Drivers of Wind Capacity Credit Results in the 5 GW Irish and 60 GW British Systems

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***Abstract*—We present a new comparative study of wind capacity credit results in the GB and Irish electricity systems, which have peak demands of 60 GW and 5 GW respectively. By using coincident data from the two systems, new insights into the drivers of the capacity credit results are obtained. In addition to confirming well-known properties of capacity credits, this reveals a major difference in the structure of the calculated risk in GB and Ireland. In GB, the tail of the conventional plant distribution decays as a Gaussian, and so the calculated risk is dominated by the very highest demands. In Ireland, however, the tail of the conventional plant distribution is approximately exponential; as a result, all demand levels between 90% and 100% of peak make approximately the same contribution to the calculated risk, and even demand levels of 80% of peak make a non-negligible contribution. This raises some important questions as to how closely the conventional capacity outage table based risk calculation represents the true risk at these moderate demands. These results are expected to generalise to other systems of similar relative sizes.**

***Index Terms*—Wind power generation, Power system reliability, Power system modeling**

I. 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 availability of wind capacity is primarily a matter of resource availability (i.e. how windy it is); this is in contrast to conventional plant, whose availability is primarily a matter of mechanical availability. This qualitative difference between wind and conventional plant has required new thinking about power system risk assessment.

One aspect of this is the calculation of capacity credits for wind generation, which quantify wind's contribution to supporting demand; differently from all-conventional systems, generation adequacy in systems with high wind penetrations cannot robustly be assessed using the margin of installed capacity over peak demand. A variety of definitions of capacity credit are in use; our preferred definition (and that of the IEEE PES Task Force on Capacity Value of Wind [5]) is Effective Load Carrying Capability (ELCC), the additional demand which new generation can support without increasing generation adequacy risk [6].

A wide range of capacity credit studies have been published as part of wind integration studies (see [7]–[9] for a review). It is clear from these that the capacity credit of wind generation depends on a variety of factors including the installed wind capacity and the level of system risk, in addition to the properties of the underlying wind resource.

This paper uses coincident time series for wind and demand in the British and Irish systems to explore the drivers of capacity credit results; moreover the very different sizes of the two systems makes this ideal for studying differences in risk structure between small and large systems. This coincident data permits a much more systematic exploration of these drivers, when compared to previous discussions which have reviewed independent capacity credit studies, as it permits isolating changes in one input while keeping others constant. The effects described are:

- Capacity credit increases as demand increases.
- Capacity credit decreases relative to installed capacity as the wind capacity increases.
- With the same wind data in each system, use of the Irish demand and conventional plant data gives higher wind capacity credits than use of the GB demand and conventional plant data.
- The detail of how the calculated capacity credit at low wind penetrations depends on the underlying wind resource is explored.

The first two of these effects are well known from previous studies; this new study provides valuable confirmation. The investigation presented for the last two, however, leads to some very deep insights into the structure of generation adequacy risk in small and large systems.

Due to the smaller number of units in Ireland, the probability distribution for available conventional capacity is both broader relative to the peak demand, and decays less rapidly in the low availability tail, compared to the equivalent distribution in Great Britain. As a consequence, demand levels down to about 90% of peak make a substantial contribution to the calculated risk in Ireland, whereas the risk in GB is dominated by demands above 97% of peak. As well as revealing what drives the capacity credit results, this raises important

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questions of whether the standard model of independent random conventional unit outages is robust down to these low demands, and whether this risk structure is consistent with practical experience in Ireland.

First, Section II describes the capacity credit methodology used, including the treatment of wind data and conventional plant. Section III then presents and interprets the new capacity credit results, and Section IV discusses which demand levels are most important in the GB and Ireland risk calculations. Finally, conclusions are presented in Section V.

II. CAPACITY CREDIT CALCULATION

A. Calculation Approach

1) Effective Load Carrying Capability:

The definition of capacity credit used in this paper is Effective Load Carrying Capability (ELCC); the ELCC of new generation is defined as the additional peak demand which that generation can support without increasing system the chosen system risk measure [10]. Alternative methods based on comparison with the load-carrying capability of conventional plant have also been used, e.g. [11]; we prefer ELCC as it does not require the definition of a test conventional unit, and load may naturally be varied continuously in a simulation (see [8] for a full description of the ELCC calculation method).

