Marginal curtailment of wind and solar PV: transmission constraints, pricing and access regimes for efficient investment

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Keywords Transmission constraints, access regimes, variable renewable electricity, marginal curtailment, nodal pricing

JEL Classification H23; L94; Q28; Q42; Q48

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Marginal curtailment of wind and solar PV: transmission constraints, pricing and access regimes for efficient investment*

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Abstract

As Variable Renewable Energy (VRE) penetration increases in poorly networked areas with suitable VRE resources, transmission constraints will increasingly force VRE curtailment. Under most European market access and pricing arrangements, location and operation decisions are based on average curtailment rates. As the marginal contribution of the last MW of VRE is 3+ times average curtailment, there is a risk of inefficient location and operation. This article compares different pricing and access regimes (including nodal pricing that gives efficient transmission scarcity signals) to compare their impact on the incentives for VRE merchant or market driven entry.

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1 Introduction

At the Paris 2015 UN Conference of the Parties COP21 196 signatories announced Nationally Determined Contributions (NDCs) setting out their approach to reducing emissions.[1] At the most recent COP28 in 2023 more than 115 countries promised to triple renewable energy capacity by 2030.[2] Both ambitions will require a massive increase in the proportion of electricity

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[1] https://unfccc.int/process-and-meetings/the-paris-agreement

[2] https://ec.europa.eu/commission/presscorner/detail/en/ip_23_6053

generated by Variable Renewable Electricity (VRE, wind and solar PV).[3] VRE has two important distinguishing characteristics. First, its avoidable costs are low (zero for PV, very low for wind). Second, VRE has a high ratio of peak:average output, 3-4:1 for wind, 4-10:1 for PV, depending on the resource quality. If VRE is to contribute a high share of annual output, peak generation will inevitably exceed demand (including for storage and export) for a significant fraction of the year and real-time wholesale prices could collapse in such periods (Frew et al., 2019, 2021; O'Shaughnessy et al., 2020; Song et al., 2018; Wang et al., 2021). Excess VRE supply will need to be curtailed, by which we mean that it will be required to produce less than its ability to produce at current levels of wind/sunshine. This concept is to be contrasted with making the economic decision to run at below potential output in order to offer increased output in the balancing market, a common strategy for flexible generation but increasingly seen as a potentially valuable option for VRE (Nelson et al., 2018).

The challenge facing liberalized electricity markets is to adapt pricing, dispatch and even access rules to address these two characteristics. Liberalized markets in Europe have adopted market designs that were able to cope reasonably well with the fleet of conventional power stations for which transmission systems had been designed. Generators face zonal or national markets that set prices on the fiction of firm access and no internal constraints, leaving it to balancing markets to ensure final balancing of supply and demand. Zonal prices give clear market signals that determine which plants are in merit (have avoidable costs below that price) and which would be unprofitable to run. With firm access rights and efficient markets, if generation cannot export otherwise profitable power, it will be compensated its lost profit, with replacement and costlier alternatives paid their variable cost.

The simplification of ignoring locational constraints and their resulting locational scarcity prices was arguably defensible with the adequate reserves and robust transmission systems that European countries inherited at liberalization. Efficient cross-border trade and hence European market integration was finally resolved with market coupling that allowed the efficient use of interconnectors, which, when fully used, would create price differences across these borders. Countries with severe internal constraints could (and some did, like Norway and Italy) choose zonal pricing. Great Britain is actively considering the theoretical attraction of Locational Marginal Pricing (LMP) or creating internal price zones.[4] A few countries (including Great Britain) recognized the importance of guiding the location of new generation with zonal connection charges, but with little need for new conventional capacity most countries have uniform and often zero transmission charges for generation. Indeed, the European Commission has mandated low average generation

[3] A list of acronyms is located at the end of the text.

[4] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements

transmission charges to level the cross-border playing field, with the required revenue raised from charges on load (final consumption).

Conventional generation provides adequate inertia from the synchronized spinning mass of turbines that stabilize frequency, which is a system-wide characteristic of interconnected AC systems. Security of supply is ensured by reserves that can rapidly replace lost power or ramp up to meet demand surges. The European Target Electricity Model was an energy-only market that was predicated on investors having sufficient confidence in the predictability of future revenue streams that they would deliver sufficient capacity for reserve adequacy. Adequate conventional generation also provided sufficient system services such as inertia and adequate ramp rates. Early market designs in the UK and the Single Electricity Market (SEM) of the island of Ireland chose a market design with separate payments for energy and capacity, the latter according to its scarcity measured by the Loss of Load Probability. If missing markets or policy uncertainty make needed new investment too risky, capacity auctions could be created to determine the missing money required to facilitate entry and guide exit (as in GB and the SEM).

