Economic Properties of Wind Power

A European Assessment

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Abstract

We investigate the concomitance of intermittent wind powered generation (WPG) with load to assess its *system value* as the cost of replacing its output, hour by hour, using more intensively thermal technologies. The difference with its actual cost defines a *social cost* of wind power which is further divided into a *technological* and an *adequacy* component. Whereas the former may become negligible once thermal technologies pay for carbon emissions, the latter is a lower bound on WPG structural weakness wrt. thermal technologies.

We apply our procedure to Germany, Denmark, Spain, France, Portugal and Ireland using to hourly load and WPG data over several years. Our empirical findings show that there is a grain of truth in both the pros and cons of wind power. The system value of WPG varies from three quarters of the equivalent thermal cost of electricity (on a yearly basis) but the incompressible adequacy cost represents a premium over the cost of serving yearly load in a system ranging around one fifth.

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JEL codes : L51, H42, D61

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1 Introduction

1.1 Context

The modern lifestyle of advanced economies depends so much on electricity that even the current economic crisis will not durably curb its demand growth. At the same time, worries are mounting regarding climate change whose probable cause are carbon emissions to which the generation of electricity out of fossil fuels contributes a third. High fossil fuel prices and the eagerness to achieve "energy independence" have triggered a mild *demand-side* strategy of reducing consumption patterns by a better education and by improving the energy efficiency of machines and buildings.[1] Yet, the preferred response of western governments has been a *supply-side* strategy, namely to raise the share of renewables in their energy mix towards 20% and beyond.

Wind powered generation (hereafter WPG) has emerged as the lead contender for that task (cf. Appendix A on the evolution of cost for WPG) since it is only second to CCGT in terms of newly installed capacity over the last decade.[2] The social benefit of WPG is measured by the avoided carbon emissions of fossil fuel generation so displaced. Hence, the benefit is proportional to electricity generation[3] which, in turn, is the product of installed capacity by *capacity factor*, the latter measuring the technical efficiency of the park of wind turbines assessed over a long period (e.g., a decade).[4] Boccard (2009b) studies the most recent capacity factor data for European countries and come to the conclusion that the overall level achieved falls short of expectations; in other words, raising wind power to 20% of total installed capacity will not deliver the expected carbon emission reduction so that more capacity will be needed.

In the present paper, we leave aside the long-term energy delivery capability of WPG to address an altogether different issue, namely the ability of wind power output to serve

[1] As recalled by Stoft (2008), the greatest episode of carbon emission reduction ever taking place in advanced economies was the (painful) reaction to OPEP's market power in the 1970s. Since then no government has dared implement energy saving policies directly affecting voters' lifestyle.

[2] Large hydropower still generates more energy but its capacity displays an almost nil growth.

[3] Recall that carbon emission reduction is the product of WPG output by the carbon content of the current fuel mix (typically computed at country level). Since fuel mix evolves slowly, we may assume it constant in a first approximation.

[4] It is alternatively measured by full-load hours per year (e.g., 2000 out of a maximum of 8760).

electricity demand all around the year, hour by hour. Indeed, as wind speed is driven by the meteorology, it varies along every possible time scale such as the minute, the hour, the day, the year and event the decade (cf. Boccard (2009b) sec. 2). The resulting uncontrolled variability of WPG known as intermittency means that its contribution to the daily peak of load may be nil (which is detrimental) or maximum (which is welcome). Up to now, the literature has tended to focus on particular events or locations to advance that intermittency was either a curse or an innocuous phenomenon (depending on which side of the renewables debate the author would fall).

To defuse this sterile debate, we take an aggregate look through space (whole country) and time (whole year) in order to come up with a monetary valuation of the service rendered to load service by WPG, we call *system value*. The difference with the private cost of WPG then becomes the *social cost* of wind power,[5] the amount per MWh that society agrees to pay to enjoy carbon free electricity. If that amount is lesser than the rate of a carbon tax or the price of an emission permit then WPG can be deemed a superior instrument to curb carbon emissions.[6] The methodology employed also enables to compute the social cost of any other RES in order to rank RES among themselves.

The data sources used in this article, listed in Appendix C, are hourly record made publicly available by several system operators in Europe. They enable to give a precise meaning to obvious statement such as “Ireland has a comparative advantage for wind” and “Spain has a comparative advantage for solar”.

In the rest of this introduction, we briefly recall the concept of “capacity credit” and then explain in relation to the literature why we do not follow this concept. Section 2 then presents our methodology to assess in a novel manner the social cost of wind power. Section 3 displays and analyzes the cost estimates for the six European countries whose load and WPG output are made publicly available. Section 4 concludes.

[5] Since the standard external cost of WPG is small compared to that of fossil fuels based generation, we assume a zero value (cf. ExternE (2002)).

[6] A carbon tax does not automatically reduce carbon emissions especially if the supply of RES is tight (as in the case of UK ROCs which are fulfilled at 70%). Yet, in the medium term investment is directed towards fuels with a lower carbon content such the coal to gas switch.

1.2 Capacity Credit

To clarify our contribution within the existing literature on the intermittency of wind power generation, we must first introduce the concepts of reliability, adequacy and capacity credit. According to NERC (2007)'s glossary:[7]

- *Reliability* is "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements".
- *Adequacy* is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements".

As we argue in our companion paper Boccard (2009a), it is only the discrepancy between estimated and realized WPG that impacts negatively the reliability of the system (and forces the TSO to call reserves into action). Given the quality of current meteorological models, this discrepancy solely regards WPG output variations below the hour span. Variations within the day (and above), being well anticipated, constitute an adequacy issue since they can be edged in the spot market (day-ahead and intra-day).[8] The present article exclusively deals with the contribution (or lack thereof) of WPG to *adequacy*. For the sake of clarity, we recall the basics of reliability.

Reliability, the foremost mission of the Transmission System Operator (TSO), is operationalized through a loss of load probability (LOLP) e.g., "one day in ten year" or "one two-hour event per year". Since electricity is extremely costly to stock,[9] sudden disturbances can only be accommodated by controllable (aka dispatchable) generating sta-

[7] Dictionaries define *adequate* as enough to meet a purpose whereas *reliability* is the quality of being dependable or trustworthy. We thus adhere to the above definitions and not the ones prevailing in the UK where reliability is called balancing and adequacy is misleadingly termed reliability.

[8] Although we use a clear cut definition of adequacy, there is an ongoing debate regarding the public good features of the generation adequacy problem. This concern stems from the insufficient level of demand side response (DSM) in most systems that could lead to unwanted curtailments (cf. Finon et al. (2008)). When public intervention is still deemed necessary (as exemplified in reports by UCTE or the French TSO RTE), some probabilistic methods are still being used to evaluate the adequacy of a system and to set the adequacy mechanisms.

[9] Pumped storage is the sole technology currently in service at a significant scale but it is not widespread because environmental constraints preclude its expansion. Apart from this, we can cite night storage in

tions (and network switches). The intermittent nature of WPG precludes a single wind farm from contributing anything to reliability.[10] Yet, reliability being a probabilistic concept, a large number of wind farms disseminated over a large geographical area **does** make a contribution to reliability.[11] Practically, it is measured with the *capacity credit* $\phi = \frac{y}{x}$ defined as follows: upon adding x MW of wind power to the system, its reliability increases so that one can remove y MW of a controllable power to return reliability to its initial level.[12] As we argued above if x represents a few MW (e.g., one wind farm), then ϕ is nill whereas if x rises to the order of the GW, ϕ is found nearby the average yield of wind power (aka the capacity factor). Yet, when wind power capacity makes up for a fifth of more of system capacity, the capacity credit of an additional GW tends towards zero so that the overall ϕ starts decreasing (cf. Eirgrid (2004)).

