



The costs and impacts of intermittency – 2016 update

A systematic review of the evidence on the costs and impacts of intermittent electricity generation technologies

Preface

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The Technology and Policy Assessment (TPA) Theme of UKERC

The Technology and Policy Assessment (TPA) was set up to inform decision-making processes and address key controversies in the energy field. It aims to provide authoritative and accessible reports that set very high standards for rigour and transparency. Subjects are chosen after extensive consultation with energy sector stakeholders and with the UKERC Research Committee.

The TPA has been part of UKERC since the centre was established in 2004 and is now in its third phase, which started in 2014. The primary objective of the TPA is to provide a thorough review of the current state of knowledge through systematic reviews of literature, supplemented by primary research and wider stakeholder engagement where required.

Acknowledgements

The project team are grateful to the Expert Group and the external peer reviewers for their extensive and very helpful comments on drafts of the report. The members of the Expert Group were: Damitha Adikaari, Keith Bell, Andy Boston, James Cox, Lewis Dale, Tim Green, Eric Ling, Mark O'Malley, Simon Mueller, Goran Strbac, and Mike Thompson. The peer reviewers were Hannele Holttinen and Michael Milligan. Responsibility for the content of the report and any errors or omissions remains exclusively with the authors.

Executive Summary

Overview

- This report updates a previous UKERC study, The Costs and Impact of Intermittency (Gross et al. 2006), which reviews the evidence on integrating variable renewable sources such as wind and solar into power systems.
- When the original report was written most of the evidence did not assess renewable penetration levels above 20%. Not all renewables are variable. However leading countries are already integrating variable renewables at above 20%, and many countries have targets to expand renewables far above what was envisaged in 2006.
- The key challenge facing policymakers, regulators and markets is delivering a flexible, low carbon system that makes best use of variable renewables whilst minimising overall cost and enhancing security and reliability.
- The additional costs of adding variable renewable generation to an electricity system can vary quite dramatically, but they are usually modest, with higher costs normally the result of inflexible or sub-optimal systems.
- Electricity systems and markets must adapt and be re-optimised to incorporate large proportions of variable renewable generation.
- A ‘whole system’ analytical approach – rather than seeking to quantify individual impacts - is essential to determine the optimal mix of technologies in substantially transformed systems.

Introduction

Ten years ago the Technology and Policy Assessment team of the UK Energy Research Centre completed its first systematic review of the costs and impacts of adding ‘intermittent’ or ‘variable renewable’ electricity, such as wind or solar, to an electricity system.

Most of the evidence available at that time did not consider variable renewable penetration levels above 20%. The project concluded that at this penetration level total costs in the UK would be relatively modest, adding less than £10/MWh (in 2015 GBP terms) to the base cost of the renewable electricity generated.

Since 2006, targets for renewable generation have increased significantly in many countries, and a substantial proportion of these targets will be met through large-scale deployment

of variable renewables. This report provides an update to the original 2006 UKERC study, reviewing the new evidence for the costs and impacts associated with higher shares of renewable generation and assessing how projected impacts may have changed. For the purposes of this project ‘new evidence’ was defined as that which has emerged since the previous UKERC review in late 2005/early 2006. Since then, a considerable number of new studies have been carried out into the likely effects of integrating renewable generation into electricity systems. The systematic review found almost 200 journal papers, reports and other evidence sources which directly address the project’s research questions.

Characterising impacts and assessing costs

Adding variable renewable generation to an electricity system creates a range of impacts, both costs and benefits. In fact, all forms of electricity generation affect the system to which they are connected. Any additional system costs created by a particular generator or technology type must be borne regardless of whether those costs are attributed to the generator or not.

Power systems have always had to be optimised to integrate a range of generator characteristics – inflexible nuclear, energy-limited hydro, coal plants which require a 24 hour warm up and so on. In the past this was a largely uncontentious area that did not feature in societal or policy discourse. Indeed, analyses rarely calculate separate integration costs for other types of generation (even though they may well impose some costs on the system), but the characteristics of the system (including conventional generation) is a key determinant of the scale of variable renewable integration costs. Failing to recognise this runs the risk of a false comparison where variable renewable integration costs are given high prominence and the costs associated with other generation technologies are entirely ignored.

In 2006 many of the impacts of and additional costs related to variable renewable generation were found to be negligible. The exceptions were 1) the cost of additional short-term reserves required to balance electricity supply and demand over the timescales of seconds to hours, and 2) the costs of the generating capacity required to ensure that a system can reliably meet peak demand. However, as penetration levels rise, other significant impacts come into play, including: curtailment (where variable renewable generation cannot be accepted onto

the grid); transmission and distribution network reinforcement costs; the potential for reduced efficiency of the remaining thermal plant on a system; and the need to ensure that a system has sufficient mechanical inertia to maintain frequency stability. Depending on their design and operation, these impacts may also manifest themselves in the relative market value of output from both conventional and variable renewable generators.

The danger of double counting and the need for a whole systems approach

Different categories of impact interact and overlap to a considerable extent. This creates the risk of double-counting some elements of costs, and the possibility that the benefits offered by particular types of generator are not accurately represented in some cost estimates. For example, increasing system reserves to meet short-term balancing requirements may also contribute to the capacity margin required to reliably meet demand peaks. Similarly, curtailment costs may be already accounted for in the costs of the total system capacity required to satisfy overall demand, and transmission costs may be offset by reductions in the costs of curtailment. It is also important to note that although several countries and regions now have significant penetrations of variable renewables, even current additional costs are usually still estimated using models because the actual costs imposed on a system are not fully transparent.

Partly in response to this complexity, in recent years there have been an increasing number of analyses which take a 'whole system' approach. These studies attempt to incorporate all the impacts described above, typically using an electricity system simulation model to assess the relative costs of different future systems. This allows a system with high levels of variable renewable generation to be compared on a full cost basis to a system without. It is also possible to consider and compare systems which are more or less well optimised to include variable renewables. This offers a more comprehensive perspective and many analysts believe that it will supersede those approaches which attempt to quantify individual impacts, particularly those that do not do so using a system simulation model.

System adaptation and the value of flexibility

One of the most important overarching conclusions from this review is that the additional costs of adding variable renewable generation to an electricity system can vary quite dramatically, depending on the characteristics of the remaining conventional plant, grid infrastructure, resource availability and location, and demand profiles. However, perhaps the single most important conclusion is that there is a substantial body of evidence that variable renewable integration costs are hugely dependent on the flexibility of the system to which they are being added. Estimates of additional costs based on assumptions of flexible systems can be several times lower than estimates of additional costs based on assumptions of inflexible systems. Linked to this is the very strong finding that

additional costs will be minimised if electricity systems are optimised to facilitate the integration of variable renewable generation. This optimisation includes changes to both the technical and economic characteristics of electricity generating plant, potential contributions from flexible demand, storage and increased interconnection capacity, as well as changes to system operation, regulatory frameworks and the design of electricity markets.

Evidence by category of impact

Notwithstanding the increasing importance of whole system cost assessment, individual cost impacts continue to feature prominently in the debate and are reported in a wide range of studies. Since it is a key objective of this report to provide a thorough and comprehensive review of the evidence, these findings are summarised below by category of impact.

Reserve requirements and costs

Introducing variable renewable generation to an electricity system would normally be expected to increase the amount of flexible, dispatchable generation capacity that must be held in reserve to cope with short-term fluctuations in output that result from varying wind speeds or solar insolation levels. Care must be taken when comparing analyses of reserves because the term is often used to cover a range of different types of reserve services which may schedule and operate over a range of timescales. The time horizon for scheduling reserves is of particular importance, because forecast accuracy improves greatly when reserve allocation is undertaken close to real time. Nevertheless, most analyses conclude that the additional cost of these reserves remain relatively modest, at least up to a 30% variable renewable penetration level, with the majority of results being £5/MWh or less, with a small number of outliers. Above this penetration level, the number of studies is much smaller and estimates of the additional costs of reserves exhibit a much wider range, varying by a factor of three at the same penetration level. The data for very high variable renewable penetration levels such as 50% suggests costs between £15 and £45/MWh, with the lower values being based on integrating intermittent renewables into a flexible electricity system and the higher values resulting from assumptions of relatively inflexible systems. In all cases it is important to emphasise that high cost outliers often make assumptions designed to test extreme conditions, such as a particularly inflexible system.

Capacity credit and costs

No generators are 100% reliable, which is why power system reliability has always been assessed statistically. A key concern is ensuring peak demands can be met reliably, usually by ensuring there is some surplus of supply over demand, a 'system margin'. Capacity credit is a measure of how much conventional plant can be replaced by variable renewable generation whilst maintaining overall reliability at peak demand. There is considerable variation in capacity credit data, depending on the country or region and the technology being analysed, reflecting the fact that the extent of correlation between the diurnal and seasonal profile of generation and peak demand periods is a key determinant of capacity credit. Generally, both the upper and lower outlying data reflect findings for solar power whereas results for wind power are much more closely grouped. Many studies suggest that capacity credit declines as variable renewable penetrations rise. Estimates relevant to the UK suggest that at 30% of electricity from wind capacity credit is likely to be around mid-20s percent.

Estimates of the capacity cost are derived from capacity credit values (in percentage terms) and the assumptions that are made regarding the costs of the conventional plant which is used to compensate for the lower capacity credit of variable renewable generators. At a 30% penetration level, where results from wind-based analyses dominate, most estimates are in a range between £4 and £7/MWh, with some outliers. All except two data points of the entire data set lie below the £15/MWh level, even as penetration levels rise to 50%. These findings are supported by the project team's own calculations based on estimates of conventional plant cost (in this case CCGT) which suggest that costs will lie in the range between around £4 and £8/MWh at an assumed 20% capacity credit, between £9 and £11/MWh at a 10% capacity credit level, reaching a peak of less than £15/MWh even if the capacity credit of the variable renewable plant is assumed to be zero.

Curtailment

The findings for the proportion of variable renewable output that cannot be accommodated on an electricity system (meaning that the output from some renewable generators may need to be curtailed even though the renewable resource is available) suggest that the level of curtailment is generally very low at low penetration levels. The evidence suggests that curtailment can remain at a low level even at very high penetrations of intermittent renewables but that the point at which curtailment becomes significant can vary dramatically, with some analyses finding the inflection point to be as low as a 15% penetration and others finding the inflection point not being reached until there is over a 75% penetration of variable renewable generation. Broadly, the findings for relatively early curtailment are from studies focussed on US electricity systems, with UK and European analyses suggesting that curtailment levels are very low until over 50% of electricity is supplied from variable renewables. A further key point to bear in mind is that some level of curtailment may be both economically rational and sensible from a system operation perspective – so, in isolation, a degree of curtailment is not necessarily an indicator of the unsuitability of any particular form of variable renewable generation.

Transmission and network costs

For the transmission and network costs associated with variable renewable penetration levels up to 30%, the evidence suggests that costs are in the range of £5-£20/MWh. Furthermore, these costs do not appear to rise sharply as penetration increases up to this level, with typically significantly more variation between studies (or different scenarios within the same study) than there is between different penetration levels within a study or scenario. This suggests that these costs are largely sensitive to the nature of the system to which the variable renewable generation is being added rather than the share of total generation which is being contributed by variable renewables. However, considerable caution should also be used if interpreting these values as being wholly additive to other integration costs, in part because of the trade-off with the curtailment impacts described above, but also because transmission infrastructure, once built, confers benefits on the whole system and so allocating the full costs to variable renewable generators alone can be misleading. Very little data was found for penetration levels above 30%.

Thermal plant efficiency and emissions

The findings on the impact of variable renewable generation on the conversion efficiency of thermal plant and the impact on CO₂ and other emissions do not lend themselves to ready comparison between analyses, due to the range of measures and metrics used. However, the majority of those studies that address these impacts typically find that they are very small at low penetration levels, and remain relatively small (typically less than 10% of theoretical maximum emissions savings) even as penetration levels rise. Impacts are often found to be sensitive to the characteristics of the system to which variable renewable generation is being added. Although this general sensitivity is broadly consistent with findings from several of the other impacts discussed above, efficiency and emission impacts are particularly dependent on the assumptions over the mix and operating characteristics of the thermal (and/or hydro) plant whose output is being varied to accommodate intermittent renewable generation, and this sensitivity can give rise to outlier results in some circumstances.

System inertia

Analyses of the impact of reducing system inertia resulting from adding variable renewable generation (and so replacing some synchronous plant that would otherwise be providing inertia) have to date tended to focus on the technical challenges that this may pose, rather than assessing any aggregated or direct monetary impact. Reduced system inertia is potentially an important issue, at least for relatively isolated electricity systems with significant penetration of variable non-synchronous generation. Of those studies that do address this issue, the typical conclusion is that it is likely to only become significant at high penetrations of variable renewables i.e. greater than 50% on an instantaneous basis (although it should be recognised that some systems have already reached this level on occasion). Nevertheless, the analyses which consider penetration levels above 50% do generally conclude that even at these very high penetration levels, sufficient inertia-like resilience could be provided, typically through a combination of very fast response frequency control systems and synthetic inertia.

Conclusions

This review reveals a very substantial body of evidence on the impact of variable renewables on electricity system reserve requirements and capacity adequacy. This has been joined in the last decade by increased attention to issues such as curtailment, transmission and distribution system impacts, impacts on the efficiency of thermal plant and on system inertia. There has also been increased research on electricity market impacts. Taken together, the full range of impacts add weight to the message that electricity systems and markets need to adapt and be reorganised to incorporate large proportions of variable renewable generation most efficiently.

The evidence reviewed for this report suggests that a 'whole system' analytical approach is essential to determine the optimal mix of technologies in substantially transformed systems. For this reason it is important to be clear that the cost estimates provided for individual categories of impact cannot simply be added together to determine total systems costs.

The evidence also suggests that the additional costs that variable renewable generation impose upon an electricity system remain relatively modest across the main categories of impact, and in aggregate when assessed on a whole system basis. Those studies and scenarios which do present significantly higher costs typically result from an exploration of the effects of particularly inflexible systems or where very little system re-optimisation is assumed.

One of the key messages from the 2006 UKERC report was that integration costs depend on the technical and economic characteristics of the system to which renewable generation is being added. This message is very strongly reinforced by the evidence reviewed for this project, and in particular that costs are very sensitive to the flexibility of the system to which variable renewable generation is added, with estimates of costs typically being dramatically lower for flexible systems. The key challenge facing policymakers, regulators and markets is how to ensure delivery of a flexible, low carbon system that makes maximum use of variable renewable generation whilst minimising overall cost and enhancing security and reliability.

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Glossary

List of Acronyms

BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BoE	Bank of England
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CIGRE	International Council on Large Electric Systems
CO ₂	Carbon dioxide
CPI	Consumer Prices Index
DECC	Department of Energy and Climate Change
EBSCR	Electricity Balancing Significant Code Review
ERP	Energy Research Partnership
EWEA	European Wind Energy Association
GBP	UK Pounds
GDP	Gross domestic product
GW	Gigawatt
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
LCOE	Levelised costs of electricity
LOLE	Loss-of-load expectation
MWh	Megawatt-hour
NAO	National Audit Office
NEA	Nuclear Energy Agency
NETA	New Electricity Trading Arrangements
NOx	Nitrogen oxides
OCGT	Open Cycle Gas Turbine
O&M	Operational and maintenance
PPI	Producer Price Index
PV	Photovoltaic
ROCOF	Rate of change of frequency
RPI	Retail Prices Index
SNSP	System Non-Synchronous Penetration
SO	System Operator
SO ₂	Sulphur dioxide
STOR	Short Term Operating Reserve
TPA	Technology and Policy Assessment
UKERC	UK Energy Research Centre
VRE	Variable renewable energy

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Introduction



1. Introduction

1.1 Background and context

In 2006 UKERC completed its first assessment of the evidence on the costs and impacts of intermittent generation on the British electricity system (Gross *et al.* 2006). As the 2006 UKERC report noted, the use of the word ‘intermittent’ is seen by some as pejorative, and other terms have also been adopted, such as ‘variable renewable energy’ (VRE) (Poyry 2011a). In this report we use the terms interchangeably, since they are both widely used in the literature. The 2006 report was the first full systematic review of the topic undertaken in the UK. The conclusion from that study was that the additional system costs imposed by intermittent generation would be relatively modest, adding around £5-£8 per MWh to the cost of the renewable electricity generated. This was based on a review of the evidence available at the time, most of which did not envisage or model more than 20%¹ of electricity to be sourced from intermittent renewables.

Since then, the UK’s targets for renewable generation have increased (DECC 2011, DECC 2016), and it seems likely that much of these will be met through large-scale deployment of variable renewables², primarily wind, and to a lesser extent solar power (CCC 2016). As a result, large amounts of power from these forms of generation will need to be integrated into the UK electricity grid without compromising the very high degree of reliability currently delivered by the UK electricity system (National Grid 2015a).

Historically, the generation technologies that are required to meet renewables targets have had significantly higher average lifetime costs per unit of output³ than the conventional fossil fuel thermal plants that they are intended to displace. However, costs for the more mature variable renewable technologies have fallen rapidly in recent years (dramatically so in the case of solar PV), to the point where estimated costs for some projects are close to parity with traditional thermal generation (Gross *et al.* 2013, DECC 2015a, Wisner and Bolinger 2016). The focus of this report is not on the absolute differences between the costs of variable renewables and thermal plant such as gas, nuclear and coal, or on the absolute costs of meeting a particular CO₂ reduction target, but on the additional impacts and costs imposed upon the system by the variable nature of the renewable resource (i.e. wind or sunlight).

This report therefore provides an update to the original 2006 UKERC report, reviewing the new evidence for the costs and

impacts associated with higher shares of renewable generation and assessing how projected impacts may have changed. For the purposes of this project ‘new evidence’ was defined as that which has emerged since the previous UKERC review in late 2005/early 2006. Since then, a considerable number of new studies have been carried out into the likely effects of integrating renewable generation into electricity systems, including those with a specific UK focus and others that address other countries or regions. The systematic review carried out for this project found almost 200 journal papers, reports and other evidence sources which directly address the research questions described in Section 1.2 below, and a significant number of these analyse the effects of penetrations of variable renewables greater than 20%.

A key outcome of the 2006 research was conceptual clarification associated with how to account for the capacity contribution of intermittent output (Skea *et al.* 2008), and by way of recap, these concepts are summarised again in this report. Whilst the 2006 report also quantified impacts on short term system-balancing, other impacts such as curtailment of renewable output or reduced efficiency of thermal plant were found to be very small or negligible. However as penetrations rise the prospect of these other impacts and associated costs can increase considerably, whilst the average load factors of conventional plant may fall to levels well below the current norm (Strbac *et al.* 2012). These effects have implications for the total costs of the electricity supply system, and bear upon the attractiveness of the investment proposition of renewables and conventional thermal plant, and are therefore discussed in this report.

1.2 The approach and research questions

The TPA approach learns from the practice of systematic review, which aspires to provide more convincing evidence for policymakers and practitioners, avoid duplication of research, encourage higher research standards and identify research gaps. This *evidence based* approach is common in areas such as education, criminal justice and healthcare.

The goal is to achieve high standards of rigour and transparency. However, energy policy gives rise to a number of difficulties for prospective systematic review practitioners and the approach is less common in energy policy analysis. The TPA team have therefore set up a process that is inspired by the evidence based approach, but that is not bound to any narrowly defined method or technique.

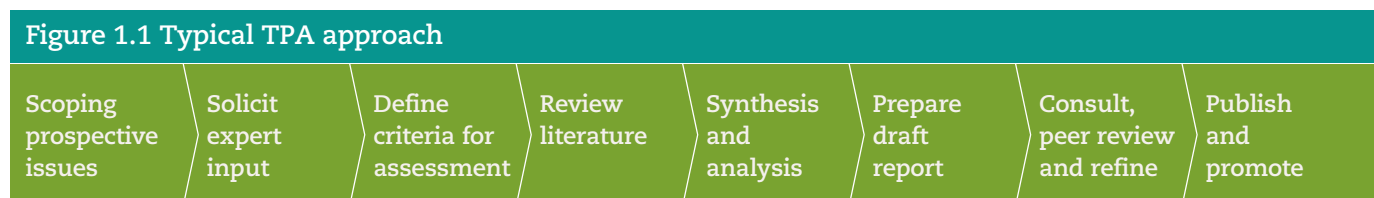
1 We use this to mean 20% of annual electricity demand being met by intermittent renewables. Other definitions are used in different contexts, for example some studies define penetration levels as a percentage of peak system load – see Chapter 3.

2 There is also currently a significant contribution from dispatchable biomass-fired thermal generation.

3 Such costs are most commonly represented by the levelised costs of electricity (LCOE) a typical formulation for which is the discounted sum of all the lifetime costs of the plant divided by the discounted sum of the lifetime output of the plant (Harris *et al.* 2013).

The TPA team has identified a series of steps that need to be undertaken in each of its assessments. These steps are outlined in Figure 1.1 below. Whilst this project followed this generalised approach developed for all TPA work, it was adapted to reflect the fact that the primary aim in this instance was to update the UKERC 2006 report, which meant that some of the steps in

Figure 1.1 were not appropriate or were revised. The assessment process summarised below is described in detail in the Annex, specifying the approach to the review including the search terms used to identify evidence, and criteria against which relevant findings were assessed.



