Commentary

An Overview of Integration Costs of Variable Renewables in the Power Sector

June 2023
Faris F. Aljamed, Frank A. Felder, Amro M. Elshurafa
Introduction

In recent years, the cost of electricity generated by renewables has significantly decreased to the point where it is cost competitive with conventional plants (Heptonstall and Gross, 2021). However, incorporating variable renewable energy (VRE) technologies like wind and solar photovoltaics (PV) into the power system creates intermittency. By adding intermittent sources of generation, demand and supply will not always match. This means that the system requires more backup generators and more flexibility to balance the mismatch between supply and demand. Integration costs must be factored in to determine the optimal share of VRE and the total system cost.

Traditionally, the levelized cost of energy (LCOE) has been used to compare the costs of different power generators. LCOE calculates the total lifetime discounted costs of constructing and operating a plant and divides it by the projected total energy produced during its assumed lifespan. However, LCOE does not consider the costs that arise due to VRE intermittency or the expenses associated with adapting the power system to the changes brought by VRE. Therefore, LCOE alone cannot capture the total system costs when VRE is introduced to the grid (Loth et al., 2022). This commentary provides a brief overview of how VRE integration costs are calculated by examining various methods available in the literature.

Definition of Integration Costs and their Components

Integration costs are categorized into three components: balancing costs, grid costs, and profile costs. Balancing costs refer to the costs imposed by the unpredictable nature of VRE generation. Supply uncertainty causes day-ahead forecasting errors, which necessitate operating reserves and/or storage to balance supply and demand. Grid costs result from VRE region-specific requirements. VRE technologies are less flexible than conventional generation in terms of where they can be built. Sometimes, VRE generators are located far from load centers, requiring additional transmission infrastructure to deliver energy. Profile costs are mostly due to the variable nature of VRE (Ueckerdt et al. 2013).

Profile costs were previously referred to as ‘adequacy costs.’ Adequacy costs are the expenses attributable to the low-capacity credit of VRE. Conventional generation capacity is considered ‘firm’ capacity, always ready to meet demand, which is not the case for VRE. As a result, capacity costs increase as more VRE is integrated into the system. Profile costs are a more comprehensive concept that captures all costs imposed by VRE variability (Heptonstall and Gross 2021).

Profile costs comprise three components. The first component is overproduction costs, which are the costs arising from the curtailment required for over-generated power. The second component is backup costs, which are the costs of backup capacity needed to balance supply...
The third component is full-load hour (FLH) reduction costs. VREs reduce the FLH of dispatchable plants, resulting in lower generation per capacity for these plants (Ueckerdt et al. 2013). Figure 1 summarizes the integration costs.

**Review of How Integration Costs of Variable Renewable Energy Are Calculated**

**Load duration curves method**

One method to assess integration costs is the load duration curve (LDC) method. An LDC displays the hourly load of a year, sorted from the highest load hour to the least load hour. When (VRE) is added, the LDC is changed to residual load duration curve (RLDC), which shows how much electricity demand is left after subtracting the supply from renewable resources. To determine the residual costs for the system with VRE, one needs to integrate along the inverse of the RLDC and multiply the value by the respective minimum screening curve value. For the system without VRE, the integration is along the inverse of the LDC. Screening curves show the total cost per kilowatt (kW) per year of different generation technologies. Figure 2 displays an example of an LDC and an RLDC.
Ueckerdt et al. (2013) introduced the system LCOE metric, which is the sum of the plant’s marginal generation costs and marginal integration costs. The authors divided the costs of the system into VRE generation cost and residual costs. The residual costs are the generation costs of conventional plants and the integration costs of VRE.

The authors compared the residual costs of two systems: one with VRE and one without. Since the system without VRE has no integration costs, comparing the residual costs of the two systems isolates the VRE integration costs. The integration costs are defined as the difference between the specific costs per unit of residual load of the two systems multiplied by the residual generation.