The bearing of massive addition of WPG upon reliability was initially hotly debated but, as wind power became a reality, studies started to converge towards the conclusion that WPG could be accommodated at a mild cost as shown by RAE (2004), Gross et al. (2006) (cf. extensive bibliography in their Annex 3) or Holttinen (2008). With the progress of predictive models, wind power output comes close to be anticipated with the same degree of precision than consumer load is. In that case, reliability is only slightly more costly to maintain because the TSO is balancing scheduled supplies against a residual load slightly more variable that the original consumer load.

1.3 Literature

The integration of large amounts of wind power generation into electrical systems was initially assessed under the *vertically integrated utility* paradigm so that reliability and adequacy were dealt together (cf. Martin and Diesendorf (1983)). At the outset of the

batteries for next day delivery is a technical reality, it is still estimated to cost 4.5M$/MW i.e., four times the capital cost of wind power. cf. also McDowall (2007) or Li and Joos (2007).

[10] Beware that the culprit here is the lack of controllability not the variable nature of wind speed. This is why the "intermittent" label associate to RES like wind power is often deemed inadequate.

[11] This is true even though they may all be standing still because the event "zero wind over the country" is more unlikely than an "unexpected surge in demand" or the "failure of a large generation station". Early reference on the topic are Kahn (1979), Haslett and Diesendorf (1981) and Carlin (1983).

[12] Because controllable power sources are also liable to failures, the exact concept is *firm power* so that the capacity credit of a dispatchable unit is close but below 100% (cf. Milligan (1996)).

deregulation process, the TSO is solely responsible for reliability and plans the necessary expansion of the network as well as the contracting of reserves. Adequacy is nowadays managed by an energy authority (e.g., commission, ministry, agency) who basically delivers construction permits to enable the generation park to follow the growth of demand. This dichotomy arises because reliability is a public good requiring a unique overseer while adequacy is not. It is probably because adequacy used to be managed as a public service that some confusion remains regarding its status. Furthermore, the persistent imperfections of energy markets have forced regulators to intervene the recently liberalized markets and mandate generators to set specific margins. Our views on this issue are further developed in Boccard (2009a).

For the historical reasons outlined above, the literature has overemphasized reliability and focused on physical dimensions such as spatial dispersion, correlations between load and WPG or minima and maxima of the residual load. Sinden (2007) relies on wind speeds measurements to build a time series of WPG and then study its correlation with load in the UK. His findings are useful for a social planner that would be able to shape the industry along its will but less so for one with limited intervention powers. The majority of studies cited by Giebel (2005) typically conclude that 1500MW of wind power can replace one 500MW thermal generation station in terms of ability to meet variable load.[13] Once again, this is a valuable information for a social planner but in the deregulated energy markets, only the private owner can decide to mothball that plant and his behavior is guided by financial returns rather than the environment. What many authors (e.g., Oswald et al. (2008)) have noted is that WPG, having zero marginal cost (or priority feed-in), will displace thermal generation in the market and this will force thermal producers to adapt. We follow this insight to assess the impact of WPG for producers as well as for society as a whole.

Our approach looks at the effective interaction between WPG and load in a variety of systems; it is thus retrospective, and as such as, not directly comparable with the prospective branch of the literature. For instance, DeCarolis and Keith (2006) investigate the economics of large scale wind development in the US with an operation research

[13]Too often authors do not make clear whether they have in mind immediate load service (under the hour) in which case they deal with reliability or whether they consider day-ahead scheduling in which case they deal with adequacy.

model extrapolating current knowledge several decades ahead (together with a high tax carbon). Although Kennedy (2005)'s interest is with long term planning, his methodology is closest to ours. His work however differs in two important aspect. Firstly, he puts much emphasis on the carbon emission externality and secondly, he only studies a small area relying on wind speed data instead of actual WPG output. This author finds a negative social benefit (i.e., a cost) of introducing a large amount of wind power. This is entirely due to the high capital cost of wind turbines and the low price currently paid by thermal generators for their carbon emissions. The possible beneficial value of wind power is thus buried under its well known disadvantages. Our approach shall avoid this garbling by using a decomposition of the total cost of WPG that enables an easier interpretation of its strengths and weaknesses.

2 Methodology

As argued above, our approach disregards reliability issues and assume that both load (consumer demand) and wind power output are known in advance, so that, firstly the TSO faces no reliability problem and secondly the entire residual demand can be contracted in the spot market from real and virtual producers i.e., thermal generation and demand side management.

2.1 Social Cost of Wind Power

The standard treatment of externalities posits that a *social cost* sums a *private cost* to an *external cost*. ExternE (2002) estimates the external cost of most technologies for electricity production. by looking at impacts on the environment (biodiversity, noise, visual intrusion), global warming, health and accidents. It reports a positive external cost for WPG but quite small when compared to fossil fuels; we can thus safely assume a zero external cost for WPG, meaning that its external benefit is simply the external cost of the thermal technologies it substitutes.[14] Unlike Kennedy (2005), we do not account explicitly for the environmental cost of fossil fuel technologies since it is a highly subjective

[14] There are no known direct external benefits for society of erecting wind turbines.

topic likely to change across time and places.[15] We simply analyze the full price paid by society to enjoy wind power. We decompose it into a series of components that expose its benefits as well as its cost for the electricity system.

$$\begin{array}{llcllcl} & \text{feed-in tariff} & = & \text{entry premium} & + & \text{private cost} \\ \text{where} & \text{private cost} & = & \text{system value} & + & \text{social cost} \\ \text{where} & \text{social cost} & = & \text{technology cost} & + & \text{adequacy cost} \end{array} \tag{1}$$

In most countries, the government sets the price of WPG that is later billed to consumers,[16] the difference with private cost represents an entry premium for developers whose role is to attract investment in the field. The entry premium being a transfer from consumers to firms, it bears no inefficiency (as far as wealth effects are absent) and shall be left aside from our study.

We define the system value of WPG as the monetary valuation of the service rendered by wind power to the system in terms of meeting electricity demand (aka load). We can then define the social cost of WPG as the wedge between private cost and system value i.e., the scarce resources society must sacrifice in order to enjoy carbon free electricity. We further divide the social cost into two independent components. The technology cost is sensitive to the price of fossil fuels and long-term wind intensity (capacity factor) whereas the adequacy cost is strictly related to the temporal congruence (all along the year) of demand and wind speed.

Among previous attempts at measuring the cost of intermittence of WPG, Dale et al. (2004) claim that one only requires to determine the least cost *energy equivalent comparator*, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation. The natural candidate is then baseload (e.g., nuclear) because if WPG participated in spot markets on equal foot with thermal technologies, it would be baseload since its marginal cost is zero. The proposed social cost of WPG would thus be the product of the capacity credit of WPG by the cost of the energy equivalent com-

[15] A convenient proxy for that is the carbon tax rate or the emission permit price; its incorporation then enables the comparison of RES and non-RES technologies.

[16] Under a compulsory certificate system, the price paid to WPG is endogenously determined but remains nevertheless fairly well anticipated so that the government can fine tune the mandatory deployment of RES to achieve what a “feed-in tariff” does.

parator. This is an incorrect approach for it assumes that every MWh of wind power generation substitutes a MWh from a cheap baseload plant which is not the case as we argue below.

2.2 Thermal Cost Structure

Following the literature on adequacy (e.g., Martin and Diesendorf (1983), Kennedy (2005)), we assume that the thermal generation mix settles at a steady-state long-run economic equilibrium, thereby neglecting the time lag for construction or mothballing of generation units as well as any variation of fuel prices or capital costs or country specificities.[17] This strong hypothesis enables to measure the total cost of electricity generation with and without wind power in a variety of years and areas against a common yardstick. By symmetry, the wind power technology is assumed constant across time and space.

