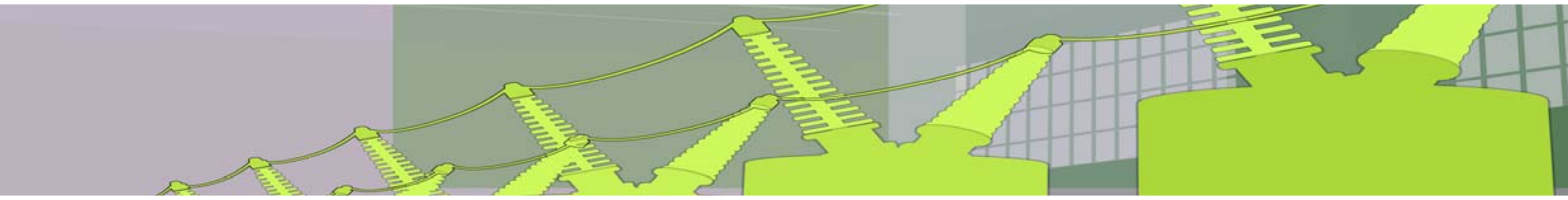

METHODS FOR REPORTING COSTS RELATED TO THE CAPACITY CREDIT OF INTERMITTENT GENERATION RELATIVE TO CONVENTIONAL GENERATORS

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Robert Gross, UKERC

UK Energy Research Centre

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Box 1. Terminology and shorthand used in this paper

Basic terms	**Derived/secondary terms to aid exposition**
CSC = change in total system cost CI= cost of intermittency (reliability impacts) K = fixed cost of technology (£/MW pa) VC = variable cost (£/MW pa assuming 100% load) CF = maximum capacity factor CC = capacity credit (%) CAP = capacity of technology installed. Subscript $_I$ refers to incumbent technology (i.e. CCGT), $_A$ to alternative (e.g. wind),	AVC = avoided variable costs AFC = avoided fixed costs FCE_I= fixed costs of equivalent incumbent generation VCE_I= variable costs of equivalent incumbent generation

Introduction

In what follows we consider a convention for estimating the 'system reliability costs' that can arise if intermittent renewable generating plant is added to an electricity network. The analysis is concerned with the costs of maintaining a measure of reliability, such as Loss of Load Probability (LOLP). This measures the probability that peak demands can be met. It is predicated on the assumption that intermittent generation tends to make a lower contribution to reliability than conventional thermal generation. In other words it estimates the costs that will arise when capacity credit is lower than capacity factor[1]. Costs, in this context, are defined as any *additional* cost relative to a situation where the same energy is delivered by a conventional generator. The paper is intended to be read in conjunction with the UKERC report *The costs and impacts of intermittency* (available at www.ukerc.ac.uk), which provides a comprehensive definition and exposition of terminology.

It is important to note that the convention described in this working paper does not seek to determine changes to *actual* system costs when new generation is added to an existing system (manifest, for example, in changes to the utilisation of incumbent generation). Neither is it concerned with the total change in system costs that will arise when a system is expanded to facilitate load growth. Rather it defines a convention by which the system reliability (LOLP maintaining) cost

[1] In all that follows we consider wind power, or other intermittent generation that makes a declining marginal contribution to reliability as their penetration level increases. We hence assume that the capacity credit of wind is lower than that of thermal plant delivering the same energy output. This would be the case were wind to provide a substantial proportion of electricity demand, since capacity credit expressed as a percentage of installed capacity falls as the penetration of wind increases. At small penetrations (lower than perhaps 5% or so of electricity demand), capacity credit is not lower than capacity factor. See Ch 3 of the UKERC report on intermittency for full details.

implications of installing relatively low capacity credit intermittent generators instead of installing thermal stations may be assessed and reported.

This analysis is solely concerned with the costs of any conventional plant retained/built to ensure system reliability. It is not concerned with the system balancing costs that arise because of short term fluctuations in wind output. In all cases we are concerned with long run marginal costs (LRMC) and hence capital investment needed or avoided. In the short run there may be old plant available to provide system margin at lower cost. Note also that for simplicity we refer to 'CCGT' and 'wind' plant. In fact the analysis is generic and CCGT is shorthand for any thermal (incumbent) and wind any intermittent (alternative).

