The use of cost-generation curves for the analysis of wind electricity costs in Spain

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A R T I C L E   I N F O

Article history:
Received 26 February 2010
Received in revised form 7 September 2010
Accepted 10 September 2010
Available online 20 October 2010

Keywords:
Onshore wind energy
Cost
Renewable energy
GIS
Cost-generation curves

A B S T R A C T

The cost of the electricity generated from onshore wind is assessed through a method based on an estimation of the geographical distribution of the technical potential and a cost structure for the estimation of the local unit cost. Generation-cost curves are then employed to portray the evolution of the specific generating cost with the increase of the generated energy, until the limit of the technical potential is reached. The study also relates the energy cost to the land occupancy, the installed power and the capacity factor, and includes an assessment of the interplay between land usage and the cost of wind electricity. An analysis is presented to determine the uncertainty in the costs of the several model parameters. The method is applied to Spain, and allows to establish that, for an electricity-generation level of 500 TW h/y (roughly equal to the overall demand in Spain in 2008), the specific marginal cost is around 8.5 €/kW h.

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1. Introduction

When estimating the overall wind-energy potential of a large region for energy planning and policy making, it is essential to analyze as well economic and social issues, such as the unit cost of the generated energy and its impacts (e.g. visual). For an economic study, a reliable evaluation of the wind resource is paramount; with such an evaluation and the corresponding estimation of the energy produced, the unit cost of the energy can be calculated from the investment costs and the O&M expenses.

In the last two decades, the capital costs for the construction of wind farms have decreased significantly due to the maturity of the technology and to the serial production of components; in the last few years, the specific capital cost is generally stable, or increasing slightly; for the USA, an analysis by the Department of Energy [1] traces this change in trend to the possible influences on price of the weakness of the US dollar, the increasing materials costs, a shortage of components and turbines and even a trend towards increased manufacturer profitability; others point to the widespread installation of larger wind turbines, which had yet to be mass-produced.

The O&M costs include operating personnel, maintenance, land rental, insurance, management and administration, and taxes. Many of these costs have also experienced a reduction in recent years due mainly to the improved reliability of the equipment. In Spain, a 2006 technical report by the Spanish Institute for Energy Diversification and Savings (IDAE), indicates that they are on average approximately 1.5 €/kW h (or 22% of the annual turnover considering a feed-in tariff of 6.9 €/kW h for 2005).

According to Blanco [2], the generating cost in Spain for a typical wind farm operating between 1700 and 3000 full-power-equivalent hours (equal to a capacity factor between 19% and 35%), is in the range 4.5–8.7 €/kW h. As the penetration of wind energy in the generation mix increases and the best feasible sites are developed, this specific cost also increases.

In the scientific literature, there are few published studies with estimations of the generating costs of the onshore wind energy, at least on the regional scale. An exception, on the global scale, is the work by Hoogwijk et al. [3,4]. In this study, an assessment is made of the energy that can be obtained worldwide from renewable resources, and also of the generating cost. The renewable energies considered are biomass, onshore wind, and photovoltaic solar. Also, a comprehensive study of the wind potential in Europe has been published recently [5]. In this study an assessment of the energy potential and its economical feasibility of the wind energy in Europe (both onshore and offshore) is developed. Among the studies on the national scale, the one by Nguyen [6] estimates the wind resources and generating costs in Vietnam; Acker et al. [7] present an analysis with a similar scope for the US state of Arizona; Harijan et al. [8] assess the wind power costs in the coastal area of Pakistan; and Yue and Yang [9] present the potential and an economic analysis for onshore and offshore wind energy in Taiwan. Other economic studies at a more local scale are: Ahmed Shata and Hanitsch [10], in Hurghada, Egypt; Ucar and Balo [11] and Gökçek and Genç [12] for several locations in Turkey; and Katsaparakis et al. [13] for the island of Dia in the Cretan Sea.

This paper places the focus on the development of a methodology, based on the procedure and results by Fueyo et al. [14], to assess the cost of onshore wind electricity. The paper is organized as follows. First, the proposed method is described. Then, the results...
obtained for a base case are reported. Finally, a parametric analysis is conducted to evaluate the impact on the results of the uncertainties in the model parameters. In a related paper by some of the present authors [15], the visual impact of wind energy for the same scenarios presented here is analyzed using several impact indexes. All the monetary quantities in the paper are referred to year 2006, unless otherwise stated.

