System Integration Costs – a Useful Concept that is Complicated to Quantify?

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***Abstract* — Several attempts have been made to produce a levelized "system integration cost" number to add to the levelized cost of electricity (LCOE) of variable renewable energy (VRE[1]) to facilitate comparison with thermal power plants and other generators. However, capturing this "system integration cost" component is a challenge. By contrast, total system costs can be calculated by simulating different configurations of a future energy system. The total costs, and benefits, can then be compared in terms of operational and investment costs across scenarios with different shares of VRE. This paper outlines the discussions on the methods for extracting system integration costs, showing the conceptual pitfalls and issues related to required assumptions. It also suggests a method to compare costs and benefits of increasing shares of VRE from a system perspective as a preferred metric to quantify impacts of VRE integration.**

Key words- grid integration, variable generation, integration cost

I. INTRODUCTION

This paper provides a discussion on the difficulties associated with quantifying system integration costs of VRE, or "the costs of variability"[2]. It reviews past and current efforts to tackle this question and highlights why quantifying total system costs, or "economic effects" of VRE on power systems is conceptually better defined and can thus be answered in a methodologically less controversial way.

The cost for providing electricity varies depending on location, moment of delivery and degree of advance notice. The fundamental reasons behind this are the cost to transport and store electricity as well as the lead time that some generators require to change output. All generators show some constraints in terms of when, where and with how much advance notice they can generate. VRE plants face constraints that are distinct from all other generators – the economically most important one is the direct dependence on availability of wind and sunlight.[3] This puts constraints on when and where they can generate as well as on how accurately their output can be forecasted. While it is intuitive that these constraints will affect the economics of VRE on the power system, isolating the cost of weather driven variability is conceptually impossible without further assumptions and hence a significant practical challenge.

It is worth noting that VRE do not face certain constraints that affect thermal plants: they do not have any issues with thermal stress on equipment during output changes and hence can adjust output rapidly, with high accuracy and extremely low increased operation and maintenance costs.

International collaboration under IEA TCP WIND Task 25 set out in 2006 to study the different methodologies to estimate impacts and costs of wind integration. Integration

[1] Variable renewable energy includes wind, solar photovoltaics, run-of river hydro and ocean energy technologies. This paper uses VRE to refer to wind and solar photovoltaics.

[2] In the broad sense encompassing all weather and climate related constraints: varying availability of the resource across time and space, uncertainty about the exact availability beyond a few hours ahead.

[3] From an engineering perspective, use of power electronics (converter based generators) is emerging as the most important characteristic. The discussion in this paper focusses on impacts arising from variability, uncertainty and location constraints of VRE.

studies at that time often set out to estimate impact on balancing costs - sometimes also capacity value and impacts on transmission reinforcement were analysed. The first reports [1][2][3][4] published summary graphs from national results:

- balancing costs, that ranged 1–4 €/MWh wind power produced at wind penetrations of up to 20 % of gross demand (energy).
- grid reinforcement costs, that ranged from 0 €/kW to 270 €/kW.

A review of literature results can also be found in [5].

VRE system effects significantly depend on the generation mix and level of flexibility, impacted by demand side response, characteristics of conventional plant, and levels of interconnection and energy storage. Increased levels of flexibility may potentially reduce system integration cost by an order of magnitude.

In the course of years, recommended practices were formulated on how to properly take wind power into account when making simulations for power system operation, and long term planning. Main caveats were found in the assessments of system integration costs [6][7][8][9]: (1) defining a suitable "non-wind" case, (2) extracting the highly nonlinear nature of these costs, and (3) calculating wind balancing cost without doing comparable calculations for other types of generation that also impose balancing related costs.

Indeed, due to the complex nature of electricity systems, all generation technologies show interactions with the broader system, which can be both positive and negative. Examples of how system integration costs may be incurred by other types of power plants, such as new base load generation and new higher contingency levels, are presented in [8][9]. A framework for system integration costs for operational aspects of the power system in addition to wind/PV is presented in [10]. A conceptual framework for system effects and related costs covering investment and operational time scales can be found in [5].