In Appendix B, we fully develop our method. We first gather cost data regarding the major thermal technologies nicknamed *nuke, coal, gas, oil* and *DSM*. For each technology i, we compute the fixed cost f_i of guaranteed power and the marginal cost c_i summing energy cost to variable O&M costs. The total cost of running one MW for $t \leq T \equiv 8760$ hours (in a non leap year) is thus $C_i(t) \equiv f_i + c_i t$. The graph of this function is called the duration cost curve. The lower envelope of those curves, $C(t)$, then defines the efficient technology curve which represents the least cost of generation for each possible duration. The average efficient technology curve is displayed on Figure 1 together with the optimal fuel for each duration of use.[18] For future reference, the capital cost of wind power is taken to be $c_W = 137$k€/MW/year.

We now introduce the random aggregate demand for electricity, known as the *load*. The observed statistic $X = (X_t)_{t\leq T}$ is first sorted in decreasing order to produce the load duration curve (LDC) $\hat{X} \equiv \left(\hat{X}_t\right)_{t\leq T}$ such that $\hat{X}_t \geq \hat{X}_{t+1}$. Bringing the efficient cost curve together with the LDC X enables to determine the thermal plant mix which minimizes

[17] Our cost computations do not correspond to the actual generation costs but to the cost associated with an optimal energy mix for each (isolated) country, free from social constraints such as opposition to nuclear energy. Moreover, the energy mix is only optimized for national demand and national wind output, neglecting cross-border exchanges.

[18] The curve is clipped at 200 to avoid visual flattening.

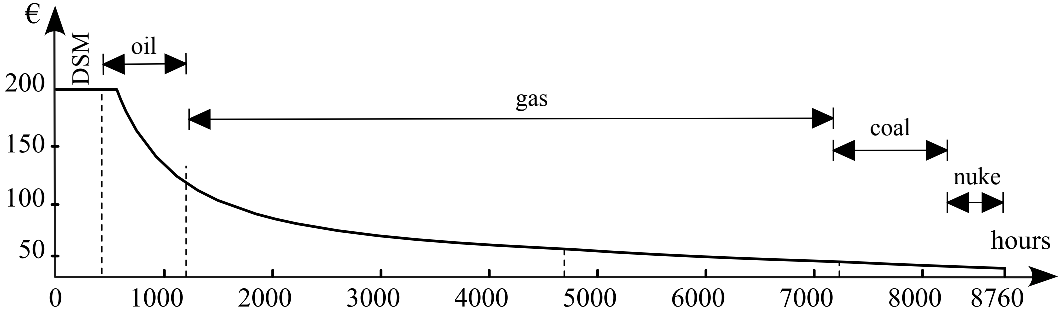

Figure 1: Average Efficient Cost Curve

the total cost of generation (over the year), the latter being

$$C_X \equiv \sum_{t \leq T} (\hat{X}_t - \hat{X}_{t+1}) C(t) \tag{2}$$

where we set $\hat{X}_{T+1} = 0$ for convenience. To understand the summation, we start from the end. Each of the $\hat{X}_T$ MW of baseload demand has a yearly cost of $C(T) = f_4 + c_4 T$ because nuclear is the cheapest fuel for baseload. Then each of the $\hat{X}_{T-1} - \hat{X}_T$ MW that run all year long expect for one hour has a slightly lesser cost of $C(T-1) = C(T) - c_4$. The sum goes on until we switch fuel and replace (f_4, c_4) by the characteristics (f_3, c_3) of coal. At the ends of the process, the peak hours are valued with the DSM technology. The last term corresponds to the $\hat{X}_1 - \hat{X}_2$ MW called for just one hour that year and whose cost per MWh is $C(1) = f_1 + c_1$.

Denoting $\mu_X \equiv \frac{1}{T} \sum_{t \leq T} X_t$, the mean of the observed statistic X, $T\mu_X$ is the total energy embodied in the LDC X. The levelized unit cost of energy associated to X is thus $c_X \equiv \frac{C_X}{T\mu_X}$.

2.3 System Value

We are now in position to investigate the value of using wind power to serve electricity demand. For a given year and system, we observe a vector of hourly demands $D = (D_t)_{t \leq T}$ and a vector of wind power outputs $W = (W_t)_{t \leq T}$ out of which we construct the residual demand $Z \equiv D - W$ that is ultimately served by thermal generators. If wind power was altogether absent from the system for an entire year, the total cost of meeting the original load (demand) would be C_D (implicitly assuming a re-optimization of the mix towards baseload). Since the actual cost associated with thermal plants is the cost C_Z of meeting the residual load, the difference $C_D - C_Z$ is the cost of replacing each MWh of wind electricity produced during the year by a thermal MWh. This *replacement cost* defines the system value of WPG. It takes into account the fact that a MWh of wind power produced at 6pm on a week day when electricity demand peaks is much more valuable, thus costly to replace, than a MWh produced in the middle of the night when there is plenty of cheap generation available. The system value of wind power is thus

$$C_D - C_Z = \sum_{t \leq T} \left(\hat{D}_t - \hat{Z}_t + \hat{Z}_{t+1} - \hat{D}_{t+1}\right) C(t) = \sum_{t \leq T} (Y_t - Y_{t+1}) C(t) \tag{3}$$

where $Y_t \equiv \hat{D}_t - \hat{Z}_t$ is the difference between the t^{th} strongest load of the year and the t^{th} strongest residual load of the year. Because these events occur at different moments of the year, all time reference is lost when constructing Y; it is thus named the *asynchronous wind yield.* By construction $\mu_Z = \mu_D - \mu_W$, thus $\mu_W = \mu_D - \mu_Z = \mu_Y$ given that the way Y is constructed out of D and Z. To enable comparison across systems with differing total wind capacity, we redefine the *system value* of WPG as the levelized cost of the asynchronous wind yield i.e.,

$$c_Y = \frac{C_Y}{T\mu_Y} = \frac{C_D - C_Z}{T\mu_W} \tag{4}$$

We now illustrate graphically our concept. Figure 2 displays for Ireland in 2006 the LDCs of D and Z (below).[19] Due to the intermittence of wind, residual load displays more variability than load so that the LDC for Z is not a downward translation of D (that would be the case of biomass which can be operated as baseload). Rather, it displays more peaks and less baseload i.e., the curves are nearby to the left and apart to the right.

Because WPG contributes a small share of total demand, the distance between the two curves is hardly interpretable. Figure 3 thus displays the difference between the above LDCs which is the asynchronous wind yield Y. The mean is normalized at 100 to enable comparisons across years and countries. In practical terms, the range of Y is compressed with respect to the original wind power output W.

[19] The highest load is by definition greatest than the highest residual load since $\hat{Z}_1 = Z_{t_1} = D_{t_1} - W_{t_1} \leq D_{t_1} \leq \hat{D}_1$. By induction, we can show that $\hat{D}$ and $\hat{Z}$ never cross.

