Title

A systematic review of the costs and impacts of integrating variable renewables into power grids

Abstract

The impact of variable renewable energy (VRE) sources on an electricity system depends on technological characteristics, demand, regulatory practices, and renewable resources. The costs of integrating wind or solar power into electricity networks have been debated for decades yet remain controversial and often misunderstood. Here, we undertake a systematic review of the international evidence on the cost and impact of integrating wind and solar to provide policymakers with evidence to inform strategic choices about which technologies to support. We find a wide range of costs across the literature, which depend largely on the price and availability of flexible system operation. Costs are small at low penetrations of VRE and can even be negative. Data are scarce at high penetrations, but show that the range widens. Nonetheless, VRE sources can be a key part of a least-cost route to decarbonisation.

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Main

The cost of integrating variable renewable generators such as wind or solar power into electricity grids has been the subject of a sustained and sometimes noisy debate. The cost of generating electricity from renewables has fallen so dramatically that in some cases there is no longer a differential between the average cost of electricity produced by renewable and conventional generators. Recent bid prices for renewables contracts in some countries are competitive with, or below, wholesale power prices [1]. Yet commentators in the mainstream media often still contend that the need for 'back-up' for wind or solar undermines their competitiveness relative to other low carbon options, such as nuclear power [2]. The concept of 'firm power' also features in some policy reports [3].

One reason the debate still rages is that the impacts of variable renewables on electricity networks are complex and context specific. Overly simple notions of 'back-up' do not adequately represent how integrating variable renewables affects power system engineering or economics. Most power systems operate with a variety of types of generator with different characteristics; some are more flexible, best suited to provide power for short periods, others cheapest to run continuously. Demand response, storage and interconnection are also important. The economic value of any form of generation in an electricity system is not well-captured in analyses that neglect system costs/benefits or market value, quite apart from CO_2 emissions or other externalities.

A long-standing debate relates to whether renewable energy is 'variable' or 'intermittent'. Hereafter we use the term *variable renewable energy* (VRE). This is now widely accepted in the literature as the most appropriate term for generators whose energy sources are renewable, temporally variable, and difficult to accurately predict over timescales of more than a few hours [4]. The term 'intermittent', whilst still not completely superseded, is seen by many as pejorative and insufficiently precise [5].

Here, we consider the key factors that change when VRE is added to electricity grids. There is a large body of evidence available, stretching back four decades [6-8]. Drawing on past work, we present an updated and expanded systematic review of the data. We analyse the quantitative impacts of variable renewables on electricity systems. Where the data permit, we provide a meta-analysis and comment on the reasons estimates differ, thus helping characterise the nature of the evidence base. Overall, we find that the range of cost estimates is largely a function of geographical factors affecting supply/demand correlation, and power system characteristics that determine flexibility of operation. However, at low and intermediate shares of electricity supply, variable renewables may well offer the lowest-cost low-carbon option in many countries because system integration costs are often modest. The more limited evidence relating to very high variable renewable shares suggests that overall integration costs can be kept relatively low, but that this requires the development of very flexible electricity systems.

The falling costs and rising share of VRE

The last decade has seen dramatic increases in the deployment of renewable electricity generation capacity in many countries, with widespread aspirations for further significant growth [9]. Much of this new capacity is VRE, dominated by onshore wind and solar PV [10]. VRE supplied over 20% of annual electricity demand for nine countries in 2018 [9]. Notably this includes grid control areas with limited interconnection with larger electricity grids such as the Island of Ireland, Spain/Portugal and Great Britain – a key point because integration across larger areas reduces the costs of accommodating VRE. Generation costs for wind and solar PV have reduced dramatically in recent years; onshore wind costs have declined by 69% since 2009 and PV costs by 88% over the same period [11].

As the costs of renewable energy fall and the share of variable renewables rises, policy attention has turned from the costs of subsidy to ‘subsidy free’ VRE. The traditional measure of relative costs of different power generators is ‘levelised costs of energy’ (LCOE) – which allocate discounted whole life costs of a power generator across lifetime output to provide a cost in the form of $/MWh. The evidence suggests that levelised costs of VRE options such as wind or solar are now significantly lower than those of new nuclear, often used as a comparator for the cost of low carbon power supply. For example, in Britain a new nuclear power station has been awarded a government-backed 35 year contract paying £92.50/MWh, whereas the most recent tenders for a 15 year contract for offshore wind came in at around £40/MWh (both values are in 2012 prices) [12, 13]. By way of comparison the average wholesale base load price in Britain in 2019 was approx. £41/MWh (€48) and the average across the EU was €43/MWh (£37) [14].

Expert analysis has long recognised that that levelised costs alone do not fully capture the costs and benefits of different generators. Economic analyses have focused on the relative system value of output from different types of generation technologies [15-18]. System value can change over hourly and daily timescales with varying system demand, or over much longer timescales in response to significant changes in the overall penetration of VRE generation. The nature and size of these effects are highly system-specific, but simply put, the value of VRE output to a system is likely to be associated with the extent to which it does or does not correlate with demand and will tend to decline as VRE penetration levels rise. This is important because it implies that meeting decarbonisation targets at lowest total cost requires a mix of generation assets with a range of technical and economic characteristics [19-21].

The impact of the timing of outputs from VRE generators on wholesale prices has also been prominent in some discourse [17, 22, 23]. This debate has focused on so-called price cannibalisation, a phenomenon where the presence of large amounts of wind or solar causes power prices to fall on sunny or windy days. However, the impact of wind and solar on power prices is a function of their low marginal cost as well as their variability, and is not a measure of the cost of VRE per se. If markets are efficient then system value and system cost should be equivalent. However, markets may not function efficiently and capture all costs, and price formation will change over time. In the short term the mix of power stations is largely fixed, but in the long run the mix of plant can change as investors respond to price signals [17]. Electricity market prices also depend on regulatory arrangements and demand profiles.

For all these reasons, we focus on costs and return to consider market prices and system value in the discussion. A cost based approach aids intelligibility and policy discussion often focuses on the system integration costs imposed by VRE and who bears them [3].

Categories of impact and the importance of terminology

Adding VRE to a power system gives rise to a number of changes, some of them to do with the timing and unpredictability of output and technical characteristics of VRE, others to do with the geographical location of wind or solar deployments. It is important that these costs are assessed holistically, since there is some overlap and interaction between them. In some cases it is not possible to disaggregate impacts, which is why some analysts argue that the most thoroughgoing approach is to compare the whole system costs of a power network with VRE to a counterfactual with no VRE [24]. Another approach is to minimise overall costs, taking into account the changing marginal value of VRE as penetrations increase [19, 21]. Nevertheless, assessing the main types of individual costs and impacts individually aids transparency and understanding.

One way to characterise the costs imposed by VRE generators is to decompose them into three main categories [17]: Costs imposed by unpredictability of output or forecasting errors (so called balancing costs); costs imposed by the relatively uncontrollable nature of output and lack of correlation between output and demand, which affects the net load met by non-VRE generation (so called profile costs); and a mix of factors related to geography and the unit size of VRE generators (so called grid costs).

We use these broad categories to organise our analysis and discuss the specific cost drivers that feature most prominently in the evidence base on VRE costs. More detail is in the methods section. However, it is important to note that these rather broad categories are not used in all of the literature and they are not uncontroversial. Many analyses focus on capacity costs (ability to reliably meet peak demand) rather than the somewhat wider concept of profile costs, which first entered the discourse in around 2013. Balancing, grid and profile cost changes due to new generators are also not confined to VRE: for example, adding large power plants may increase system balancing requirements; historically transmission extension was built to access hydro or coal resources, or to locate nuclear power stations away from population centres; and any new power station will affect the operation and economics of existing power plants, which complicates the concept of profile costs Wider changes in the use of energy, such as the electrification of road transport or provision of heating will also affect time of day demand profiles and the availability of options to store energy. As a result it is difficult to conceptualise VRE costs in the absence of a counterfactual – what would be the alternative low carbon energy source and what impact would it have on all of the above [25].

The evidence base

The literature on VRE costs is complex and varied. The complexities include whether different studies define the same categories of cost, whether data are for market prices or estimates of cost derived from power system models, and varied contextual assumptions about the power system in question. Some studies also use different measures and metrics for the same categories of impact, making comparison more difficult.

To deal with the diverse nature of the evidence base, the approach we took was to search for a range of impacts and report upon the categorisations as found in the literature. Where possible we provide a meta-analysis, showing the ranges of findings, and comment on the reasons estimates differ. This allows also us to review which impacts receive most attention and where evidence is limited, thus helping characterise the nature of the evidence base.

The evidence revealed through the systematic review is illustrated in Figure 1 below. This suggests that capacity costs/credit together account for just under 40% of the data revealed in our review. Around 16% of data volume was for aggregated costs, with similar data volumes for reserves/short term balancing and grid costs, and slightly less for curtailment. Our review did not reveal a large volume of studies explicitly assessing profile costs or impacts on fuel use and emissions.

Operating reserves for short-term system balancing

Balancing costs as defined by ref. [17] include any action taken to adjust for unpredicted changes in VRE output. This is affected by market and regulatory design. Relevant factors include how far ahead of real time wholesale markets close (called gate-closure; see Supplementary Table 1 for a list of terminology) and the actions available to system operators after gate closure to balance supply and demand (for example through a balancing mechanism). For a more detailed discussion see ref. [8].

Our systematic review revealed that most analyses of balancing costs focus on system balancing or operating reserves, available to respond to a possible mismatch of supply and demand over timescales ranging from instantaneous to several hours. All power grids need reserves, including those without any variable renewables, since neither demand nor supply can be forecast with complete accuracy. Reserve services are provided by a mix of sources, including generation, storage and demand response [26-30]. Together with country or regional variations, this leads to a wide range of terms that are used to describe these services so hereafter we use the general term 'operating reserve', consistent with ref. [31].

Operating reserve requirements are determined by probabilistic analysis, taking into account data for historical demand fluctuations, unplanned unavailability of conventional plant, the degree of fluctuation in VRE output and the size of VRE output forecasting errors [32, 33]. Increasing the amount of variable renewable generation connected to a system would typically be expected to increase the amount of operating reserves that are required to ensure that supply matches demand at all times. However, at low penetrations of VRE their impact on operating reserves tends to be modest because there is only a small change in the total variance that needs to be covered to keep the system reliable. See Supplementary Notes 1 for a description of the basic principles used to assess operating reserves requirements.

As power systems adapt to increasing penetrations of VRE it may also be that operating reserve is provided by a wider range of actions and technologies, including a greater use of storage and demand-side actions [34]. Recent analysis of balancing actions in Germany and Great Britain show that operational innovation can avoid the need for additional operating reserves or reduce operating reserve needs, even as the share of VRE rises substantially [35]. This shows how rising experience in operating systems with rising shares of wind and solar power provides opportunities to minimise costs.

