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Club goods and a tragedy of the commons: the Clean Energy Package and wind curtailment[1]

David
Newbery

Abstract

The EU's Clean Energy Package is a club to collectively increase renewables and reduce CO2 emissions. At high levels of wind penetration, surplus wind that cannot be exported must be curtailed. Marginal curtailment is 3-4+ times the average curtailment, but even in an efficiently designed market, price signals for wind investment are given by average not marginal curtailment, creating a « tragedy of the commons » that requires a corrective charge to restore efficiency. The paper sets out a model calibrated to Ireland in 2026, showing the source of distortion, and derives new formulae for the capacity credit of wind, the learning subsidy and corrective charge needed to deliver the efficient level of renewables penetration, and estimates of their magnitude.

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December 31, 2020

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The EU's *Clean Energy Package* is a club to collectively increase renewables and reduce CO_2 emissions. At high levels of wind penetration, surplus wind that cannot be exported must be curtailed. Marginal curtailment is 3-4+ times the average curtailment, but even in an efficiently designed market, price signals for wind investment are given by average not marginal curtailment, creating a "tragedy of the commons" that requires a corrective charge to restore efficiency. The paper sets out a model calibrated to Ireland in 2026, showing the source of distortion, and derives new formulae for the capacity credit of wind, the learning subsidy and corrective charge needed to deliver the efficient level of renewables penetration, and estimates of their magnitude.

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1 Introduction

Ambitious plans to decarbonize electricity will require very high levels of variable renewable electricity (VRE) generation, mainly on- and off-shore wind and solar PV. Both decarbonization and supporting VRE are global public goods, VRE through its learning externalities that lower the cost of future investment. To solve the problem of financing such public goods, the EU requires (in its *Clean Energy Package*) member states to agree to targets for emissions reduction and VRE penetration – an excellent example of turning these into club goods (Buchanan, 1965).

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[†]I am indebted to very helpful comments from Par Holmberg, Robert Ritz, Richard Green, Stan Zachary and Chris Dent with the usual disclaimer.

The UNFCCC Paris Agreement and *Mission Innovation*[1] are examples of widening the club, ideally to the whole world. The EU's targets are set out in the *2030 Climate and Energy Framework*.[2] For these to be delivered in liberalized electricity markets, a number of market failures and distortions will have to be addressed.

The first and most obvious is that the external costs of fossil generation, and particularly CO_2 emissions, will need to be properly charged.[3] The EU's chosen instrument is the Emissions Trading System, but until its reform in 2018, the resulting carbon prices were well below the social cost of carbon, recognized in Great Britain by levying an additional Carbon Price Support charge on the carbon content of fuels used for electricity generation.

The second is that the external learning benefits of deploying VRE should be appropriately rewarded (see Newbery, 2018 and references therein). The EU's policy here has been to set targets for renewables share in total energy, and to encourage innovation through its European Strategic Energy Technology Plan (which, however, is aspirational rather than requiring binding commitments). As learning depends on developing, designing and installing reliable capacity, the learning benefits are a function of cumulative installed capacity, not subsequent output (when the electrons are the same as those from fossil generation). That implies the subsidy should be paid to reliable capacity (e.g. for the first 25,000 MWh/MW)[4] and not to output (as with the EU's assigned target shares of output), which would distort the market (Newbery, et al., 2018). Unfortunately, most subsidy systems create considerable distortion costs (Peng and Poudineh, 2019), to the extent that Green and Léautier (2015) feel the need to explicitly model that as part of VRE system costs.

The third implication of a high VRE penetration is to threaten the efficiency of investment decisions in flexible plant required for capacity reliability in an energy-only market. There is growing consensus that, while an energy-only market with prices capped at the Value of Lost Load might, in ideal circumstances, deliver the right level of reliability, a capacity auction, perhaps for Reliability Options, reduces the risk (particularly of future policy uncertainty) and hence the cost of delivering reliability (Battle et al.,2007; Grubb and Newbery, 2018; Newbery, 2016a; 2017). Holmberg and Ritz (2020) investigate the case for capacity payments with price caps for systems with high renewables penetration in a model complementary to that developed here. There is an earlier literature on reliability (e.g. Joskow and Tirole, 2007) and increasingly sophisticated modelling of the role of uncertainty discussed briefly in Appendix A and below. This article highlights the difference between the way in which conventional plant, whose outages

[1] see http://mission-innovation.net/

[2] at https://ec.europa.eu/clima/policies/strategies/2030_en

[3] Other air pollutants, particularly from coal, can also be costly – see Holland et al. (2020).

[4] Steinhilber (2016) notes that this is the support used for wind in some parts of China.

are uncorrelated, and VRE, whose output can be highly correlated, should be treated in de-rating for procuring adequate capacity, and provides a simple formula for de-rating wind.

The fourth implication is that system costs (providing inertia and other ancillary services, storage, more transmission and interconnection, and additional back-up reserves) will increase, and their costs are logically targeted on the source of these costs. Kaffine et al. (2020) point to an additional cost of VRE, in that intermittency over short time periods raises CO_2 emissions from flexible fossil generation, but that would be covered in these system costs if CO_2 were correctly priced. There are empirical estimates of the systems costs of variable renewables at varying levels of penetration[5] and simulations of possible future costs at high VRE levels (e.g. the extensive list of references in Committee on Climate Change, 2019), but little by way of simple modelling that can give quicker estimates.[6]

All of these are widely recognized in the literature discussed below, but there is an additional cost that does not appear to have been either recognized or quantified. Beyond some level of penetration, excess wind must be curtailed. If wholesale prices are efficiently set, this will cause the price to fall to the avoidable cost of the marginal VRE, encouraging them to self-curtail, otherwise mandatory curtailment will be required. Efficient markets will provide the necessary operating signals to self-curtail. The contribution of this article is to argue that the *marginal* curtailment is many times higher (3-4+) than the *average* level of curtailment. For investment decisions it is marginal curtailment that is relevant, while the market only values (or penalizes) average curtailment, resulting in a "tragedy of the commons" (Hardin, 1968). This is similar to the distortion that is claimed to arise in some models (e.g.Meade, 1987) of collective ownership in which n workers share in total profit, but may have only $1/n$ incentive to add to that profit – a theory that has spawned an immense literature. A relevant feature that gives bite to the "tragedy" is that marginal analysis usually assumes that supply and demand schedules are smooth, so a small change is supply leads to a small change in equilibrium prices. In this case the move from curtailment, when the efficient price is the avoidable cost of wind, to non-curtailment, means a discrete and rather large jump in the efficient price to the avoidable cost of flexible generation.[7]

This article models and quantifies this implication of curtailment for the specific case of wind. It also argues that the normal way of de-rating conventional capacity to estimate its equivalent firm capacity is not appropriate for high levels of VRE. The forced outage rate of conventional capacity is typically low (below 10%) and together with maintenance outages can provide a fair

[5] Gowrisankaran et al. (2016) examine this for VRE, notably solar PV, for Arizona.

[6] But see Ueckerdt et al. (2013).

[7] I am indebted to a conversation with Richard Green for clarifying why the normal continuous supply function approach fails in this case.

measure of its equivalent firm capacity. The same is not true for VRE, which is dependent on both availability and the external resource (wind or solar strength). Unlike conventional plant, wind availability is highly correlated across different wind farms, increasing the cost of providing capacity adequacy. Thus the average capacity factor of wind in winter, when scarcities are more likely, may be well above its annual average, but despite this, wind cannot be relied upon to deliver that proportion of the time to count as firm. If VRE is paid the value of lost load in scarcity hours, it may earn considerably more than its derated capacity suggests, so that unless its unpredictability is properly taken into account, it will be overpaid, inducing excess entry. This is not a purely hypothetical case, as Greve and Roche (2020) discuss the case of multiple successful zero-subsidy bids into recent German off-shore wind tenders.

The article sets out a simple model to show first, the source and magnitude of this unreliability cost and second, the source and size of the shortfall between social value (that depend on *marginal* curtailment) and market revenue that is only reduced by *average* curtailment. It derives the formulae for the learning subsidy and corrective charge needed in a liberalized market to deliver the desired level of renewables penetration and estimates their magnitude. The data for the empirical estimates is taken from the Single Electricity Market (SEM) of the island of Ireland downloadable from Newbery (2020). The SEM is a particularly important market to study, as it is widely recognized as being at the forefront of addressing the challenge of high VRE penetration in a small, isolated system.