High VRE penetration casts doubt on almost all these features of current European market designs. VRE resources are very differently located to existing fossil and nuclear generators for which transmission was designed. Consequently, they will likely face local transmission constraints more frequently than well-sited existing conventional generation. This was dramatically revealed in China, where the initial spurt of VRE development incentivized by a single support price naturally encouraged rapid investment in high resource areas distant from load centres, resulting in very high curtailment rates (16% for wind and 10% for PV in the Northwest in 2018 according to O'Shaughnessy et al., 2020) until transmission was expanded (Zhang et al., 2021) and better price signals adopted (Song et al., 2021). Texas experienced the same high but then falling curtailment as transmission was expanded (Bird et al., 2016; Golden and Paulos, 2015).

VRE lacks inertia and at high penetration in systems lacking AC links to other markets, threatens system stability (Vázquez Villamor et al., 2020). Inflexible generation, minimum operating levels and a lack of responsive storage and demand side response can limit VRE penetration as enough adequately flexible capacity needs to be available to maintain stability (Bistline, 2018; Denholm et al., 2016, 2018). At some level of instantaneous share VRE will need to be curtailed to keep adequate spinning turbines synchronized, or replacement synthetic inertia activated (when available). Finally, and almost universally, most European VRE units pay on metered output rather than holding financial hedging contracts that pay on delivery. This cuts the link between balancing and real-time prices and operation that is crucial to address constraints not dealt with in the fictitious copper-plate day-ahead market. Peng and Poudineh (2019) and Schermeyer et al. (2018) identify a number of flaws in European market design hampering the efficient use of

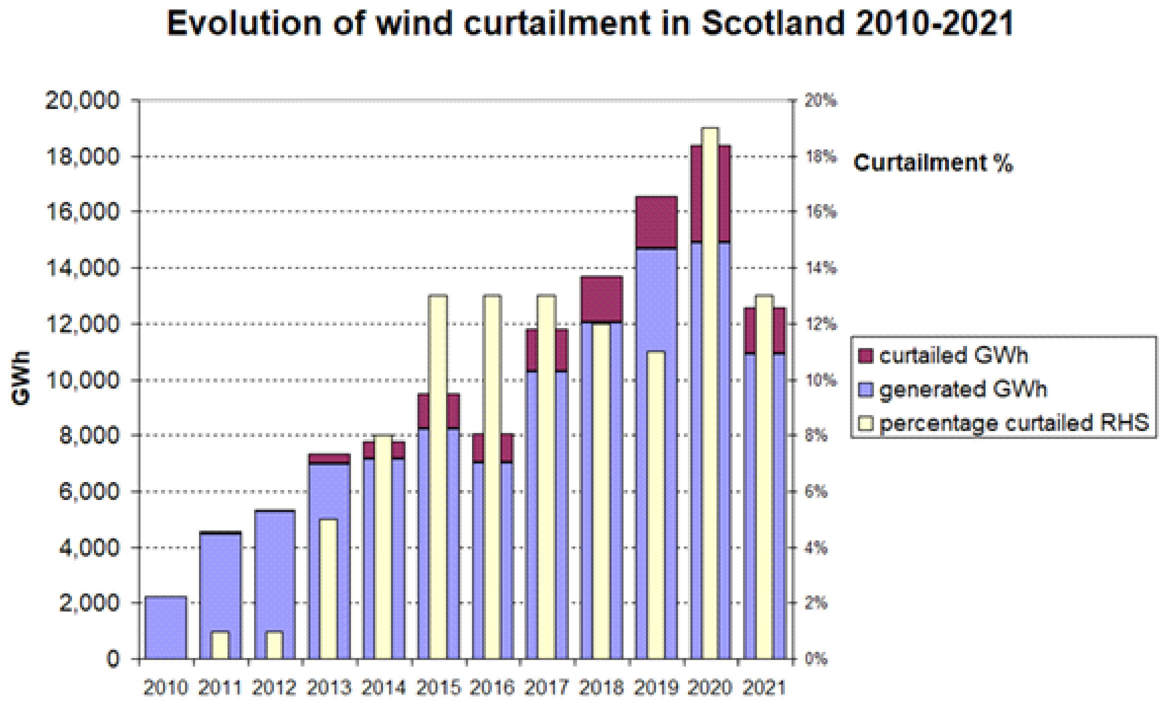

Figure 1: Evolution of wind output and curtailment in Scotland, 2010-2021

VRE.