2. Methodology

The methodology used consists of two main steps; first, the so-called technical potential is estimated at each location; then, a cost structure is applied leading to a local, specific cost of wind electricity. These geographically-distributed costs are reported in a compact way in the form of generation-cost curves.

2.1. Technical potential

The electricity that can be generated annually in Spain (excluding the Canary Islands) from onshore wind was estimated and reported in an earlier paper [14]: this electrical energy will be referred to in this paper as the technical potential. For the sake of completeness, a short summary of this procedure is provided here. The estimation of the technical potential starts with the computation of a local wind-speed Probability Density Function (PDF) at each point in the target territory, viz. the whole of Spain; to do so, a Numerical Weather Prediction tool (viz. MM5, [16]) is employed to calculate the weather for a whole year (2006) with a resolution of 10 km and 1 hour. As an indication of the wind resource in Spain, the spatial distribution of the mean wind speed resulting from this procedure is shown in Fig. 1.

The domain was then tessellated into 200 m × 200 m pixels. Every pixel in the domain was classified as viable or otherwise for the installation of wind turbines on geographical or technical grounds. Thus for geographical reasons the following land uses are excluded: urban and industrial areas; protected areas (such as national parks); communication lines, and their buffer zones; the hydraulic public domain (which includes rivers and bodies of water); and the maritime public domain (i.e. 500 m inland from the shoreline). On technical grounds, terrains with slope greater than 15% [7,17]) or at a high altitude [3,6] are excluded. At this stage, however, technically-viable locations are not disqualified on the bases of their economic performance. Wind-turbine and wind-farm characteristics (such as the turbine spacing) are then selected and the technical potential is computed at each pixel by integrating the wind-speed PDF multiplied by power delivered by the turbine as a function of the wind speed (the so-called wind-turbine performance curve) [14]. The result is a technical potential \( \pi_i \) (MW h/y) at pixel \( i \), which will be later used to determine the unit cost of the generated energy (e.g. €/kW h).

The main characteristics of the wind farm used are indicated in Table 1. For these settings, the global technical potential is 1078 TW h/y; for the sake of comparison, this is roughly equivalent to 3.5 times the electricity consumed in Spain in 2008.

2.2. Cluster detection

The present study assesses the potential for wind generation in a wide area (a whole nation) using a fine spatial discretization of the domain. The suitability of every pixel for the installation of wind turbines is considered from the geographical and technical points of view; however, this process may result in isolated pixels that, while technically suitable for the installation of wind energy, are economically not viable because they do not result in a critical minimum farm size. To detect those clusters of pixels that would support a sufficiently-large farm, or, conversely, to filter out locations which are isolated and therefore are impractical or uneconomical, we use a procedure we term cluster detection, which involves spatial filtering.

The spatial filter centers around every pixel in the domain a window, or kernel, of given fixed dimensions. Then, the total power that can be installed in the kernel is assigned to the pixel. This is done for the whole domain, and then a pixel qualifies as a member of a sufficiently-large cluster if the total power in the kernel is above a certain threshold, or if the pixel is part of any other suitable kernel. In this study, we have required a minimum installed power of 12 MW in a 9 × 9 pixel (1.8 km × 1.8 km) kernel. For the nominal farm used in the base case in this study, this is equivalent to six 2 MW wind turbines in a 3.24 km² area around the pixel.

2.3. Cost model

The present economic analysis of the wind-generated electricity estimates the specific cost, \( c_i \), of the electricity \( \pi_i \) generated in a pixel \( i \) over the course of one year. This can be calculated from the (annuitized) investment costs and the operation and maintenance ones (O&M). The equation used to perform this calculation is:

\[
c_i \pi_i = a f^p p_i + \max[C_i^p \pi_i, C^E p_i]
\]

where \( \pi_i \) is the annual electricity generated at pixel \( i \); \( f^p \) is the specific investment cost per unit installed power; \( p_i \) is the power installed in the pixel; \( C^p \) and \( C^E \) are the annual O&M costs, respectively per unit of installed power and per unit of generated energy (the rationale behind the max function will be explained below); \( a \) is the investment annuitization coefficient, \( a = r [1 - (1 + r)^{-N}] \), with \( r \) being the interest rate (taken as 0.09 for the base case) and \( N \) is the investment lifetime (taken as \( N = 20 \) [3,6]).

