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Wind Integration Cost and Cost-Causation

Michael Milligan and Brendan Kirby (Consultant)
National Renewable Energy Laboratory, CO, USA

Hannele Holttinen and Juha Kiviluoma
VTT Technical Research Centre, Finland

Ana Estanqueiro
Laboratório Nacional de Energia e Geologia, Lisbon, Portugal

Sergio Martin-Martinez and Emilio Gomez-Lazaro
University of Castilla–La Mancha, Spain

Iván Pineda
European Wind Energy Association, Brussels, Belgium

Charlie Smith
Utility Variable-Generation Integration Group, VA, USA

***Abstract*—The question of wind integration cost has received much attention in the past several years. The methodological challenges to calculating integration costs are discussed in this paper. There are other sources of integration cost unrelated to wind energy. A performance-based approach would be technology neutral, and would provide price signals for all technology types. However, it is difficult to correctly formulate such an approach. Determining what is and is not an integration cost is challenging. Another problem is the allocation of system costs to one source. Because of significant nonlinearities, this can prove to be impossible to determine in an accurate and objective way.**

Keywords-wind; integration cost

I. INTRODUCTION

Increasing deployment of wind energy in many parts of the world, coupled with a desire to accurately assess and assign costs to their source, has given much attention to the question of integration costs in the past several years. Although the basic idea appears to be quite simple, it turns out to be much more difficult in practice. The fundamental interest is to estimate the costs that are imposed on the power system for accommodating wind power, consisting primarily of the operational impact of wind power's variability and uncertainty and investments in grid infrastructure. This information is needed on the one hand for policy makers to ensure that the benefits of increasing wind energy will not be offset by negative impacts, and on the other hand for system operators and regulators to ensure fair treatment of all producers when designing market rules, tariffs, and allocation of costs. For policy makers, the integration costs could be compared with the benefits of wind power. For system operators and regulators, it is also important to see how current tariffs take into account these costs, such as network charges (to cover investments in network) and imbalance payments (to cover extra balancing costs). In many regions, wind power producers also pay for direct investment costs for grid connection. To treat wind power producers fairly, the same cost-calculation methodology should also be applied to other generation assets.

Any change in the resource mix, whether in shares of wind power or other forms of generation, will likely result in shifts in total system costs and changes in the costs incurred by other generators. Determining which of these costs are "integration costs" has proven to be surprisingly difficult. Integration costs are not directly observable, and this has resulted in numerous methods to calculate them. The use of different methods means that it is difficult, or impossible, to compare integration costs from different power systems or studies. Allocating integration cost to wind, or to any other technology, is really a policy question, and there may be multiple plausible (but not necessarily correct) ways to do so. Production cost modeling is now quite good at comparing costs between defined future scenarios. The problem is in specifying the scenarios to compare so that integration costs can be determined.

Allocating integration costs to a single resource type is challenging. The principles of cost-causation and methodological challenges to calculating integration costs have been discussed in [1]. Cost-causation-based tariffs provide transparent signals to markets and regulators that, if well defined, provide appropriate incentives for efficient investment and behavior [2]. Common errors and important assumptions in integration cost analyses are reported in [3].

Integration costs, once calculated, are not always applied in the same way. One application is to add the integration cost to the cost of energy from wind power to provide a comparison of wind energy to a more dispatchable technology, such as natural gas. Another application is to use increases in balancing costs or ancillary services in tariffs that aim to allocate the cost of the variability and uncertainty impacts of wind power. However, as wind turbine technology advances so that some ancillary services can be provided by wind power, estimating the need for more ancillary services as a result of wind power is no longer enough. This calls for a more rigorous assessment method that can capture both consumption and provision of ancillary services. Further, a performance-based approach would be technology neutral and provide price signals for all technology types.

In this paper, the focus is first on the issue of operational integration cost. We then discuss total system cost (fixed plus variable). The focus is on total portfolio cost, which can be compared for two or more portfolios. Methods for the estimation of integration costs and benefits are discussed.