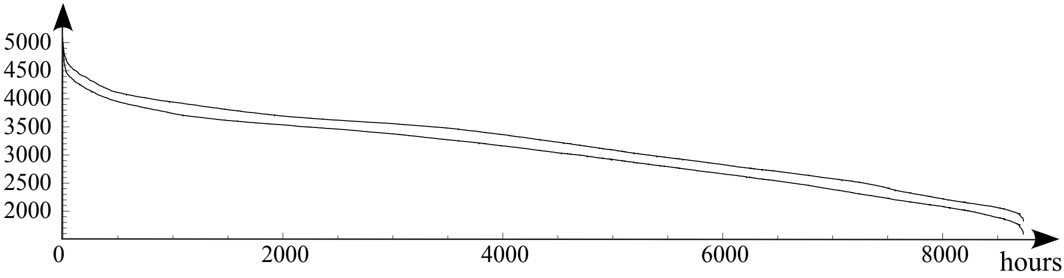

Figure 2: Original and Residual Load Duration Curves

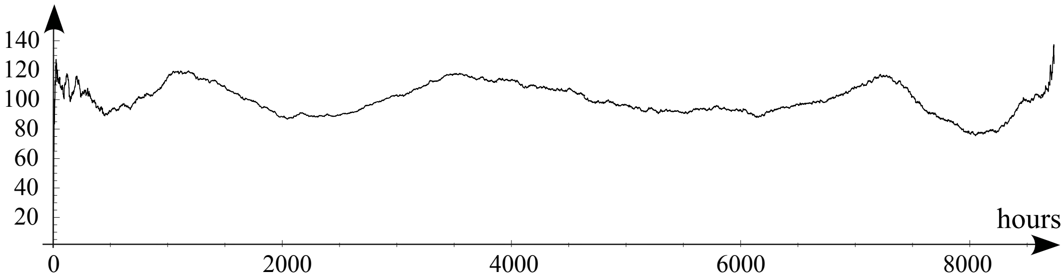

Figure 3: Asynchronous Wind Yield

Given our definition of the system value of wind power, the asynchronous wind yield plotted on the left side of the graph corresponds to WPG meeting peak demand that is inherently costly to serve whereas values plotted on the right side corresponds to WPG meeting baseload demand which is cheap to serve. Wind is thus more valuable if more of its yearly output appears on the left side i.e., if it tends to be above average. Notice that our characterization is independent of the overall wind capacity as it refers to the temporal distribution of wind output across the year and its correlation with load.[20] To better grasp the issue at hand, Figure 4 displays the detail of the previous graph for the 2.5% top hours of system stress (220 hours). For the particular case of Ireland in 2006, we notice an above average contribution of wind power output when the marginal cost of electricity is well above 100€/MWh.

Whereas Figure 2 to 4 regard Ireland, Figure 5 displays the asynchronous wind yield

[20]Obviously, more capacity or the same capacity seated in a country with better wind resource will yield more energy.

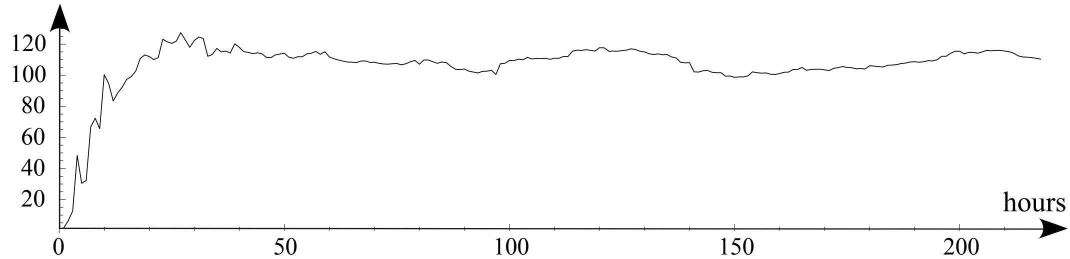

Figure 4: Detail of Asynchronous Wind Yield

of Denmark for 2006. We clearly observe that much of the danish wind power output is coincidental with baseload demand (the right side of the top graph rises to 250%) and that the contribution to peak hours is deceptively small (left side below 100%). As we see on the bottom panel for peak hours, the more stress there is in the Danish system, the less wind is able to contributes to its alleviation. Unsurprisingly, our calculations reveals that Irish WPG has a greater system value than the Danish one.

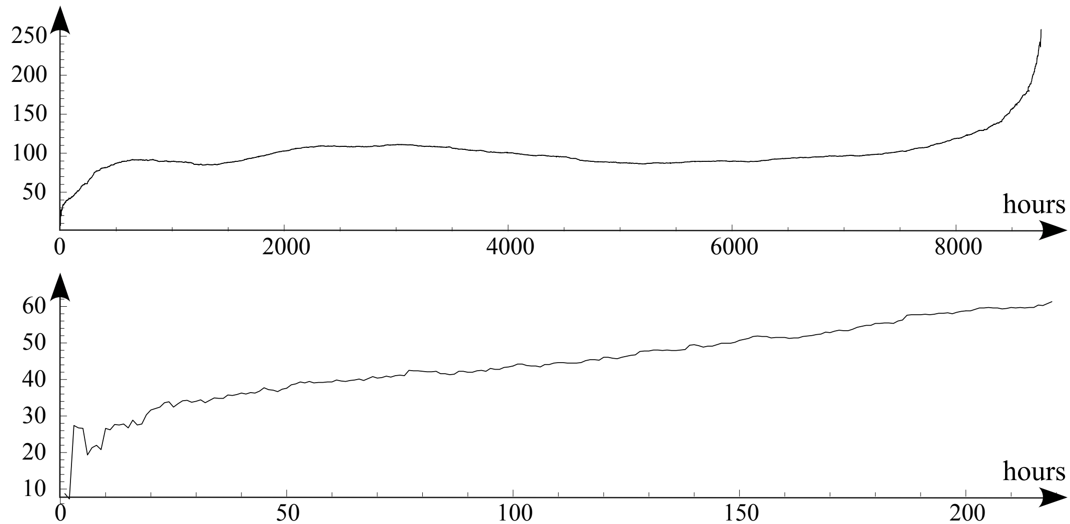

Figure 5: Asynchronous Wind Yield: Denmark 2006

2.4 Adequacy Cost

We can now work out the cost decomposition formula proposed in equation (1). The private cost of wind power in the system is taken to be the levelized cost $c_W = \frac{C_W}{T\mu_W}$ where C_W is simply the annualized cost of capital derived in Appendix A.[21] Next, we abusively use the average cost of energy for thermal producers c_Z as a proxy for the market value of electricity. We then interpret the (levelized cost) difference $c_W - c_Z$ as a *technology* cost for WPG. In the long run, this disadvantage will decrease as thermal fuels become dearer and are forced to pay for carbon emissions (or nuclear waste treatment) and also as wind turbines become cheaper (per MW) with technical progress (cf. learning and scale economies in Appendix A). Lastly, we define the adequacy cost as $c_Z - c_Y$, the excess of market value of electricity over system value of WPG (given that in a competitive market the price ought to be close to c_Z). Using "replacement cost" as a synonym for "system value", we have the following cost decomposition:

$$\begin{array}{ccccccc} \text{Private} & = & \text{Replacement} & + & \text{Technology} & + & \text{Adequacy} \\ c_W & = & c_Y & + & c_W - c_Z & + & c_Z - c_Y \end{array} \tag{5}$$

We noticed in the data that the thermal cost c_Z depends mostly on the capacity factor, the yearly energy delivered by WPG that is to say, is almost independent of the precise periods of strong winds over the year. Since the private cost c_W exclusively depends on the capacity factor, the technology cost is mostly determined by the capacity factor. This tells us that the system value of wind is determined by the temporal congruence of wind power output and load, independently of how strong is the wind resource in the country. By construction of the adequacy cost, it shares the same qualitative features. We also noticed in a preliminary robustness analysis that the cost decomposition appears to be quite insensitive to the scale of demand or alternatively to the scale of WPG deployment. If confirmed, it would mean that each country is characterized by a unique (although time varying) decomposition.

[21] Recall that fuel is free for wind, thus the duration cost curve is flat.

3 Results

We present countries by decreasing installed wind power capacity: Germany (cf. 3.1), Spain (cf. 3.2), Denmark (cf. 3.3), France (cf. 3.4), Portugal (cf. 3.5) and Ireland (cf. 3.6). We provide two tables for each country, the first with basic information and the second with the cost decomposition along the formula of equation (5) together with the levelized cost of thermal generation c_Z and the "real" cost of meeting electricity demand $\frac{C_Z+C_W}{T.\mu_D}$.