Questions/issues							
What are the key problems and issues	Need to reflect a range of informed opinion	Ensure transparent, rigorous and replicable process	Need to review literature thoroughly	Need to apply rigorous criteria to evaluation of relevant studies	Need to identify key issues and discuss initial findings with stakeholders	Need to seek peer review and gain wide ranging criticism of initial work	Need to ensure report reaches key audience
Actions							
Write scoping note	Appoint expert group	Develop assessment protocols	Apply protocol to literature search	Apply protocol to evaluation and synthesis of literature	Write preliminary draft assessment	Host stakeholder workshop to discuss draft report	Design and graphics
Seek feedback from advisory group	Hold expert/stakeholder workshop	Discuss with expert group and AG	Detailed and transparent 'trawl'	Detailed and transparent assessment of evidence base		Send draft report for peer review	Publication
Seek feedback from online listing of initial scoping		Place protocols in public domain	Identify relevant sources			Make appropriate revisions to draft report	Launch events
Outputs							
Scoping note	Web publication of expert group	Assessment protocols			Draft report	Final report	Published report

Bearing in mind that this project is an update to the earlier UKERC work, the overarching research question which this project addresses is:

- *What new evidence has come to light since UKERC reviewed the costs and impacts of intermittency in 2006 and what does the available evidence now suggest about the costs and impacts of intermittent generation (including relatively high penetrations of 20% and above)?*

From which a series of supplementary questions follow:

- *What are the full range of impacts and associated costs of intermittency that are identified in the literature, and how do these impacts and costs compare to the evidence that was available in 2006?*
- *Has the reported range of impacts expanded, and if so, why?*
- *Which categories of impact are the focus of interest?*
- *To what extent is there a consensus within the current body of evidence on the size and range of the cost and impacts of intermittency?*

The systematic review phase of this project was conducted in late 2015/early 2016, and as expected, revealed a very rich technical and economic literature in both the academic and non-academic domains that addresses the impacts of intermittent generation. These impacts cover the full range of timescales from the second to second system balancing requirements (including the impacts of reduced system inertia) through to the effect on overall system development over multiple decades. During the systematic review, well over 400 papers and reports were initially identified as being pertinent, with approximately half of these being judged by the project team to be the most relevant to the research questions above, applying the assessment criteria described in the Annex.

The expanded and broadened evidence base meant that, in addition to updating the findings of the UKERC 2006 work, a range of impacts which were not quantified in the earlier study need to be considered so that the scale of their implications can be assessed. Therefore, this project considers curtailment, the electricity market implications, the effect (both technical and economic) of the reduced load factor of the thermal plant, as well as the balancing and reliability impacts that the original UKERC work focussed on.

1.3 Structure of this report

Chapter 2 explains the concepts and terminology used when discussing the integration of variable renewable generation into electricity systems, drawing on the earlier 2006 UKERC report and also introducing those issues and impacts which were not considered in the earlier work.

Chapter 3 presents the results of the systematic review, summarising both the quantitative and qualitative findings, and addresses the ongoing discussions over how costs and impacts are most appropriately presented.

Chapter 4 summarises the principal findings and draws conclusions, where appropriate, about what the current evidence base tells us about the costs and impacts of integrating large volumes of variable renewable generation into electricity systems.

2. Electricity systems and intermittency



2.1 Introduction

In the UK as in most countries a combination of market mechanisms, regulatory codes and actions by the System Operator (SO) ensure that demand is matched by supply with a very high degree of reliability. The 2006 UKERC intermittency report provides a general introduction to the operation of electricity systems and the GB⁴ system in particular. This chapter first recaps, and updates where necessary, the main terminology and concepts described in the 2006 report, and then goes on to consider how the way in which the challenges of intermittency are conceptualised may be changing.

The terminology used has changed over the years as a result of liberalisation and revisions to regulatory codes. Terms are used in different ways in different contexts, for example in moving from engineering to regulatory or commercial practice or in different countries. Table 2.1, below defines the key terms as used at the time of writing (2016), drawn largely from the GB Grid Code (National Grid 2016a), the GB System Operator's documentation on balancing services (National Grid 2016b), and the ELEXON⁵ guide to the GB electricity trading arrangements (ELEXON 2015).

Table 2.1 Terminology

Term	Definition
Balancing mechanism (BM)	Set of arrangements in place after gate closure (see below) in which the System Operator can take bids and offers to balance the system. The prices of bids and offers are determined by market participants and, once accepted, are firm contracts, paid at the bid price. These bilateral contracts are between market participants and the system operator.
Balancing services	Services purchased from balancing service providers by the System Operator. Includes Balancing Mechanism bids & offers, various energy trades to aid system balancing, black start capability and ancillary services such as, Frequency Response, Reserve, and reactive power.
BETTA	British Electricity Trading and Transmission Arrangements (BETTA). The market rules under which generators, consumers and the system operator operate. These include the GB Grid Code, Balancing & Settlement Code and Connection & Use of System Code which contains detailed definitions of contracts and rules. Under BETTA and, before it, the New Electricity Trading Arrangements (NETA), most electricity is traded through bilateral contracts, with relatively small volumes traded through power exchanges and as a result of System Operator actions for system balancing. Prior to BETTA and its precursor NETA, the GB electricity market used a single-price auction-based 'pool' system.
Capacity credit	Capacity credit is a measure of the contribution that a generator can make to the ability of the power system to reliably meet peak demands. Often expressed as the amount of load that can be served on an electricity system by intermittent plant with no reduction in the ability of that system to reliably meet demand, or in terms of conventional thermal capacity that an intermittent generator can replace ⁶ . A closely related term is Equivalent Firm Capacity which is a measure, expressed as a percentage, of the contribution that a renewable generation fleet makes to security of supply, relative to a notional 100% available conventional plant.

4 The GB (Great Britain) electricity system and market covers England, Wales and Scotland. The electricity system of Northern Ireland is operated separately, within an electricity market covering Ireland and Northern Ireland. The term 'GB' is therefore used in this report when referring specifically to the electricity system and market of England, Scotland and Wales, and the term 'UK' is used when referring more generally to the whole of the United Kingdom.

5 ELEXON (an arms-length subsidiary of National Grid) is the organisation responsible for running the GB electricity market Balancing and Settlement process.

6 For further discussion of these definitions, see, for example (Ensslin et al. 2008, Keane et al. 2011).

Table 2.1 Terminology (continued)

Term	Definition
Capacity factor	Energy that can be produced by a generator as a percentage of that which would be achieved if the generator were to operate at maximum output 100% of the time. Capacity factor for baseload thermal generators can be around 85% – 90%. Wind turbines typically achieve capacity factors of 20% – 40%, depending on location, design characteristics and weather conditions in a particular year. The term ‘load factor’ is typically used interchangeably with capacity factor and that is the usage adopted in this report.
Capacity Mechanism/Market	This takes the form of a pay-as-cleared, price-capped auction, run annually by National Grid in which eligible generators able to provide firm capacity can bid to provide that capacity four years ahead of real time.
Gate closure	The point in time (one hour before real time under BETTA) at which the energy volumes in bilateral contracts between electricity market participants for a particular settlement period (in GB, half-an-hour) must be notified to the central settlement system. Between gate-closure and real-time the System Operator is the sole counterparty for contracts to balance demand and supply. Also see ‘Balancing Mechanism’.
Load factor	See capacity factor
Frequency Response and Reserve Services	<p>Frequency Response and Reserve Services are purchased by the System Operator⁷ in order to ensure there is sufficient capability in the short-term to undertake system balancing actions and frequency control.</p> <p>The GB System Operator defines a range of Frequency Response services to provide second by second system balancing, some of which are dynamic (in that they are continuously provided by generators) and some are non-dynamic (in that they are triggered by changes in system frequency of a particular magnitude).</p> <p>Primary Response must react within a few seconds, but only has to sustain for 20 seconds, Secondary Response must be able to react within 30 seconds but sustain for 30 minutes, and High Frequency Response must be able to reduce power within seconds and sustain indefinitely. In the summer of 2016, the GB system operator also tendered for the first time for Enhanced Frequency Response that can respond to grid frequency deviations in less than one second. This service is intended to help maintain system frequency under normal operation (i.e. it is not intended to respond to system faults). Other contracts may be put in place for Frequency Control by Demand Management (i.e. interruption of demand) and Firm Frequency Response to respond to both low and high system frequency.</p> <p>Reserve services are intended to provide for un-forecast demand increases and/or the unplanned unavailability of generators, and is provided through a range of synchronous and non-synchronous resources contracted through tender processes.</p> <p>Fast Reserve is synchronised generation capacity that is capable of responding within 2 minutes, at a minimum rate of 25MW per minute to provide at least 50MW and can be sustained for at least 15 minutes. Short Term Operating Reserve (STOR) is non-synchronised capacity that is capable of responding within 4 hours to provide at least +/- 3MW for at least 2 hours. In 2016, the GB System Operator began inviting tenders to provide an enhanced STOR service aimed at attracting potential service providers who do not currently supply any balancing services.</p>

⁷ The terminology used here is that of the GB System Operator. Other operators may use different terms, see for example (Rebours et al. 2007).

Table 2.1 Terminology (continued)

Term	Definition
Frequency Response and Reserve Services (continued)	BM Unit Start-Up is intended to allow access to generating units which would not otherwise have run and cannot provide the shorter-notice services described above because of their technical characteristics. This Reserve service has two elements – Start-Up, where generators are instructed to get to a state where they can synchronise, and Hot Standby, where those generators are held in a state of readiness to synchronise. The final category of Reserve service is the recently introduced Demand Turn-Up, which is intended to provide an increase in demand (or for example reduced onsite generation at an industrial site) when there is excess electricity production on the system (typically overnight and weekend afternoons). This service is instructed several hours ahead of time and each provider must be capable of increasing demand by a minimum of 1MW.
Ramping rates	A measure of how quickly any plant on the system can increase or decrease its output – normally measured in MW/h. More technically described as loading rate but ramping rate is in more common usage.
System margin	The difference between installed capacity, including imports and exports, and peak demand. Operating margin is the difference between available generation and actual demand. The terms capacity margin and de-rated capacity margin are typically used more frequently in the context of longer-term system adequacy, with capacity margin being the excess of installed generation over demand and de-rated capacity margin being defined as the expected excess of available generation capacity over demand, taking into account the expected degree of intermittency, plant failure and unavailability due to maintenance ⁸ .
System Operator (SO)	The company or body responsible for the technical operation of the electricity system. In Britain, National Grid owns and operates the transmission network in England and Wales, operates the transmission network in Scotland and is responsible for system balancing across the whole GB system, subject to regulation.
System Security Services	<p>Whilst the GB System Operator has a range of actions and services available to ensure system security in a broad sense, there are two contracted services in this category that are aimed directly at ensuring that there is sufficient generation capacity to meet short-term balancing requirements.</p> <p>Contingency Balancing Reserve is composed of Demand Side Balancing Reserve⁹, where large electricity users reduce demand, and Supplemental Balancing Reserve, intended to encourage power stations to remain operational (i.e. not mothballed) so that they can provide Reserve Services if required.</p> <p>Maximum Generation service, initiated via emergency instruction is intended to provide generation capacity above the normal operating range.</p>

Whilst some of the terminology has been revised slightly and new terms and services introduced since the 2006 UKERC report, the underlying principles of the operation of electricity systems have not changed, driven as they are by the fundamentals of electricity and electro-mechanical systems. The following two sections therefore in large part draw upon

the earlier UKERC work to explain the challenge of meeting variable demand, what changes when variable renewable generation is added to a system, and what the key categories of impact are (including impacts which were not directly addressed by the previous work).

⁸ See (Ofgem 2011) for more details.

⁹ National Grid recently announced that this service would not be procured for the winter 2016/17 period as the tender processed revealed that 'minimal volume would be available' (McClay 2016).

2.2 System operation: meeting varying demand and ensuring reliability

2.2.1 Short term system balancing

Electricity demand varies continuously over timescales from second to second through to very large changes over each day. Over longer timescales, demand changes seasonally, and from one year to the next. Most consumers are not under the control of system operators nor are they direct participants in wholesale electricity markets, so the system operator and market mechanisms must, for the most part, ensure increased electricity generation as demand increases, and reductions as demand falls¹⁰. To prevent serious problems this adjustment must be continuous, and almost instantaneous. Some forms of generation can vary their output rapidly, others only over a longer time period. Some are largely inflexible (whether that is technical or economic inflexibility) and have powerful reasons to operate at a fixed and constant level. However, no plant is able to operate 100% of the time because all types of generator require periodic maintenance, and every power station will suffer occasional unplanned outages due to a breakdown or fault. As a result, power systems are engineered to cope with both demand fluctuations and periods when several power stations are unavailable due to planned maintenance or unexpected breakdowns. We explore the processes through which demand fluctuations and supply side failures are managed in the following sections.

In practice, a range of plants are used to meet demand at any point in time, from very flexible plant designed to meet rapid swings in demand to inflexible (but cheaper to operate) plant that run all the time they are able to. Prior to privatisation of the GB electricity system, the process of 'dispatching' plant to meet demand was, in common with many other countries, under the direct central control of nationalised entities. Under

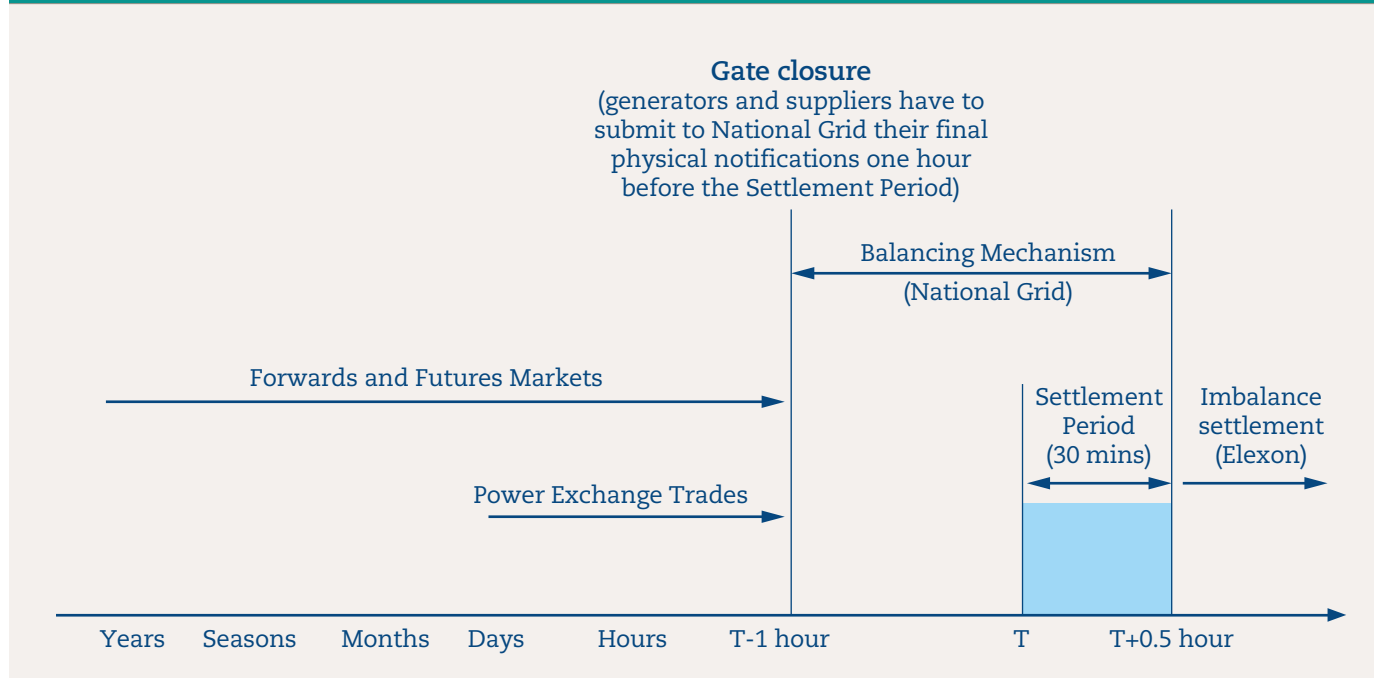
these circumstances, the system operator would typically use some form of 'unit commitment'¹¹ algorithm to ensure that demand was met at least total cost, subject to the technical constraints of the system. In a privatised and liberalised market such as the GB system with no (or very limited) central dispatch of generation it is not the system operator's job to decide which plants will actually run. Instead, policymakers and regulators must try to design and structure a market which delivers investment in, and efficient dispatch of, a mix of actual generation capacity which approaches the theoretical least-cost solution to the unit commitment problem (Stoft 2002).

In the GB system most of the variation in supply to meet changing demand is now handled by market arrangements based upon bilateral trading between suppliers and generators. Demand variation is reflected in market prices and/or supply contracts that ensure more generation when demand is high and less when it is low. Under the current GB market 'BETTA' which extended 'NETA' from England and Wales into Scotland (see Table 2.1) these arrangements mean that more than 90% of electricity is traded in bilateral contracts between generators and wholesalers/suppliers (NAO 2014). Such contracts can be long term – months or even years ahead of real time. Smaller volumes (around 5%) of electricity trade through 'power exchanges', which allow market players to buy and sell electricity for rolling half hourly periods. These markets operate in GB from a couple of days until one hour ahead of real time. At the one hour point in time bilateral trading between generators and consumers is suspended and the energy volume of bilateral trades between generators and suppliers for a particular settlement period is notified to the settlement system. This is known as 'gate closure'. After gate closure, a balancing mechanism operates in the period from one hour ahead of real time and allows anticipated shortfalls or excesses to be accommodated through direct trades between the System Operator and large consumers or generators of electricity, with around 2% of electricity traded in this way. The timeline for this combination of arrangements is shown diagrammatically in Figure 2.1 opposite.

10 A certain amount of demand reduction (and increase) services have historically been available to system operators, in the past mostly from large industry such as steel and aluminium works though also from 'teleswitched' domestic demand – "Economy 7" - and used by them to help balancing. (Teleswitched electric heating demand remains a major feature of the electricity system in France, for example). As described in Table 2.1, there is now a renewed focus on enabling contributions from the demand side.

11 The 'unit commitment problem' can be defined as: given a particular mix of available generating plant (i.e. units), what is the actual mix that should be operated (i.e. committed) that will satisfy demand for a defined demand period at minimum cost? Solving the unit commitment problem is an optimisation process using data from all available generating plants on fuel cost curves, maintenance cost curves, unit start-up costs, unit ramping rate limits, unit capacity limits, minimal stable generation levels, and unit minimum up and down times (Sheble and Fahd 1994). Although it is a cornerstone of centralised system operation, it is also used in substantially decentralised markets, such as Britain's, by generation owners that have large portfolios of plant as a means of minimising the cost of meeting their own contractual obligations.

Figure 2.1 The balancing timeline (NAO 2014), original source: Ofgem



The majority of these market activities reflect anticipated demand and supply, with relatively small (but crucial) adjustments being made by the System Operator. These allow residual market imbalances and events occurring post gate-closure, such as errors in prediction of demand or variable renewable energy or sudden failures at power stations, to be managed. Adjustments are made through automatic controls on power stations and by the system operator calling upon fast responding reserve plants. It does this through the balancing mechanism and directly with market participants with whom it has entered into a range of reserve service contracts (see Table 2.1). These reserves are sized on a statistical basis according to the range of unpredicted variation in demand, the reliability of conventional generators, and the scale of potential faults (Dent *et al.* 2010). The aim is to meet specific criteria for operational reliability to ensure that the risk of demand being unmet is small. It should be noted that there are differences between countries in the terminology used to describe the range of electricity system reserves services (Ela *et al.* 2010), and care must be taken when comparing impacts to ensure that these differences are understood¹².

2.2.2 Ensuring reliability through capacity provision

In addition to the arrangements made for short term reserves, a larger margin of maximum possible supply over annual peak demand is considered when assessing the capability of the system to reliably meet peak demand (which in the GB system is on workday winter evenings). Given a certain desired level

of reliability in meeting all of the peak demand, the size of this margin can be determined probabilistically taking into account the number and reliability of generators and the variability of demands (discussed in more detail below). Before UK market liberalisation, the practice was to ensure installed capacity (using nameplate ratings, not 'de-rated' capacity) should be approximately 20% larger than expected peak demand. Close to real time the amount of margin over peak demand will normally become smaller, as breakdowns, maintenance and decisions to remove generation for commercial reasons become manifest. On the other hand, closer to real-time there will also be greater certainty about demand and the generation that will be available. Hence, the required margin will be smaller.

The current approach to ensuring that there is sufficient margin on the GB electricity system is based on two mechanisms. The first of these is for the System Operator and regulator to monitor and report on the margin over both short and medium-term time horizons (National Grid 2015a, Ofgem 2015a) so that market participants can respond if margins are forecast to be insufficient. The second mechanism is through the Capacity Market whereby National Grid runs an annual auction process for the delivery of firm generation capacity four years ahead of real time. The first of these auctions was run in late 2014 for the delivery of capacity in 2018/19 (National Grid 2015b). Together, these actions are aimed at ensuring that the risk of demand being unmet as result of insufficient generation is very small. By way of illustration, the loss-of-load expectation (LOLE) of the GB system for 2015/16 was calculated to be only 1.1 hours/year, compared to the UK government standard of

12 In recent years there have been attempts to define new standard terms, see (ENTSO-E 2013).

up to 3 hours per year (Ofgem 2015a). In practice this would be very unlikely to result in demand disconnections¹³ (National Grid 2015a). In addition to these mechanisms, a process known as an Electricity Balancing Significant Code Review (EBSCR) was launched in 2012 and approved in 2014 which made changes to the GB electricity market arrangements to increase the incentives for generators and suppliers to fulfil their contracted positions, which assists in both the short-term balancing described in the previous section and also in encouraging investment in capacity (NAO 2014, Ofgem 2015b).

In the sections that follow we summarise what changes with the introduction of significant volumes of intermittent generation onto an electricity system.

2.3 The effects of adding intermittent generation to a system

2.3.1. Overview

Intermittent renewable generation has a range of characteristics that distinguish it from conventional generation plant. Intermittent generators can provide energy, have zero fuel costs, very low operational and maintenance (O&M) costs, and can reduce emissions. The typical cost profile of a variable renewable generator means that the short-run marginal costs of generation are very low (in practice often close to zero) so it would usually make sense to operate such plant whenever it is available. The energy supplied by an intermittent generator is a function of the resource available to it, and the amount of generation capacity installed. The annual load factor achieved for the GB wind power fleet over the last ten years ranged between approximately 24% and 38% (offshore) and between 22% and 28% (onshore) (DECC 2015b), with a long-run average across the entire GB wind fleet of approximately 32% (Staffell and Pfenninger 2016). Whilst generally speaking the load factors that can be achieved by intermittent generators are lower than that of conventional generators, in practice in a GB context wind farms would be expected to be operating for much of the time, albeit at an output level lower than their rated capacity, for the reasons described below.

Intermittent renewable plants show a wide variation of output, indeed for much of the time the output of a wind farm or other installation might be less than half of its maximum potential output. The nature of the outputs of intermittent generators varies markedly, depending on the nature of the technology and where it is located. It might be largely predictable (solar power in sunny regions), entirely predictable (tidal power) or much more stochastic (wind power in some regions, solar in

UK). But all forms of intermittent renewable energy contrast with a conventional generator which (if required) would be able to operate close to its maximum output for most of the time, after allowing for unplanned outages. In practice, not all conventional plant on a system will operate at its maximum output, even if there is no intermittent generation on the system, for the reasons we have discussed above. In broad terms, high capital cost, low operating cost plant (such as nuclear) would be expected to operate as much as it is technically able to do so, with the progressively lower capital cost, higher operating cost plant (such as coal and gas) running at lower load factors.