II. WHAT ARE INTEGRATION COSTS AND WHY CALCULATE THEM?

The idea of integration costs at first seems quite simple. They are supposed to be the "extra" costs imposed on the power system as it accommodates an unusual resource. Integration costs, once calculated, are sometimes used to compare wind power with some form of conventional power, which presumably has no integration cost itself (we show that may not be true in a later section of this paper). Production cost modeling appears to provide an ideal tool for the analysis. Production cost modeling with security-constrained unit commitment and security-constrained economic dispatch is quite accurate when it is coupled with time-synchronized, high-quality wind resource time-series data, time-series load data, and good data on the conventional generators' costs and capabilities. The power system can be modeled with and without wind generation for a year or more, and the costs can be compared. However, if the without-wind case is the power system load supplied by conventional generators, then the difference between the with and without wind cases will be dominated by the fuel, emissions, and water savings that wind offers. These fuel, emissions, or water savings are benefits of wind energy. Only the "extra" costs imposed by wind variability and uncertainty should be included as an integration cost. As will be discussed below, one possible solution is to include a suitable proxy resource that does not have fuel, emissions, or water costs, but even this solution is not ideal.

The question of what constitutes integration costs is more complex than simply accounting for fuel, emissions, and water. Integration cost for conventional generation will be discussed more fully in Section IV, but here we examine a few costs imposed by conventional generators that have not historically been allocated to them as integration costs to show that assigning similar costs to wind may not be appropriate or consistent across multiple technologies.

Increased cycling of conventional generators is often considered a wind integration cost, but a new thermal generator can also cause increased cycling of existing generators. A new high-efficiency baseload generator will displace existing baseload and mid-merit power plants, causing them to cycle more. This increased cycling of existing generators has not been considered an integration cost for new thermal plants [1].

Adding new wind power will also result in the reduction in capacity factors for some conventional generators unless reductions are offset by simultaneous load increases. Large wind penetration levels mean that the optimum composition of the remaining generation fleet is different than in cases of no wind. There will be less baseload units and more mid-merit/peaking units. This also means that the total costs (operating and capital costs) of the electricity system may be higher (or lower, depending on relative fuel prices and costs). In many countries, the power system is in a transition period in which the system is adapting to the widespread introduction of wind power plants. This transition will likely involve costs that will be reduced or eliminated when the system has evolved to a new generation mix. The power plant fleet will not reach the new capacity equilibrium immediately because power plant retirements and new investments take years. This is already seen in some power systems with high penetration levels of wind power; the remaining conventional power plants are used less and are not as profitable. This is an important cost component for the power system; however, the same happens when new thermal power plants are built. Older power plants with higher operational costs will generate less. Adding storage or demand response can have a similar impact on reducing the capacity factors of higher cost generators. This is not typically considered an integration cost that should be charged against storage or demand response.

Similarly, contingency reserves are required, in part, to compensate for the sudden loss of the largest generator. Yet contingency reserves are not allocated to generators as integration costs. A new large generator may increase the contingency requirement within a reserve-sharing pool, causing the cost of supplying a higher reserve level to be incurred by others.

Hourly block scheduling of generation and of inter-balancing authority area transactions increase regulation requirements more than 5-minute dispatch and schedules, but are not typically considered an integration cost or allocated the increased cost of the required regulation [7].

In conclusion, determining integration costs is much more complex than simply calculating differences in total between a production cost simulation with and without wind.

III. Sources for Wind Integration Costs

In this section, we review what properties of wind generation cause integration costs, starting with a short discussion of power system characteristics.

A. Characteristics of the power system

The costs to integrate the variability and uncertainty of wind power will change considerably between power systems [9], [6]. They are impacted by the cycling and efficiency characteristics of existing power plants as well as rules and regulations of the system [10]. When estimating integration costs for future systems, the integration cost can be heavily impacted by the assumptions of available flexibility options [11]. The opportunities for future cost reductions are not yet fully known, which causes a layer of uncertainty for the results.

B. Variability

Variability of wind power, even if correctly forecasted, will result in increased regulation and ramping of the remaining system.