The risk measure used in the capacity credit calculation is Loss Of Load Expectation (LOLE), defined as the expected number of periods (here hours) in which generation is insufficient to meet demand, or equivalently the sum over periods of Loss Of Load Probabilities (LOLP) [12].

2) Hindcast Method for Demand and Wind:

A ‘hindcast’ approach is taken, in which n years of historic data (here 2 years, 2007 and 2008) are used to simulate n versions of the study year. The wind output is modelled as negative demand, and the historic wind and demand data is rescaled to the projected wind capacity and demand in the study year. This robustly accounts for the statistical relationship between wind output and demand, as well as spatial relationships in wind availability, and has been used successfully in wind integration studies worldwide (e.g. [13]).

Only the conventional generation is treated explicitly stochastically in the risk calculation; the probability distribution for available conventional capacity is derived through a capacity outage probability table method [12].

3) Interpretation and Use of Risk Calculations:

It is important to keep in mind what is and is not included in standard probabilistic risk calculations. These usually only consider independent random outages of conventional plant; they do not consider common-mode issues such as loss of fuel supply and type faults, for which probabilities cannot be quantified robustly. They also do not consider the risk from disturbances (i.e. the immediate consequences of sudden fault events), which currently dominates the customer disconnection risk in GB and Ireland. In addition, a shortage of available generating capacity might not mean actual customer disconnections, but rather a voltage reduction to allow the system to ride through peak demand.

Capacity credits are used for a variety of purposes in GB and Ireland, including

- Assessment of effective plant margin in GB [14].
- Generation adequacy constraints in economic projection models [15].
- Capacity payments in the Irish Single Electricity Market [16].

More detail on these applications may also be found in [6].

B. Data

1) Great Britain Data:

The Great Britain wind load factor time series used is derived from the aggregate output of transmission-metered wind farms [17]; due to the small wind capacity pre-2007, that is the first year for which a reliable and representative time series is available. This brings the benefit that metered data is directly representative of real wind farm output, which is not guaranteed for wind data based on meteorological records. However, all of the transmission metered wind in GB is in Scotland, so this dataset does not cover the entire wind fleet.

The GB peak demand used in the study is 60 GW, which gives an LOLE of 0.061 hour/year before the wind generation is added. GB does not have a formal target for LOLE.

2) Irish Data:

The Irish wind load factor time series used is derived from the aggregate output of transmission-metered wind farms [18]. Due to more comprehensive metering, a reliable and representative time series covering the whole country is available back to 2006; a series covering at least six wind farms is available stretching back to 1999.

The Irish peak demand used in the study is 5.05 GW, which gives an LOLE of 1.87 hour/year before the wind generation is added. Ireland has a formal target for LOLE of 8 hours/year, which is employed by the TSO for generation planning calculations using assumed load growth and planned generator FORs.

3) Discussion:

Time series for wind and demand for 2007 and 2008 are used in this paper, due to the relatively short history of wind data in GB. For a full wind integration study more years of data would be needed [19], with better geographical coverage in GB; however the data is sufficient to support the comparison between small and large systems presented here, and for this purpose coincident data from the two systems is vital. Over this period, the mean load factors (ratio of mean output to installed capacity) for the GB and Irish wind generation were respectively 26.8% and 33.6%.

One set of capacity credit results is presented using the original demand levels stated above. As the calculated risk level is much higher in Ireland, in order to aid comparison between the systems, a second set of results is presented with the demands in each system scaled to give an LOLE of 2.4 hours per year (the Irish target of 8 h/y is not used, as it is much higher than historic experience in developed countries including Ireland itself.) This practice of scaling demands to give a target risk level is common in wind integration studies [7], the motivation being precisely to aid this kind of comparison; however, it clearly comes at the price of making the calculations less representative of the real system.