Capacity adequacy and profile costs

As well as ensuring that supply and demand is in balance over the short-term, there must also be sufficient generation capacity available so that periods of peak demand can be met with a high degree of reliability [36]. The timing of demand peaks vary geographically and depend on hours of daylight, climate and weather, and a range of economic and cultural factors. For example, peak demand in northern European regions would typically be expected during winter evenings, but many warmer countries experience a summer afternoon peak, driven by air-conditioning [37]. Some countries have both winter and summer peak periods. As with operating reserve requirements, the capacity required to meet peak demand is calculated through probabilistic analysis, taking into account the reliability of conventional generation and the likelihood (and size) of the contribution from VRE at times of peak demand [38].

The key determinant of the contribution that VRE can make to meet peak demand is the degree of correlation between VRE output and peak demand periods. This depends on both the nature of VRE resource and the drivers of demand at peak periods. For example, in hot, sunny regions where peak demands are driven by air conditioning loads, solar PV may be able to make a significant contribution to meeting peak demand. By contrast, PV will make no contribution in regions where demand peaks occur during the hours of darkness.

Conventional generation would normally be expected to have a very high probability of being able to generate at times of peak demand, typically driven by the operational reliability of the plant rather than the temporal availability of the energy resource [39]. Factors such as fuel or cooling water availability in extreme weather can affect thermal output too, but are exceptional events. Generally (although not always), the contribution that a VRE generator can make to meeting peak demands would be expected to be less than a conventional plant providing the same amount of energy, and it is this that gives rise to the additional capacity costs that are incurred as VRE penetration increases [40]. The term 'capacity credit' is often used to denote the contribution that a VRE generator can make to reliably meeting peak demand [41-43].

In much of the literature and for many years, analysis of the impacts of VRE on conventional capacity focused on capacity adequacy. However, some more recent commentators have argued for a broader approach, referred to as profile costs [16, 17, 44]. This approach attempts to capture all of the impacts of VRE on conventional generators, and includes increased ramping (discussed below) and impact on the load factors of non-VRE generators meeting net-loads. In addition, analyses that look at very high VRE penetrations are increasingly moving towards a full system cost approach. This may not facilitate comparison of individual component costs, but instead presents costs on an annualised total cost basis or as a general 'aggregated integration cost' which encapsulates all the categories described in the paper [24].

Estimates of costs by category

Figure 2 draws together the full data set we obtained from our review for the additional costs of operating reserve and capacity required to meet peak demand that result from adding VRE to a system. Comparable data from studies that present profile costs and aggregated system integration costs are also included.

There is a considerable degree of clustering within the 600+ data points in Figure 2, and the resultant over-plotting means that it is not always clear where the bulk of the findings actually lie. To overcome this problem, the data for each category of impact are grouped into bins based on ranges of penetration levels and presented below. Data aggregation of this form is a widely accepted approach to the problem of data overplotting [45]. In terms of the total volume of data shown in Figure 2, Europe dominates the geographical coverage. Over 90% of the data relate to Europe, with 16 individual European countries covered. The remainder of the data are from the USA and Asia. It is important to note that few studies provide data for any cost impact at higher penetration levels. Whilst the data range at high penetration levels can be wide, this is often a product of assumptions about the cost and availability of flexibility. In the case of [24] the low end of the range of costs may result from ambitious assumptions about the costs of flexibility and the high end may result from conservative ones. The small number of studies providing estimates at high VRE levels means that these findings need to be treated with caution. More research is needed on high VRE penetrations, taking into account a wider range of geographies and to test assumptions and analytical approaches.

The costs of providing additional operating reserves

The data for the additional operating reserves costs shown in Figure 2 suggest that these costs are relatively small at lower penetration levels, with most values below €5/MWh up to 25% VRE penetration. This is consistent with a recent empirical study of the German and British electricity markets which found that despite substantial increases in wind penetration levels within the last few years, these costs had remained relatively constant in Britain and reduced in Germany [35]. As shown in Figure 3, above the 25% level, operating reserves costs appear to rise as the VRE penetration levels increase but median values remain well below €10/MWh up to 45% VRE penetration (25^{th}-75^{th} percentile for the 35-45% bin: €4.34-€13.53). This is also consistent with reviews such as [17] who also note that balancing costs are low even at high penetration rates.

Figure 3 also shows that in addition to median costs increasing, the full range of costs found at each penetration level becomes wider as penetration levels rise above 25%. As might be expected, the median values within each bin also follow a rising trend. However, for penetration levels above 25% the median values are in the lower part of each bin range, suggesting that that the results cluster more towards the lower end of the ranges. The full reasons for this are complex and differ between the studies reviewed, but a strongly recurring factor is the key role played by assumptions over the availability and cost effectiveness of providing greater levels of electricity system flexibility. This message is reinforced by findings from analyses which show that the costs of integrating high penetrations of VRE are to a great extent dependant on the modelled level of system flexibility [46, 47].

The overall picture which emerges from the data is that at penetration levels up to 25%, the costs associated with the additional operating reserves required when adding VRE to a system are likely to be below €5/MWh – less than 10% of typical average wholesale power prices in many countries [48]. At higher penetrations costs increase, and the increase in costs is, in large part, a function of electricity system flexibility. Hence those studies that report lower costs are predicated on the availability and adoption of a range of options to increase flexibility. These options are not costless and it is important to interrogate judgements made about the costs of providing flexibility. Evidence from empirical reviews is relatively limited but tends to suggest that the costs of integrating VRE have fallen as penetrations rise, this suggests that in real world situations low cost sources of flexibility have been found and/or that changes to operating practices have decreased the cost of integrating VRE [35] .

Costs of providing sufficient capacity to meet peak demands

Figure 4 shows the range of capacity costs imposed by VRE identified in our review. The most immediately notable aspect is the presence of negative data, albeit for only a small number of data points and at low penetration levels. These data relate to capacity costs for solar PV in Greece, and reflect the close correlation between peak PV output and electricity demand in that country [49]. The implication is that at low penetration levels, and given the right resource and demand profile, adding solar PV can help make the system more reliable, and/or reduce the cost of meeting peak demand.

Overall, Figure 4 shows a narrowing of the range of findings for capacity costs as penetration levels rise. In part, this is because negative values do not appear at high penetration levels. Adding to this, the data for VRE at higher penetration levels are dominated by wind rather than PV, which tends to have a narrower range of capacity credit, and therefore capacity cost, values.

Even when the data relating to PV in Greece is included, the median values for the additional capacity costs of VRE are around €10/MWh or less, across all penetration level bins (25th-75th percentile: €7.84-€13.02). The lower median values for VRE penetration levels above 25% should be interpreted with a degree of caution since less than 10% of the capacity costs data points cover these two bins. Nevertheless, the reducing spread as penetrations rise is consistent with the view that there is a ceiling on capacity costs. This aligns with earlier work [7, 50], and also the analysis presented in [40]. That paper concluded that even if the installed VRE is assumed to make no contribution to meeting peak demands (i.e. its capacity credit is zero), then the additional capacity costs will not exceed an upper value whose determinant is the fixed cost of the energy-equivalent conventional plant which will be providing the required capacity reliability. Variation in capacity costs, regardless of penetration levels, is very sensitive to the assumptions made regarding the costs of the technology assumed to provide capacity to reliably meet peak demands [40].

Profile costs and aggregated integration costs

Whilst estimates of capacity cost are widespread in the literature, several recent studies have sought to quantify the wider concept of profile costs, usually by using a range of approaches to calculate the impact of VRE on the utilisation of conventional generators. This analysis suggests that profile costs lie in a range of €15-25/MWh (25th-75th percentile: €13.97-€27.47) at a 25-35% market share [16, 44]. It appears that these costs may be negative at low penetrations, if VRE has good correlation with demand [44].

It has not been possible to determine the extent to which estimates of profile costs are additional to capacity adequacy since both concepts measure the cost of maintaining conventional capacity, either to meet net load or to meet peak demand. Double counting with reserve costs is possible in all instances, since the same capacity may provide reserve services, serve net loads and meet peak demands. However, it is important not to neglect profile costs or aggregated costs data in any meta-analysis of the total costs of VRE. Therefore, we present a range of data on profile costs and 'aggregated integration costs' in Figure 5 alongside data on operating reserves and capacity costs. The aggregated costs data have been selected from studies that are explicit that they include profile and grid costs.

Figure 5 shows that there is a degree of overlap in the findings between aggregated costs and those attributed to balancing and capacity adequacy alone. This is in part a function of the differing assumptions made by the underlying modelling studies but is also because the individual categories of cost impacts are not simplistically additive. The median aggregated integration costs in the data set range from approximately €14/MWh (25th-75th percentile: €12.87-€15.68) at the 15-25% VRE penetration level, rising to approximately €30/MWh (25th-75th percentile: €28.73-€37.38) at the 75-85% penetration level. We reiterate the observation made above about the small number of studies providing data at high VRE penetrations and for aggregated costs. The very wide ranges of aggregated cost estimates at 45-55% and 55-65% penetration levels are driven by a single study and divergent assumptions about the provision of flexibility.

Grid costs

The systematic review revealed more limited data on grid costs. Our earlier work found that transmission and network costs lie in a range of £5- £20/MWh [8] at up to 30% penetration of VRE, with little data available at higher penetrations. A review by Hirth [17] finds that quantitative data on grid-related costs are 'scarce', that marginal costs are seldom reported and also notes that it is usually not clear if VRE or other factors drive grid investments. This is consistent with the note we make in [8] that the wider benefits of transmission expansion are seldom factored into analyses. Nevertheless Hirth concludes that VRE expansion has only moderate or 'single digit €' impact on grid-related costs, which is consistent with the findings in [51]. For all these reasons we do not believe that there are sufficiently disaggregated data on grid costs to present them in equivalent format to the data on operating reserves, capacity adequacy profile costs and aggregated costs.

Grid related costs also run into some boundary setting and definitional difficulties. Grid costs are undoubtedly a feature of some renewable energy developments: Some wind or solar farms might be remote and require transmission extension; others are connected to local networks that may require upgrades. How much of this is attributable to variability is more difficult to disentangle. For example, the geographical location of renewable resources is not a function of their variable nature, but the utilisation of any connections to them is affected by variability. Other considerations include the extent to which new interconnection or transmission upgrading costs might be attributed to VRE integration: Connecting across different locations will help diversify the timing of VRE outputs but interconnection can also bring wider system benefits and lower overall costs. Similarly, the distribution network connected nature of some renewable resources may impose or reduce costs. However, connecting *any* form of generation at distribution-network level changes how that network will operate – irrespective of variability. Grid costs thus present a particular *conceptual challenge* – it is not easy to dissociate geographical factors from considerations that stem solely from the variable nature of VRE.

