UKERC Technology and Policy Assessment

An assessment of evidence on the costs of intermittent power generation

Discussion note on initial questions

Prepared for the first meeting of the 'intermittency' Expert Group
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UK Energy Research Centre
58 Prince's Gate, Exhibition Road
London SW7 2PG
T: 020 7594 1574
F: 020 7594 1576
E: admin@ukerc.ac.uk

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Introduction

This note has been prepared in order to facilitate discussion at the initial meeting of the Expert Group that will advise the UKERC TPA[1] assessment of the costs and impacts of intermittency. The paper's aim is to highlight and deconstruct some of the key issues under debate, particularly areas of controversy, and hence provide an overview of some of the questions we are exploring in our initial work. It does not attempt to be comprehensive in its coverage or to summarise all of the literature being reviewed in the initial work on this assessment. The note is aimed at informed commentators and therefore takes some knowledge for granted – for example of terminology, recent literature and the principal concepts. Its focus is on why and where opinions differ, and the objective is to highlight questions and disagreements, but not answer or resolve either. A more general introduction to the subject is provided in the project scoping note and protocol.

Feedback and comment is invited on all of what follows, and in particular on the set of summary questions at the end of this note.

The remainder of this note covers the following topics:

- Identification of key issues
- Capacity values
- System balancing
- Allocating costs
- Framing questions

Key issues

Intermittent generation gives rise to two main types of potential additional costs – those associated with balancing the system on a minutes to hours basis (**balancing costs**) and those costs associated with the limited capacity value of most intermittent sources (**capacity value** or capacity credit issues).

For the most part the literature focuses on these two aspects[2]. Their relevance to the debate is not in question. That some changes to the operation of the system/network are needed and that these entail some cost is also widely appreciated. Controversy arises when we come to consider what the evidence suggests about the extent, range and cost of procuring additional response and reserve services (balancing issues), and on how to account for, maintain and cost implications for plant margin (capacity value issues). A range of more detailed issues underpin these debates and need to be unpicked. The next two sections provide an introduction to these questions. The latter sections consider some more generic and conceptual problems.

Capacity values

Capacity values (or credit) are ascribed to all forms of generation, and reflect the probability of plant being available when needed. No plant is 100% reliable, and

[1] Technology and Policy Assessment function, which is managed by ICEPT, Imperial College and provides reports for policy and other stakeholders, that draw upon the UKERC research base.
[2] Other system costs associated with renewable generators include transmission system upgrades and distribution network costs. Other issues include fault ride through, which may create additional costs for generators to ensure that larger wind farms do not trip off as a result of voltage or frequency excursions. Further issues that could become significant if the penetration of intermittent power were to reach very high levels include black and fast start capabilities. We will seek views on how wide the scope of the assessment should be.

all plant needs to be taken out of use for maintenance. If a judgement about 'forced outage' can be made then statistical techniques such as *loss of load probability* (LOLP) and *expected unserved energy* can be used for system planning or informing markets about expected capacity requirements[3].

Traditionally, most system operators have used a 'proxy' – plant margin – to ensure system reliability. Capacity values are aggregated and used by system operators to determine plant margin and ensure that the system is 'secure'.

Whilst the 'standards' for reliability (LOLP etc) and plant margin used by the old CEGB no longer formally apply, the *principle* of aggregating capacity values in order to assess the statistical probability of sufficient capacity being available when required is retained. Hence, capacity value is central to assessing total levels of capacity on the electricity network. When we come to consider the capacity value of intermittent options, debate surrounds three core issues:

- What is the capacity credit of different forms of intermittent generation at different levels of penetration?
- How should the lower capacity value of intermittent sources be accommodated – i.e. how much, and what form of, non-intermittent capacity is retained or constructed?
- How much does this cost and how should such costs be ascribed/allocated?

Much of the debate over capacity value for intermittent sources has concentrated on wind power. A number of studies, dating back to early work by the CEGB and others, suggest that the capacity value of wind is at least equal to its load factor at low penetrations (of energy output), but that it falls as the share of generation increases. At or around 20% of energy provision, capacity credit falls to around half load factor. Hence capacity credit might be around 15% of rated capacity. According to these analysts, this is the amount of conventional capacity that might be retired or displaced[4]. However, this is the subject of debate:

Does wind in fact offer ZERO capacity value?
Some commentators point to 'cold anti-cyclone' conditions that (it is claimed) result in almost all UK wind plant lying idle during the same time period. It is argued that there is a significant correlation between such weather events and peak demand. Hence, the capacity credit of wind should be close to zero. Others argue that these events simply do not occur (provided wind plant is spread out across the country). A related argument applies to storm conditions (see below).

