

Application of Wind Generation Capacity Credits In the Great Britain and Irish Systems

C.J. DENT and J.W. BIALEK
Durham University
United Kingdom

B. HASCHE and A. KEANE
University College Dublin
Ireland

SUMMARY

The concept of capacity credit is widely used to quantify the contribution of renewable technologies to securing demand. This may be quantified in a number of ways; this paper recommends the use of Effective Load Carrying Capability (ELCC, the additional demand which the new generation can support without increasing system risk), with system risk being measured using Loss of Load Expectation (LOLE, this is calculated through direct use of historic time series for demand and wind load factor). The key benefit of this approach is that it automatically incorporates the available statistical information on the relationship between wind availability and demand during the hours of very high demand which are most relevant in assessing system adequacy risk. The underlying assumptions are discussed in detail, and a comparison is made with alternative calculation approaches; a theme running through the paper is the need to consider the assumptions carefully when presenting or interpreting risk assessment results.

A range of applications of capacity credits from Great Britain and Ireland are presented; this includes presentation of effective plant margin, ensuring that the optimal plant mix secures peak demand in economic projection models, and the Irish capacity payments system.

Finally, new results comparing capacity credit results from the Great Britain and Irish systems using the same wind data are presented. This allows the various factors which influence capacity credit results to be identified clearly. It is well known that increasing the wind load factor or demand level typically increases the calculated capacity credit, while increasing the installed wind capacity typically decreases its capacity credit (as a percentage of rated capacity). The new results also show that the width of the probability distribution for available *conventional* generating capacity, relative to the peak demand level, also has a strong influence on the results. This emphasises further that detailed understanding of risk model structures is vitally important in practical application.

KEYWORDS

Wind Generation, Capacity Credit, Risk Assessment, System Adequacy

1. INTRODUCTION

The installed capacity of wind generation is increasing rapidly worldwide. For instance, in Great Britain (GB, peak demand ~60 GW) it increased from 0.9 GW in 2004 to 3.4 GW in 2007 [1], and may exceed 20 GW by 2030 [2]. In Ireland (peak demand 5 GW) the wind penetration has also grown rapidly over the past decade, from an installed capacity of just under 100 MW in 1999 to one of 1,427 MW at present, representing approximately 20% of total installed generation capacity [3]; there is a target to supply 40% of electrical energy demand from renewable sources by 2020 [4].

The contribution of wind generation to supporting demand is very different from that of the same capacity of conventional plant. Firstly, the mean proportion of installed capacity available at times of very high demand is lower for wind. Secondly, the availability of different conventional units is to a very good approximation independent, as this is a matter of mechanical availability; it follows that the total available conventional capacity in a system does not vary very far from the mean, and in particular near-zero available conventional capacity is impossible. In contrast, the availability of wind capacity is primarily a matter of resource availability (i.e. how windy it is); it follows that the proportion of installed wind capacity which is available can take any value between zero and 100%.

Traditional transparent system adequacy metrics such as gross plant margin (i.e. of installed capacity over peak demand), and expected or net margin (i.e. of mean available capacity over peak demand), are therefore insufficient in systems with high penetrations of wind generation. The concept of capacity credit (or capacity value; the terms are used interchangeably) is therefore used to quantify the contribution of wind generation to securing demand. This is not a new concept, having been used for conventional plant for several decades (see e.g. [5]), but it is of far greater importance for renewable plant.

This paper surveys different approaches to capacity credit calculation (Section 2), and reviews applications from the Great Britain and Irish systems (Section 3). It then presents new results comparing calculations from the two systems using the same wind data (Section 4); this enables the various factors influencing the calculated capacity credit results to be clearly identified. A common theme implicit throughout the paper is the need to examine in detail the assumptions underlying risk calculations when interpreting their results. This is not merely a matter of academic interest; it is vital in industrial application, as results can vary significantly depending on the calculation structure used.