Comparing wind and solar

Figure 6 shows the capacity credit of VRE by technology type to allow comparison between wind and solar power. At lower penetration levels, some analyses found that PV can have a particularly high capacity credit, where there is a very strong correlation between PV output and peak demand. Generally though, the capacity credit values for PV were found to have a wider range than for wind, with a majority of values for PV tending to be relatively low, with a smaller number of (much) higher values.

This illustrates the strong techno-geographical dimension of capacity costs – capacity credit for wind lies in a reasonably wide range of below 10 to over 40% of installed capacity. Yet the data points for PV, of which [52] and [49] make up a considerable fraction by volume, strongly cluster at below 10% and the 50 to 80% range. This is because capacity credit for PV in countries with a winter peak is likely to be at or close to zero whereas it can be very high in countries with a summer daytime peak. The reason that capacity credit for both wind and PV falls as penetration levels rise is that periods when firm capacity are needed shift to periods when wind and solar availability is low [15]. The data also suggest that this effect is more pronounced for solar than for wind, which is likely to be a function of the diurnal pattern of solar output.

Other impacts

This section summarises findings from three other categories of VRE impact: curtailment; the effect on conventional plant efficiency and emissions; and how the technical characteristics of VRE impacts on frequency and voltage. Further detail is provided in Supplementary Notes 2, 3 and 4 respectively.

There may be times when the output from a VRE plant cannot be accepted onto the electricity system and the output from the VRE plant would need to be curtailed. This may happen either because of transmission or distribution grid constraints, or where VRE output would otherwise exceed instantaneous demand net of any conventional generation required to provide essential services to the system such as operating reserves and inertia (described below). The review found a relatively wide range of results which reflects the sensitivity of curtailment levels to the characteristics of the system to which VRE is added, in particular the flexibility of the other generators on the system, the degree of correlation between VRE output and demand, and transmission and distribution grid capacity. See Supplementary Note 2 and Supplementary Figures 1 and 2. Despite this, the median values for the share of VRE output curtailed across all penetration levels is consistently low, not exceeding 5% (25^{th}-75^{th} percentile: 0.5-8.87%) until penetration levels are above 65% of energy from VRE, and not exceeding 12.5% (25^{th}-75^{th} percentile: 0.5-10.84%) for any penetration level. The overall message therefore is that most studies find that the level of VRE curtailment is likely to be low.

Adding VRE to an electricity system may change the way in which some of the conventional plant on that system is operated. Impacts include faster ramping or cycling rates (rate of increase or decrease in output), or operating for longer periods at low output levels. More frequent variation in the output of conventional thermal generators may reduce the operating efficiency of these plants and/or mean that these plants operate in a manner which affects emissions of other pollutants such as nitrogen oxides (NOx). More frequent start-ups and shut-downs, and variations in output will also put additional thermal stress on components which may reduce their service life [53-55]. The bulk of the studies examined that addressed the efficiency and emissions impacts on thermal generation of adding VRE to a system find that the effects are small. Of the maximum theoretical emissions benefits from installing VRE less than 6% were lost through reduced efficiency of the conventional plant, even at relatively high penetration levels [56, 57]. See Supplementary Note 3 for more detail.

Before the advent of VRE, most electricity systems relied upon generating technologies which use large, relatively fast-rotating generators which are electro-magnetically linked to their host electricity system (and therefore to each other). This characteristic provides a degree of resilience to disturbances to the system such as the breakdown of a generator [58, 59]. This is because in the case of a generator failure the increased electrical load on the other operating generators will cause the rotation speed of those generators to reduce, but the rate at which this reduction happens is slowed by the generators giving up some of the kinetic energy in their rotating masses to the system. The overall effect of this 'system inertia' is to slow down what is known as the rate of change of frequency (ROCOF). This reduces the negative impact of a system disturbance and allows crucial time (typically only a few seconds) for compensating operating reserve actions to be taken, either automatically or through active intervention by the system operator [60]. VRE generators, as currently typically designed and configured, may not contribute to the inertia of an electricity system, which means that the resilience of a system to a disturbance may reduce as the instantaneous penetration of VRE reaches high levels. Analyses of system inertia impacts has tended to focus on the technical implications and/or assessments of the maximum instantaneous VRE penetration level for a given system (and what system changes may be required to increase this threshold), rather than a focus on the cost implications [61, 62]. Therefore we are not able to present cost data here. Any additional fast frequency response contracts would show up in assessments of operating reserve costs described above, but the review did not reveal data providing this level of detail.

Many of the impacts on voltage are focused on the low voltage distribution network impacts of clusters of PV leading to voltage increase. Systems with weak transmission grid may also encounter voltage-related issues with high VRE penetration levels. Overall, we conclude that the impact on costs of the operating characteristics of wind and solar energy appear to be small, but that these impacts have the potential to become significant at very high penetration levels. Perhaps more importantly these effects may impose constraints on either the instantaneous penetration of wind and solar or the concentration of solar capacity in some grid supply areas. Both these concerns will show up in other categories since they will add to curtailment or operating reserve requirements. See Supplementary Note 4 for further information.

Costs Vs Prices and how to conceptualise the impacts of VRE

The VRE impacts described so far mainly reflect the physical manifestations of VRE on electricity systems as represented in system simulations and models. These physical impacts have cost impacts that are the focus of this review. Characterising VRE in terms of a cost to be added to generation/system costs has been described as a bottom up or 'engineering' view of power system operation [16]. This can be compared with an 'economic' perspective that considers the role of VRE in terms of system and market value. Analysis of the market value of VRE dates back almost 30 years and uses a range of approaches including analytical or economic (e.g. merit order) and simulation models of electricity market price formation, as well as empirical data on prices [44, 63, 64]. The 'economic' approach typically presents the market value factors for VRE (fraction of a reference wholesale price that can be secured by VRE) and shows how it declines as penetrations rise (for a review see [44]). For example at higher penetrations wind might typically achieve 75% of average wholesale prices, because of the tendency for wind energy to reduce prices during windy periods.

Hence, analyses of the electricity market impacts of VRE typically group these into two main categories. The first, which is often referred to as the merit order or utilisation effect and described as a cost, results from the fact that conventional generators may run for fewer hours per year and/or at less than full capacity if they have to compete with VRE whose marginal costs of generation are very close to zero. This may impact the ability of conventional plants to cover their full long-run costs [65, 66]. The second category of impact is that the market value of VRE output may be lower than output from conventional generators because of temporal and geographical resource availability constraints i.e. the output from variable renewables may not be when or where the market demands it [67, 68]. Some analysts e.g. [15, 44] suggest that this reduction in the market value of VRE output can be very significant, although others e.g. [63, 69] suggest that these reductions in value may be relatively small.

The two approaches are complementary, and if markets allocate resources efficiently then value and cost should be equivalent. For example [17] and [16] provide similar demonstrations that show that reduction in value (the difference between the market price achieved by VRE compared to a reference wholesale price) equals cost (the various cost additions to LCOE that constitute system costs – profile, grid and balancing costs as defined above).

However, both market design and market power can affect this outcome. The range of estimates of VRE value reinforces the message that the effects are a function of both the nature of the renewable resource and demand, and the design and operation of electricity markets. Since power sector investments tend to be large and long lived there may also be significant differences between short and long term price effects [17]. *Costs* may be higher in the short term, reflecting the need to run inflexible generators in an inefficient fashion, whereas system *value* (and possibly overall impact on prices) tend to be lower. Longer term, a re-optimisation may occur with new sources of flexibility coming into operation and inflexible or poorly utilised capacity closing.

Conclusions

Adding VRE to an electricity system has a range of physical impacts and related costs which depend largely on a power system's technological characteristics, patterns of demand, regulatory and operating practices, and renewable energy resource availability.

Costs (and benefits) arising from different physical impacts overlap, so treating different categories of cost as simply additive is likely to be misleading. This highlights the need, from a societal perspective at least, to look at electricity systems as a whole using sophisticated power system simulation models and comparing the findings to economic approaches and empirical data from electricity markets where large penetrations of VRE are already present.

We have reviewed the main categories of impact and make the following five summary observations.

First, the costs for the additional operating reserves associated with VRE are likely to be relatively low with median values below €5/MWh (25th-75th percentile: €1.13-€4.29) up to a 35% penetration level, and below €10/MWh (25th-75th percentile: €7.84-€13.02) up to a 45% penetration level. The range of costs is strongly linked to the flexibility of the electricity system.

Second, additional capacity adequacy costs lie within a range starting from negative (net benefit) but with a median range of approximately €10/MWh (25th-75th percentile: €7.84-€13.02) or less at all penetration levels. These costs have a ceiling, which is set by assuming that capacity credit is zero.

Third, profile costs have also emerged in recent literature as a more thoroughgoing conceptualisation of capacity adequacy that take into account the full range of impacts of VRE on the balance of plant used to meet net load. The data on such costs are less well-developed than those for capacity adequacy but could lie in a range of €15 – 25/MWh at a 25-35% penetration level (25th-75th percentile: €13.97-€27.47).

Fourth, grid-related costs such as upgrades to transmission and distribution networks are also important but more difficult to allocate specifically to the variable nature of VRE, with the impact of variability not often disaggregated from geographical costs or wider system benefits. Estimates of total cost vary widely – in a range from €7 – 28/MWh in literature reviewed by the authors.

Finally, aggregated VRE integration costs are available in the literature that seek to represent all of the above costs. They may be very sensitive to assumptions over the level of system flexibility, with inflexible systems incurring up to four times the integration costs of very flexible systems. Median values range from approximately €14/MWh (25th-75th percentile: €9.91-€14.83) up to a 35% penetration level to approximately €30/MWh (25th-75th percentile: €28.73-€37.28) at up to 85% VRE penetration. Our review revealed only limited data sources for aggregated costs at high VRE penetrations, with the ranges determined by assumptions made in these studies about sources of flexibility. Further research is needed on all categories of impact at high VRE levels in order to diversify the evidence base. To put these values in context, the average wholesale baseload electricity price across the EU for the 2nd quarter of 2019 was a little over €43/MWh.

Wind and solar schemes have secured contracts paying below €50/MWh in many countries, a price level often compared to the £92.50/MWh strike price agreed for the UK's new nuclear power station. A key goal of this paper is to assess the evidence on whether system integration costs tip the balance away from VRE and towards non-variable options. Our review suggests that the combined impacts of the most thoroughly characterised VRE integration costs could be below €15/MWh if the share of renewables were up to 35% or so of annual electricity generation and are much smaller, or even negative, at low shares of generation. The paper does not demonstrate that wind or solar is cheaper than new nuclear in every instance but it does provide strong evidence to suggest that it is important to avoid simplistic claims that suggest that system integration costs are large.

The rather limited evidence relating to very high VRE shares suggests that overall integration costs can be kept relatively low, but that this requires very flexible electricity systems. Further research at high VRE levels would improve the confidence with which it is possible to form judgements about costs and what drives the range.

