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High levels of low variable cost intermittent renewables lower wholesale electricity prices, and the depression of these prices could legitimately be recovered from consumers, preferably through capacity payments. Given that renewables are frequently subsidized for their learning benefits and carbon reduction, this paper asks what part of these subsidies should be recovered from final consumers. In long-run equilibrium, renewables have no impact on the number of hours peaking capacity runs, and its impact is to displace largely baseload capacity. The fall in competitive prices is considerably less than the fall in fossil operating costs and provides a case for only a modest share of total subsidies to be charged to electricity consumers. The paper quantifies the amount that can legitimately be charged.

Keywords renewables, electricity prices, subsidies, investment,

JEL Classification D47, H23, L94, Q42, Q48, Q54

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High levels of low variable costintermittent renewables lower wholesale electricity prices, and the depression of these prices could legitimately be recovered from consumers, preferably through capacity payments. Given that renewables are frequently subsidized for their learning benefits and carbon reduction, this paper asks what part of these subsidies should be recovered from final consumers. In long-run equilibrium, renewables have no impact on the number of hours peaking capacity runs, and its impact is to displace largely baseload capacity. The fall in competitive prices is considerably less than the fall in fossil operating costs and provides a case for only a modest share of total subsidies to be charged to electricity consumers. The paper quantifies the amount that can legitimately be charged.

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1 Introduction

Intermittent renewable electricity supply (RES) is currently subsidized in many liberalized electricity markets, partly to redress the underpricing of carbon, but also to support the

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public good aspect of delivering learning benefits. As mitigating the damaging impacts of climate change is a global public good, these learning benefits that drive down future costs should encourage other countries to adopt RES and hence reduce carbon emissions to benefit citizens everywhere. RES displaces conventional fossil generation, reducing both carbon emissions and fuel costs. It also depresses wholesale electricity prices, so some, but not necessarily all of the cost savings are automatically passed through to final consumers in lower prices. This paper asks by how much consumers gain in the long run from the RES capacity when all assets have had time to adjust to the new equilibrium. That additional consumer cost saving (above the price fall effect) is a legitimate capacity charge to impose on final electricity consumers, leaving the remaining subsidy for public good aspects, logically a charge on general tax revenue (Newbery, 2015).

To be quite clear, the wholesale price of electricity should remain at its efficient level, equal to the short-run marginal cost, which may be depressed in some hours by increased RES, plus an efficiently directed capacity charge, effectively the insurance paid for a reliable electricity supply. This capacity charge would be augmented by an amount that recovers the remaining justified RES support from electricity consumers. Increased RES (beyond the critical level at which it firsts exceeds demand) will increase the number of hours in which the efficient wholesale price falls to low or zero levels, which directly benefits consumers, and will also reduce capacity payments to fossil generation, and together these cost savings are a legitimate transfer to RES via an increased capacity charge to consumers. This paper shows how to calculate this additional capacity charge, which is likely to fall considerably short of the full cost of the RES, leaving the bulk of RES support as a charge for its public good aspects. In an example in which derated wind capacity is about one-fifth of peak demand, the fossil cost saving is about one-quarter of the no-wind amount, justifying a payment to wind slightly more than the displaced fuel cost. The cost saving comes from reductions in baseload capacity and fuel costs, leaving the peaking fuel cost as a higher share of total fossil fuel cost, and this can be recovered by a slightly higher capacity charge.

The fact that RES can lower wholesale prices through the merit-order effect has been widely noted in the literature,[1] where the focus has been on the short-run impact on wholesale prices, although Green and Vasilakos (2010, 2011) also study the potential medium and longer run impacts of future wind capacity targets on British wholesale prices. Liski

[1]e.g.Leprich (2012), Keterer (2014) , Renewable Analytics (2013), Wirth (2015).

and Vehviläinen (2015) have econometrically estimated the short-run impact that wind has on electricity wholesale prices and hence on the distribution of rents between producers and consumers in the Nordic market in the presence of massive storage hydro. In contrast this paper models the impact of RES on wholesale prices in a fossil-based electricity industry with no storage in long-run free entry equilibrium. In that state with constant returns to investment, wholesale prices will be driven to the point that all conventional generators earn a normal rate of return on their investments, and so conventional plant needs no compensation for the presence of the subsidized RES capacity. Fischer (2010) has modeled the impact of a fixed supply schedule of RES on an industry in long-run equilibrium with a variety of conventional generation plant types, to explore the impacts, via supply and demand elasticities, of renewable portfolio standards on energy prices, but her paper is a comparative statics exercise that does not model the intermittency of RES such as wind and PV.

Ambec and Crampes (2012) look at the long-run optimal plant mix with wind and conventional generation facing price-responsive demand. Their model has a single kind of conventional generation and the wind either blows at full strength some fraction of the time or not at all the remainder of the time. In the model studied here, demand does not respond to prices but does vary over the hours of the year, as does the output of RES. Costs are minimized and the industry is in long-run equilibrium with the optimal plant mix for any specified level of RES capacity. The aim is to find the impact of changes in RES capacity on plant mix and cost, which will be reflected in changes in average prices if they are efficiently set. In a very recent paper, Green and Léautier (2015) develop a fully analytical model of plant mix, price determination and various distorting RES subsidy regimes to examine the long-run equilibrium for very high levels of renewables penetration, examining the likelihood that subsidies will decline as their costs fall.