Ueckerdt et al. estimated balancing and grid costs from previous studies and calculated profile costs. For wind shares from 5% to 30%, balancing costs range from 2.5 to 5 euros per megawatthour (€/MWh), and grid costs are around 13 €/MWh for 40% wind penetration. Profile costs reach about 30 €/MWh at 30% wind penetration, and overall integration costs can go up to 60 €/MWh at 40% wind penetration. Integration costs can be reduced by introducing options such as long distance interconnection, storage, and demand management. Note that the study being reviewed does not optimize the energy mix. The only option considered was the capacity mix of residual power generation by thermal generators. Thus, the profile costs calculated are overestimated.
Cost production model method

Another method to assess integration costs is the cost production model method. Here, the modeler compares a scenario without renewables to another with renewables. The difference in cost between the two scenarios would be the integration costs. The models can be built using standard software or programming languages.

For instance, Brouwer et al. (2015) used PLEXOS, a commercially available software package that models power systems, to simulate the power sector for Western Europe in 2050. For different penetration levels, the authors considered five complementary options to integrate VRE at the lowest cost: demand response (DR), gas-fired power plants with and without carbon capture, increased interconnection capacity, curtailment, and electricity storage. PLEXOS optimizes unit commitment and economic dispatch while meeting five constraints: balancing electricity supply and demand, flexibility constraints of generators, limited transmission capacity for interconnections, scheduled and unscheduled outages, and the balancing reserves requirements.

Profile costs were calculated for variable renewable energy (VRE) penetration levels between 22% and 59%, with values between 0% and 22% linearly interpolated. The increase in profile costs due to VRE addition is mainly attributed to two factors: the reduction in the capacity factor of thermal generators caused by increased VRE, and the need for more curtailment due to overproduction from renewables (Brouwer et al. 2015). Marginal profile costs ranged from 0 €/MWh to 100 €/MWh for penetration levels of 0% to 60%. Up to 40% penetration, integration costs increased linearly, reaching approximately 30 €/MWh. However, after the 40% mark, integration costs started to grow exponentially.

Reichenberg et al. (2018) focused on the integration costs of VRE in Europe by dividing it into 10 regions. They used an electricity investment model that accounts for variability and variation management to optimize the dispatch and investment in generation, storage, and transmission for all penetration levels. The authors calculated the system levelized cost of electricity (LCOE) using the same definition as Ueckerdt et al. The marginal system LCOE increased linearly as VRE penetration increased, with a rate of 6 €/MWh for each 10% increase until reaching 80% penetration. After that point, the marginal system LCOE started to increase exponentially due to allocating VRE in regions with lower capacity factors and the need to curtail or store excess energy.

Xi et al. (2022) calculated the integration costs for the power system in the Jilin province of China, comparing a system with no VRE generation to a system with VRE generation. Due to the coal-dominated nature of the Jilin power system, it experienced a rapid increase in integration costs at an earlier penetration level compared to other power systems. Yao et al. (2020) simulated the power system of Guangdong province in China and found that integration costs for wind and solar PV ranged from -2.18 €/MWh to 11.47 €/MWh and -5.21 €/MWh to 6.73 €/MWh, respectively, for penetration levels up to 30%.
Overall, the integration costs of VRE vary depending on the penetration level, system flexibility, and the specific characteristics of the power system being analyzed. While marginal system LCOE and incremental operating costs of thermal plants tend to increase linearly with higher VRE penetration, curtailment costs, idle costs, and balancing costs can decrease or remain constant in more flexible power systems.

The two studies we discussed on China only consider integration costs for penetration levels up to 40%. However, to increase the deployment of VRE in the Chinese power system, better system flexibility is needed. Ru et al. (2022) propose that the Chinese power system can achieve VRE penetration levels between 70% and 85% by implementing variation management options such as different energy storage technology and ultra-high voltage direct current-based (UHVDC-based) transmission.

Discussion

In Ueckerdt et al.’s model, the integration costs started to increase at a higher rate at lower penetration levels than in other studies. For wind, the jump occurred at 25% penetration, while for PV, it occurred at 15% penetration. Reichenberg et al. suggest that the reason behind this relatively early jump in integration costs is due to the absence of variation management solutions such as trade, storage, demand response, or complementarity of wind and solar.