The reason for producing this note is that two distinct strands of thought can be found in the literature on how to conceptualise the costs associated with any additional capacity required to maintain reliability when intermittent generators are added to an electricity network. The first does not explicitly define a system reliability cost rather it assesses the overall change in system costs that arises from additional capacity (Dale et al 2003). This approach can be used to derive 'system reliability cost' if combined with an assessment of the impact on load factors of incumbent stations when new generators are added (see footnote 2). The second includes an explicit 'system reliability cost'. This approach requires that we make an assumption about the nature of the plant that provides 'back up'(Ilex and Strbac 2002). Both approaches should arrive at the same change in total system costs. In what follows we demonstrate that they can be reconciled, and that this provides a convention for estimating the costs of maintaining reliability of supplies when intermittent generation is added to an electricity system.

Algebraic analysis is presented in full in annex 1 of this working paper.

Approach 1: Total system cost

Using this method a *system* with intermittent stations can be compared with an equivalent system (same energy output, same system reliability) without such generation in place. More plant (intermittent plus conventional) is required than would be the case in the absence of intermittent stations, but this approach does not attempt to directly attribute 'capacity reserves' due to intermittent stations (Dale et al 2003; Milborrow 2001)[2]. It hence provides an estimate of the total cost of intermittent generators without being drawn into any controversy about the nature or need for any 'back up' plant and the attribution of costs to particular aspects of intermittency. The approach derives the *total* change in

[2] These authors note that the cost of accommodating the lower capacity credit of intermittent stations is manifest through a depression of the load factors of the conventional plant on the system. This is correct, and it can be shown that such an analysis provides results consistent with the analysis here, provided both approaches compare the cost with intermittent with the cost of equivalent thermal plant (Pers Comm David Milborrow, Oct 2005).

system costs which result from replacing a proportion of thermal generating plant (e.g. CCGT) with intermittent generation (e.g. wind). It can be described in terms of the following steps:

1. Start with the fixed and variable costs of the wind generating plant.
2. Subtract the CCGT generation variable costs avoided (primarily fuel cost).
3. Subtract the CCGT fixed costs avoided due to being able to retire some of the CCGT plant (this is the *benefit* of the capacity credit of the wind).

= Total change in system cost

Steps 1-3 above can be more fully explained:

1. There are two terms: the fixed cost of wind is capacity of wind generation multiplied by its unit fixed cost, and the variable cost is the energy produced multiplied by the unit variable costs. The energy produced can be expressed as the capacity of the wind generation multiplied by its capacity factor. These two terms are the cost of building and operating the wind plant.
2. The capacity of wind generation multiplied by its capacity factor and the unit variable costs of the CCGT generation. This is the avoided variable costs of the CCGT resulting from operating the wind.
3. The capacity of wind generation multiplied by its capacity credit and the unit fixed cost of the CCGT technology. This is the benefit of the capacity credit of the wind.

Rephrased in simple notational terms, these steps are as follows:

(a). Change in system costs = cost of building and operating wind – fuel saved by wind – avoided fixed cost of CCGT displaced by capacity credit of wind

In equation form these steps are:

(i). $\mathbf{CSC = FC_A + VC_A - AVC_I - AFC_I}$

Or in full (see box 1):

$$\mathbf{CSC = (CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A) - (CAP_A \times CF_A \times VC_I) - (CAP_A \times CC_A \times K_I)}$$

Approach 2: Capacity reserve

Expressions (a) and (i) above produce a figure for the change in total system costs that include but do not specifically identify the costs attributable to the fact that wind has a lower capacity credit than conventional stations for an equivalent amount of energy. In other words the calculation does not explicitly identify the cost of maintaining system reliability, referred to here as the *cost of intermittency* (the *cost* that arises because the capacity credit of wind is lower than its capacity factor)[3]. However, the *same* change in system cost can also be described in terms of a slightly different sequence of steps:

1. Start with the fixed and variable costs of the wind generating plant.
2. Add the cost of intermittency.
3. Subtract the fixed and variable costs of energy-equivalent CCGT generation.