The high peak:average ratio of VRE output becomes a problem once supply exceeds demand and VRE needs to be curtailed. Newbery (2021, 2023) demonstrated that marginal curtailment is typically 3+ times average curtailment, and that in current European market designs entry decisions are driven at best by average curtailment. However, while the concept of average curtailment is well recognized (Golden and Paulos, 2015; Joos and Staffell, 2018; O'Shaughnessy et al., 2021) the concept of marginal curtailment has been underappreciated, which is surprising given that many authors draw attention to the rapid rise in curtailment with penetration (e.g. Fig. 2 in Frew et al., 2021). The marginal contribution of the last MW will be more heavily curtailed than the average, and so will deliver fewer useful MWh for the same cost. When VRE curtailment is primarily driven by the problem of maintaining system-wide inertia, then new VRE entry anywhere on the system risks being excessive. At the system level (i.e. ignoring any internal transmission constraints) Newbery (2023) showed that the incentive for excess entry was proportional to either the volume of inertial generation needed for stability, or the minimum reserve requirement to insure against the loss of the largest critical element (generation or transmission).

This article addresses the more immediate problem of curtailment caused by the mismatch of transmission and the location of recently entered VRE. Figure 1 shows on-shore wind curtailment rates in Scotland rising over time, and similar problems have already arisen in other countries where VRE locates in less connected parts of the system (as noted above, China and Texas in particular). Novan and Wang (2024, p2) econometrically estimate marginal curtailment rates for wind and solar PV in California and find that although average curtailment of solar is only 4.3%, marginal curtailment is 9% or roughly twice as large. In the case of wind, while average curtailment is only 0.4 of 1%, marginal VRE curtailment (mainly solar PV) is 10%. The question addressed is whether existing or potential market designs and access regimes (i.e. who gets curtailed and how much) give rise to inefficient VRE entry signals, and if so what changes to these rules can resolve the problem. Whereas it is difficult to devise simple market price signals to charge for inertial requirements,[5] pricing transmission constraints should be simple and has already been addressed in markets with nodal and zonal pricing. If the transmission constraint binds, then prices at each side of the constraint will differ, with the difference equal to the scarcity value of the constraint. This article asks whether that is sufficient, and, if nodal pricing has been ruled out, whether there are alternative solutions that can provide efficient VRE investment signals.

2 The Australian model

Australia has developed an innovative way of overcoming the various obstacles of connecting VRE and avoiding existing local transmission constraints by creating Renewable Energy Zones (REZs). These almost inevitably require a dedicated line to the Main Interconnected Transmission System (MITS) which, like most of the population, is located near the coast, while the best VRE resources of sun and wind are typically farther inland. This might be a useful model for other countries, and has some similarities to the GB off-shore wind regime. The Transmission Owner, TO, acquires suitable sites where developers would be keen to invest and builds the link to connect the REZ to the MITS. Entrants then pay an average charge based on the expected final volume of VRE and so are not dissuaded by bearing the full cost of early entry. However, the REZ export capacity is limited and above some volume of VRE capacity, supply will exceed the line limit and will have to be curtailed. The main difference with the European cases of internal transmission constraints is that the REZ export limit can, within certain limits, be tailored to the expected capacity of the REZ. As a stand-alone merchant entity the REZ can more readily adopt access rules that address

[5] Part of the problem is that the binding reliability constraint can change rapidly from the need for inertia to the need for other flexibility/reliability services, so the relevant price can switch from zero to a positive, possibly large, price from moment to moment. Real-time payments for such services would stretch the concept of market rather than administered pricing.

curtailment more efficiently than the type of wholesale market designs prevalent in Europe and Australia. While storage can (and increasingly does) mitigate curtailment, beyond some level it is more costly to provide extra storage than the value of curtailed energy saved – batteries suffer rapidly decreasing marginal revenues as successive MWh of storage are called on less and less.

2.1 Renewable Energy Zones in Queensland[6]

The Australian state of Queensland has been at the forefront of pro-actively creating REZs to harness the massive renewable resources of wind and sun in that state. Powerlink, the state-owned transmission service provider, identifies and responds to the choice of suitable locations for investment in VRE. Powerlink agrees to build a suitable radial link to the grid with one or more 'anchor investors' who are ready to build. While user charges for the MITS are regulated and paid by end-use consumers, Queensland's REZ model is one of merchant investment paid by connecting generators. The REZ connection is optimally sized for expansion well beyond the initial VRE proponent's investments, with each user charged only a suitable fraction of the REZ cost. The commercial attractiveness of VRE under this merchant model depends on the fraction of (unrewarded) expected curtailment resulting from future entry of wind and solar PV into the REZ (and later, into the National Electricity Market, the NEM).