The model in section 3 introduces the equation for the curtailment function and hence the relationship of the marginal to average curtailment. The cost saving from an extra MW of wind capacity is derived from the equation for fossil generation cost in §3.3 and Appendix A, to provide an expression for the net social benefit of an extra MW of wind. Section 4 derives the equilibrium prices in an ideal competitive wholesale market, and hence the corrective charge needed to make free entry of wind deliver the socially efficient level of entry. Appendix A also sets out the equivalence of different ways of efficiently delivering capacity adequacy, while Appendix B provides the formula for the efficient level of learning subsidy. Together with the parameters describing a base case and ambitious scenario, §4.2 estimates the required corrective charge to decentralize efficient wind entry. Conclusions in section 5 suggest that the efficient learning subsidy and entry charge are comparable and offsetting, once wind capacity credit is properly calculated, and it might be simpler just to auction a suitable capacity payment to deliver the target volume of wind.

2 Literature Review

We are interested in high levels of VRE penetration that lead to the need for system-wide curtailment, rather than local congestion management. Unfortunately, Heptonstall and Gross (2020) find that their comprehensive and recent review "revealed only limited data sources for aggregated costs at high VRE penetrations, with the ranges determined by assumptions made in these studies about sources of flexibility." Most studies of the impact of VRE concentrate on their price impact – the merit order effect in which low variable cost renewables push out the supply curve and lower prices. The static merit order impact of renewables capacity in displacing fossil plant is well-understood (Clò et al., 2015; Cludius et al., 2014; Deane et al., 2017; Green and Vasilakos, 2012; Ketterer, 2014; Csereklyei et al., 2019). The long-run equilibrium effect is more nuanced, depending on entry and exit decisions of conventional plant. Green and Léautier (2015) provide the most sophisticated analytical model.

A systematic review of the costs and impacts of integrating VRE into power grids is provided by Heptonstall and Gross (2020), updating an earlier review by Hirth (2013). They find total (aggregated) costs of approximately €30 per MWh at levels of penetration of interest (above 45%), but very sensitive to system flexibility "with inflexible systems incurring up to four times the integration costs of very flexible systems". These studies typically do not estimate the distortionary costs of poorly designed support systems, which can be high in directing VRE to more costly locations within and between countries. Newbery et al. (2013, p4) estimate that efficiently allocating renewables across the EU and integrating flexibility services and interconnection could save €16bn-€30bn. Green and Léautier (2015) note the distortionary costs of recovering subsidies by levies on energy, without pointing to the more efficient form of subsidy to capacity mentioned above. Bothwell and Hobbs (2017) survey the distortionary effects of VRE support schemes and their interaction with capacity credits in the US,

High VRE penetration raises particular problems for measuring their contribution to capacity adequacy and measuring their equivalent firm capacity (EFC) – the amount by which 1 MW of the considered technology can displace firm capacity (guaranteed to be present when needed) and maintain the same reliability standard. Joskow and Tirole (2007) set out the stringent conditions under which well-designed markets could deliver the specified level of reliability in markets with price caps and capacity obligations, and a mixture of price-responsive customers who can respond to real-time scarcity prices and unresponsive customers who face fixed prices. Working back from a derivation of the value of lost load (which they point out is unlikely to be independent of nature of the load-shedding event), they show in their benchmark case that all generators and Load Serving Entities should face the value of lost load in cases of load shedding. They conclude that the unusual physical characteristics of electricity and networks "makes achieving an efficient allocation of resources with competitive wholesale and retail market mechanisms a very challenging task." (Joskow and Tirole, 2007, p83).

Bothwell and Hobbs (2017, p174) argue that "many nontraditional resources have limitations that are not directly translatable into equivalent forced outage rates in adequacy calculations." They also note that "the marginal contribution of wind and solar often decreases as the installed amount increases (Keane et al. 2011)." Part of the reason is curtailment, discussed below, but a more important reason is that while failures of conventional plant are uncorrelated, wind and solar PV outputs are typically quite highly correlated with similar plant in the same region. Keane et al. (2011) is particularly relevant in underlining that the EFC of wind not only depends on the amount of wind capacity, but on the strength of the wind in any year, illustrating this for Ireland between 1999 and 2008. This dependency and its implication for the measurement of EFC has been brought more up to date in Zachary et al. (2019). That article also provides a useful discussion of the relationship between two different reliability metrics, the Loss of Load Expectation (LoLE, number of hours on average per year when load may be shed) and Expected Energy Unserved (EEU), the fraction of MWhs per year that may be shed. For many but not all purposes there is a direct mapping between them, justifying the choice of LoLE as a suitable metric (but not for the evaluation of storage). They note that VRE can be treated in the same way as conventional plant only if "the process of variable generation is statistically independent of that of demand, in which case the de-rated level of variable generation is close to its mean value" – a condition that is not satisfied in the case of high wind penetration, as demonstrated in this article. We give a simple expression for de-rating in such cases.

The literature on learning effects is mainly concerned to estimate its rate, summarized in Newbery (2016 and Appendix B). Green and Léautier (2015) include learning-by-doing in their model of optimal support for renewables, and calibrate the model for GB, estimating the required marginal subsidy for on-shore wind (p. 32) allowing for the distortionary effects of charging consumers to provide the subsidy. Newbery (2016) develops an algebraic model to estimate the social benefits of additional investment and the justified subsidy, ignoring distortionary charges on electricity consumers as the benefits are global public goods that should logically be charged to general taxation.

The literature on curtailment concentrates on either local curtailment and congestion management, discussed by Joos and Staffell (2018) for Britain and Germany, or the need for storage (Pudjianto et al., 2014; Weiss and Wänn, 2013). Bothwell and Hobbs (2017) point to the potential distorting interactions between VRE support design and curtailment, and also its role in delivering reliability, partly explaining why the EFC of VRE declines with increasing penetration. At past rather low levels of penetration, Heptonstall and Gross (2020) find that "the median values for the share of VRE output curtailed across all penetration levels is consistently low, not exceeding 5%" but as this article shows, because the marginal curtailment is many times the average level, this can rapidly rise without a very flexible system. The SEM, where curtailment is already above 8%, therefore provides a foretaste of the future. In the most fully articulated dynamic model of VRE, Green and Léautier (2015) examine the marginal value of renewable capacity but only in so far as it displaces conventional generation, drives down future VRE capital costs and increases the distorting effects of the tax on energy to recover the subsidies. To the best of our knowledge there are no studies on the implications of the difference between marginal and average curtailment for market distortions.

3 The model

Consider an island (e.g. the island of Ireland) with a given interconnector and electrical storage capacity, which has set a reliability standard of L hours Loss of Load Expectation (LoLE) per year.[8] In the SEM this is currently 8 hrs per year, while in the UK and most of the EU it is 3 hours per year. Let $D(t)$ be demand net of imports in hour t (i.e. the amount to be provided from domestic supply) and let the Load Duration curve be $D(h)$ with $D' < 0$, so that load is re-ordered with the highest load in hour 0, where h is the number of hours that demand is higher than $D(h)$. Then $D(L)$ is the required firm (de-rated) capacity required to meet the reliability standard. National Grid (2014) shows how, under conditions of probabilistic supplies and demands, to determine the required de-rated capacity to deliver the reliability standard.

In an energy-only market with no capacity remuneration mechanism, capacity adequacy depends on the willingness of investors to enter if profitable. As noted above by Joskow and Tirole (2007) the System Operator will need to ensure that the energy price reaches the Value of Lost Load in scarcity hours. Jurisdictions in which electricity markets face both tight supply conditions and unhedgable future market uncertainty often choose some form of capacity remuneration mechanism to reduce entry risk. In such cases the System Operator needs to predict the capacity needed to deliver the chosen reliability standard. This involves forecasting demand and supply perhaps four years ahead of plant commissioning to give time to build the required additional plant. The firm capacity needed requires a de-rating factor for each technology. For conventional plant there is a deterministic derating factor for each plant based on its reliability (forced outage rate, maintenance intervals) that allows their random contributions to be summed to an approximately normal distribution (see, e.g. National Grid, 2014).

However, calculating the Equivalent Firm Capacity (EFC) of wind at high levels of VRE

[8] LoLE L and the Value of Lost Load, V, are intimately related, as shown in equation (18) below. The approach here follows standard European practice.

is problematic, as Zachary et al. (2019) show. It will depend on the amount of wind capacity, the state of the wind in that year and specific system characteristics. Nevertheless, the System Operator has to publish a de-rating factor for wind based on its best forecast of the state of the system, including the amount of wind capacity expected to enter. This article will provide a simple formula for determining this factor.

