

# Integration costs revisited – An economic framework for wind and solar variability<sup>☆</sup>



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## ABSTRACT

The integration of wind and solar generators into power systems causes “integration costs” – for grids, balancing services, more flexible operation of thermal plants, and reduced utilization of the capital stock embodied in infrastructure, among other things. This paper proposes a framework to analyze and quantify these costs. We propose a definition of integration costs based on the marginal economic value of electricity, or market value – as such a definition can be more easily used in economic cost-benefit assessment than previous approaches. We suggest decomposing integration costs into three components, according to the principal characteristics of wind and solar power: temporal variability, uncertainty, and location-constraints. Quantitative estimates of these components are extracted from a review of 100 + published studies. At high penetration rates, say a wind market share of 30–40%, integration costs are found to be 25–35 €/MWh, i.e. up to 50% of generation costs. While these estimates are system-specific and subject to significant uncertainty, integration costs are certainly too large to be ignored in high-penetration assessments (but might be ignored at low penetration). The largest single factor is reduced utilization of capital embodied in thermal plants, a cost component that has not been accounted for in most previous integration studies.

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## 1. Introduction

As with any other investment, wind turbines and solar cells incur direct costs in the form of capital and operational expenses. These costs can be aggregated to average discounted life-time costs, called “levelized energy costs” or “levelized costs of electricity” (LCOE). In addition, integrating wind and solar power or other variable renewable energy sources (VRE)<sup>1</sup> into power systems causes costs elsewhere in the system. Examples include distribution and

transmission networks, short-term balancing services, provision of firm reserve capacity, a different temporal structure of net electricity demand, and more cycling and ramping of conventional plants. These costs have been called “hidden costs” [3,87], “system-level costs” [19,61], or “integration costs” [67,33,68,53–55,58]. These need to be added to direct costs of wind and solar power when calculating total economic costs.<sup>2</sup> Integration costs are relevant for policy making<sup>3</sup> and system planning; ignoring or underestimating these leads to biased conclusions regarding the welfare-optimal generation mix and the costs of system transformation. This paper proposes a valuation framework for variable renewables and offers a new perspective on integration costs.

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<sup>1</sup> Variable renewables have been also termed “intermittent”, “fluctuating”, or “non-dispatchable”.

<sup>2</sup> Total economic costs is the sum of all direct and indirect costs of increasing VRE generation. Total economic costs can be used to calculate welfare-optimal deployment levels, conducting cost-benefit analysis, or comparing LCOE across generation technologies. We define this term more rigorously in Section 2 and label it “System LCOE”.

<sup>3</sup> There has been a major public policy debate on integration costs in recent years in many countries, including the USA, the UK, and Germany.

Previous studies have identified three specific characteristics of VRE that impose integration costs on the power system [9,68,86]:

- The supply of VRE is *variable*: it is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable power plants. VRE generation does not perfectly follow load and electricity storage is costly, so integration costs occur when accommodating VRE in a power system to meet demand.
- The supply of VRE is *uncertain* until realization. Electricity trading takes place, production decisions are made, and power plants are committed significant time in advance of physical delivery. Deviations between forecasted VRE generation and actual production need to be balanced at short notice, which is costly.
- The supply of VRE is *location-specific*, i.e. the primary energy carrier cannot be transported in the same way as fossil or nuclear fuels. Integration costs occur because electricity transmission is costly and good VRE sites are often located far from demand centers.<sup>4</sup>

While these properties of VRE are well-known and the term “integration costs” is widely used, there does not seem to be a consensus on a rigorous definition [68]. Previous studies have defined integration costs as “an increase in power system operating costs” [67], as “the additional cost of accommodating wind and solar” [68], as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” [53], as “the cost of managing the delivery of wind energy” [26], as “comprising variability costs and uncertainty costs” [58], or as “additional costs that are required in the power system to keep customer requirement (voltage, frequency) at an acceptable reliability level” [54].<sup>5</sup> All these definitions are qualitative and challenging to operationalize. According to our reading of the literature it is not clear how to interpret the sum of generation and integration costs, and if and how integration cost estimates can be used for economic analyses of VRE – such as calculating their welfare-optimal deployment, conducting cost-benefit analysis, or comparing LCOE across generation technologies.

Lacking a rigorous definition, integration studies typically operationalize integration costs as the sum of three cost components: “adequacy costs”, “grid costs”, and “balancing costs”. However, there is no consensus on how to consistently calculate and compare each of these cost components, and it is not clear if this enumeration is exhaustive.

This paper addresses these issues by making two contributions to the literature. First, we propose a valuation framework for wind power. This includes a definition of integration costs that has a rigorous welfare-economic interpretation, and a decomposition of these costs into three components. We show that reduced capital utilization has a major impact and explain why it has not been accounted for in many previous studies. Second, we provide a

quantification of these components, based on an extensive literature review.

Section 2 provides the definition and Section 3 proposes the decomposition. Section 4 discusses the underlying technical constraints that explain integration costs, with a focus on reduced capital utilization. Section 5 reviews the literature and extracts quantitative estimates while Section 6 elaborates on who bears the costs under current market and policy design and identifies externalities. Section 7 concludes.

Readers mainly interested in numerical findings might proceed directly to section 5. The costs of forecast errors (“balancing costs” in our terminology) are found to be less than 6 €/MWh even at high wind penetration rates. In contrast, the reduction of energy value (“profile costs”) are 15–25 €/MWh at high penetration. Increasing wind penetration affects profile costs about ten times more than balancing costs.

## 2. A new definition of integration costs

Our definition of integration costs aims to be economically rigorous and comprehensive. Integration costs should be defined such that they can be used in economic assessments, e.g. on the welfare-optimal deployment of VRE. Moreover, the definition should include all economic impacts of variability to make sure that an economic evaluation of VRE is complete.

The definition of integration costs is derived from the marginal economic value of electricity from VRE in terms of €/MWh. The marginal economic value (or benefit) is the increase in welfare when increasing wind generation by one MWh. If demand is perfectly price-inelastic, this equals the incremental cost savings when adding one MWh to a power system. This value is impacted by the properties of VRE mentioned in the introduction: variability, uncertainty, and location. Here we assume perfect and complete markets so that the marginal value of VRE equals the market value.<sup>6</sup> The market value is the specific (€/MWh) revenue that an investor earns from selling the output on power markets – excluding subsidies such as green certificates or feed-in premiums. In other words, the market value is the wind-weighted average electricity price,  $p_{\text{wind}}$ . A formal definition can be found in the Appendix.

Previous studies have shown that the characteristic properties of VRE reduce the market value of VRE with increasing VRE penetration [30]; [8,32,44,57,62,70,72]. This reduction in market value is caused by the interaction of VRE variability<sup>7</sup> and the inflexibilities of the rest of the power system. We interpret this reduction as integration costs. Already at this point it becomes clear that integration costs are not “caused by VRE”, but by the interactions of VRE and power system properties.

We define integration costs of wind  $\Delta_{\text{wind}}$  as the market value of wind  $p_{\text{wind}}$  compared to the load-weighted average electricity price  $p_{\text{electricity}}$ .<sup>8</sup>

$$\Delta_{\text{wind}}(q) = p_{\text{electricity}}(q) - p_{\text{wind}}(q) \quad (1)$$

<sup>4</sup> VRE generators have more specific characteristics, e.g. they are typically not electromechanically synchronized with the system frequency and hence provide no inertia to the system. We believe, in accordance with most authors, that the economic implications of these features are small, and neglect them in the further discussion.

<sup>5</sup> According to most definitions (including ours), it is not only VRE that are associated with integration costs. In Ref. [45]; we generalize the concept of integration costs to all generating technologies. Moreover, strictly logically one cannot say that VRE “cause” integration costs, as such costs emerge from the interaction of VRE and the rest of the power system. This implies that integration costs are not only affected by the properties of the VRE generator, but are system-specific. On the “cost-causation” debate see Ref. [68].

<sup>6</sup> We assume perfect and complete markets mainly to allow a more simple terminology. In Ref. [45] we drop this assumption and use the more general (but also more complicated) terminology.

<sup>7</sup> We use *variability* as an umbrella term for the three characteristic properties of VRE: temporal variability, uncertainty, and location.

<sup>8</sup> The average electricity price is chosen as a point of reference to estimate integration costs. It corresponds to the market value of a benchmark technology that generates electricity in perfect correlation with load. Choosing other reference points would be possible, but the average electricity price has a number of advantages [45]. With a different reference point, integration costs and System LCOE are different, but resulting optimal VRE shares are the same.

This definition of integration costs is comprehensive as it captures the economic impact of all characteristic properties of a technology that reduce (or increase) its market value. It implies that *all* generating technologies have integration costs, not just VRE. As prices reflect marginal costs, this definition specifies integration costs in marginal, not average, terms.