Whilst any plant could be described to some extent as intermittent, insofar as it will suffer occasional outages, intermittent/variable renewables fluctuate to a much greater degree. Depending upon technology, location and timing of demand peaks, their output may or may not be available during peak demand periods. In many cases, the contribution to system reliability may be lower than for conventional stations, because there is more uncertainty surrounding the contribution of an intermittent generation fleet to meeting peak demands than there is for a conventional generation fleet contributing a similar amount of energy.

2.3.2. Short-run system balancing

Intermittent generators can increase the short-run unpredictable fluctuations that have to be managed by system operators. As a result, they may require that additional system balancing plant is held in readiness. Reserve and response service needs are calculated probabilistically and must deal with demand swings and un-planned outages of conventional plants as well as any additional fluctuations due to intermittency. Additional short run fluctuations in the output from variable renewables can increase the utilisation of automatic controls on the output of conventional power stations, and it may also be necessary to have more part loaded plant running that can increase or reduce its output as intermittent generation varies¹⁴. Fluctuations over minutes to several hours can require increased reserve services of the types described in Table 2.1 above.

The size of additional system balancing requirements is determined by a combination of how rapidly the outputs of different penetrations of different types of intermittent plant will fluctuate, the magnitude of forecasting errors, and the possible scale of total, system-wide, changes in a given period. This requires a representation of the aggregated behaviour of individual intermittent plants, drawing upon weather data, plant size, and geographical dispersion to provide an indication of the variability (and probability of that variability) of intermittent output. Historical data on forecasting accuracy can be used to determine the extent of unpredicted variation.

13 LOLE is described in (National Grid 2015a) as 'an approach based on probability and is measured in hours/year. It measures the risk across the whole winter of demand exceeding supply under normal operation. It does not mean that there will be a loss of supply for X hours/year. It gives an indication of the amount of time across the whole winter that the System Operator may need to call on a range of emergency balancing tools to increase supply or reduce demand, typically through voltage reduction. In most cases, loss of load would be managed without significant impact on end consumers'.

14 Variable renewables can also provide system services – at the expense of some lost generation – but in surplus situations this can be a cost effective way to contribute balancing services.

Forecast accuracy is improving, and is key to providing cost effective reserve services. The more accurate the forecasting the greater the opportunity to use (lower cost) planned/wholesale market changes as opposed to holding reserve plant in readiness, in particular reserves comprised of additional part loaded (and therefore probably less efficient) plant. In market terms, the effects of predicted fluctuations can be contractually committed prior to gate closure, which should permit the market to reveal the most cost effective means to manage these variations. For this reason, the time horizons over which gate closure is operated are also important¹⁵.

A further factor is how existing variations of demand or load compare with that of intermittent output and the reserve capabilities that already exist on the system. These existing reserve capabilities are a function of the variability of demand, the reliability of existing plant, the number of plants on the system, and the size of the largest single unit that could suffer a fault-related outage due a single event (Ofgem 2015a). System operators are concerned with the total amount by which the system might be out of balance. As a result, reserve requirements are a function of both the unpredicted load variation and unpredicted intermittency.

The operating and capital costs for reserve plant used for system balancing can be calculated in a relatively straightforward fashion, once the additional reserves required to deal with the combination of varying output and forecasting errors for intermittent generation have been assessed as described above. The most typical approach is to determine the least cost option for provision of such reserves, although an alternative is to use market prices to reveal prices for these services. Both the need for and cost of provision will vary from system to system – for example depending on the size and nature of existing reserves. The principal challenge with estimating costs of reserve and response services arises from terminological, operational and regulatory differences between countries, and costs may vary according to which actions fall to system operators and which are dealt with by markets.

2.3.3. Meeting peak demand

In addition to replacing output from conventional plant, intermittent generation plant may be able to replace some proportion of conventional thermal plant capacity. The extent to which intermittent plant can do this without negatively affecting system reliability is referred to as its 'capacity credit'. This is derived from probabilistic calculations based on forecasts of variable renewable generation for peak demand periods and the characteristics of the system to which such generation is connected. Intuitively, it might be thought that intermittent plant cannot contribute to reliability at all since in most cases we cannot be certain that it will be available at times of peak demand. However, there is a possibility that any plant on the system will fail unexpectedly, so reliability

is always calculated using probabilities. Intermittent plant can therefore contribute to reliability provided there is some probability that it will be operational during peak demand periods. However, the output from intermittent plant can be forecast with less accuracy than conventional generation, and the capacity credit of intermittent plant is usually lower than it is for conventional generation (Ofgem 2014). This means that there must be more installed capacity on the system than there would be without intermittent generators, which therefore gives rise to an additional cost that would otherwise not be incurred if the capacity credit of intermittent and conventional generation were the same. It is also the reason that the definition of system margin used in Table 2.1 above is often replaced with 'de-rated capacity margin' when intermittent generation is added to a system. This takes into account the capacity credit of intermittent generation as well as assumptions for conventional generator availability and the direction and flow of electricity through interconnectors (Ofgem 2013).

The key determinants of capacity credit are the degree of correlation between demand peaks and intermittent output, the range of intermittent outputs, and the average level of intermittent output. Positive correlation between high output and high demand will tend to increase the capacity credit of intermittent plant. No, or negative, correlation; will have the opposite effect. For example, in the UK solar PV (on its own, without any associated storage) is unable to provide any contribution to peak demands, because these peaks occur in winter evenings, when there is no sunlight, whereas in some countries or regions demand peaks are driven by loads (often air conditioning) that are highest on hot sunny days, in which case there is a very high probability of significant PV output that is highly correlated with demand. In these cases, PV can have a very high capacity credit (Pudjianto et al. 2013). However, a partial relationship between demand and renewable output does not necessarily imply a meaningful correlation. Wind energy in Northern Europe tends to have higher availability and higher average output in winter, when peak demand also occurs. However, wind does not exhibit any significant diurnal pattern in winter months since it is largely a function of weather fronts (Poyry 2011b).

Where demand and intermittent output are largely uncorrelated, for example in the case of wind energy in Britain, a decrease in the probable range of intermittent outputs will tend to increase capacity credit. In statistical terms this is because the variance decreases, and more consistent resource regimes will decrease the variance and increase capacity credit. Variance may also be reduced through geographical dispersion of plants (which has the effect of smoothing outputs), and by having different types of intermittent plant on a system. This is because different types of renewable resource fluctuate over different timescales, which also has the effect of smoothing outputs such that overall variation decreases. As the fleet

15 At the introduction of NETA in 2000, gate closure was at 3.5 hours ahead of real time. Although it gives the system operator less time to carry out balancing actions within the Balancing Mechanism (BM), in 2002 this was reduced to 1 hour, largely in order that market participants could have more confidence in the values of their 'final physical notifications' submitted to the BM. In some US markets, the economic dispatch process has been reduced to as little as 5 minute steps to allow almost all reserve provision to be economically optimised.

of a particular weather-dependent resource such as wind or solar increases, the contribution of the next MW of capacity in meeting the peak demand with a certain level of reliability may decline. This is because, due to the typical size of weather systems, each new MW of capacity cannot be regarded as totally independent of existing capacity. However, the larger the area across which output can be aggregated, the more each installation can be regarded as independent and the more confidence there can be about its contribution to meeting the peak.

Notwithstanding the caveat over correlation raised above, a higher level of average output over peak periods will tend to increase capacity credit. Again, taking UK wind as an example, whilst there is little correlation between wind output and demand, wind farm outputs are generally higher in winter (when peak demands occur) than they are in summer, so analyses typically use winter wind output data to calculate capacity credit.

The costs resulting from the need to have more installed capacity on the system than there would be without intermittent generators can be assessed by comparing a system that contains intermittent generators with one that meets the same reliability criteria without those intermittent generators, whilst ensuring that both systems have the same energy output. Under GB electricity market arrangements there was no explicit payment for 'reliability services' until the introduction of the Capacity Mechanism in 2014¹⁶, and the system operator did not contract for plant in order to maintain a capacity margin or to act as 'back up' to intermittent generators. Whilst the Capacity Mechanism is clearly intended to ensure that there is sufficient capacity available to meet peak demand periods, the rationale for its introduction was based partly on concerns over the impending retirement of older thermal capacity (due to a combination of emissions regulations and low wholesale power prices) and partly due to a poor economic outlook for new thermal plant. It was not solely due to the impact that intermittent renewable generation was having on capacity margins (Ofgem 2013). As such, the costs revealed through the Capacity Mechanism auction process cannot simply be directly attributed to intermittent renewable generation.

The 2006 UKERC report found two distinct strands of thought in the literature on how to conceptualise the costs associated with the conventional capacity required to maintain reliability when intermittent generators are added to an electricity network. The first does not explicitly define a 'capacity cost,' rather it assesses the overall change in system costs associated with incorporating variable renewables whilst maintaining system reliability. This approach does not attempt to directly attribute a cost of 'capacity reserves' or 'stand by' to intermittent stations. Rather it compares a system with variable renewables to one without, allowing for whatever capacity credit variable

renewables can provide. It is also possible to derive the cost of maintaining reliability using this approach by assessing the impact on system load factors (Dale *et al.* 2004). One effect of adding intermittent generators is that the load factor of the remaining conventional generators on the system will fall. Intermittent generation is typically offered at a lower price and taken in preference when available. However if the system is to maintain reliability, conventional plant will need to be retained in order to be used when renewable output is low and overall load factors will be reduced.

However, it is unlikely that intermittency will affect each type of generator equally. In fact, it is possible that particular categories of generating plant might be used to maintain reliability. These may include older plant retained and maintained primarily for demand peak duty and/or open-cycle gas turbines. Hence, other analyses have used 'stand by' generation to estimate the cost of intermittency (Ilex and Strbac 2002). In this approach, costs are assessed for the provision of capacity sufficient to close any gap between the capacity credit of intermittent plants and that of conventional generation that would provide the same amount of energy. These costs will vary depending upon what form of generation is assumed to provide this capacity and this can give rise to a degree of uncertainty, since there is no explicit market for the proportion of capacity requirement that results from the addition of intermittent renewables. It is also not clear that we can know the long run marginal cost of such capacity, as this will be a product of future system optimisation (market based or otherwise), which will be affected by new technologies or practices.

The two approaches can be reconciled using the algebraic approach developed for the earlier UKERC work (Skea *et al.* 2008). This work demonstrated that the additional capacity cost imposed on a system by intermittent generation is equal to the fixed cost of energy-equivalent thermal plant (e.g. CCGT and allowing for the availability of thermal plant) minus the avoided fixed cost of thermal plant displaced by capacity credit of wind. 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, whilst making no judgement about the nature of the plant that actually provides capacity to maintain reliability. Instead, all that is required is determination of the least cost energy equivalent comparator, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation (often assumed to be CCGT).

2.3.4 Transmission network capacity

Since the physical location of variable renewable generation is driven in large part by the location of the available resource, the addition of such plant to a system may impose costs for the electricity transmission infrastructure required to connect the plant to the grid. Reinforcement of other parts of the grid

16 There was a payment for 'availability' in the former 'pool' arrangements prior to NETA.

may also be required to allow the electricity generated to reach centres of demand if these are not located close to the grid connection point for the new generation.

The additional transmission costs associated with new intermittent renewable generation are not strictly a cost resulting from the intermittent nature of those renewables but are solely a function of the fact that they may be located some distance from centres of demand and/or not close to existing grid infrastructure. New transmission often offers system wide benefits and it is important to note that existing infrastructure will often have been constructed to connect large thermal generation plants, themselves remote from demand. Such costs are, however, frequently included in analyses of the additional system costs incurred by adding variable renewables e.g. (NEA 2012), and are of course included in the ‘whole system’ analyses which we discuss in Section 2.4 below. When considering those studies which do account specifically for transmission costs, care must be taken to understand the assumptions that have been made in relation to the most appropriate sizing of the capacity required. This is because it is possible that the additional transmission capacity is sized by a power system model such that it is able to accommodate the maximum output from the new renewable generation (which may very rarely be attained), whereas it may be more cost effective overall to size the additional transmission capacity at a lower level and curtail some wind output when wind speeds are very high (see below) (EWEA 2014).

2.3.5 Curtailment

Partially related to the transmission system capacity impacts described above is the issue of curtailment. This may become necessary where output from variable renewable generation cannot be accepted into the electricity system, either because of insufficient transmission grid capacity (i.e. a grid constraint) or where the volume of intermittent output at a given time would otherwise exceed total demand. In practice, in the latter case this may happen before total instantaneous intermittent output exceeds total instantaneous demand. This is affected in part by the nature and flexibility of conventional plant, with a less flexible plant mix more likely to impose constraints than a system better optimised to high variable renewable penetrations. It will also be affected by operational requirements to maintain inertia (see below), system balancing and the range of ancillary services required for the reliable operation of the electricity system (Burke and O’Malley 2011).

As discussed above, some curtailment may be a result of decisions taken to restrict the size of new transmission infrastructure to below what would be required to accept the notional maximum output from new renewable generation, if it is economically rational to do so (Ault et al. 2007). Such decisions involve weighing the additional costs of higher capacity grid infrastructure against the value of any electricity

generation from variable renewables which may be curtailed at times of peak output – which the ‘whole system’ analyses described in Section 2.4 may do as part of the cost optimisation process. Alternatively, the costs associated with curtailment can be derived from analyses which use time-series wind speed data, demand profiles and transmission capacity constraints to forecast the volume of curtailed output, which can then be translated into either a direct cost (using the lower actual useful output from the renewable plant¹⁷) or by applying the market value of the lost output. However, it is important to recognise that once the costs of installing the additional capacity required to reliably meet a given level of demand are accounted for as described in the sections above, curtailment does not necessarily represent an *additional* cost, emphasising the point that there are complex interactions between individual categories of impact and that these are not necessarily additive.

2.3.6 Thermal plant efficiency

The principal aim of adding intermittent generation to a system is to replace the output of fossil fuel stations and hence secure fuel and emissions savings, but those savings may be partially offset if the efficiency of the remaining conventional plant is detrimentally affected. This may occur as a result of more frequent changes in the output of load-following plant and/or greater use of more flexible (but possibly less efficient) plant to manage predicted variations. Start up and shut down of certain types of plant can consume fuel to ‘warm’ plant, without generating any electricity¹⁸. The way such changes are provided for is also affected by the accuracy with which fluctuations in variable renewable output can be forecast. In general, better forecasting results in fewer losses, since the most efficient mix of plant can be scheduled. However, improved forecasting does not eliminate these costs, since the need to manage predicted fluctuations may still lead to some degree of efficiency reductions.

It is important to note that in those electricity systems that operate largely through decentralised market processes, there is no single body with responsibility for optimising efficiency but rather each market participant optimises their own position such that, given an efficient market design, overall efficiency is achieved. Total system efficiency impacts, and the costs thereof, are therefore something of an abstract concept for individual market participants but, nonetheless, can be monitored in terms of total fuel use relative to thermal plant output. In these circumstances it is important to consider the potential difference between theoretical fuel and emission savings, such as those calculated through whole system optimisation modelling e.g. (Strbac et al. 2015), and those actually delivered by the market, since this provides a comparator against which the effectiveness of market arrangements can be judged.

17 This lower output could for example be applied to a levelised cost calculation, as described in the footnote at the start of Chapter 1, to arrive at the difference between levelised cost with and without curtailment.

18 More frequent start-up and shut-down and changes in output may also lead to accelerated wear on equipment and increased O&M costs, increased unavailability for maintenance or more unplanned unavailability, or shortened operational lifetime.

2.3.7 System inertia

A further impact of adding a significant proportion of variable renewable generation is the reduction of what is known as system inertia. In systems where electricity production is largely in the form of thermal power stations driving heavy rotating generators at high speed, there is a considerable degree of kinetic energy in the system. These generators' mechanical systems are electro-magnetically linked to the grid and therefore provide a degree of resilience to system disturbances because whilst in the event of a sudden loss of any one generator the increased electrical load on all the other generators will cause them to slow down (thereby reducing system frequency), the rate at which this slowing down happens is reduced by the kinetic energy in the rotating mass of the remaining generators¹⁹. Modern 'type 4' wind turbines are connected to the grid through power electronics which means that there is no direct link between the rotating mass of the turbine and the grid, and the considerable kinetic energy in the turbine does not, therefore, contribute to system inertia (Ela et al. 2014a). Moreover, solar PV generation displaces rotating plant and has no inherent useful energy store. The impacts of reduced system inertia do not generally manifest until very high instantaneous penetration levels of variable renewables are achieved, and were not considered by the evidence reviewed in the 2006 UKERC study. More recently, however, there has been considerable interest and research into the potential impacts, particularly on smaller electricity systems with limited interconnection, and the possibility of using power electronics to provide so-called 'synthetic inertia' so that variable renewables are able to provide some rapid access to the energy stored in their rotating plant (EirGrid and SONI 2011, EirGrid and SONI 2016).

2.3.8 Electricity market impacts

One impact that was considered to an extent in the evidence reviewed for the 2006 study, but which has received considerably more attention in recent years is that which is variously referred to as the merit-order, market or utilisation effect (Hirth 2013). This is concerned with how the addition of low marginal cost variable renewable plant to an electricity system may reduce the number of hours that existing conventional generators are able to operate, since as we discuss above, such plant are likely to have higher marginal costs of generation than variable renewables. They may therefore find that the times when they can compete in the electricity market are restricted to those periods when the renewable resource availability is low. In terms of reducing emissions, this may well be considered a desirable outcome. However, if the effect is to reduce the load factors of conventional plant to the extent that the long-term profitability is affected, then this may influence whether such plants continue to operate and also whether

any new conventional plants are constructed. This may have important implications for the electricity system if such plants continue to be required to provide system balancing services and to ensure that peak demand can be met reliably. This has been a factor in the increasing development of capacity remuneration mechanisms in several European countries. It is in some respects the corollary of the issues associated with capacity credit and meeting peak demand discussed in section 2.3.3 above.

A further market impact is the extent to which the revenue of a renewable generator may be reduced by the fact that markets may attach less value to renewable output, compared to output from a conventional generator. This may be, for example, because that output will only be available when the renewable resource is available (and not necessarily when there is demand for it) or that actual output may differ from forecast output.

A key point is that these impacts are neither intrinsically separate nor additional to other impacts since they are the market manifestations (or approximations) of the range of physical impacts described in the sections above. Whether or not a renewable generator actually bears these impacts will depend upon the design of the electricity market and/or the policies used to incentivise and reward renewable generation.

¹⁹ Synchronous grid-connected generators give up some of their stored kinetic energy to the system and this slows down the rate of change of frequency (ROCOF) (Ela et al. 2014a). It should however be noted that in the case of wind turbines, extracting this kinetic energy from the turbine rotor will move it away from its optimum aerodynamic speed so output is likely to decrease.

2.4 Differing perspectives on system costs

The impacts described above can be quantified, but are highly context specific. They vary markedly between regions, countries or systems. In addition, short-run marginal costs will differ from long-run marginal costs and systems may be re-optimised in the longer run, to reduce overall costs.

Some categories of costs, for example, those resulting from short term system balancing requirements, are relatively self-contained. If the required services are procured by system operators and/or in balancing markets then at least approximate prices for these services will be transparent. Even in these relatively straightforward instances costs are highly system specific, and accrue at a system (as opposed to individual plant or plant type) level. It is also important to be mindful that market design will affect the need for and price of a variety of system services and distribution of costs and benefits within wholesale and balancing markets, and/or system service contracts. Nevertheless at least in relative terms it is reasonably straightforward to assess and discuss these costs. Other categories of system costs, such as the implications of a lower capacity credit on maintaining system reliability, can *only* be assessed from a systemic perspective (Holtinen *et al.* 2016). Quantification requires a comparison of the capital, operating and fuel costs of a system with new intermittent generation against a credible counterfactual scenario without intermittent plant, and where the volume of electricity delivered, power quality and reliability remains

constant. Adding further complexity is the potential for considerable overlap between cost categories, the possibility for costs to manifest themselves through different routes, and that there may be trade-offs between apparently separate costs. For example, increasing system reserves to meet short-term balancing requirements may also contribute to the capacity margin required to reliably meet demand peaks. Similarly, curtailment costs may be already accounted for in the costs of the total system capacity required to satisfy overall demand, and transmission costs may be offset by reductions in the costs of curtailment.

Partly in response to this complexity, in recent years there have been an increasing number of analyses which take a 'whole system' approach to the entirety of the challenge of adding intermittent generation to a system. These studies all attempt to incorporate the impacts described above and present the results in terms of future whole system costs, where individual categories of impacts may not be the main focus. The 'whole system' approach offers a more thoroughgoing integration of a wide range of impacts and many analysts believe that it will supersede approaches which attempt to quantify individual impacts in isolation. However, a key objective of this report is to provide a thorough and comprehensive review of the full range of evidence in this area, irrespective of approach. Chapter 3 therefore presents the results from the systematic review of post-2006 analyses, using individual categories of impact that are broadly similar to those UKERC presented in 2006. In Chapters 3 and 4 we discuss the advantages of assessing impacts using a whole system approach.

3. Findings from the systematic review



3.1 Introduction and overview

This chapter provides an overview and discussion of the main quantitative findings from the literature review. The quantitative findings are supplemented by qualitative findings, in particular for those intermittency impacts where the data available are less comprehensive and/or less amenable to aggregated presentation in graphical form. The review initially identified over 400 documents, which on the basis of inspection of the title and abstract were judged as likely to be useful in addressing the research questions identified in Chapter 1. These comprised of a mixture of academic journal papers and 'grey literature' such as reports from consultants, industry and regulators. Each document was allocated a unique reference ID number, and these ID numbers are used in the charts shown later in this chapter. Table 6.2 in the Annex cross-references the ID numbers used in the charts to the relevant original document.