Suppose that expected wind capacity is W MW, that its de-rating factor is δ_W (to be determined below) and that ϕW MWh is average hourly output over an average wind year ($\widetilde{\phi} W$ in a random year, with $E\widetilde{\phi} = \phi$, with $\theta = \widetilde{\phi}/\phi$ as an index of wind output in any year). Then $\delta_W W$ MW will be assumed as its firm contribution to capacity adequacy in deciding how much conventional plant to procure.[9] Similarly, let F MW be derated baseload fossil capacity (in a low carbon world mostly CCGTs), and let P be derated peaking capacity. The difference between these two fossil technologies is that base-load has lower variable but higher fixed costs than peaking plant. Newbery (2016b, Proposition 1, reproduced in Appendix A below) shows that as a result peaking plant will, in equilibrium and in expectation, run a fixed number of hours $h_P = \Delta r/\Delta v$, where Δr is the excess annual capital and fixed cost per derated MW per year of base over peak load plant,[10] and Δv is the excess of peaking over baseload variable cost per MWh. The expected number of hours peaking plant runs is therefore independent of wind capacity, as is the required capacity to run those number of hours. Wind capacity therefore only impacts the amount of baseload plant and its capacity factor.

The normal way of measuring wind penetration would be as a share of total output, $W\phi H/\int_0^H D(t)dt$, where H is the number of hours per year (8,760) and ϕH is the average number of full wind hours per year (e.g. 2,500). The System Operator has to determine the amount of flexible capacity to procure well in advance to give time for constructing and commissioning new plant, and so makes a prediction of the amount of wind, W, to meet renewables (and/or carbon) targets, and its de-rating factor, δ_W, (based on the expected future system characteristics and reliability standard. The required fossil capacity must satisfy

$$F + P = D(L) - \delta_W W, \quad \text{so} \tag{1}$$

$$\frac{\partial F}{\partial W} = -\delta_W. \tag{2}$$

Thus if $\delta_W = 9.6\%$ (for the SEM from Eirgrid, 2020c), $\partial F/\partial W = -0.096$. In any hour the System Operator must have adequate capacity running or instantly available (e.g. from very fast

[9] National Grid ESO (2019) announces the wind EFC for auctions four years ahead. The EFC for on-shore wind has fallen steadily from 8.98% in 2020 to 7.42% in 2023. Keane et al. (2011) show that the EFCs at comparable levels of penetration are higher in Ireland than in GB. Eirgrid (2020c) gives the EFC for wind in the SEM as 9.6%.

[10] Capital and fixed costs are normally given per MWyear of full capacity and will have to be inflated by 1/derating factor to be consistent with the approach taken here.

response batteries) to meet demand, allowing for imports, while retaining sufficient dispatchable capacity to meet the N-1 standard – the loss of the single largest infeed (which may be the largest generating set, the largest import over any one interconnector, or the loss of a single high voltage transmission line).

In addition, the system must have a sufficient number of well-located individual units to ensure system stability. These units can be ramped down to their Minimum Stable Generation (MSG) level, but no lower if they are to be immediately available. Newbery (2020) gives their MSG for the SEM calculated from Eirgrid (2020a) as 795 MW, sufficiently high to meet the N-1 condition, and so it is MSG that is the relevant constraint. This will only be relevant if wind would otherwise displace too much fossil plant, and so would not happen in stress hours when all available fossil capacity will be called on.

Neither wind nor solar PV can normally offer inertia,[11] which is required to reduce the rate at which frequency drops with a supply loss or a sudden increase in demand. The Grid Codes specify the allowable Rate of Change of Frequency (RoCoF, in herz per second) which in turn determines the amount of inertia to avoid breaching the RoCoF standard.[12] Consequently, there must be enough inertia to adequately stabilize frequency. This is normally specified by the maximum acceptable System Non-Synchronous Penetration (SNSP). Thus in the SEM the aspiration is to reach 75% SNSP by 2020, where non-synchronous generation is all plant without a spinning mass directly synchronized to the grid frequency (like wind, solar PV and DC interconnectors). The level of SNSP will be critical in determining the amount of curtailment and hence the size of the resulting market distortion, and to that end define β = 1 - SNSP (so β = 25% in the base case considered below).

3.1 Curtailment

Wind and solar PV have rather low capacity factors, ϕ, (ϕ is normally below 30% for on-shore wind, while PV in Northern climes may be as low as 10%). Consequently the ratio of peak to average output will be high (= $1/\phi$, for on-shore wind more than 3:1) so that above a certain level of penetration there will be more wind than domestic demand. If neighbouring countries can accept additional imports, some of this surplus can be exported, and some may be stored if there is unused storage capacity, but beyond a certain level, also dictated by the reserve and SNSP requirements, the excess wind must be curtailed. Given the current state of the system

[11] If deliberately part-loaded and equipped with suitable control equipment they may be able to offer some synthetic inertia.

[12] Electrical equipment and synchronous generators automatically disconnect if they detect a higher than specified RoCoF for protection. If generation trips off as a result it would exacerbate the RoCoF and in a serious case might cause a black out, or at least require controlled disconnection, as happened in GB on 9 August 2019.

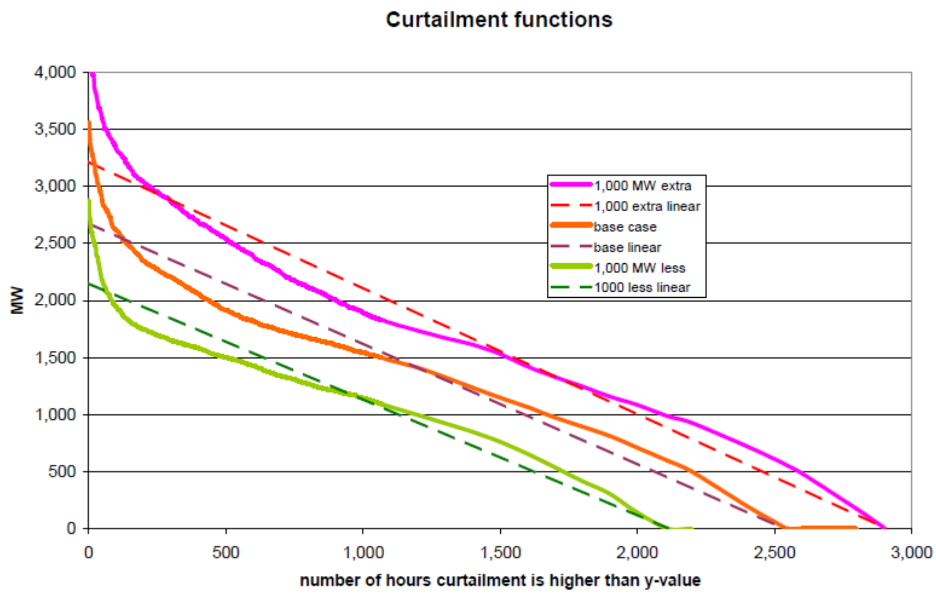

Figure 1: Curtailment for the SEM, 2026, base case SNSP = 75%

(demand, allowable exports, etc.) this curtailment function in a particular year can be written as $k(\theta W, h)$, ordered like the load duration curve.[13] That means for h hours per year, curtailment is no less than $k(\theta W, h)$ MW. Note that the position of the curve will vary with wind index, θ, with a higher intercept and more curtailed hours in windy years ($\theta > 1$) than on average. Unless relevant, the index θ will be dropped in most of what follows. Newbery (2020) provides a downloadable spreadsheet model of projected hourly demands and wind output for the SEM in 2026. This time sequence can capture the pattern of wind output and the state of storage in each hour, and allows the impact of alternative scenarios and different wind capacities to be analyzed at hourly resolution, The curtailment function can be calculated by ranking curtailment hours in descending order, as illustrated in figure 1.

For a given level of wind (and interconnector and storage capacity) the number of hours that wind is curtailed in a particular year, $h^*(\theta)$, solves

$$k(\theta W, h^*(\theta)) = 0. \tag{3}$$

During the h^* hours when wind is curtailed, with a sensible support system (described in the Introduction) and competitive markets, surplus supply should cause the price to fall to the avoidable costs of wind generation, v_W. That would mean that wind producers would be indifferent between generating and self-curtailing. If the support system makes subsidies contingent on generation, curtailment would be unattractive and some way of rationing (*pro rata* or Last-in

[13]It is a convenient simplification that the position of k depends on a single parameter, θ. As we shall be considering future average years this is not a critical assumption.