A key strength of this definition is that it reconciles the concept of integration costs with standard economic theory: it is a basic economic principle that the welfare-optimal deployment  $q^*$  of a technology is given by the point where market value  $p_{wind}(q)$  and marginal costs coincide. The long-term marginal costs of a technology can be expressed as LCOE (€/MWh). Hence, VRE like any technology, are optimally deployed when their market value equals their LCOE.<sup>9</sup>

$$p_{wind}(q^*) = LCOE_{wind}(q^*) \tag{2}$$

$$p_{electricity}(q^*) - \Delta_{wind}(q^*) = LCOE_{wind}(q^*)$$

As defined here, integration costs can be used for the economic evaluation of VRE and have a welfare-economic interpretation. Integration costs reduce the market value of VRE and consequently reduce their optimal deployment  $q^*$ . We refer to this way of accounting for integration costs and evaluating VRE as the *value perspective* (Fig. 1, left).

There is an alternative but equivalent perspective of understanding integration costs. From a *cost perspective*, integration costs can be added to the LCOE of wind, resulting in the metric “system levelized costs of electricity” (system LCOE, [96]). This metric comprises the total economic costs of a technology (Fig. 1, right).

$$sLCOE_{wind}(q) = LCOE_{wind}(q) + \Delta_{wind}(q) \tag{3}$$

In the cost perspective the above optimality condition (equation (2)) can be analogously formulated: VRE, like any technology, are welfare-efficient when their system LCOE equals the average electricity price.

$$p_{electricity}(q^*) = sLCOE(q^*) \tag{4}$$

Consequently the sum of generation and integration cost (system LCOE) of each generation technology is identical in the long-term optimum.

This shows that there are two ways of accounting for integration costs. First, from a value perspective they reduce the market value of a technology, and second, from a cost perspective they can be added to the marginal costs (LCOE) of a technology. Fig. 2 illustrates this duality. Integration costs of VRE tend to increase with VRE penetration. At low penetration VRE typically have negative integration costs because their output is often positively correlated with demand. The welfare-optimal deployment  $q^*$  is equivalently given either at the intersection of market value and LCOE, or where system LCOE intersect with the average electricity price.

A cost perspective has at least three merits [96]: LCOE is commonly used in industry, policy, and academia as a metric to compare technologies - apparently there is demand for cost comparisons. System LCOE can correct the flawed metric while retaining its intuitive and familiar touch. Secondly, a cost perspective is often applied by the integration cost literature. System LCOE can help to connect this literature with the economic literature on market value. Finally, a cost metric that comprises generation and integration costs can help parameterize VRE variability in multi-sector models.

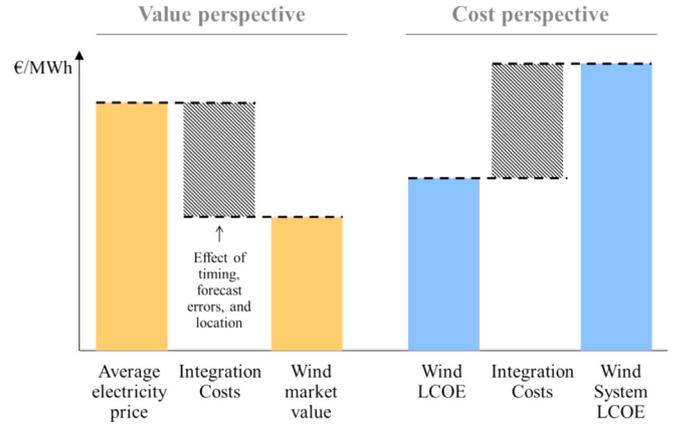


Fig. 1. We define wind integration costs as the gap between its market value and the average electricity price. The *value perspective* (left) is equivalent to the *cost perspective* (right).

Integration costs not only depend on the characteristics of VRE technologies but also on the power system into which they are integrated, and the power system's flexibility to adapt [97]. Published studies typically estimate integration costs by analyzing the impact of VRE on currently existing power systems with a fixed capacity mix and transmission grid. This is a short-term perspective. Integration costs depend on the properties of the legacy system: short-term integration costs are increased by a large stock of inflexible and capital-intensive base-load power plants, a scarce grid connection to regions with high renewable potentials and an inflexible electricity demand profile that hardly matches VRE supply.

In contrast, over the long term, the power system can fully and optimally adapt to increased VRE volumes. These potential changes comprise operational routines and procedures, market design, increased flexibility of existing assets, a shift in the capacity mix, transmission grid extensions, a change in load patterns, demand-side management and technological innovations. Integration costs can be expected to be generally smaller in the long term than in the short term (Fig. 3). Hence, short-term costs should be carefully interpreted and should not be entirely attributed to VRE. Integration cost studies should be explicit about the assumed time horizon

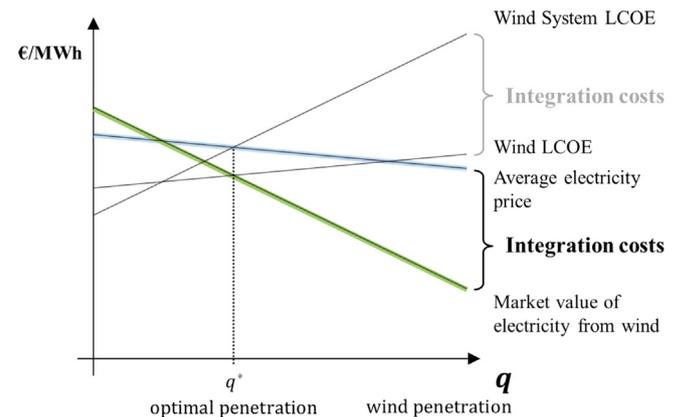
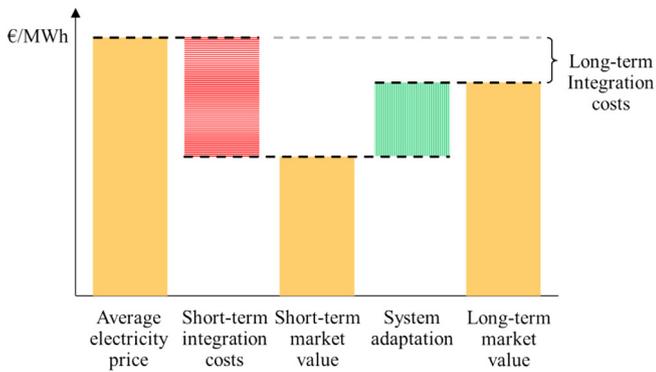


Fig. 2. Integration costs can be accounted for by reducing the market value of VRE compared to the average electricity price (value perspective). Alternatively, they can be accounted for by adding them to the generation costs of VRE leading to system LCOE (cost perspective). The welfare-optimal deployment  $q^*$  is defined by the intersection of market value and LCOE, and, equivalently, by the intersection of system LCOE with the average electricity price.

<sup>9</sup> For quantitative estimates of the “optimal share” of wind power see Ref. [46].



**Fig. 3.** Integration costs depend on how the system adapts in response to VRE deployment. In the short term when the system does not adapt integration costs can be high (red area), while in the long term VRE can be better accommodated and thus long-term integration costs are smaller. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

and considered system adaptations. In Section 5 we show report costs estimates from both a short and long-term perspective.

### 3. Decomposing integration costs

This section suggests a decomposition of integration costs into three approximately additive components.

Our definition of integration costs can in principle be directly used in economic assessments – there is no need to disentangle integration costs into components. However, such a decomposition might be helpful for three reasons. First, it allows single components with specialized models to be estimated. Estimating total integration costs directly would require a “super model” that accounts for all characteristics and system impacts of VRE, and such a model might be impossible to construct. By contrast, estimating individual components allows using specialized models. Second, a decomposition allows the cost impact of different properties of VRE to be evaluated and compared to each other. It helps identifying the major cost drivers and prioritizing integration options (e.g., storage vs. transmission lines vs. forecast tools) to more efficiently accommodate VRE. Third, by decomposing integration costs, the new definition can be compared to the standard literature that typically calculates integration costs as the sum of balancing, grid and adequacy costs.

Previous authors have identified three fundamental properties of VRE: uncertainty, locational specificity, and variability. We propose to decompose integration costs according to the effect of each of these characteristics. The impact of uncertainty is called “balancing costs”, the impact of location “grid-related costs”, and the impact of temporal variability “profile costs”. We define them here in terms of prices<sup>10</sup>:

- **Balancing costs** are the reduction in the VRE market value due to deviations from day-ahead generation schedules, for example forecast errors. These costs appear as the net costs of intraday trading and imbalance costs. They reflect the marginal cost of balancing those deviations. We define balancing costs to be zero if VRE forecast errors are perfectly correlated to load forecast errors.
- **Grid-related costs** are the reduction in market value due to the location of generation in the power grid. We define them as the

spread between the load-weighted and the wind-weighted electricity price across all bidding areas of a market. They reflect the marginal value of electricity at different sites and the opportunity costs of transmitting electricity on power grids from VRE generators to consumers.

- **Profile costs** are the impact of timing of generation on the market value. We define them as the spread between the load-weighted and the wind-weighted electricity price over all time steps during one year. They reflect the marginal value of electricity at different moments in time and the opportunity costs of matching VRE generation and load profiles through storage.