In this simplified model. which can be considered as complementary to Green and Léautier (2015), the market design assumes efficient prices and RES supports, and the focus is on the extent to which electricity consumers, rather than general taxes, can logically be charged for renewables penetration in return for the reduced prices that RES might induce. Thus payments for the system services needed to provide flexibility and reserve power attributable to RES are allocated entirely to RES, and assumed not to impact fossil generators nor affect consumer bills. The market structure can be thought of as a Pool (like the former Electricity Pool of England and Wales and the 2007-16 Single Electricity

Market, SEM, of the island of Ireland) in which generators are paid the system marginal cost for energy, including the carbon cost, and capacity payments are only paid to plant available, with payments concentrated in tighter hours, as set out in equation (1) below. Buyers (e.g. electricity retailers) face efficient prices and pay the wholesale price, p_h, (up-rated by various ancillary service costs), which includes any capacity payments. The final consumer price will include additional transmission, distribution and retailing costs.

Thus in hour h, p_h is the sum of the system marginal cost, SMC, the first term, and a capacity payment, the second term, the risk of scarcity – reflecting the value of reliability to the demand side:

$$p_h = SMC(h) + \pi_h(V - m_i), \quad \pi_h \approx e^{-\beta(D(h)-A(h))}, \quad \text{LoLE} = \textstyle\sum_0^Y \pi_h, \tag{1}$$

$$SMC(h) = m_p, \quad h \leq H, \quad = m_b, \quad h > H, \tag{2}$$

where π_h is the Loss of Load Probability (LOLP) in that hour, V is the Value of Lost Load (VOLL), $D(h)$ is demand and $A(h)$ is available capacity in hour h. The marginal cost of a peaking plant is m_p and of baseload plant is m_b, with hours ranked in order of decreasing residual demand, and the SMC, $m_i = m_p$ or m_b depending in which hour the scarcity occurs. The parameter β will depend on the characteristics of demand and the plant mix (demand predictability, generation unit size compared to peak demand, plant reliability).

The regulator or government will set a reliability standard, normally as a Loss of Load Expectation, LoLE, in hours per year (in most EU countries, at 3 hours/yr). That determines the (de-rated) capacity required, P, and the capacity cost can then be determined through a capacity auction, such as that run as part of the GB Electricity Market Reform (National Grid, 2014). Baseload generators will receive some inframarginal rent when peaking plant sets the price and all plant will be assured of recovering the balance of their capital cost via the capacity agreement secured in the auction. The effect of this pricing is that the cost of the capacity required to meet the reliability standard will be recovered in an average year. If wind output exceeds demand, the price is set to the very low avoidable cost of RES, taken as zero, for demand-ranked hours $y \leq h \leq Y$.[2]

[2] The value of y is thus the hour in which expected residual demand falls to zero, and for $h > y$, wind output will exceed demand. Other zero variable cost baseload plant like nuclear power should be subtracted from baseload generation, leaving less baseload fossil plant and thus increasing the likelihood of $y < Y$. Green and Léautier (2015) consider the important case of inflexible nuclear plant that may require negative prices (as might some forms of RES support) but such niceties are ignored here.

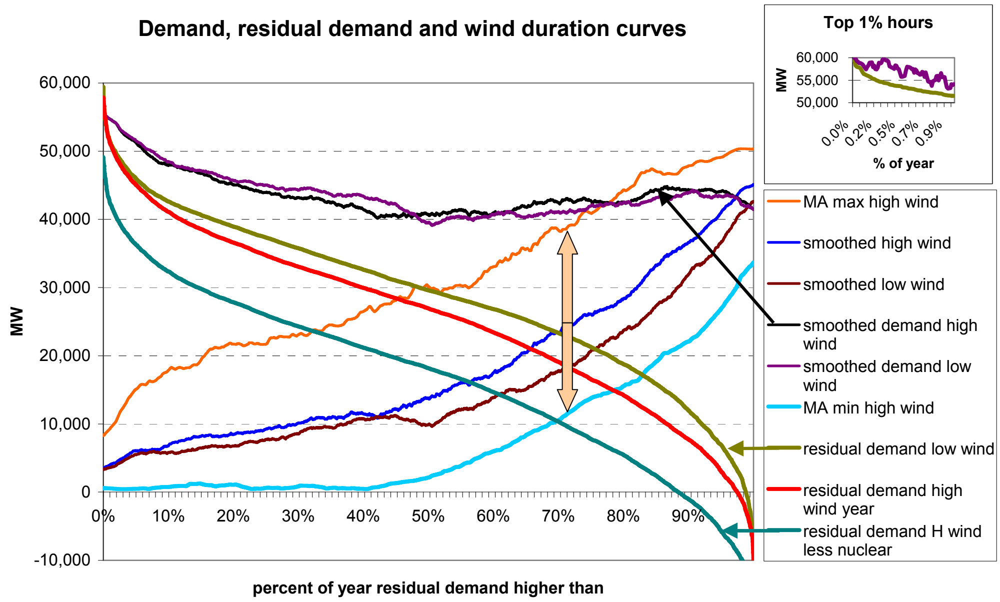

Figure 1: Data source: Green and Vasilakos (2010)

2 The model

In this simple model, there are only two conventional technologies: peaking plant with capacity b, and baseload plant with capacity B. Capacity for both plants is measured by its derated capacity (i.e. adjusted for its availability, which can now be assumed to be on average 100% of the derated value). The nameplate capacity of RES is W MW, its derated capacity is δW (its firm equivalent capacity for contributing to stress periods). The required total derated capacity to meet the specified reliability standard is P MW, so the required capacity of conventional plant is $P - \delta W \leq b + B$.