First-out) would be needed.

The marginal impact on the number of curtailed hours can be found by implicitly differentiating (3) with respect to W:

$$\frac{\partial h^*}{\partial W} = -\frac{\partial k/\partial W}{\partial k/\partial h^*}. \tag{4}$$

The normal way to measure curtailment is the volume of wind curtailed, $\int_0^{h^*} k(W,h)dh$, which in general will be higher than $h^* W\phi$ as curtailment hours are likely to be hours of above average capacity factors. The average curtailment as a share of potential wind output is

$$\frac{\int_0^{h^*} k(W,h)dh}{W\phi H}. \tag{5}$$

Thus Eirgrid (2020b) gives the total wind curtailed in the SEM for 2019 as 1,008 GWh or 8.3%. The shape of the curtailment function will depend on its correlation with demand less exports and injections into storage (which we can term net wind demand). In the case of the SEM under the EU *Clean Energy Package* in 2026 as set out in Newbery (2020), the ability to export surplus wind is frequently constrained by the ability of its neighbours to import, as surplus wind in the SEM often corresponds to surplus wind in neighbours, preventing exports.

However, the more serious constraints are the required stability units running at Minimum Stable Generation and SNSP constraints. If these are taken into account, the curtailment curve is somewhat more concave (with a sharp upturn near the y-intercept) than the linearized version used to evaluate expressions, shown in figure 1 and represented by:

$$\begin{aligned} k &= A(1 - h(\theta)/h_r^*) + \alpha(\theta W - W_r), & (6)\\ h^*(\theta) &= h_r^* + \frac{\alpha h_r^*}{A}(\theta W - W_r), & (7) \end{aligned}$$

where subscript r is the reference (2026) level. If we took this linearization seriously, then at W_0 there would be no curtailment (assuming a copper plate, that is with no internal transmission constraints limiting wind in particular locations), and hence $h_0^* = 0$, making $A = \alpha(W_r - W_0)$. Rewriting (6)

$$\begin{aligned} k &= \alpha(\theta W - W_0 - (W_r - W_0)h/h_r^*), \\ h^*(\theta) &= h_r^* \frac{\theta W - W_0}{W_r - W_0}. & (8) \end{aligned}$$

From equations (8) and (7)

$$\frac{\partial h^*}{\partial W} = \frac{h_r^* \theta}{W_r - W_0} = \frac{\alpha \theta h_r^*}{A}. \tag{9}$$

Both expressions for $\partial h^*/\partial W$ are useful, in that the first is readily interpreted, while the second is more useful in numerical calculations where A and α can be directly calculated.

3.2 Two scenarios for the SEM in 2026

The spreadsheet model described in Newbery (2020) allows the wind in each hour to be scaled by a given multiple to allow for discrete estimates of the partial derivatives, $\partial k/\partial W$, $\partial h^*/\partial W$, and for each simulation the other parameters can also be read off. The amount of interconnector and storage capacity can also be varied to construct the associated curtailment functions. The less ambitious scenario (the base case) assumes that SNSP cannot be increased above the 2020 target level of 75%, that the planned 700 MW Celtic Interconnector to France is delayed, and that only the projected level of Battery Electric Storage (BES) is available, in addition to the existing Pumped Storage Plant. The more ambitious scenario assumes that SNSP can be increased to 85%, the Celtic Interconnector is commissioned, and that BES is trebled by an ambitious programme of smart controls for charging Battery Electric Vehicles, electric storage heaters and immersion water heaters. Newbery (2020) describes these options and simulates hourly impacts for different scenarios.

The target wind penetration is 55% in 2026, the reference year, and the spreadsheet model will be used to calibrate this algebraic model, when full wind capacity required to deliver this is $W_r = 10,234$ MW[14] (based on scaling up actual hourly wind and associated capacity in the average wind year 2018) and the capacity factor $\phi = 28.4\%$. The key parameters for each case are given in Table 1, with the explanations of their derivation in the next section. The main problem with considering an average wind year is that it fails to account for the infrequent years in which extended periods of cold weather and low wind give rise to a high loss of load, as the distribution of such events is far from normal.

Table 1 Parameters for base and ambitious scenarios

Parameters	Base case	Ambitious case
h^* curtailed hours	$2,581$ hrs	$1,900$ hrs
$\int kdh$, spilled wind	$3,388$ GWh	$1,674$ GWh
$A = k(0)$, intercept	$2,678$ MW	$1,762$ MW
$\alpha = \partial k/\partial W$, slope	0.47	0.37
ϕ_e effective capacity factor	24.6%	26.5%
ϕ_P capacity factor in peak	44.1%	49.6%
ϕ_{H-h^*} CF around curtailment	34.3%	46%

[14] The highest wind output in the scaled year is 8,673 MW, or only 85% of actual capacity, because of the imperfect correlation of wind output across the island.

3.2.1 Base case scenario

In the base case with SNSP = 75% and no Celtic Link interconnector, the simulation model finds $h_r^* = 2,581$ hrs and $h_r^*/H = 29.4\%$. The value of the intercept of the linear curtailment function, A, is found from the spreadsheet value of curtailed wind and shown in Table 1.

$$\int_0^{h^*} k(W,h)dh = \frac{1}{2}Ah_r^* = 3,388 \text{ GWh}. \tag{10}$$

Given the spreadsheet value of h^* and the curtailed volume, this determines $A = 2,678$ MW. The value of $\alpha = \partial k/\partial W = 0.47$ is found by discrete variations of W around the reference wind level of ± 100 MW, (but 0.53 MW/MW for a wider range of $\pm 1,000$ MW, shown in figure 1). From the equation for $A = \alpha(W_r - W_0)$, $W_0 = 4,535$ MW (but directly sensitive to the uncertainty in α). Averaging over a range about this base case of ± 100 MW, the value of $\partial h^*/\partial W = 0.46$ hrs/MW (and 0.4 for $\pm 1,000$ MW), while the formula gives a value of $\partial h^*/\partial W = \alpha h_r^*/A = 0.45$ (or 0.51 for a wider variation in W). Using this equation the volume of wind curtailed evaluated at W_0, h_0^*, which is the observed value in the base case and the way in which the value of is A set.

In the base case of a nominal wind penetration (before curtailment) of 55%, the potential wind generation, $W\phi H$, is 25,437 GWh, so the average curtailment is 13.3%. Another way to look at the impact of curtailment is that it reduces the average full operating hours of ϕH to an average effective operating hours of $H(\phi - \frac{1}{2}(A/W)(h_r^*/H))$, so that instead of a nominal capacity factor of $\phi = 28.4\%$, the effective capacity factor is reduced by 3.8% to 24.6% (i.e. by 13.3% of 28.4%).

The marginal loss of wind output is

$$\begin{aligned}
\frac{\partial}{\partial W}\int_0^{h^*} k(W,h)dh &= k(W,h^*)\frac{\partial h^*}{\partial W} + \int_0^{h^*} \frac{\partial k(W,h)}{\partial W}dh, & (11)\\
&= \int_0^{h^*} \frac{\partial k}{\partial W}dh. & (12)
\end{aligned}$$

In this linearized case equation (12) becomes (in the base case)

$$\int_0^{h_r^*} \frac{\partial k}{\partial W}dh = \int_0^{h_r^*} \alpha dh = \alpha h_r^* = 1,213 \text{ MWh/MW}. \tag{13}$$

This can also be expressed as a fraction of the full potential output of 1 MW of $\phi H = 2,488$ hours, or 48.8%.