Variability also impacts the planning time scale for power system resource (capacity) adequacy. During peak load situations, only a little wind may be available. Because capacity is typically valued explicitly, this will tend to be captured as a reduction in the value of wind rather than as an integration cost. This issue also typically applies to hydro power.

C. Uncertainty

Uncertainty of wind power will result in increases in (flexibility/operating) reserves over multiple time frames. Large amounts of wind typically have only a modest impact on the second-to-second regulation requirements,[1] but the need for load-following/ramping reserves can be higher. It can result in keeping more reserves (allocation and dimensioning reserve requirements) and more use of reserves. Uncertainty can be mitigated through better forecasting. The economic impact is greatly reduced in regions with subhourly energy scheduling for all generators.

[1] In the United States, regulation is provided by units on automatic generation control, and typically covers the variability that occurs between successive economic dispatches.

D. *Location of resources—transmission infrastructure*

All forms of generation include grid-connection costs, and they are usually borne by the producers as part of their investment costs. On top of that, depending on the site and the grid adequacy, reinforcements to the existing grid may also be needed—or they may prove cost efficient to get all electricity generated to load centers. Grid reinforcements usually also provide a reliability benefit to the system and may also decrease existing bottlenecks and therefore decrease operational costs of the power system. In some cases, adding new transmission can reduce the need for installed capacity. This occurs because transmission additions may have a capacity value, as shown in [8].

IV. Integration Costs for Conventional Generation

Integration impacts are not exclusive to wind and solar. Nearly all generators can impose costs on the power system or other generators when they are added to the power system. These impacts are seldom calculated as integration costs and never applied to conventional generators as integration costs.

Thermal power plants are different in their design and flexibility and possibilities of providing ancillary services. There can be units that have difficulty following automatic generation control (AGC), for example [3].

Adding a new baseload plant can also increase the costs of operating other generators, in the same manner as wind power—decreasing the operation time (capacity factors) for mid-merit power plants and increasing cycling of these plants [1].

Contingency reserve requirements result largely because some conventional generators are large. No generator is 100% reliable, and the power system must continuously stand ready to respond if a large generator or transmission facility suddenly fails. Exact rules vary from region to region and country to country, but contingency reserve requirements are typically based on the size of the largest generator. Each balancing authority area or reserve sharing pool must keep enough spinning and nonspinning reserve ready to respond if a generator fails. The cost of maintaining these reserves is not allocated to the generators that cause the need, however. Instead the cost is broadly spread across all users of the transmission system. This has the effect of allocating costs based on capacity or output rather than on size or contribution to contingency reserve requirements. Costs could be allocated based on cost-causation, as shown in Fig. 3, but they are not. Instead, these costs are socialized, and have been for many years. Current practice has the effect of subsidizing the large generators at the expense of the small generators (or their customers) [5][12].

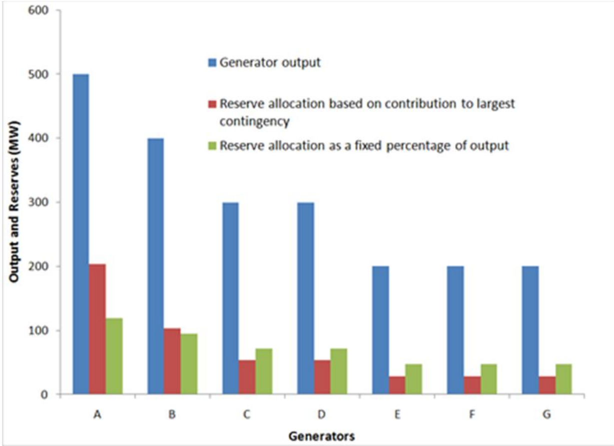

Figure 3. Contingency reserve costs could be allocated to each generator based on their contribution to the contingency reserve requirements [5].