This disagreement appears to have been ongoing for some time. One reason is that there are both uncertainties and methodological differences in assessing the statistical correlation between low wind speeds across the UK and peak output. The issues that need further investigation/clarification include:

- Weather data: Does the weather data support the 'UK-becalmed' claim in principle; how frequent are such events and do they correlate with demand peaks?
- Wind farm output vs aggregate weather data: does Met Office weather data properly reflect wind farm outputs?

[3] No view is taken on the usefulness of these concepts for this debate, but this issue will be revisited in later analysis

[4] In the absence of transmission constraints and/or if intermittent plant is geographical dispersed

- Scenarios for plant location: Greater geographical concentration will tend to increase the likelihood of all plant being subject to similar weather[5].
- Interpretation and statistical methodologies: If such events do occur and wind outputs are consistently low, does this imply a zero capacity credit?

How is capacity provided and at what cost?
Whatever the answers to the questions above, it is clear that at larger penetrations the share of energy contributed by intermittent sources will usually exceed its contribution to capacity. In other words, it can displace the *output* from conventional plant, but cannot (commensurately) displace actual *plant* without affecting reliability in some way.

So what type of plant provides firm capacity as the energy from intermittent sources increases and how should we conceptualise and account for its costs[6]? For instance, is the assumption that other plant is retained on the system (if so what plant, held in what condition, and at what cost?[7])? Or is it assumed that new 'back up' capacity is needed (again, of what kind and at what cost?)? What are the roles of storage and of active management of demand? Assumptions, question framing and 'starting points' are required to answer each of these questions – and since these may differ, so to do the answers (and costs) provided by different analysts with different perspectives. This issue of question specification is returned to below.

Allocation of costs is also both difficult and controversial, some analysts take an explicitly systems based approach whilst others have looked at wind largely in isolation. This issue is explored below.

System balancing

As with capacity credits, provision of shorter term system balancing services also appears to be rather contentious. Again, very modest penetrations of intermittent generation are generally agreed to be of very minor concern to system operators (though they might give rise to localised implications for individual distribution network operators). There is also relatively little disagreement that as penetrations rise additional actions will be needed and system balancing costs will increase. But the scale of such costs and a range of other impacts (such as CO2 emissions) are the subject of debate. Areas of disagreement (and/or uncertainty) include:

- Assumptions about the type of plant that is 'marginal' (load following) – hence costs and emissions. For example, increasing utilisation of coal plant on spinning reserve is likely to be less efficient and more carbon intensive than increasing the utilisation of storage or demand side management[8].

- Another important issue relates to how predictable wind is over different timescales and how improved forecasting might reduce costs. For example, it

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[5] High levels of geographical concentration (for example a very large capacity of wind farms in Scotland) might also result in a substantial reduction in wind output due to storm conditions.
[6] The issue is not that reserve will be needed – it will be whatever form of generation is on the system – but how to estimate and allocate the cost of reserve with various mixes of generation on the system.
[7] A related issue concerns the load factors and hence economics of non-wind plant. If conventional plant load factors fall (as they must if firm capacity is held constant but wind provides a substantial share of energy) how does this affect their energy costs?
[8] Changes to incentive structures and market conditions – for example the creation of the NETA – can also change the services that different plants provide and the way in which plant is dispatched, and hence can change emissions and overall efficiency. This important subject is under analysis elsewhere.

appears that unpredicted variation after gate closure is low for wind, which lowers potential imbalance penalties under BETTA[9].

- Scenarios of the location and nature of intermittent plant affect projected costs, since geographical proximity will tend to increase fluctuations whilst geographical dispersion tends to smooth variations.

Finally, as with capacity credits, it is important to consider carefully which costs should be attributed solely to intermittent generation, which are system wide and the basis on which to make this distinction (see below).

How are costs to be allocated and attributed?

Were the issues above to be agreed, it should be possible to define the total cost of maintaining capacity margin and balancing the system as the share of intermittent generation increases, compared to a system without intermittent plant. However, *allocation* of such costs is not straightforward and also gives rise to controversy. This section attempts to outline why.