II. Relevance of Quantifying Economic Integration Effects

A. *Why is there less interest in system integration cost?*

The question of integration cost triggered an important wave of interest among utilities and regulators in the United States, when wind saw deployment at scale in the early 2000s driven more by policy than the will of utilities. Faced with a requirement to connect new wind generators and integrate their output into the system, vertically integrated utilities requested to be compensated for the "cost of variability" they incurred for balancing VRE in their portfolio. Five or ten years ago, it was not unusual for an operational integration cost adder to be placed on renewable energy in evaluations against conventional energy With experience of higher shares of wind power (ERCOT, Southwest Power Pool (SPP), Hawaii, Colorado and California) the confidence in the ability to operate systems without significant cost additions has been demonstrated [11]. Today, combined with the continued rapid decline in the cost of wind and solar compared with the alternatives [12][13][14], the integration cost in its original sense as an operational cost adder is of little interest. System operators who thought ten years ago that there was an upper limit of 10-20% instantaneous wind and solar energy penetration are now routinely operating systems with two to three times that amount, and studying the behavior of their systems for future hourly shares of 60-80%. The focus of interest in the US has thus shifted and now emphasizes new concerns associated with the transition to the planning, design and operation of systems dominated by converter-fed generation, and the associated concerns of market design and operation of such systems [15].

In Europe, the move to market integration of VRE power plants has brought more transparency to balancing costs, and also put these costs to wind and solar operators to bear. Similarly, more transparent grid connection costs facilitate identifying the part of grid investments for grid operators that is directly related to connection to the grid.

B. *Why is there still relevant interest in system integration cost?*

However, the question of economic impacts of VRE at the system level is becoming more relevant as LCOE of VRE drops and, on an LCOE basis, it is on par or below fossil fuel and nuclear generators in a growing number of markets. Reflecting this trend, both IEA and IRENA are confronted with questions on system effects from countries new to large amounts of VRE. In most cases there is a desire to compare renewable scenarios with other alternatives.

In countries with ambitious decarbonisation targets or uncertainty around the future of nuclear energy (such as is currently the case in France, Japan and the UK) there is a need to compare renewables with the low carbon option from nuclear energy. An example is the UKERC literature review on system integration cost [16]. However, such meta-analyses of system costs face challenges, due to the lack of a consistent methodology and the sensitivity of results to the assumed level of system flexibility. Hence reporting of costs should ideally put estimates into context, including levels of assumed flexibility.

In summary, there is a shift of interest away from the original concept of system integration costs as a tariff charged for more complex system operation and towards more integrated assessments of the economics of high VRE power and energy systems. The following sections provide further details on why extracting specific system costs is challenging and what alternative approaches are available.

III. Challenge: Isolating System Costs

Isolating the system integration cost for VRE is equivalent to answering the following question: "How much cheaper would it be for the power system to use VRE, if VRE was *non-variable*?" The cost of variability is precisely the difference between such a *non-variable* VRE scenario and the situation using real-life VRE technology. The issue with answering this question is that *non-variable* VRE power plants do not *exist*.

As such – and this is the crucial point –, any attempt for isolating the cost of variability necessarily relies on constructs that use additional assumptions to strip away the impact of variability from *all other* impacts VRE bring to the power system (the primary impact being that VRE plants generate electricity at very low short-run marginal cost and displace other generators when they are added to a power system, all else being the same). One thus needs to introduce a benchmark technology *ad-hoc.* This benchmark functions as the non-variable VRE technology. Calculating system integration costs requires comparing two cases: one with using VRE and another using a benchmark technology.