To allow the project team to focus on those documents which were deemed most likely to contain usable quantitative data and/or key qualitative insights each document was assigned a relevance rating on a scale of 1 to 4, with 1 being the most relevant and 4 being the least. This relevance rating was assigned following a more detailed inspection of the initial set of documents. The project team then concentrated their investigations on those documents which had been allocated a relevance rating of 1 or 2, on the basis that documents with lower relevance ratings were found to contain no data that was directly usable or were found on closer inspection to be not relevant or a duplicate. Approximately 43% of the initial set of documents was allocated a relevance rating of 1 or 2, see Table 3.1 below. The systematic review which identified, ranked and categorised the literature is described in more detail in the Annex.

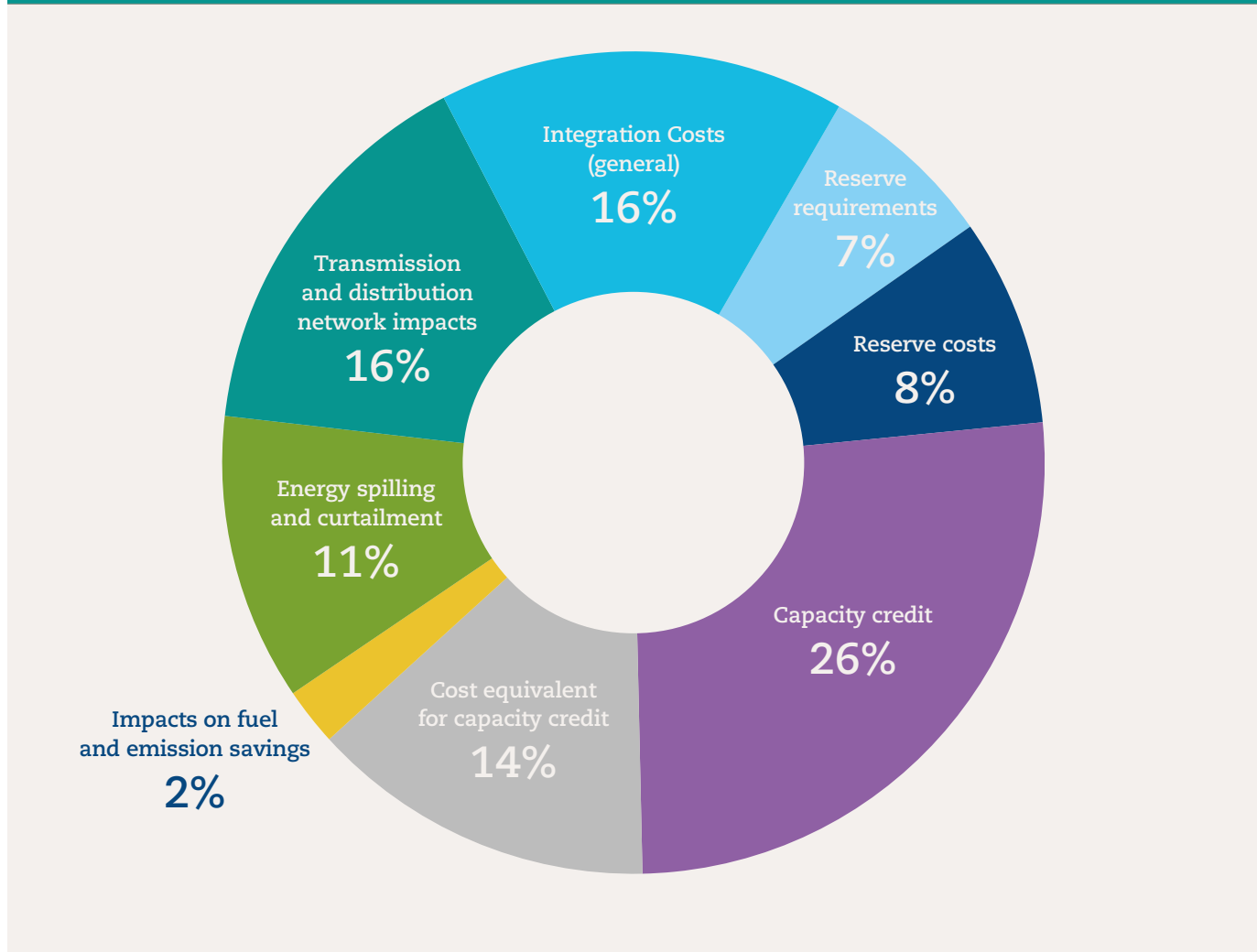
Table 3.1 Numbers of inspected documents by relevance rating

Relevance rating	No. of documents	% of total
1	102	23%
2	92	20%
3	191	42%
4	69	15%
Total	454	100%

The quantitative data from each of the documents with a relevance rating of 1 or 2 were recorded in a spreadsheet, with over 2000 individual data points being captured, distributed

across the range of impacts associated with intermittent generation. Figure 3.1 below shows the breakdown of the number of data points by category of impact.

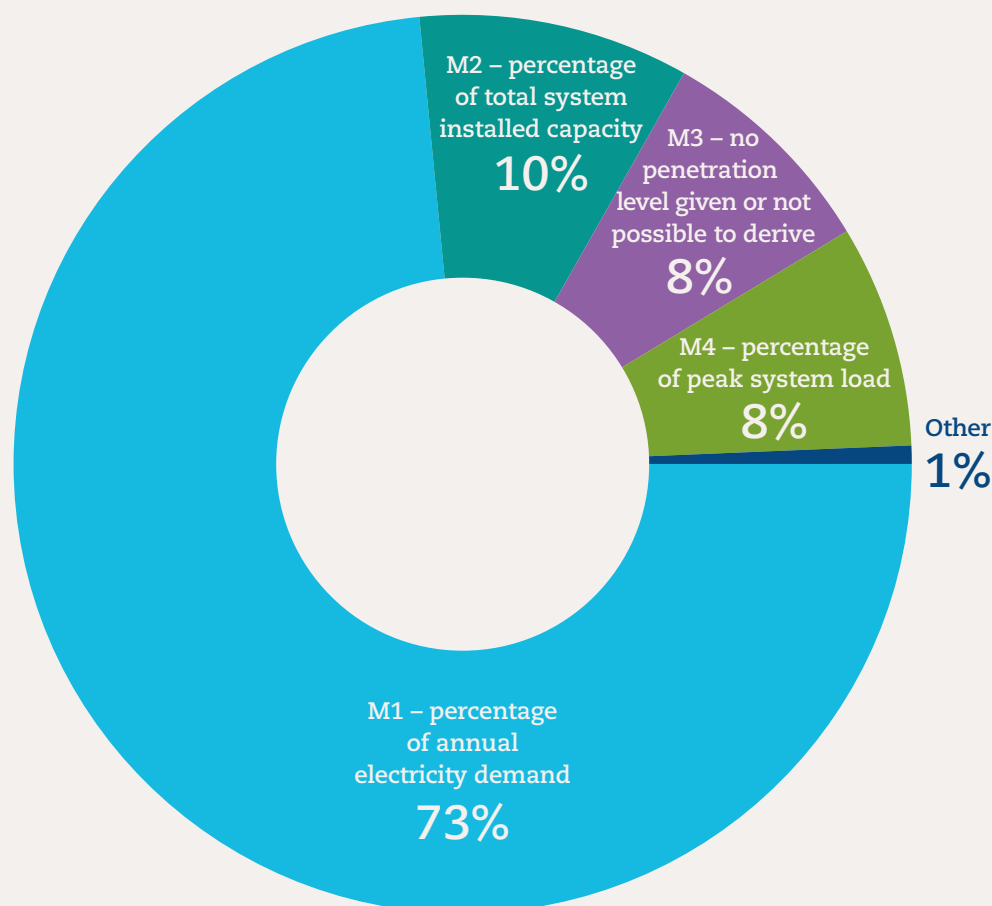
Figure 3.1 Breakdown of the full data set by category of impact



For those data where the impact is reported in cost terms, each data point is normalised to 2015 GB Pounds (GBP) in a two-step process. The first step is to convert to GBP at the rate prevailing at the time when the document concerned was published (or the explicit 'reporting year' if that was declared) using historical exchange rates from the Bank of England Statistical Interactive Database (BoE 2016). The second step is then to convert these amounts in historical GBP terms into 2015 GBP using the UK Government GDP deflator (HM Treasury 2015). There are of course other measures of inflation, such as the Consumer Prices Index (CPI), the Retail Prices Index (RPI), and the Producer Price Index (PPI) but we have used the GDP deflator because it is a much broader index, and is widely used in policy analyses.

As explained in Chapter 1, a key variable in assessing intermittency impacts is the percentage penetration level of the intermittent generation in question but comparison of data is hampered by the fact that a number of different approaches can be found to presenting this percentage. The most commonly used metric in the literature examined for this project is the percentage of annual electricity demand being met by intermittent renewables. Therefore the charts in this chapter show data from sources which use this metric, and this is the measure of penetration level that is used throughout this report unless a different measure is specifically identified. To give an indication of the use of other measures of penetration level, Figure 3.2 below shows the proportions of the total data set that use each metric type.

Figure 3.2 Breakdown of the full data set by definition of penetration level



Taken together, the studies which underlie the documents reviewed by the project team explore the influence of a very wide range of variables on the potential impacts of adding intermittent generation to an electricity system, including:

- The effects of the degree of system flexibility
- The degree of geographical dispersion of intermittent sources of generation
- The impact of energy storage in a range of forms and ability to operate over a range of timescales
- The location and size of cross-border electricity transmission capacity
- The effects of much increased demand response
- The interaction with large-scale hydro power, including exploring the impact of inter-year availability due to variances in annual rainfall
- The differential impact of alternative 'back-up' technologies such as coal vs. gas
- The impacts of fossil fuel prices and CO₂ emissions costs
- The effects of wider economic conditions

The previous UKERC report noted that there had been a very significant increase in research activity in the area of intermittency, with the volume of documents reviewed that were published in the five years preceding the 2006 UKERC report exceeding the number from both the previous decades by more than two to one. This trend has sustained, as may be expected given the very ambitious goals for the deployment of variable renewable generation in many countries. There is now a very large body of literature in the electrical engineering journals which considers impacts of a very technical and detailed nature, such as the development of system control algorithms to optimise the integration of variable renewables, and many of these are based upon the use of virtual environments such as the IEEE reliability test system e.g. (Zhu *et al.* 2012). Nevertheless, this report is concerned primarily with explaining and summarising analyses undertaken over the last decade that assess aggregated impacts at a system level and in financial terms, and within this area there have been marked developments in both the volume of analyses and quantitative results.

For the sake of completeness and transparency, in what follows we present all of the results revealed in our systematic review. We note that methods and approaches differ, and studies vary in terms of quality of analysis and how effectively they tackle the question of system change. As we explain below, increasing system flexibility has a profound impact on overall estimates of costs. Therefore in each instance we present the full range of findings, discussing the reasons for the range and which factors or assumptions serve to increase or decrease costs.

Whilst the number of documents examined in detail for the current project is approximately 30% larger than for the 2006 report, it is important to bear in mind that the earlier work was concerned with *all* the available evidence up to that date, covering the very early work in the area from the late 1970s through the period of methodological development during the 1990s and rise in activity from 2000 onwards. By contrast, the current project considered only documents published from 2006 onwards, meaning that the project team examined a roughly 30% larger volume of documents but which were published over little more than a third of the time.

Two examples of the changing volume of quantitative results can be found in the data for capacity credit and reserve costs respectively. For capacity credit the 2006 report gathered approximately 50 individual data points for this impact from those studies which had used the most common measure of intermittent generation penetration levels. The current project found over 400 data points for capacity credit (again from analyses that used the most common measure of penetration level). For reserve costs data, the 2006 report collected less than 50 data points, compared to over 120 data points for the current project.

In addition, some categories of impact have received considerably more attention in recent years. Analyses of energy curtailment is an example of this, with the 2006 report finding only six studies in total (i.e. regardless of penetration level metric) which presented quantitative results, and these were not considered to be sufficiently consistent to allow aggregated presentation. For comparison, the current project found almost 250 data points that used the most common penetration level metric for curtailment, drawn from approximately 15 studies, with more than 20 studies providing some type of quantitative results.

In recent years there has also been considerably more analysis of the impacts of integrating solar power in relatively northern (and cloudy) countries. These can be seen as a response to the very rapid increase in installed capacity of PV in some countries where this technology was historically seen as occupying a rather small specialist niche. The results from these analyses reinforce the message of how important it is to be very clear over what technology is being assessed and the country or region in which that technology is located, because the results can vary dramatically. This supports the point made in the earlier UKERC work that impacts can only be properly assessed for a specific system and that generalising findings from one system to another is unwise unless those systems have very similar characteristics.

The remainder of this chapter presents the findings of the systematic review for each of the categories of impact described in Chapter 2. The data represented in the figures shown in the following sections frequently show a wide range of results, driven largely by alternative considerations of the range of variables described above and/or differing analytical approaches. For example, a key influence is whether impacts are assessed on the basis of adding variable renewables to a largely unchanged system or whether modelled systems are substantially revised with the aim of minimising any additional integration costs. Some of the outlying findings result from quite extreme assumptions about the nature of the system for which additional variable renewable generation is being modelled (see the results for curtailment in Section 3.4 for an example of this) and others are the result of unconventional approaches in the underlying analysis. Nevertheless, the general approach adopted by the project team was that data should be presented where possible, but with a careful explanation provided where there are concerns over the quality of the results or their likely relevance to real-world situations.

Note that the findings in the 2006 UKERC report are not reproduced in the charts below (so all the data shown is from sources found in the review described above), but comparison is made with the earlier data sets in the text accompanying each chart. Also, many of the evidence sources reviewed present multiple data series within the same study, for example to show results for differing assumptions over technology mixes or where the analysis covers several countries or regions. This means that there can be multiple data series in the charts below with the same reference ID number. Where costs are presented, they are shown on a per MWh of intermittent generation basis and are normalised to 2015 GBP using the process described above.

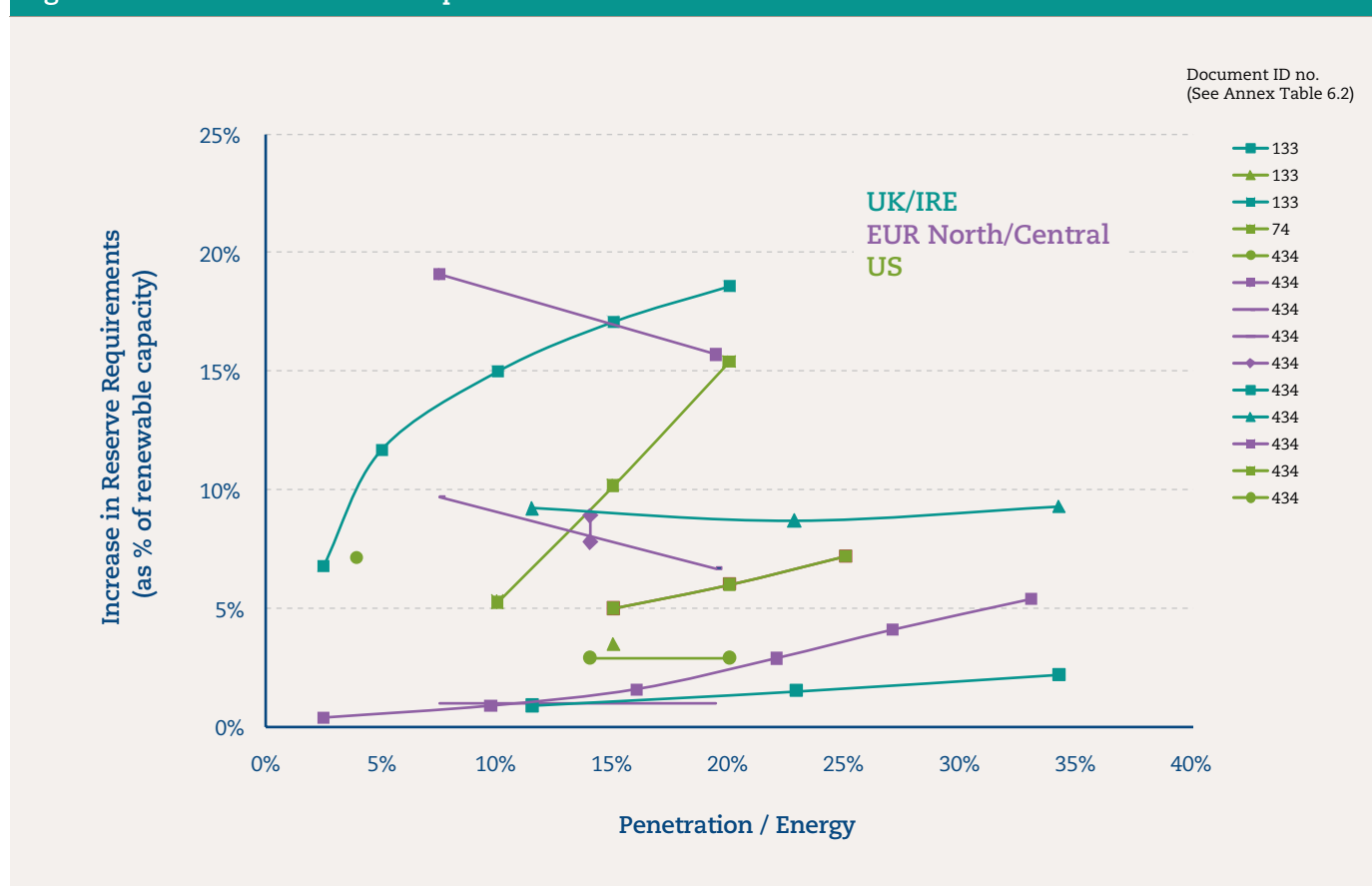
3.2. Reserve requirements and costs

As was noted above, there is a range of different services operating over a range of timescales (e.g. from frequency response, through second to second balancing, up to several hours ahead of real time) which may, depending on the definition and terminology adopted, fall into the category of reserve services. Results for reserve requirements usually do however, aggregate the impact of both the variability of output from intermittent renewable generators and the forecasting errors associated with that output.

3.2.1 Reserve requirements

Figure 3.3 below shows the findings collated for the percentage increase in system reserve requirements, as reported in the evidence reviewed. As explained above, the penetration level is expressed as a percentage of annual electricity demand which is met by variable renewable generation, and the increase in system reserve requirements is represented as a percentage of the renewables capacity installed, following the approach adopted in IEA Wind Task 25 publications such as (Holtinen et al. 2013, Holtinen et al. 2016). The data is colour-coded by geographical country or region.

Figure 3.3 Increase in reserve requirements



Excluding the outlying data²⁰, the additional reserve requirements reported in the 2006 UKERC work ranged between an almost negligible increase at the 5% penetration level up to a maximum of just under a 20% increase in required reserves at the 20% penetration level (with most of the data showing a 10% or less increase in reserves at the higher penetration level). The data collected from post 2005 analyses also do not exceed a 20% increase in reserves at any penetration level for which data was found, although in some respects the picture is now more complex with impacts ranging from negligible to potentially significant across all penetration levels, depending on the modelled characteristics of both the renewable resource and the electricity system. The increase in reserve requirements shown in Figure 3.3 is less than 10% at penetration levels between 20% and 35%, but it is difficult to draw firm conclusions from this since the studies with higher estimates of reserve requirements do not provide data above a 20% penetration level. There is however evidence that improvements to the accuracy of wind energy forecasts can have a very positive impact on balancing requirements. For example, a 2011 study by the German Energy Agency found that the volume of

balancing capacity likely to be required for a 39% penetration of variable renewables in 2020 was ‘considerably lower’ than in the same organisations 2005 analysis²¹ – a result which was credited to substantial improvements in wind forecasting. The impact of the timescale over which reserves are forecast and scheduled is emphasised by findings from the latest IEA Wind Task 25 report (Holtinen et al. 2016), which concluded that at a 20% variable renewable generation penetration level the reserves requirement would be only 3% of the installed wind capacity over a 1 hour forecast horizon, rising to 10% over a 4 hour horizon and 18% with a day-ahead horizon.

3.2.2 Reserve costs

Figure 3.4 below shows the findings for the costs associated with increases in system reserve requirements as the intermittent generation penetration level rises. As before, the penetration level is expressed as the percentage of annual electricity demand which is met by variable renewable generation. Similar to Figure 3.3 above, the data is colour-coded by geographical country or region.

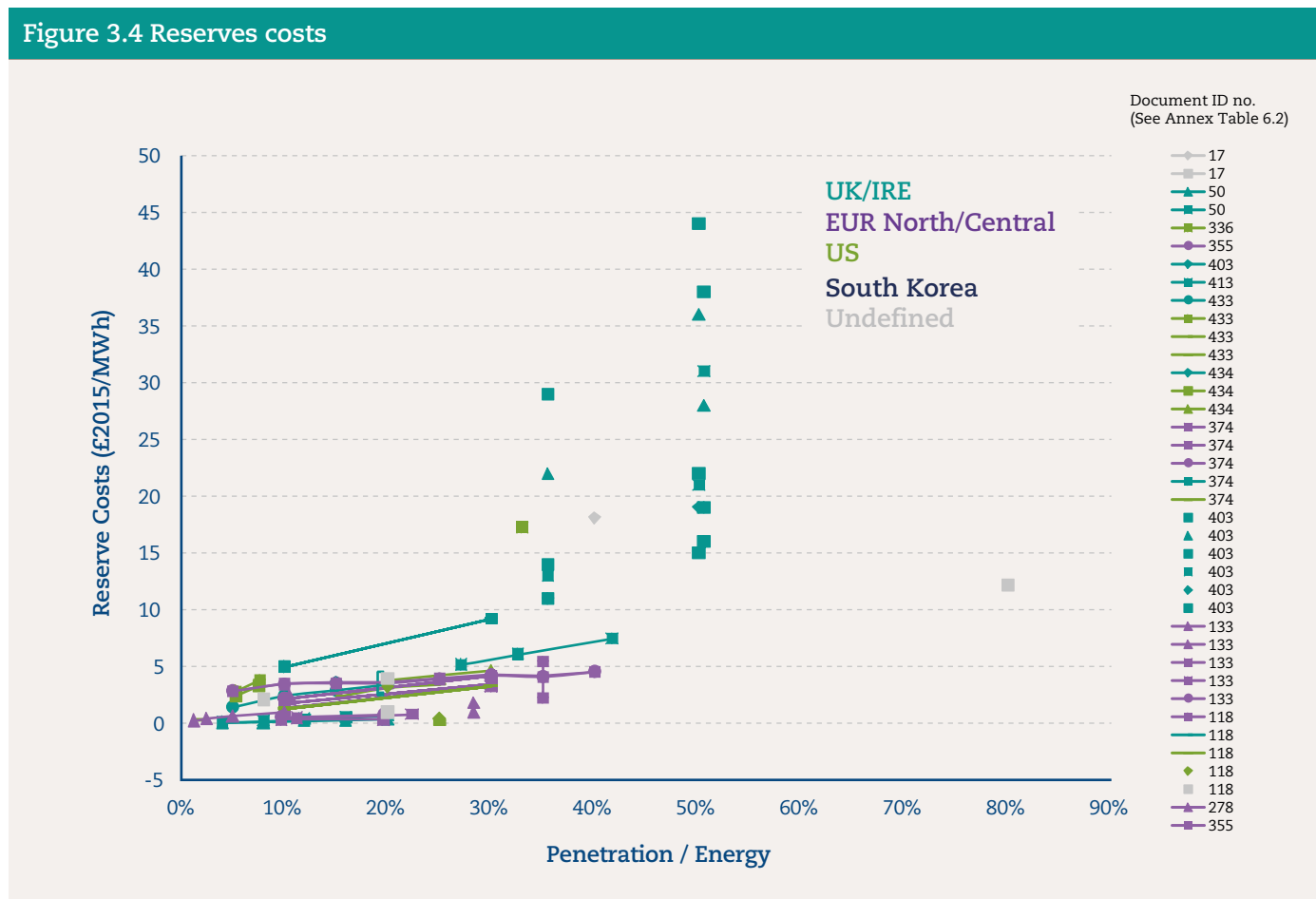
20 The outlying data for additional reserves shown in the 2006 UKERC report was taken from (E.ON Netz 2005). There was some uncertainty over what services the data represented (it may also have included an element of capacity provision), and the particular difficulties faced with the Eon Netz region – see page 38 of the 2006 UKERC report.