Whilst not the focus of this paper, the declining value of VRE to a system as penetration level rises may well have important consequences for the mix of generation technologies that will deliver the lowest overall cost for very high decarbonisation targets. We should also not lose sight of the fact that from a societal perspective, what matters is the overall cost of decarbonising power generation rather than individual cost components. Nevertheless, it is clear is that as the costs of renewables fall and the share of renewables rises in many countries it will become ever more important to ensure that power systems provide flexible operation at minimum cost. Doing so will allow the world to take maximum advantage of the clean energy offered by the declining cost of building and operating variable renewables.

Methods

Overview

The data presented in this paper is an updated version of a dataset derived from a systematic review carried out in 2016 by the authors as part of UK Energy Research Centre's Technology and Policy Assessment team [8]. The systematic review was limited to post-2005 material since earlier evidence is covered in detail in previous work by the authors [7] (which was the first example of the use of systematic reviews in this energy policy context). The systematic review was updated between mid-2018 and mid-2019 to include additional relevant sources published from 2016 onwards. Very few of these later sources provided quantitative evidence in a format that allowed inclusion in the figures in this paper because most of it is not directly comparable e.g.[46, 47]. This reinforces the observation made in this paper, which is that analyses that look at very high VRE penetrations are increasingly moving towards a full system cost approach. This may not facilitate comparison of individual component costs, but instead presents costs on an annualised total cost basis or as a general 'aggregated integration cost' which encapsulates all the categories described in the paper such as balancing, back-up, curtailment and network costs, as for example used in [24].

Most of the data presented in the paper comes from using power system models of some sort, rather than observations of market price impacts on power systems. Some types of VRE integration cost are not explicitly revealed as prices, and as such it is more straightforward to estimate them based on engineering and economic principles [7]. In addition, many studies examine future systems with higher penetrations of VRE than is currently the case. Since it is possible for market arrangements, system characteristics and operating practices to change, many analysts use models to represent power systems of the future, and extract from such models estimates of integration costs with high shares of VRE.

Categorisation of impacts

We grouped the costs and impacts of VRE on power grids into three categories of impact.

The first category is system balancing costs, which includes the additional costs associated with any increased short-term system balancing (or operating) reserves required as a result of adding VRE to an electricity system, and those issues related to managing frequency and voltage, in particular for a reduction in overall system inertia to affect a system's resilience to disturbances.

The second category covers profile costs, capacity adequacy and impacts on the balance of plant. This includes the costs of ensuring that a power system is able to reliably meet peak demand when VRE covers a higher portion of the generation. It also includes the effect that VRE can have on the net load and hence operating patterns and utilisation of the non-VRE plant in electricity markets, and the effect that adding VRE to a system may have on the operational efficiency, emissions and longevity of conventional power stations still on the system.

The third category is grid/network costs, which includes transmission and distribution system costs associated with the location of renewable energy.

We also discuss the extent to which VRE output is curtailed because it cannot be accommodated on the system, which may occur for both operational reasons related to frequency or voltage control, or because of transmission constraints. Whilst we categorise inertia and voltage as part of system balancing, since managing these issues can impact operational reserve requirements, we also include a separate sub-section discussing lack of inertia. This is because there is a distinction between the relative unpredictability of VRE and the fact that they are not synchronised rotating, alternating current generators and the two topics are dealt with separately in many analyses.

The evidence review process

The systematic review followed a process developed and refined by the authors over the last decade and a half to address contentious issues in the energy policy sphere by providing rigorous, transparent assessments of the available evidence [70, 71]. The process is summarised in Supplementary Figure 3. The first stage was to identify the keywords to be used in the search terms and these were then combined into 18 search strings (see Supplementary Data file), each of which was applied to Google Scholar (having first demonstrated that Google Scholar included relevant journal paper databases such as IEEE). Google was used to search for non-academic literature.

The search terms and the searches were informed by conversations with a group of eleven experts convened to advise on the research, including suggesting any known data sources. These experts represented industry (in the form of the UK system operator and specialist consultancies), academia (from three universities with specialism in this field), policymakers and international agencies (the UK government department with responsibility for this sector, its climate change advisory body, and an international agency). Documents returned by the searches went through a three step screening process by the authors. The first step assessed whether a document appeared to be broadly relevant, based on reading the title and abstract only. For those searches which returned more documents in total than could realistically be checked, the first 250 of these were initially checked for relevance. If apparently relevant documents were still being seen at the end of this set, then a further 50 were examined, and so on until no relevant documents were appearing. This approach was adopted to allow the search to be constrained so as to fit within the resources available. It is possible that some potentially relevant documents may not be revealed, if the search engine algorithm chose to return such documents sufficiently far down the set so as to be below the point where checking of the title and abstract was halted by the authors. The second step was a more detailed assessment of the resultant set based on an examination of the full text. This stage was used to assign a relevance rating to each document with 1 being the most relevant and 4 being the least (see Supplementary Data file). Only documents assigned a relevance rating of 1 or 2 (i.e. those that contained clear, relevant data, even if uncommon metrics were used) passed this step. The third step separated documents into those that had data that was both relevant and comparable (i.e. that data was presented in such a way as to allow direct quantitative comparison) and those where this was not possible (but where the document was still able to provide useful qualitative material). The numbers of documents at each step in the process are shown in Supplementary Figure 3.

Quantitative data from each of the most relevant evidence sources were collated in a series of Excel worksheets, focussing on the main categories of quantitative findings discussed in this paper i.e. operating reserve (balancing) requirements and costs, capacity credit values and costs, aggregated system integration costs, and curtailment. Within each worksheet, any cost data were normalised to 2017 Euros (€) using historical exchange rates [72] and the Eurozone harmonized index of consumer prices [73]. Data that was presented using the most common measure of VRE penetration level (i.e. the percentage of annual electricity demand met by VRE) was then used to create the charts presented in this paper. The text of this paper draws upon both this quantitative data and the qualitative evidence from the set of documents that passed the first two screening steps.

The review process has been developed by the authors to ensure that the evidence gathered is as comprehensive and as replicable as possible, within the inevitable resource constraints. The overall aim is that the results provide a robust summary of the state of the current evidence base, explain where and why results differ, and highlight the reasons for any outlying findings.

Figures in Main Text

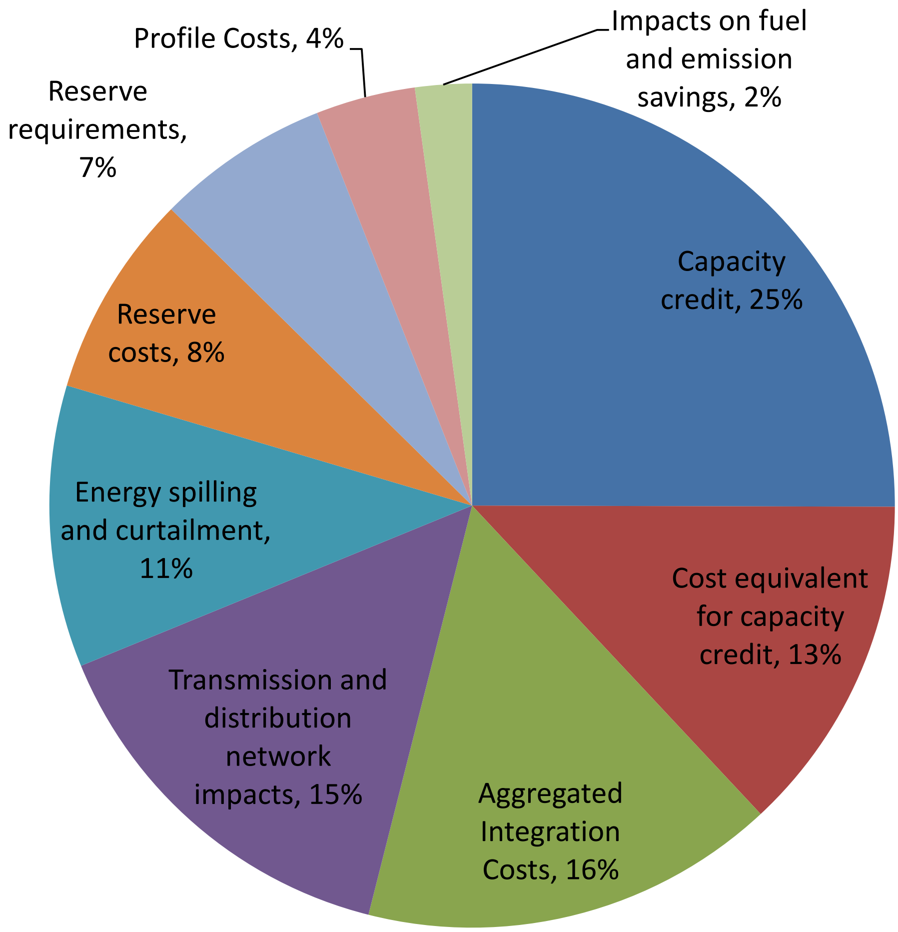

Figure 1 Breakdown of dataset by category of impact

The percentages in this figure relate to each category's share of the total number of individual data points gathered, not the number of papers or studies revealed, since many papers will deal with several categories of cost/impact.

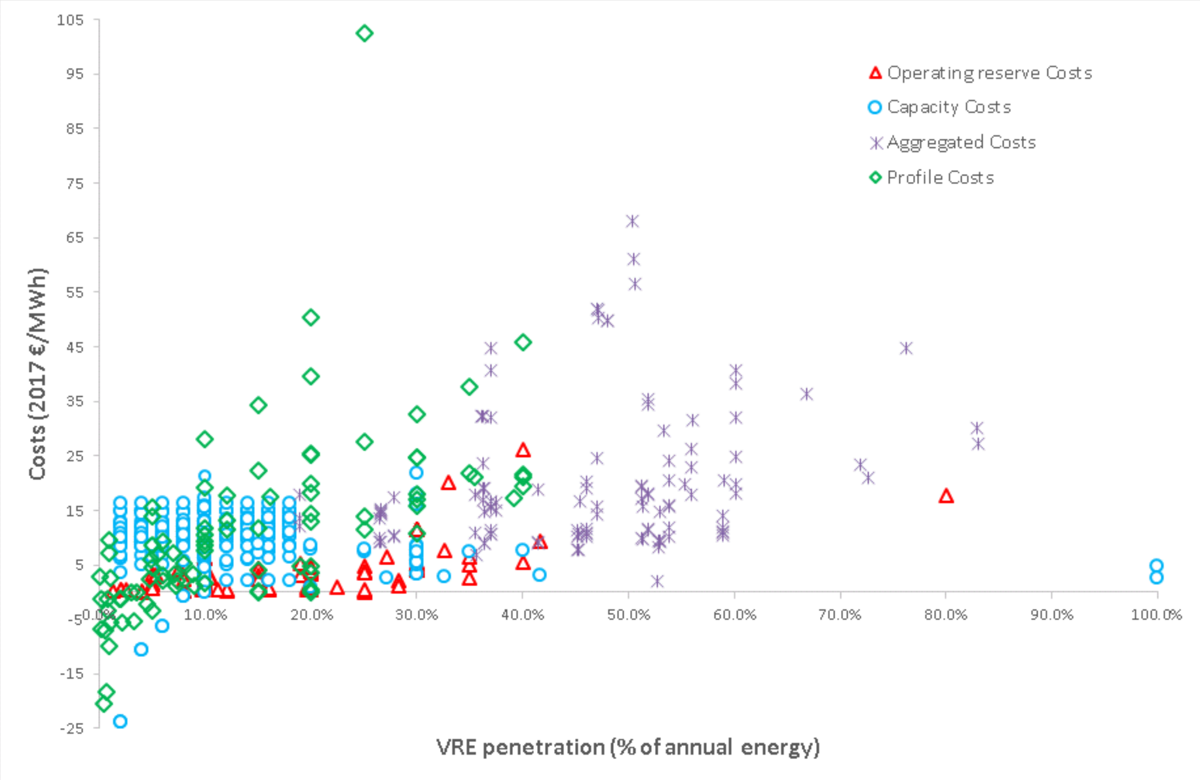

Figure 2 Data for operating reserve, capacity adequacy, aggregated and profile costs