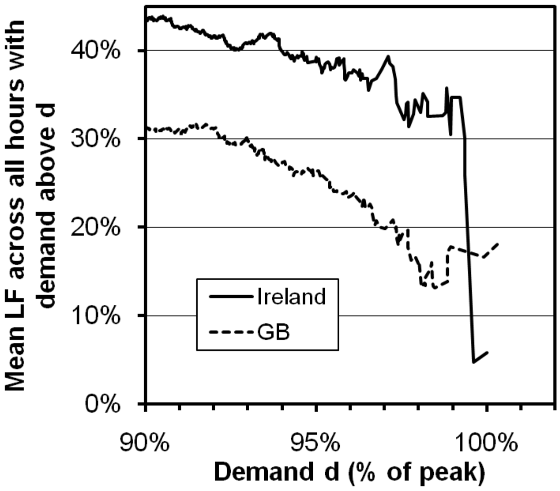

Fig. 1. Horizontal axis: demand (d) as a percentage of peak. Vertical axis: mean wind load factor across all hours with demand higher than d.

The interconnector from GB to France has been treated as 2 GW of firm generating capacity in the GB calculation. The interconnection between the Republic of Ireland and Northern Irish systems has not been considered in the risk calculation. However, as the results are presented with demands scaled to give a target risk level, the way interconnectors are treated will make no qualitative difference to the results and only a small quantitative one; such a difference will not affect the conclusions of this comparison study.

C. Wind Resource Visualisation

The wind resource at times of high demand in the two systems is visualised in Fig. 1. This representation, plotting on the x-axis demand (d) as a percentage of peak, and on the y-axis mean wind load factor across all hours with demand higher than d, is an extremely powerful visualisation; it combines the degree of aggregation of data necessary to reveal trends in the data, with the focus on very high demands which is necessary when looking at loss-of-load risk.

This shows that Irish load factors are typically higher than those from GB at all demand levels where the graph gives robust information; at the very highest demands, where the Irish plot is lower, there are so few data points that random variation dominates any trend. In each system, the typical load factor at demands close to absolute peak is lower than that for more typical peak season demand hours (in the 90-95% range). This deterioration in the quality of the wind resource as demand approaches absolute peak is more pronounced in the GB data; it might therefore be expected a priori that capacity credit values in GB will be further below the peak season mean load factor than in Ireland.

D. Conventional Plant Distribution

The probability distributions for available conventional generating capacity in GB and Ireland are shown in Fig. 2. These are derived from a standard capacity outage probability table (COPT) calculation [12], with the exception that in GB the total output from some stations is capped at the station's maximum output (due to transmission or emissions constraints). The assumptions underlying this model are that outages of different units are independent, and that either maximum or zero capacity is available from each unit.

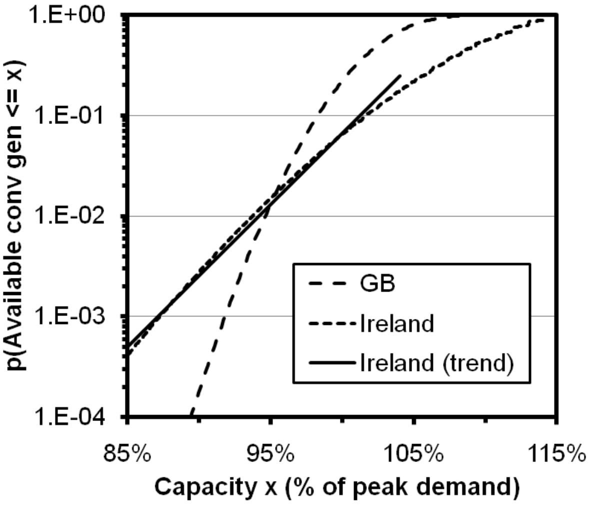

Fig. 2. Cumulative distribution function for available conventional capacity in the GB and Irish systems. Capacities are expressed relative to peak demand.

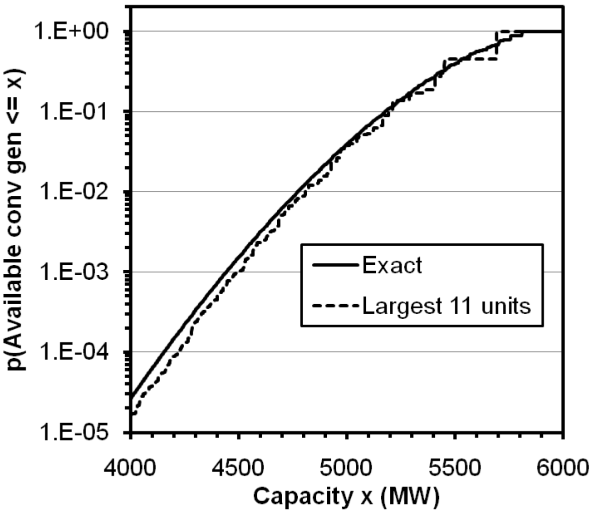

Fig. 3. Probability distribution for available conventional capacity in the Irish system. Results from both the exact calculation, and a calculation based on the largest 11 units, are displayed.