2. CAPACITY CREDIT CALCULATION APPROACHES

2.1 Capacity Credit Definitions

A variety of capacity credit calculation approaches are in use. The principle versions are:

- *Effective Load Carrying Capability (ELCC)*. The additional load which the new generation can support without increasing the value of a chosen risk index [5].
- *Comparison with load carrying capability of conventional plant*. This might either be in terms of the conventional capacity which can be displaced without increasing risk, or by direct comparison with the load-carrying ability of a test conventional unit, e.g. [6].
- *Percentile of peak-period availability distribution*. The capacity credit of the new generation is defined as the increase in a chosen percentile (e.g. lower 1% or 5%) of the distribution for total available generating capacity (at time of peak demand) when the new generation is added [7].

We believe that the first of these (ELCC) provides the most robust approach; it requires the fewest parameters to be defined in order to perform the capacity credit calculation, and moreover load may naturally be varied within a simulation. The second (comparison with conventional plant) requires a test conventional unit to be defined; hence, the 'headline'

capacity value calculated depends on the properties of the test conventional unit chosen. The last (distribution percentile) will be discussed in more detail in Section 2.4; under certain conditions it is very closely related to ELCC.

The relationship between these approaches and others are discussed further in [8]-[10]. There is an ongoing debate in GB as to the most suitable risk modelling and capacity credit approach for renewables; an alternative view may be found in [11].

2.2 Preferred Capacity Credit Calculation Approach

Sections 2.2 and 2.3 describe an ELCC-based approach to capacity credit calculation; this has been adopted as the preferred approach by the IEEE Power and Energy Society Task Force on Capacity Value of Wind Generation [cite if accepted in time].

The risk index used is Loss of Load Expectation (LOLE), defined as

$$[\text{LOLE}] = \sum_{\text{periods } t} [\text{LOLP}]_t,$$

where the Loss of Load Probability for period t , $[\text{LOLP}]_t$, is defined as the probability that the available generation in period t is less than demand [12]. It is customary to measure system risk in terms of generation being insufficient to meet full demand. The periods considered may be half-hours, hours or days; in the latter case, the LOLP would be calculated for daily peak demand. The results from LOLE calculations based on different period lengths are not directly comparable; for example, hourly LOLE would count a 3 hour shortage as 3 hours, whereas daily LOLE would effectively count it as 24 hours.

It would be possible instead to work in terms of the generation capacity required to meet demand plus a minimum required operating reserve level [13], or alternatively in terms of the capacity required to avoid customer disconnections assuming demand may be reduced by voltage and frequency reductions¹ [14]; however, as any of these options makes a reasonable measure of system risk, we follow the customary definition of LOLP in terms of full demand.

2.3 LOLE Calculation Method

The LOLE is evaluated using a ‘hindcast’ approach, which asks what the risk would have been over a number of past years, given time series for system-wide wind load factor (available output divided by installed capacity) and demand covering those years.

For any time during these years, a probability distribution for available conventional plant may be derived using standard methods [12]. Without the intermittent wind plant, the LOLE may then be evaluated by summing over periods the LOLPs obtained using this distribution. When the wind generation is considered, the same calculation may be applied, modelling the wind output in each period as negative load.

If a measure of the underlying demand level is available, it is beneficial to scale all demands to a common value of this measure. In GB, ACS (Average Cold Spell) peak demand, defined as ‘a level of peak demand within a financial year (1 April to 31 March) which has a 50% chance of being exceeded as a result of weather variation alone’ [15], would be used; as seen from the definition, it varies with changes in underlying demand volume and behaviour, rather than depending on weather conditions at time of peak demand in any particular year.

¹ While much of the material in [14] is still relevant, all of the present authors now prefer the use of time series risk calculations to annual peak calculations, for the reasons given later in this section.

The historic wind load factors would be scaled according to the wind capacity for the year being studied. Ideally, the wind time series used would take account of the geographical location of the wind fleet under study. In Great Britain, very little metered wind output data is available, and hence time series calculated from meteorological records must be used, e.g. [16]. In Ireland, metered data is more widely available, and may be used directly provided the geographical dispersion of the historic wind fleet is considered representative of the year studied. Risk calculations considering offshore wind are problematic in both systems, as there is neither a substantial history of metered offshore output data, nor one of offshore wind speed records from a wide variety of locations.