Because *non-variable* VRE is not defined as such, the choice for such a benchmark is discretionary – explaining part of the lively debate on integration cost and the sometimes large disparity between estimates. A generator with a flat output is a common benchmark of choice, arguably owing to its resemblance with conventional generation technologies. One problem with this benchmark is that it cannot meet 100% of electricity demand for actual load profiles, because demand always shows some variability [7]. Other choices are possible and reasonable, although more abstract. An example is a benchmark showing a perfect output correlation with electricity demand. This approach provides a single technology that could meet all demand, thus avoiding the issue with the flat block approach. However, it is hard to imagine an actual technology that would have this property. Challenge: Defining what is "The System"

Another issue – unrelated to the complications of extracting system integration costs – that makes it challenging to assess the economic effects of high shares of VRE is that such effects are the result of an interaction. Power systems show strong differences in the difficulty or ease to integrate VRE, mainly linked to the amount of flexibility that is available to the system at what cost. It has been shown that system integration costs are very system dependent and driven by assumptions [17][18]. In addition to being system-specific, they are time-specific, and in general changing any component or operational practice in a system leads to changes in integration costs.

An important finding is that flexibility in power systems make system integration costs lower [5][8][17][18]. This makes economic effects of high shares of VRE different from one system to the other, and even for the same system they change over time. For instance, costs related to short-term adjustments in response to forecast uncertainty in Germany (balancing costs) have severely decreased since the four TSOs in the country started to share balancing reserves and converge operational practices closer to real time [19]. As the power system becomes more integrated with other parts of the energy system, the questions of system boundary for studying system effects will become an increasingly relevant issue. For example, when assessing electrification of heating as a power system flexibility option, possible savings in the natural gas system would need to be taken into account for a robust assessment.

IV. CHALLENGE: CATEGORISING INTEGRATION EFFECTS

Another complication arises from the desire or need to segment integration effects into different categories. The main body of literature so far has been about estimating a separate system integration cost - by dividing it into components arising from short term balancing, grid expansion and reinforcement, and profile or capacity cost due to changes in generation mix.

While it is straightforward to distinguish the most relevant properties of VRE (variability, uncertainty, location constraints) and assign cost categories to each (profile costs, balancing costs, location costs), clearly separating and quantifying the different categories is challenging.

For example, establishing a reference technology for extracting each category in isolation becomes challenging to the point of impossibility. (Or can you imagine a technology that is strictly non-variable, i.e. fully constant in output, yet uncertain?[4]).

Nevertheless, disaggregation of costs can be relevant for three reasons. First, understanding the magnitude of each type of cost is important for setting research and policy priorities as well as efforts to design market mechanisms. Second, for purposes of cost-allocation, disaggregation can be required, because different entities may have different responsibilities for the power system. Third, it may be inevitable to use different power system models or analytical methods to capture system effects. This will naturally yield costs from different categories (roughly following the difference between generation capacity expansion, production cost and grid planning models). Fortunately, there are a number of factors that facilitate disaggregation.

A. System integration costs from grid investments

First, grid costs can be reasonably well isolated from other cost impacts. This is not to say that cost allocation of grid costs is easy – the opposite is the case. However, it is straightforward to separate grid and non-grid costs.

Transmission grid planning includes power flow and dynamic/transient analyses to assess if the grid is sufficient to cope with both temporary disturbances and significant failures. Adding large amounts of VRE can require grid upgrades to maintain reliability. One can try the Put In one at a Time (PINT) or the Take Out One at a Time (TOOT) approach [16] to compare costs. Here the challenges lie in how to choose the VRE case to be able to extract the VRE-induced costs only.

It should be noted that this system integration cost component is not positive by definition. Adding solar or wind power at a favourable location can relieve grid congestions, resulting in a negative need for grid expansion and therefore negative system integration cost. This might not be the case for a majority of new sustainable power plants, as new wind plants are often far away from load centres..

System operators in Europe do not publish grid reinforcement costs for any technology/cause for grid upgrade. This is because it is extremely difficult, if not impossible to allocate a cost of an asset that is used by all users to one single cause to build that asset. The Portuguese TSO made an effort to allocate only part of the costs for wind power in 2007 [2], but that allocation is not transparent. A meshed line of additional transmission typically provides a reliability benefit beyond the benefit of connecting the generator in question, and thus allocation of this cost to wind/PV power only is not accurate. The ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (CBA 2.0) addresses this issue [21].