The mean and SD of the calculated distribution for aggregate available capacity from the 50 conventional units in Ireland are 5522 MW and 247 MW, respectively 95.0% and 4.3% of the installed capacity of 5811 MW. The mean and SD in GB from 245 units are 64.86 GW and 1.98 GW, respectively 87.6% and 2.7% of the maximum capacity of 74.01 GW. The unit availability probabilities were supplied by the two System Operators; the GB probabilities are publicly available in the annual Winter Outlook [14].

1) Great Britain:

In the GB conventional fleet, the largest unit capacity is thus of the order of 1% of the total installed capacity. The Central Limit Theorem (CLT) implies that the distribution for total available capacity is then approximately Normal, as the following conditions are met:

- Unit availabilities independent
- Large number of units
- No one unit dominates the sum

As is commonly the case, the low-availability tail of the distribution is slightly fatter than Normal.

2) *Ireland:*

In the smaller Irish system, the largest unit accounts for almost 10% of the total installed capacity of 5811 MW. As a consequence, several of the individual units make up substantial proportions of the installed capacity, and it is no surprise that the resulting aggregate distribution is far from Normal. In fact, the distribution is very close to Exponential in the key range between 85% and 100% of peak demand, and there is a macroscopic probability of around 11% that all the units are available (this latter contrast with GB is due to both the smaller number of units, and due to the Irish units being on average much more reliable than the British ones.)

The origins of this distribution shape may be explored further by performing a second COPT calculation involving just the 11 largest units, and then adding the mean available capacity from the remaining 39 units to the resulting random variable; this is displayed as the dotted line in Fig. 3, and compared with the solid line showing the result including all 50 units in the COPT.

The similarity between the two series in Fig. 3 demonstrates that the basic shape of the distribution is driven by the largest units, and that remaining 39 units essentially smooth out this distribution derived from the largest units. At low availabilities, the ‘all units’ curve lies to the left of the ‘largest 11 units’ one; this is due to the additional broadening of the distribution when a full probabilistic treatment of the other 39 units is used.

III. CAPACITY CREDIT RESULTS

A. *Results*

Capacity credit results from the Great Britain and Ireland systems are presented in Fig. 4. Results using various combinations of data are shown:

- Original demand levels (see Section II-B), or demands rescaled to give LOLE of 2.4 hours/year.
- The four combinations arising from use of conventional generation data from either system, and also wind data from either system.

The calculations with demand from one system and wind data from the other is made possible by the use of coincident time series from the two systems; While in once sense being rather artificial, this will prove helpful in deducing which factors are driving the capacity credit results. The capacity credit results are plotted in terms of installed wind capacity as a percentage of peak demand, again in order to aid comparison between the two systems of very different sizes.