Demand in hour h is $D(h)$, $0 \leq h \leq Y$ (the number of hours in the year). Expected RES output in that hour is $r(h)W$, so the expected demand to be met by conventional generation (residual demand) is $R(h) = D(h) - r(h)W$, and hours are ranked such that $R(h)$ is monotonically decreasing, $R' < 0$, so that hour h is the h^{th} highest *residual* demand hour. Figure 1 shows a number of residual demand duration curves for Britain, calculated by averaging demand in each hour of the years 1994-2005, then subtracting the scaled highest average wind year, 1994, and the scaled lowest average wind year, 2003, from this average demand. The scaled wind outputs in each year are the sum of on-shore and off-shore wind output, scaled to deliver 37.5% wind (the 2030 target under the *Gone Green*

Future Energy Scenario, National Grid, 2015), using data kindly supplied by Green and Vasilakos (2010). These two residual demands span the likely range of residual demand duration curves. The last residual demand duration curve subtracts the average expected output from nuclear power (20%) to give the residual demand for fossil generation in a high wind year (which is the lowest fossil residual demand). The smoothed demand duration curves are the total demands corresponding to the residual demand hours, h, for the low and high wind years, and the smoothed wind duration curves are similarly the wind outputs in those residual demand hours. The curve labeled 'MA of max high wind' is the moving average of the maximum wind output over the previous and following 24 residual demand hours and gives an indication of the variability of the wind at each residual demand hour, bearing in mind that successive residual demand hours are not successive temporal hours. Similarly, 'MA of min high wind' gives the moving average of minimum wind output, and the broad arrows indicate the range of wind outputs (from the highest to the lowest) in the neighbourhood of the h^{th} highest *residual* demand hour.

The top 1% of residual demand hours is shown in the top right of the figure giving a clearer sense of the wind contribution to meeting demand in peak fossil demand hours. The curves are labeled in the descending order in which they meet the right hand y-axis. Britain, in common with other countries, has a fairly linear residual demand duration curve except for the top and bottom 10% or so of hours. Expected GB wind output ranked by residual demand hours is increasing as residual demand falls, because low residual demand correlates with high wind output. However, average wind output is positively correlated with *total* demand and a graph of smoothed wind against the total demand duration curve (shown in Appendix B) is fairly flat for the highest third of demand hours, and then almost linearly decreasing (to lower levels with the lower summer demand).

The investment decision is taken before actual RES output and hence residual demand are observed and so only depends on expectations. It seems reasonable to suppose that both *expected* total demand and residual demand are smoothly decreasing in h, although for investment purposes we are only concerned with the residual demand duration curve (which, by construction in Fig. 1 is smoothly decreasing). Baseload plant will fill up the bottom B MW of the residual duration curve, so that peaking plant will then only expect to generate in hours $h \leq H$, where $R(H) = B$, so $H = R^{-1}(B)$. Baseload will run in all hours for which residual demand is positive, although its average capacity factor will depend on the shape of $R(h)$. Fig. 2 illustrates these terms and concepts, as well as the

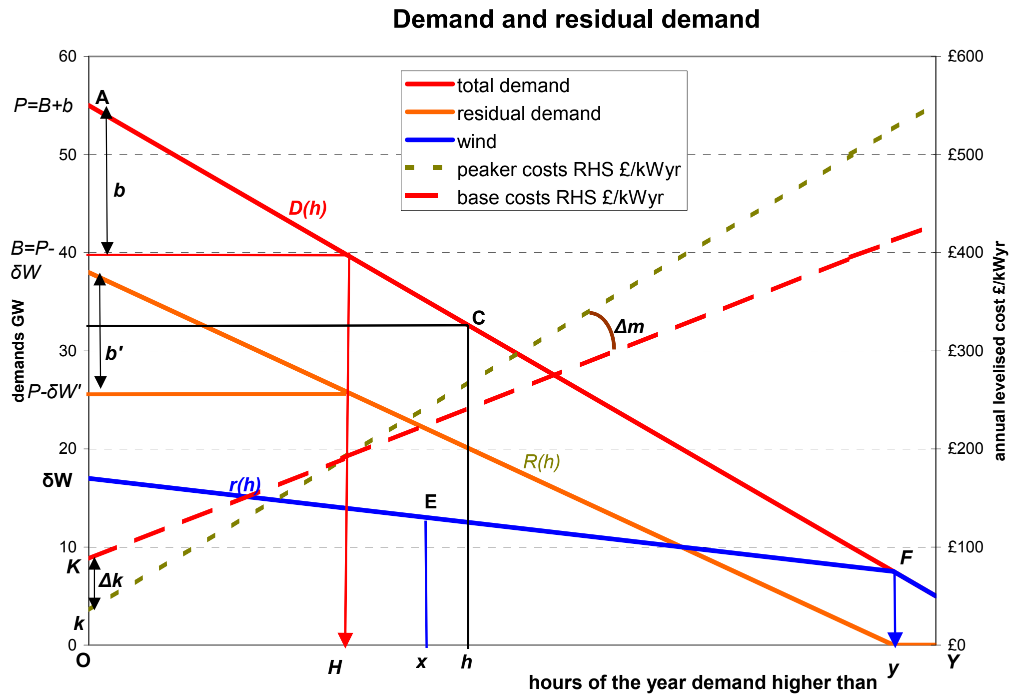

Figure 2: Illustration of algebraic terms

screening curves, shown on the right hand axis and discussed below.