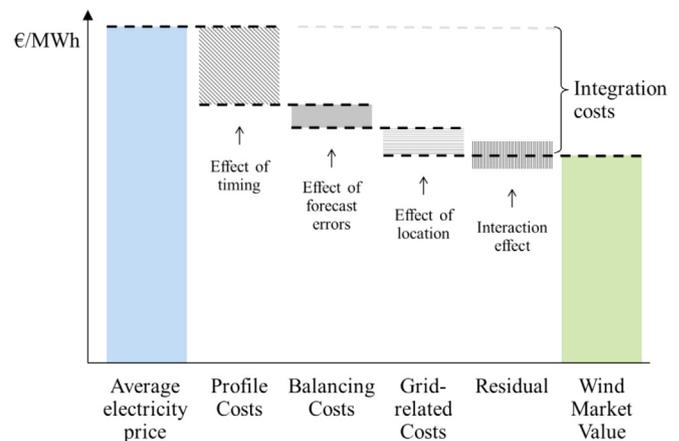
A formal definition is provided in the Appendix. Fig. 4 illustrates how each cost component can reduce (or increase) the market value of a VRE technology.

These cost components interact with each other and we do not know the direction or the size of the interaction. This should be the subject of further research. In this paper we assume that the integration cost components are independent and can be approximately summed. This approximation allows the three components to be separately estimated and totaled to determine integration costs.

The decomposition has four beneficial properties:

1. Temporal variability, network constraints, and forecast errors can be evaluated *consistently* in a uniform valuation framework. Balancing costs of one €/MWh are equivalent to one €/MWh of grid-related costs in the sense that both have the same effect on the marginal economic value of VRE.
2. All costs of variability at the system level are accounted for *comprehensively*, including reduced energy value (profile costs). This allows using integration costs for economic assessment of VRE.
3. The decomposition allows *operationalizing* integration costs. Integration costs can be estimated by summing up its components. This is important as an accurate estimation of integration costs with one “super model” might be infeasible.
4. It allows *robust* estimation in the sense that a quantification of each component can either be derived from empirical market prices or from modeled shadow prices.

The next section investigates the techno-economic mechanisms behind each cost component and relates them to traditionally used cost components.



**Fig. 4.** We decompose integration costs into three components, balancing, grid-related, profile costs. They correspond to the three characteristics of VRE uncertainty, locational specificity, and temporal variability.

<sup>10</sup> We use prices to avoid complex language. Recall the assumption of perfect and complete markets. Hence prices correspond to marginal costs and marginal benefits.

#### 4. The technical fundamentals behind integration costs

We have proposed a definition of integration costs derived from the market value of electricity and suggested a decomposition into balancing, grid-related, and profile costs. Although these have been defined in terms of prices, prices are nothing more than the monetary evaluation of underlying technical constraints and opportunity costs. This section discusses these fundamental constraints. We will discuss profile costs particular, since they have received least attention in the literature. We also try to explain why they have received so little attention.

##### 4.1. Balancing costs

Balancing costs are the marginal costs of deviating from announced generation schedules, for example due to forecast errors. They are reflected in the price spread between day-ahead and real-time prices. Depending on the market, real-time prices can be intraday prices and/or imbalance charges. As a result of correlated forecast errors, VRE generators tend to produce disproportionately more power at times of depressed real-time prices. The corresponding reduction in market value represents balancing costs.

There are three fundamental technical reasons jointly causing balancing costs. (i) Frequency stability of AC power systems requires supply and demand to always be balanced with high precision. (ii) Thermal gradients cause wear and tear of thermal plants, implying that output adjustments (ramping and cycling) are costly; ramping constraints also make costly part-load operation necessary for spinning reserve provision. (iii) The forecast errors of individual wind (and solar) generators are positively correlated because weather at nearby sites is correlated and operators use similar forecast tools.

Under complete and perfect markets, balancing costs reflect the marginal costs of providing balancing services: both capacity reservation and activation.

In addition to forecast errors, there is another (and minor) reason for balancing costs: electricity contracts are specified as stepwise schedules with constant quantities over certain time periods such as 15 or 60 min. Costs arise to balance the small variations within these dispatch intervals (intra-schedule variability).

The size of balancing costs depends on a number of factors:

- The absolute size of the VRE forecast error, itself being a function of (i) installed VRE capacity, (ii) the relative size of individual forecast errors, which is determined by the quality of forecast tools [31], and (iii) the correlation of forecast errors between VRE generators. It is sometimes argued that solar can be more accurately forecasted than wind, hence solar power should feature lower balancing costs. The correlation of forecast errors is a function of the geographic size of the balancing area: a larger area typically reduces correlation and hence reduces the absolute size of VRE forecast errors [35].
- The correlation of VRE forecast errors with load forecast errors and other imbalances. At low penetration, VRE forecast errors might even decrease the system imbalance.
- The capacity mix of the residual system. Specifically, hydro power can typically deliver balancing services at lower costs than thermal plants [14]; [1].
- The design and liquidity of intraday markets [51,101] and balancing markets [49,77,100].

##### 4.2. Grid-related costs

Grid-related costs are the marginal costs of transmission constraints and losses. They are reflected in the price spread between

locations. Locational prices can be implemented as nodal or zonal spot prices, or as locational grid fees. VRE generators tend to produce disproportionately more power in regions of low electricity prices. The corresponding reduction in market value represents grid-related costs.

There are three fundamental technological reasons for grid-related costs: (i) transmission capacity is costly and hence constrained; (ii) transmitting electricity is subject to losses; (iii) VRE generation costs vary geographically with varying resource quality and land prices.

In the long-term market equilibrium under complete and perfect markets and endogenous transmission capacity, grid-related costs reflect the marginal costs of building new transmission capacity and recovering losses.<sup>11</sup>

The size of grid-related costs depends on several factors:

- The location of good wind and solar sites relative to the geographic distribution of loads. An often mentioned example is that windy sites where land is cheap and there are little acceptance issues are typically located far away from load centers.
- The location of good VRE sites relative to the location of conventional power plants.
- Existing transmission constraints.
- The cost of transmission expansion.
- The design of locational price signals to electricity generators: nodal prices, zonal prices, differentiated grid fees, and cost-based re-dispatch can result in quite different grid-related costs.

Typically solar photovoltaics is installed closer to consumers than onshore wind, which in turn is closer than offshore wind. Thus grid-related costs are lower for solar than for onshore wind and highest for offshore wind. Highly meshed and strong transmission networks (as in many parts of continental Europe) feature lower grid-related costs than large countries with weak grids (e.g. the Nordic region and several regions in the U.S.).

##### 4.3. Profile costs

Profile costs are the marginal costs of the temporal variability of VRE output. They are reflected in the structure of day-ahead spot prices and materialize as reduced “energy value” [67] of wind and solar power. VRE generators tend to produce disproportionately more power at times of low electricity prices. The corresponding reduction in market value represents profile costs.

To understand their nature, consider the following thought experiment: assume that VRE generation can be perfectly forecasted and that the entire market is a copper plate with unrestricted transmission capacity. This would dissolve balancing and grid-related costs. Despite this, VRE variability would have economic consequences, which are reflected in varying spot prices and (often) in lower market value for VRE generators than for hydrothermal generators [44].

##### 4.3.1. Flexibility effect

One reason for this gap is the cost of adjusting the output of thermal plants. Thermal gradients of power plants cause ramping and cycling to be costly and ramping constraints require plants to run at part load to be able to follow steep gradients of residual load (load net of VRE generation). Following Ref. [72]; we call this the “flexibility effect.” The flexibility effect covers only scheduled

<sup>11</sup> See Refs. [83,50,78] point out several market failures that might prevent such an equilibrium to be reached.

ramping and cycling, while uncertainty-related ramping and cycling are reflected in balancing costs.

We now derive a rough estimate of the size of the flexibility effect. We use German load and VRE in-feed data from 2010, and scale in-feed to simulate VRE penetration rates between 0% and 40%.<sup>12</sup> Fig. 5 illustrates that residual load ramps increase with penetration. We measure cycling in terms of “system cycles”, the sum of upward residual load ramps during one year over peak load. Without renewables, i.e. with load variability only, the system follows about 100 of such system cycles. At 40% VRE, the number increases to 160. This means that the average plant cycles 60% more often. Assuming high cycling costs of 100 €/MW per cycle,<sup>13</sup> the increase in cycles results in marginal costs of 3 €/MWh<sub>VRE</sub> (Fig. 6).

In other words, the economic impact of cycling is very small. This rough calculation is confirmed by the literature review in Section 5.3.

4.3.2. Utilization effect

For further understanding of the nature of profile costs, let us continue the thought experiment. Assume that all plants can ramp and cycle without costs, hence the flexibility effect disappears. Still, the market value of wind and solar generation is often lower than the average electricity price, and it decreases with penetration. In the following, we will show that these costs are caused by a reduced utilization of thermal plants, the “utilization effect”.