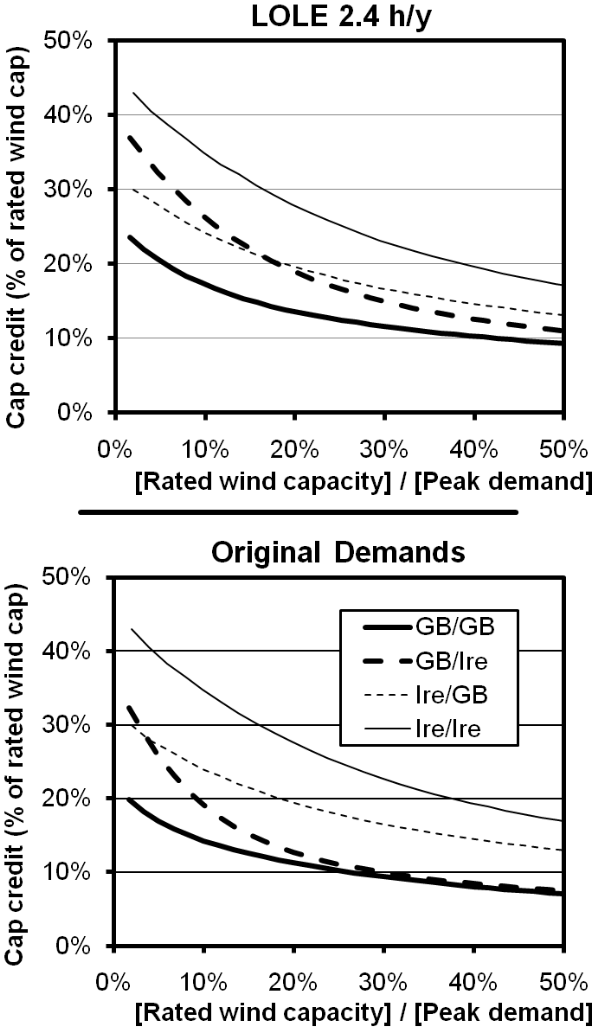

Fig. 4. Capacity credit results from the Great Britain and Irish systems. Sys1/Sys2 denotes [conventional plant and demand data from Sys1]/[wind data from Sys2]. ‘Rated’ wind capacity refers to the total installed nameplate capacity. Lower panel: original demands used. Upper panel: demands scaled to give LOLE of 2.4 hours/year.

B. *Interpretation of Results*

1) *Capacity Credit Increases as Demand is Increased:*

It is well known that capacity credit values typically increase as demand increases, all other parameters in the model being held constant. This is illustrated in Fig. 4 by the difference between the plots using the original demands, and the plot with demand rescaled to give LOLE of 2.4 hours/year. This is commonly interpreted as additional generation being more valuable to the system in capacity terms, when the demand (and hence risk) increases.

This result of higher capacity credit values at higher risk levels is explored from a more mathematical perspective in Fig. 5, using a simple example where all of the distributions are Normal. The initial probability distribution for available conventional capacity is the solid thick curve. If 3 GW of completely reliable firm generating capacity is added, then demand may be increased by 3 GW without increasing the LOLP (thick dotted curve), and the ELCC is 3 GW.

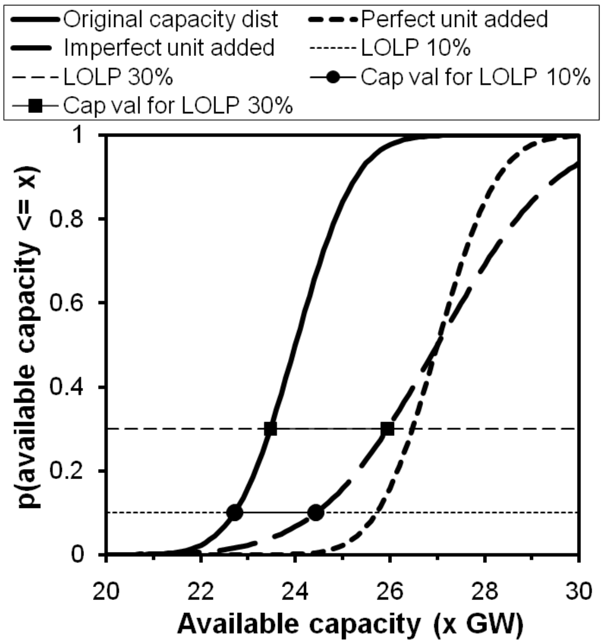

Fig. 5. Demonstration of how higher initial risk results in a higher capacity credit for new generation. The graph is described in Section III-B1.

If an imperfect unit is added so that the mean of the distribution increases by 3 GW, but the standard deviation increases from 1 to 2 (thick dashed curve), then (for realistic LOLPs below 50%) the ELCC. The ELCC of the new generation is then higher if the LOLP level is 0.3 (capacity value represented by the line joining the two squares) than if the LOLP is 0.1 (capacity value represented by the line joining the two circles); this is due to the broadening of the distribution being proportionally greater at low risks.

This explanation would generalise to non-Normal distribution; while in some cases the conventional plant distribution is close to Normal, that for the available wind capacity is usually far from Normal.

2) Percentage Capacity Credit Decreases as Wind Penetration Increases:

Once more, this is a well-known effect, observed in capacity credit studies worldwide as well as the new results in Fig. 4; it is due to a fundamental qualitative difference between the availability properties of wind and conventional generation.