One of the considerable advantages of Queensland is that there is reliable sunshine with a fairly predictable peak in the daytime, while wind resources are stronger at night and so complementary with solar. At present, Queensland is a single wholesale price zone within the NEM, whose five-minute price is determined by the Australian Electricity Market Operator (AEMO) under a conventional uniform first price auction. The NEM is an energy-only market allowing free entry of generators (provided they meet the stringent grid codes for generator performance standards, and do no harm with regards to system strength – remediation typically being via installing synchronous condensers or inverter tuning). Prices fall below zero when excess regional supply occurs – typically in solar-rich periods – as inflexible generating units will bid negative prices to stay at minimum load and avoid costly shut-down and subsequent restarts. In normal conditions (no constraints on exporting to the grid) the REZ will face the transmission loss-adjusted AEMO wholesale price. The NEM price within each state is set at the average nodal price at a hub, with prices at each node based on transmission losses, so prices will be lower the farther the node is from the hub.

Australia is contemplating a move to Locational Marginal Pricing (LMP) or nodal pricing, under which the price at each node is the loss-adjusted marginal cost of delivering an extra

[6] This section draws extensively on Simshauser and Newbery (2023) that also describes the policy debates over market design and reform.

MW to that node. If LMP were introduced and also applied to REZs, the price within a REZ would fall to the avoidable VRE cost (taken as zero) whenever potential output exceeds the export capacity. The price difference across the REZ boundary would then be the loss-adjusted nodal price at the connection point to the MITS. This will generate congestion revenue whose allocation is relevant for the topic of this article. If REZ output is less than the export capacity then the REZ price will just be the local loss-adjusted nodal price at the REZ exit point, with no congestion revenue.

VRE in a typical Queensland REZ has a peak:average output of about 3:1, so that to achieve an acceptable average output within the REZ, entry will occur until it is almost inevitable that output in some hours will exceed export capacity and will be curtailed. The way in which VRE is then curtailed, and its rights to congestion revenue under LMP, can affect whether entry is efficient or over-encouraged (which, if desired, should then be an explicit choice). This article also compares different access and pricing regimes as they affect entry incentives into other constrained VRE export zones.

3 The model

The model is the simplest version to illustrate the problem. The VRE is located in a constrained subset of the network with no other dispatchable generation or flexible demand.[7] For convenience, this constrained zone will be called a Renewable Energy Zone, REZ, a generic constrained zone that could be anywhere, defined as one with no internal network constraints connected to the rest of the interconnected system through a single link. Problems of connecting different REZs through a constrained meshed network are beyond the scope of this model but will clearly be increasingly important as VRE penetration grows but that will be left for possible future work. Outside the REZ all market failures are assumed away or internalized, so that external market prices are efficient and correctly measure social value. There are constant returns to building VRE, and the annualized unit cost of VRE capacity (including any fixed O&M costs) is r_V \$/MW/yr. Avoidable costs are assumed zero. The capacity of the export link is K, the loss-adjusted price immediately outside the REZ is assumed constant at p and independent of REZ output.[8]

[7] As such the model is applicable to more isolated regions with few sources of flexibility. Flottmann et al. (2023), Gilmore et al. (2023), Tigas et al. (2015) and Wang et al. (2021) discuss the options available to absorb excess VRE generation, but all conclude that beyond some point VRE will need to be curtailed.

[8] In Simshauser and Newbery (2023) prices vary hourly and can fall to zero if there is excess supply outside the REZ. If VRE output impacts the NEM price p and consumer demand is inelastic in the short run, then the fall in price will involve a one-for-one transfer from VRE to consumers, and will net out of total social surplus, but the fall in the NEM price will have a slight negative effect on merchant profits. Using the regression results