Security is a systemic concept, and one that has been traditionally ‘smeared’ across all output. However, some commentators have taken the view that, in order to draw comparisons between technologies, the full costs of additional system balancing and of capacity provision should be added to the generating cost of intermittent generators. In this way intermittent generation could be costed as if, in effect, it behaved exactly like a conventional station. This view holds some attraction, since it appears to offer parity between generation options, which is required if fair cost comparisons are to be drawn. However, it is not clear that this is consistent with the treatment of other forms of generation, because all forms of generation impose system costs:

- One of the principles that system operators use to ensure security of supply is that plant margin is always larger than the largest single generator on the system. Yet it is never assumed that as large plants impose a more significant system cost than smaller ones, they should have this cost added to their generating costs.
- Similarly, whilst market conditions clearly reward flexibility there is no attempt to add a ‘cost of inflexibility’ to the generating costs of inflexible output.

In addition, the costs intermittency ‘imposes’ on the system are also in part determined by the nature of the other plant on the system. For example, it is likely to prove less costly to manage variable outputs on a system with a large number of flexible plants than one dominated by relatively inflexible stations. So it is only possible to determine the costs of intermittency against a particular counterfactual (say the current UK system but where no intermittent plants exist). Marginal analysis can tell us the cost of changing one aspect of a system, and this provides a *relative* cost for intermittency (cost of system ‘a’ compared to system ‘b’). It does not provide an *absolute* cost that can be attributed solely to intermittent generation.

Despite this, it is clear that intermittent generation **does impose costs** that conventional generation does not. Put another way, it *lacks* certain capabilities that must be provided by other generators. It appears inappropriate to simply

[9] It is important to distinguish between PRICE effects, for example payments under BETTA and COST impacts, for example where system operators need to contract for additional spinning reserve. This distinction will be explored in more detail as work proceeds.

smear any costs associated with intermittency across all generation, as if it cannot be attributed in any way to intermittent options.

One of the issues at the heart of the debate on the costs of intermittency is therefore how to draw the line between those that are system wide and those that are attributable directly and unequivocally to intermittent output – and indeed those that might lie somewhere in between.

Framing questions

Because several of the controversial subjects outlined above are dependent upon assumptions and upon how issues are conceptualised, it is possible that different analysts actually ask *different questions.* This difference may be masked by very similar terms of reference and hence give rise to disagreement and debate.

For example, one recent paper assesses the *total* and systemic cost of additional renewables, with a focus on wind power and taking account of both generation and system costs. Various options for the allocation of these costs are discussed. Another study attempts to estimate the full cost of wind power, including the costs of 'back up', so that it can be compared to other forms of generation. The latter study explicitly attempts to cost wind *as if it were a conventional station*. One reason these studies come to different cost estimates is that the 'allocation of costs' issue described above is not made explicit, and is addressed differently.

Summary of key questions

This note attempts only to introduce some of the key areas of debate. The key questions that we believe arise are outlined below. In each case we will attempt to highlight what is known and uncontroversial, what is uncertain, subject to disagreement, or based in assumption or interpretation.

What is the evidence of the capacity value of intermittent sources?

- What is the evidence for a zero credit for wind?
  - Weather data: Does the weather data support this claim?
  - Does Met Office weather data properly reflect wind farm outputs?
  - What can we learn from other countries?
  - How do scenarios for plant location affect capacity credit?

- How is firm capacity provided and at what cost?
  - What are the roles for different types of plant/load management?

What is the evidence on system balancing costs?

- How variable are different intermittent outputs, over what timeframe?
- How predictable are they and how does this affect balancing costs?
- What types of plant provide system balancing services?

How wide is the variation between scenarios in respect of different capacity credits and balancing costs?

- How significant are scenario assumptions in driving cost differentials?

What is the range of approaches to allocating of costs?

- How significant are differences in allocation and interpretation to sustaining controversies?
- On what criteria do different studies differentiate between those that are system wide and those that are attributable directly and unequivocally to intermittent output?

Closing remarks

Because this paper is intended to open up questions and inform debate at the expert group meeting, we do not intend at this stage to draw any conclusions. However, it certainly appears as if the differences in approach, assumption and conceptualisation described above have the potential to give rise to a great deal of disagreement. We will seek to explore and evaluate the evidence base on all of these and other issues over the coming months, using the criteria set out in the project scoping note.

At this stage we welcome comments and criticism of the ideas and issues described above, as well as recommendations of relevant analysis within the academic, policy and industry literature, both UK and international. It is important to note that this paper deliberately focuses on methodologies and on areas of disagreement. The final assessment report will seek to provide an authoritative statement on what *is known* about the costs of intermittency as well discussing methodologies, evidence gaps and issues that are uncertain and subject to debate.