Given that there is no value in exceeding the reliability constraint, de-rated capacity can be set equal to the capacity requirement and solved for $b = P - \delta W - B$. Total fossil output, O, is

$$O = \int_0^y R(h)dh = \int_0^y (D(h) - r(h)W)dh = L(y) - W\rho(y), \tag{3}$$

$$y = Min(R^{-1}(0), Y), \quad L(y) \equiv \int_0^y D(h)dh, \ \rho(x) \equiv \int_0^x r(h)dh. \tag{4}$$

Here y is the maximum number of hours baseload plant is running, $L(h)$ is the total demand satisfied in the highest h demand hours in the year (i.e. the area under the total demand duration curve to that point, OACh in Fig. 2) and $\rho(x)$ is the area under the unit wind/RES profile $r(h)$ for the highest x demand hours (area OδWEx in fig. 2). Thus $\rho(Y)$ is the capacity factor for wind/RES, averaged over the year.

The plant mix is chosen to minimize total conventional generation cost, C, given the externally specified volume of RES, W, subject to meeting the reliability constraint and demand in each hour. If unit variable operating cost of plant type i ($i = p, b$) is m_i and the annuitized hourly capital cost of baseload is K, and of peaking capacity is k, then the difference between the capital costs (baseload *less* peaking) is $\Delta k = K - k$ (shown on the left hand axis but to be read on the right hand axis of Fig. 2) and the difference between unit operating costs is Δm (peaking *less* baseload, shown as the difference in the slopes of the two screening curves), so that each is positive.

The appendix derives the results of this optimization and demonstrates that the optimal level of baseload capacity (and that of the peaking plant) just depends on the capital and variable cost differences, Δk and Δm. This can also be demonstrated geometrically in Fig. 2, which shows screening curves for peakers and baseload plant. Screening curves (see e.g. Stoft, 2002, p35) plot the total fixed and operating costs of different plants against the number of running hours per year to determine which types of plant are cheapest for different capacity factors (defined as the number of full running hours as a fraction of a year). Thus for peaking plant, the screening curve is $s(h) = kY + m_p h$, and for baseload is $S(h) = KY + m_b h$. Here the peaking plant cost intersects the baseload cost at H, the number of hours per year at which they are equally costly. For plant that only runs less than H, peakers are the preferred investment, while for plant running more than H, baseload plant is cheaper. It follows from simple geometry that $H = \Delta k/\Delta m$, regardless of the shape of the residual demand schedule and hence the level of RES (at least, as long as some conventional baseload plant is still economic). This would also be true for several types of plant that were cheaper over some intermediate range of capacity factor (e.g. mid-merit plant), and in each case their optimal maximum capacity factor would be independent of the level of RES.

This has an important implication, stated as

Proposition 1 *In a cost-minimising constant returns long-run equilibrium with just peaking and baseload fossil capacity, the impact of changes in RES has no effect on the number of hours peaking capacity runs, $H = \Delta k/\Delta m$. The System Marginal Cost in (1) will remain unchanged except for those hours in which RES displaces all conventional plant. If the average RES capacity factor is constant over the hours that peaking plant runs, then in addition the impact of changes in RES is solely on baseload capacity and the peaking capacity is unaffected. If wind output is negatively correlated with residual demand in high residual demand hours, then increased wind also increases the amount of peaking capacity required. An increase in carbon costs will reduce optimal peaking capacity if baseload capacity has a lower carbon intensity than peaking capacity.*

The proof is given in the appendix.

2.1 Examples

One simple and plausible (future) case is that in which all conventional plant runs on gas, so the only differences between base and peaking plant are their efficiencies and cost:

$$\Delta m = (f_g + c\gamma_g)(\frac{1}{e} - \frac{1}{E}),$$

where f_i is the fuel cost in £/MWh$_{th}$ ($i = g$ for gas, subscript $_{th}$ means the thermal content of the fuel), c is the price of carbon (£/tonne CO_2), γ_i is the carbon intensity of the fuel (tonnes CO_2/MWh$_{th}$), and e, E are the efficiencies of the peaker and baseload plant (in percentages). The term in brackets is just the difference in heat rates, the inverse of the efficiency, measured here in MWh$_{th}$/MWh$_e$. For example, for combined cycle and open cycle gas turbines, $E = 54\%$, $e = 35\%$, so the heat rates are 1.85 and 2.85 and the last term is 1.0. If the price of gas is £10/MWh$_{th}$ and the carbon price is zero, $m_b = \pounds 18.5/\text{MWh}_e$ and $m_p = \pounds 28.5/\text{MWh}_e$ so $\Delta m = \pounds 10/\text{MWh}_e$. The total installed cost of CCGTs might be \$1,320/kW or $K = \pounds 10.30/\text{MWh}_e$ and of OCGT \$640-840,[3] so the difference in capital costs annuitized in £/MW per hour is of the order of $\pounds 2 - 5/\text{MWh}_e$, so $\Delta k/\Delta m = H = 20\% - 40\%$. If the price of gas is £15/MWh$_{th}$ and the price of carbon is £30/tonne, and $\gamma_g = 0.19$, $m_b = \pounds 38.3/\text{MWh}_e$, $m_p = \pounds 59/\text{MWh}_e$, so $\Delta m = \pounds 20.7/\text{MWh}_e$ and $\Delta k/\Delta m = H \approx 10\% - 20\%$, depending on capital and fuel costs.