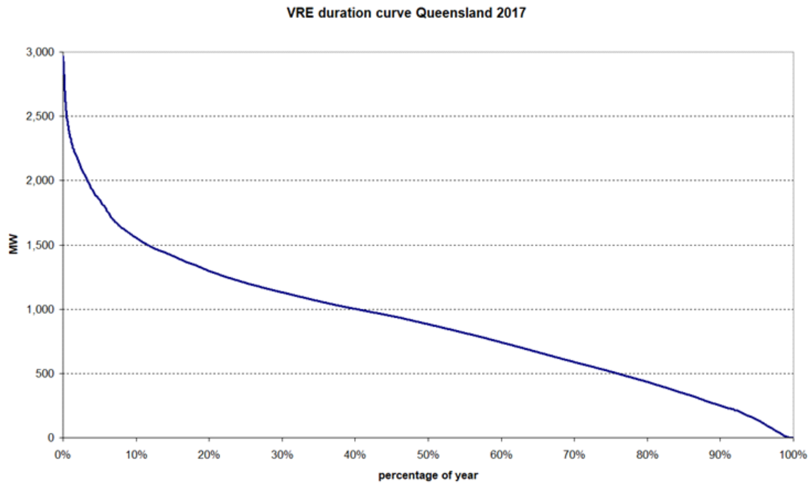

Figure 2: VRE duration curve for Western Downs, Queensland, 2017

VRE capacity is $V > K$, and potential output at fraction of the year y is $\phi_y V$. It is convenient to order hours of production such that the capacity factor ϕ_y is decreasing in y as in figure 2. The curtailment function $k(V,K,y) = \phi_y V - K$ is defined for y such that $\phi_y V \geq K$, and will be similarly ranked so that $k(V,y)$ is decreasing in y up to y^* (the hour of highest VRE is also the hour of maximum curtailment) so that

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

Periods of zero curtailment are distinguished by $y > y^*$, with $y < y^*$ curtailed (see figure 3). Under efficient pricing (e.g. LMP) the REZ internal prices would fall to zero when output is curtailed, but would be p under current European and NEM market arrangements. As y is measured in fractions of the year, output will be measured in MWyears of 8,760 MWhs. The average load factor, ALF, is then ϕ:

$$\phi = \int_0^1 \phi_y dy.$$

In figure 2 the ratio of peak output (ignoring the top $\frac{1}{4}$ of 1% or the top 22 hours to rule out extremes that vary from year to year) to the average is 3:1, which the linearized duration curve in figure 3 can replicate. Average curtailment, AC, is $(\int_0^{y^*} k(V,y)dy)/V$, but marginal curtailment, MC, caused by the entry of 1 MW of extra VRE capacity, is, after setting $k(V,K,y^*) = 0$ from

of Gonçalves and Menezes (2022) the impact of the Queensland REZ on market prices is very small – the 5-year average spot price reduces by about \$0.30/MWh/GW (primarily wind, solar PV has an insignficant impact at the observed, low levels of penetration) and does not affect the optimal choice of VRE to install.

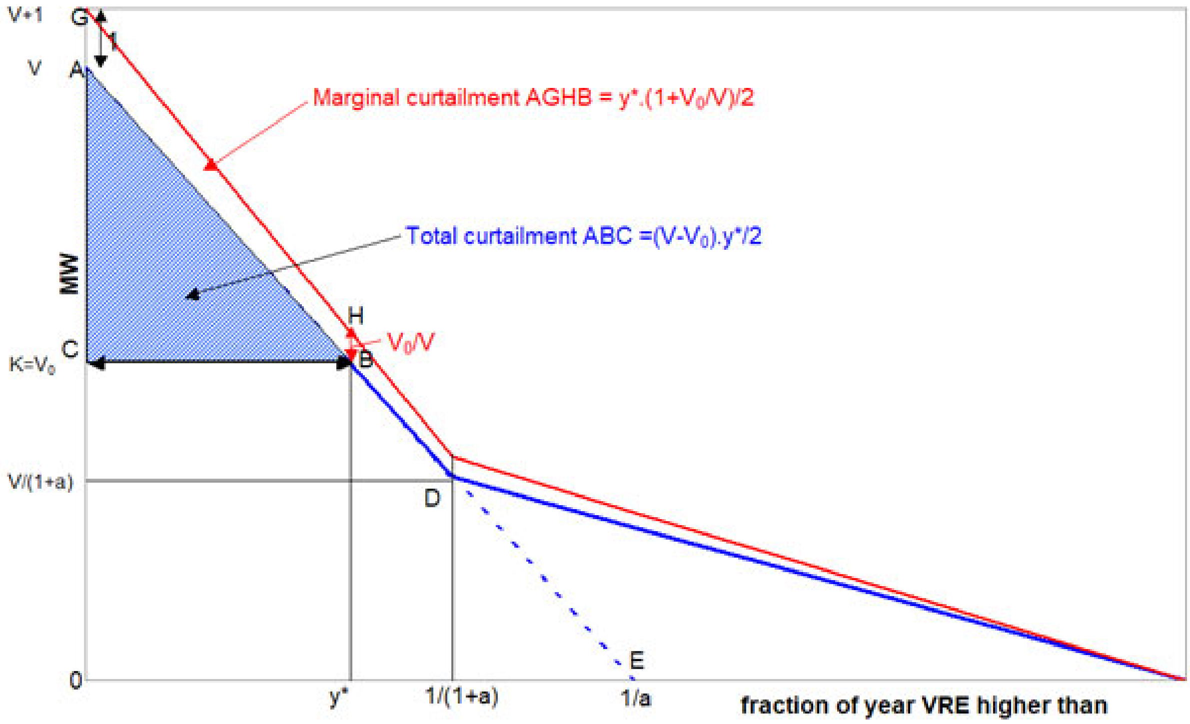

Figure 3: Geometric illustration of average and marginal curtailment

(1),

$$\begin{aligned}\frac{d}{dV}\int_0^{y^*} k(V,K,y)dy &= k(V,K,y^*)\frac{dy^*}{dV} + \int_0^{y^*} \frac{dk(V,K,y)}{dV}dy,\\ \text{MC} &= \int_0^{y^*} \frac{dk}{dV}dy. \end{aligned} \tag{2}$$