The generation of new VRE plants is correlated with that of existing VRE, so VRE generation is increasingly concentrated in times of low residual load. The impact of VRE on residual load can be expressed as residual load duration curves (RLDC), the sorted hourly residual load of one year. With increasing VRE penetration, the RLDC becomes steeper (Fig. 7). The y-intercept of the RLDC is the thermal capacity requirement,<sup>14</sup> while the integral under the RLDC is thermal generation. The average utilization of thermal plants is given by the ratio of y-intercept to integral. With increasing VRE penetration the ratio decreases.

Using the above data we roughly estimate the size of the utilization effect. Without renewables, the utilization rate of thermal capacity is roughly 70% (Fig. 8, Table 1). As VRE penetration grows to 40%, utilization decreases to 47%. Reduced utilization increases specific (€/MWh) capital costs. Assuming constant annualized capital costs of € 200/kW<sub>a</sub>, which roughly represents the costs of a coal-fired plant, reduced utilization drives up capital costs of thermal generation from 33 €/MWh to 49 €/MWh. Moreover, if VRE generation is curtailed at times of negative residual load, VRE capacity utilization is also reduced, driving up the capital costs of VRE generation from 80 €/MWh to 85 €/MWh.

We then relate this cost increase to the increase in VRE generation. For example, increasing the VRE share from zero to 10% increases thermal capital costs from 33 €/MWh<sub>thermal</sub> to 34 €/MWh<sub>thermal</sub> (Table 1, row 5), which corresponds to 10 €/MWh<sub>VRE</sub> (row 6), as the thermal generation volume is about ten times larger than VRE generation. In this example, VRE capital costs do not increase, as no generation is curtailed (rows 9–11). Rows 6 and 11 show the cost increase (relative to the prior column), reflecting the

<sup>12</sup> We use empirical wind and solar in-feed data as well as load data from 2010. All data come from the four German transmission system operators and is publicly available. To illustrate different shares, we scale VRE profiles to reach between 0% and 40% of electricity generation, assuming a wind-to-solar ratio of 2:1 in energy terms.

<sup>13</sup> This corresponds to start-up costs of 100,000 for a one-GW block, which is a conservative (high) estimate, even for a cold start, let alone for warm or hot starts. This also ignores that part of the ramps are covered by hydro plants, which have much lower cycling and ramping costs.

<sup>14</sup> Ignoring balancing and planning reserves.

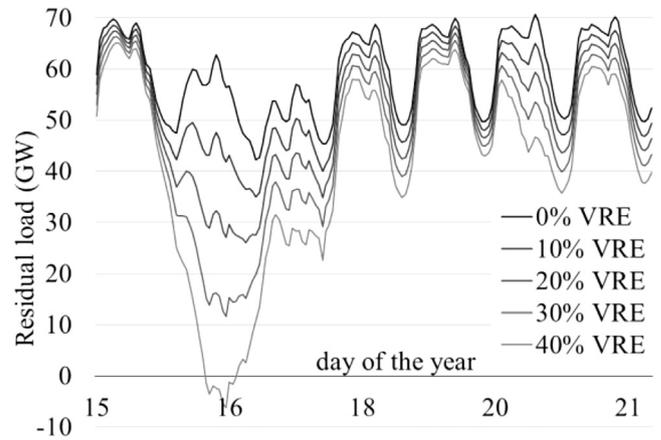


Fig. 5. Residual load curves during one week. Residual ramps increase at high VRE shares.

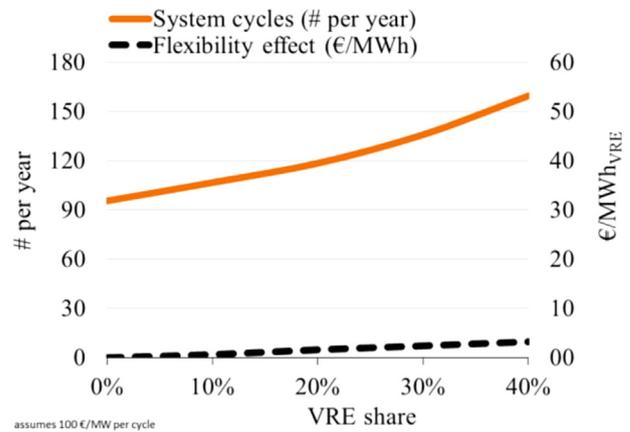


Fig. 6. The flexibility effect, based on simple residual load scaling and assuming 100 €/MW per cycle (same right-hand scale as Fig. 8 for better comparability).

marginal nature of our integration cost definition. The sum of increased capital costs for thermal and VRE generation is the utilization effect (row 12).

At 40% penetration, the utilization effect is about 51 €/MWh, almost 20 times larger than that of cycling costs, and in the same order of magnitude as VRE generation costs. Of course, this

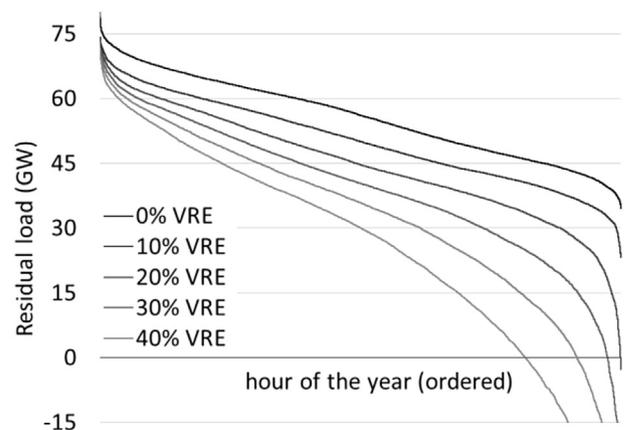


Fig. 7. Residual load duration curves for one year. The average utilization of the residual generation fleet decreases.

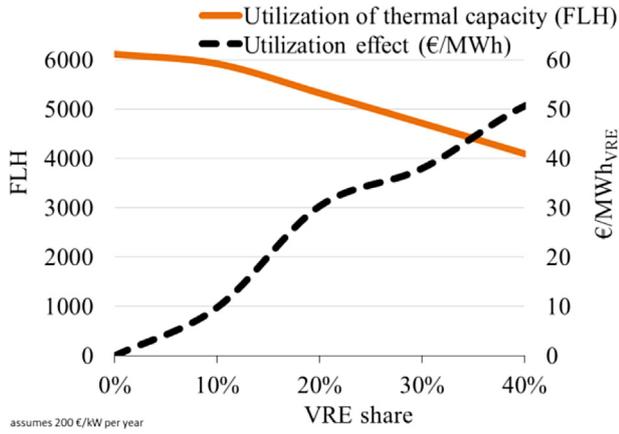


Fig. 8. The utilization effect, based on simple residual load scaling and assuming thermal capital costs of 200 €/kW<sub>a</sub>.

calculation has made a number of (very) simplifying assumptions. Most importantly, the thermal capacity mix will adjust (capital costs will not remain constant at 200 €/kW<sub>a</sub>), mitigating the utilization effect. However, we believe the general findings to be valid. The literature review of Section 5.3 supports the finding that the capital cost-driven utilization effect is the single most important integration cost component and finds quite similar absolute cost levels.

Reduced thermal plant utilization is *not* only a *transitory* phenomenon. While it is true that a swift introduction of renewables reduces thermal plant utilization (and reduces investor profits [47]), high VRE shares lead to lower average plant utilization even in the long-term equilibrium. Fig. 9 shows the share of energy that is generated in plants that run base load (>8000 FLH), mid load, peak load, and super peak load (<1000 FLH), using the same data as above. Without VRE, three quarters of all electricity is generated in base load plants. At 40% penetration, virtually no base load generation is left. This leads to higher average generation costs even in the long-term, since levelized electricity costs strongly decrease with increasing utilization, even under optimal technology choice (Fig. 10). The fact that steeper RLDCs require a different technology

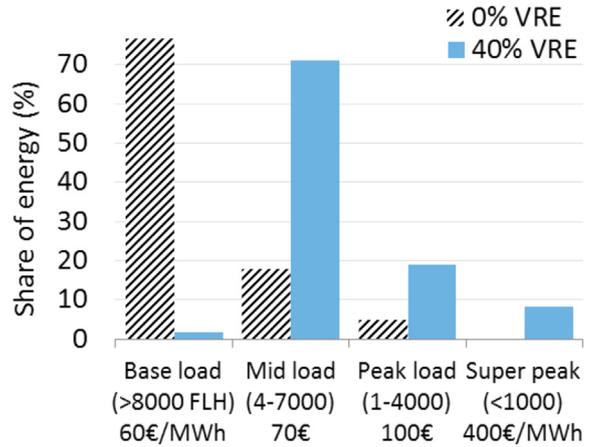


Fig. 9. Utilization of residual capacity without renewables and at 40% penetration. Electricity generated in base load plants strongly decreases, while mid and peak load generation increase (not only relatively, also absolutely).

mix and that such a mix is more expensive is implicit in the classical screening curve literature [37,79,90].