[4] One may be tempted to name a baseload generator that has a risk of an unscheduled outage. However, such an outage – the moment it occurs – will make the generators output variable.

Most of grid capacity additions are due to increase of electric load rather than wind energy supply - visible from the European system operators transmission planning work (TYNDP). The build out of hydro power was accompanied by a large grid investment in Nordic countries and Italy, and the recent addition of nuclear power in Finland required a grid reinforcement in the Western part of Finland as well as was the main reason for building out a new interconnector to Sweden. Also a move toward road transport electrification and electrification of heating in buildings will need transmission and, especially, distribution upgrades. Funding complementary approaches to system design where supply and demand are smartly coupled (distributed generation plants – such as hybrid wind and solar systems - connected closely to electric vehicles charging points) can help to contain grid expansion but does not facilitate the allocation of grid investment costs to specific categories of generators or loads.

B. System integration costs from system operations: balancing costs

It is possible to obtain empirical estimates of balancing costs. Due to the way the power system is operated, observable balancing costs always combine both uncertainty and an element of short-term variability. Because power system schedules are made for discrete time steps (ranging from typically one hour to five minutes granularity), the impact of uncertainty on the one hand and variability on the other is indistinguishable within each programming time block of the schedule.

As long as one accepts this limitation, it is possible to assess the costs of dealing with short term variability and uncertainty by analysing costs associated with the respective system services (balancing, operating reserves). While allocating costs specifically to VRE is very difficult (real-life imbalances aggregate uncertainty and short-term variability of load and all generation), it is straightforward to obtain an order of magnitude of associated costs. Such quantifications critically depend on the scheduling interval used for operating the system, however. It is worth pointing out that uncertainty can also impact operational costs at longer time scales than during operations as part of scheduling and unit commitment processes.

The balancing costs include increase in the need or allocation for additional operating reserves when VRE uncertainty exceeds other criteria used to calculate reserve requirements (e.g. loss of largest infeed) and the use of those reserves or balancing (market) in real time to maintain the system balance.

Improvements in operational practices and market design can provide significant benefits in systems with increasingly large shares of VRE making such “soft” improvements necessary before considering investments in hardware [17][18].

The ideal methodology for simulations to assess balancing impacts would take all possible market and grid dynamic aspects into account and cover several years with a small time step (on the order of a second). This is currently impossible in practice, although the simulation tools are developing to this direction. Limitations arise from the simulation methodology and from assumptions that need to be made when simulating the system operation.

In summary, the main difficulties for isolating balancing costs are:

- how to choose the base case “no VRE” simulation, in order to get the costs incurred by VRE as a result of comparison with “VRE” case.
- quantifying the increase in balancing costs is challenging as the major impact usually is a decrease in operational costs due to reduced fuel use that VRE will replace.
- allocating any difference in operational costs to VRE involves assumptions impacting the results.

It should be noted, that also this system integration cost component can be negative. If production of VRE is positively correlated with the electricity price (e.g. solar power with cooling loads, wind power with heating loads), these power plants can actually contribute to balancing the system instead of creating the need for balancing. This results in negative system integration cost. However, with large amounts of solar or wind, the marginal generation has poor correlation to the net load peak. At this stage, flexibility should be harnessed on the demand side, to ensure that integration of VRE does not translate into investments in large scale storage (see next section). Ideally, an increasing share of the demand for electricity should start following price signals, so that not only production cost but also cost-to-load (i.e. sum of electricity demand in each time step multiplied by the electricity price in that time step) is minimized.

Making sure that flexibility is harnessed in all parts of the power system is a necessary condition to prevent integration cost (or, better, total system cost) from increasing significantly as VRE deployment progresses. Production cost models should therefore be set up considering all available flexibility options when exploring high-VRE scenarios.

C. System integration costs from the long term generation capacity mix

Tackling the impact that VRE have on the generation capacity mix – or more generally required power system investments - has proven to be the most challenging. Early approaches focussed exclusively on contribution of VRE to meeting peak demand. The reasoning behind this is that VRE may not be generating when the system has the tightest capacity margin. Hence, other generation capacity would be needed to ensure reliability. The cost estimate would involve determining the cheapest way to provide the required capacity against peak at a level that matches the energy contribution for VRE [22].