The ratio of the marginal curtailment to average curtailment is MC/AC:

$$V\int_0^{y*} \frac{dk}{dV}dy / \int_0^{y*} kdy > 1, \tag{3}$$

a number typically above 3 at modest levels of curtailment. Figure 3 illustrates this geometrically and assumes that, in a modest size REZ, increments of VRE increase each point on the duration curve proportionately. As such it represents a more realistic simplification than assuming the curtailment curve is shifted vertically as in Newbery (2021). The VRE duration curve of figure 2 has been linearized to preserve the key feature that the curve is steeper for higher levels of output than lower (and could, if necessary, have additional linear segments without altering the argument). The duration curve in figure 3 takes the form

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

The Appendix gives the algebraic derivation of the resulting curtailment function as

$$k(V,y) = V - V_0 - aVy,\ K = V_0,\ \ y^* = (1 - V_0/V)/a,$$

and derives the AC and MC for this case. Its piece-wise linear form allows a simple geometric interpretation. In figure 3 the average output is the area under the duration schedule ADF0, which is the sum of the two triangles AE0 and DEF. By simple geometry their areas are $\frac{1}{2}V/a + \frac{1}{2}V(1-1/a)/(1+a) = V/(1+a)$. Peak output is V so the peak:average is $1/(1+a)$. Thus if $a = 2$, the peak:average = 3 as in figure 2. Figure 3 also shows the export capacity $K = V_0$ at C, with the linear curtailment function AB and total curtailment the triangle ABC. As noted. increasing VRE scales up each point proportionately both for the duration curve and also the curtailment function. The figure shows that a 1 MW increase in VRE moves the curtailment function from AB to GH. Total curtailment is the area ABC $= \frac{1}{2}(V - V_0).y^*$ so AC $= \frac{1}{2}(V - V_0).y^*/V$. Marginal curtailment of the 1 MW entry is the area GABH,[9] MC $= \frac{1}{2}(1 + V_0/V).y^*$, so MC/AC $= (V + V_0)/(V - V_0)$. Thus if $V = 2V_0$, MC/AC = 3.

3.1 Entry conditions for the REZ

In modelling European curtailment problems, consider a local REZ defined by export constraints in a region potentially attractive to VRE, and suppose that there are no other flexible generation or demand resources within the REZ nor any internal network constraints. Suppose hypothetically (and already a reality in countries like Australia, see Gohdes and Wilson, 2022) that VRE investment is commercially viable without a long-term contract, so that we can consider subsidy-free merchant entry. Suppose also that the export constraint, K, has been pre-determined and cannot be relaxed in a reasonable time frame. Finally, and as a first step to be relaxed, that in common with most European systems, generation pays no charge for grid access, which is entirely paid for by load (i.e. off-take from the MITS).

The annual social value of the REZ is the value of the uncurtailed output (the area CBDF0 in figure 3, $\phi V - \int_0^{y^*} k(V,y)dy$), less its cost, Vr_V, less the cost of the link, F (which for the moment is assumed a sunk cost). Consumers and producers (connected to the MITS) experience no change in price p (assumed constant) and hence no change in surplus. The total social benefit of the REZ, W, is

$$W(V) = p[\phi V - \int_0^{y^*} k(V,K,y)dy] - Vr_V - F. \tag{5}$$

Efficiency requires that the choice is socially optimal. Social value is maximized when (using

[9] plus the small triangle formed by extending the curtailment line CB and height BH, which in the limit is vanishingle small.

equation (2))

$$\frac{dW}{dV} = p(\phi - \text{MC}) - r_V = 0, \tag{6}$$

whose solution is $V = V^*$. The following possible access and pricing arrangements will determine whether entry signals for new VRE are efficient or not.