Costs are normalised to 2017 Euros (€).VRE penetration level is expressed using the most common metric found in the literature: the percentage of annual electricity demand met by VRE. Approximately three-quarters of the entire data set used this metric. Less common metrics for assessing VRE penetration levels include the percentage of total system installed capacity and the percentage of peak system load. Findings that used these metrics are not included in the figures in this paper because the data are not directly comparable. Data sources for this figure [16, 17, 24, 33, 37, 44, 49, 74-86]. The operating reserve data were drawn from 11 studies with no single study dominated the results. Capacity cost data were drawn from 7 studies with ref. [49] contributing approximately 75% of the total number of data points. Aggregated cost data were drawn from 3 studies with ref. [24] contributing over 60% of the data. Profile costs data were drawn from 5 studies with [17] contributing a little under half of the data points. This data is available in the Supplementary Data file.

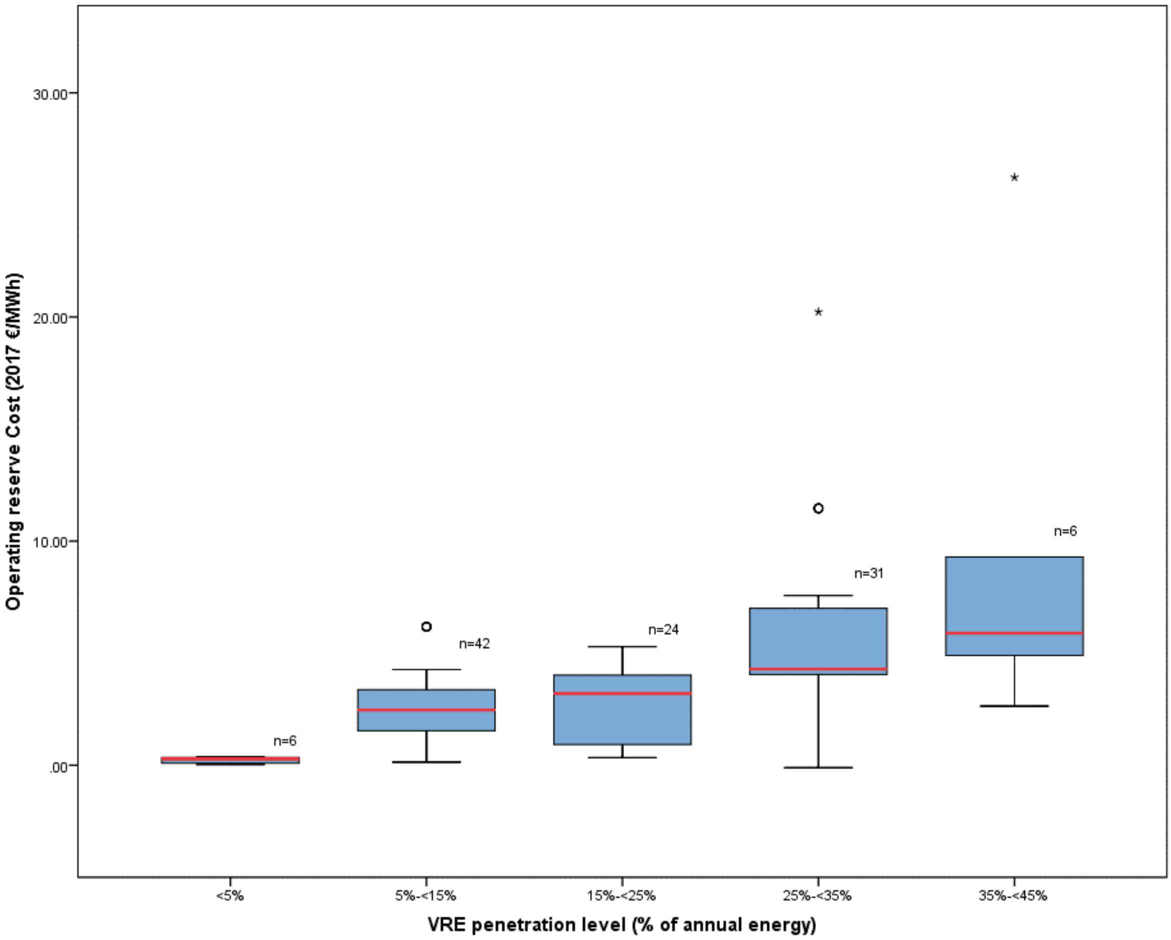

Figure 3 Operating reserves costs

Costs are normalised to 2017 Euros (€).This figure summarises the operating reserves costs data shown in Figure 2.The first data bin is for data points up to penetration levels of 5% to capture those results for very low penetration levels, with bins covering 10% ranges from that point upwards, to a maximum of 45%, which covers all the data expect the three extreme outliers described below. Within each bin the median values are shown by a horizontal red line and the blue box covers the 25^{th} to 75^{th} percentile. The vertical lines from each box extend to 1.5 times the height of the box (or the maximum and minimum values if smaller), with any values outside this range shown with a circle or star (depending on how outlying the values are). The number of data points within each bin, including outliers, is shown adjacent to each box. The single data point for additional operating reserves costs at an 80% penetration level (value of €17.66/MWh) has been excluded from this figure because it is from a highly stylised system modelling exercise [74] that investigated a specific combination of wind energy and compressed air energy storage (CAES).

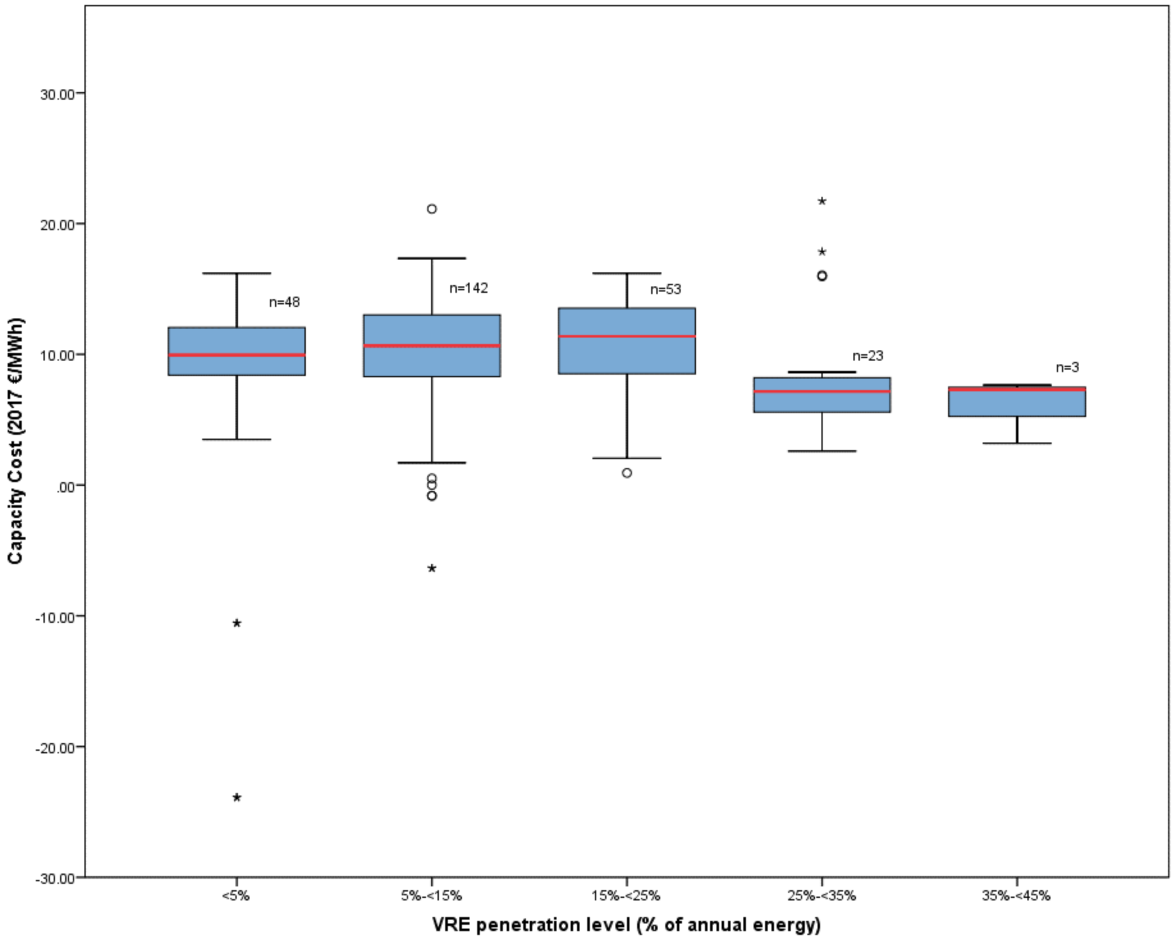

Figure 4 Capacity adequacy costs

Costs are normalised to 2017 Euros (€).This figure summarises the capacity costs data shown in Figure 2.Within each bin the median values are shown by a horizontal red line and the blue box covers the 25th to 75th percentile. The vertical lines from each box extend to 1.5 times the height of the box (or the maximum and minimum values if smaller), with any values outside this range shown with a circle or star (depending on how outlying the values are). The number of data points within each bin, including outliers, is shown adjacent to each box. Data from [49], relating to the capacity costs of PV for a range of European countries, features strongly in the first three bins but not at all for the two higher penetration level bins. The two data points for the additional capacity costs at a notional 100% penetration level (the values of €2.50/MWh and €4.75/MWh from [83]) have been excluded from this figure because they are the result of an assumption that all the conventional generators required to ensure that demand peaks can be reliably met are open-cycle gas turbines (OCGT). These have very low capital costs but much higher running costs when compared to more efficient combined-cycle gas turbines (CCGT). In isolation, this may well be a low cost method of providing reliable capacity but is very unlikely to deliver the lowest overall system costs.