The ratio of the marginal to the average curtailment factors will be

$$\frac{W_r \int_0^{h_r^*} \frac{\partial k}{\partial W}dh}{\int_0^{h^*} k(W,h)dh} = \frac{2\alpha W_r}{A} = \frac{2}{1 - W_0/W_r}. \tag{14}$$

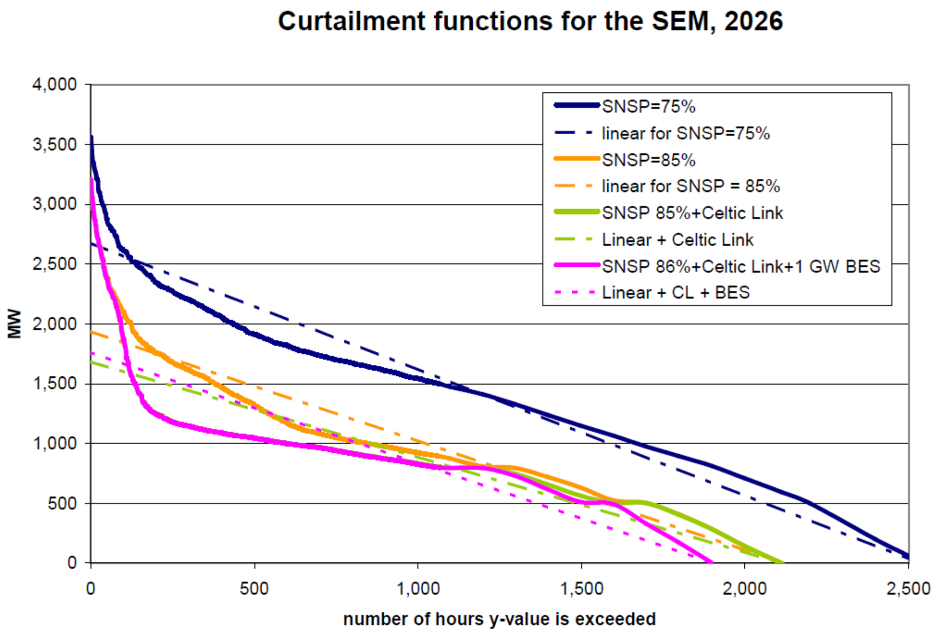

Figure 2: Curtailment in SEM, 2026, ambitious scenario

With $\alpha = 0.47$, the striking finding is that the marginal curtailments 3.66 times the average, but with the higher $\alpha = 0.53$, nearly four times the average. Note that if the curtailment function were a triangle with constant slope independent of wind capacity, and if $W_0 = 0$, its area would be proportional to W^2 so the ratio of the margin to the average would be 2. The denominator in (14) corrects for case where $W_0 > 0$.

3.2.2 Ambitious scenario

This assumes the 700 MW Celtic Link is in operation, that BES has been trebled, and SNSP raised to 85%. Figure 2 shows the successive curtailment curves from introducing these additional flexibility measures cumulatively. The curve is now increasingly far from linear as the various measures interact, while the original constraints on exports remain. The non-linearity is not worrying, as the calibration ensures that the area under the curve is made equal to that under the linear fit by solving for A. Curtailment falls to $1,674$ GWh or 6.6% but the marginal curtailment (for an increase of 100 MW capacity) is 28.2%, or using (13), $0.37 * 1,674/2,488 = 24.9\%$, reasonably close to the properly simulated measurement. In this case the ratio of the marginal to average curtailment is more than 4:1.

3.3 System cost

For simplicity we assume only two types of fossil plant, with all baseload plant identical and similarly all peaking plant identical (a justifiable simplification of the continuous range of technologies in Holmberg and Ritz, 2020). We are interested in the benefit of introducing an extra MW of wind capacity in reducing fossil system costs. Appendix A equation (23) derives the equation for fossil generation costs, $C_f(W)$, as

$$C_f(W) = (D(L) - W\delta_W)r_P + \Delta v \int_0^{h_P} (D(h) - \widehat{\phi}(h)W)dh + v_F \int_0^{H-h^*(W)} (D(h) - \widehat{\phi}(h)W)dh + mh^* v_F,$$

where $\widehat{\phi}(h)$ is the curtailed capacity factor in hour h and $h_P = \Delta r/\Delta v$ is the number of hours of peak running, independent of any decision variable. The fossil cost saving of 1 MW of extra wind investment is:

$$-\frac{\partial C_f}{\partial W} = \delta_W r_P + \Delta r \phi_P + v_F\{(H - h^*)\phi_e + \frac{\partial h^*}{\partial W} R_{H-h^*}\}, \tag{15}$$

where $\Delta v.h_P$ in the second term has been replaced by Δr, ϕ_P is the average wind capacity factor in the peak hours (allowing for curtailment) and ϕ_e is the effective wind capacity factor after allowing for curtailment. The saving, $-\partial C_f/\partial W$, is positive as extra wind displaces the need for some fossil capacity and output. The residual demand for fossil generation when wind just does not need to be curtailed, R_{H-h^*}, must be just high enough to cover the various system stability requirements, which are most likely set by SNSP, a fraction β (25% in the base case) of wind output in that hour, so $R_{H-h^*} = \beta\phi_{H-h^*}W$ MWh.

Equation (15) can be interpreted as follows. The first term is the capacity credit for the amount of peaking plant displaced to meet the reliability standard. The second term is the cost saving of displacing some peaking output, but only its excess above the baseload operation in that period, with the balance bundled into the third term. The third term is the intensive margin of cost saving holding the number of curtailed hours constant, while the last term is the extensive margin of increasing the number of curtailed hours.

The net social value, S_W, of 1 MW of extra wind is the reduction in system cost *less* the cost of running that 1 MW for the year, so $S_W = -\partial C_f/\partial W - (r_W + v_W(H - h^*)\phi_e)$. Substituting from (15) this gives

$$S_W = \delta_W r_P - r_W + \Delta r \phi_P + (v_F - v_W)(H - h^*)\phi_e + v_F \frac{\partial h^*}{\partial W} R_{H-h^*}. \tag{16}$$

If wind investment choices are to be left to the market, so that investors only enter if they can cover their fixed costs, then for entry to be efficient (and deliver the optimal amount of wind capacity) the net social surplus should equal the net market profit, which may need to be adjusted by taxes or subsidies to make them equal. The next section compares (16) with net market profit in a competitive market to compute the corrective charge.

4 Pricing in a liberalized market

In an ideal efficiently designed competitive liberalized electricity market the wholesale price in hour t, $p(t)$, depends on the system marginal cost (SMC) if there is adequate capacity, and otherwise the Value of Lost Load, VoLL, V. If, as is normal, the price is set before dispatch and with some remaining uncertainty about output and demand, $p(t) = (1 - \pi(t)).\text{SMC} + \pi(t).V$, where $\pi(t)$ is the Loss of Load Probability in hour t, and $\int_0^H \pi(t)dt = L$, the Loss of Load Expectation in hours per year (on average over a lengthy period). Two corrections are needed to make even competitive electricity markets reach this ideal.

First, all external costs from fossil generation have to be reflected in taxes or charges, notably for CO_2, through a proper emissions charge. Second, the external, mainly learning benefits of renewables (here wind) should be subsidized, with the subsidy targeted on the source of the benefits, e.g. calculated according to the methodology set out in Newbery (2018) and summarized in the Introduction as an auctioned additional supplement paid per MWh e.g. for the first 25,000 MWh/MW). That leads to the question whether setting the social value of r_W would be sufficient to induce efficient wind entry, or whether, and if so how much, additional penalty (or subsidy) is needed to reflect the extra system costs and capacity benefits of wind.

If wind is curtailed, the efficient wholesale price falls to $p = v_W$ (assuming certainty at the time of price-setting and no distorting wind output subsidies). The only fossil generation running would be for stability and frequency (i.e. to handle SNSP) purposes. The amount above that required for security of supply (the N-1 constraint, the loss of the largest infeed) is clearly attributable to wind, as otherwise demand would be high enough to ensure this constraint would be automatically met. Peaking capacity is only required in the top h_P hours, when $p = v_P > v_F$. The efficient price in the remaining hours when baseload is running is $p = v_F$, and in stress hours, when load has to be shed to avoid system collapse, the price is $p = V$.[15] Wind varies considerably from year to year, and in an average year, the number of load-shedding hours, $\lambda(\theta)$, $\theta = 1$, will be below average, and may even be almost zero, but $E\lambda(\theta) = L$ (where E is the expectations operator).

Peaking capacity will only earn profits in stress hours, but baseload capacity will earn profits whenever peaking plant is running. In an ideal deterministic market the efficient prices should induce the right amount of fossil generation to enter, but under uncertainty the System Operator may need to define the capacity to procure and run a capacity auction as discussed in Appendix

[15] In a normal year day-ahead prices will gradually rise above v_P towards V as the Loss of Load Probability π increases (exponentially as the reserve margin falls). The simplifying assumption is that the revenue in scarcity hours is on average V, rather than starting below V but for more hours.