Table 2 summarizes the findings of a survey, carried out by the present authors, of the costs of wind energy in Spain, as reported by several sources and applicable to the period 2005–2006. In this table, the first entry is for the Spanish Renewable Energy Plan [18]; IDAE refers to the figures quoted in the Wind Power Handbook.
[19], a 2006 technical report by the Spanish governmental agency Institute for Energy Diversification and Savings (IDAE); IEA reports the figures in the 2007 IEA Wind technical report [20]; AEE1 and AEE2 are figures provided in two different studies by the Spanish industrial sector (the Wind Energy Association, AEE), respectively [21,22]. It can be noticed that there is a difference between the costs considered by government agencies and by the industrial sector. For this work, we have chosen for the base case some intermediate costs, viz. an investment cost of 1000 €/kW and O&M costs of 1.6 c€/kW h. The influence of these costs on the results will be assessed in the parametric analysis of Section 4.

The reporting of the operating costs per unit generated electricity is the usual practice in the literature but may be misleading if used in a large-scale study such as the present one. This is so because when the operating cost is reported per unit generated electricity a certain level of electricity production (or capacity factor) is assumed. For instance, in the Spanish Renewable Energy Plan an annual production of 58,750 MW h in a 25 MW farm is assumed for the costs reported in Table 2. This linear dependence of the operating costs with the generated energy breaks down for low capacity factors; thus, in the limit of zero generation, zero O&M would ensue. To redress this deficiency, we use as operating costs the larger of the per-unit-energy \( G^E_{p_i} \) and a per-unit-power one \( G^{P_i} \), the latter being calculated with \( G^{P_i} = G^E_{p_i} P_i = 37.6 \) €/kW, using the above-reported generation \( p_i = 58,750 \) MW h for the \( P_i=25 \) MW farm.

From Eq. (1), the specific cost (per unit generated electricity) \( c_i \) can be obtained for each pixel in the domain; and a production-cost curve can be constructed by ordering, in increasing costs, the energy generated in every pixel. Since the specific costs vary over a wide range for the whole of the technical potential, a representative cost is defined as the most frequent cost in the domain considered (i.e. the statistical mode). This representative cost is therefore a typical cost of the electricity generated from wind power over the whole of the territory. The electricity that can be generated with a cost lower than the representative one will be termed the economic potential. In using these definitions and terminology, we of course do not preclude the economic feasibility of

### Table 1
Parameters for the reference wind farm (see Fueyo et al. [14] for details).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated power</td>
<td>2.0 MW</td>
</tr>
<tr>
<td>Rotor diameter</td>
<td>90 m</td>
</tr>
<tr>
<td>Rated wind speed</td>
<td>13 m/s</td>
</tr>
<tr>
<td>Cut-in speed</td>
<td>3.5 m/s</td>
</tr>
<tr>
<td>Cut-out speed</td>
<td>25 m/s</td>
</tr>
<tr>
<td>Hub height</td>
<td>78 m</td>
</tr>
<tr>
<td>Spacing</td>
<td>8d \times 8d</td>
</tr>
<tr>
<td>Wake efficiency</td>
<td>0.84</td>
</tr>
<tr>
<td>Operating efficiency</td>
<td>0.98</td>
</tr>
</tbody>
</table>

### Table 2
A survey of the wind-energy investment and O&M costs in Spain for 2005–2006; see text for details of sources.

<table>
<thead>
<tr>
<th>Source</th>
<th>( P^e (€/kW) )</th>
<th>( G^{P_i} (€/kWh) )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spanish Renewable Energy Plan</td>
<td>937</td>
<td>1.51</td>
</tr>
<tr>
<td>IDAE</td>
<td>940</td>
<td>1.5</td>
</tr>
<tr>
<td>IEA</td>
<td>1250</td>
<td>–</td>
</tr>
<tr>
<td>AEE1</td>
<td>1057</td>
<td>1.66</td>
</tr>
<tr>
<td>AEE2</td>
<td>1110</td>
<td>1.82</td>
</tr>
</tbody>
</table>

![Fig. 1. Spatial distribution of the average wind speed at a height of 10 m; the contour labels are m/s.](image-url)
actually implementing the economic potential; rather, they are convenient single-figure data which are intrinsic to the technology, and that can be used to characterize a scenario, thus permitting a quick comparison among several of them, as will be shown below. The production-cost curve has therefore four noteworthy points: the entry cost (the cost of generating the first unit energy), the representative cost (or the most usual cost over the whole of the territory), the economic potential (the potential that can be generated up to the representative cost), and the technical generation limit (given by the last point in the curve). A more thorough analysis of generation-cost curves can be found in [23].