In the long-term market equilibrium under complete and perfect markets, day-ahead spot market prices reflect both the utilization and the flexibility effect. The size of profile costs is dependent on the VRE share and power system characteristics. Specifically, it depends on:

- VRE penetration rate. Profile costs increase with penetration, mainly because the utilization of residual capacity decreases [44,62].
- The distribution of VRE generation. A flatter (more constant) generation profile leads to lower profile costs at high penetration rates. Offshore wind profiles are flatter than onshore wind profiles, which are flatter than solar PV profiles [8,36,45,70,72]. A geographically larger market leads to a flatter aggregated VRE generation profile resulting from geographical smoothing [35].
- The correlation of VRE generation with demand. Positive correlation can to negative profile costs. An obvious example is the diurnal correlation of solar power with demand, often leading to negative solar profile costs at low penetration (high energy value).

Table 1  
Calculating the utilization effect.

VRE share (% of consumption)		0%	10%	20%	30%	40%
(1)	Thermal capacity (GW)	80	74	73	73	72
(2)	Thermal generation (TWh)	489	440	391	342	293
(3)	Utilization of thermal capacity (%)	70%	68%	61%	54%	47%
	Utilization of thermal capacity (FLH)	6100	6000	5300	4700	4100
(4)	Thermal capital costs (€/kW <sub>a</sub> )	200	200	200	200	200
(5)	Thermal capital costs (€/MWh <sub>thermal</sub> )	33	34	38	42	49
(6)	Increase of thermal capital costs ("marginal costs") per VRE generation (€/MWh <sub>VRE</sub> )	0	10	30	34	38
(7)	Installed VRE capacity (GW)	0	36	72	110	154
(8)	Potential VRE generation (TWh)	0	49	97	149	208
(9)	VRE Curtailment (TWh)	0	0	0	2	13
(10)	VRE capacity costs (€/MWh <sub>VRE</sub> )	80	80	80	81	85
(11)	Increase of VRE capital costs ("marginal costs") per VRE generation (€/MWh <sub>VRE</sub> )	0	0	0	4	12
(12)	Utilization effect (€/MWh <sub>VRE</sub> ) (6) + (11)	0	10	30	38	51

Assuming that all residual load is served by thermal units, no intertemporal flexibility or constraints, 80 €/MWh<sub>VRE</sub> and a constant average capital costs of the thermal system of 200 €/kW<sub>a</sub>. The underlying excel sheet is available from the authors on request.

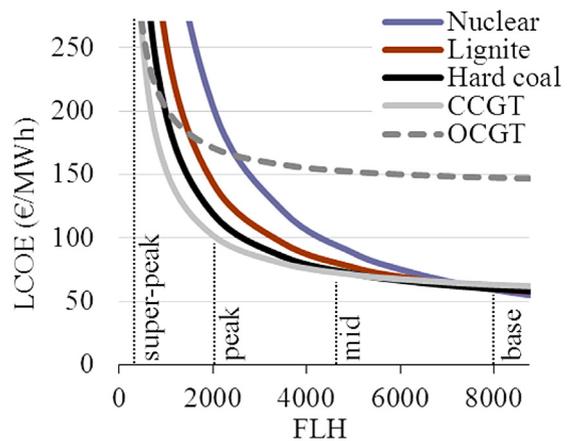


Fig. 10. Average costs for different technologies at different full load hours. CCGT and OCGT are combined-cycle and open-cycle gas turbines, respectively. While base load plants (8000 FLH) supply electricity for around 60 €/MWh, super peakers cost around 400 €/MWh.

- The shape of the merit-order curve: the steeper the curve, the larger the utilization effect [44]. In the long term, the shape of the merit-order curve is determined by the differentiation of available technologies in terms of fixed-to-variable cost ratio.
- The intertemporal flexibility of the power system, both on the supply side (e.g., storage) and the demand side (e.g., demand response). Reservoir hydro power can have an especially large impact. This technology allows shifting generation over time, hence “flattening-out” residual load [70,82].

Wind integration studies and other integration cost literature often account for the costs of grid extensions, balancing services, and cycling of thermal plants. Our findings indicate that it is at least as important to account for the reduced utilization of thermal generators and their capital costs. Surprisingly, many previous studies have not done this.

#### 4.4. Relation to the standard integration cost literature

There is a rich body of wind and solar integration studies that estimate integration costs. For an overview see Refs. [53]; [20,88]; or [40]; [54] provides a blueprint of such an assessment. These studies typically understand integration costs in a more narrow sense: their definition of integration costs does not cover the utilization effect. This might be because costs due to this effect differ conceptually from other cost components. Grid and balancing costs are *additional costs* in the strict sense of increased expenses due to a higher VRE share, e.g. for more grid infrastructure, fuel consumption, or maintenance. By contrast, the utilization effect does not refer to increasing expenses but *diminishing cost savings* in the non-VRE system when increasing the VRE share.

Note that some integration cost studies also cover a specific aspect of the reduced utilization of non-VRE plants: the low capacity credit of VRE [2,27]. Motivated by the need for firm capacity to ensure generation adequacy these costs are called “adequacy costs”. Hereby the studies expand their focus away from only calculating *increasing expenses*: it is not necessary to add conventional capacity when introducing VRE to an existing system. Adequacy costs refer to the dispatchable capacity that could be removed in the long term if VRE had a higher capacity credit. Similarly, profile costs refer to the dispatchable capacity that could be better utilized if VRE followed load.

While adequacy costs only address the low capacity credit of VRE, the utilization effect is more general: thermal utilization is reduced as the RLDC becomes steeper and VRE utilization is reduced as generation needs to be curtailed. These three cost impacts are all determined by the same driver: the (lack of) temporal coincidence of VRE generation and load. Hence, profile costs and the utilization effect can be understood as a generalization of adequacy costs.

From an economic perspective these two categories of *increasing expenses* and *diminishing cost savings* are equivalent: both are opportunity costs [97]. It makes no difference for the economic evaluation of VRE if more balancing costs are imposed or if less peak capacity can be substituted when adding additional VRE capacity. In fact, a comprehensive economic evaluation of VRE needs to account for both categories and thus needs to cover all cost components of integration costs described in this paper. Hereby each cost component can be either accounted for as increasing the costs of VRE or as decreasing their value. Consequently, there are a number of different ways of comprehensively attributing the cost components, which are all equivalent in the sense that they lead to the same cost-optimal share of VRE. We can think of four intuitive ways of attributing the cost components:

- First, one can take a *value perspective* where all cost components reduce the value of VRE (see Section 2). In order to derive the cost-optimal share of VRE the resulting market value needs to be compared to the generation costs of VRE (LCOE).
- Second, from a pure *cost perspective*, all cost components need to be added to the LCOE of VRE (see Section 2). The resulting costs (system LCOE) can be compared to the average annual electricity price to derive optimal VRE shares.
- Third, from a *mixed perspective*, diminishing avoided costs can be counted separately from additional costs: balancing and grid costs can be added to the LCOE of VRE because they reflect increasing expenses. Profile costs can be regarded as reducing the value of VRE because they reflect diminishing avoided costs of VRE. At the cost-optimal deployment of VRE the increased costs equal the resulting reduced value (Fig. 11).
- Fourth, an attribution can also be made considering the way a *real-world power market* deals with these costs. The specific market design determines whether a certain cost component is reflected in reduced market value or is put to generators as a cost after markets have cleared. In most European power markets, profile costs appear as reduced value. Balancing and grid-related costs often appear as a mix of reduced value (e.g., low intraday prices) and costs (e.g., imbalance charges).

## 5. Quantifications from the literature

One merit of the proposed cost decomposition is that cost components can be estimated individually, and that they can be estimated either from models or market prices. We reviewed more than 100 published studies, of which about half could be used to extract quantifications of balancing, grid-related, or profile costs. The studies varied significantly in methodology, rigor, and related to different power systems. Model-based estimates are valid only to the extent that models can be regarded as realistic, and estimates from market data are only valid to the extent that markets can be treated as being complete and free of market failures. We discuss market failures in the following section.

### 5.1. Balancing costs

There are three groups of studies that provide wind balancing cost estimates: wind integration studies often commissioned by system operators, academic publications based on stochastic unit commitment models, and empirical studies based on market prices. We discuss these publications in turn and summarize results in Fig. 12. Ref. [45] provides a similar review for solar power.