A common, but not universal, practice is to scale the demands to give a target risk level (for instance 1 day in 10 years [17]). This can aid comparison of studies in different systems, and makes the capacity value independent of the plant margin in a particular year. However, even if these benefits are desired, care must be taken in performing this scaling if it involves a substantial change from the actual demand level.

2.4 Comparison with Other Risk Calculation Methods

The same definition of ELCC may be used with other risk indices, e.g. the LOLP at time of annual peak [14,17]. Benefits of the LOLE-based approach include automatically accounting for the wind-demand relationship and geographical diversity in the resource, and giving a broader picture of risk beyond the time of annual peak. An annual peak LOLP calculation requires a probability distribution to be derived for the available wind capacity at time of annual peak. By definition there are few hours of direct relevance; indeed, as extreme demands tend to be driven in most power systems by extreme weather, it might be expected that that error will be induced if an annual peak distribution is based on either all periods with demand within a certain percentage of peak, or all daily peaks in the peak season.

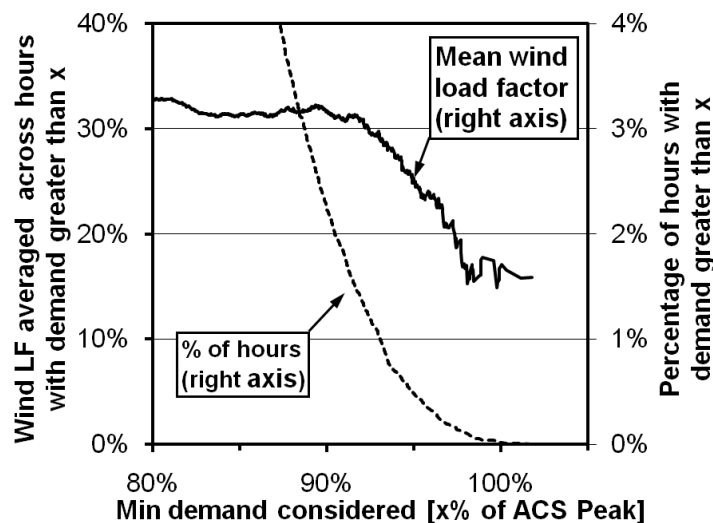


Fig. 1: Relationship between available wind load factor from the transmission-connected wind farms in GB and system-wide demand. Data from the three winters 2006-9 are plotted.

Fig. 1 illustrates the critical importance of accounting correctly for the relationship between wind availability and demand. It shows clearly that over the winters 2006-9, the mean wind load factor across the hours of very highest demand was considerably lower than the mean load factor across more typical (lower) winter demands. This confirms that any group of hours spread across the whole winter, without consideration of demand level, will not be representative of absolute peak demand; plotting the mean load factor across all hours above a certain demand (as in Fig. 1) combines the degree of aggregation which is needed to reveal any trend, with the necessary focus on the hours of highest demand.

The German DENA study [7] uses an apparently very different approach to capacity credit calculation. It defines ‘firm capacity’ as the change, on addition of the wind generation, in a chosen percentile of the distribution for available generating capacity (e.g. the demand at which the LOLP would be 1% or 5%). The DENA method is however equivalent to an annual peak LOLP-based ELCC calculation, with a target risk level as described in Section 2.3.

One advantage of using ELCC as defined in this paper is that it does not rely on an ability to calculate an absolute level of risk. Due to both approximations in model structures, and data uncertainties, it is widely acknowledged that it is only robust to compare relative levels of risk under different circumstances; this is precisely what ELCC does (i.e. equate risk levels with and without the wind generation). It will be verified (in Section 4) that ELCC results are not very sensitive to a chosen target risk level as described in Section 2.3.

2.5 The Nature of Capacity Credits

Differently from load factor, which may be calculated directly from historic wind records, because of data uncertainties and the range of calculation methodologies in use there can be no one definitive value of wind capacity credit in a system. It should therefore be regarded as an indicative quantity, whose value cannot even in principle be known exactly.

