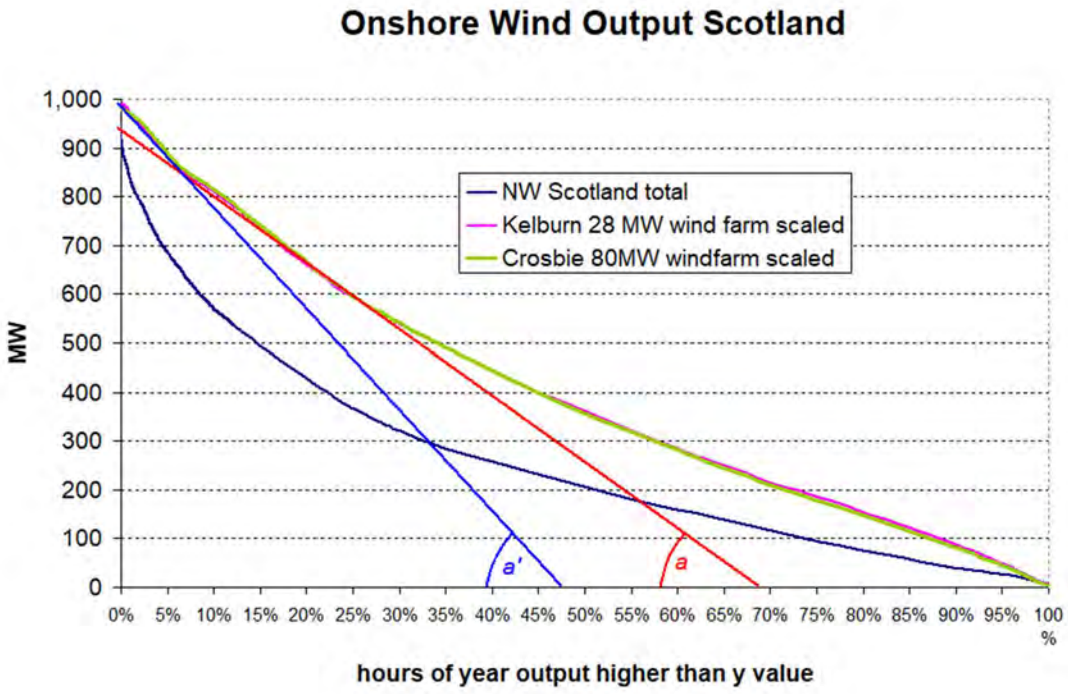

Figure 1 On-shore wind capacity factor duration curves, NW Scotland, Kelburn and Crosbie wind farms