3. Results and discussion

3.1. Costs and generation-cost curves

With the method and data described in the previous section, the spatial distribution of the specific cost of the generated energy is obtained. This is shown in Fig. 2; the lowest cost, in zones with a very good wind resource, is around 4 c€/kW h, and the cost obviously increases as the quality of the wind resource decreases. In considering these results, it is important to bear in mind that in large-scale studies such as the present one, it is difficult to account for the cost impact of site-specific factors (other than the wind). For instance, the model used includes the cost of a 10 km evacuation line from the site to the transport grid, but no provision is made to tailor this cost for a particular site. Similarly, the investment cost assumes a common accessibility to the sites, and no corrections are made for local accessibility conditions.

From the local specific cost in Fig. 2, a production-cost curve can be built as indicated in the previous section by plotting the generated electricity (up to the technical potential) in increasing costs. The result is shown in Fig. 3, where in the left-hand ordinate axis we plot the marginal costs while in the right-hand one the occupied surface (as a percentage of the overall surface of Spain) is displayed for information purposes. Thus, the graph indicates for instance that for a production level of 300 TW h/y, which is the total electricity consumed in Spain in 2008, the marginal cost is about 8.5 c€/kW h with an occupation of 6.9% of the Spanish surface, or 34,000 km². The figure also indicates the representative cost, defined as the statistical mode of the costs for all the technically-feasible sites, which results to be 8.8 c€/kW h; the level of production at a lower cost (which is called in this paper the economic potential) is 321 TW h/y, corresponding to an installed power of 147 GW. The vertical asymptote in Fig. 3 is the technical potential, which for the present case amounts to 1078 TW h/y.

3.2. Land use scenarios

The generation of energy from wind is, as many other renewable-energy sources, intensive in the use of the available territory. Unlike other renewable energies, wind may be compatible with certain simultaneous uses of the land; however, the change of use is not always socially acceptable. The above generation-cost curve has been calculated on the assumption that all the land is available for wind-energy developments, with the exceptions due to geographical or technical reasons listed in Section 2.1. Further constraints on the available territory (via restrictions to changes in land usage) have two main effects in the wind-generated
electricity: firstly, the overall technical potential is obviously decreased as less land is available for wind-energy collection; but, most importantly, the overall cost of the generated energy increases as sites with otherwise good wind potential become unavailable. In order to analyze the influence on the potential and cost of wind energy of placing restrictions to the change in the land use, three main scenarios have been considered, in addition to the base one presented in earlier sections. They correspond to an increasingly-restrictive availability of the land for wind-energy deployment, and are the following (with the mnemonics used later indicated in bold typeface):

- LAND-EXIR: all the forests (including non-protected), IRRigated lands, and lands with permanent crops (olive trees, vines and orchards) are EXcluded (but non-irrigated lands are available).
- LAND-EXHP: all the forests (including non-protected forests), irrigated lands, lands with permanent crops (olive trees, vines and orchards) and High Productivity non-irrigated lands are EXcluded. High-productivity non-irrigated lands are defined as those with an annual rainfall in excess of 500 mm. The available territory, before geographical and technical restrictions, is 272,972 km².
- LAND-EXAG: all the forests (including non-protected forests), and all of the AGRicultural land are EXcluded as available for the deployment of wind farms. The available territory, before geographical and technical restrictions, is s 145,227 km².

Table 3 summarizes the main results for these scenarios, and Fig. 4 shows the corresponding generation-cost curves. The table indicates that overall technical potential decreases substantially as new restrictions are successively introduced; and the figure reveals that the unit cost of the electricity generated also increases with the restrictions. The cost increase becomes substantial from a generation level of approximately 100 TW h/y, or one third of the total electricity consumed in Spain in 2008.