If the baseload plant is sub-critical coal with $E = 36.8\%$, heat rate is 2.72, $\gamma_c \equiv \Gamma = 0.341$, fuel cost $f_c =$£7//MWh$_e$, so at zero carbon cost the variable cost is $m_c = \pounds 19/\text{MWh}_e$. If the peaker is a gas turbine with heat rate 2.85 running on distillate, $f_d = \pounds 30/\text{MWh}_e$, at zero carbon costs its variable cost is $m_d = \pounds 85.5/\text{MWh}_e$ and $\Delta m = \pounds 66.5/\text{MWh}_e$. Levelised baseload capital costs $K = \pounds 16.3/\text{MWh}$[4] and for the peaker $k = \pounds 5.3/\text{MWh}$, so $\Delta k = \pounds 11/\text{MWh}$, and $\Delta k/\Delta m = H = 17\%$. If the carbon cost is £30/tonne, variable costs increase to $m_c = \pounds 29.2/\text{MWh}_e$, and if the peaker runs on gas, $m_p = \pounds 59/\text{MWh}_e$ so $\Delta m = \pounds 29.8/\text{MWh}_e$. In this case $H = \Delta k/\Delta m = 37\%$. Both figures lie within the range $10 - 40\%$ from the first example.

[3] See http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates _for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf?1400252453 for the real levelised costs of OCGT and CCGT for 2018 entry in PJM.

http://www.ipieca.org/energyefficiency/solutions/77801 suggests lower costs for OCGTs. Δk will depend on discount rates, life time, and other financial parameters such as gearing and taxes.

[4] See http://www.netl.doe.gov/KMD/cds/disk50/PC%20Plant%20Case_Subcritical_051507.pdf

3 Cost impact of extra wind capacity

The question of central interest is how the total cost of generation and the wholesale price vary with changes in the installed wind capacity, considering for the moment that the wind has zero variable costs (and whose support cost is to be separately identified).[5] An increase in W will shift the residual demand curve down and reduce total fossil output and hence the total fossil cost. The impact on efficient prices is determined by (1). From Proposition 1, SMC is unchanged while conventional plant is at the margin, but will fall to zero when RES displaces all conventional plant. The RES will be paid the SMC, which will contribute to covering its total cost. The consumer price when RES displaces all conventional plant will then just be the system services element required for secure RES operation, which is added on to the wholesale price. The capacity element will reflect the security standard, which will be set by a balancing of the costs of increasing reliability by installing more derated capacity against the Value of Lost Load. More RES displaces some conventional capacity, reducing that cost, but if the system reliability is held constant then the reduction on conventional capacity payments can be offset by an equal increase in capacity payments to RES. Any shortfall in RES capacity and energy payments then represents a subsidy, which is to be justified on a combination of a carbon reduction credit (if the carbon price is inadequate) and a subsidy to learning benefits (or to meet the EU mandated RES target, itself part of the EU environmental policy, and effectively the country's contribution to providing that club good). As these learning or club good contributions are public goods, good public finance principles require that they are funded out of general taxation, not distorting taxes on electricity consumers (Newbery, 2015).

The volume of wind capacity will affect the amount of peaking and baseload capacity (which, as we are looking at the long-run equilibrium, will be assumed to be optimal for the new level of W). The appendix derives the impact for the general non-linear case, but the linear case in which the expected wind output is constant over the year, so $r(h) = \delta$, is particularly intuitive, and illustrated in fig. 3.

[5] Intermittent RES will require additional flexible balancing and reserve capacity, whose costs are to be separately attributed and charged to RES and which therefore do not impact other system costs.