A. For peaking plant to cover its full costs

$$L(V - v_P) = r_P, \tag{17}$$
$$V = v_P + \frac{r_P}{L}, \tag{18}$$

showing that once the reliability standard L has been set, the required VoLL, V, is determined (or vice versa, if the VoLL is known then the LoLE, L, is determined). Baseload plant will earn supernormal profits

$$\begin{aligned} & L(V - v_F) + (h_P - L)\Delta v - r_F, \\ = \; & L(\Delta v + \frac{r_P}{L}) + (\Delta r/\Delta v - L)\Delta v, \\ = \; & r_P + \Delta r - r_F = 0, \end{aligned}$$

ensuring that baseload plant can also cover its full costs – a standard result in constant return models. Appendix A shows that this requirement in an energy-only market (with its strong assumptions of either perfect foresight or risk neutrality and rational expectations) can be delivered with less risk (or without relying on these demanding assumptions) in a market with a Capacity Reliability Mechanism, and specifically, the Reliability Option employed in the SEM. For simplicity we only model an efficient energy-only market.

If prices fall to the avoided cost of wind when wind is surplus, then it does not matter which wind turbines are curtailed, as they only just cover avoidable costs. Wind output subsidies would change that presumption and would likely be accompanied by compensation for lost output when curtailed (but this would be at variance with the ideal market design described above). Ranking hours according to residual demand, prices in the $\lambda = \lambda(\theta)$ stress hours (which will vary from year to year, indexed by θ) will be V, in the next $h_P - \lambda$ hours, v_P, in the remaining $H - h^*$ hours before curtailment, v_F, and then v_W. Instead of aggregating revenues as areas under this step function and above v_W, it is simpler to consider rectangles of height equal to the successively lower price differences and width to the end of that price. Thus the second rectangle would have height $v_P - v_F$ and width h_P. Wind would not be curtailed in stress or peak hours, and so over the typical year it would earn market surplus, M_W, per MW capacity of

$$\begin{aligned} M_W &= (V - v_W) \int_0^{\lambda} \widehat{\phi}(h)dh + (v_P - v_F) \int_0^{h_P} \widehat{\phi}(h)dh + (v_F - v_W)) \int_0^{H-h^*} \widehat{\phi}(h)dh - r_W, \\ &= (v_P + \frac{r_P}{L} - v_W)\lambda\phi_\lambda + \Delta v h_P \phi_P + (v_F - v_W)(H - h^*)\phi_e - r_W, \\ M_W &= r_P(\lambda/L)\phi_\lambda - r_W + (v_p - v_W)\lambda\phi_\lambda + \Delta r \phi_P + (v_F - v_W)(H - h^*)\phi_e, \qquad (19) \end{aligned}$$

where $\widehat{\phi}(h)$ is the capacity factor in hour h (allowing for curtailment) with the hours ranked by the residual demand duration function, $R(h)$, that determines which plant are operating and whether or not it is a stress hour. V in the first term has been replaced by it value in (18) and $h_P = \Delta r/\Delta v$. The average wind capacity factors are ϕ_λ, ϕ_P, for stress and peak hours and ϕ_e is the effective capacity factor in non-curtailed hours. Note that in the λ stress hours, wind would not be curtailed, and although $E(\lambda/L) = 1$, it does not follow that $E(\lambda/L)\phi_\lambda = \phi_L$ (the average wind capacity factor in the year with L hours of load shedding). In the SEM, wind is normally stronger in winter months when stress events are more likely. The effective wind capacity factor, ϕ_e, is reduced by the curtailment factor from its nominal capacity factor, ϕ.

4.1 Decentralized equilibrium

If it is left to wind producers to decide whether or not to enter,[16] then efficient entry requires that net social surplus, S_W, of equation (16) is equal to the expected net market surplus, which will depend on $E[\lambda\phi_\lambda]$ in (19). Normally one might expect that if all externalities (emissions pricing, learning spill-overs) are internalized, then the efficient equilibrium ought to be supported in a competitive market, but that is not the case here. Instead it requires an annual fixed charge, τ (if negative, a subsidy) to restore equality and hence efficient entry, or $\tau = M_W - S_W$. Note that while several terms in (16) and (19) are the same and therefore cancel, some differ, immediately suggesting that free entry will not necessarily be efficient without a charge or subsidy.

In an energy-only market in long-run equilibrium the corrective charge will be

$$\tau(W) = r_P(E\lambda\phi_\lambda/L - \delta_W) + (v_p - v_W)E\lambda\phi_\lambda + v_F\beta\phi_{H-h^*}W\frac{\partial h^*}{\partial W} > 0, \tag{20}$$

where the value of δ_W is to be determined. While the terms ϕ_λ, ϕ_P, ϕ_e vary from year to year (with θ), the charge/subsidy τ take the form of an annual fixed charge to be set each year for new entrants based on the expected conditions looking forward from the moment of entry. The last term replaces R_{H-h^*} by $\beta\phi_{H-h^*}W$, which could be estimated directly, as could $\partial h^*/\partial W$, or $\partial h^*/\partial W$ could be replaced by $\alpha h^*/A = h^*/(W - W_0)$ from (9). The first two terms reflect the fact that the characteristics of wind make derating its value to the market quite problematic. The main reason why the System Operator needs a de-rating value for wind, δ_W, is to determine the amount of flexible plant to procure (if not in an auction, then as in Joskow and Tirole, 2007, by placing an obligation on Load Serving Entities to contract). In an energy-only market that determines the Value of Lost Load required to induce efficient entry, which would require

$$\delta_W = \frac{E\lambda\phi_\lambda}{L}\left(1 - \frac{(v_p - v_W)L}{r_p}\right). \tag{21}$$

The second term in the bracket is much less than 1, so the correct derating of wind depends on the correlation of λ and ϕ_λ. Intuitively these would seem to be negatively related as if ϕ_λ is high,

[16] Greve and Rocha (2020, p91) note that a 2019 Dutch off-shore wind tender "introduced a no subsidy requirement."

then load shedding is less likely and λ will be shorter, and conversely. Given a sufficiently long run of data on wind and demand, it should be possible to estimate $E\lambda\phi_\lambda$.

Assuming that the first two terms can be collectively set to zero by the choice of δ_W, the remaining reason for a charge derives from the impact of extra wind increasing curtailment, $\partial h^*/\partial W$. This curtailment effect reflects a different decentralization problem. It may seem surprising that the small change in curtailment has such a large numerical impact (as the next section shows), but the reason lies in the first term, v_F, which reflects the large step change in the equilibrium price from v_W, which gives wind zero profit, to v_F, which is substantially higher. Economic intuition tends to assume that supply curves are continuous and hence small changes in supply lead to small changes in price, but that is not the case here.

The simplest way in which the systems charge could be levied is as an annual Transmission Network Use of Systems charge (TNUoS, to use the British terminology), which would depend on the expected level of curtailment measured by $h^*(W)$. It would be desirable to offer a long-term contract for TNUoS specific to each wave of entry, as the charge is only relevant for prospective new entrants.

4.2 Numerical estimates

The expression that remains to evaluate is

$$\tau(W) = v_F \beta \phi_{H-h^*} W \frac{\partial h^*}{\partial W}.$$

The first term does not vary between scenarios, while $\beta = 1-$ SNSP and will be 25% in the base case, 15% in the ambitious scenario. In the linear curtailment case $W\partial h^*/\partial W = h^*W/(W - W_0) = \alpha h_r^* W/A$, a multiple of h^*. That leaves the capacity factor at the margin of non-curtailment, which is likely to be above the average capacity factor. Taking the base case SEM 2026 parameters first, $\phi = 28.4\%$, $\phi_e = 24.6\%$, $h_r^* = 2,581$ hours, $\alpha = 0.47$, $\alpha h_r^* = 1,213$ hours and $A = 2,678$ MW. The wind capacity factor $\phi_{H-h^*} = 35\%$, confirming this intuition. BEIS (2020) gives 2025 (medium) capital costs for CCGTs, peaking plant (open-cycle gas turbine) and on-shore wind, as well as the fixed and variable operating costs and fuel efficiencies.[17] The GB estimates of the derating factor for CCGTs is 90%, needed to compute the fixed costs per unit of de-rated capacity shown in Table 2. The costs are converted (at 2018 exchange rates of €1.13=£1) to € and shown in Table 2. The projected median gas price is €21.4/MWh (FES, 2019) while the CO_2 price is taken as €40/tonne.

Table 2 Cost estimates[18]

[17] OCGT efficiency is 34%; CCGTs efficiency is 53%.