Symbol	Unit	Meaning
μ_D	GW	Mean hourly load during the year
K_W	GW	Mid-Year Installed Wind Power Capacity
$\overline{CF}$	%	Maximum WPG achieved during the year
$\underline{CF}$	%	Minmum WPG achieved during the year
μ_W/μ_D	%	Share (%) of Load served by WPG
σ_D	%	Mean absolute hourly load variation
σ_W	%	Mean absolute hourly WPG variation
σ_Z	%	Mean absolute hourly residual load variation

Table 1: Terminology

For the wind power capacity K_W, we use TSOs reports and wind energy barometer for end-of-year values. The maximum yearly WPG shown in percentage of installed capacity is build as follows. We compute first the vector of ratios $R = \left(\frac{W_t}{K_t}\right)_{t\leq T}$ using the linearized estimate of installed capacity $K_t = \underline{K} + \frac{t}{T}(\underline{K} - \bar{K})$ where $\underline{K}$ and $\bar{K}$ are respectively the previous and current end-of-year installed capacities. To account for the presence of measurement errors in our data, we do not use the maximum of R but the mean value of the 8 hours of maximum output (99.9% quantile). This maximum output is negatively impacted by a country's geographical extension. To assess the minimum WPG achieved during the year, we report the mean value of the 88 hours of minimum output (1% quantile) is reported as it is extremely low in all the sample across countries and years.

3.1 Germany

There are four German Transmission System Operators whose control areas more or less coincide with federal states as shown on Figure 6. Table 2 displays relevant statistics.

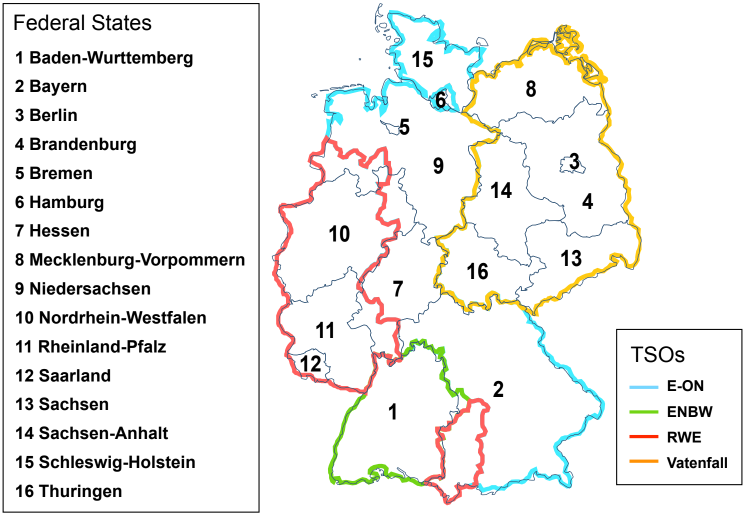

Figure 6: German TSOs and Federal States

	Power	Energy	Cap. Factor	Load	Share
TSO	GW	TWh	%	TWh	%
EON	8.6	13.2	17.6	204	38
VAT	8.3	12.3	16.9	84	16
RWE	3.4	4.8	11.6	171	32
ENBW	.3	.3	10.3	80	15
Germany	20.6	30.6	16.9	540	100

Table 2: German Aggregate Data for 2006

Each TSO publishes the "wind energy" fed into its transmission grid and the load on their transmission grid (Vertikale Netzlast) which does not include any measure from the distribution grid and thus ignore distributed generation. We also use the WPG data published by the Federal Ministry in charge of applying the renewables law (and making payments); it does agree fairly well with the summation of the data originating from the TSOs. For load, we use the UCTE hourly load data corrected for the UCTE monthly aggregate.[22]

Although wind power contributes more than a sixth of installed capacity in Germany, its generation share is only 7% due to extremely low capacity factors. ENBW's dramatic 10% figure is due to the continental climate affecting its zone which happens to be the least developed in Germany. Boccard (2009b) develops on this previously unpublicized feature of WPG in Germany. As a consequence of the low quality of the German wind resource, the levelized cost is currently twice the standard estimate (independently of the chosen capital cost for wind turbines). Matching this is the fact that the average feed-in tariff paid to WPG has grown from 85€/MWh in 2000 to 96€/MWh in 2006 (source: union of TSOs (VDN)).

Table 3 presents the basic characteristics of load and WPG over the three years of available data. Overall, load is decreasing whereas wind power continues to grow so that the share of load served by WPG is now above 7%. Due to the concentration of wind farms along the North sea shore, the maximum and minimum yearly output are extreme.[23] The measures of hourly variation show that load gets smoothed out by the very large German demand size while WPG is only partially smoothed out by the geographical dispersion of wind farms.

Table 4 displays our numerical cost estimates. Notice first that the private cost of WPG varies significantly from year to year as a consequence of long term meteorological evolution (cf. Boccard (2009b) sec. 2). The data analysis reveals a high cost of WPG, a direct reflection of the country's low capacity factor, and a low cost of thermal generation due to the importance of baseload. About half of the private cost of WPG corresponds to the technology gap whereas the other half is made up by the system value and the adequacy cost at about 6€/MWh.

[22] Oddly enough, the reported monthly aggregate load levels do not coincide with the sum of hourly loads. For some countries the difference is small but for Germany it is significant.

[23] Power equal to the nameplate capacity cannot be achieved at all turbines at the same time, thus the maximum output falls short of 100%.

Loc	Firms	Sales	Profits	Industry	Firms	Sales	Profits	
US	26.8	29.9	31.7	Oil	Gas	5.8	12.1	16.7
CN	5.7	4.4	7.7	Banking	15.4	11.7	16.3	
UK	4.3	6.2	6.7	Telecom	3.7	4.5	8.9	
FR	3.2	6.7	4.9	Drugs	Biotech	2.2	3.0	8.5
RU	1.4	1.6	4.5	Utilities	5.9	5.3	7.6	
CH	2.4	2.4	4.0	Food	Tobacco	4.3	3.7	6.5
ES	1.5	1.9	3.7	Materials	6.7	4.2	5.2	
HK	2.5	1.2	3.6	Software	Services	1.8	1.1	4.1
BR	1.7	1.6	3.5	Retailing	3.6	5.3	3.9	
CA	3.1	2.2	3.3	Conglomerates	2.1	3.6	3.5	
DE	2.9	5.9	2.8	Household Products	2.0	1.4	2.6	
IT	1.9	2.8	2.6	Media	2.5	1.7	2.3	
IN	2.8	1.3	2.4	Health Care	2.3	2.1	2.3	
AU	2.2	1.4	2.4	Construction	4.2	3.5	2.3	

Table 3: German Data

3.2 Spain

Spain hosts Europe's second largest wind power capacity having past the 15GW barrier. The successful development of WPG came in two phases as recalled by Dinica (2008). Before 2000, public agencies were involved in financing the initial investment and enabling partnerships to reduce risk. Since then, law has been modified to provide a secure low-risk legal framework together with a still attractive subsidy formula that has triggered a lasting wave of private investments from large national energy and infrastructure players.

Table 5 presents the regions where wind power is most developed together with the average capacity factor over the 2003-07 period (data source: REE annual reports). The Castille regions, altough very much developed, do not host strong wind in comparison with Navarra, Galicia or Aragon. The large geographical extension of this country implies that wind always blow but never at full capacity (cf. max W below 75%).

The basic data for Spain show an increase of load due to economic convergence as well as a sustained development of wind power that now contributes 12% of load service.

Loc	Firms	Sales	Profits	Industry	Firms	Sales	Profits	
UK	17.6	18.0	22.4	Banking	15.3	15.5	17.7	
FR	13.1	19.5	16.3	Oil	Gas	6.1	11.8	17.2
CH	9.8	6.9	13.4	Utilities	5.9	8.0	13.9	
ES	5.7	5.5	12.5	Drugs	Biotech	2.4	2.4	10.6
DE	11.6	17.2	9.2	Telecom	4.1	4.7	9.0	
IT	7.8	8.0	8.7	Food	Tobacco	4.1	3.9	9.0
SE	5.5	2.7	5.2	Construction	6.9	4.9	5.2	

Table 4: German WPG Cost Decomposition (€/MWh)

Region	Share	CF
Castile L.	20.1%	21.5%
Castile M.	20.0%	22.7%
Galicia	20.0%	28.2%
Aragon	12.2%	26.9%
Andalucia	7.5%	22.9%
Navarra	6.5%	28.1%
La Rioja	3.5%	20.3%
Valencia	2.9%	22.7%
Catalonia	2.6%	21.7%
Asturias	2.0%	24.5%
Spain	100%	24.9%

Table 5: Spanish Regions

The maximum yield is rather low because the large extension of the country creates heterogeneous weather patterns. For the same reason, the wind always blows somewhere in Spain, even if little. The Spanish load displays a greater variability than other large and populous countries such as France or Germany; this reflects the lesser contribution of industry demand on the baseload. The wind variability is likewise intermediate and larger than the size of installed capacity would lead one to believe a priori i.e., the smoothing out effect of geographical dispersion seems weak in Spain.