To a good approximation, the availabilities of different conventional units are independent. As a consequence, with a sufficiently large number of conventional units the available capacity is never far from the mean; an important consequence of this is that near zero available capacity from the entire conventional fleet is vanishingly improbable. Conventional plant's contribution to supporting demand may therefore be quantified using its mean available capacity.

The available capacities from different wind farms, however, are not independent, as they are primarily determined by the weather. One key consequence of this is that near-zero available capacity from a system's wind fleet is possible. At low wind penetrations, this is not dissimilar to the properties of a single conventional unit, and hence at low wind penetrations the ELCC of wind generation is closely related to its mean available capacity. For high wind penetrations, however, this possibility of near-zero available capacity is in complete contrast to the distribution of available capacity from the same installed capacity of conventional plant; as a result, as the wind penetration increases, the ELCC falls increasingly far below the mean available capacity.

The results in this paper assume that as the installed wind capacity increases, the wind load factor in given wind conditions remains constant. In a country where wind generation is very mature, the later sites to be developed will usually be those with the lowest average wind speeds, causing a further decrease in the percentage capacity credit. On the other hand, in some systems such as GB with a large exploitable offshore wind resource, the far-offshore sites with the highest load factors have not yet been developed; the influence of this offshore capacity will mitigate the decrease in percentage capacity credit as total installed capacity increases.

3) Using the Same Wind Data, the Irish System Gives Higher Capacity Credit Results:

A less intuitive result is that using the same wind data and penetration relative to peak demand, the Irish conventional plant and demand data gives a wind higher capacity credit result than that obtained using the GB conventional plant and demand data (for example curves Ire/Ire and Ire/GB in Fig. 4).

This may be explained via the probability distributions for available conventional capacity in the two systems (which is shown in Fig. 2). Relative to peak demand, the distribution for available conventional capacity in Ireland is broader than that for GB. As a consequence the same installed capacity of wind generation relative to peak demand, with the same statistical profile, appears firmer in the Irish system; this is because the variability of this wind plant in Ireland is less relative to the width of the distribution for available conventional plant in Ireland. The capacity credit for the wind in Ireland is thus greater.

This will generalise to a result that capacity credit values for the same wind penetration will be typically be larger in smaller systems, all other parameters being equal. The variance of the distribution for available capacity (assuming the profile of the generation units remains the same) will be approximately proportional to the system size, as variances of independent variables are combined by simple addition, and the number of units is approximately proportional to the system size). It follows that the ratio of the standard deviation to peak demand will be approximately inversely proportional to the square root of system size; as a result, by the argument above capacity credit figures will typically be higher in smaller systems.

4) Capacity Credit Values at Low Wind Penetrations:

In GB, the percentage capacity credit of the wind generation at low penetrations is in the mid 20s percent, compared to a mean wind LF near absolute peak demands of 15-20%, and mean LF at lower peak season demands in the low 30s percent. The equivalent figures for Ireland are capacity credit at low penetrations in the mid-40s percent, mean LF near peak in the low 30s, and mean LF in typical winter hours in the mid-40s.

The capacity credit of wind generation in GB is thus equal to the mean load factor at about 95% of peak demand, whereas the capacity credit in Ireland is equal to the mean load factor at around 90% of peak demand. This suggests that in Ireland, hours of lower demand are more important in the LOLE calculation, when compared to the most important hours in the GB calculation. This will be explored more thoroughly in the next section.

IV. MOST IMPORTANT DEMAND LEVELS IN RISK CALCULATIONS

A. Low-Availability Tail for Conventional Generation

It is clear from Fig. 2 that at low availabilities the probability distribution for available conventional capacity in GB decays faster than exponentially. This is as expected; in this fairly large system with several hundred units, the Central Limit Theorem implies that near the mean the distribution will be approximately Normal, In such models, the distribution tails typically decay slightly less rapidly than a Normal distribution, but more rapidly than an Exponential distribution.

By contrast, however, the distribution for available conventional capacity in Ireland is approximately exponential in the region of interest, decreasing by a factor of around 10 when capacity is reduced by 5% of peak demand (see trendline in Fig. 2). Due to this slower decay of the Irish distribution, hours further below peak demand will be of importance in the Irish LOLE calculation (and hence also in the capacity credit calculation), when compared to those hours which are most important in the GB LOLE calculation.