### Table 3

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Land occupancy (%)</th>
<th>Pmax (GW)</th>
<th>cmin (€/kWh)</th>
<th>πc (TW h/y)</th>
<th>cπ (€/kWh)</th>
<th>ππ (TW h/y)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>50.5</td>
<td>983</td>
<td>4.0</td>
<td>1078</td>
<td>8.8</td>
<td>321</td>
</tr>
<tr>
<td>LAND EXIR</td>
<td>37.7</td>
<td>733</td>
<td>4.0</td>
<td>743</td>
<td>11.3</td>
<td>280</td>
</tr>
<tr>
<td>LAND EXHP</td>
<td>27.3</td>
<td>531</td>
<td>4.0</td>
<td>535</td>
<td>11.8</td>
<td>214</td>
</tr>
<tr>
<td>LAND EXAG</td>
<td>12.0</td>
<td>136</td>
<td>4.0</td>
<td>278</td>
<td>10.4</td>
<td>104</td>
</tr>
</tbody>
</table>

4. Parametric uncertainty

We analyze in this section the influence on the technical potential and on the generation cost of changing some of the key model parameters used in the base case as presented in Section 2. Specifically we estimate the influence in the minimum cost $c_{\text{min}}$, the representative cost $c_{\pi}$, the economic potential $\pi_{\epsilon}$ and the technical potential $\pi_{\tau}$ of the following parameters: the turbine cut-in and cut-off speeds, the wind turbine size, the spacing between wind turbines, the parameters of the cluster-detection algorithm, the initial investment, the investment lifetime, the O&M costs and the interest rate. Some of these parameters have an influence on the technical potential and in the cost, while others affect only the latter.

The impact of these parameters (except for the cluster-detection algorithm and the wind turbine size) on the technical and economic results is quantified through the elasticity $\epsilon$, defined as the ratio of the percent change in the dependent variable to a ±1% change in one of the independent ones. The sign of the elasticity indicates whether there is a direct (if positive) or inverse (if negative) relation between both parameters. As an additional indicator, a $\chi^2$ parameter is employed to estimate the linearity of the dependency (in the neighbourhood of the calculation point). Thus, $\chi^2$ is the function minimized when fitting the three data points to a straight line using a least squares method, and it would be zero for a strictly linear dependence; otherwise the relationship is closer to linear as the $\chi^2$ parameter is closer to zero (the sign indicating whether the non-linear relationship is concave or convex).

Table 4 lists the calculated values of $\epsilon$ and $\chi^2$ for the parameters whose influence has been analyzed; the results are further commented upon in subsequent paragraphs.

4.1. Cut-in and cut-out speeds

As shown in Table 4, the influence of the cut-in speed on the production-cost curve is negligible. The null effect in the minimal cost can be expected since for these sites the wind resource is of a higher quality, and a small change in the cut-in speed does not result in the addition of a significant number of operating hours. The technical potential does not vary significantly, because the
amount of energy contained in the wind at such low speeds is small (since the power of the wind is proportional to its velocity cubed).

The influence of the cut-out speed on the main properties of the generation-cost curve, although larger than that of the cut-in speed, is not significant (for moderate changes), as the corresponding entry in Table 4 evinces; this reflects the low probability of wind speeds greater than 25 m/s, which is the value considered in the base case.

4.2. Wind turbine spacing

The large-scale nature of the present analysis prevents the consideration of local terrain and climate characteristics in micro-siting analyses that would locally optimize the turbine layout; thus a single, common spacing is used throughout. The spacing used in the layout is an important parameter in the overall results because it affects the power installed per unit terrain area, and because in cases of dense packing the wake-turbine interaction can significantly decrease the efficiency of the downwind turbine [24]. The model used for estimating the technical potential of a site [14] takes into account the latter influence through a collection-efficiency factor which changes as the spacing does. The effect of turbine spacing is analyzed in this section for three spacings, viz. $5d \times 5d$, $8d \times 8d$ (base case) and $10d \times 10d$.

Table 5 summarizes the main global results for the three spacings, and Fig. 5 shows the generation-cost curves. It is observed that the base case and the $10d \times 10d$ case have similar costs in the low-cost range of the curve (slightly lower for $10d \times 10d$); however, in the $5d \times 5d$ case generation costs are approximately 1 €/kWh higher in the low-cost range, due to the larger wake losses in the $5d \times 5d$ case. Nevertheless, the main influence of turbine spacing is on technical and economic potentials, as shown in the elasticity analysis (see Table 4), which indicates elasticities of $-1.72$ and $-1.38$ respectively.