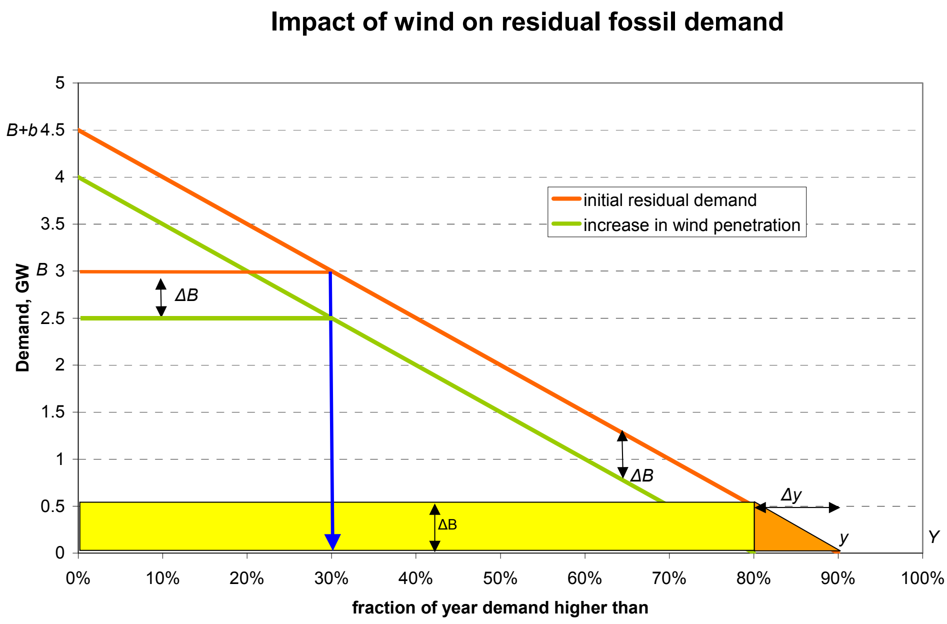

Figure 3: Illustrative impact for a small isolated system

The appendix demonstrates that in this case

$$\frac{\partial C}{\partial W} = -\delta(K + m_b y), \tag{5}$$

$$\frac{\partial C}{\partial \delta W} = K + m_b y. \tag{6}$$

This has a natural interpretation. The first term in (5) is the saving in baseload costs, given the derating factor for the RES (there is no change in peaking capacity in this linear case). The second term is the reduction in variable baseload costs caused by the additional RES adjusted for its capacity factor. Equation (6) shows more clearly that a unit change in derated wind capacity, δW, which results in on average 1 MWh of wind every hour of the year, leads to a unit saving in baseload capacity cost, K, and a baseload fossil cost saving for all the hours, y, that the baseload fossil plant runs.

Fig. 3 shows this geometrically. If baseload plant runs a maximum of $y < Y$ hours per year, a small but permanent increase in wind capacity ΔW leads to a fall in (derated) baseload capacity ΔB, which reduces maximum running hours by Δy. The fall in baseload output is given by the shaded area, which is $\Delta B.(y + \frac{1}{2}\Delta y)$. Now $\Delta B = -\delta \Delta W$ and $y = (P - \delta W)/\alpha$ so $\Delta y = -\delta \Delta W/\alpha$ and the fall in baseload output is $\frac{\delta}{\alpha}(P - \delta W - \frac{1}{2}\delta \Delta W)\Delta W$, which for a small change in wind is $\frac{\delta}{\alpha}(P - \delta W)\Delta W$. The saving in capital cost is $\delta \Delta W K$

and the saving in operating cost is $\frac{\delta}{\alpha}(P-\delta W)\Delta W m_b$ so $\partial C/\partial W = -\delta(K+m_b(P-\delta W)/\alpha)$, confirming the algebraic proof.

If the capacity auction is setting efficient prices, then that part of the cost reductions in (5) will be passed through to consumers in lower fossil capacity payments. The energy payments $m_b y$ per MWh of derated wind will automatically be passed on to the wind farm owners, but the capacity element can be credited against the subsidy required for their capacity costs. In deciding what total cost savings can be charged to consumers and credited to wind, the first part would be the difference between the baseload capacity cost required for full baseload operation and the amount actually needed by fossil generation, and the second part would be the difference between the baseload energy cost for the full $Y-H$ hours and the actual $y-H$ hours, or $m_b(Y-y)\delta W$. Figure 1 suggests that this last part may be quite small as y/Y is close to 100% (and even with 20% nuclear is near 90%) even with massive wind. However, this energy cost saving should be recovered through the less distortionary capacity payment, as it is efficient to confront consumers with the efficient energy price.

These results can be summarized in

Proposition 2 *The legitimate charge to levy on electricity consumers for derated wind capacity δW is the difference in fossil baseload capacity payments with no wind and that needed with wind, together with an additional capacity charge of $m_b(Y-y)\delta W$, where m_b is the system marginal cost of electricity when baseload plant is price-setting, and $Y-y$ is the number of hours that wind sets the wholesale price.*

To gain a sense of the magnitude, consider the gas case above with carbon cost of £30/tonne CO_2 and $K = £10.3$, $H = 20\%$. If $y = 90\%$, $\delta = 25\%$, $m_b = £38.3/\text{MWh}_e$, so an extra 1 MW of derated wind capacity (4 MW of nameplate capacity) would receive a capacity subsidy chargeable to electricity consumers of £10.3/MWh x 8760hrs = £90,000/MWyr, and an energy subsidy charged as a capacity payment of £38.3/MWh x 876hrs = £33,600/MWyr, or in total £123,600/MWyr or £124/kWyr. To put this in perspective, the 2014 capacity auction in GB cleared at a price of £19.40/kWyr (National Grid, 2014) and the auction for a (roughly) fixed price contract for wind cleared at £80/MWh, fixed in real terms for 15 years. With $k = £6/\text{MWh}$, $m_p = £59/\text{MWh}$, the average SMC would be £42.4/MWh so the wind subsidy is £37.6/MWh or £82/kWyr on nameplate capacity, or £330/kWyr on derated capacity. The allowable subsidy chargeable to electricity consumers would be 37% of the total, with the balance of 63% being a charge to public finance. Of course, higher fuel prices and hence higher SMCs would lower the balance to be recovered from taxation.