B. Density of Demand Hours

In addition to the loss of load probability at a particular demand level, the relative importance of different demand levels in the LOLE calculation is also influenced by the density of hours at those demand level.

The proportion of hours with demand above a given level in GB and Ireland is plotted in Fig. 6; this provides a better visualisation than plotting density directly, as it does not require aggregation into a histogram.

The distributions of demands close to absolute peak are similar in the two systems. As expected, the overall trend at high demands is for the density to decrease as demand increases. In particular, the distribution of hours in the key range between 90% and 97% of peak demand approximately Exponential, as seen by comparison with the exponential trend line shown (thin dashed line). Between 80 and 90% of peak, the distribution is very close indeed to Exponential, with a smaller decay constant.

C. Influence of Different Demand Levels on LOLE Results

The relative influence of hours with different demand levels on LOLE is shown for both systems in Fig. 7; this is extracted directly from the LOLE calculation, rather than being derived implicitly from the distributions in Figs. 2 and 6.

In GB, as demand is decreased, the super-exponential decay of the distribution for available generating capacity overwhelms the approximately exponential increase in density

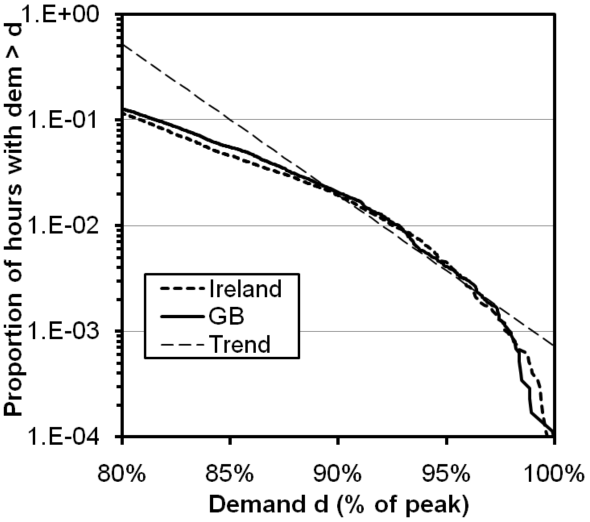

Fig. 6. Density of demand points versus demand level in GB and Ireland; the vertical axis scale is logarithmic. The trends for GB and Ireland are very similar.

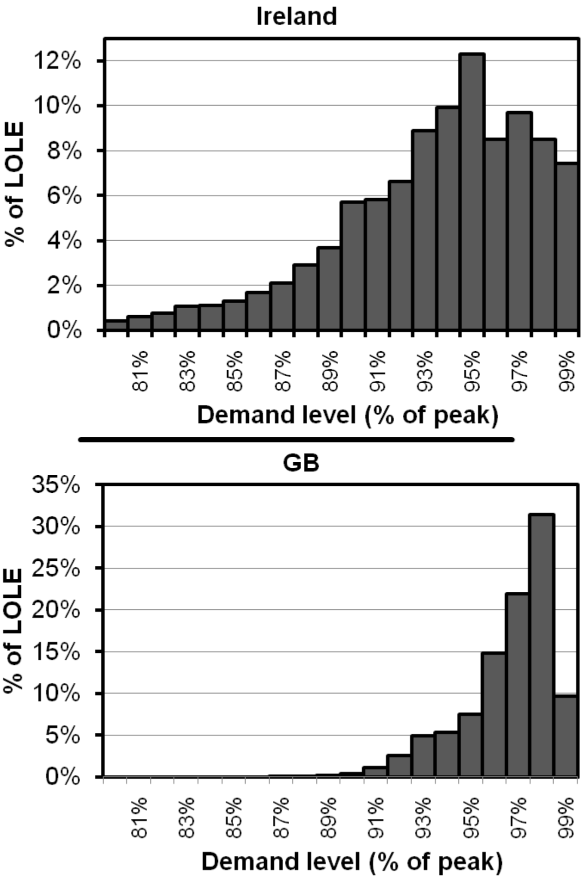

Fig. 7. Relative influence of different demand levels on the calculated LOLE. The bar labelled x% gived the proportion of LOLE contributed by demands between x% and $(x+1)$%.

of hours, and hence the LOLE is dominated by hours very close to absolute peak demand (lower panel of Fig. 7).