The most detailed picture of system adequacy risk is obtained through the detailed risk calculations which underpin a capacity credit study, rather than the capacity credit itself. The results of such calculations, however, can be difficult to interpret; it is usually difficult to trace cause and effect between input parameters and the output risk level. Capacity credits therefore play a valuable role in interpreting such results, and also in communicating results to interested parties who do not have a background in mathematical risk modelling.

This indicative nature of capacity credits naturally invites questions as to how detailed the underlying risk modelling should be. As discussed above, it is certainly vital to capture the relationship between wind availability and demand in the calculation. In capacity credit studies, a two-state (i.e. zero or full rated capacity) representation of conventional generating plants is usually considered sufficient; pollution or major transmission constraints may also be included in this picture [14]. Including a full network model would add greatly to the computational overhead; moreover, it might not be very relevant to wind’s contribution to securing demand, as if network constraints cause wind output to be curtailed then generation availability is probably quite high.

3. APPLICATIONS OF CAPACITY CREDITS IN GB AND IRELAND

3.1 Assessment of Effective Plant Margin in GB

This represents the archetypal capacity credit application. It is common both in GB and other systems to use plant margin to assess generation adequacy, bringing the transparency benefits described in Section 2.5 (without central generation planning, an assessment of generation adequacy remains important in informing market players’ decision making.)

In order to retain the benefits of transparency from a plant margin approach, the GB System Operator’s Winter Outlook applies a risk-based capacity credit for wind generation in this calculation rather than the mean load factor [18] (conventional plants’ contributions are directly related to their mean availability). This also illustrates the need for good wind data in adequacy calculations; in GB, even the System Operator only has access to metered wind output data from transmission-connected wind farms, which covers only about half of the total installed wind capacity and a limited geographical extent (distribution-connected wind output is seen as negative demand in the metered demand time series; this provides some information for reserve setting, but is less useful for projection to higher wind penetration).

3.2 Generation Adequacy Constraint in Economic Models

Economic projection models for future energy supply mixes typically work by assuming that a competitive market maximises the net present social welfare arising from future energy supply. An example of this is the UK MARKAL model [19], used in analysis of decarbonisation pathways under different scenario assumptions.

As described in [20], this model constrains the energy supply mix in a given year to support both the projected year-round energy demand and also the projected annual peak power demand; the latter is enforced using an effective plant margin requirement, scaling renewable capacity by capacity credits as in Section 3.1.

3.3 Contributory Generation in the Transmission Planning Standard

Historically, when applying the deterministic part of the GB transmission network planning standard, generation up to a maximum capacity of 20% above peak demand has been considered; the philosophy is that this is the plant margin which is sustainable in the long term [21]. With a high renewables penetration, it would be natural to extend this approach using capacity credits to scale the installed capacity of renewable generators, in order to obtain an effective plant margin of 20% (however, if a cost-benefit analysis between capital and constraint costs is performed, the full forecast generating capacity would be considered.)

3.4 Capacity Payments in the Irish Single Electricity Market

Capacity credits are commonly used to calculate payments in capacity markets; an example of this is the All Island Electricity Market in Ireland [22]. The capacity credit calculation is LOLP-based. As the risk of generation deficit varies across the year and tends to be higher at times of high load, the capacity credit is calculated on a monthly basis. A more detailed method would result in more efficient allocation of payments; however, as the capacity credit of wind generation depends on the total installed capacity (not just the properties of individual wind farms), new capacity would reduce the capacity payments to existing generators.

4. CAPACITY CREDIT RESULTS FROM THE GB AND IRISH SYSTEMS

4.1 Motivation

Many papers, including those cited here, have reported capacity credit results from systems worldwide. As this paper is an exploration of capacity credit methods and interpretation, rather part of a wind integration study, we present results illustrating points made earlier in the paper rather than a full study. In particular, calculations for the GB and Ireland systems are performed using wind time series from the other system; this will prove very revealing in isolating the consequences of different factors driving capacity credit results.