Hydro generation with storage is typically very responsive with low cycling costs. There is both seasonal and annual variability and uncertainty in the water availability, which can reduce the long-term capacity value. There are cases in which constraints can cause inflexibility and also an integration burden. For example recent environmental restrictions in the United States associated with preserving endangered fish have reduced the flexibility available to the power system from many hydro projects. If excess water cannot be spilled but must be run through the turbine generators, the power system must accept the excess power. This may require uneconomic cycling of thermal power plants or curtailing wind with a loss in production tax credits and renewable certificates. What was previously only a lost economic opportunity (spilled water that did not generate electricity revenue) is now a direct cost (uneconomic cycling of thermal plants and curtailed wind production). This represents a real integration cost of constrained hydro. There are ways to mitigate the impacts—just as for excess wind power during light loads—with load processes redesigned to make profitable use of the surplus energy, or with storage systems in the future, but there may be costs associated with implementing these solutions as well.

Run-of-river hydro is variable and somewhat uncertain, though both the short-term variability and uncertainty of hydro are typically much less than for wind or solar generation. The same analysis techniques used to determine wind and solar integration costs are appropriate for run-of-river hydro.

Gas scheduling and contracting can limit the flexibility of gas-fired generators significantly below the physical capability. Although there is ample physical capability to respond to changing load conditions and changes in the rest of the generation fleet up until the operating hour, the gas scheduling restricts this flexibility if gas is nominated day-ahead, committing the generator to operate or not operate in essentially the same time frame as coal plant commitment. This problem is compounded on weekends and holidays.

Another issue that can impact gas availability is extreme weather conditions that can result in gas shortages impacting all gas-fired generators in a region. This may represent a much larger contingency than the power system is designed to survive. This occurred in Texas and the Southwest region of the United States in February 2011, when system operators were forced to shed firm load to cope with the loss of generation.

V. DIFFICULTIES IN ALLOCATING INTEGRATION COSTS

System costs in many places are not allocated to generators but borne by consumers (contingency reserve costs, for example). Allocation is often a policy choice. Because of the difficulty of calculating and allocating costs to parts of system, in some cases simple rules of thumb are used. This will mute incentives for generators to improve their performance, and may not be consistent with cost-causation. Two wind plants, for example, may have different variability per unit, yet the variability impact, if assigned based on a rule of thumb, would not differentiate between them. There may also be unintended consequences of allocation.

The allocation of grid investments to wind power is also challenging, and rarely done by transmission system operators, because new infrastructure usually benefits all users and investments are also made for improving electricity markets and increasing the security of the system.[2] If grid adequacy is insufficient during limited time periods, grid reinforcements could be compared with the option of not using all available wind or altering the operation of other generation. This comparison can yield information about the most economic option. Building new transmission, or increasing transmission capacity that has only a marginal impact on congestion, may be less economic than occasionally curtailing wind power (or other options).

Aggregation is a very powerful concept that has been used to increase system reliability and reduce costs for more than a century. It provides benefits because many individual requirements (contingency reserves, peak load, regulation, etc.) are not 100% correlated. Consequently, the total system needs far less reserves than would be required if each individual had to supply its own needs. Contingency reserves provide a clear example in which many generators can share the same reserve pool.

However, it is not straightforward to allocate the reduced requirement among participants. Incremental allocation may make sense, but the drawback is that it is dependent on the order (wind plant 1, 2) added to the system. It is possible to allocate regulation requirements based on an individual entity's contribution to the total requirement, but this has never been done for any resource other than wind [12]. Interestingly, although individual steel arc furnaces have a dramatically higher impact on power system regulation requirements, they are never allocated their cost of regulation. Instead, the rest of the customers subsidize the arc furnace regulation requirements.

The allocation problem is made more difficult because the differences between allocation method results are often subtle and it is not immediately obvious which method is "better." Some methods can be shown to be simply wrong. Charging each entity for the full amount of reserves required to meet its own needs if it were independent fails to recognize the physical aggregation benefits and dramatically over collects for resources the power system does not actually acquire and costs it does not incur. Many of the methods are numerically "correct" (they sum to the physical requirement), but can still lead to dramatically different results for each of the participating resources. Many are not "fair" in that the allocation results depend on sub-aggregation and/or the order individuals are included [13].