Loc	Firms	Sales	Profits	Industry	Firms	Sales	Profits	
CN	17.5	16.7	46.0	Banking	20.1	9.4	26.3	
HK	7.6	4.4	21.5	Telecom	2.7	4.5	17.7	
IN	8.7	4.9	14.3	Oil	Gas	4.2	11.3	15.9
KR	8.0	10.8	7.2	Materials	7.6	6.3	10.8	
TW	6.1	4.4	5.9	Trading Companies	3.1	6.8	5.6	
SG	2.8	1.6	3.4	Food	Tobacco	4.4	2.4	4.7
TH	2.2	1.2	3.0	Conglomerates	2.2	3.6	4.3	

Table 6: Spanish Data

As can be noted from Table 7, the system value of WPG in Spain is a few euros higher than in Germany and Denmark probably because the wider geographic distribution makes a better match with Load whose daily shape is also different due to the mediterranean way of life. Given the overall greater quantity of wind available in Spain (as compared to North Sea area), the private cost of WPG is smaller so that the technology cost is also smaller (about half the German value). Notice finally that the adequacy cost remains at levels similar to Germany or Denmark because thermal production is more expensive in Spain since more peaker technology is required to run.

Table 7: Spanish WPG Cost Decomposition (€/MWh)

3.3 Denmark

Electricity demand in Denmark, both at the energy and power levels, seem to have stabilized as can be noted from Table 8; this is an indication that advances in efficient use of energy compensate for the natural growth associated with GDP growth. Although absolute capacity stagnates around 3GW, Denmark, thanks to its small size holds the world's largest share of wind powered electricity. As reported by Munksgaard and Morthorst (2008), capacity has stagnated since 2003 due to a change in regulation (from feed-in tariff to market price) and a saturation of available locations.[24] The current trend is the re-powering of old sites to save on land and connection cost. The fact that the capacity factor and also the maximum country output increased during the period 2000-05 might

[24] Capacity and yearly generation data from the Danish Energy Authority's wind register.

well reflect the switch to more advanced wind turbines able to run under a larger span of wind speeds.

Table 8: Danish Data

The low system value of WPG in Denmark (as compared to other countries) indicates a low degree of congruence between demand and wind speed. Since the capacity factor is also relatively low, total cost is high and so is the technology cost. The most worrying element is the adequacy cost making up a quarter to a third of the total cost of wind power. Because this dimension is incompressible at national level, Denmark is the country which has most to gain from connecting with other networks in order to increase the system value of its WPG.

Table 9: Danish WPG Cost Decomposition (€/MWh)

From a more general point of view, the major quality of the Danish data is the 9 years duration of the data sample; it enables to observe how indexes vary across years which is the reason why we do not jump to conclusions for countries with less than 4 years of observation such as Germany or France. The North Sea winds appear to be changing from year to year with a strong impact on total cost and milder but still important on technology and adequacy cost. The minima and maxima are however observed on different years, an indication that the underlying phenomena cannot be well summarized by the capacity factor or the correlation coefficient between wind speed and demand. Interestingly, the most stable statistic is the system value. This is why we can afford to make some extrapolations in the case of France or Germany.

3.4 France

Though having an excellent wind resource, France has jumped lately on the WPG bandwagon; if one is to believe the government's environmental plan, it seems dedicated to make up its backlog; the installed capacity has already reached the 3GW mark (cf. France Energie Eolienne). As can be noted from Table 11, and although two years of observation impede jumping to conclusions, the French profile seems closer to the Spanish one than the nordic ones. It features a high system value of WPG and a low adequacy cost indicating a good temporal fit between load and wind speed. However, the technology cost is relatively high because the capacity factor is rather low in France.

Table 10: French Data

Table 11: French WPG Cost Decomposition (€/MWh)

3.5 Portugal

The development of WPG in Portugal is recent but strong as it already accounts for 8% of the electricity consumption. As can be noted from Table 13, Portugal displays results quite similar to its neighbor Spain taking advantage of its atlantic exposure as most of the WPG is deployed nearby the south coast. The smaller size of the country also means a greater variability of the wind resource but with limited impact on the variability of residual demand. Contrary to most other countries, the system value of WPG displays an important variability in passing from 44 to 37. This may indicate that Atlantic winds follows patterns different from North Sea winds.

Table 12: Portuguese Data

Table 13: Portuguese WPG Cost Decomposition (€/MWh)

3.6 Eire (rep. of Ireland)

Over the period 2002-2008, electricity demand in Ireland, both at the energy and power levels, grew at 3% per year, faster than population growth (1%) but less than the GDP growth (6%). This indicates a moderate increase in the use of comfort equipment such as electric heater or air conditioning in the household segment and a switch to services from industry in the business segment.

Installed wind power capacity grew at the sustained rate of 30% per year and now accounts for nearly 8% of total electricity consumption. The capacity factor was initially very large and has been varying (2004 was a noticeably still year) but remains by far the largest in our sample of countries, driving the levelized cost of WPG towards 50€/MWh. There is no doubt that this is one of the better places on earth to develop further wind power.

Table 14: Irish Data

Our empirical results reported in table 15 show that the system value of WPG is the largest among the sample. Secondly, the technology cost is low because the wind resource is abundant in Eire leading to a low private cost of WPG (high capacity factor). The most interesting fact is that adequacy cost is the sustained minimum among our sample of countries, indicating that this country can increase Wind Power development without expecting too much cost from keeping up with adequacy. All along the year, the temporal distribution of wind is well in line with the distribution of load. The year 2004 is a case in point to illustrate the independence of the adequacy and technology components of the social cost of WPG. Being a year of low winds, private cost rose together with the technology cost. Yet, the temporal distribution of wind speed was so favorable that the system value ended up being greater than the cost of equivalent thermal power.

Table 15: Irish WPG Cost Decomposition (€/MWh)

4 Conclusion

Adding large amounts of wind power in an electrical system generates reliability and adequacy problems. There is now agreement that modern electronic control technologies are able to solve the first problem at a moderate cost. We have argued that the much studied “capacity credit” concept is of little use to assess the economic contribution of WPG to load service because it is a quantitative measure (MW) only fit for a vertically integrated utility whereas in today’s deregulated markets, public authorities require monetary estimates of much consumers ends paying for carbon -free electricity. Such a monetary value is then useful to guide public policies toward wind power and other competing renewable energy sources.

Our decomposition of the private cost of wind power enables to measure the cost and benefits that WPG brings to an electrical system on a yearly average. We apply these concept to hourly wind output and load data made publicly available by TSOs in Europe. Much of the work done incorporated in this paper is in fact cleaning the raw data from missing values and measurement errors.

Our overall empirical conclusion is that wind power has a social value in line with the thermal cost of electricity. As a corollary, we may say that meanwhile wind power remains uncompetitive, it bears a sizable social cost made of almost independent components *technology* and *adequacy* cost. The former, which is currently the greatest, may be drastically reduced by the rising prices of fossil fuel and CO_2 emission permits or taxes. The latter synthesizes the temporal misalignment between the distribution of load and wind all along the year.