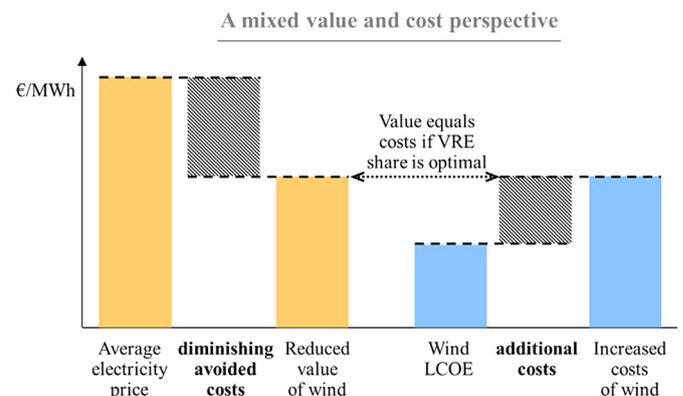
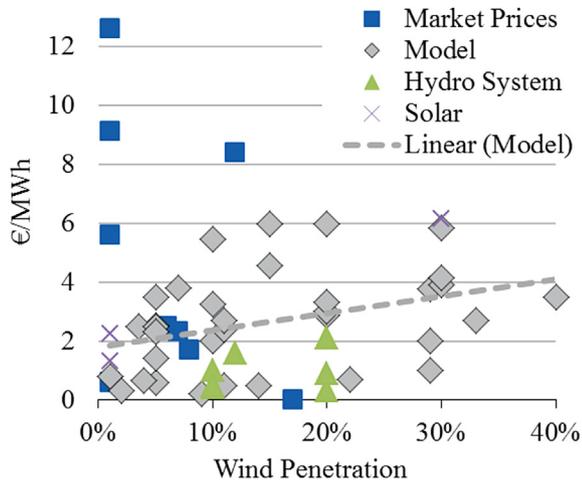


Fig. 11. From a “mixed” perspective diminishing avoided costs of VRE reduce the value of wind compared to the average electricity price whereas additional costs increase costs of wind. VRE deployment is optimal when their value and costs coincide.



**Fig. 12.** Balancing cost estimates for wind and power from market prices (squares) and model prices (diamonds) for wind and solar power (crosses). Three market-based studies report very high balancing costs. All other estimates are below 6 €/MWh. Studies of hydro-dominated systems show low balancing costs (triangles). A list of studies can be found in the [Appendix](#).

There are too many wind integration studies to review all of them individually here. A number of meta-studies have reviewed wind integration studies. Covering much of the earlier literature [40], reports balancing costs to be below 3 £/MWh in most cases. Surveying six American studies [88], report a range of 0.7–4.4 \$/MWh. [21]; focusing on the United States, find costs of 3–4.5 \$/MWh for penetration rates around 30%, but find one outlier of 9 \$/MWh. The most recent survey is provided by Refs. [53]; who estimate balancing costs at 20% penetration rate to be 2–4 €/MWh in thermal power systems and less than 1 €/MWh in hydro systems. In several of the studies reviewed, balancing costs arise mainly because wind power increases reserve requirements.

A handful of academic articles have derived balancing costs from stochastic unit commitment models. They typically compare total system costs with and without wind forecast errors. Forecast errors introduce costs because more expensive plants have to be scheduled than under perfect foresight. Ref. [70] estimate wind balancing costs to be in the range of 2–4 \$/MWh at penetration rates up to 30%. Several other studies do not report balancing costs in marginal terms, as we have defined them, but only report system costs with and without forecast errors. As a rough indication, we calculate average, not marginal, balancing costs by dividing the cost increase by wind generation. Ref. [94] find average wind balancing costs of about 3 €/MWh at 34% penetration in Ireland, which is similar to that found by Ref. [34]. Ref. [98] find costs for The Netherlands to be “small”. [41] and [91] assess balancing costs based on the statistical properties of wind forecast and reserve costs, resulting in low estimates. Grubb reports 3.6% of the value of electricity and Strbac 0.5 £/MWh, both at a 20% penetration.

The third group of studies does not use models, but evaluates wind forecast errors with observed imbalance prices or the price spreads between day-ahead and intraday markets. Such market-based evaluations are of course limited to historical conditions, such as low penetration rates. Ref. [51] reports balancing costs in Denmark to be 3 €/MWh. If intraday markets had been liquid up to two hours ahead of delivery, balancing costs would be reduced by 60%. Denmark has an impressive wind penetration rate, but benefits from the integrated Nordic balancing market and much interconnector capacity. Ref. [80] report balancing costs of 4 €/MWh for

the best unbiased forecast based on Dutch data. However, the profit-maximal (biased) bidding strategy reduced balancing costs by half. Ref. [77] use Austrian, Danish, and Polish data. They confirm that balancing costs are often reduced by biased forecasts. The authors find balancing costs of close to zero in Denmark, 6 €/MWh in Austria, and 13 €/MWh in Poland. Ref. [52] use 2004 Finnish market prices to evaluate wind balancing costs. They report costs to be 0.6 €/MWh if all forecast errors are settled via balancing markets. Surprisingly, they find costs to increase if the intraday market is used. Ref. [58] estimate balancing costs in Texas to be 2–5 \$/MWh for a small group of turbines.

For this study, we have assessed wind imbalance costs for Germany. Using historical system operator wind forecast errors and observed imbalance prices at quarter-hourly granularity, we find balancing costs for wind of 1.7–2.5 €/MWh during the last three years.<sup>15</sup>

Estimating balancing costs from market prices is not without problems, because many real-world balancing markets are subject to market failures and do not reflect the marginal costs of balancing forecast errors [49]. Moreover, day-ahead forecasts are sometimes biased, either because of biased prediction tools, or because it is profitable to under- or oversell on day-ahead markets. Such strategic behavior can be profitable if real-time and day-ahead markets are not arbitrage free, or if punitive mark-ups for forecast errors are imposed [6,15,80,100]; [64].

Fig. 12 displays the results from all studies. A complete list of studies and estimates can be found in the [Appendix \(Table 2\)](#). Despite the heterogeneity of results, the findings are striking: virtually all estimates are below 6 €/MWh even at high penetration rates in thermal power systems, and several estimates are well below that number. All estimates above 6 €/MWh are market-based estimates of systems where imbalance prices contain punitive mark-ups and are not likely to reflect the marginal costs of balancing. There is not a single model-based estimate above 6 €/MWh, even at 40% wind penetration. All estimates for hydro systems are below 2 €/MWh. The trend-line is fitted on modeled prices for wind power in thermal systems. It indicates that for each percentage point market share, the balancing costs of wind power increase by 0.06 €/MWh. Balancing costs increase from 2 €/MWh to 4 €/MWh as wind penetration increases from zero to 40%. In other words, even at high penetration rates, balancing costs are quite low.

VRE do not only increase the demand for balancing, but can also supply balancing services [60]; [7,89]; and [49]; [24]. While this is a possible additional income stream for VRE, it will not be considered here due to lack of robust quantifications.

## 5.2. Grid-related costs

Quantitative evidence on grid-related costs is scarce. Integration studies sometimes calculate the cost for additional grid investments, but seldom report marginal costs. Furthermore, results are often not based on cost-optimized grid expansion, and it is usually not clear if VRE expansion or other factors drive grid investments.

Ref. [91] find grid-related costs in the UK to be 0.9 £/MWh at 20% wind penetration. Ref. [23] report them to be about 3 €/MWh

<sup>15</sup> [www.tennet.eu/de/kunden/bilanzkreise/preise-fuer-ausgleichsenergie.html](http://www.tennet.eu/de/kunden/bilanzkreise/preise-fuer-ausgleichsenergie.html), [www.tennet.eu/de/kunden/eegkwk-g/erneuerbare-energien-gesetz/windenergie-on-und-offshore/tatsaechliche-und-prognostizierte-windenergieeinspeisung.html](http://www.tennet.eu/de/kunden/eegkwk-g/erneuerbare-energien-gesetz/windenergie-on-und-offshore/tatsaechliche-und-prognostizierte-windenergieeinspeisung.html), [www.50hertz.com/cps/rde/xchg/trm\\_de/hs.xml/Netzkennzahlen.htm?rdeLocaleAttr=de&rdeCOQ=SID-E67C66B1-E5C66222](http://www.50hertz.com/cps/rde/xchg/trm_de/hs.xml/Netzkennzahlen.htm?rdeLocaleAttr=de&rdeCOQ=SID-E67C66B1-E5C66222), [www.amprion.net/windenergieeinspeisung](http://www.amprion.net/windenergieeinspeisung), [www.transnetbw.de/de/kennzahlen/erneuerbare-energien/windenergie?activeTab=table&app=wind](http://www.transnetbw.de/de/kennzahlen/erneuerbare-energien/windenergie?activeTab=table&app=wind).

in Ireland for 30–40% penetration. Ref. [22] estimates the transmission-grid related costs to integrate 39% renewables in Germany by 2020 to be about € 1bn per annum. If that is attributed to the increase in renewable generation, it translates to about 10 €/MWh. Ref. [73] estimates grid investment costs to support 80% renewables (of which half are VRE) to be about 6 \$/MWh. Ref. [53] review a handful wind integration studies that estimate grid costs. They report wind-related investment costs of 50–200 €/kW at penetration rates below 40%, which is equivalent to 2–7 €/MWh.<sup>16</sup> However, all these estimates are average costs and do not represent the impact on the marginal value of wind and solar electricity.

Ref. [42] model locational marginal prices to derive the locational value of wind power. They find the value of wind power to differ by 18 €/MWh between locations. Ref. [92] models locational marginal prices in Germany to evaluate wind power. He finds that transmission constraints introduce a spread in the value of VRE between low and high price areas of about 10 €/MWh. With VRE being quite well distributed around the country however, the average impact of location on the market value is close to zero – both for solar and wind.