= Change in system cost

Rephrased in simple notational terms, these steps become:

(b). Change in system costs = cost of building and operating wind + cost of intermittency – fixed cost and variable cost of energy-equivalent CCGT[4]

In equation form this is:

(ii). $CSC = FC_A + VC_A + CI - FCE_I + VCE_I$

Or in full:

$$CSC = (CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A) + CI - (CAP_A \times CF_A / CF_I \times K_I) + (CAP_A \times CF_A \times VC_I)$$

This approach conceptualises the impact of the lower capacity credit in the form of additional ‘capacity reserve’ put in place to ensure system reliability. It may give rise to controversy because step 2, above, may be derived using a range of methods and assumptions about the nature and amount of ‘back up’ that is needed to maintain system reliability. This cost estimate will vary according to assumptions about the nature of the plant that provides ‘back up’. Different assumptions are found in the literature, ranging from, for example, the capital and operating costs of new gas-fired peaking plant, projected future costs of storage devices, or the maintenance and operating costs of retaining old power

[3] NB reliability aspects, i.e. neglecting system balancing and other costs

[4] This is the thermal plant that would provide the same amount of energy as the wind plant at minimum cost. As an approximation we assume this is CCGT operating at baseload capacity factor – see annex 2.

stations that would otherwise be retired. (Ilex and Strbac 2002; Milborrow 2001; Royal Academy of Engineering and PB Power 2004). Also, in the absence of a central planner, it is not clear by what means such plant is provided.

Reconciliation between approach 1 and approach 2

Because CSC is the same in expressions (a) and (b) we have a simple identity that can be rearranged in order to allow the derivation of the cost of intermittency:

Cost of wind + the cost of intermittency - the fixed and variable cost of energy equivalent CCGT = cost of wind - fuel saved by wind - avoided fixed cost of CCGT displaced,
then the cost of intermittency = fixed cost of energy equivalent CCGT - avoided fixed cost of CCGT displaced by capacity credit of wind.

In equation form this is:

(iii) $\mathbf{FC_A + VC_A + CI - FCE_I + VCE_I = FC_A + VC_A - AVC_I - AFC_I}$

The variable costs on each side of this identity cancel because $AVC_I = VCE_I$, and rearranging yields:

(iv) $\mathbf{CI = FCE_I - AFC_I}$

With the terms defined in full:

$\mathbf{CI = (CAP_A \times CF_A \times K_I / CF_I) - (CAP_A \times CC_A \times K_I)}$

In simple notational terms this is:

(c). Cost of intermittency = fixed cost of energy equivalent CCGT – avoided fixed cost of CCGT displaced by capacity credit of wind

We can also see this result if we go through a slightly different sequence of steps, this time starting from the change in system cost:

1. Start with the change in total system cost from equation (i)
2. Add the fixed and variable costs of energy-equivalent CCGT generation.
3. Subtract the fixed and variable costs of the wind generating plant.

= Cost of intermittency

In equation form this becomes:

$$CI = (CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A) - (CAP_A \times CF_A \times VC_I) - (CAP_A \times CC_A \times K_I) + (\{CAP_A \times CF_A\} / CF_I \times K_I) + (CAP_A \times CF_A \times VC_I) - (CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A)$$

Which also reduces to:

$$CI = (CAP_A \times CF_A \times K_I / CF_I) - (CAP_A \times CC_A \times K_I)$$

This expression represents the fixed cost of the incumbent plant required to maintain system reliability in the system given that intermittent sources of energy can displace more incumbent plant from the system on the basis of energy than they can on the basis of capacity credit.

The benefit of this approach is that it allows the capacity credit related costs associated with adding intermittent plant to the system to be made explicit in a way that is consistent with systemic principles, without making any judgement about the nature of any 'back up'. Instead, all that is required is determination of the least cost, baseload, *energy equivalent comparator*, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation (assumed here to be CCGT).