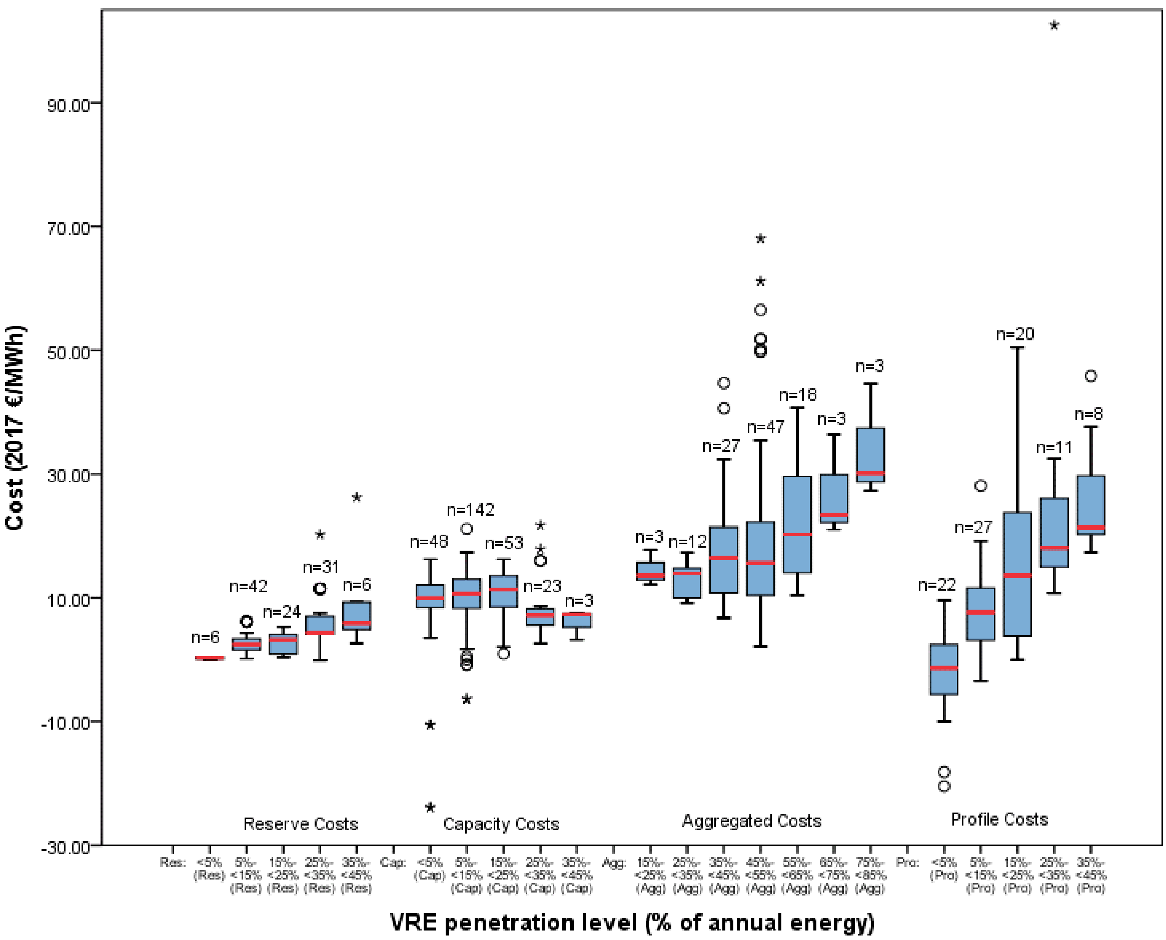

Figure 5 operating reserve, capacity adequacy, aggregated and profile costs.

Costs are normalised to 2017 Euros (€).This figure summarises the full data set shown in Figure 2.Within each bin the median values are shown by a horizontal red line and the blue box covers the 25th to 75th percentile. The vertical lines from each box extend to 1.5 times the height of the box (or the maximum and minimum values if smaller), with any values outside this range shown with a circle or star (depending on how outlying the values are). The number of data points within each bin, including outliers, is shown adjacent to each box.

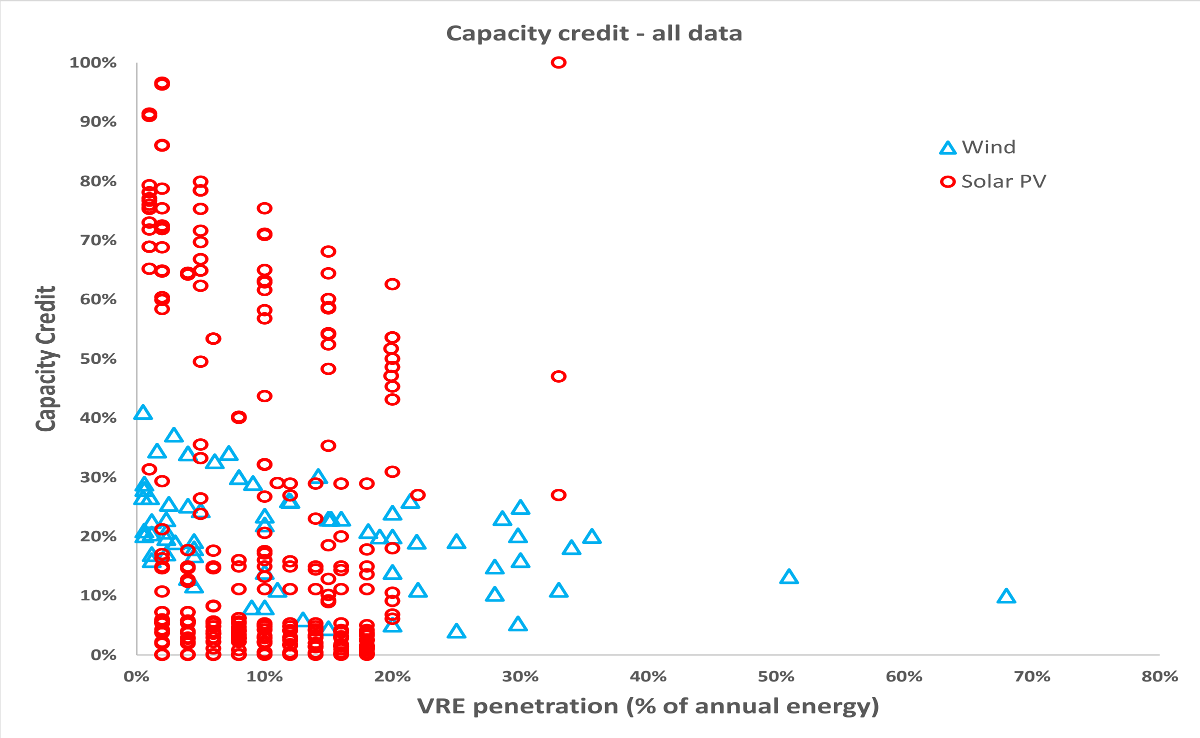

Figure 6 Capacity credit data by VRE type

This figures plots the capacity credit data, split by VRE by technology type to allow comparison between wind and solar power. Data sources for this figure: [38, 49, 52, 75-77, 79, 87-89]. The data were drawn from 10 studies with [49] contributing over half of the data points. This data is available in the Supplementary Data file.

Data availability

The quantitative data shown in Figures 2-6 and described in this paper (and in the Supplementary Information) are available in the Supplementary Data file. They will also be deposited with the UKERC Energy Data Centre, a UK Research Councils funded data repository hosted by the STFC Rutherford Appleton Laboratory (https://ukerc.rl.ac.uk/) Once deposited in the UKERC Energy Data Centre, the data will be publically and freely available.

Author contribution statement

Both authors contributed extensively to the work presented in this paper, including conception of the study, data identification and analysis, and drafting of the manuscript.

Competing interests

The authors declare no competing interests.

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Supplementary Information

Supplementary Table 1 Terminology

A wide range of similar sounding and sometimes overlapping terms are used in the discussion of renewables integration. Terminology also differs between grid control areas and has changed over time. This can lead to conflict and confusion and in earlier work we identify terminology as a key cause of controversy [1]. For this reason, we use carefully defined terms, based on industry norms. Supplementary Table 1 below provides a short summary of some key nomenclature, and defines the terms based on those used by the GB System Operator and European TSOs [2-5].

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.
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. For further discussion of these definitions, see, for example [6, 7]. 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.
Capacity factor (also called Load 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.
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 counter-party for contracts to balance demand and supply. Also see ‘Balancing Mechanism’.
Operating Reserves	In most countries frequency response and reserve services are purchased by the System Operator in order to ensure there is sufficient capability to undertake system balancing actions and frequency control. Reserve services provide for un-forecast demand increases (or decreases) and/or the unplanned unavailability of generators. They are provided through a range of synchronous and non-synchronous resources contracted through tender processes. See also ‘Balancing Services’. Many definitions focus on the timescale for operation and whether reserve services come in action automatically or in response to instruction from the TSO. Also how long the service can sustain for. Time of response varies from less than a second to hours and services are also differentiated by duration – from less than a minute to several hours. ENTSO-E distinguish between “Frequency Containment”, “Frequency

Term	Definition
	Restoration” and “Replacement”. The GB System Operator defines a range of Frequency Response services the system operator for Great Britain lists fifteen different categories including ‘Demand side response’, ‘Enhanced frequency response’, ‘Fast reserve’, ‘Firm frequency response’, and ‘Short term operating reserve’ – at least some of which can be provided through electricity storage technologies
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 VRE output data, plant failure and maintenance.
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.

Supplementary Notes 1 Calculating operating reserve requirements

Operating reserve requirements are determined by probabilistic analysis, taking into account data for historical demand fluctuations, unplanned unavailability of conventional plant, the degree of fluctuation in VRE output and the size of VRE output forecasting errors [8, 9]. Increasing the amount of variable renewable generation connected to a system would typically be expected to increase the amount of operating reserves that are required to ensure that supply matches demand at all times. However, at low penetrations of VRE their impact on operating reserves tends to be modest because there is only a small change in the total variance that needs to be covered to keep the system reliable. These notes provide a description of the basic principles used to assess operating reserves requirements and uses a simplified example to illustrate this point. The UKERC report of 2006 provides a simplified explanation of the statistical fundamentals of adding VRE to existing operating reserve requirements. A revised version of the main points are reproduced here.

Operating reserve is used to handle unpredicted short term variations resulting from demand prediction errors or generation failures i.e. where there is a difference between predicted and actual supply and demand. Operating reserve needs are calculated through analytical techniques using statistical principles or simulation models based on statistical principles. The objective is to ensure that operating reserves are available that can deal with almost all the unpredicted short term variations that can be envisaged. The analytic techniques presented here provide approximate results but simulations are needed to deal with the more complex real-world situations faced by system operators, for example where correlations between variables exist or where generator outputs need to be managed to cope with grid constraints. We present the analytical approach in order to provide an explanation of principles that come into play.