Three studies use empirical locational electricity prices to estimate grid-related costs. Ref. [12] estimate the market value of solar power in Ontario to be 20–35 \$/MWh higher in large cities than the system price. Ref. [65] finds similarly large differences for different locations in Michigan. However, the data provided by these two studies does not allow the impact of spatial price variations on the market value of electricity from VRE to be calculated. Evaluation locational prices in Texas [92], finds, surprisingly, that the value of wind power is slightly *increased* by its location – grid-related costs are negative. This can be explained by the fact that electricity price in Western Texas, where most wind power is situated, are above state average.

For this study, we have assessed grid-related costs in Sweden. In Sweden, zonal prices were introduced in November 2011, making it one of the few European countries with locational price signals. The price difference between the Northern bidding zone, where many future wind projects are planned, and the system price has been 0.5–1.1 €/MWh for the past two years. In addition, there are geographically differentiated grid fees for generators.<sup>17</sup> If these are totaled, grid-related costs are in the order of 5 €/MWh.

The quantitative evidence on grid-related costs is thin. Notwithstanding, the few studies available provide a consistent picture: VRE expansion causes only moderate costs for grid expansion. While individual sites provide a significantly higher value than others, the market value of wind or solar generators as a whole does not seem to be affected much by spatial price variation, because generators are spatially quite well distributed. Grid-related costs seem to be in the single-digit range in €/MWh terms.

### 5.3. Profile costs

We discuss the flexibility effect and the utilization effect separately. Costs estimates of the *flexibility effect* are rather scarce and most of these find the cost of hour-to-hour variability to be very small. Based on an analytical approach [41], estimates variability costs to be 0.2–0.3% of the value of wind electricity. Ref. [88] find

slightly higher values of 0.4–1.7 \$/MWh; [43] report 0.2–2 \$/MWh. Recently, [74] published an extensive assessment of ramping and cycling costs, estimating the cost to be 1.0–3.2 \$/MWh at a renewables share of 33%. Ref. [72] finds the utilization effect to be much larger than the flexibility effect. Ref. [16] concludes that ramping constraints are not binding even at high penetration rates in Germany. Similarly, report that ramping requirements are easily met in all power systems except small island systems. Overall, increased ramps do not seem to have significant impact on the market value of VRE generators. This finding is consistent with the simple calculations in Section 4.3.

Many studies (implicitly) report estimates of the *utilization effect*. Elsewhere, we have provided extensive quantitative assessments for wind and solar power [44,45]; hence we keep the discussion here short. Fig. 13 summarizes wind profile cost estimates from some 30 publications. A complete list of references can be found in the Appendix (Table 3). Wind profile costs are estimated to be zero or slightly negative at low penetration rates and to be around 15–25 €/MWh at 30–40% market share.

The gray dotted trend-line is fitted on short-term (dispatch) models, the blue bold line on long-term (combined dispatch and investment) models. As expected, the bold line has a lower gradient, reflecting system adaptation. The bold line indicates that for each percentage point market share, the profile cost of wind power increase by 0.5 €/MWh. This is a full order of magnitude larger than the increase in balancing cost. The estimate from short-term models is 50% higher.

Summing up all three cost components, integration costs might be around 25–35 €/MWh at 30–40% penetration rate in thermal power systems, if the average electricity price is around 70 €/MWh. In other words, electricity from wind power is worth only 35–45 €/MWh under those conditions, 35–50% less than the average electricity price. Levelized electricity costs of wind are currently around 70 €/MWh in Europe. This means, integration costs increase direct generation costs by 35–50%.

Of integration costs at high penetration, about two thirds are profile costs. An increase in the wind penetration rate of one percentage point is estimated to increase profile costs by 0.5 €/MWh, almost ten times more than balancing costs.

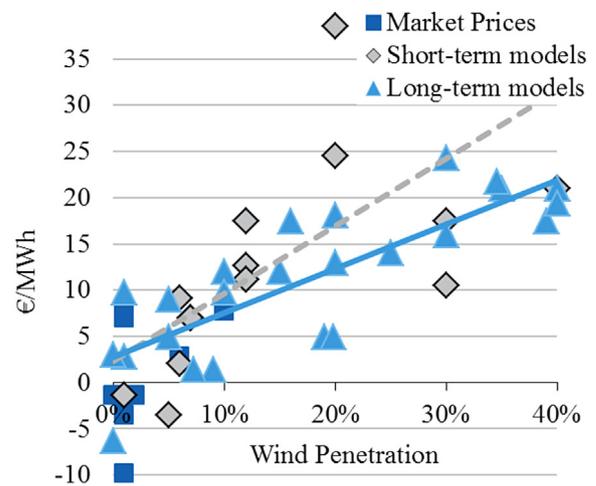


Fig. 13. Wind profile cost estimates from about 30 published studies. Studies are differentiated by the way they determine electricity prices: from markets (squares), from short-term dispatch modeling (diamonds), or from long-term dispatch and investment modeling (triangles). To improve comparability the average electricity price was normalized to 70 €/MWh. The OLS-estimate of all long-term models results in profile costs of 15–25 €/MWh at 30–40% market share. A list of studies can be found in the Appendix.

<sup>16</sup> At a 7% discount rate and 2000 wind full load hours.

<sup>17</sup> Spot prices from <http://www.nordpoolspot.com/Market-data1/ElsSpot/Area-Prices/ALL1/Hourly/>, retrieved 20 May 2014. Grid fees from personal communication with Svenska Kraftnät.

## 6. Who bears integration costs?

The last sections discussed how integration costs are defined, how they are composed, and how large they are. A related, but independent question is who *bears* these costs. Are integration costs an externality? This is a question of policy and market design and will be discussed (briefly) in this section.

Under perfect and complete electricity markets in long-term equilibrium, profile costs would appear as reduced revenues from the day-ahead spot market, balancing costs would arise from the net costs for intraday trading and imbalance charges, and grid-related costs would appear as differentiated locational spot prices or differentiated grid fees. If electricity and ancillary service prices reflect social costs, there are no externalities and “integration costs are borne by those who cause them”.

In the real world, markets are not always perfect and complete:

- Externalities in generation distort the market price of electricity. Negative externalities from thermal and hydro generation, such as carbon and pollutants emissions, biodiversity, and visual impact, are often considered to be larger than those of VRE [9,29].
- There is disagreement in the literature as to whether energy-only markets can appropriately price capacity via scarcity prices [5]; [18]; [17].
- Market power distorts electricity prices and reduce VRE market value [71,95].
- Given the long investment cycles, power markets can be out of equilibrium for extended time periods after shocks [47,84,97].
- Balancing prices often reflect average, not marginal, costs for providing balancing services. Furthermore, they typically only cover the costs for balancing energy, but not the costs of reserve capacity. These costs are often socialized via grid fees [28,49,100].
- Many power systems lack locational price signals. Spot prices are often settled in larger geographical bidding areas, grid fees are not locationally differentiated, and re-dispatch costs are socialized via grid fees.

Finally, most VRE generators are currently subsidized. Many subsidy schemes such as fixed feed-in-tariffs remunerate energy supply independent of temporal, locational, or uncertainty-related price signals. This implicitly socializes all integration costs. However, under some support policies, such as most tradable green certificates schemes, investors bear integration costs to the extent that the market internalizes costs.

Considering these potential externalities, at least two conclusions can be drawn. First, the empirically observed (private) market value might deviate from the theoretical (social) marginal value. Hence, any inference of marginal values from market prices needs to check for potential bias from externalities. Second, for efficient resource allocation externalities should be internalized: environmental and health externalities should be priced, spot markets should be allowed to price scarce capacity, locational prices should be introduced, and imbalance prices should reflect marginal costs of balancing. Once that is completed, integration costs do not constitute an externality.

## 7. Concluding remarks

This paper proposes a valuation framework for variable renewables and offers a new perspective on “integration costs”. Integration costs are those costs that do not occur at the level of the wind turbine or solar panel, but elsewhere in the power system. We suggest

defining them as the gap between the average electricity price and the market value of electricity from wind (or solar) power. This definition is rigorous, comprehensive, and has a straightforward welfare-economic interpretation: in the long-term optimum, the sum of generation and integration costs of all generation technologies coincide. We propose a decomposition of integration costs along three inherent properties of VRE: uncertainty causing balancing costs, locational inflexibility causing grid-related costs, and temporal variability causing profile costs. We believe this decomposition to be comprehensive, robust, consistent, and operationable.