One obvious recommendation is to keep insisting on sitting turbines where they render the greatest service i.e., where their social cost is minimum which, incidentally in our samples, is also where their private cost is smallest. In the current landscape of national schemes, this translate into the recommendation that German and Danish wind power developers go abroad and sit turbines in Ireland or Scotland and then sell their clean output into the German market using physical exchange contracts. To avoid dumping load into the ground, an issue frequently mentioned for Denmark, it will be necessary to plan the necessary HV reinforcement to make sure that WPG output makes its way to its intended end-users.

Appendix

A Cost Estimates for Wind Power

We substantiate here the claims made in the introduction regarding the success of wind power and its underlying economics. Forty years ago, tidal and solar energy were claimed to be as promising as WPG but have utterly failed to make a significant contribution to electricity generation. There is no doubt that the massive subsidies to WPG from Denmark, California and Germany in the 80s (and Spain in the 90s) have turned it into a full-fledged industry. IEA's Global Renewable Energy Policies and Measures Database shows that Denmark started funding research on renewables in the 1970s. During the 1980s, Denmark and Germany introduced regulations and support schemes for WPG. Most remaining EU members followed during the 1990s.

Economies of scale Taller wind turbines not only are more powerful but also capture speedier winds so that their output increases more than linearly with respect to size; connections costs are also smaller for a group of few large turbines as compared to a group made of many small units. However, Kaltschmitt et al. (2007) (cf. Table 7.3 p369), looking at the levelized energy cost, report a mild 10% saving from using 5MW turbines instead of 1MW (both current state of the art).

Economies of experience Bolinger and Wiser (2009) study US data over the 1982-2006 period which indicate a decrease from 4M\$/MW down to a minimum of 1.3M\$/MW in 2004 ($\approx -2.4\%$/year) and since then a slight increase up to 1.5M\$/MW in 2006 (cf. fig. 18). According to English study SDC (2005), the price of wind turbines fell from 1.4M€/MW down to .8M€/MW ($\approx -3.7\%$/year) over the 1990-2004 period. German data indicate a fall from 1.5M€/MW down to 1.05M€/MW ($\approx -2.3\%$/year). Notice finally that turbines account for 3/4 of the price of a wind farm.

Geographical Dispersion The best sites for WPG are found on the coastal areas of Europe. Even though these are sparsely populated in Northern Europe, saturation might become a problem in the future. The issue is more serious in the Mediterranean as it is densely populated and/or devoted to tourism. As a consequence, local business and residents are opposed to wind turbine sitting, both on-shore and off-shore. Commenting on the development of wind farms in France during 2005 and 2006, RTE (2007) reports that local opposition has proved a particular obstacle to projects in the Mediterranean and coastal areas, leading to more inland installations in northern and eastern France where wind conditions are relatively worse. There is here an avenue for future research but detailed project data is needed to find out if this potential problem already bites. According to Bolinger and Wiser (2009), capacity factor in the US has increased over the last decade thanks to taller turbines, improved siting and technological advancements. Thus the exhaustion of quality sites does not seem to be a problem in that very large country.

Current Cost SDC (2005) aggregating data from Denmark and IEA, reports an average capital cost of 1M€/MW and O&M cost of 2.5% (of the yearly cost of capital) for onshore WPG (conversion rate 0.7£/€). Kaltschmitt et al. (2007), building on the German experience, indicate 1 M€/MW for onshore but a considerable O&M in the range 5–8% of the investment. More recently, Ernst & Young (2007) find 1.6M€/MW for current development in the UK, rising w.r.t. previous years due to a capital cost increase and delays from manufacturers, in turn created by the surge in world demand for wind turbines.[25] Assuming this is a temporary phenomenon, we settle for an average value of 1.1M€/MW regarding capital cost as found in Eirgrid (2004) or reported by the portuguese TSO for project benefitting from public subsidies. Regarding O&M, we take an optimistic attitude and disregard the finding by Bolinger and Wiser (2009) according to which O&M costs quadruple over the lifetime of a turbine. Assuming there is still a margin of improvement on the learning curve, we adopt a low value of 1.5% of the capital cost.

For the sake of comparison, we report similar cost estimates for offshore wind farms although no output data is yet available. According to SDC (2005), capital cost is 1.6M€/MW O&M cost is 3.5%. Kaltschmitt et al. (2007) indicate 2M€/MW for Germany and O&M above 3%. Private developer Airtricity reports the same capital cost and expected levelized cost of 77€/MWh over the first 25 years for a large scale project in the North Sea linking farms from Netherlands, Germany and the UK.

[25] Most professional organization have lately made the same basic observation.

Current Subsidies The current subsidy schemes in place in Europe either use price or quantity support. The UK and Italy require distributors to either include a minimum share of renewables in their electricity purchases or to buy-out their obligation. The tightness of current quotas is sufficient to induce high prices and this should attract more investment; yet a third firms buy-out their obligation instead of reducing their emissions (by either filtering smokes or adding wind power to their generation park). This unexpected outcome is probably the consequence of a perceived high market risk associated with entering the renewables electricity market. The other support mode pioneered by Denmark, Germany and Spain has proved much more effective and is currently more popular. A typical version of the scheme uses an initial feed-in tariff around 80€/MWh together with a phasing down towards 65€/MWh after five years. Spain is even more attractive as it gives the option to earn 40€/MWh on top of the Iberian pool price (currently above the 40€/MWh mark). At current feed-in tariffs, our findings show that the wind power market remains attractive for entry.

B Cost Estimates for Thermal Technologies

In this section, we present the general methodology to assess the levelized cost of electric generation which enables comparison among technologies; we draw on a variety of studies to pick representative estimates.

Levelized Cost Since we shall deal with fixed and variable cost, the duration of the period under study is an important ingredient. We use the year for expositional simplicity i.e., $T = 8760$ hours but any other choice would be acceptable (especially longer periods to smooth out yearly variations in wind speeds). Given the yearly interest rate r defined by the cost of capital and the amortization period τ (in years), the annuity factor is $\frac{r}{1-(1+r)^{-\tau}}$. Letting F be the capital cost of a plant with standard capacity q (in MW) and η the operation and maintenance (O&M) yearly fixed cost in percentage of the initial investment, the yearly fixed cost per MW is[26]

$$g = \left(\frac{r}{1-(1+r)^{-\tau}} + \eta\right)\frac{F}{q} \tag{6}$$

[26]In US parlance, the ratio $\frac{F}{q}$ is referred to as the "overnight capacity cost".

At the outset, technology $i = 1,..,n$ is characterized by the pair (c_i, f_i) of energy and power cost where

- c_i is the marginal cost (€/MWh) summing energy cost to variable O&M costs[27]
- $f_i \equiv \frac{g_i}{a_i}$ is the fixed cost (k€/MW) or cost of (guaranteed) *power* with
- g_i being the (name plate) fixed cost (k€/MW) computed in eq. (6)
- a_i being the availability factor: the probability that a plant using this technology is available for generation. It accounts for scheduled maintenance and unscheduled failures.[28]

Against usual convention, we relabel technologies so that $c_1 > c_2 > ... > c_n$ i.e., #1 is the peaker whereas #n is the baseload. We then introduce a virtual technology. Two choices are available. The first, used by pre-deregulation integrated utilities, is the curtailment with power cost $g_0 \equiv 0$ and energy cost $c_0 \simeq 5000$€/MWh, the value of loss load (VOLL) i.e., the average that consumers would agree to pay in order to maintain service (and avoid curtailment). Nowadays, with the development of demand side response (DSM), some clients agree to get curtailed on short notice for a brief period (a few hours) with a maximum number of yearly occurrences.[29] Their compensation is a fixed payment g_0 for agreeing to participate and a variable payment c_0€/MWh each time the mechanism is activated. It is probably feasible to negotiate $g_0 \simeq 5$ and $c_0 \simeq 2000$€/MWh.