Brouwer et al. calculated the integration costs of VRE for up to 60% penetration. The sharp increase in profile costs happened later than in Ueckerdt et al.’s study. Brouwer et al.’s model is implemented across Europe, not just in Germany. This gives it a wider scope that accounts for trade between regions. However, one downside to the model is that VRE capacity and transmission locations were not optimized, and the sharp increase in profile costs occurs at around 40% penetration due to reduced FLH and curtailment costs.

Integration costs in Reichenberg et al. start increasing sharply at a much higher penetration level than that of previous studies, which happens at around 80% penetration. The authors state that the values of the integration cost are mostly attributed to cost assumptions, while the point at which the costs start to increase sharply stems from system dynamics. This study shows the benefits of accounting for variation management options and how they affect the linear increase of integration costs with respect to VRE penetration at small shares. Employing different integration options could also prove to be complementary to each other. For example, Auguadra et al. (2023) demonstrate that demand response is complementary to energy storage and provides flexibility for storage technology.

A limitation of Reichenberg et al.’s model is that it doesn’t consider some technical aspects like forecasting errors and the need for balancing power from thermal plants. Another limitation is that, while the model invests in transmission between the regions, transmission within each region is unaccounted for. A limitation of solar PVs is that the time resolution is not hourly, which impacts solar availability, as it can change drastically
from one point in time to the next (e.g., from 9 a.m. to 11 a.m.). Finally, a limitation of wind generation is the interannual variability of wind speed, which was not accounted for in the study.

According to the literature, balancing costs are generally low when compared to other components, with estimates their values typically below 6 €/MWh. When the trend line is fitted to the data, balancing costs increase from 2 €/MWh to 4 €/MWh for wind penetration from 0% to 40% (Hirth et al. 2014). Hirth et al. find that grid costs are also small, and they are not usually reported in marginal terms. Furthermore, the results are usually not based on cost optimization. Grid costs are estimated to be in the order of 5 €/MWh. Wind profile costs are estimated to be negative or close to zero at low penetration rates. However, at higher penetration rates of between 30% and 40%, profile costs for wind are estimated to be around 15 to 25 €/MWh (Hirth et al. 2014).

Another study that reviewed past literature estimates was conducted by Heptonstall and Gross (2021). They estimated that additional costs for operating reserves (used to balance supply and demand) are below 5 €/MWh for up to 35% penetration and below 10 €/MWh for penetration levels up to 45%, with the size of these costs depending on the flexibility of the system. Adequacy costs, which are a specific type of profile cost, are estimated to be around 10 €/MWh or less for all penetration levels. Profile costs are estimated to range from 15 to 25 €/MWh at 25% to 35% penetration. The authors also estimated grid costs to be in the range of 7 to 28 €/MWh. However, they noted that estimates for these costs vary widely across the literature, and it is challenging to attribute all grid and transmission upgrades to the variable generation of VRE. Table 1, below, summarizes the costs discussed in this section.

### Table 1. An estimate of the costs calculated in the studies covered.

<table>
<thead>
<tr>
<th>Study</th>
<th>Method</th>
<th>Location</th>
<th>Penetration percentage</th>
<th>Balancing costs (€/MWh)</th>
<th>Grid costs (€/MWh)</th>
<th>Profile costs (€/MWh)</th>
<th>Point of exponential increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ueckertd et al.</td>
<td>LDC calculations</td>
<td>Germany</td>
<td>0% - 40% (wind) 0% - 25% (Solar)</td>
<td>2.5 - 5 (wind)</td>
<td>0 - 13 (wind)</td>
<td>-5 - 60 (wind) -10 - 100 (solar)</td>
<td>25% (wind) 15% (solar)</td>
</tr>
<tr>
<td>Brouwer et al.</td>
<td>Cost production model</td>
<td>Europe</td>
<td>0% - 60%</td>
<td>0.2 - 1</td>
<td>N/A</td>
<td>0 - 100</td>
<td>40%</td>
</tr>
<tr>
<td>Reichenberg et al.</td>
<td>Cost production model</td>
<td>Europe</td>
<td>0% - 100%</td>
<td>N/A</td>
<td>0 - 110</td>
<td>80%</td>
<td></td>
</tr>
<tr>
<td>Xi et al.</td>
<td>Cost production model</td>
<td>China</td>
<td>0% - 40%</td>
<td>Included with profile</td>
<td>N/A</td>
<td>0 - 16.8</td>
<td>20%</td>
</tr>
<tr>
<td>Yao et al.</td>
<td>Cost production model</td>
<td>China</td>
<td>0% - 30%</td>
<td>-2.18 - 11.47 (wind) -5.21 - 6.73 (solar)</td>
<td>N/A</td>
<td></td>
<td>N/A</td>
</tr>
<tr>
<td>Hirth et al.</td>
<td>Cost production models</td>
<td>USA and European countries</td>
<td>0% - 40%</td>
<td>2 - 4</td>
<td>5</td>
<td>0 - 25</td>
<td>N/A</td>
</tr>
<tr>
<td>Heptonstall and Gross</td>
<td>Cost production models</td>
<td>Europe, USA, Asia</td>
<td>0% - 45% (Balancing) 0% - 35% (Profile) N/A (Grid)</td>
<td>0 - 10</td>
<td>7 - 28</td>
<td>0 - 25</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Conclusion