This approach has an important shortcoming. By focussing only on the moment of peak demand, impacts during other hours are left out of consideration. Indeed, the task of flexible resources in a high VRE power system is not only to supply electricity during peak demand. Rather, resources need to cover net load at all times.

Considering the structure of net load is most suitable to understand variability related impacts. Despite important differences from system to system, the net load duration curve at high and growing levels of VRE typically exhibits three properties: 1) peak demand reduces less quickly than minimum demand; 2) minimum demand becomes negative at some point while peak demand does not reduce further or reduces very slowly; 3) as a consequence, the net load duration curve between maximum and minimum demand becomes steeper.

The consequence of this is that the non-VRE power plant fleet (in the absence of measures such as demand response and storage, see below) experiences a falling utilization rate: the need for capacity remains high (high peak demand), while the need for energy continues to fall (falling minimum demand). It is clear that the overall cost of meeting residual demand at a higher VRE share will continue to fall as VRE grows – less total generation is needed from the non-VRE system. However, the specific cost of meeting this residual demand (expressed per MWh) from non-VRE generation *increases*. The main driver for this increase is the fixed costs of power plants, which need to be 'spread' over a lower amount of MWh generation. Appropriately accounting for this effect has arguably been the biggest source of controversy and confusion regarding economic effects of VRE [5][17].

The degree to which this effect is economically significant depends on a number of factors:

- Peak demand in the future might occur in different time of day or year, depending on a multiplicity of climate factors, electrification of end uses, energy efficiency and demand side management programmes. This can make the net-load shape less challenging to meet.
- Demand response can "move" demand to better follow available generation.
- Energy storage can adjust net load both upwards and downwards, again helping to meet net load more economically.
- Interconnection over larger areas can flatten the (net-load) curve, making it less challenging to meet.

Looking further into the future, it is not clear how large the impact of the contribution of these resources are and what associated costs will be. In any case, studies that consider only dispatchable generation and rely on current demand structures should be seen as a highly conservative upper limit to variability related costs.

Irrespective of how much alternative flexibility is considered, a clear distinction between social and private costs as well as proper consideration of time horizons are paramount for reaching a correct understanding of this economic effect.

Social costs of the power system cover all operation and investment costs for building and running the power system, factoring in the cost of all relevant externalities. Private costs describe the revenues and expenditure of a specific actor. The main difference between private and social costs is that private costs critically depend on the allocation of profits (rents), while social costs do not. For social costs, it does not matter if a certain player receives higher profits at the expense of another player. What matters is how much resources (labour and capital) are required to supply electricity at a given amount of reliability and environmental impact.

When VRE are added to a power system and other generators experience a fall in their utilisation and hence revenue, this can have devastating effects for the private costs of a particular generation company. However, there are no additional social costs incurred: power plants have been built already anyway, no additional resources (labour and capital) need to be mobilised. There is no reason why VRE – as a competitor of other generation resources – should be obliged to pay a compensation for the loss of business to its competition. Nor should this be considered as a cost element for uptake of VRE – the existing plants have already been built, their cost is sunk.

By contrast, in the long-run existing power plants and other assets will need to be replaced. At that point, there can be real social costs associated with the need to cover demand at times when VRE are generating at a low level. This cost is reflected in the higher specific costs for meeting net demand – in the long-run. A quantification of these long-run effects needs to take full consideration of the possibility to optimise resource investments to the presence of VRE. While an optimisation of the dispatchable plant fleet is a minimum requirement, other advanced flexible resources (interconnection, demand response, storage) should also be allowed in a long-term optimisation to meet net load at least cost to yield more meaningful results. Advanced options help contain the increase in the specific cost of the residual system, or – if system flexibility becomes cheap enough – high shares of VRE will simply be least-cost, even when accounting for the cost of the residual system.