3.2 Uniform pricing with pro-rata curtailment

After curtailment $\int_0^{y^*} k(V, y)dy$, total output will be $\phi V - \int_0^{y^*} k(V, K, y)dy$. If VRE continues to receive the market price p but is all uniformly (pro-rata) curtailed (the default in many markets), then the profit of a marginal entrant facing no transmission charges with capacity v is

$$\pi = vp[\phi - \frac{1}{V}\int_0^{y^*} k(V, K, y)dy] - vr_V, \tag{7}$$

$$\frac{d\pi}{dv} = p(\phi - \text{AC}) - r_V. \tag{8}$$

The profit is maximized when $d\pi/dv = 0$ at which point $\pi = 0$, the free entry equilibrium. Excess entry will occur if (8) less (6) is positive, which is the case as

$$p\,(\text{MC} - \text{AC}) > 0. \tag{9}$$

The strong conclusion is that market signals for entry are excessive if VRE continues to face external market prices, pays no transmission charges and is curtailed in proportion to capacity (i.e. pro-rata). If, as is also common at present, VRE has firm access (guaranteeing compensation if curtailed) the incentive to excess entry will be even greater.

3.3 Non-firm access and priority dispatch

In the Single Electricity Market (SEM) of the island of Ireland, faced with an growing problem of curtailment and the difficulty of building transmission to resource-rich areas sufficiently quickly, Eirgrid (the SEM Transmission Owner) has proposed offering non-firm access to new entrants.[10] Existing VRE will be allowed to produce as before but new VRE entrants will be curtailed in a last-in first-curtailed basis, which is effectively curtailing them according to marginal, not average, curtailment. This should make the market entry condition $p(\phi - \text{MC}) - r_V = 0$ and so identical to the social optimum (6). Thus non-firm access rights and priority dispatch should restore efficient VRE entry signals, at least in the context of the assumptions we have made here (namely, only VRE generation in the REZ with uniform avoidable costs). Note that this result applies to VRE entry, and not necessarily to dispatchable capacity, where it may be desirable to

[10] Eirgrid (2022). The proposal is to move to firm access when the transmission constraint is removed or after five years, whichever is sooner.

encourage entry of more flexible plant, or plant offering system stability resources, which may be more valuable behind the export constraint than existing plant. Clearly such plant can be exempted from the priority dispatch rule as could VRE generators that offer similar flexibility options.

3.4 Locational marginal pricing

Under LMP, prices in the REZ fall to zero whenever the export constraint binds. In that case total output, Y, revenue, R, (ignoring any congestion rent if REZ prices fall to zero), and the profit π of entrant with capacity v, will be

$$\begin{aligned}
Y &= \phi V - \int_0^{y^*} k(V, K, y)dy, \\
R &= pV \int_{y^*}^1 \phi_y dy = pY - pKy^* = pV(\phi - \int_0^{y^*} \phi_y dy), \\
\pi &= v\left(p(\phi - \int_0^{y^*} \phi_y dy) - r_V\right), \qquad (10)
\end{aligned}$$

as VRE faces a price of zero during the curtailment period up to y^*. The curtailed output during this period is Ky^*, so the volume that receives a positive price is potential output, ϕV less the zero price volume $\int_0^{y^*} \phi_y$. Again the free entry condition is $d\pi/dv = 0 = \pi$. Free entry under LMP will be efficient if (10) = (6), which for the linear curtailment function in the Appendix is the case. Note that the beneficial incentives under LMP would be lost if incumbents in constrained regions could successfully claim compensation for the loss of revenue. If so, pKy^* will be returned to the VRE and will return them to the original inefficient entry condition (8).

4 The Queensland REZ model

The REZ model developed in the state of Queensland is described above in §2.1 In the most favourable case, the REZ will be designed with an export capacity that is optimally sized for the planned final level of VRE. Suppose that exit capacity K can be expanded continuously at a marginal cost of c per unit of capacity. The social value of the REZ is now

$$\begin{aligned}
W(V, K) &= p[\phi V - \int_0^{y^*} k(V, K, y)dy] - Vr_V - cK, \\
&= p[\phi V - \int_0^{y^*} V\phi_y dy + Ky^*] - Vr_V - cK.
\end{aligned}$$

The first order conditions for K and v are

$$\frac{\partial W}{\partial K} = py^* - c = 0, \qquad (11)$$

which is the condition for choosing export capacity, K, and

$$\frac{\partial W}{\partial V} = p[\phi - \int_0^{y^*} \phi_y dy] - r_V = 0, \tag{12}$$

which is the same as the free market entry (10). Thus assuming that the REZ is optimally sized and keeps all congestion revenue as the cost of the link, the free merchant entry condition supports the efficient equilibrium.