Historically, operating reserves have been sized to cover approx. ±3 standard deviations of the potential uncertain fluctuations that arise from this combined demand prediction error and generation plant failure (informed by empirical data for plant reliability). Power system planners add to this a provision for the sudden loss of the largest single unit (known as n-1 criteria, or disturbance reserve). The ±3 criteria ensure 99% of unpredicted demand or supply fluctuations are covered by reserves: Reserves = $\pm 3\sqrt{(\sigma_d^2+\sigma_s^2)}$ (plus disturbance reserve) where $\sigma_d \sigma_s$ represent the standard deviations of fluctuations in demand and supply respectively. When intermittent generation is added the variance of the supply side term increases. This is usually estimated by adding the effect of intermittence to existing operating reserve requirements – that is to say, adding the variance of unpredicted fluctuations in intermittent supply to the variance of demand and conventional supply.

Two factors are notable: First that even for a relatively unpredictable intermittent source like wind power the standard deviation of unpredicted output fluctuations in the period from minutes to a few hours is relatively modest. This is because there is considerable smoothing of outputs in the sub-hourly timeframe (a result of the aggregation of outputs from a geographically dispersed wind turbine fleet), and considerable prediction accuracy up to a few hours ahead. Secondly, variance of intermittent fluctuations must be combined statistically with the variance of demand and conventional supply. These factors suggest that operating reserve impacts from intermittency will be relatively modest.

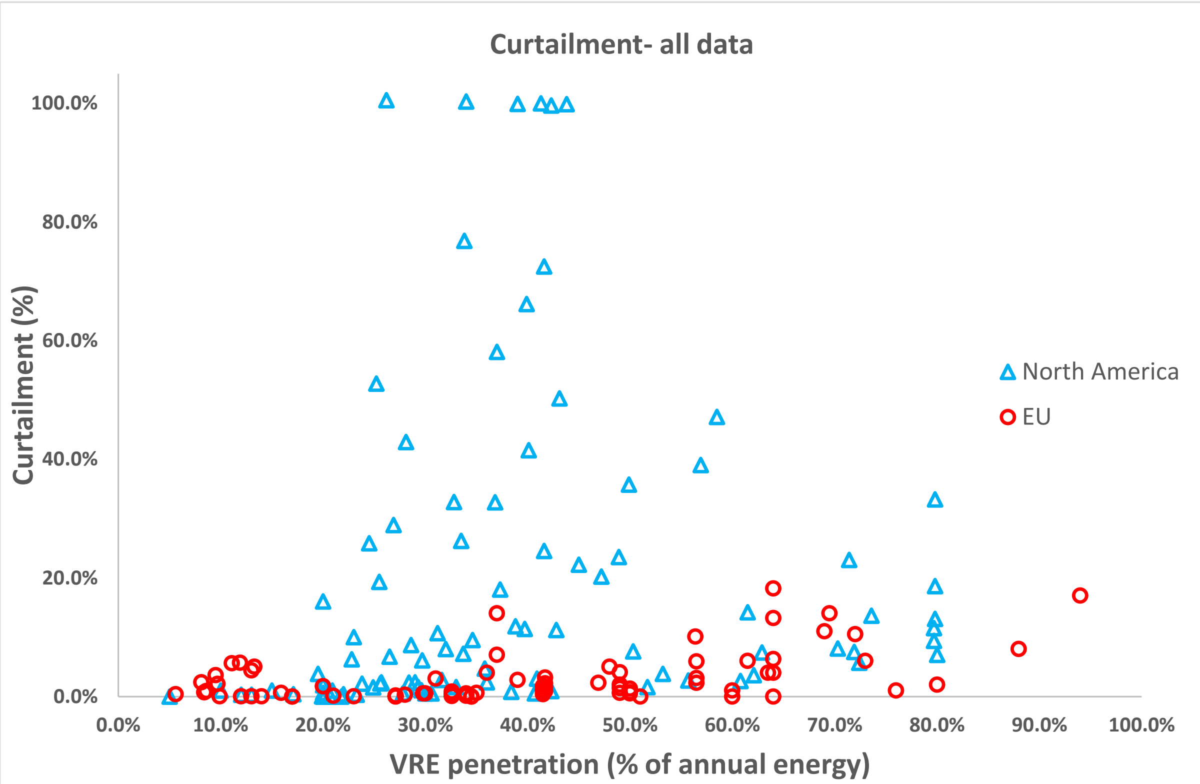
It is possible to provide a simple example of this in practice, based on analysis of wind data for Great Britain [10]. The standard deviation of wind forecast errors at the half hourly time horizon was found to be 1.4% of installed wind capacity. For example, if 10GW of wind was installed, the standard deviation is 140 MW. This means that the range of possible changes (99% or 3 standard deviation s) would be ±420 MW. The report notes that the standard deviation of demand and conventional generation $\sqrt{(\sigma_d^2+\sigma_s^2)}$ is around 340 MW at the half hour period. Therefore the standard deviation with wind would be $\sqrt{(340^2 + 140^2)}$ or 368 MW - a minor addition. Operating reserve requirements, excluding disturbance reserve, would be $\pm 3\sqrt{368^2}$ or 1103 MW – compared to 1020 MW without wind. In both cases total GB reserves would also require 1.1 GW disturbance reserve – hence in this example 10 GW wind accounts for less than 100 MW reserve needs out of approximately 2.2 GW total operating reserve needs. Note that for the purposes of this illustration we assume wind forecast errors are normally distributed, when in fact the distribution is usually somewhat skewed - but the broad point and principles are unaffected. Note also that whilst we have used a notional figure of 10GW of wind installed in this example (which would supply approximately 7 % of GB electricity), the GB system now has approaching 14GW of onshore wind capacity installed, which provides around 10% of electricity.

Supplementary Notes 2 Curtailment

The owners of a VRE plant would typically want that plant to generate electricity whenever the variable resource is available, provided the price at which it can be sold exceeds operating costs. This is because the marginal costs of generation are near to zero and maximising the plant output ensures that the capital and fixed operating costs are spread across the maximum units of output, effectively minimising the LCOE [11]. However, there may be times when the output from a VRE plant cannot be accepted onto the electricity system and the output from the VRE plant would need to be curtailed. This may happen either because of transmission or distribution grid constraints, or where VRE output would otherwise exceed instantaneous demand net of any conventional generation required to provide essential services to the system such as operating reserves and inertia (described below) [12]. Evidence from analysis of the German and British electricity systems suggest that transmission constraints are the dominant factor [13].

From the VRE owner's perspective, curtailment increases both the levelised cost (as the denominator in the LCOE calculation is reduced) and represents a potential revenue loss. Alternatively this can be viewed as a reduction in the marginal value of VRE output. Curtailed output would normally offer no benefits for the system or revenue to the generator, although it is possible for wind farms operating below maximum output to contribute to system balancing or provision of reserve services. Curtailment could therefore be considered as fully internalised into generation costs and traditional LCOE. However we align here with [14] who state that [these costs] 'depend on the system e.g. the temporal patterns or grid infrastructure we rather separate them from pure generation costs.' Curtailing the output of VRE would also be expected to reduce the CO_2 and other emission reductions that would result from operating VRE. However, from a system (or societal) perspective, what is required is a total cost-minimising solution to meeting demand. The key trade-off here is between the implied cost of VRE output being curtailed and the cost of grid reinforcement or system balancing actions to reduce curtailment. Therefore, there may be circumstances where it is economically optimal (that is least overall cost to society) to accept some curtailment of the output of VRE plant on those occasions when full production cannot be accepted onto the system [15, 16].

Supplementary Figure 1 presents the full curtailment data set gathered for this review, with approximately 180 data points. A little over half of the data set relates to North American studies (almost all from the US), with the remainder being EU-based studies. Whilst some analyses, such as [17] present both average and marginal curtailment values, we have used the average curtailment values.

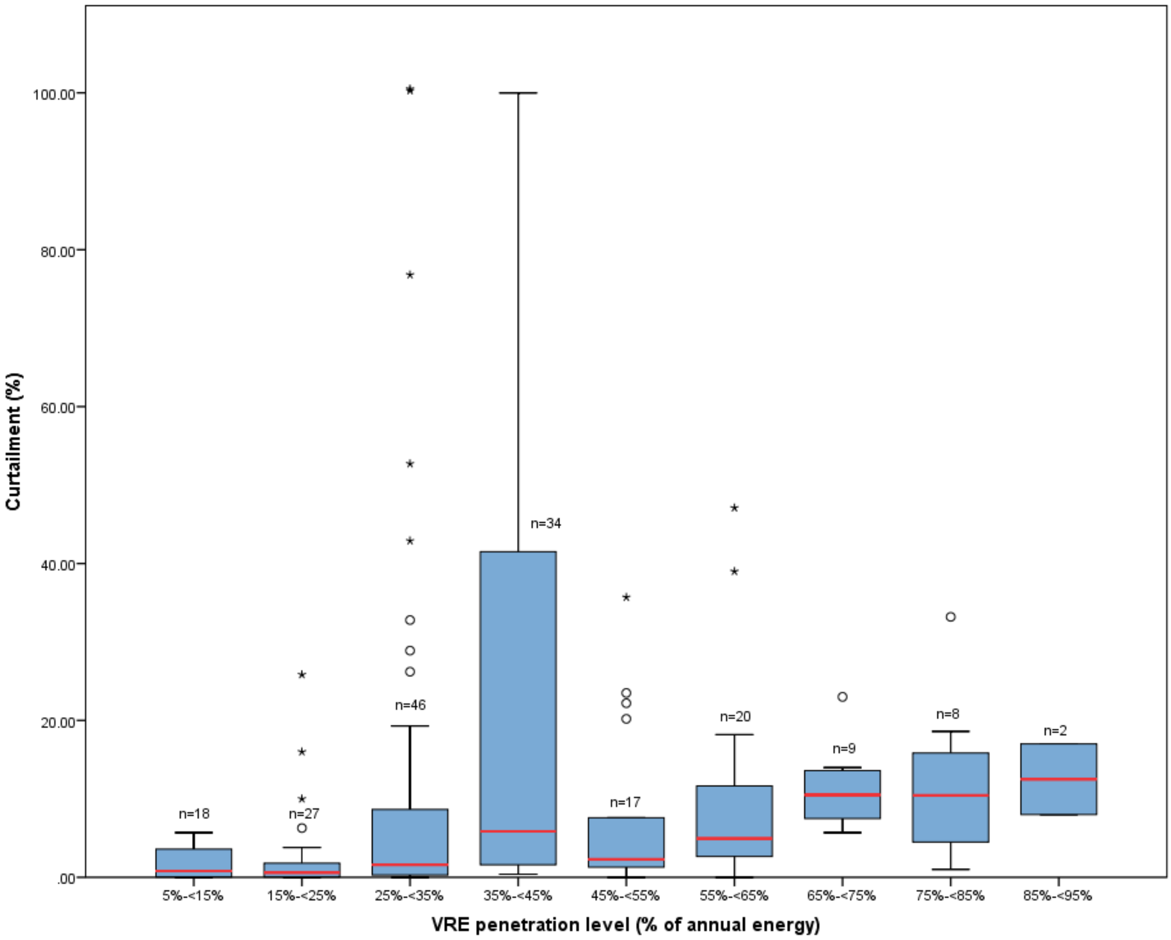


Supplementary Figure 1 VRE curtailment data

Notes: As for the previous charts, the VRE penetration level is expressed as the percentage of annual electricity demand that is met by VRE. The curtailment level on the y-axis is expressed as the percentage of annual VRE production that is curtailed, relative to the VRE production that is accepted onto the electricity system. Data sources for this figure: [13, 17-34]. The data were drawn from 19 studies with no single study dominating the results. This data is available in the Supplementary Data file.