Even when assessing variability impacts in the long-run, this situation still leaves a possible source of confusion. The non-VRE system needed to meet net load will be cheaper in total compared to a non-VRE system meeting all of the load. Why then should there be a *cost* that can be attributed to VRE when actually their presence is *saving* money?

The answer to this question leads back to the different ways of capturing economic effects of VRE. In the system integration cost approach, all costs are always expressed *relative* to a benchmark technology. Hence, we need to compare the following two situations: What is the cost of the residual system when using VRE? What is the cost of the residual system using the benchmark? A higher cost when using VRE is then *by definition* a system integration cost relative to that benchmark.

The system value and total system cost approaches allow for a much more intuitive interpretation. The diminishing savings in the non-VRE system will be reflected by a higher overall total system cost (because the non-VRE costs reduce more slowly than VRE generation increases in high VRE scenarios) or a saturating system value, i.e. the per MWh net savings from VRE diminish.

V. APPROACHES FOR ESTIMATING ECONOMIC IMPACTS OF VRE

A. System integration costs

Over the past two decades a number of attempts have been made to derive a standard methodology to isolate "system integration costs". However, for the fundamental reasons explained above, any approach will always rely on ad-hoc assumptions. The most important one relates to the choice of benchmark technology (i.e. what is used as the *non-variable* VRE basis of comparison). Hence, any integration costs calculated in practice does not quantify the "cost of variability". Rather, it calculates a difference between either using VRE power plants or using a specific benchmark technology.

Such costs are usually expressed as monetary value per unit of energy (USD/MWh) either of VRE or all power demand and added to the levelized cost of electricity. The resulting metric can be referred to as system LCOE [23] (Figure 1).

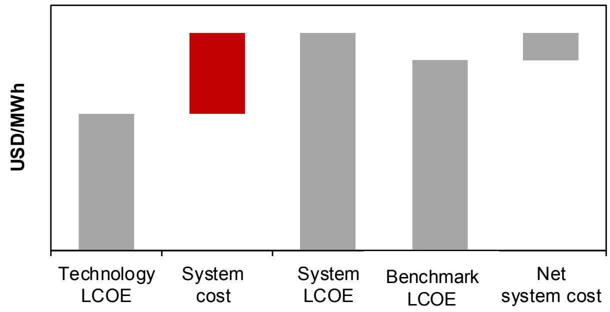

Figure 2. Comparing VRE to a benchmark technology to calculate system cost and system LCOE.

It is possible to avoid challenges linked to system integration cost calculations by asking a different question: "How much cheaper or more expensive will it be for the power system to rely on a certain amount of VRE generation compared to an alternative scenario." This question can be answered by calculating total power system costs under different future scenarios [24] and either assessing costs and benefits between scenarios or comparing the total cost of different scenarios.

B. *System value cost benefit analyses*

This approach relies on separating a) the direct cost of VRE and b) all other costs and benefits for the system. Costs and benefits belonging to b) can only be calculated by comparison of a high(er) VRE with a low(er) VRE reference scenario – hence there is a similarity with the total system cost approach. A possible reference scenario is the 'system as is', i.e. neither adding VRE nor any other technology.

Costs and benefits are measured as the difference between the VRE and reference scenarios. The resulting net impact for the system has been termed system value [25]. One can then divide both the direct cost of VRE and its system value by the amount of VRE generation in MWh. This yields two numbers: first, the LCOE of VRE and, second, the system value per unit of VRE. This approach is known as calculating "system value" of VRE. It has to be noted that the system value – as its name suggests – critically depends on the power system under study. It also depends on the level of VRE penetration. Thus results are valid on for a specific system and a specific level of VRE.

The advantage of this approach is that it allows to directly compare the per MWh cost of building new VRE plants with its net effect for the system. As long as system value exceeds LCOE, building more VRE will help reduce total system costs. The disadvantage is that system value is conceptually somewhat more complex than a direct comparison of total system costs, because it measures the difference between a subset of costs between two scenarios. Also, other benefits like emission savings are not easy to monetize in many cases.