4.2 Results

The capacity credit results from the two systems use exactly the same LOLE-based approach. The probability distribution for available conventional generating capacity is derived through a capacity outage probability table method [6]. Metered wind and demand data from the years 2007 and 2008 (for which coincident time series were available for both systems) is used; this is not sufficient for a detailed quantitative capacity credit study, but is ideal for this purpose. Before adding the wind generation, the GB peak demand and LOLE are 60 GW and 0.061 hour/year; the figures for Ireland are 5.05 GW and 1.87 h/y.

Capacity credit results are shown in Fig. 2, both for the original demands and for demands rescaled to give a target LOLE of 24 hours/10 years (following the procedure described in

Section 2.3). As expected, the Irish wind data gives higher capacity credit results than the GB data, as the Irish wind load factors are on average higher. Also, in common with other studies, the capacity credit as a percentage of installed wind capacity decreases with increasing wind capacity (because at higher wind capacities the possibility of very low output becomes more important on a system scale), and the capacity credit result increases as demand is increased (as any generation is more valuable to the system when risk is higher.)

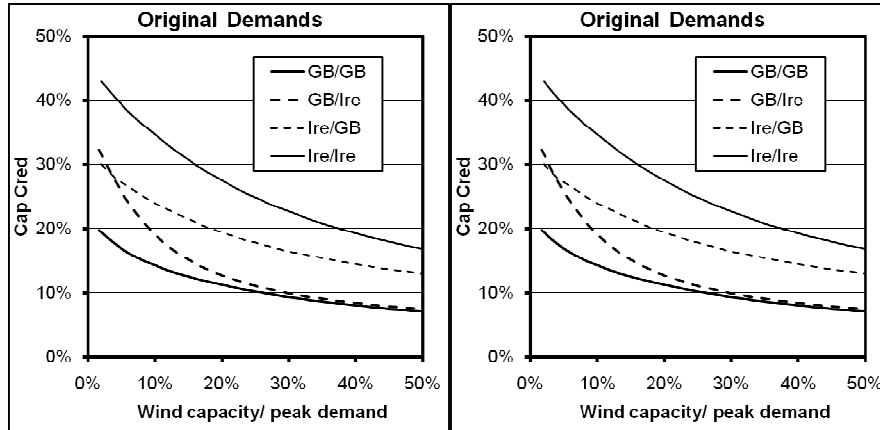


Fig. 2: Capacity credit results from the GB and Irish systems. Sys1/Sys2 denotes demand and conventional generation from Sys1/wind data from Sys2.

More surprising is the result that the Irish system consistently gives higher capacity credit values than GB for the same wind data. This is explained by the fact that in the smaller Irish system the variations in available conventional capacity are larger relative to installed capacity or peak demand. As a result, when the same percentage wind penetration is added to the two systems, the distribution for available capacity broadens less in the Irish system than in GB; hence, in this calculation the wind capacity appears ‘firmer’ in Ireland than in GB, and the calculated capacity credit is then higher.

Additional calculations have been performed to investigate the influence of increased interconnection on the capacity credit values; the resulting increased geographical diversity of the wind resource helps mitigate the volatility of its output, and hence might be expected to increase the capacity credit. However, it was found that the change in risk structure on adding interconnection (i.e. the huge reduction in risk due to reserve-sharing, whether or not wind was included) dominated the change in capacity credit results. This is consistent with the comments earlier in this section that capacity credit results depend on system properties other than those specifically relating to the wind generation. As a consequence, the capacity credit results were not informative about the benefits of interconnection for wind integration.

5. CONCLUSIONS

This paper has reviewed the calculation of capacity credits for wind generation, and presented new results from the GB and Irish systems. The key conclusions are:

- When comparing results from different studies, it is important to examine carefully the capacity credit definition and structure of the underlying risk calculation.
- In evaluating loss-of-load risk, it is vital to account properly for any relationship between demand and wind availability near absolute peak demand.
- Capacity credit results depend on system properties other than those relating directly to the wind generation. It is well known that calculated capacity credits are higher at higher risk levels. This paper also suggests that capacity credit results depend on the width of the distribution for available conventional capacity, expressed as a proportion of system demand; as a result, there is a tendency for capacity credit results with the same wind penetration to be higher in smaller systems

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