Source: https://www.renewables.ninja/

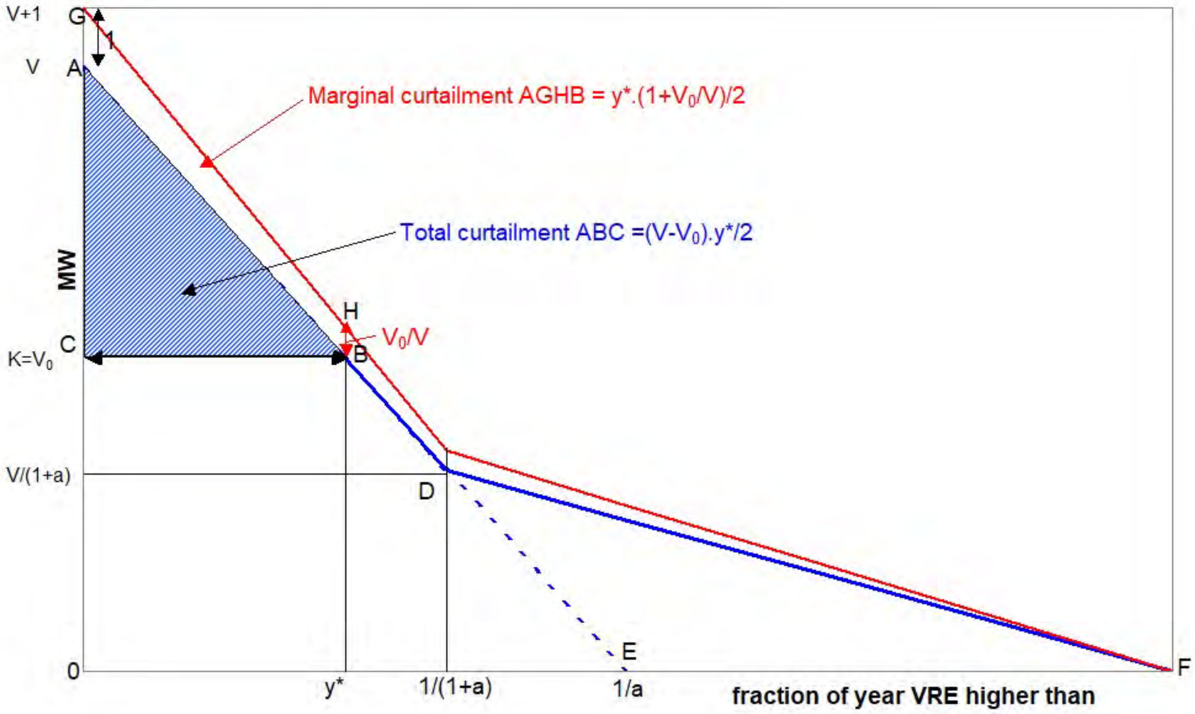

Figure 2 Piece-wise potential VRE output duration curve

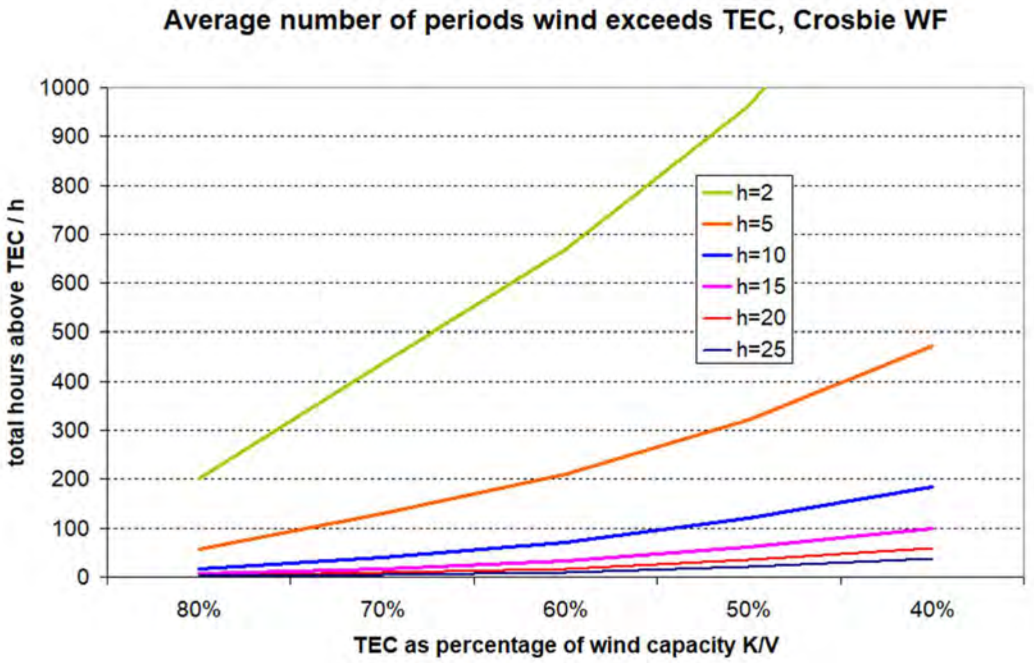

Figure A1 Total time wind exceeds TEC by length, *h* hours, for Crosbie Wind Farm
Note: total hours above TEC is number of periods, n_h, of length h times their length, $n_h.h$.

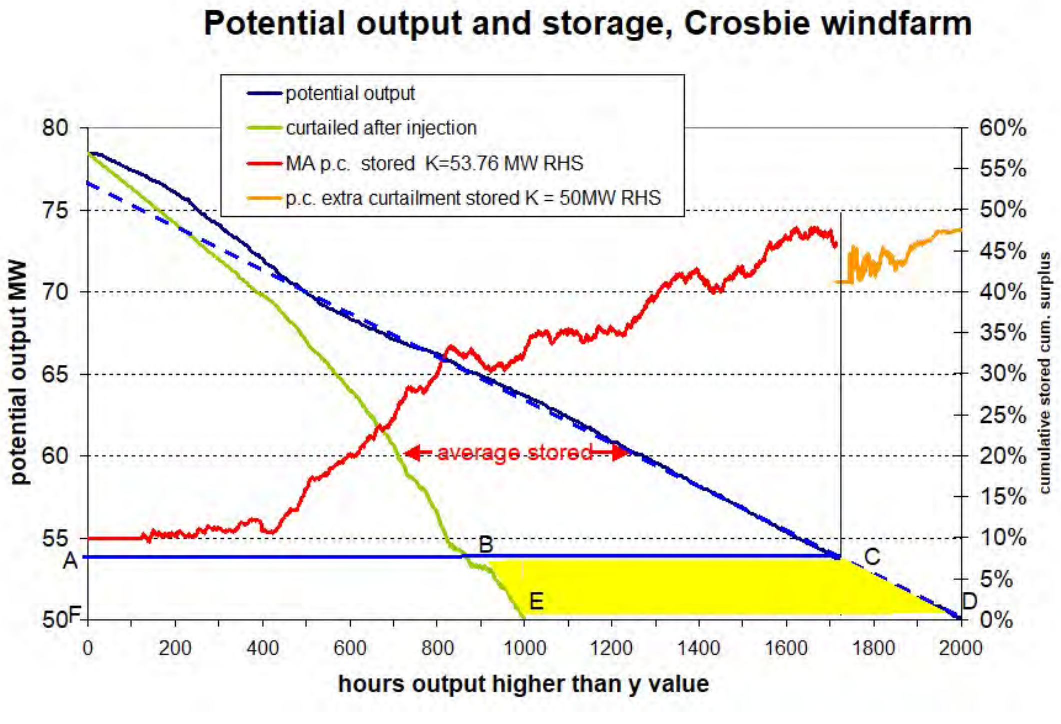

Figure A2 Potential output, curtailment and amount injected into BESS, Crosbie Windfarm
Note: Capacity *V*= 80 MW, K^* = 53.76 MW Point A), $K = K^*+\Delta K$=50 MW (point F), BESS = 50 MW, 100 MWh. Potential output is accurately plotted, potential surplus is potential output less TEC, *K*, the average stored is highly smoothed, the percentage stored is a moving average of cumulative injections divided by cumulative surplus over 200 hours, as injections are intermittent; curtailed after injection is the (1- MA p.c. stored)*potential surplus.