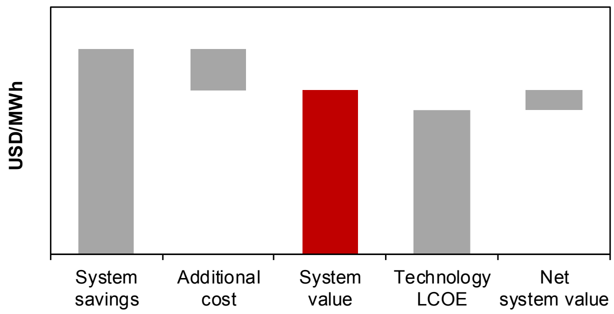

Figure 2. Calculating system value by evaluating costs and benefits of VRE (technology) compared to a reference scenario.

C. *Total system costs*

The most conceptually straightforward approach is to simply compare the all-in system costs of different scenarios. This approach is referred to as calculating "total system costs". High-VRE scenarios tend to bring a substantial net reduction in operational costs (mostly fuel savings) compared to scenarios with higher shares of fossil fuels. Reasons for higher costs in high-VRE scenarios can be a) cost of VRE itself, but due to continued cost reductions this is less and less the case, b) cost of flexible resources, notably a need to maintain a relatively large non-VRE generation fleet with low utilisation or larger grid requirements. These costs can be minimised by considering more advanced solutions, such as storage and systematic changes to electricity demand (electrification, targeted energy efficiency, demand response). .

The advantage of both approaches (system value and total system cost) is that they avoid the pitfalls of introducing a *non-variable* VRE benchmark technology. However, results still depend strongly on what is chosen as reference scenarios for the comparison. Thus, the approach is conceptually clearer, but still requires ad-hoc assumptions and choices.

A shared disadvantage of both approaches is that the question on the economic impact of variability is only answered implicitly, i.e. while the total cost of different scenarios can be compared, it does not provide a direct quantification of different VRE related effects.

Most importantly, these methodologies cannot be used directly to answer questions concerning cost allocation between different stakeholders in the power system. This aspect is beyond the scope of this paper.

One aspect that is relevant for all three approaches is the difference between studying marginal and average impacts of adding a certain amount of VRE. Marginal effects can be studied by calculating the derivative of the cost indicators, i.e. system integration cost, total system cost and system value. This information can be useful, because it shows the difficulty or ease with further increasing VRE from a given level [5].

VI. Conclusions

In the past, several attempts were made to produce a system integration cost number to add to the levelized cost of electricity (LCOE) of VRE in order to facilitate comparison with thermal power plants and other generators. However, capturing this "system integration cost" component is a challenge. The complications involved include: (1) isolating or extracting an system integration costs from other costs in the system, including the difficulty of defining a suitable benchmark "non-VRE" case as a baseline, (2) accurately dividing costs into different categories linked to variability, uncertainty and location constraints, respectively (3) consistently defining system boundaries in the context of increasing electrification and energy sector coupling.

Such problems can be avoided by using other metrics than system integration costs. In cases where there is a desire or need to look more specifically at the economic impact of adding a certain amount of VRE to the power system, it is possible to perform a cost-benefit analysis. For planning purposes, calculating total system costs – including operational and investment costs – is a preferred approach. This allows to compare different future scenarios for the energy system on an equal footing.

Irrespective of the chosen approach, assessments are only valid for a specific system and at the shares of VRE assessed. It is not possible to generalise results from one system to others. As power systems evolve with electrification of new end-use sectors (e.g. electric mobility), defining appropriate system boundaries is becoming more challenging. As a rule, assessments should draw the system boundary is wide as data and computational resources allow.

Assumptions regarding the availability and cost of flexible resources have a strong impact on results across all presented approaches. Obtaining meaningful results for the cost of future high-VRE power and energy systems thus need to take into account the possibility to use advanced flexibility options and account for possible learning effects and cost reductions.

Indeed, as VRE are becoming the cheapest source of new electricity generation in a growing number of circumstances, the key for delivering low-cost, reliable power to customers is shifting to removing inflexibility and the cost it brings.

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