4.1 Current NEM pricing in the REZ

Under current NEM pricing, the price facing VRE would be p regardless of constraints, and some method of curtailing would be required, with those curtailed receiving zero revenue, but others receiving p. In this case there is no congestion revenue so VRE would need to pay for the exit transmission at a rate cK/V^* where V^* is the design (optimal) level of entry and $c = py^*$ from (11). Under pro-rata rationing, merchant profits will now be

$$\begin{aligned} \pi &= vp[\phi - \frac{1}{V}\int_0^{y^*} k(V, K, y)dy] - vr_V - cv\frac{K}{V^*}, && (13) \\ &= v\left(p[\phi - \int_0^{y^*} \phi_y dy] - r_V + \frac{pKy^*}{V} - c\frac{K}{V^*}\right). && (14) \end{aligned}$$

If transmission is optimized as at (11) then the solution is $V = V^*$ is consistent with the free-entry solution to (14), which is the same as (12).[11] VRE entry into an isolated REZ is efficiently incentivized provided it is charged the efficient transmission fee for the connection to the MITS. Priority access would be incompatible with charging all entrants the same transmission charge (and unnecessary).

4.2 Moving to LMP in the NEM

Australia is considering a move to LMP, which would lead to efficient VRE entry signals to an optimally-sized REZ provided the congestion revenue were retained by the REZ to cover the cost of the transmission link, or, less elegantly, if VRE were granted Transmission Congestion Revenue contracts that allowed them to receive congestion rents pro-rata, provide they were also charged the marginal transmission expansion cost.

5 Conclusions and policy recommendations

The first observation is that most current VRE support policies exacerbate the inefficient dispatch of VRE. Network charging arrangements frequently fail to provide good locational guidance and,

[11] As with other claims, this is under the maintained assumptions of the model of an isolated REZ.

if generators are paid a regional price rather than the local price, the access arrangements can encourage excessive entry into export-constrained zones – and not just for VRE. As many authors have noted, these design flaws call for immediate reform of either transmission pricing and/or locational marginal pricing. While the concept of average curtailment is well recognized and even that curtailment can rise rapidly with increased penetration, the concept of marginal curtailment has been underappreciated and brings new challenges to market and access design. This article has developed a simple but robust model to examine these issues for resource rich regions facing a single transmission constraint for exporting VRE. Even under ideal conditions in which merchant entry is commercially viable with no long-term contracts distorting dispatch decisions (e.g. by paying only on metered output) there are problems with most current market designs. Thus merchant VRE entry incentives are excessive in most liberalized European electricity markets with country-wide or regional zonal pricing where there are binding intra-zonal constraints, zero transmission charges and firm access (i.e. the right to compensation if curtailed).

Modest changes to the access regime for new VRE entrants into an REZ granting them non-firm access and priority dispatch (last in, first curtailed) mitigate the problem while not disturbing revenue streams to VRE incumbents, under the assumption that all VRE entrants have the same (or similarly low) avoidable costs and that entrants cannot incur additional costs to rush entry to obtain priority dispatch. (Priority dispatch would not necessarily be efficient for dispatchable generation offering required system services within the constrained zone.) In Queensland's REZs, if exit capacity is optimized and VRE pays the marginal exit capacity charge, then entry signals would be efficient even under current state-wide pricing, at least assuming that all units have the same (zero) avoidable costs.[12] Indeed, priority access would both be unnecessary and give inefficient signals. If Australia adopted LMP, then if VRE is charged for transmission, efficient entry signals would require pro-rata allocation of Transmission Congestion Revenue contracts. A simpler solution would be to remove the transmission charge and allocate all congestion revenue to the transmission owner.

The main conclusion is that transmission charging, access regimes and market pricing rules all interact to determine the efficiency of entry signals facing new VRE investors, most importantly in existing networks with a variety of possible location options. While this article has shown that LMP requires natural adjustments to the access regime as far as VRE is concerned, it is not an argument against LMP. On the contrary, the main attraction of LMP is its ability to give efficient real-time dispatch signals for all forms of generation and load, including technologies

[12] Merit order effects caused by different VRE having different avoidable costs could introduce small inefficiencies if all are curtailed equally, but the low average curtailment rate and the low avoidable costs would make this inefficiency very small.

not yet invented. Discussions about the case for LMP (e.g. Ofgem, 2023) note that contracts for supporting VRE would probably need modification, and this article has shown that a move to LMP could require revisiting existing charging and access rules.

Acronyms

AC: Average curtailment; AEMO: Australian Electricity Market Operator ; LMP: Locational marginal price; MC: Marginal curtailment; MITS: Main interconnected transmission system; NEM: National Electricity Market (of Australia); O&M: Operation and maintenance; REZ: Renewable Energy Zone; SEM: Single Electricity Market of the island of Ireland; VRE: variable renewable electricity (i.e. wind and solar PV).

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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. The curtailment function is

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

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

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