By contrast the upper panel of Fig. 7 demonstrates that in Ireland, all demand levels above 90% of peak have a similar influence on the calculated LOLE; in this demand range the exponential decrease in the conventional capacity distribution (and hence in the LOLP at a given demand), and the near-exponential increase in the density of hours, approximately cancel as they have very similar decay constants.

The contribution to the calculated LOLE gradually decreases as the demand level decreases between 90% and 80% of peak; while both the demand and conventional plant distributions are still approximately exponential, but the generation distribution then has a larger decay constant. However, even demand levels of just 80% of peak have a non-negligible influence on the LOLE.

This explains why the wind capacity credit results for Ireland are influenced by the wind load factors of just over 40% seen in typical winter demands (below about 93% of peak), as described in Section III-B3; these fairly moderate demand hours have a substantial influence on LOLE results in Ireland.

By contrast, in GB the capacity credit is related instead to the poorer wind resource see close to absolute peak demand; due to the super-exponential decay of the tail of the conventional plant distribution in GB, hours of lower demand have very little influence on the LOLE results.

D. Discussion: Consequences for Risk Calculation

The calculations presented above discuss the influence of different demand levels on the *calculated* LOLE in a typical power system risk calculation, in which the distribution for available conventional capacity is evaluated using a capacity outage probability table calculation (i.e. convolving two-state distributions for each conventional unit).

The key result is that not only is the probability distribution for available conventional capacity broader relative to peak demand in Ireland than in GB (this is inevitably the case in a smaller system with fewer units); also, in the region of interest around peak demand the decay of the distribution in Ireland is exponential, while in GB it is more rapid than exponential.

This result for Ireland raises a number of issues:

- How does this strong influence on the calculated risk of hours down to 90% of peak demand compared to historic operational experience in Ireland and similar systems? Our view is that most engineers would intuitively expect the overall adequacy risk to be dominated in all systems by the hours of very highest demand; based on historic records, is this intuitive expectation simply wrong, or is it the case that the standard capacity outage probability table calculation misses some aspect of the true situation?
- Verification of such risk models is often complicated by the scarcity of loss-of-load events. For instance, in GB the last actual compulsary demand disconnection due to absolute adequacy at time of high demand was in the mid-1960s. Moreover, loss-of-load events at transmission level in GB have usually been the immediate consequences of sudden disturbances, rather than steady-state adequacy issues; while conventional LOLE calculations may describe well one aspect of system risk, is this the most important part?
- The standard probabilistic model for conventional unit reliability represents each unit as a 2-state system (i.e. either rated capacity or nothing available), and assumes that the availabilities of different units are independent; in some models further derated operating states are also included [12]. However, in the tail of the distribution, common mode failures such as type faults and loss of fuel supply to multiple stations may become important in the adequacy risk. Is the capacity outage calculation realistic for the LOLPs below 0.01 seen in the hours below 95% of peak demand which contribute half of the LOLE?

V. CONCLUSIONS

We have presented a new comparative study of wind capacity credit results in the GB and Irish electricity systems. This confirms some widely recognised properties of risk-based capacity credit results, namely that the capacity credit increases as the demand is increased, and that when the installed wind capacity increases the capacity credit decreases as a proportion of installed capacity.

Much more importantly, this comparison reveals a major difference in the structure of the calculated risk in GB and Ireland. In GB, the tail of the conventional plant distribution decays as a Gaussian, and so the calculated risk is dominated by the very highest demands. In Ireland, however, the tail of the conventional plant distribution is approximately exponential; as a result, all demand levels between 90% and 100% of peak make approximately the same contribution to the calculated risk, and even demand levels of 80% of peak make a non-negligible contribution (the smaller risk in each hour at lower demands is balanced by the increase in the number of hours as demand decreases.

This raises some important questions as to how closely the conventional capacity outage table based risk calculation reflect reality. Do independent random outages dominate the adequacy risk at these low instantaneous risk levels (LOLPs down to 0.01%), or are common mode failures (type faults and loss of fuel supply) also important? And does this large contribution of moderate demand levels to the calculated risk reflect operational experience? As this risk structure has been explained in terms of the size of the Irish system (around 5 GW peak demand), these issues are expected to generalise to other small systems.

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