21 The findings from this very comprehensive study (dena 2011) are not included in the charts in this chapter because the results are not presented in a way which is directly comparable, and the costs are presented as either investment costs or annualised costs rather than per MWh.

Up to the 30% penetration level, additional reserve costs range between negligible values and a maximum of £5/MWh, albeit with one higher outlier, drawn from a study (NEA 2012) whose methodology was criticised in (Holttinen 2012) – see Section 3.3.2 below. This compares to a range for the 2006 data (excluding outliers) between negligible values and around £3.6/MWh (inflated to 2015 values). These findings are consistent with the range of values reported in (Hirth and Ziegenhagen 2015), although the authors of that study do go on to draw attention to the discrepancy between these modelled results and observed actual market prices of balancing services (in that observed prices show a much wider range and do not appear to be correlated with variable renewable penetration level). They suggest that this discrepancy is largely a function of market design rather than inaccuracy in the modelled results, which does reinforce the point that the efficient integration of variable renewable generation requires changes to both the physical characteristics of the electricity system and electricity markets²². The 2006 report found very little data for additional reserve costs beyond the 20% penetration level, and that

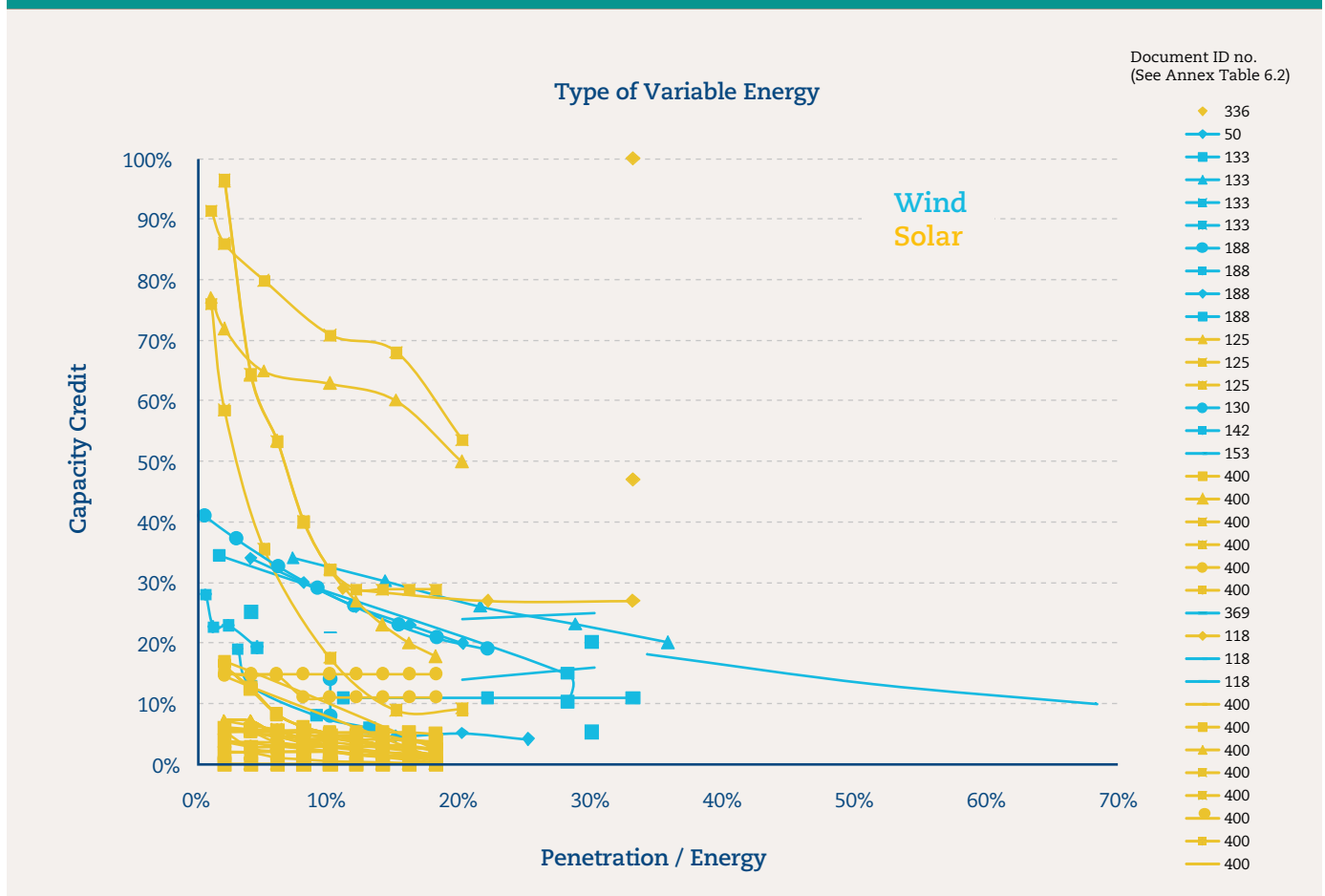
which did exist did not show costs above those at the 20% penetration level. The current project collated considerably more data relating to penetration levels above 20%, and shows a significant increase in forecast reserve costs by some analyses for penetration levels above 30%.

There are a cluster of results at around 35% and around 50% penetration that are drawn from a single study (Strbac et al. 2015). These reflect that study’s exploration of the impact of the assumed level of system flexibility on integration costs for wind and PV. The findings reinforce the key influence of flexibility, with reserve costs (taken from what are described as ‘balancing OPEX’ and ‘balancing CAPEX’ in the study) varying from a low of £11/MWh (for PV on a flexible system) to a high of £29/MWh (for wind on an inflexible system) at around a 35% penetration level. At around a 50% penetration level, costs vary from £15/MWh for PV on a flexible system to £44/MWh for wind on an inflexible system. The intermediate values from this study reflect what is described as a ‘semi-flexible’ system.



22 This message is echoed by many electricity system practitioners, for example in publications from the International Council on Large Electric Systems such as (CIGRE 2013).

Figure 3.6 Capacity credit values (renewable generation type)

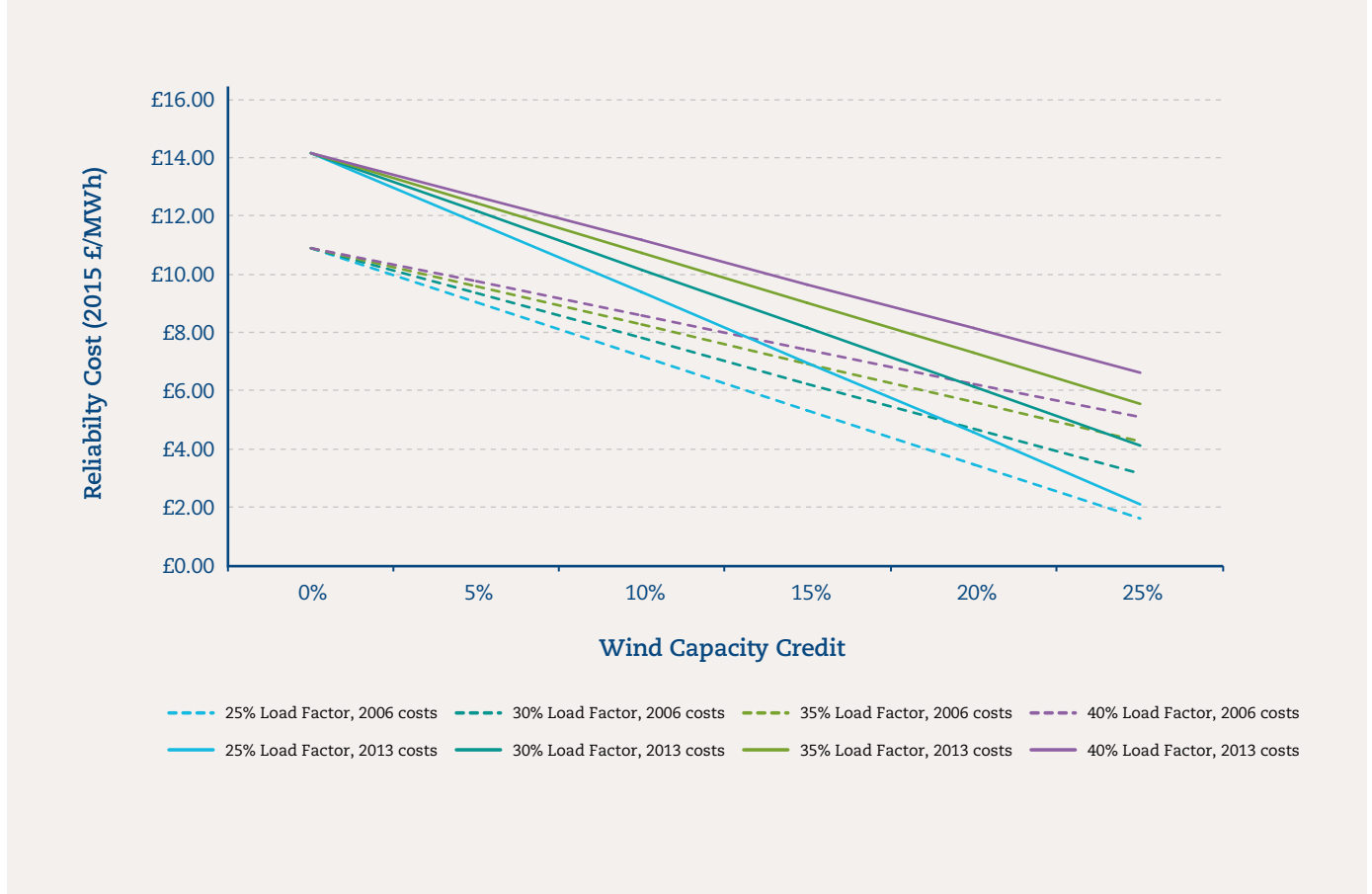


3.3.2 Capacity credit costs

The capacity credit costs data collated by the UKERC project team are shown in Figure 3.7. As explained in Chapter 2, these costs result from the need to have more installed capacity on the system than there would be without intermittent generators, because of the generally lower capacity credit of variable renewables (see above). Whilst the data are drawn from a relatively small number of studies, there are nevertheless a number of interesting observations to be made. Perhaps the most immediately striking are the negative costs shown for one data series. These relate to the costs associated with solar power in Greece and are the corollary of the very high capacity credit values referred to above and shown in Figures 3.5 and 3.6. The remaining data are drawn from the same analysis (also for solar PV but in other European countries) and show a range of costs up to a little under £15/MWh, which is roughly consistent with costs shown in Figure 3.8 below for wind plant if it were to have zero capacity credit (shown as the left-hand topmost data point). This is also consistent with the data for the higher penetration levels shown in Figure 3.7 below with costs generally not exceeding £15/MWh even at a greater than 50% penetration level. The data series which is above £15/MWh was drawn from a study (NEA 2012) which subsequently came under criticism (Holtinen 2012). The criticisms focused

on problems with the methodology used for estimating system adequacy (capacity) costs, on not using the most cost-effective technology in those adequacy cost calculations, a poor choice of reference for onshore wind grid costs, and on confusion over the allocation of those costs. At the 30% penetration level, most costs lie in the £4-£7/MWh range. However the data at these higher penetration levels is dominated by the (generally lower) results for the capacity credit costs of wind. Very little data was found for PV penetration levels beyond 20%. The outlying data at a 100% penetration level represents an analysis by (Soder and Amelin 2008) which made the assumption that all the thermal plants required to provide capacity adequacy are low capital cost open-cycle gas turbines (OCGT).

Figure 3.8 Updated capacity credit costs sensitivity analysis from 2006 UKERC report



3.4. Curtailment

Figure 3.9 below shows the findings collated for the level of energy curtailment, as reported in the evidence reviewed. As with the charts above, the penetration level is expressed as a percentage of annual electricity demand which is met by variable renewable generation. The level of curtailment is represented as a percentage of the annual electricity production from intermittent generation that cannot be accepted onto the system, relative to the volume of electricity from renewable generation which is actually used. The data is colour-coded by geographical country or region. As was described in Section 2.3.5 above, curtailment may become necessary where output from variable renewable generation cannot be accepted into the electricity system because of insufficient transmission grid capacity (i.e. a grid constraint), or where the volume of intermittent output at a given time would otherwise exceed total demand (net of the minimum level of conventional generation required to provide the full range of system services necessary for the operation of the grid).

The curtailment²³ data collected for the 2006 UKERC report was not considered at the time to be sufficiently comparable to allow presentation in chart form, and drew from a small number of analyses (a total of six studies, only three of which

used the most common measure of penetration level). However, it is worth noting that the report found that for penetration levels up to approximately 20%, curtailed electricity production ranged between zero and less than 7% for all but one of the studies. The sixth study suggested a higher curtailment level but had a very specific focus on existing grid constraints in northern Sweden.

The review carried out for the current project found considerably more data for curtailment than for the 2006 work, with approximately 250 data points captured in total, with the bulk of these (over 200) using the most common measure of penetration level, and drawn from more than 15 separate studies. Figure 3.9 shows that many analyses find that percentage curtailment levels are typically very small at the lower penetration levels considered and that they may remain so even as penetration levels rise, but that there is a marked non-linearity within some (but certainly not all) of the data series. This means that after a certain penetration level is reached, curtailment can sometimes rise steeply, although some analyses find that the relationship between intermittent generation penetration level and curtailment is much more linear. The findings also suggest that there is a considerable degree of variation in when the inflection point is reached, ranging from around 15% penetration to over 75%. Some

23 The 2006 report favoured the phrase 'energy spilling' but curtailment is more commonly used in more recent literature so it is this term that is used here.

studies are particularly optimistic concerning the likely scale of curtailment of variable renewable generation e.g. (EWIS 2010), although that analysis (which focusses on cross-border transmission within the European Union) acknowledges that the effect of internal (i.e. within member state) bottlenecks are excluded.

Care must also be taken when interpreting results from those studies which make particularly extreme assumptions over the nature of the system to which variable renewables are being added, and the findings from (Chang *et al.* 2013), denoted as ID 117 on Figure 3.9, make an interesting example in this regard. The analysis models the impact of very large variable renewable capacity additions, driven by a desire to achieve a (very high) predetermined percentage penetration level of a particular technology, but without making any changes to the remainder of the plant on the modelled system or any other actions that would normally be expected to facilitate an increased penetration of intermittent generation. The results suggest that beyond a certain point, adding more of the variable renewable capacity can make only a very marginal contribution to useful delivered energy because most of the output from the additional capacity is curtailed. However, the analysis still continues to add very large amounts of renewable capacity after this point and it is therefore possible to end up with a level of renewable capacity that is theoretically capable of supplying more than total annual demand, but much of this is curtailed as it is not available at the right times. Clearly, this is an extreme case and not one that would be economically rational to pursue.

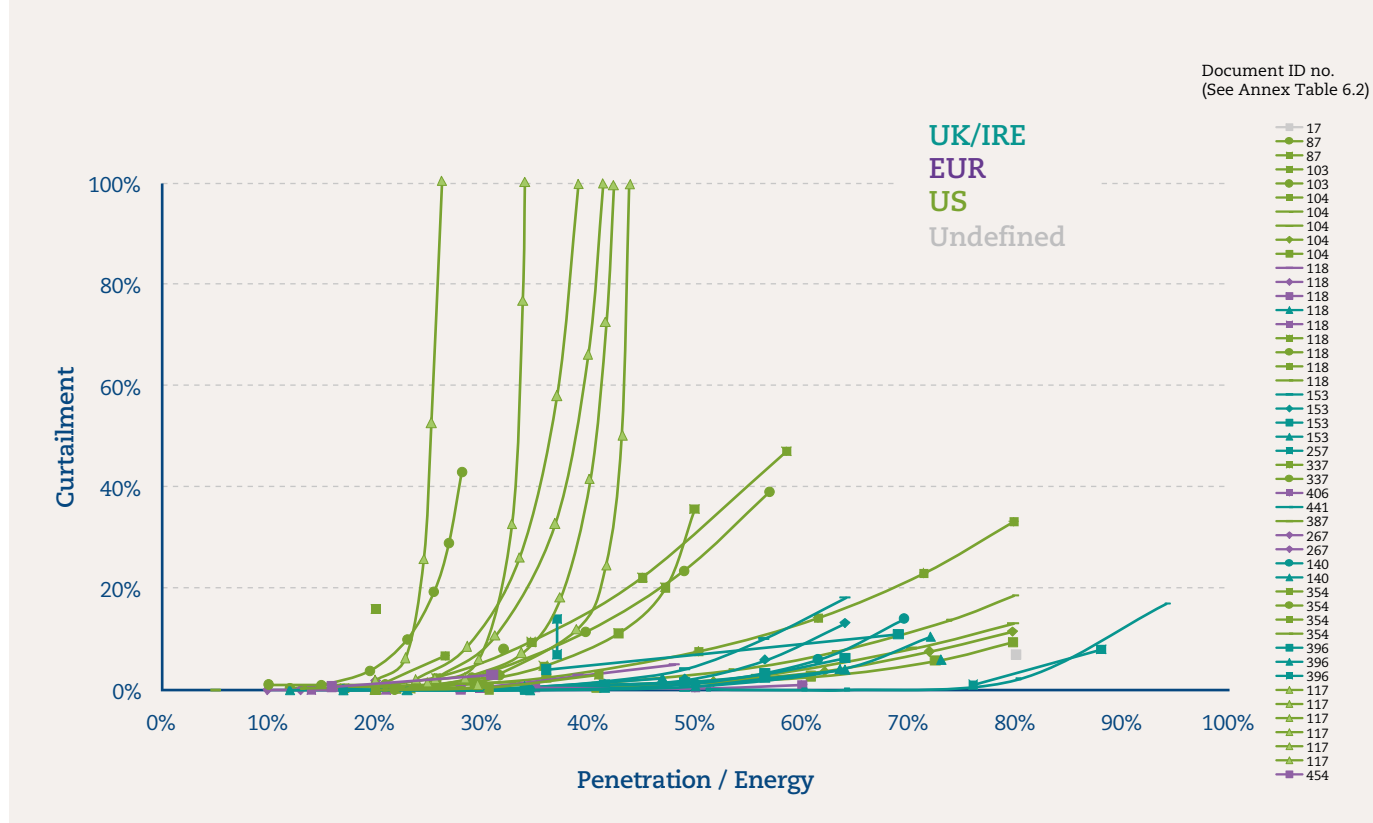
More conventionally, the degree of variation in the data reflects the fact that the circumstances under which energy may have to be curtailed are dependent on a range of system characteristics. These include the level of flexibility of the other generating plant on the system, with the point at which intermittent renewable generation capability is not fully utilised being lower on systems with a relatively high proportion of inflexible plant (Strbac *et al.* 2015). The degree of correlation between the renewable output and demand will also have a major impact on the threshold at which curtailment will occur, with the level being higher for those systems where high levels of renewable generation are positively correlated with periods of high demand (*ibid.*).

Transmission capacity will also influence curtailment. If renewable generation capacity is remote from demand and the transmission system has little spare capacity, the likelihood of transmission bottlenecks will be higher, and this may require that intermittent renewable generation is sometimes constrained off the system. This is supported by analyses which show that strengthening grid connections, and revising market arrangements to encourage more efficient use of network capacity, can reduce curtailment, even when installed renewable capacity is increasing (DeCesaro and Porter 2009). Other analyses, such as (Ault *et al.* 2007) draw attention to the considerable degree of trade-off between transmission costs and the costs incurred as a result of any curtailment due to insufficient transmission capacity.

The curtailment data shown in Figure 3.9 may therefore be due either to a surplus of intermittent generation across the system as whole²⁴, or transmission and distribution constraints. In general, curtailment due to an overall surplus of intermittent generation is less likely to happen at lower penetration levels whereas grid constraints may occur even at relatively low penetration levels. In respect of the latter there is a potential trade-off between the costs of curtailment (unused output whose marginal costs of generation are effectively zero) and the costs of transmission system reinforcements necessary to avoid such curtailment. From a system perspective, there may be a non-zero level of curtailment which minimises total costs, but achieving (or getting close to) this optimised state requires the right combination of market and regulatory incentives. The studies reviewed for this project that assessed curtailment levels generally did not convert their results into a cost per MWh, although curtailment would serve to increase costs per MWh for a renewable generator since the reduced load factor would mean that fixed costs are spread across fewer units of output. An alternative proxy for the cost of curtailment may be those other system costs that need to be incurred in order to reduce or eliminate curtailment of variable renewable output. The contention is that these additional system costs can then be compared to the implied costs of curtailment (in terms of lost output), so that the most cost-effective trade-off between these two sets of costs can be determined.