[18] The capital cost figures for base and peaking are per *derated* MW, and so the cost per installed MW needs to

r_F	€$85,218$/MWyr	v_F	€61/MWh
r_P	€$37,012$/MWyr	v_P	€91/MWh
r_W	€$120,132$/MWyr	v_W	€7/MWh
Δr	€$48,206$/MWyr	Δv	€30/MWh
h_P	1,607 hours	L	8 hours

The corrective charge τ in this case is €$24,461$/MWyr, just 20% of the annual fixed cost.

4.3 Ambitious scenario

In this case, $\phi = 28.4\%$ as before but $\phi_e = 26.5\%$, $h^* = 1,900$ hours, $\alpha = 0.31$, $\beta = 15\%$ and $A = 1,762$ MW. The wind capacity factor $\phi_{H-h^*} = 37\%$, slightly higher as windier hours are curtailed. The corrective charge falls to $\tau =$ €$11,582$/MWyr, reduced mainly by the higher SNSP (the other two terms are slightly increased). The corrective charge is now under 10% of annual fixed costs.

4.4 Learning externalities

The assumption above was that the learning spillovers were already corrected, but the empirical figures for the annualized capital costs were not so corrected. Newbery (2016) shows how to calculate the globally desirable level of subsidy. Appendix B gives the relevant formula for this subsidy, with a central estimate for 2026 of 10% of the capital cost. This is comparable to, and offsets, the ambitious scenario corrective charge and therefore roughly cancels it out. Taking the uncorrected IRENA (2016) learning rate estimates at face value, as discussed in Appendix B, the learning subsidy might be 16% of the capital cost, again, not far short of the corrective charge in the base case.

5 Conclusions

Once a wind turbine is commissioned and connected, it will generate so long as it is not constrained or off-line. Some constraints are local, caused by transmission limits, and are best handled by offering non-firm connections in such locations (with the option of paying a fair share of any grid reinforcement costs needed to provide firm access to the rest of the system, as described by the LCNF project *Plug and Play*).[19] The constraints considered here are system

be inflated to allow for this.

[19] at https://www.ofgem.gov.uk/sites/default/files/docs/2015/05/fpp_sdrc_reward_application_v2.0_pxm_2015-05-01_final_0.pdf

wide, and need a system-wide solution. The first part of good system design is to ensure that carbon costs are properly charged, innovative technologies are compensated for their external learning benefits, and electricity pricing into the grid reflects the social marginal cost of generation, cleansed of distortionary subsidies (except where, as a second best, carbon taxes are below their social cost, and zero carbon generation can be compensated per MWh for the underpricing of any carbon displaced).

The remaining element of good design is to ensure the efficient entry (and type) of new generation. With an efficient energy-only market, or suitably auctioned capacity payments, fossil entry can be left to market signals. The capacity credit for wind is rather more complicated to calculate (and very sensitive to demand and wind conditions in winter months, as Appendix A shows. The tentative conclusion from rough calculations is that its capacity credit seems lower than those currently used. The key new factor considered here is that once wind penetration is high enough to cause system-wide curtailment, additional wind imposes an additional cost that is not reflected in market prices, as the marginal curtailment is many times higher than the average curtailment that sets prices. This is the "tragedy of the commons" that is at the heart of the market failure. These extra costs are almost proportional to $\beta = 1-$ SNSP, but will also be affected by the amount of storage and the ability to export. Export opportunities in turn depend on export capacity but also on the extent and simultaneity of wind abroad. The two cases considered here give rise to material annual charges of 10-20% of annual fixed costs, roughly proportional to 1 - SNSP. Offsetting this corrective charge, the global learning externality (mostly reaped abroad, but internalized if other countries offer similar subsidies as a club payment, e.g. under the EU *Clean Energy Package*) might be 11-17% of annual fixed costs and therefore of comparable magnitude.

The conclusion is that the capacity credit might need separate attention and that the curtailment effect will depend very much on system characteristics (penetration and SNSP most directly) and is comparable to the likely justified global learning subsidy. Whether this would be true in other systems or with higher wind penetration should be explored as part of wider study of the appropriate way to support wind, and the extent to and manner in which to grant capacity payments to wind. The simpler alternative is to set the renewables target and run auctions for the amount of renewables by allowing them to bid for the strike price in a Contract for Difference for the first 25,000 full operating hours (i.e. MWh/MW), which would provide a revenue stream for about 10 years. Recent Continental auctions for off-shore wind suggest this might even fall to zero (Greve and Rocha, 2020).

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Appendix A Pricing in peak and scarcity hours

Let $R(h) = D(h) - \widehat{\phi}(h)W$ be the residual demand curve in hour h, where $\widehat{\phi}(h)$ is the curtailed wind capacity factor in that hour, $R' < 0$. If the top L hours are shed, the volume lost by consumers is $\int_0^L R(h)dh$, where each MWh lost is valued at the Value of Lost Load, V. Peaking plant will run in the top h_P hours (which will depend on the derated baseload capacity, F) while baseload plant will run in the top $h_F = H - h^*$ hours, i.e. the full year less wind curtailed hours. $R(h_P) = F$, derated baseload capacity, above which peaking plant is required as well. During curtailment m MW will have to run to satisfy the system stability requirement, and this will also be baseload plant. The cost of running the fossil plant to meet the various security of supply standards is

$$C_f(W) = Fr_F + Pr_P + v_P \int_0^{h_P(F)} (R(h) - F)dh + v_F \int_0^{H-h^*} Min(F, R(h))dh + mh^* v_F,$$

As peak capacity, P, must meet the reliability standard in (1), namely $F + P = D(L) - W\delta_W$, P can be replaced by $D(L) - W\delta_W - F$ to give

$$\begin{aligned} C_f(W) &= F(r_F - r_P) + (D(L) - W\delta_W)r_P - v_P h_P(F)F \\ &\quad + v_P \int_0^{h_P(F)} R(h)dh + v_F\{h_P F + \int_{h_P(F)}^{H-h^*} R(h)dh\} + mh^* v_F, \\ &= F\Delta r + (D(L) - W\delta_W)r_P - \Delta v h_P(F)F \\ &\quad + v_P \int_0^{h_P(F)} R(h)dh + v_F \int_{h_P(F)}^{H-h^*} R(h)dh + mh^* v_F, \end{aligned} \tag{22}$$

where $\Delta r = r_F - r_P$, the difference in annual capital and fixed costs per derated MWyr, and $\Delta v = (v_P - v_F)$ is the difference in variable costs per MWh. The first order condition for F is

$$\begin{aligned} \frac{\partial C_f}{\partial F} &= \Delta r - \Delta v(h_P + Fh'_P) + \Delta v h'_p R(h_P) = 0, \\ \Delta r &= \Delta v h_P, \text{ or } h_P = \Delta r/\Delta v, \end{aligned}$$

as $R(h_P) = F$.

Substituting for $\Delta v h_P(F)$ in (22) and replacing residual demand by $D(h) - \widehat{\phi}(h)W$ (where $\widehat{\phi}(h)$ is the curtailed capacity factor in hour h) gives

$$\begin{aligned} C_f(W) &= (D(L) - W\delta_W)r_P + v_P \int_0^{h_P(F)} (D(h) - \widehat{\phi}(h)W)dh \\ &\quad + v_F \int_{h_P(F)}^{H-h^*} (D(h) - \widehat{\phi}(h)W)dh + mh^* v_F, \\ C_f(W) &= (D(L) - W\delta_W)r_P + \Delta v \left(\int_0^{h_P(F)} D(h)dh - \phi_P \right) \\ &\quad + v_F \left(\int_0^{H-h^*} D(h)dh - \phi_e \right) + mh^* v_F, \end{aligned} \tag{23}$$

where ϕ_P is the average wind capacity factor in the peak hours and ϕ_e is the effective wind capacity after allowing for curtailment.

Capacity Remuneration Mechanisms

As renewables increase so the risk of investing in fossil capacity increases, both because annual residual demand becomes more uncertain and because renewables policy and policies to address reliability (such as allowed SNSP) need to adapt in hard-to-predict ways. In response, markets requiring additional fossil investment often adopt Capacity Remuneration Mechanisms. The SEM has an auction for Reliability Options, ROs, that pay winners V_{RO} per MW derated capacity per year, in return for accepting a cap on their sales price of s per MWh. This takes the form of a one-sided Contract for Difference, in that the holder pays consumers $Max(p^* - s, 0)$ in stress hours, where p^* is set to be the minimum of the market price or some fraction (up to 1) of $\pi(t).V$, the value of expected lost load.[20] The efficient auction clearing price, V_{RO}, should give the same answer as (17):

$$\begin{aligned} L(V - v_P) &= V_{RO} + L(s - v_P), \\ V_{RO} &= L(V - s) = L(v_P - s) + r_p, \end{aligned} \tag{24}$$

from (18). It is easy to check that this induces the same efficient fossil entry as paying the VOLL, V, in an energy only market (under perfect certainty, at least).