There are generally two methods for calculating integration costs. The first method we covered uses the load duration curve and residual load duration curve to compare the residual costs of a non-VRE system and a system with VRE. The second method uses production cost models, which is the most commonly used method due to its higher accuracy and descriptive power. We also saw that each system has its own characteristics and integration challenges, and therefore requires a dedicated study.

The production cost method is the most commonly used method to estimate integration costs due to its higher accuracy, despite it being more data and modeling heavy.

Although the calculations performed on different systems were not exactly the same, we generally observe similar trends. Balancing costs are usually below 10 €/MWh and are typically in the single digits. While literature on grid costs is scarce, these costs are usually greater than balancing costs. Profile costs are always the largest component of integration costs, and they typically amount to around 25 €/MWh at 35% to 40% penetration. In some cases, they can even be higher if the system does not account for appropriate variation management solutions.

At lower VRE penetration levels, integration costs can be close to zero or even negative in some cases. However, as more VRE generation is added to the system, these costs increase rapidly. Depending on the system characteristics and integration options considered, the level of increase in integration costs varies. Moreover, the point at which these costs begin to increase exponentially also depends on the aforementioned factors. For flexible systems, integration costs start to increase exponentially at penetration levels above 40%. If the system also implements variation management solutions, then the point of exponential cost increases can be delayed to up to 80% penetration.

These results must be considered when VRE technologies are integrated into the power system. Factors such as system flexibility and interconnectivity, for example, need to be carefully evaluated to ensure a smooth transition to the targeted VRE penetration level. Furthermore, keeping in mind the power system’s characteristic and challenges is of the utmost importance to successfully select the appropriate integration options. Although these considerations will not affect the LCOE of VRE, the system LCOE (the overall system marginal costs) will be decreased.
References


About the Project

The Kingdom intends to reduce or eliminate its use of liquid fuels by deploying considerable renewable energy capacity. The Assessment of the Changing Economics of the Saudi Electricity Industry project assesses the impacts of deploying renewables on the Saudi power sector in terms of costs, reliability, emissions, and natural gas consumption.
About KAPSARC

KAPSARC is an advisory think tank within global energy economics and sustainability providing advisory services to entities and authorities in the Saudi energy sector to advance Saudi Arabia’s energy sector and inform global policies through evidence-based advice and applied research.

Legal Notice

© Copyright 2023 King Abdullah Petroleum Studies and Research Center (“KAPSARC”). This Document (and any information, data or materials contained therein) (the “Document”) shall not be used without the proper attribution to KAPSARC. The Document shall not be reproduced, in whole or in part, without the written permission of KAPSARC. KAPSARC makes no warranty, representation or undertaking whether expressed or implied, nor does it assume any legal liability, whether direct or indirect, or responsibility for the accuracy, completeness, or usefulness of any information that is contained in the Document. Nothing in the Document constitutes or shall be implied to constitute advice, recommendation or option. The views and opinions expressed in this publication are those of the authors and do not necessarily reflect the official views or position of KAPSARC.