24 As explained in Chapter 2 this may happen well before total instantaneous intermittent output exceeds total instantaneous demand because of the operational requirements to maintain sufficient conventional plant running to ensure reliable operation of the electricity system.

Figure 3.9 Curtailment levels



3.5 Transmission and distribution network costs

Figure 3.10 below shows findings for the additional transmission and network costs associated with variable renewable generation. As with the charts above, the penetration level is expressed as a percentage of annual electricity demand which is met by variable renewable generation. Costs are shown on a per MWh basis, spread across total electricity generation from variable renewables. The data is colour-coded by country or geographical region.

The evidence review collated a total of over 300 data points for transmission and network costs across all penetration level measures, with approximately 250 of these able to be shown on Figure 3.10 because they use the most common penetration level measure. These data were drawn from six studies. The number of data points is masked to some extent by the relatively tight grouping of the data although there are a number of outliers. Perhaps the most striking of these is the negative cost data (albeit at low penetration levels) which is from an analysis of PV in Greece, and reflects the savings in distribution network costs that results from the close correlation between peak PV output and peak demand, and the distributed nature of PV which means it can be sited close to local demand, thereby reducing loads on the distribution network. The opposite outlier in terms of cost is from an analysis of PV in Germany where the absence of PV generation availability during peak demand periods means

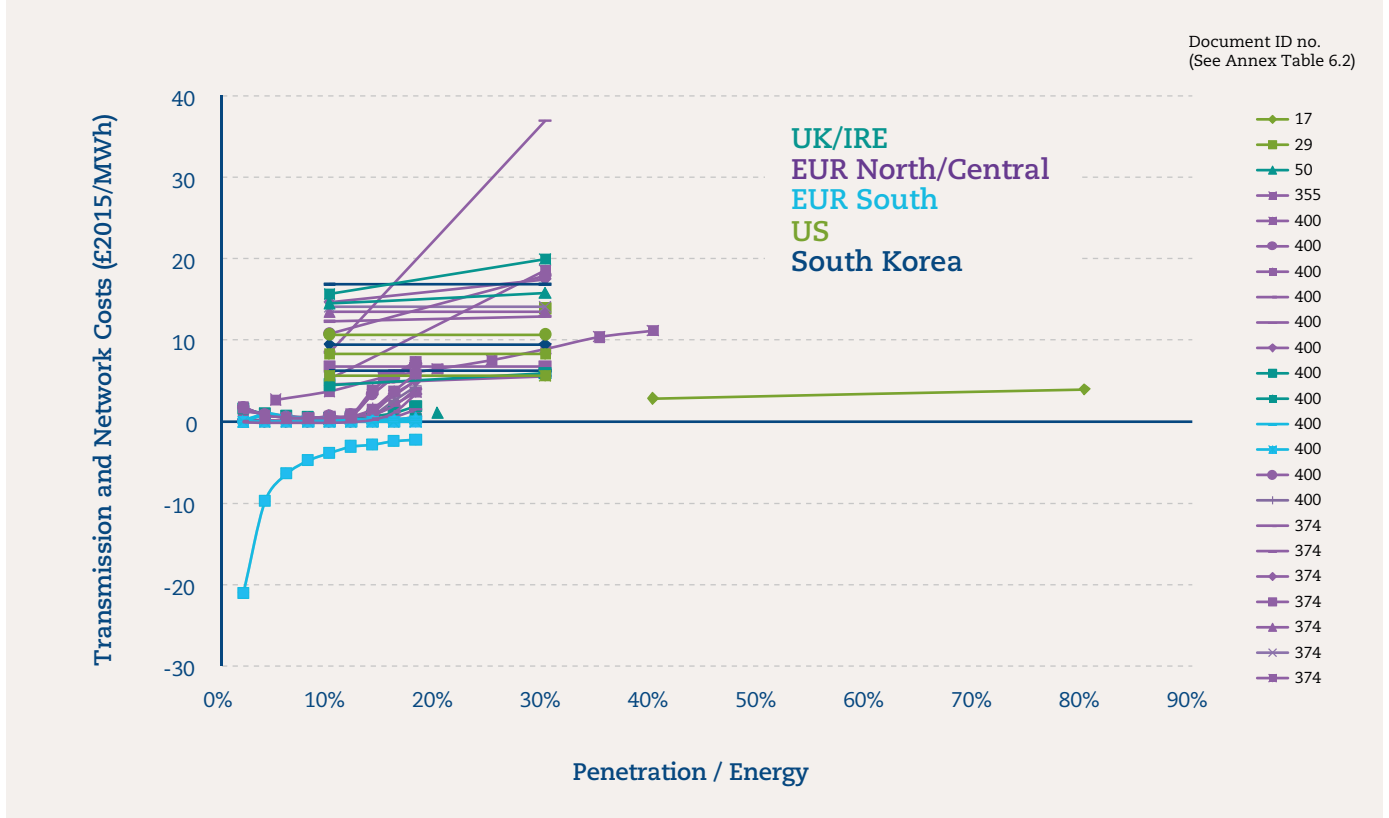
that costs are relatively high when penetration levels reach 30%, largely because of the network reinforcement costs required to accommodate the PV capacity. This analysis is also unusual in that it found that costs rise steeply with increasing penetration, whereas the majority of other findings suggest that the slope of the costs increase is much shallower. Some analysts, such as (Sijm 2014) for example, have suggested that this is because additional grid costs are more sensitive to the characteristics of the existing grid (such as the structure, layout, and relative location of generators and demand) than the penetration level of variable renewables. The third significant outlier shows very low costs even at very high penetration levels (up to 80%) for wind generation with compressed air storage, in a highly stylised US-based modelled system with a single (albeit relatively long) transmission line. Notwithstanding these outliers, the bulk of the data suggests that costs are in the range of £5-20/MWh for penetration levels up to 30%, with very little data for penetrations beyond this level. There is a grouping of very low costs (well below £5/MWh) up to a penetration level of around 15% although many of these are from an analysis which was focussed on distribution system costs.

Interpretation of the additional transmission and distribution costs associated with variable renewable generation does require care if those costs are to be appropriately compared to conventional generation. Any generation plant that is connected to a grid imposes some transmission costs, because any such plant needs physical connection to the electricity network. For example, much of the current GB transmission grid is a result of the desire during the post-Second World War decades to connect the main centres of demand to large coal-

fired power stations whose sites were typically selected on the twin requirements of ready access to the fuel source and cooling water. Renewable generators are constrained by the availability of the resource (and often by land-use limitations) and may not be located near to demand centres so may need significant investment in transmission capacity, but many new nuclear and carbon capture and storage plants are also likely to be location-constrained, and may also need new or substantially reinforced transmission capacity.

Whilst the 2006 UKERC report did not address the direct costs of extending the transmission system to accommodate new generation, it did nevertheless recognise that the results from integration studies that attempt to calculate total additional system costs of variable renewables are sensitive to assumptions over transmission network constraints and links to other networks, reinforcing the point made above concerning the trade-off between additional network costs and curtailment.

Figure 3.10 Transmission and network costs



3.6 Thermal plant efficiency losses and impact on fuel and emissions savings

As explained in Chapter 2, the conversion efficiency of thermal plant may reduce as a result of adding variable renewable generation. These losses may occur as a result of more frequent changes in the output of load-following plant, greater use of more flexible (but possibly less efficient) plant, and increased frequency of thermal plant start-up and shut down. These impacts may therefore manifest themselves in the form of increased emission of, for example, CO₂ and NO_x per MWh of output. It is important to note that these are not absolute increases in emissions. Rather they represent a reduction in emission savings relative to what those emissions would have been if each MWh from variable renewables could displace output from thermal plant with no impact on the conversion

efficiency or operation of those thermal plants.

Given that one of the primary functions of installing renewable generation is to reduce emissions from electricity production, it is not surprising that there are a large number of studies that analyse emissions reductions in absolute terms. However, the review found only a small number of studies which presented results on efficiency losses and their resultant impact on relative emissions savings. The previous UKERC work also found very few studies which specifically addressed efficiency losses. Findings that do deal with efficiency impacts are presented using several different penetration level metrics and a range of measures including percentage reduction in theoretical emissions savings, change in costs per MWh or unit of CO₂ saved, and change in volume of emissions per year. This variation in format prevents the aggregated reporting of findings in chart form. However, there are a number of interesting findings from individual studies and these are discussed below.

Several studies highlight the need to carry out emissions impacts analysis on a whole system basis. This is because emission reductions achieved by installing variable renewable generation will depend on the mix of the thermal plants that will vary their output to accommodate the varying output from renewables. This in turn will be a function of the modelling assumptions about plant characteristics, the nature of the renewable resource and demand profiles, and potentially also the design of the electricity market (because market design can influence what type of thermal plants are built and operated in the presence of intermittent generators). The complexity of the analysis is increased because there is both the lower conversion efficiency of thermal generation plant at various stable part-loaded states which is typically accounted for using published part-load efficiency data (Maddaloni *et al.* 2008), but also efficiency losses during transient periods when plant is ramping output (i.e. changing from one level of output to another). For a full representation of the impacts on costs, it is also necessary to take into account the negative impact on plant operating life associated with the increased frequency of the thermal stress of plant start-up and shutdown (Denny *et al.* 2006).

These reductions in thermal plant efficiency that result from part-loading and varying output may manifest as a partial flattening of the emissions savings curve as the penetration of variable renewable generation increases (Maddaloni *et al.* 2008). In other words, the marginal (but not absolute) emissions savings may decline as intermittent penetration level rises. Several studies that present findings show very small efficiency impacts. A study (Kling *et al.* 2008) that modelled the effects of wind generation on the Netherlands system concluded that efficiency impacts were small at lower penetration levels and that marginal emissions reduction benefits declined as penetration level rises²⁵. Another modelling study, of the effects of wind generation on the island of Ireland electricity system (Denny *et al.* 2006), found results for CO₂ and SO₂ emissions which are consistent with the findings from other studies in that efficiency impacts were found to increase as variable generation penetration level rises²⁶.

A major study (Lew *et al.* 2013) which simulated the operation of the western grid (covering western areas of the US, Canada and Mexico) concluded that impacts are very modest. This study found that at a 33% penetration level for variable renewables, CO₂, NO_x and SO₂ emissions savings were more than 95% of the maximum theoretical savings i.e. if there were no impacts on thermal plant. Similarly, the cost impacts of increased

thermal plant cycling were found to be very small, ranging up to approximately \$0.67/MWh (£0.4/MWh in 2015 GBP) when spread across total wind and solar generation. Other studies such as (Fripp 2011) that directly address efficiency reductions conclude that for a very large geographical region (over 500km across) with well distributed wind generation and gas-fired thermal plant, the impact on CO₂ emissions is that less than 6% of the theoretical maximum savings are not realised. The analysis by (Taylor and Tanton 2012) does not specifically model the thermal plant efficiency reductions that result from variable renewable generation but draws upon the work of (Fripp 2011) and others (Katzenstein and Apt 2009a, Katzenstein and Apt 2009b, Mills *et al.* 2009) to justify a proposed upper bound for realised fuel savings of 80-90% of the maximum theoretical savings. These results are consistent with the small number of relevant findings from the 2006 UKERC report, in which reductions in efficiency were found to range from a negligible level up to 7%.

Modelled results that suggest impacts are modest are backed up by analysis of actual impacts on real systems. For example, National Grid calculated actual CO₂ emissions reduction impacts of wind on the GB electricity system for the period April 2011 to September 2012, based on observed gas consumption by power stations during this period, relative to the measured electricity generation from those power stations (National Grid 2012). The analysis found that CO₂ reductions were between 0.017% and 0.14% less than the theoretical maximum (i.e. if there had been no reduction in gas to electricity conversion efficiency), with an average efficiency loss of 0.081% for the whole 18 month period.

The review revealed a small number of studies that argue that CO₂ savings from wind will be smaller than others envisage, with (Henney and Udo) for example suggesting in their 2012 paper that there is a substantial discrepancy between calculated CO₂ emission reductions based on 'static' conversion efficiency data and those based on analyses that measure actual fuel used. The authors of this paper go on to suggest that the static approach can overstate the achieved emission savings considerably, and that there can be a very wide range in efficiency impacts over time (the authors suggest that in the case of Ireland, the efficiency losses can vary between zero and 60%)²⁷. The analysis in (Tsagkaraki and Carollo 2016) also suggests that fuel efficiency impacts can be significant.

25 An interesting counter-intuitive result from this study was that adding electricity storage capacity to a system may increase CO₂ emissions under some circumstances. This was explained by the authors of this study as being a result of a combination of gas-to-coal substitution and storage energy conversion losses. Storage was found to be of benefit in decreasing CO₂ emissions only at very high wind penetration levels when it can reduce the volume of wind generation that would otherwise be curtailed. Comparable counter-intuitive results are found in (Houghton *et al.* 2016) which modelled the effects of international interconnectors in Europe. More interconnection was found to reduce wind curtailment but annual CO₂ emissions increased as coal-fired generation in the east displaced gas-fired generation in the west of Europe when wind resource availability was low.

26 This study found that in some circumstances, some types of emissions can actually rise in absolute terms – in this case the volume of NO_x emissions were found to increase because gas-fired plants began to operate at part-loaded states below the level at which NO_x-minimising operating practices are possible.

27 It should perhaps be noted that one of the authors of this paper declares that he has 'no vested interest other than a dislike of the visual impact of enormous on-shore windmills and a strong objection to the government incompetently wasting even more of people's money than it already does'.

The final point to bear in mind with regard to the cost implications of emissions savings is that these can only be properly assessed if emissions are also properly costed, for example by using a carbon price that fully reflects the environmental impacts of such emissions. Historically, CO₂ emissions have been significantly under-priced (where priced at all) (The World Bank 2015) which means that the value of emissions savings is not fully reflected in analyses which use market prices of CO₂. This also means that there is a risk that electricity market-based analyses of the type discussed in Section 3.8 below may undervalue output from variable renewable generation. The findings described above also reinforce the importance of considering the full system characteristics when assessing what fraction of theoretical fuel and emissions savings can be achieved in practice.

3.7 System Inertia

As was noted in Chapter 2, when UKERC reviewed the evidence of intermittency impacts for their 2006 report, the reduction in system inertia appeared to have received very little attention (although there was evidence of some recognition of the potential issues around this time (Abreu and Shahidehpour 2006)). The 2006 report made only a passing reference to inertia, and that was in the context of the approach to determining system reserve requirements. Since then, the potential impact of reduced system inertia has received more attention, particularly in regard to smaller island systems with significant instantaneous penetrations of wind or solar power and limited interconnection with other electricity systems. In some of these cases the system operator has imposed a limit on System Non-Synchronous Penetration (SNSP). Examples include a limit of 50% for the Island of Ireland (see below) and 30% for some of the French Island systems (Delille et al. 2012). There is also evidence that increases in SNSP can lead to noticeable frequency fluctuations across a control area. Examples include Ireland (caused by short circuits in the west of country where the wind generation predominantly is, whilst the major demand centres are in the east) and in GB, which has experienced situations where the Rate of Change of Frequency (ROCOF) has varied considerably between geographical areas.

Analysis by (ECOFYS et al. 2010) highlights the impact of high wind penetrations on 'frequency stability after loss of generation, and frequency as well as transient stability after severe network faults', and goes on to propose a metric of 'inertialess penetration' and suggests limits on this of 50-80% of instantaneous power, even assuming significant system adaptations. These values appear to be broadly consistent with the findings in (EirGrid and SONI 2011) which concluded that the all-Ireland system could be securely managed with a SNSP of 50%, given current system characteristics and capabilities and that a SNSP of 75% would be achievable with changes to the system infrastructure and operational policies.

The importance of a system's degree of interconnection with other electricity systems is reinforced by evidence from those countries which have achieved renewable generation instantaneous penetration levels of close to 100%, with a particular striking example being the case of Germany which during one day in May 2016 achieved 45.5GW of renewable generation against a total demand of 45.8GW. During the period in question, conventional thermal generation was still at 7.7GW so total generation exceeded demand by more than 16%, implying that a significant proportion of generation was exported through cross-border connections²⁸ (Shankleman 2016).

Much of the literature on system inertia focusses on the technical challenges²⁹ rather than the costs, and neither technical impacts or costs (where considered) are presented in a way which permits aggregated presentation in either chart or tabular form. Some analysts have suggested that the level of non-synchronous generation curtailment may give an indication or proxy for the cost of maintaining system inertia. However, there are several confounding factors which would make such an analysis problematic, not least that such curtailment may be due to grid constraints rather than ensuring sufficient system inertia. A number of analyses that consider the economic aspects do however draw attention to the current lack of market incentives to provide inertia (Ela et al. 2014a, Ela et al. 2014b). This lack of incentives is largely because inertia is an inherent characteristic of large synchronous generators (i.e. conventional thermal plant). When such plant dominates electricity production there is no need for plant operators to be explicitly incentivised to deliver inertia to the system.

An increasingly significant area of analysis concerns the extent to which variable renewable generation may be able to provide so-called synthetic or virtual inertia to a system. There is considerable inertia in the rotating mass of wind turbines, with some studies suggesting that the theoretically available inertia is as much as a conventional synchronous generator of the same rated power (Zeni et al. 2013), albeit harnessing this requires additional features on wind turbine power conversion sub-systems and controls (Delille et al. 2012). This is supported by findings from the very detailed analysis in (EirGrid and SONI 2016) which suggest that synthetic inertia from wind turbines may offer a solution to maintaining frequency changes within acceptable limits, with the caveat that the findings are very sensitive to the characteristics of the devices which might provide this service. Recognition of these concerns has led some analyses to focus instead on the use of very fast responding other forms of storage to provide frequency response services (Delille et al. 2012).

Whilst it appears that reduced system inertia will become an increasingly important issue, at least for relatively isolated electricity systems with significant penetrations of variable non-synchronous generation, the evidence suggests that it is likely to only become significant at substantial penetrations (i.e. greater than 50% on an instantaneous³⁰ basis) of variable renewables.

28 It is also important to bear in mind that the German electricity system is part of the same synchronous area as neighbouring countries which assists with the management of the reduced inertia of the German system at times of high levels of renewable generation.

29 See for example (Ashton et al. 2015).

30 The relationship between instantaneous power and annual energy penetrations can vary depending on technology and nature of the resource availability. A large but short lived level of instantaneous power penetration may not result in high level of penetration on an annual energy basis.

3.8 Electricity market impacts

In recent years there has been considerable attention paid to the impacts of variable renewable generation on electricity markets. As explained in Chapter 2, these impacts can be grouped into two broad categories. The first is the merit order or utilisation effect on conventional generators, where those generators find that the introduction of zero marginal cost variable renewables means that they are moved lower down the merit order³¹. Conventional generators may operate at significantly lower load factors than would be the case without renewable generation on the system, which may have important implications for the ability of such plants to cover their full long-term costs (Poyry 2009, Poyry 2011b, Phillips 2012). The second category of impact is concerned with the extent to which the market value of renewable generation is affected by the variable nature of the resource and the fact that it can be locationally constrained (because it must be sited where the resource is which may not be where the main centres of demand are) (Borenstein 2011, Joskow 2011).

Some analysts have concluded that the market value of variable renewable generation can fall quite dramatically with increasing penetration levels. For example Hirth, using an electricity market model, calculated that the market value of wind output might vary from 110% of average wholesale power prices at very low penetration levels to between 50% and 80% of average wholesale power prices at a 30% penetration level (Hirth 2013). The same analysis found that the reducing market value was even more pronounced for solar PV generation. Hirth ascribes this reducing market value to a combination of three factors: i) the temporal mismatch between variable renewable generation and system demand (described as 'profile costs'), ii) the uncertainty over whether the forecast output from variable renewable generation will actually be achieved for any given period, due to forecasting errors (described as 'balancing costs'), and iii) the additional transmission costs of connecting possibly remotely located renewable generators to the electricity system (described as 'grid-related costs'). The approach described in (Mills and Wiser 2013) is similar in some respects to this in that it aimed to decompose the 'marginal economic value' of variable renewable generation into its constituent parts. This analysis found that the total marginal economic value for wind in California declined from \$67/MWh (£41.2/MWh in 2015 GBP) at a notional zero penetration level to \$40/MWh (£24.6/MWh in 2015 GBP) for wind at a 40% penetration level. For solar PV (again, in California), marginal economic value reduced from \$89/MWh (£54.8/MWh in 2015 GBP) at a notional zero penetration level to \$25/MWh (£15.4/MWh in 2015 GBP) at a 30% penetration level.

The Hirth analysis recognises that the costs which it described may not actually materialise as such for a variable renewable operator (because the party that bears these cost is a function of the market design), and that the impacts can be mitigated to some extent by system adaptation over time. In this latter respect, Hirth finds that the market value of wind is between 40% and 70% of average wholesale power prices in the medium term, increasing to between 50% and 80% once long-term adaptations are accounted for.

The analysis presented in (Green and Vasilakos 2010) found that a high penetration of wind power on the GB electricity market would increase the volatility of electricity prices, leading to annual variability in revenues. Whilst the variability of revenues would affect all generators, wind generators would, on average, receive approximately 8% less than the baseload electricity price. This was found to be due to the correlation between periods of higher wind output and lower wholesale electricity prices, which adversely affects average revenue from wind plants. However, it is important to bear in mind that this is a function of the assumptions made for how wind output participates in, and is remunerated by, the wholesale market. The analysis was based on a modelled total of approximately 30GW of wind installed (a mix of onshore and offshore) out of a total system capacity of almost 100GW.

These results from modelling studies are backed up by empirical evidence from those studies which have examined actual prices secured by variable renewable generators. One such study, (Klinge Jacobsen and Zvingilaite 2010) found that wind generators in Denmark received between €3.6 and €5.2/MWh (£3.3-£4.8/MWh in 2015 GBP) less than the average electricity market price during the period analysed. The authors of this study make it clear that a significant cause of this is the prevalence of electricity production from Combined Heat and Power (CHP) plants whose operation is led in large part by heat demand, and also stress the importance of increasing system flexibility in order to minimise the market impacts of intermittent generation.