Supplementary Figure 1 shows that the modelled levels of VRE curtailment from the primarily EU-based analyses are generally low, even at very high VRE penetration levels. Real world curtailment data collected for Germany and Britain is consistent with this with values of approximately 1%-6% for Britain and 1%-5% for Germany for the period from 2012 to 2016 [13]. The majority of the results from North American studies also suggest that VRE curtailment will be relatively low, but there are several higher results and a small number of very high outlying values. This perhaps reflects a greater willingness in some of the North American studies to explore a very wide range of possible system flexibilities, and also the strong interconnection between many European systems which can help minimise curtailment levels. The extreme outliers, shown clearly in Supplementary Figure 2, have curtailment levels above 50% and are drawn from a single study [20]. This study, which described the curtailment values they presented as 'percent of total demand', modelled the impact of adding VRE to a system up to an approximately 50% VRE penetration level without making any relevant changes to the remainder of the electricity system (such as more flexible conventional generation, grid reinforcement or demand-side measures). This would not be an economically rational course of action on any real system and we include the results from this outlying study because they help to demonstrate the need for system adaptation to minimise the additional costs of VRE.

Supplementary Figure 2 groups the curtailment data into bins based on ranges of penetration levels. The first bin starts at a 5% penetration level since no data was found below this level, with bins covering 10% ranges from that point upwards, to a maximum of 95%, which covers the entire curtailment data set. However, even without the outliers described above (which are only present in the 25-<35% and 35-<45% bins), there is still a relatively wide range of results within penetration-level groups. This reflects the sensitivity of curtailment levels to the characteristics of the system to which VRE is added, in particular the flexibility of the other generators on the system, the degree of correlation between VRE output and demand, and transmission and distribution grid capacity.



Supplementary Figure 2 VRE curtailment

Notes: This figure summarises the curtailment data shown in Supplementary Figure 1.Within each bin the median values are shown by a horizontal red line and the blue box covers the 25th to 75th percentile. The vertical lines from each box extend to 1.5 times the height of the box (or the maximum and minimum values if smaller), with any values outside this range shown with a circle or star (depending on how outlying the values are).). The number of data points within each bin, including outliers, is shown adjacent to each box. Data sources for this figure : [13, 17-34].

Despite the wide range of results, the median values for the share of VRE output curtailed across all penetration level bins is consistently low, not exceeding 5% (25th-75th percentile: 0.5-8.87%) until penetration levels are above 65% of energy from VRE, and not exceeding 12.5% (25th-75th percentile: 0.5-10.84%) for any penetration level. The overall message therefore is that most studies find that the level of VRE curtailment is likely to be low.

Supplementary Notes 3 Impact on conventional plant efficiency and emissions

An important additional aspect of profile costs is the impact of VRE on the operational regime and efficiency of generators used to meet net loads [35]. Adding VRE to an electricity system may change the way in which some of the conventional plant on that system is operated. Impacts include faster ramping or cycling rates (rate of increase or decrease in output), or operating for longer periods at low output levels. More frequent variation in the output of conventional thermal generators may reduce the operating efficiency of these plants and/or mean that these plants operate in a manner which affects emissions of other pollutants such as nitrogen oxides (NOx). More frequent start-ups and shut-downs, and variations in output will also put additional thermal stress on components which may reduce their service life [36-38]. These effects may be reduced (but not eliminated) by more accurate forecasting of VRE output.

Those studies that have addressed these impacts use a range of different measures for both penetration levels and efficiency losses, which prohibits direct comparison. A relatively small number of studies that addressed the impact of VRE on relative emissions (i.e. relative to what emissions savings would be in the absence of any efficiency-related reductions) were identified. However, the bulk of the studies examined that addressed the efficiency and emissions impacts on thermal generation of adding VRE to a system find that the effects are small. Of the maximum theoretical emissions benefits from installing VRE less than 6% were lost through reduced efficiency of the conventional plant, even at relatively high penetration levels [39, 40] (although [40] does not address the effect of thermal plant starts and stops). The relatively small scale of these impacts is confirmed in other reviews, for example [35], who refers to these as 'flexibility effect', presents a small amount of data suggesting that costs are below $3/MWh and concludes that the economic impact of increased cycling is small.

Supplementary Notes 4 The technical characteristics of VRE and impacts on frequency and voltage

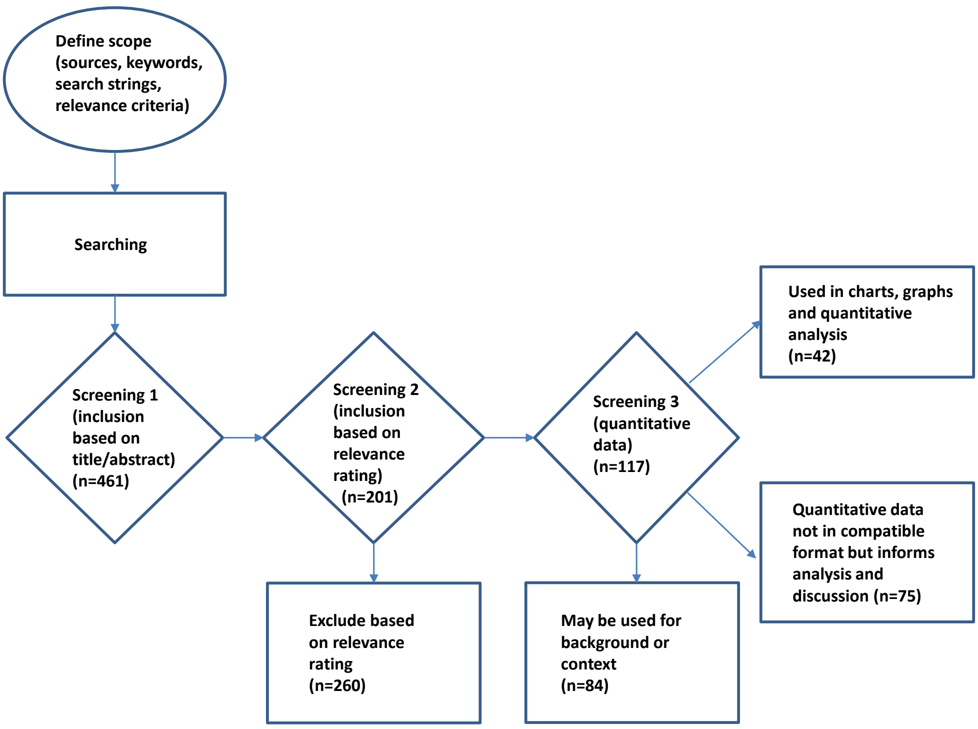
Wind and solar have technological characteristics which can affect power system operation, in particular their contribution to maintaining frequency and voltage. These issues are somewhat distinct to the unpredictable nature of VRE output, though may also affect reserve requirements. Before the advent of VRE, most electricity systems relied upon generating technologies which use large, relatively fast-rotating generators which are electro-magnetically linked to their host electricity system (and therefore to each other). This characteristic provides a degree of resilience to disturbances to the system such as the breakdown of a generator [41, 42]. This is because in the case of a generator failure the increased electrical load on the other operating generators will cause the rotation speed of those generators to reduce, but the rate at which this reduction happens is slowed by the generators giving up some of the kinetic energy in their rotating masses to the system. The overall effect of this 'system inertia' is to slow down what is known as the rate of change of frequency (ROCOF). This reduces the negative impact of a system disturbance and allows crucial time (typically only a few seconds) for compensating operating reserve actions to be taken, either automatically or through active intervention by the system operator [43].

VRE generators, as currently typically designed and configured, may not contribute to the inertia of an electricity system, which means that the resilience of a system to a disturbance may reduce as the instantaneous penetration of VRE reaches high levels. One response by system operators to this reduced system inertia has been to limit the instantaneous penetration level of VRE (see 'curtailment' above), and also to investigate the provision of synthetic system inertia [44] using power electronics to harness the large rotating mass of wind turbines so that they are able to contribute to overall system inertia. Interconnection of an electricity system can also help. Electricity systems which are strongly linked to others grids have demonstrated that they are able to accept very high instantaneous penetrations of VRE [45]. Partly in response to this challenge of reduced inertia, some system operators are also tendering for new classes of very fast frequency response such as 'enhanced frequency response' – very rapid/instantaneous operating reserve services usually provided by battery storage [46].

Analyses of system inertia impacts has tended to focus on the technical implications and/or assessments of the maximum instantaneous VRE penetration level for a given system (and what system changes may be required to increase this threshold), rather than a focus on the cost implications [47, 48]. Therefore we are not able to present cost data here. Any additional fast frequency response contracts would show up in assessments of operating reserve costs described above, but the review did not reveal data providing this level of detail.

Many of the impacts on voltage are focused on the low voltage distribution network impacts of clusters of PV leading to voltage increase. There may also be more complex affects such as phase imbalance. However systems with weak transmission grid may also encounter voltage-related issues with high VRE penetration levels. Whilst some of these effects do have a time of day dimension (for example, voltage rises in line with PV output, particularly when demand is low) we are not aware of any studies that have attempted to quantify the cost implications and reflect them in analysis of the costs of integrating VRE. For a review of the impact of PV on voltage see [49]. Overall, we conclude that the impact on costs of the operating characteristics of wind and solar energy appear to be small, but that these impacts have the potential to become significant at very high penetration levels. Perhaps more importantly these effects may impose constraints on either the instantaneous penetration of wind and solar or the concentration of solar capacity in some grid supply areas. Both these concerns will show up in other cost categories since they will add to curtailment or operating reserve requirements.

Supplementary Figure 3



Supplementary Figure 3 The systematic review process

The protocol for our process is shown here, with numbers of documents accepted/rejected at each screening stage.

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