Qualifications for intermittency

Wilton et al. (2014, p753) point out that the theory set out above, although suitable for "classical thermal generation stations" is not suited to VRE, as that there may be infrequent cases of extended periods of near-zero output from VRE sources. As Zachary et al. (2019) and Keane et al. (2011) point out, treating uncorrelated small variables additively is valid, but not if they are correlated and cumulatively a large share of the total, so δ_W is no longer a parameter independent of W. In addition, the Value of Lost Load, V, is not a constant independent of the length of the period of loss of load, and is likely to steadily increase (at least for some consumers) as outages lengthen. As wind output is highly correlated across different wind farms, a lack of wind (and hence unavailability) has a non-marginal impact on the system, while the failure of one conventional plant typically leads to a proportionately small impact on overall supply (less than 1% in larger systems). While VRE penetration is low this is not material but becomes so when penetration reaches the levels considered here (more so in moderately isolated systems like the SEM). The implications for de-rating wind are addressed in equation (21).

[20] Zachary et al. (2019) derive an essentially similar formula for the case of stochastic demand and supply, relating the cost of new entry to the VOLL and the LoLE.

Estimating the de-rating factor for wind

The main determinant of δ_W in (21) is $E\lambda\phi_\lambda/L$, which is very sensitive to demand and wind conditions in stress hours, which invariably occur in winter months in the cases studied (and usually in December and January at 5pm). The key determinant of the number of hours of lost load, λ, is the volume of de-rated flexible capacity, $F + P$, (and in practice, the derated capacity to import in stress hours). Small changes in equivalent firm capacity (EFC) lead to large changes in λ in any year. Table A1 shows for each electricity year[21] the implied values for λ and the average wind capacity factor in these hours, ϕ_λ, for varying levels of the EFC available. The table is constructed by first scaling up wind output in each hour by the ratio of the end-of-year wind capacity to the capacity available at that hour, to simulate a year of constant wind capacity. Hourly demand and hourly wind are then scaled up to a notional 2026, but allowing for the difference in wind capacity factors in each year, ϕ, shown for each year in the top line of Table A1.

Table A1 Implied capacity credits

EFC MW	2015-16	2016-17	2017-18	"2026"
	ϕ	annual	wind	CF
	25.0%	20.8%	22.0%	28.4%
	λ	lost	load	hrs/yr
6,893	108	59	110	10
7,000	85	55	93	8
7,600	19	22	12	0
7,800	11.5	12.5	6	0
	ϕ_λ	%		
6,893	3.1%	3.5%	3.8%	5.3%
7,000	3.1%	3.3%	4.0%	4.0%
7,600	2.4%	2.8%	3.6%	n.a.
7,800	1.9%	2.5%	4.7%	n.a.
	$\lambda\phi_\lambda/\lambda$	derating		
6,983	42%	25.6%	52.8%	6.6%
7,000	33.3%	22.7%	46.2%	4.0%
7,600	5.6%	7.7%	5.3%	0%
7,800	2.8%	0.5%	0.4%	0%

The table shows that 2017-18 was a low wind year with only 77.4% of the annual capacity

[21] The years run from April 1 to March 31 to ensure the whole of just one winter.

factor for “2026” and its scaling factor is therefore $0.774 W_{2026}/W_{17-18}$. While 7,000 MW of EFC gives “2026” a LoLE equal to the target 8 hrs, that EFC would give quite unacceptable load shedding in the earlier years, suggesting that considerably more EFC would be required. At 7,800 MW, the average LoLE is about the target 8 hrs. The high sensitivity of the LoLE to the EFC implies the need for more careful stochastic analysis of the kind demonstrated in National Grid (2014).

While the value of λ varies substantially from year to year for a given EFC (and also within a year with variations in the EFC), the average capacity factor in these stress hours, ϕ_λ, varies substantially less and is also remarkably low (which is one reason why there is a risk of loss of load). As a result, the implied wind derating factor, $\lambda\phi_\lambda/L$, is also highly sensitive to the EFC. Nevertheless, for an EFC that gives the desired average LoLE of 8 hrs (7,800 MW), $\lambda\phi_\lambda/L$ is only about one-quarter of Eirgrid’s (2020c) chosen wind derating factor of δ_W of 9.6%. The rather tentative conclusion emerging from this very rough set of estimates is that the derated value of wind at high levels of wind penetration is likely to be far lower than even the current low values used in estimating the required capacity to procure.

Appendix B Quantifying learning externalities

Newbery (2016) sets out a methodology and gives formulae for estimating the justifiable subsidies for technologies whose costs fall with cumulative installed capacity, on the assumption of *Mission Innovation,* that is, that the key countries collectively commit to support subsidizing roll-out guided by the size of the global externalities. The first step is to estimate the rate of cost fall as a function of cumulative installed capacity, K_t, given by Newbery (2016, equation (2)):

$$c_t = c_m + \alpha K_t^{-b} = c_0(\phi + (1-\phi)\left(\frac{K_t}{K_0}\right)^{-b}),$$

where $\phi \equiv c_m/c_0$ is the ratio of the minimum achievable long-run unit cost, c_m to that at date zero.

IRENA (2019) gives helpful data on past, current and projected cumulative on-shore (and off-shore) wind capacity and unit costs that allow an estimate of both ϕ and b. The learning rate λ – the cost fall for a doubling of capacity when $\phi = 0$ – is $\lambda = 1 - 2^{-b}$. Taking on-shore wind cumulative capacity estimates for 2010 of $K_{2010} = 179$ GW, $K_{2018} = 542$ GW, and targets of $K_{2030} = 1,787$ GW, $K_{2050} = 5,044$ GW, and unit costs (in US\$$_{2018}$) of $c_{2010} = \$1,913$/kW, $c_{2018} = \$1,497$/kW, and assuming $c_m = \$600$/kW, the estimated value of $\phi_{2018} = 0.4$, and $b = 0.34$, implying $c_{2030} = \$1,196$/kW, within the projected cost range from IRENA (2019, p33) of \$800– \$1,350/kW. This implies a remarkably high learning rate $\lambda = 20\%$, whereas the consensus learning rate for on-shore wind is more like $7 - 12\%$ (Newbery, 2016).[22] Part of the cost fall may be due to moving to auctions that encourage more competitive pricing, part to a shift in the source of turbines to lower cost countries, neither of which are directly attributable to technology learning. The implications of this range of learning rates will be considered in the numerical calculations.

The key expression for the justified subsidy rate σ_t (as a ratio to current installation cost, where t is the date less 2018, so for 2026 $t = 8$) is Newbery (2016, equation (16)):

$$\sigma = (1-\phi)e^{rt}\left(\frac{e^{-(bg+r)t} - e^{-(bg+r)T}}{1 + r/(bg)} + e^{-b(g-m)T}\frac{e^{-(bm+r)T} - e^{-(bm+r)N}}{1 + r/(bm)}\right),$$

where g is the growth rate of total capacity to saturation T years hence (taken as 2050, 32 years after the initial date, 2018), m is the rate of growth of saturated installation until N years hence, when all learning technologies have been exhausted ($N = 35$ years from 2018), r is the social discount rate ($r = 3\%$), and while $\phi = 0.4$, $b = 0.105,\ 0.184$, or its highest value, $b = 0.34$.

[22] The best fit (using data from IRENA, 2019, fig 10 and fig ES1) for the projected average investment costs in 2050 is for $\phi = 0$ and $\lambda = 25\%$, which is implausible. Earlier, IRENA announced an updated estimated learning rate for investment costs for on-shore wind 7%, at https://www.irena.org/newsroom/articles/2017/Mar/Onshore-Wind-Industry-Learning-Fast

Inserting these values into the formulae for $t = 0$, the 2018 justified rate of subsidy would be 9%, 14% or 22% for the lowest to highest learning rates. However, we are interested in the 2025 subsidy rates when $t = 8$, and when the subsidy rates range from 7% to 10% to at most 16%.