Relating these electricity market impacts back to the findings discussed earlier in this chapter, it could be argued that these market impact analyses use the lower market value of output from variable renewable generation as a proxy for the costs of intermittency. However, care must be taken when interpreting the results because using market prices in this way will only uncover the true economic cost (or something usefully close to it) if the electricity market in question is structured in such a way as to allow those costs to be accurately revealed. Overall though, the evidence suggests that there can be significant impacts on the load factors of the remaining thermal plant on the system and that the market value of output from intermittent generators declines as penetration levels rise.

31 As explained in (Gross et al. 2007), strictly speaking, there is no 'merit order' in the GB electricity market since generators are free to trade as they see fit within the constraints of their operating characteristics and the regulatory framework. The term is however useful shorthand to describe what typically happens in the market, which is that very low variable cost plant will operate whenever it is physically able to do so and progressively higher variable cost plant will operate to follow diurnal and seasonal demand variation.

3.9 Allocation of costs and the value of flexibility

The debate over whether traditional electricity cost metrics such as the levelised cost of electricity (LCOE) should attempt to capture the additional system-wide costs which a particular plant or generation type imposes on an electricity system is not new. However, the increasing share of electricity provided by intermittent generators has meant that there is an increased focus on this issue. It is clear from the evidence reviewed that different studies can have very different conceptual framings of the problem and methodological approaches to analysing impacts and associated costs, and that there are considerable challenges in determining the most appropriate techniques for calculating and representing those costs (Milligan *et al.* 2011).

Some analyses take the position (sometimes explicitly but perhaps more often implicitly) that a form of ‘enhanced LCOE’ can be used to reflect the costs of integrating variable renewable generation. Traditionally, plant level analyses using cost measures such as LCOE have drawn a notional boundary at the point where a plant is connected to the wider electricity grid, and ignored any costs which a generator may impose on the grid. In recognition of this, Ueckerdt *et al.* (2013) propose a new metric of ‘system LCOE’ that is designed to capture technology-specific generation costs and the system integration costs that should be associated with that technology. Their modelled results for wind power in Europe show how the ‘system LCOE’ is calculated to rise as the penetration level increases. The authors acknowledge the considerable complexity of isolating the technology-specific integration costs. They also make the point that they expect integration costs per MWh will be lower in the longer term as power systems adapt to high penetrations of renewables, reinforcing the observation made in (Hirth 2013), and those made by the analyses discussed below.

A potential concern with the ‘enhanced levelised cost’ approach is that it masks the fact that whilst individual variable renewable energy plants may in reality impose different system costs, similar plants will nevertheless be assigned similar enhanced levelised costs. This stems from the fact that the approach implicitly treats similar variable renewable plants as an homogenous fleet, which may be acceptable if the purpose of the exercise is to gain a broad-brush understanding of how the ‘full’ costs of intermittent plants compare to the alternatives, but is of much less value if the purpose is to compare one project with another.

The alternative to the various types of ‘enhanced LCOE’ is the ‘total system cost’ approach adopted in (Druce *et al.* 2015, Strbac *et al.* 2015), and which is also supported by several other analyses such as (Agora Energiewende 2015) and (Holtinen *et al.* 2016) which advocate a similar cost scenario approach. These analyses also make the important point that electricity systems are not static and change over time, and that this affects the costs associated with integrating variable renewables. This point links to one made in (IEA 2014) which emphasises the need for power systems to be transformed if the integration costs of variable renewable generation are to be minimised, and also recommends that integration costs should be assessed at the system level. The Boston and Thomas (2015)³² analysis is another example where results are presented in terms of annualised total system costs, and this study goes on to draw the conclusion that assessing electricity generation costs (whatever the technology) using the LCOE approach is no longer helpful since costs must be assigned at the system level, and LCOE ignores non-energy services (such as inertia) and the grid mix influences the value of those services. Earlier work, also by the ERP, raised the concern that some other analyses may have underplayed the challenges of integrating variable renewables at very high penetration levels (Radcliffe 2012). Nevertheless, these total system cost approaches have also been used to apportion and calculate integration costs on a £/MWh basis such as in (Radov *et al.* 2016).

One of the key arguments used some by analysts who advocate the total system cost approach is that it is better able to incorporate (and value) the impact of system flexibility. This is particularly important because a strong message that comes out of many of the analyses reviewed by the UKERC project team is that the costs of integrating variable renewable generation into an electricity system depend heavily on the flexibility of the system to which it is being added. The UK-focussed analysis in Strbac *et al.* (2015) stresses that more flexible systems have much reduced (‘an order of magnitude’ page i) system costs. The ‘policy implications’ complement to this report (Druce *et al.* 2015) goes on to conclude that integration costs are material and argues that renewables which benefit from support should be exposed to market price signals that reflect the full costs of integration (which the authors of the report argue is not the case at the moment).

However, since the reality is that electricity systems are in transition, the incremental representation of costs (which is what the ‘enhanced LCOE’ approach is) can still be useful because it can tell us what the costs may be during the transition, whereas the long-term ‘whole system’ approach may tell us which technology and infrastructure mix may give the most cost-effective long-term (i.e. post-transition) solution to a particular set of policy goals.

32 A commentary on the ERP analysis in (Bell and Hawker 2016) goes on to draw attention to the significant degree of uncertainty over the absolute costs of different power generation technologies. These uncertainties may outweigh those around integration costs, such that the ‘optimal’ generation mix may be more sensitive to the underlying LCOE values than the costs of integration.

4. Summary and conclusions



4.1 Findings

This report set out to provide an update to the previous UKERC analysis of the costs and impacts of intermittency, to answer the question:

What new evidence has come to light since UKERC reviewed the costs and impacts of intermittency in 2006 and what does the available evidence now suggest about the costs and impacts of intermittent generation (including relatively high penetrations of 20% and above)?

It is clear that the number of analyses of the implications of adding variable renewable generation to an electricity system has increased substantially in the last decade, and this is reflected in the quantitative and qualitative evidence reviewed by the TPA research team during this project. This reflects the substantial increase in aspirations for renewable generation in many countries and regions, and these aspirations, combined with dramatic cost reductions for some technologies, have also prompted increased interest in the effects of particular technologies such as solar PV that were not previously considered for large-scale implementation in some regions.

The quantitative data for some impacts lend themselves more readily to relatively straightforward comparison than others, despite ongoing controversy over a range of relevant issues, both methodological and empirical. These impacts are: the additional reserve requirements and costs, capacity credit and costs, curtailment, and (perhaps to a lesser extent) the transmission and network costs associated with intermittent generation capacity. The data for the other impacts considered in this report i.e. thermal generator efficiency and emissions savings, system inertia, and electricity market impacts are less amenable to consolidation and direct comparison. This summary section deals in turn with the former group of impacts and then the latter. As is the case for the preceding chapters, the definition of the penetration level used below is the percentage share of annual electricity demand that is met by variable renewables, unless another measure is specifically identified.

Reserve requirements and costs

Introducing variable renewable generation to an electricity system would normally be expected to increase the amount of flexible, dispatchable generation capacity that must be held in reserve to cope with short-term fluctuations in output that result from e.g. varying wind speeds or solar insolation levels. Care must be taken when comparing results between analyses of the required level of reserves because the term is often used to cover a range of different types of actual reserve services which may schedule and operate over a range of timescales. The time horizon for scheduling reserves is of particular importance, because forecast accuracy improves greatly when reserve allocation is undertaken close to real time. Nevertheless, most analyses conclude that the additional cost of these reserves remain relatively modest, at least up to a 30% variable

renewable penetration level, with the majority of results being £5/MWh or less, with a small number of outliers. Above this penetration level, the number of studies is much smaller and estimates of the additional costs of reserves exhibit a much wider range, varying by a factor of three at the same penetration level. The data for very high variable renewable penetration levels such as 50% suggests costs between £15 and £45/MWh, with the lower values being based on integrating intermittent renewables into a flexible electricity system and the higher values resulting from assumptions of relatively inflexible systems. In all cases it is important to emphasise that high cost outliers often make assumptions designed to test extreme conditions (such as a particularly inflexible system).

Capacity credit and costs

Capacity credit is a measure of how much conventional plant can be replaced by a given capacity of variable renewable generation whilst still maintaining the ability of the electricity system to meet peak demand. The findings for capacity credit values suggest that capacity credit declines as variable renewable penetration levels rise, with values up to mid-20s percent for penetration levels up to 30% for wind generation in countries/regions with relatively good wind resources such as the UK. There is considerable variation in capacity credit data, depending on the country or region and the technology being analysed, reflecting the fact that the extent of correlation between the diurnal and seasonal profile of intermittent generation and peak demand periods is a key determinant of the extent to which such generation capacity can replace existing conventional generation capacity. Generally, both the upper and lower outlying data reflect findings for solar power whereas results for wind power are much more closely spread.

Estimates of the cost implications of the generally lower capacity credit of variable renewables relative to conventional generation would be expected to be primarily dependant on a combination of the derived capacity credit values (in percentage terms) and the assumptions that are made regarding the costs of the conventional plant which is expected to compensate for the lower capacity credit of intermittent generators. The findings from the studies reviewed by the project team suggest that at a 30% penetration level, where results from wind-based analyses dominate, most estimates are in a range between £4 and £7/MWh, with some outliers. All except two data points of the entire data set lie below the £15/MWh level, even as penetration levels rise to 50%. These findings are supported by the project team's own calculations based on estimates of conventional plant cost in a UK context (in this case CCGT) which suggest that costs will lie in the range between around £4 and £8/MWh at an assumed 20% capacity credit, between £9 and £11/MWh at a 10% capacity credit level, reaching a peak of less than £15/MWh even if the capacity credit of the variable renewable plant is assumed to be zero.

Curtailement

The findings for the proportion of variable renewable output that cannot be accommodated on an electricity system (meaning that the output from some renewable generators may need to be curtailed even though the renewable resource is available) suggest that the level of curtailment is generally very low at low penetration levels. The evidence suggests that curtailment can remain at a low level even at very high penetrations of intermittent renewables but that the point at which curtailment becomes very significant can vary dramatically, with some analyses finding that the inflection point to be as low as a 15% penetration and others findings that the inflection point will not be reached until there is over a 75% penetration of variable renewable generation. Broadly, the findings for relatively early curtailment are from studies focussed on US electricity systems, with UK and European analyses suggesting that curtailment levels are very low until over 50% of electricity is supplied from variable renewables. A further key point to bear in mind is that some level of curtailment may be both economically rational and sensible from a system operation perspective – so, in isolation, a degree of curtailment is not necessarily an indicator of the unsuitability of any particular form of variable renewable generation. The evidence on curtailment levels also contained a particularly good example of where an analysis has produced a marked outlier result because of very extreme input assumptions. This reinforces the general point that great care should be taken with data that results from extreme assumptions or model runs that are perhaps best seen as boundary-exploring experiments rather than as indicators of what may happen under any plausible set of real conditions.

Transmission and network costs

For the transmission and network costs associated with variable renewable penetration levels up to 30%, the evidence suggests that costs are in the range of £5–£20/MWh. Furthermore, these costs do not appear to rise sharply as penetration increases up to this level, with typically significantly more variation between studies (or different scenarios within the same study) than there is between different penetration levels within a study or scenario. This suggests that these costs are largely sensitive to the nature of the system to which the variable renewable generation is being added rather than the share of total generation which is being contributed by variable renewables. Considerable caution should also be used if interpreting these values as being wholly additive to other integration costs, in part because of the trade-off with the curtailment impacts described above, but also because transmission infrastructure, once built, confers benefits on the whole system and so allocating the full costs to variable renewable generators alone may be misleading. Very little data was found for penetration levels above 30%.

Thermal plant efficiency and emissions

Our findings on the impact of variable renewable generation on the conversion efficiency of thermal plant and the impact on CO₂ and other emissions do not lend themselves to ready comparison between analyses, due to the range of measures and metrics used. However, the majority of those studies that address these impacts typically find that they are very small at

low penetration levels, and remain relatively small (typically less than 10% of theoretical maximum emissions savings) even as penetration levels rise. Impacts are often found to be sensitive to the characteristics of the system to which variable renewable generation is being added. Although this general sensitivity is broadly consistent with findings from several of the other impacts discussed above, efficiency and emission impacts are particularly dependant on the assumptions over the mix and operating characteristics of the thermal (and/or hydro) plant whose output is being varied to accommodate intermittent renewable generation, and this sensitivity can give rise to outlier results in some circumstances.

System inertia

Analyses of the impact of reducing system inertia resulting from adding variable renewable generation (and so replacing some synchronous plant that would otherwise be providing inertia) have to date tended to focus on the technical challenges that this may pose, rather than assessing any aggregated or direct monetary impact. Reduced system inertia is clearly an important issue, particularly for relatively isolated electricity systems with significant penetration of variable non-synchronous generation. Of those studies that do address this issue, the typical conclusion is that it is likely to only become significant at high penetrations of variable renewables i.e. greater than 50% on an instantaneous basis (although it should be recognised that some systems have already reached this level on occasion). Nevertheless, the analyses which consider penetration levels above 50% do generally conclude that even at these very high penetration levels, sufficient inertia-like resilience could be provided, typically through a combination of very fast response frequency control systems and synthetic inertia.

Electricity markets

Those analyses that consider the effect on electricity markets of variable renewable generation generally find that there are significant impacts on the load factors of the remaining thermal plant on the system and that the economic value of output from intermittent generators declines as penetration levels rise. Some of these studies have suggested that this reduction in economic value can be very significant at high penetration levels. A degree of caution is required in interpreting these findings to understand whether they are the result of assumptions over the electricity market design and characteristics and whether they are an accurate reflection of the true economic value of such output. In theory at least, these market impacts should represent the corollary of the physical impacts described above, but the extent to which the difference between the value of intermittent generation and the value of conventional generation can be seen as a useful proxy for the actual integration costs associated with variable renewables is, to large extent, a function of market design. Nevertheless, the potential for market impacts is real, and this suggests that this is an area that will require careful management and market adjustments as the penetration of variable renewable generation increases.

4.2 Methodological and conceptual differences

The ‘traditional’ approach to the representation of the additional system costs imposed by intermittent generators can be broadly categorised as the ‘enhanced LCOE’ approach. This method seeks to determine the total additional costs which a particular level of intermittent generation will impose, and converts that cost into per MWh value by apportioning it over the expected output from the intermittent generation. If desired, that MWh cost can then be added onto the base LCOE figure so that comparisons can be made between technologies which may have both different underlying LCOE and system integration costs. Some analysts describe this as ‘system LCOE’ since it is intended to capture technology-specific generation costs and the system integration costs that should be associated with that technology.

A variation of this approach starts with a ‘system price’ for each unit of electricity generated and then subtracts the costs which intermittent generators should bear as a result of their operating and location characteristics (which could also be described as revenue reductions). This is based on the premise that the market value of the output from an electricity generator can vary considerably depending on when that output is produced. Analyses that favour this approach typically argue that output from intermittent generators may be overvalued by traditional LCOE analyses when compared to dispatchable technologies, if there is a mismatch between the availability of the variable resource and typical demand peaks.

There is also evidence that as variable renewable penetration levels rise, the concept of LCOE and representing impacts in additional costs per MWh is no longer a useful approach for comparing between generation technology options (despite being still very widely used, as the findings described above show). Instead, the focus should be on assessing how different technologies can contribute to minimising total system costs, to reflect the fact that electricity systems need a range of services, not just units of electricity and intermittent generators generally tend to be consumers of those services rather than providers. Such analyses typically use some form of cost-minimising electricity system simulation model to assess the relative costs of different future systems, with results normally presented as total annualised system costs relative to an assumed baseline or counterfactual. Whilst the results from such exercises do not lend themselves to ready comparison with the LCOE-based approaches discussed above, their supporters argue that they offer a more complete assessment of true system costs. Lending weight to this argument is the fact that system costs are not static, and if modelling simply internalises contemporary system costs and allocates these to variable renewable generation then it cannot reflect the system re-optimisation and system transformations that will be required if the additional system costs imposed by variable renewables are to be minimised. A further argument in favour of the ‘whole system’ approach is that there is the potential for considerable overlap between cost categories, trade-offs between apparently separate costs, and the possibility for costs to manifest themselves

through different routes, all of which means that individual costs are not directly additive.

However, in practice, both the ‘enhanced LCOE’ and ‘full system cost’ approaches can provide valuable insights, with the former being particularly useful in understanding costs during the transition to systems with a very high penetration of variable renewable generation, and the latter being particularly useful in understanding the long-term costs of what are likely to be highly adapted electricity systems.

4.3 The value of flexibility

Any grid-connected electricity generator will impose costs on the system to which it is connected, even if those costs are simply to cover the physical connection. The additional system costs created by a particular generator or technology type must be borne regardless of whether those costs are attributed to the generator or not, but in the past when the large majority of electricity was supplied from conventional thermal generators with a broadly complementary range of operating characteristics, this was a largely uncontentious area. What is changing now is that the increasing share of electricity that is supplied from variable renewable sources, and policy aspirations for very large contributions from renewables in the medium and long-term, are bringing the additional system costs which variable renewable generators impose into sharper focus.

A very clear message from the majority of the evidence reviewed is that those additional costs will be minimised if electricity systems are adapted to facilitate the integration of variable renewable generation. This adaptation includes changes to both the technical and economic characteristics of electricity generating plant, potential contributions from flexible demand, storage and increased interconnection capacity, as well as changes to system operation, regulatory frameworks and the design of electricity markets.

4.4 Final remarks

Almost all analyses find that the costs of integrating variable renewable generation into an electricity system will rise as the share of total supply from those sources increases, and the costs of the conventional thermal plant that would normally be expected to facilitate that integration have also risen considerably in the last decade. However, these cost increases for conventional plant have been mirrored by significant (in some cases remarkable) cost reductions for variable renewable generation technologies. Whilst these cost reductions are not the focus of this report, it is important to bear in mind that they do have a very beneficial impact on the total costs of providing reliable electricity supply with a large share of variable renewables. When discussing costs, it is also important not to lose sight of the benefits that renewable generation can bring, or indeed the external costs that other forms of electricity generation can impose on society.

The very substantial body of evidence on the impact of variable renewables on electricity system reserve requirements and capacity adequacy have been joined in the last decade by increased attention to issues such as curtailment, transmission and distribution system impacts, emissions savings, system inertia and electricity market impacts. Taken together, the full range of impacts add weight to the message that electricity systems and markets need to adapt and be re-optimised to incorporate large proportions of variable renewable generation most efficiently. There is already evidence that this adaptation process is underway in many countries and regions. In the UK for example the Electricity Balancing Significant Code Review and the GB System Operator are seeking to encourage and procure additional and innovative system balancing services. It should also be noted that the current GB system has already incorporated a significant contribution from variable renewable generation whilst maintaining reliability, and that balancing costs to date have proved to be a very small component of total electricity supply costs.

One of the key messages from the 2006 UKERC report was that integration costs depend on the technical and economic characteristics of the system to which renewable generation is being added. This message is strongly reinforced by the evidence reviewed for this project, and in particular that costs are very sensitive to the flexibility of the system to which variable renewable generation is added, with estimates of costs often being dramatically lower for flexible systems. Perhaps the key challenge facing policymakers, regulators and markets is to ensure delivery of the system re-optimisation required to successfully integrate variable renewables whilst minimising costs.

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ZHU, S., ZHANG, Y. & CHOWDHURY, A. A. 2012. Capacity Credit of Wind Generation Based on Minimum Resource Adequacy Procurement. *IEEE Transactions on Industry Applications*, 48, 730-735.

6. Annex

A large, light blue, stylized number '6' is centered on the page. The number is composed of thick, rounded strokes. The top curve of the '6' is slightly open on the right side. The overall design is clean and modern, matching the blue color scheme of the document.

The systematic review process

A systematic review protocol typically provides a rationale for the choice of sources and lists the main databases, bibliographies, catalogues, personal contacts and other sources that are to be searched. It will also specify the years to be covered and the search criteria that will be used. For this project, the research team adopted an approach that was consistent with the available resources and timescale.

The literature that is relevant to the intermittency debate was drawn from:

- Peer reviewed academic journals in electrical engineering, economics and energy policy
- Working papers on electrical engineering, economics and energy policy
- Specialist electrical engineering and energy trade journals
- Technical reports produced or commissioned by electricity network operators, suppliers, regulators, and former national and regional state electricity companies, national energy labs, international agencies e.g. National Grid, Ofgem, NREL, IEA

- Technical and economic reports commissioned by government departments e.g. DECC, BERR, US DoE
- Reports and conference proceedings commissioned or produced by learned societies and institutes such as the IET, IEEE and RAEng
- Specialist consultancies (e.g. Oxera, Poyry, Parsons Brinckerhoff, Mott MacDonald)

This study included sources which:

- Are relevant, as far as possible, to the key issues captured in the research question
- Cover either engineering or economic aspects of electricity system operation
- Contain primary evidence from modelling, and/or real world experience
- Contain modelling but also reviews of modelling and/or empirical studies
- Contain expert views or represent the opinion of professional bodies/societies

The set of key words, search terms and evidence categorisation are described below.

Table 6.1 Keywords selected for use in the search terms

Technologies	Infrastructure	Descriptors	Markets
Wind	Network	Intermittent	Wholesale market
Solar	Grid	Intermittency	Power market
Storage	Transmission	Variable Generation	Electricity pool
Renewable		Capacity credit	
Thermal		Capacity margin	
		System reserve	
		System balancing	
		Load factor	
		Ramp rates	
		Inertia	
		Backup	

Combination of search terms

- 1 Wind
AND (intermittent OR intermittency OR variable generation)
- 2 Solar
AND (intermittent OR intermittency OR variable generation)
- 3 Storage
AND (intermittent OR intermittency OR variable generation)
- 4 Renewable
AND (intermittent OR intermittency OR variable generation)
- 5 Network
AND (wind OR solar OR storage)
- 6 Grid
AND (wind OR solar OR storage)
- 7 Transmission
AND (wind OR solar OR storage)
- 8 Capacity credit
AND (wind OR solar OR storage)
- 9 Capacity margin
AND (wind OR solar OR storage)
- 10 System reserve
AND (wind OR solar OR storage)
- 11 System balancing
AND (wind OR solar OR storage)
- 12 Load factor
AND (wind OR solar OR storage)
- 13 Inertia
AND (wind OR solar OR storage)
- 14 Ramp rates
AND thermal
AND (wind OR solar OR storage)
- 15 Backup
AND thermal
AND (wind OR solar)
- 16 Wholesale market
AND (intermittent OR intermittency OR variable generation)
- 17 Power market
AND (intermittent OR intermittency OR variable generation)
- 18 Electricity pool
AND (intermittent OR intermittency OR variable generation)

The search was limited to post-2005 material.