Basic philosophy

1. Expression (i) subtracts the benefits of wind from the costs of wind
2. Expression (ii) adds together the cost of wind and cost of accommodating the intermittency of wind and compares these to the cost of the thermal capacity that could provide the same energy as wind.
3. Expressions (i) and (ii) must reach the same overall change in costs. Therefore expression (iii) rearranges (i) and (ii) to derive the cost of intermittency.
4. This is predicated on a '*with* and *without'* comparison: that is, extracting CI from what we know of CSC depends upon a comparison between a system with wind and a system that supplies the same energy using a thermal equivalent.

Annex 1: detailed propositions

General framework

Change in system cost = cost of alternative generation ***minus*** cost of equivalent incumbent generation ***plus*** cost of intermittency

and

Change in system cost = cost of alternative generation ***minus*** avoided variable cost of incumbent generation ***minus*** capacity credit

T1 Change to system cost after an extra unit of demand is met by alternative technology		
(1)	$(CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A)$	Cost of building and operating alternative
(2)	$CAP_A \times CF_A \times VC_I$	avoided cost of operating incumbent
(3)	$CAP_A \times CC_A \times K_I$	Value of capacity credit
(4) = (1) – (2) – (3)	$(CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A) - (CAP_A \times CF_A \times VC_I) - (CAP_A \times CC_A \times K_I)$	Change in system cost (CSC)

T2 UKERC derivation		
(1)	$(CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A) -$ $(CAP_A \times CF_A \times VC_I) - (CAP_A \times CC_A \times K_I)$	CSC
(2)	$VC_A + K_A/CF_A$	Unit cost of building and operating alternative
(3)	$VC_I + K_I/CF_I$	Unit cost of building and operating incumbent at base load
(4)	$CAP_A \times CF_A$	Alternative production
(5) = (2) x (4)	$(CAP_A \times K_A) + (CAP_A \times CF_A \times VC_A)$	Total cost of building and operating alternative
(6)= (3) x (4)	$(CAP_A \times CF_A \times VC_I) + (CAP_A \times CF_A \times K_I/CF_I)$	Total cost of building and operating incumbent at base load
(7) = (1)+(6) – (5)	$(CAP_A \times CF_A \times K_I/CF_I) - (CAP_A \times CC_A \times K_I)$	'UKERC' cost of intermittency
(8) = (7) / (4)	$(K_I/CF_I) - (CC_A \times K_I/CF_A)$	Unit cost of intermittency (normalised on alternative)

Annex 2: Thermal equivalent plant assumptions – why ‘baseload’?

Thermal energy-equivalent plant is a least cost comparator to the capacity and fuel savings benefits of wind plant. When a wind plant is operating at full MW capacity it is displacing an equal amount of MW output from a thermal plant, and when it is operating at less than this, at X MW, then it is displacing X MW output of a thermal plant; and on average it will displace an amount of MW output equal to its capacity factor. There are three effects on costs associated with this (neglecting balancing costs):

1. + The fuel savings, which equal the mean MW output over the year times the fuel costs times 8760.

2. + Over the peak period only, the value of capacity savings. The mean value of the capacity savings equals the mean MW output of the wind plant, times the marginal system capacity costs per MW. We usually base the latter on the capital costs of OCGTs divided by their availability.

3. - The capital costs of capacity required to maintain system reliability.

We then deduct the capital costs of the intermittent alternative to calculate the change in system costs. But we need to compare this with the option of staying with the incumbent technology, and the cheapest option for supplying the same energy and capacity over the lifetime of the intermittent plant is a thermal plant with the following characteristics:

1. Capable of supplying the same amount of energy.

2. Capable of supplying the same mean MW capacity over the peak.

This is approximately equal to the costs of a base load thermal plant. One problem is that the thermal plant in question will move down the merit order as new and more efficient plant are brought onto the system. However, the wind plant will still be first in merit order and the capacity and fuel savings will still be obtained. The values of both the capacity and fuel savings will change over time with improvements in plant design and efficiency, fuel prices etc. So when estimating these quantities we really need to take the following:

Present Worth of the Sum: {marginal value of capacity savings in each year + value of fuel savings in each year}. Base load thermal plant *approximates* to this.

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