4 Policy implications

If the electricity supply industry has had time to adjust its plant mix to the specified level of RES and is in an efficient long-run equilibrium, then the number of hours that peaking plant will run on average is independent of the RES capacity and as a fraction of the year is equal to $\Delta k/\Delta m$, where Δk is the levelized differential cost difference between baseload and peaking capacity per MWh, and Δm is the cost difference of variable costs per MWh between peaking and baseload plant. To a rough approximation (which is accurate if the average RES capacity factor is constant over the hours that peakers run), additional wind capacity merely displaces baseload capacity in proportion to its derating factor.

The impact on fossil costs has two parts. The first is a fossil capacity cost saving resulting from the firm capacity contribution of the wind, and the second is the fuel cost saving by displacing fossil baseload generation. The charge that can legitimately be levied on electricity consumers is thus the value of the baseload capacity saving and the difference between the fossil baseload energy cost and the variable cost of wind, but only in those hours in which wind is setting the wholesale price. These charges should be levied in the least distorting way as a capacity charge recovered in stress hours, allowing the spot price to fall to the variable cost of wind in hours when wind is price-setting. This is agreeable to common sense. Most, but not all, of these cost savings are passed through directly to wind farms, leaving the balance as an additional capacity cost support chargeable to electricity consumers. In an efficiently priced electricity market, RES is paid the wholesale price, which in non-stress hours (when wind is contributing) is the system marginal cost (SMC), and consumers will pay no more while conventional plant is at the margin but would potentially pay a reduced price (just the system balancing costs for RES) when RES is at the margin. Some of the displacement impact of RES will therefore be passed through directly to consumers. The SMC cost reduction per MW of *derated* wind (i.e. $\delta\Delta W$) will be $\frac{1}{2}m_b\Delta y$ where $\Delta y = 1/dD(h)/dh$, the inverse slope of the total demand duration curve evaluated at $h = y$. This is a small fraction of the total reduction in fossil generation costs of (roughly) $K + m_b y$ £/MWh per MW extra derated wind capacity. Green and Vasilakos

(2011) note a similar finding in their simulation of the long-run impact of wind on GB wholesale prices. The remainder of the cost saving comes from reduced fossil capacity costs and this part should be reflected in additional capacity payments, as it is efficient to confront consumers with the SMC for the overwhelming fraction of the time that there is no capacity scarcity. That part of the RES subsidy not covered by these legitimate electricity consumer charges should be funded from general taxation as the public good element.

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5

6 Appendix A

Peaking plant has a capacity cost k/MWyr, efficiency as a fraction, e, fuel price, f £/MWh$_{th}$ (subscript $_{th}$ refers to the energy content of the fuel), and carbon intensity, γ tonnes CO_2/MWh$_{th}$. The baseload plant costs K/MWyr, has efficiency E, faces fuel price F £/MWh$_{th}$, which has a carbon intensity Γ tonnes CO_2/MWh$_{th}$. The carbon price is c £/tonne CO_2. Total annual fossil generation costs are

$$
\begin{aligned}
C(B,H,W) &= bk + BK + m_p \int_0^{H(B)} (R(h) - B)dh + BHm_b + m_b \int_{H(B)}^{y} R(h)dh, && (7) \\
&= (P - \delta W)k + B(\Delta k - H\Delta m) + m_p \int_0^{H(B)} R(h)dh + m_b \int_{H(B)}^{y} R(h)dh && (8) \\
m_p &= \frac{f + c\gamma}{e}, \quad m_b = \frac{F + c\Gamma}{E}, \quad \Delta k \equiv K - k, \quad \Delta m \equiv m_p - m_b. && (9)
\end{aligned}
$$

In equation (7) the first two terms are the annual capital cost of the peaking and baseload plant, the first integral is the operating cost of the peaking plant, and the remainder of the expression is the operating cost of the baseload plant (the number of MWh supplied times the unit variable cost, m_i).

The baseload capacity B satisfies the first order condition (f.o.c.) from (8) (after substituting for b), noting that y is fixed by P, W.

$$
\begin{aligned}
\frac{\partial C}{\partial B} &= 0 = \Delta k - H\Delta m - B\Delta m H' + \Delta m B H'(B), \\
H &= \frac{\Delta k}{\Delta m}, \quad B = R^{-1}(\Delta k/\Delta m). && (10)
\end{aligned}
$$

Proof The proportion of the time that peaking capacity runs is $H = \Delta k/\Delta m$ *from (10), independent of* W*, the RES capacity. The SMC will be* m_p *for hours* $h \leq H$*,* m_b *for* $H < h < y$*, but zero for* $y \leq h \leq Y$*, the low residual demand hours in which* $r(h)W \geqslant D(h)$*. The amount of peaking capacity,* $b = D(0) - D(H) - W(r(0) - r(H)) - B$*, so* $\partial b/\partial W = r(H) - r(0)$ *as* $\partial B/\partial W = 0$*. But if* $r(h) = r$*, constant for* $0 \leq h \leq H$*,* $r(H) = r(0)$*, so* $\partial b/\partial W = 0$*. If wind output is negatively correlated with residual demand in high residual demand hours,* $r(0) < r(H)$ *and* $\partial b/\partial W = -(r(0) - r(H)) > 0$*. Carbon intensity is* $\gamma_i/e_i = \mu_i$*, so if* $\mu_p > \mu_b$*, then* $\partial \Delta m/\partial c = \mu_p - \mu_b > 0$ *and* $\partial H/\partial c < 0$ *so* $\partial b/\partial c < 0$*.*