Databases / sources

Google scholar

Note that searches using Google scholar have been demonstrated to include the relevant journal paper databases such as ScienceDirect and IEEE.

Google

Documents published by the following institutions were searched for directly on the organisation websites using a subset of the search terms shown above, and supplemented by additional sources as suggested by Expert group members.

- DECC / Ofgem
- National grid
- IEA / OECD
- British / American / European Wind Association
- European Commission
- Energy Network Association (ENA)
- European Network of Transmission System Operators for Electricity (entsoe)
- Frontier Economics
- Poyry
- NERA economic consulting
- EIA
- NREL

Categories for quantitative findings

- 1 Reserve requirements
- 2 Reserve costs
- 3 Capacity credit
- 4 Cost equivalent for capacity credit
- 5 Impacts on fuel and emission savings (less efficient use of thermal plants)
- 6 Energy spilling, curtailment (restriction of intermittent generation)
- 7 Transmission and Distribution network impacts

Relevance ratings

A relevance rating was assigned to each piece of evidence as follows:

- 1 Article shows clear data on at least one of the terms above
- 2 Article shows clear data on at least one of the terms above, however, misses some data or uses an uncommon metric
- 3 Article mentions at least one of the terms above, however, does not include relevant data
- 4 Irrelevant article or duplicate

Expert group

The project team engaged with a team of expert advisors to bring their experience and perspectives to bear on the research questions. The expert group met formally in February 2016 and this meeting was supplemented by bilateral discussions with individual members of the expert group as required. The expert advisors were asked to comment on the scope of the project and the approach, advise and assist the project team in the identification and selection of relevant evidence sources, and review and comment on draft results.

Expert group members and affiliation:

Damitha Adikaari (Department of Energy & Climate Change)

Keith Bell (University of Strathclyde)

Andy Boston (Energy Research Partnership)

James Cox (Poyry)

Lewis Dale (National Grid)

Tim Green (Imperial College)

Eric Ling (Committee on Climate Change)

Mark O'Malley (University College Dublin)

Simon Mueller (International Energy Agency)

Goran Strbac (Imperial College)

Mike Thompson (Committee on Climate Change)

The final draft of the project report was peer reviewed by Hannele Holttinen (VTT Technical Research Centre) and Michael Milligan (National Renewable Energy Laboratory). Responsibility for the content of the report and any errors or omissions remains exclusively with the authors.

Document ID numbers cross-reference

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
1	The costs of wind's intermittency in Germany: application of a stochastic electricity market model	(Swider and Weber 2007)
4	A Stochastic Unit-commitment Model for the Evaluation of the Impacts of Integration of Large Amounts of Intermittent Wind Power	(Barth <i>et al.</i> 2006)
5	Overview of wind power intermittency impacts on power systems	(Albadi and El-Saadany 2010)
6	The economics of large-scale wind power in a carbon constrained world	(DeCarolis and Keith 2006)
9	Supplying Baseload Power and Reducing Transmission Requirements by Interconnecting Wind Farms	(Archer and Jacobson 2007)
11	Exploring the impact on cost and electricity production of high penetration levels of intermittent electricity in OECD Europe and the USA, results for wind energy	(Hoogwijk <i>et al.</i> 2007)
13	Technical challenges associated with the integration of wind power into power systems	(Georgilakis 2008)
14	Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies	(Joskow 2011)
17	Baseload wind energy: modelling the competition between gas turbines and compressed air energy storage for supplemental generation	(Greenblatt <i>et al.</i> 2007)
18	Wind power: the economic impact of intermittency	(van Kooten 2010)
19	Compressed Air Energy Storage in an Electricity System With Significant Wind Power Generation	(Swider 2007)
28	Optimal wind power deployment in Europe - a portfolio approach	(Roques <i>et al.</i> 2010)
29	Wind and Energy Markets: A Case Study of Texas	(Baldick 2012)
33	The role of demand-side management in the grid integration of wind power	(Moura and de Almeida 2010)
34	Network constrained wind integration on Vancouver Island	(Maddaloni <i>et al.</i> 2008)
36	Value of storage in providing balancing services for electricity generation systems with high wind penetration	(Black and Strbac 2006)
45	MPC for reducing energy storage requirement of wind power systems	(Li <i>et al.</i> 2013)
50	Impact of wind generation on the operation and development of the UK electricity systems	(Strbac <i>et al.</i> 2007)
52	Market behaviour with large amounts of intermittent generation	(Green and Vasilakos 2010)
53	Balancing management mechanisms for intermittent power sources – A case study for wind power in Belgium	(Vos and Driesen 2009)
55	Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date	(DeCesaro <i>et al.</i> 2009)
59	Cost-minimized combinations of wind power, solar power and electrochemical storage, powering the grid up to 99.9% of the time	(Budischak <i>et al.</i> 2013)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
61	The economics of wind power with energy storage	(Benitez et al. 2008)
65	Value of Bulk Energy Storage for Managing Wind Power Fluctuations	(Black and Strbac 2007)
70	Design and operation of power systems with large amounts of wind power	(Holtinen et al. 2009)
73	Evaluating the limits of solar photovoltaics (PV) in traditional electric power systems	(Denholm and Margolis 2007b)
74	Intermittency and the value of renewable energy	(Gowrisankaran et al. 2011)
77	Evaluating the limits of solar photovoltaics (PV) in electric power systems utilizing energy storage and other enabling technologies	(Denholm and Margolis 2007a)
81	Very large-scale deployment of grid-connected solar photovoltaics in the United States: challenges and opportunities	(Denholm and Margolis 2006)
86	Household Solar Photovoltaics: Supplier of Marginal Abatement, or Primary Source of Low-Emission Power?	(Palmer 2013)
87	Enabling greater penetration of solar power via the use of CSP with thermal energy storage	(Denholm and Mehos 2011)
95	Utilizing Load Response for Wind and Solar Integration and Power System Reliability	(Milligan and Kirby 2010)
96	Modelling the potential for thermal concentrating solar power technologies	(Zhang et al. 2010)
99	Solar feed-in tariffs and the merit order effect: A study of the German electricity market	(Tveten et al. 2013)
103	The role of energy storage with renewable electricity generation	(Denholm et al. 2010)
104	Grid flexibility and storage required to achieve very high penetration of variable renewable electricity	(Denholm and Hand 2011)
107	Grid vs. storage in a 100% renewable Europe	(Steinke et al. 2013)
108	Planning for a 100% independent energy system based on smart energy storage for integration of renewables and CO2 emissions reduction	(Krajcar et al. 2011)
112	Renewable electricity and the grid: the challenge of variability	(Boyle 2012)
114	Metrics for evaluating the impacts of intermittent renewable generation on utility load-balancing	(Tarroja et al. 2012)
115	Switch: A Planning Tool for Power Systems with Large Shares of Intermittent Renewable Energy	(Fripp 2012)
117	Buffering intermittent renewable power with hydroelectric generation: A case study in California	(Chang et al. 2013)
118	Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modelled	(Brouwer et al. 2014)
119	Large scale integration of intermittent renewable energy sources in the Greek power sector	(Voumvoulakis et al. 2012)
120	Current methods to calculate capacity credit of wind power, IEA collaboration	(Ensslin et al. 2008)
121	An analytical formula for the capacity credit of wind power	(Voorspools and D'Haeseleer 2006)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
123	A review of different methodologies used for calculation of wind power capacity credit	(Soder and Amelin 2008)
125	Reaching Consensus in the Definition of Photovoltaics Capacity Credit in the USA: A Practical Application of Satellite-Derived Solar Resource Data	(Perez et al. 2008)
126	On the effect of spatial dispersion of wind power plants on the wind energy capacity credit in Greece	(Caralis et al. 2008)
127	Capacity Value of Wind Power	(Keane et al. 2011)
129	Impact of Wind Power Growth on Capacity Credit	(Karki and Hu 2007)
130	Establishing the role that wind generation may have in future generation portfolios	(Doherty et al. 2006)
131	Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation	(Milligan and Porter 2008)
132	Capacity Credit of Wind Generation Based on Minimum Resource Adequacy Procurement	(Zhu et al. 2012)
133	Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration	(Holttinen et al. 2011)
135	A variance analysis of the capacity displaced by wind energy in Europe	(Giebel 2006)
138	Capacity Value of Wind Power, Calculation, and Data Requirements: the Irish Power System Case	(Hasche et al. 2011)
139	A Reliability Model of Large Wind Farms for Power System Adequacy Studies	(Dobakhshari and Fotuhi-Firuzabad 2009)
140	Impact of pumped storage on power systems with increasing wind penetration	(Tuohy and Malley 2009)
142	Applying Markov chains for the determination of the capacity credit of wind power	(Luickx et al. 2009)
145	Realistic calculation of wind generation capacity credits	(Aguirre et al. 2009)
146	Power output variations of co-located offshore wind turbines and wave energy converters in California	(Stoutenburg et al. 2010)
147	A 100% renewable electricity generation system for New Zealand utilising hydro, wind, geothermal and biomass resources	(Mason et al. 2010)
148	Wind Integration in Power Systems: Operational Challenges and Possible Solutions	(Xie et al. 2011)
152	System Reliability Assessment Method for Wind Power Integration	(Vallee et al. 2008)
153	Pumped storage in systems with very high wind penetration	(Tuohy and O'Malley 2011)
154	Dispatch modelling of a regional power generation system – Integrating wind power	(Göransson and Johnsson 2009)
156	Analysis of impacts of wind integration in the Tamil Nadu grid	(George and Banerjee 2009)
157	Estimating the impacts of wind power on power systems – summary of IEA Wind collaboration	(Holttinen 2008)
158	Rigorous model for evaluating wind power capacity credit	(Zhang et al. 2013)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
160	Application of a Joint Deterministic-Probabilistic Criterion to Wind Integrated Bulk Power System Planning	(Billinton <i>et al.</i> 2010)
164	Eastern wind integration and transmission study	(Corbus 2010)
165	Dynamic Modelling of Thermal Generation Capacity Investment: Application to Markets With High Wind Penetration	(Eager <i>et al.</i> 2012)
168	Economic properties of wind power: A European assessment	(Boccard 2010)
171	Quantifying Risk of Interruptions and Evaluating Generation System Adequacy with Wind Generation	(Shakoor <i>et al.</i> 2006)
187	Multiarea Stochastic Unit Commitment for High Wind Penetration in a Transmission Constrained Network	(Papavasiliou and Oren 2013)
208	Agent-based micro-storage management for the Smart Grid	(Vytelingum <i>et al.</i> 2010)
215	The economics of wind energy	(Krohn <i>et al.</i> 2009)
217	The effect of diurnal profile and seasonal wind regime on sizing grid-connected and off-grid wind power plants	(Carapellucci and Giordano 2013)
220	Frequency deviation of thermal power plants due to wind farms	(Changling and Boon-Teck 2006)
221	The value of compressed air energy storage with wind in transmission-constrained electric power systems	(Denholm and Sioshansi 2009)
224	Utility Wind Integration and Operating Impact State of the Art	(Smith <i>et al.</i> 2007)
230	“Take the long way down”: Integration of large-scale North Sea wind using HVDC transmission	(Weigt <i>et al.</i> 2010)
231	Coordinating Large-Scale Wind Integration and Transmission Planning	(Gu <i>et al.</i> 2012)
232	The cost of transmission for wind energy: A review of transmission planning studies	(Mills 2009)
236	Calculation of economic transmission connection capacity for wind power generation	(Ault <i>et al.</i> 2007)
241	A Stochastic Model for the Optimal Operation of a Wind-Thermal Power System	(Pappala <i>et al.</i> 2009)
242	Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power	(Holttinen <i>et al.</i> 2008)
244	Reserve determination for system with large wind generation	(Yong <i>et al.</i> 2009)
246	Statistical Wind Speed Interpolation for Simulating Aggregated Wind Energy Production under System Studies	(Gibescu <i>et al.</i> 2006)
250	Wind power forecasting uncertainty and unit commitment	(Wang <i>et al.</i> 2011)
251	System integration of large-scale wind power in the Netherlands	(Ummels <i>et al.</i> 2006)
252	Impact of Wind Power Forecasting on Unit Commitment and Dispatch	(Wang <i>et al.</i> 2009)
255	Generation expansion planning in wind-thermal power systems	(Kamalinia and Shahidehpour 2010)
257	How much wind energy will be curtailed on the 2020 Irish power system?	(Mc Garrigle <i>et al.</i> 2013)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
258	Wind power forecasting for reduction of system reserve	(Wang <i>et al.</i> 2010)
264	A quantitative analysis of the net benefits of grid integrated wind	(Denny <i>et al.</i> 2006)
267	Valuation framework for large scale electricity storage in a case with wind curtailment	(Loisel <i>et al.</i> 2010)
268	Impacts of Wind Power on Thermal Generation Unit Commitment and Dispatch	(Ummels <i>et al.</i> 2007)
269	The Effect of Large-Scale Wind Power on System Balancing in Northern Europe	(Aigner <i>et al.</i> 2012)
271	Impact of large scale wind integration on power system balancing	(Jaehnert <i>et al.</i> 2011)
274	European Balancing Act	(Ackermann <i>et al.</i> 2007)
278	Impact of wind power on the power system imbalances in Finland	(Helander <i>et al.</i> 2010)
282	Wind Energy Curtailment Case Studies	(Fink <i>et al.</i> 2009)
283	Imbalance Costs of Wind Power for a Hydro Power Producer in Finland	(Holtinen and Koreneff 2012)
285	Facilitating Wind Development: The Importance of Electric Industry Structure	(Kirby and Milligan 2008)
286	Intermittent renewable generation and the cost of maintaining power system reliability	(Skea <i>et al.</i> 2008)
287	Integration of wind and solar power in Europe: Assessment of flexibility requirements	(Huber <i>et al.</i> 2014)
289	Estimating the impact of wind generation on balancing costs in the GB electricity markets	(Swinand and Godel 2012)
290	Assessment of imbalance settlement exemptions for offshore wind power generation in Belgium	(De Vos <i>et al.</i> 2011)
293	Implementation of wind power in the Dutch power system	(Kling <i>et al.</i> 2008)
298	Evolution of operating reserve determination in wind power integration studies	(Ela <i>et al.</i> 2010)
300	Greenhouse Gas Emissions from Operating Reserves Used to Backup Large-Scale Wind Power	(Fripp 2011)
301	Estimating the Capacity Value of Concentrating Solar Power Plants With Thermal Energy Storage: A Case Study of the Southwestern United States	(Madaeni <i>et al.</i> 2013)
302	The market value and cost of solar photovoltaic electricity production	Borenstein 2008)
303	Gone with the wind? – Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply	(Traber and Kemfert 2011)
304	Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain	E(Sáenz de Miera <i>et al.</i> 2008)
311	Measuring the Environmental Benefits of Wind-Generated Electricity	(Cullen 2013)
316	Successful renewable energy development in a competitive electricity market: A Texas case study	(Zarnikau 2011)
317	Integrating wind: Developing Europe's power market for the large-scale integration of wind power	(Van Hulle 2009)
318	Dynamic Frequency Control Support by Energy Storage to Reduce the Impact of Wind and Solar Generation on Isolated Power System's Inertia	(Delille <i>et al.</i> 2012)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
320	Grid Inertia and Frequency Control in Power Systems with High Penetration of Renewables	(Tielens and Van Hertem 2012)
321	Estimation of Wind Penetration as Limited by Frequency Deviation	(Luo et al. 2007)
326	Impact on transient and frequency stability for a power system at very high wind penetration	(Meegahapola and Flynn 2010)
327	Frequency Control in Autonomous Power Systems With High Wind Power Penetration	(Margaris et al. 2012)
329	Grid code requirements for artificial inertia control systems in the New Zealand power system	(Pelletier et al. 2012)
330	Impacts of Wind Power Minute-to-Minute Variations on Power System Operation	(Banakar et al. 2008)
331	Virtual inertia for variable speed wind turbines	(Zeni et al. 2013)
334	Wind integration into various generation mixtures	(Maddaloni et al. 2009)
336	An analysis of concentrating solar power with thermal energy storage in a California 33% renewable scenario	(Denholm et al. 2013)
337	Toward a Solar-Powered Grid	(Brinkman et al. 2011)
340	Impacts of Large-Scale Wind Penetration on Designing and Operation of Electric Power Systems	(Kabouris and Kanellos 2010)
342	Estimating the Spinning Reserve Requirements in Systems With Significant Wind Power Generation Penetration	(Ortega-Vazquez and Kirschen 2009)
343	Incorporating Uncertainty of Wind Power Generation Forecast Into Power System Operation, Dispatch, and Unit Commitment Procedures	(Makarov et al. 2011)
344	Assessing the Impact of Wind Power Generation on Operating Costs	(Ortega-Vazquez and Kirschen 2010)
345	Stochastic security for operations planning with significant wind power generation	(Bouffard and Galiana 2008)
347	The market value of variable renewables: The effect of solar wind power variability on their relative price	(Hirth 2013)
348	Reducing the market impact of large shares of intermittent energy in Denmark	(Klinge Jacobsen and Zvingilaite 2010)
354	Changes in the economic value of variable generation at high penetration levels: a pilot case study of California	(Mills and Wiser 2013)
355	System LCOE: What are the costs of variable renewables?	(Ueckerdt et al. 2013)
356	Conditions and costs for renewables electricity grid connection: examples in Europe	(Swider et al. 2008)
360	Sizing Energy Storage to Accommodate High Penetration of Variable Energy Resources	(Makarov et al. 2012)
361	Models for Quantifying the Economic Benefits of Distributed Generation	(Gil and Joos 2008)
362	Modelling An Integrated Northern European Regulating Power Market Based On A Common Day-Ahead Market	(Doorman and Jaehnert 2010)
363	Challenges and options for a large wind power uptake by the European electricity system	(Purvins et al. 2011)
364	Understanding the Balancing Challenge	(Strbac et al. 2012)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
366	Electricity Capacity Assessment Report	(Ofgem 2014)
369	Winter Outlook Report	(National Grid 2015a)
372	Operating the Electricity Transmission Networks in 2020	(National Grid 2011)
374	Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems	(NEA 2012)
377	Harnessing Variable Renewables: a guide to the balancing challenge	(IEA 2011)
378	IEA Wind Energy Annual Report 2009	(IEA 2010)
381	Managing large scale penetration of intermittent renewables	(Pérez-Arriaga 2011)
386	Wind Power Reassessed: A review of the UK wind resource for electricity generation	(Aris 2014)
387	Wind and Solar Energy Curtailment: Experience and Practices in the United States	(Bird et al. 2014)
396	Managing Flexibility Whilst Decarbonising the GB Electricity System	(Boston and Thomas 2015)
397	2014 Wind Technologies Market Report	(Wiser and Bolinger 2014)
400	Grid Integration Cost of Photovoltaic Power Generation	(Pudjianto et al. 2013)
401	The net benefits of low and no-carbon electricity technologies	(Frank 2014)
402	System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications	(Druce et al. 2015)
403	Sensitivity of 2030 Carbon Intensity to Uncertainties and System Externalities of Power Sector Technologies	(Strbac et al. 2015)
404	Meeting the Renewable Energy Targets in the West at Least Cost: The Integration Challenge	(Schwartz et al. 2012)
406	Power Perspectives 2030: On the road to a decarbonised power sector – A contributing study to Roadmap	(Hewicker et al. 2012)
412	The Power of Transformation Wind, Sun and the Economics of Flexible Power Systems	(IEA 2014)
413	Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks	(Sinclair Knight Merz 2008)
415	Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States	(Parsons et al. 2006)
419	Revision of reserve requirements following wind power integration in island power systems	(De Vos et al. 2013)
422	The cost of wind power variability	(Katzenstein and Apt 2012)
424	Renewable energy deployment – do the benefits outweigh the costs?	(Lehr et al. 2012)
425	Operational costs induced by fluctuating wind power production in Germany and Scandinavia	(Meibom et al. 2009)
427	The Western Wind and Solar Integration Study Phase 2	(Lew et al. 2013)

Table 6.2 Cross-referenced list of relevance rating 1 and 2 documents and ID numbers

Unique ID number	Title	Author/year
428	All Island Electricity Grid Study	(DCENR 2008)
429	Facilitation of Renewables	(ECOFYS <i>et al.</i> 2010)
430	Exploration of the integration of renewable resources into California's electric system using the Holistic Grid Resource Integration and Deployment (HiGRID) tool	(Eichman <i>et al.</i> 2013)
431	European Wind Integration Study. Towards a successful Integration of Large Scale Wind Power into European Electricity Grids	(EWIS 2010)
432	Estimating the impacts of wind power on power systems – summary of IEA Wind collaboration	(Holttinen 2008)
433	Design and operation of power systems with large amounts of windpower. Final report, IEA WIND Task25, Phase one 2006–2008	(Holttinen <i>et al.</i> 2009)
434	Design and operation of power systems with large amounts of wind power. Final summary report, IEA WIND Task 25, Phase two 2009–2011	(Holttinen <i>et al.</i> 2013)
436	World Energy Outlook 2012	(IEA 2012)
437	Strategies for an efficient integration of wind power considering demand response	(Klobasa <i>et al.</i> 2007)
438	Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power	(Mills and Wisner 2010)
439	Submission to the Scottish Parliament's Economy, Energy and Tourism Committee	(National Grid 2012)
440	Impact of intermittency: How wind variability could change the shape of the British and Irish electricity markets. Summary Report	(Poyry 2009)
441	Analysing technical constraints on renewable generation to 2050 – A report to the Committee on Climate Change	(Poyry 2011a)
445	The Hidden Costs of Wind Electricity. Why the full cost of wind generation is unlikely to match the cost of natural gas, coal or nuclear generation	(Taylor and Tanton 2012)
446	2011 Wind Technologies Market Report	(Wisner and Bolinger 2012)
447	Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment	(EirGrid and SONI 2011)
448	Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes	(Redpoint <i>et al.</i> 2008)
449	The Integration Cost of Wind and Solar Power. An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems	(Agora Energiewende 2015)
454	Limits to integration of Renewable Energy Sources. The Spanish experience and challenge	(Revuelta 2011)

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