The comparability principle—that all entities should receive comparable treatment under similar circumstances—would seem to require that (a) all integration costs should be calculated and allocated to all cost-causers, or (b) integration costs should be considered as part of system costs and should not be allocated to individual entities. Allocating costs to one type of generator and not to other types does not treat entities comparably, unless based on some type of performance metric related to the cost-causation in question. Similarly, allocating variability costs to individual generators but not to individual loads does not treat all entities comparably. The principle of comparability is consistent with a performance-based approach that is applied to all generators and loads.

VI. METHODS FOR ESTIMATING INTEGRATION COSTS

Many methods have been used to calculate an integration cost. All of the methods discussed here rely on security-constrained unit commitment and security-constrained economic dispatch production cost modeling covering a year or more and including time-series load data, time-series of actual or modeled wind resource data [14], and data on the capabilities and costs of each conventional generator. Production cost modeling has advanced significantly, and it produces reasonably good results. Integration costs are calculated as the difference between a production cost modeling run with wind and a production cost modeling run without wind, but with something else that supplies the energy that wind would have if it were available. Variability and uncertainty (forecasting errors) are handled well. The problem with calculating integration costs is not with the production cost modeling itself, but rather with determining what to include in the without-wind case.

Across the integration cost-estimation methods there are inconsistent definitions, and as a result also inconsistent cost estimates. Because wind integration cost is not directly observable, multiple definitions and approaches have yielded different estimates, most of which are not comparable. Given the difficulties discussed above, we propose a few alternative approaches that may be useful to calculate integration cost. However, we caution that these proposed methods, along with other potential methods, cannot be objectively characterized as "correct" methods, because allocation of these costs can conceivably be done in several ways.

Because other types of generators can impose integration costs that consist of adding to system variability and uncertainty, a robust measure of integration cost would need to be technology neutral and performance based. Calculating integration cost would therefore not be restricted to certain types of generators or loads, but would be applied to all and with the same method of calculation. One would expect to find differences among technologies, and among the same technologies, depending on the configuration of the generator.

[2] A radial connection from a wind plant to a grid is often an exception.

Any proposed metric and approach to calculating integration cost should be examined to see how it would perform under alternative conditions. For example, Kirby et al. [2] describe a scenario in which a wind power plant can provide AGC (or regulation). In this case, the wind plant would clearly be providing regulation service, not consuming it. Therefore, using cost-causation principles would suggest that this plant should be paid for providing AGC, and would not cause an increase in cost to provide regulation. Conversely, [1] shows that some thermal units that are attempting to sell regulation are actually consuming regulation—increasing the regulation burden of the system. In this case, the thermal plant has an integration cost based on its consumption of regulation. In yet a third example, a wind plant that does not provide regulation likely consumes it, and therefore would incur an integration cost for this regulation.

A. Possible approaches to calculate integration cost

Here we discuss several potential approaches to calculating integration cost.

1) Flat block

The most direct approach to calculating integration costs is to model the power system with and without wind. One option for the without wind case is to use a flat block of energy that equals the wind plants' annual energy production in the without case. The flat energy block prevents the wind energy from being supplied by fuel burning and expensive generation. This method fails because a flat block has capacity value that the wind does not claim. The flat block likely has more on-peak hours than wind, hence the energy itself has a higher value. (Conversely, for solar a flat block has fewer on-peak hours and the solar energy has a higher value.) Because the integration cost is supposed to represent the added cost of integrating wind, it is inappropriate to include shifts of energy value. More-complex methods are needed.

2) Separating variability and uncertainty

Ignoring for now the impact of uncertainty, we focus on how to measure the cost impact of variability. With variability alone, and temporarily assuming perfect knowledge of the future, wind (and solar) generation still varies. This will increase the system regulation and following requirements (unless the wind/solar plants provide regulation). It will also increase cycling of other generators. This cycling cost has two components: (1) heat rate penalties and (2) cycling damage [14]. The regulation impact of each generator can be measured, and the cycling costs can be estimated. Together these would comprise the variability cost component of integration cost. To estimate the cycling cost, two simulations would be executed. The first case would represent the system without including the cycling cost as part of each unit's variable cost. The second case would include this cycling cost [14], and the difference in cost between the two cases would represent the cycling cost.