4.3. Economic parameters

The initial investment, the investment lifetime, the interest rate, and the O&M costs are all purely-economic parameters, which therefore do not influence the technical potential. For small variations around their respective base-case values (viz. $N = 20$, $r = 0.09$, $P = 1000 \text{ €/kW}$, $C = 1.6 \text{ €/kW h}$, $Q = 37.6 \text{ €/kW}$), the initial investment is the parameter which bears a larger influence on the cost, with the elasticity being around $0.58$ for the minimum cost of the energy generated, and $0.49$ for the representative cost. (see Table 4)

4.4. Wind turbine size

The analysis for this parameter can not be developed through the elasticity method used above because the technical character-
The capacity factor for a wind turbine at a given location is calculated as the energy actually produced along the year divided by the energy that would be generated by operating at the rated power for the whole year. It has therefore the physical meaning of the equivalent fraction of time that the turbine would operate at full power to produce the same amount of energy as it really produces. The capacity factor is a function of the quality of the wind resource at the location, and of the power curve shown in Fig. 6. The results (Fig. 7) indicate that the smaller turbines have a very similar economic performance, while the larger one results in increased unit costs. The reason, as revealed in Fig. 8, is that the larger turbine results in lower capacity factors, because it requires a larger wind speed (approximately 15 m/s, Fig. 6) for operating at the rated power.

4.5. Cluster detection

In this subsection we analyze the sensitivity of the results to the parameters used in the cluster-detection algorithm; these parameters are: the minimum installed-power required for a cluster to be regarded as viable, and the kernel size. In order to compare with the scenarios developed in this analysis, we report the reference values corresponding to a scenario without cluster detection in Table 8, which summarizes the results from the cluster detection parametric analysis.

For the analysis of the influence of the minimum installed power, in addition to the base-case level of 12 MW we use 8 MW or 16 MW per cluster, which correspond to four or eight turbines respectively. The kernel size is the same as in the base case. For the four-turbine case, the resulting technical potential is 1103 TW h/y, representing a increase of 25 TW h/y in comparison with the base case. For the eight wind-turbine scenario, the technical potential decreases to 1027 TW h/y, a loss of 51 TW h/y with respect to the base case. For both cases, the minimum cost is not significantly affected, and neither is the representative cost, while the economic potential behaves in the same way that the technical potential.

The influence of the kernel size in the cluster detection results is next studied. The selected kernel sizes are 7 pixels (1.96 km²) and 11 pixels (4.84 km²). The minimum kernel power is the same that as for the base case, viz 12 MW. As shown in Table 8, more restrictive parameters lead to lower potentials (technical and economic), while the minimum and representative costs do not change significantly.

5. Conclusions

This work has presented a method for the evaluation of the cost of electricity generation from onshore wind energy, and its application to Spain. The method combines a detailed estimation of the wind resource with a cost structure for the technology to yield a local unit cost of the generated electricity. Generation-costs
curves are used to summarize the information from the model in a complete, yet compact, form.

The results indicate that the cost range starts at about 4 €/kW h; the most frequent (termed in this study as ‘representative’) cost is 8.8 €/kW h. As an indication, the study suggests that for the annual electricity produced in Spain in 2008, the marginal specific generation cost is about 8.5 €/kW h.

The influence of curtailing the change of land use from other current uses to wind-electricity generation has been studied. In addition to the usual exclusions arising out of technical and geographical considerations, three scenarios with increasing restrictions have been examined: the exclusion of land currently occupied with forests (including non-protected), irrigated crops, and permanent crops; the additional exclusion of high-productivity non-irrigated land; and additional exclusion of all agricultural land. As these additional restrictions are progressively introduced, the results indicate that, apart from the expected decrease in the overall technical potential, the cost of the generated electricity increases substantially for a generation level in excess of approximately 100 TW h/y (equivalent, for the sake of comparison, to about one third of the current total annual electricity generation in Spain).

Acknowledgement

This work is partly funded by the Spanish Ministry for Science and Innovation, under Project ENE2007-67217/ALT.

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