6.1 Impact of wind on cost

The volume of wind capacity will affect the amount of peaking and baseload capacity (which, as we are looking at the long-run equilibrium, will be assumed to be optimal for the new level of W). It is convenient to rewrite (8) in terms of the total demand duration curve, $D(h)$, as in (3):

$$C = (P-\delta W)k+B(\Delta k-H\Delta m)+\Delta m \int_0^{H(B)} D(H)-Wm_p \int_0^{H(B)} r(h)dh-Wm_b \int_{H(B}^{y} r(h)dh, \tag{11}$$

where $r(h)$ is given and depends only on the wind characteristics. From (10) $\Delta k - H\Delta m = 0$ in equilibrium, and $\partial H/\partial W = 0$. Also note that y is defined by $R(y) = 0$, so $R'(y)dy/dW = 0$, and so $dy/dW = 0$. It is convenient to write $r(h) = \delta + \varepsilon(h)$, where ε measures the departure of the wind capacity factor in demand hour h from the capacity factor, $\delta = r(0)$. The impact of a small change in wind capacity on total fossil cost will be, differentiating (11) and substituting for $H = \Delta k/\Delta m$:

$$\begin{aligned}\frac{\partial C}{\partial W} &= -\delta k - m_p\delta H - m_p \int_0^{H(B)} \varepsilon(h)dh - m_b\delta(y-H) - m_b \int_{H(B)}^{y} \varepsilon(h)dh, \\ &= -\delta(K + m_b y) - m_p \int_0^{H(B)} \varepsilon(h)dh - m_b \int_{H(B}^{y} \varepsilon(h)dh.\end{aligned}$$

The impact in the constant capacity factor case when $r(h) = \delta$ and $\varepsilon = 0$ is just

$$\frac{\partial C}{\partial W} = -\delta\left(K + m_b y\right).$$

If $\varepsilon(h) = \varepsilon h$ (wind is negatively correlated with residual demand as in fig. 1) so that $\int \varepsilon h dh = \frac{1}{2}\varepsilon h^2$

$$\frac{\partial C}{\partial W} = -\delta\left(K + m_b y\right) - \frac{\varepsilon}{2}(\Delta m H^2 + m_b y^2).$$

If the wind capacity factor rises from $r(0) = \delta/4$ to $r(Y) = 7\delta/4$, (c.f. fig.1, with an *average* wind capacity factor of δ), then $\varepsilon = \frac{3}{2}\delta/Y$ and

$$-\frac{\partial C}{\partial W} = \frac{\delta}{4}\left((K + m_b y(1 + \frac{3y}{Y}) + 3\Delta m Y(\frac{H}{Y})^2\right).$$

The effect of the negative wind correlation is to amplify the variable cost reduction by a rather modest amount (although in this case the firm wind capacity contribution is only one-quarter the average capacity factor, complicating comparisons with the constant capacity factor case).

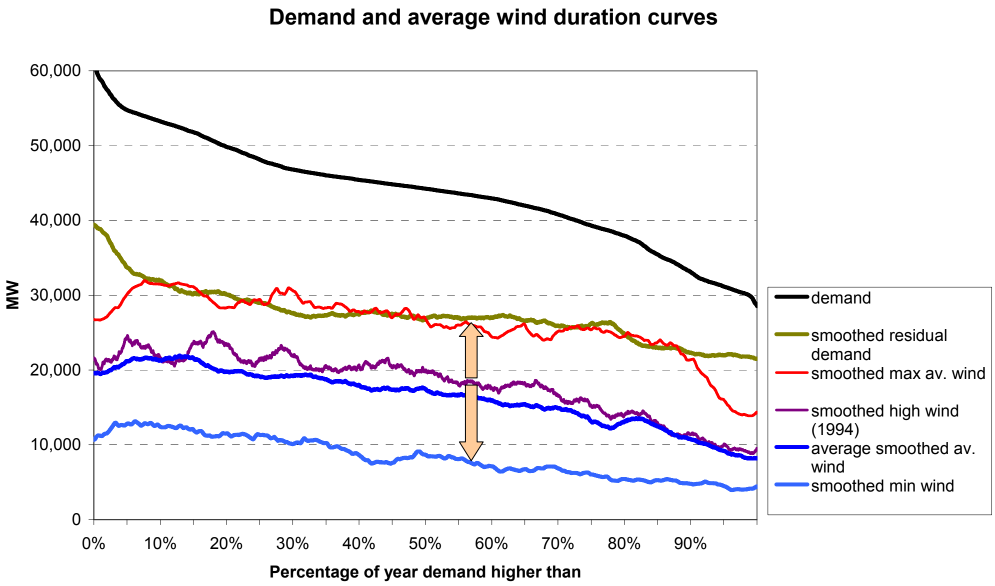

Figure 4: Data source: Green and Vasilakos (2010)

7 Appendix B

Figure 4 shows the relationship between average scaled wind (averaged over years 1994-2003) aligned with demand hours ranked in order of decreasing total demand, together with a moving average of the maximum and minimum scaled wind in neighbouring demand hours (not temporal hours), in the same way as figure 1.

It is clear that when aligned with demand hours wind shows a declining trend (both for the average of all years and for the high wind year of 1994). The large variability of wind is equally clear in this figure, and accounts for the mismatch in aligning wind hours with either demand hours or residual demand hours.