It should be noted that these costs are a function of the installed generation fleet characteristics as well as correlation of wind generation with electricity demand. Even with perfect foresight, wind variability would increase the regulation, following, and cycling cost of some generators. However, it is also clear that any new baseload generation that is introduced to the power system at low variable cost would increase the cycling of at least one generator that moves up the merit-order and must cycle more than before. Thus, it must be recognized that variability cost may be imposed by conventional generators.

Uncertainty costs can be measured by evaluating additional flexibility reserves and calculating their cost using either market data or production simulation. Reserves are needed to protect against the unknown future. Although methods to calculate flexibility reserves are still evolving [14], the integration cost component that is calculated in this way would reasonably represent the incremental uncertainty cost from the variable generation.

3) Comparison to a "perfect" unit

This approach would involve comparing wind case with a "perfect unit" and simulating with wind variability and uncertainty. A "perfect" unit would have the same shape as load. With this approach, many different types of units would have an integration cost: baseload, wind, etc. Using this approach, a generator that can achieve a profile that is identical to load would have no integration cost. Conversely, the more diverse the generation profile becomes in relationship to the load, the higher its integration cost would be. This approach suffers from the inclusion of differences in the value of the energy in the calculated integration cost, as does the flat block approach discussed above. This approach is relatively new and has not received wide application or attention.

The many complex interactions among components of the power system and assumptions regarding the no-wind base case all have important influences on integration cost estimates, and in fact raise questions of whether cost components that are commonly thought to be integration costs can be correctly untangled [1].

B. Total costs—including fixed costs

Another approach is to compare total costs (including fuel and investments) with and without wind (and solar). This method does not attempt to separate and identify integration cost, but instead allows for a full comparison of costs. It can be applied to operating costs only, or to the combined fixed and variable cost, depending on the objective of the analysis. This approach therefore avoids the methodological and practical difficulty of extracting integration cost correctly, but may have similar challenges regarding the comparison of cases.

This approach compares the all-in cost of alternative portfolios. The impacts of modelling assumptions may increase considerably. One approach would require generation optimization to take into account the changes in the optimal power plant portfolio [14] and preferably assess operational costs with a unit commitment and dispatch model [19].

It is not realistic to assume that a power system can be operated on wind power alone. Other types of plants are needed. Similarly, the power system cannot be run on baseload power alone because there is a need for more flexibility to follow load variability than some baseload plants can provide. Indeed, some plants cannot provide AGC or have very limited ramping capability, requiring the addition of mid-merit units that have more flexibility. When such a plant is added to the power system, the cost of the needed flexibility is not charged or allocated to that plant. The system needs flexibility, voltage support, AGC, and many other products to be run reliably. There is no history of allocating the cost of ancillary services that are needed, but not supplied by the plant. Hence, allocating additional capacity or other costs to wind power would appear to be inappropriate for the same reasons.

Alternative portfolios and their respective costs and benefits can, and should, be compared. One example is the approach taken in an Irish integration study 0. Costs of different portfolios are compared with the benefits, as the amount of CO_2 emissions from each scenario.

One part of total costs is the investment for upgrading the network. However, the difficulty of comparison is that the benefit of increased system of security is not quantifiable.

Allocating integration costs to individual generators, whether in the operational or investment time domain, is difficult at best, and is something that appears to apply only to wind power even though there are other sources of integration costs. Energy markets allow for the internalization of many costs, and the existence of ancillary service markets helps to provide for generally cost-effective provision of these services.

VII. Summary and Discussion

Although it is relatively straightforward to calculate total system costs under different sets of assumptions with and without wind or solar in the generation mix, it is difficult to determine integration costs that do not include fuel impacts. It is also difficult to allocate integration costs without some unintended consequences. The concept of comparability requires that integration costs be allocated to all generators (and loads) based on performance if they are to be allocated to any.

However, total portfolio costs can be compared without arguing over cost allocation. Having a cost impact does provide signals for suppliers to provide what is valuable to power system operations. If costs cannot be calculated and allocated directly, other mechanisms should be found to encourage all generators (and loads) to minimize adverse system impacts and to provide the flexibility the system needs to lower costs for all users.

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