Numerical Estimates For thermal technologies, we use the estimates reported by RAE (2004) and Ernst & Young (2007) and a 7.5% (real) interest rate except for nuclear for which we add a further 2.5% risk premium to account for the various sources of uncertainty surrounding this technology (cf. Dixit and Pindyck (1994)). Table 16 displays all the cost parameters and the resulting fixed and marginal cost for thermal technologies.[30]

[27] This approach disregards the cost associated with ramping up and down units.

[28] For WPG, Kaltschmitt et al. (2007) reports an average value of 98% but since the generation data for WPG does not distinguish failures, maintenance or the lack of wind, there is no loss of generality in adopting a 100% availability factor instead of scaling down installed capacity and scaling up the capital cost.

[29] In Spain, for instance, maximum curtailment durations of 12, 6, 3 hours and 45 minutes are to be notified 16, 6, 1 hour and 5 minutes ahead.

[30] Using a conversion rate of 1.4US$/€, Borenstein (2008)'s estimates, in k€/MW and €/MWh are (150, 18) for coal (baseload), (66, 36) for CCGT and (51, 54) for combustion turbine (peaker) which are nearby our choices.

These estimates are for illustrative purpose only and should not be taken at face value since they are slightly tweaked to enable a clear separation of the domains where each technology is the optimal fuel in the next section.

Technology	Thermal					Wind	
Item (unit)	Nuke	Coal	Gas	Oil	DSM	land	sea
Investment (k€/MW)	2200	1500	600	500	na	1100	2000
Int. rate (%)	10	7.5	7.5	7.5	na	7.5	7.5
Amortization (years)	40	30	25	20	na	20	20
Annuity (%)	10.2	8.5	9.0	9.8	na	9.8	9.8
K cost (k€/MW/year)	225	127	54	49	na	108	196
O&M (% invest.)	1.5	2	2	2	na	2	3
Availability (%)	90	90	90	95	100	95	95
F. cost (k€/MW/year)	287	174	73	62	5	137	270
Marg. cost (€/MWh)	7	20	35	45	2000	0	0

Table 16: Cost of technologies

Thermal Optimum We restrict our attention to switchable (controllable) technologies, including DSM, participating in the continuous market for power. We leave aside WPG as it works under a feed-in tariff with priority dispatching.

The total cost of running one MW of technology $\#i$ for t hours during a year is $C_i(t) = f_i + c_i t$ whereas its average cost is $AC_i(t) = \frac{f_i}{t} + c_i$; it is called a screening curve by Stoft (2002). We define the efficient technology curve as $C(t) \equiv \min_{i \leq n}\{C_i(t)\}$; it represent the least cost of generating during exactly t hours per year. The efficient average cost is $AC(t) = \frac{C(t)}{t}$. Whenever the curve of a particular technology is entirely above C, it means the corresponding technology should not enter the generation mix.[31] By relabeling the remaining ones, we can define for $i \leq n$, the technology characteristic as the ratio of incremental power cost over decremental energy cost $\rho_i \equiv \frac{f_i - f_{i-1}}{T(c_{i-1} - c_i)}$ and, by construction, it is true that $\rho_1 < \rho_2 < ... < \rho_n$. Using the estimates from Table 16, we compute levelized

[31] Some are known to be present because generation markets are not fully competitive and therefore remunerate generation above C.

cost for a variety of duration; they are reported in Table 17 together with on-shore and off-shore WPG for their relevant range of duration as indicated by the capacity factor CF.[32]

	Duration	10	100	500	1000	2000	3000	4000	5000	6000	7000	8000	8760
Thermal	Nuke	+10k	2873	580	294	150	103	79	64	55	48	43	40
	Coal	+10k	1765	369	194	107	78	64	55	49	45	42	40
	Gas	7349	766	181	108	72	59	53	50	47	45	44	43
	Oil	6260	667	169	107	76	66	61	57	55	54	53	52
	DSM	2500	2050	2010	2005	2003	2002	2001	2001	2001	2001	2001	2001
	marginal	DSM	Oil	Oil	Oil	Gas	Gas	Gas	Gas	Gas	Coal	Coal	Nuke
Wind	onshore				137	68	46						
	offshore				270	135	90	67					
	CF				11%	23%	34%	46%					

Table 17: Levelized Average Cost by Duration and Technology

Efficient Technology mix The aggregate demand for electricity, the load, is random.[33] The observed statistic $X = (X_t)_{t\leq T}$ is first sorted in decreasing order to produce the load duration curve (LDC) $\hat{X} \equiv \left(\hat{X}_t\right)_{t\leq T}$ such that $\hat{X}_t \geq \hat{X}_{t+1}$. The peak is $\hat{X}_1$ while the baseload is $\hat{X}_T$; we also set $\hat{X}_{T+1} = 0$ for convenience.

The empirical distribution H associated to $\hat{X}$ is computed as follows. For the observations, we set $H(X_t) = \frac{t}{T}$ and fill the gaps linearly. We complete with $H(x) = 1$ for $x < \hat{X}_T$ and $H(x) = 0$ for $x > \hat{X}_1$. For practical reading, $T \times H(x)$ is the number of hours where demand exceeds x.

The optimum mix of technologies to serve the yearly load X is the one minimizing the cost of serving it. Let $(q_i)_{i\leq n}$ denote the generation park[34] and $Q_i \equiv \sum_{j=i}^{n} q_j$ the maximum output of the cheapest i technologies. By switching one firm MW from baseload to peaker i.e., from technology $\#i$ to $\#i-1$, we save $f_i - f_{i-1}$ on capital cost but we spend an additional $c_{i-1} - c_i$ for every MWh that will be called for generation. The MW under consideration is called to produce each time the demand is greater than Q_i, thus the yearly

[32] The numerical estimates are tweaked so that the all thermal technologies are conditionally efficient for some duration.

[33] We treat it as being completely inelastic. We hope to account for price elasticity in future work.

[34] We use "park" for absolute MW levels since "mix" is rather used with percentages.

number of hours of generation is $T \times H(Q_i)$. The installed baseload capacity q_i is optimal if there is no incentive to increase or decrease it i.e.,

$$f_i - f_{i-1} = (c_{i-1} - c_i)T \times H(Q_i) \Leftrightarrow \rho_i = H(Q_i)$$

Since $Q_n = q_n$, the adequate amount of baseload capacity is $q_n = H^{-1}(\rho_n) > \hat{X}_T$ the baseload (beware of the abuse of terminology here). Recursively, $q_i = H^{-1}(\rho_i) - Q_{i+1}$ for all $i < n$. Notice that since $\rho_1 > 0$, $Q_1 < \hat{X}_1$ the yearly peak of demand. This means that curtailment or DSM (technology #0) is bound to be in service for $\rho_1 T$ hours each year. Increasing the VOLL to infinity amounts to nullify ρ_1 and eliminate curtailment. This corresponds basically to the obligation imposed until recently upon TSOs by governments. This is why the capacity margin, which the difference between installed capacity and foreseen peak load, is so large (often more than 20%).

C Data Sources

- Danish TSO Energinet: download area for a large selection of data
- Association of German Network Operators (VDN)
- German Federal association of the energy and water management (BDEW)
- SouthWest German TSO ENBW (in German): click on *Windenergieeinspeisung* for wind data and on *Vertikale Netzlast* for Load
- NorthWest German TSO RWE (in German): bottom of the page, click on *Winddaten* for wind data and on *Vertikale Netzlast* for Load
- North German TSO EON : choose Excelsheet at the bottom of pages Load and Wind
- Eastern German TSO Vattenfall (in German): choose *Vertikale Netzlast* for load data and *Windenergieeinspeisung* for wind data.
- French TSO EDF for load data and Distribution Operator ERDF for wind data (courtesy of Olivier Gonbeau).
- Spanish TSO REE: we use the publicly available daily reports and the graphical display of daily outputs for load and WPG since there is no download area on the website and the TSO refused to share that information with us.
- Irish TSO Eirgrid: download center

- Portuguese TSO REN: daily load curve and daily wind output curve (in Portuguese)
- UCTE for load data

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