The decomposition is operationable in the sense that existing models can be used to quantify the components, and it is robust in the sense that a range of methods can be used, including numerical modeling and empirical estimates. We reviewed the literature and extracted quantitative estimates. The studies vary considerable in definitions, methodology, regional focus, and quality, so the results need to be interpreted carefully. Moreover, the large range of estimates testifies considerable methodology and parameter uncertainty. We nevertheless synthesize:

- Wind and solar integration costs are high if these technologies are deployed at large scale: in thermal systems, wind integration costs are about 25–35 €/MWh at 30–40% penetration, assuming a base price of 70 €/MWh. Integration costs are 35–50% of generation costs.
- As integration costs can be large in size, ignoring them in cost-benefit analyses or system optimization can strongly bias results.
- The size of integration costs depends on the power system and VRE penetration: integration costs can be negative at low (<10%) penetration, they generally increase with penetration, and are typically smaller in hydro than in thermal systems.
- System adaptations can significantly reduce integration costs. For example, dispatch models estimate profile costs to be 50% higher than investment models. Authors should be explicit about the time horizon and boundary conditions. High-penetration studies should account for system adaptation.
- Balancing costs are quite small (<6 €/MWh). The cost of scheduled thermal plan cycling, the flexibility effect, is even smaller. This is surprising, as these phenomena receive much attention in the literature and public debate.
- In thermal systems with high VRE shares, the utilization effect amounts to more than half of all integration costs. Maybe this is the most important finding of this study: the largest integration cost component is the reduction of utilization of the capital embodied in the power system. Most previous integration cost studies have not touched upon this effect. VRE-rich power systems require flexible thermal plants, but even more so they require plants that are low in capital costs.

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## Appendix

### Formal definition of wind market value $p_{wind}$

Formally, the wind market value is the sum of electricity prices at time step  $t$ , location  $n$ , and lead-time  $\tau$ , weighted with the share of wind generation  $w_{t,n,\tau}$ .

$$p_{wind} = \sum_{t=1}^T \sum_{n=1}^N \sum_{\tau=1}^T w_{t,n,\tau} \cdot p_{t,n,\tau} \quad (5)$$

The weights are defined to sum up to unity:  $\sum_{t=1}^T \sum_{n=1}^N \sum_{\tau=1}^T w_{t,n,\tau} = 1$ .

Think of time steps as the temporal granularity of power markets, such as hours. Locations refer to the spatial granularity of power markets, such as bidding zones or transmission nodes. Lead-time refers to the sequence of power markets with decreasing time between contract and delivery, such as day-ahead, intraday, and real-time markets. If wind power is traded only day-ahead, the weights for the other markets are zero. See Ref. [48] for a more in-depth discussion of these dimensions. The average electricity price  $p_{electricity}$  is defined accordingly, using load  $l_{t,n,\tau}$  as weighting factors instead of wind generation.

### Formal definition of profile, grid-related, and balancing costs

We define profile costs for the situation in which only information about the temporal structure of the electricity price is known, hence  $p_{t,n,\tau}$  reduces to  $p_t$ . Wind profile costs  $\Delta_{wind}^{profile}$  are

defined as the difference between the load-weighted and the generation-weighted price:

$$\Delta_{wind}^{profile} = \sum_{t=1}^T (l_t - w_t) \cdot p_t \quad (6)$$

The weights are defined to sum up to unity:  $\sum_{t=1}^T \sum_{n=1}^N \sum_{\tau=1}^T w_t = \sum_{t=1}^T \sum_{n=1}^N \sum_{\tau=1}^T l_t = 1$ .

This implies a VRE generator has zero profile costs if it is perfectly correlated with load over time. Profile costs are negative if it generates disproportionately at times of high prices and positive if it generates disproportionately at times of low prices.

We define grid-related costs and balancing costs accordingly:

$$\Delta_{wind}^{grid-related} = \sum_{n=1}^N (l_n - w_n) \cdot p_n \quad (7)$$

$$\Delta_{wind}^{balancing} = \sum_{\tau=1}^T (l_\tau - w_\tau) \cdot p_\tau \quad (8)$$

We do not suggest decomposing integration cost estimates if they stem from models that represent all three properties of VRE. Only if such a “super model” is unavailable, integration costs should be calculated by adding up estimates of components. For instance, a model that does neither represent uncertainties nor grid constraints can be used to calculate profile cost – and estimates for balancing and grid-related costs need to come from other models.

**Table 2**  
Balancing cost literature.

Prices	Reference	Technology	Region	Balancing cost estimates [range] (at different market shares)
Market prices	[51]	Wind	Denmark	2.8 €/MWh (12%)
	[80]	Wind	Netherlands	3.7 €/MWh (small)
	[77]	Wind	Austria	5.6 €/MWh (small)
			Denmark	0 €/MWh (17%)
			Poland	12.6 €/MWh (small)
	[52]	Wind	Finland	0.6 €/MWh
	[64]	Solar	California	1.7–2.9 \$/MWh (small)
	<i>this study</i>	Wind	Germany	1.7–2.5 €/MWh
	[41]	Wind	UK	2.5 €/MWh (5%)
	Model results	[40], survey	Wind	several UK studies
[88], survey		Wind	UWIG	1.9 \$/MWh (3.5%)
			MNDOC	4.6 \$/MWh (15%)
			CA	0.5 \$/MWh (4%)
			We	1.9–2.9 \$/MWh (4–29%)
			PacificCorp	4.6 \$/MWh (20%)
			PSCo	2.5–3.5 \$/MWh (10–15%)
[21], survey		Wind	several US systems	3–4.5 \$/MWh (~30%) –one outlier of 9 \$/MWh
[70]		Wind	California	1–4 \$/MWh (0–30%)
[36]		Solar	Arizona	8 \$/MWh (30%)
[53], survey		Wind	Finland	2–3 €/MWh (10–20%)
			UK 2007	1.4–3.3 €/MWh (5–20%)
			Ireland	0.2–0.5 €/MWh (9–14%)
			Colorado	2.3–3.8 €/MWh (5–7%)
			Minn. 2006	2.3–3.4 €/MWh (15–25%)
			California	0.3 €/MWh (2%)
			PacificCorp	3.5 €/MWh (5%)
			Germany	2.4–2.7 €/MWh (11%)
			Denmark	1–2 €/MWh (29%)
			Finland	0.5–0.7 €/MWh (11–22%)
Model results (for hydro systems)	[34]	Wind	Ireland	2.7 €/MWh
	[91]	Wind	UK	0.5 £/MWh (20%)
	[53]	Wind	Nordic	1.0–2.1 €/MWh (10–20%)
			Norway	0.4–0.3 €/MWh (10–20%)
			Sweden	0.5–0.9 €/MWh (10–20%)
	[14]	Wind	Sweden	1.6 €/MWh (12%)

Where necessary, output was re-calculated to derive balancing costs. Where marginal costs could not be calculated, average costs are reported. Some studies report balancing costs for shorter prediction horizons than day-ahead. If costs were given relative to the base price, a base price of 70 €/MWh was assumed.

**Table 3**  
Profile cost literature.

Prices	Reference	Technology	Region	Profile costs estimates in €/MWh [range] (at different market shares)	
Historical Prices	[8]	Solar	California	–14 to 0 at different market design (small)	
	[84,85]	Wind	Germany	–1 to 3 (2% and 6%)	
		Solar		–23 to –10 (0% and 2%)	
	[32]	Wind	WECC	–4 to 7 at different sites (small)	
	[12]	Solar	Ontario	–14 based on system price (small)	
	[65]	Wind	Michigan	–10 to 8 at different nodes (small)	
	[39]	WIND	Denmark	only monthly value factors reported	
	[41]	Wind	England	11 to 18 (30%) 21 to 42 (40%)	
		[82]	Solar	Utility	only absolute value reported
		[81,10]			
Prices from Dispatch Model	[43]	Wind	Utility	7 to 49 (0% and 60% capacity/peak load)	
	[56,11]	Solar	Germany	only absolute value reported	
	[76]	Wind	Europe	–1 to 2 (0% and 6%)	
	[75]				
	[4]	Wind	Germany	7 to 9 (6–7%)	
			Spain	7 to 13 (7–12%)	
			Denmark	18 to 25 (12–20%)	
	[38]	Wind	UK	39 (20%)	
	[25]	Wind	Germany	11 (12%)	
			Solar	–4 (6%)	
			Wind	–4 (5%)	
	Dispatch & Investment Model	[99]	Wind	PJM	only absolute value reported
		[66]	Wind	England	only absolute value reported
		[93]	Wind	Germany	5 to 14 (5% and 25%)
		[62]	Wind	California	10 to 18 (0% and 16%)
			Solar		0 to 11 (0% and 9%)
		[13]	Wind	WECC	no prices reported
		[36]	Solar	Arizona	7 to 21 (10% and 30%)
[70]		Wind	California	3 to 21 (0% and 40%)	
[69]		Solar		–19 to 43 (0% and 30%)	
[72]		Wind	Germany	1 to 21 (9% and 35%)	
		Solar	Germany	–1 to 21 (0% and 9%)	
		Wind	ERCOT	18 (25%)	
[59]	Wind	Germany	5 (19%) and 18 (39%)		
[44]	Wind	Europe	–6 (0%) and 14–35 (30%)		

These publications usually do not use terms “profile cost” or “utilization effect”. Profile costs were calculated from reported output assuming a load-weighted electricity price of 70 €/MWh. Source: updated from Ref. [44].

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