The Integration Costs of Wind and Solar Power

An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems

BACKGROUND

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An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems

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DISCLAIMER ON CITATION

This report is not an academic study. Its purpose is to provide an overview of debate. Though an extensive – but certainly not exhaustive – list of publications has been consulted for the project, we abstained from in-depth citations and explicit references in all but a few cases.

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Preface

Dear reader,

The cost to generate electricity from wind and solar has significantly declined in recent years – in fact, the levelized cost of electricity of wind energy and solar PV is now below that of conventional power in many parts of the world, and further cost reductions are expected. Across the globe, more and more countries are therefore planning to add significant amounts of renewable energy to their electricity systems.

Yet wind and solar power plants are different from conventional power plants in one key respect: They provide electricity when the wind blows and the sun shines, but cannot be switched on based on demand. Furthermore, they are often built far away from high demand areas, which may create a need for new grid infrastructure. Therefore, in order to compare the cost of power from wind and solar with that of coal and gas, the term "integration cost" is often used.

The proper measurement of integration costs is a hotly debated subject in academic and policymaking circles. To shed more light on this debate, we conducted two expert workshops in Germany and France, inviting experts from the domains of academia, industry and politics to discuss different perspectives on integration costs. The following paper is the product of this discussion and our own analysis.

With this paper, our aim is not to "solve" this issue. Rather, we hope to make a positive contribution to informed debate.

Yours,

Dr. Patrick Graichen
Director, Agora Energiewende

Key Insights at a Glance

1 **Three components are typically discussed under the term "integration costs" of wind and solar energy: grid costs, balancing costs and the cost effects on conventional power plants (so-called "utilization effect").** The calculation of these costs varies tremendously depending on the specific power system and methodologies applied. Moreover, opinions diverge concerning how to attribute certain costs and benefits, not only to wind and solar energy but to the system as a whole.

2 **Integration costs for grids and balancing are well defined and rather low.** Certain costs for building electricity grids and balancing can be clearly classified without much discussion as costs that arise from the addition of new renewable energy. In the literature, these costs are often estimated at +5 to +13 EUR/MWh, even with high shares of renewables.

3 **Experts disagree on whether the "utilization effect" can (and should) be considered as integration costs, as it is difficult to quantify and new plants always modify the utilization rate of existing plants.** When new solar and wind plants are added to a power system, they reduce the utilization of the existing power plants, and thus their revenues. Thus, in most cases, the cost for "backup" power increases. Calculations of these effects range between -6 and +13 EUR/MWh in the case of Germany at a penetration of 50 percent wind and PV, depending especially on the CO_2 cost.

4 **Comparing the total system costs of different scenarios would be a more appropriate approach.** A total system cost approach can assess the cost of different wind and solar scenarios while avoiding the controversial attribution of system effects to specific technologies.

Contents

Key Insights

1. Three components are typically discussed under the term "integration costs": grid costs, balancing costs and the cost effects on conventional power plants (so-called "utilization effect"). The magnitude of these costs depends on the system and on the scope of effects considered.

A generally accepted definition of "integration costs" does not exist and their calculation is subject to large uncertainties and controversies, including predictions about future development of power systems. The results yielded by different calculations differ substantially, not only depending on the specific power system and its share of renewable energy, but also, and perhaps more crucially, on what costs are included, which methodology is applied and whose perspective is considered.

Typically, three components are included under integration costs:

→ 1. Grid cost: Costs to bring the electricity to where it is needed
→ 2. Balancing cost: Costs to offset differences between forecasts and actual production
→ 3. Costs (or benefits) from interaction with other power plants: most significantly, the increase in the specific costs of production of other power plants due to the reduction of their full load hours[1]

In principle, each of these costs occur when a new power plant is added to an existing power system – be it a new wind turbine, solar module or thermal power plant. Due to their specific, weather-dependent generation profile, integration costs for wind turbines and solar PV differ from those of base load plants in several aspects. (These differences are discussed in sections 3, 4 and 5.) A clear separation of the different cost components is not straightforward, as mutual dependencies and tradeoffs exist. Given realistic assumptions, the costs of integrating 50 percent wind and solar PV into the German power system could range between 5 to 20 EUR/MWh.[2] Due to the significant costs of grid connections, values for wind offshore may be higher.

Cost for grids and balancing are very case specific, yet rather well defined and small, ranging between 5 and 13 EUR/MWh for onshore wind and solar power (see figure 3). Subject to the largest controversy in academic and political discussions are the costs related to the interaction between new (renewable) capacities and other (existing) power plants. Calculating the need for "backup" may appear as an intuitive approach but is not appropriate, as it takes into account only the costs of additional capacity (resulting in "backup" costs between 1 and 3 EUR/MWh), but ignores the costs involved in using this capacity.

A more appropriate approach to quantifying the costs of interaction with other power plants is to calculate the "utilization effect," which includes the modification of the use of different types of power plants. As the name suggests, the key cost driver incurred in this effect is the reduced utilization of other power plants, increasing their specific generation costs. While this cost includes the need for more backup capacity, it incurs a number of further controversial calculations, leading to results that may range between -6 and +13 EUR/MWh, even when the same system is considered at a penetration rate of 50 percent wind and solar.[3] The two

1 This issue has been discussed by researchers under the terms "backup cost," "adequacy cost," "profile cost," "utilization effect" and "capacity-factor effect".

2 Calculations of average integration costs for the case of Germany at 50 percent wind onshore and PV result in values between -1 and +26 EUR/MWh. Both the minimum (-1 EUR/MWh) and maximum (+26 EUR/MWh) values require a combination of significant best- or worst-case assumptions, and are therefore not included in the estimation of typical values.

3 These results are based on the German power system, with a three-technology model (section 5.3.5). Higher values can result when one-technology systems are assumed (5.3.4.1) with base load power plants only or if a significant amount of re-

Overview of key discussion points surrounding integration costs — Figure 1

Area of discussion		Key controversy / difference
Calculation of cost	Short term	"lost revenues" vs. "cost to consumers" (esp. utilization effect) "non-optimized approach" vs. "optimized approach" (esp. grid & balancing)
	Long term	"legacy system" vs. "adapted system"
Attribution of cost		"integration cost of new technologies" vs. "interaction cost between technologies"
Definition of system boundaries		"cost excluding environment, health and risk" vs. "high internalisation of external cost"
Context of analysis		"marginal cost" for scientific analysis vs. "average cost" for political debate
Focus of analysis		"system in transition" vs. "system after transition"

Own illustration

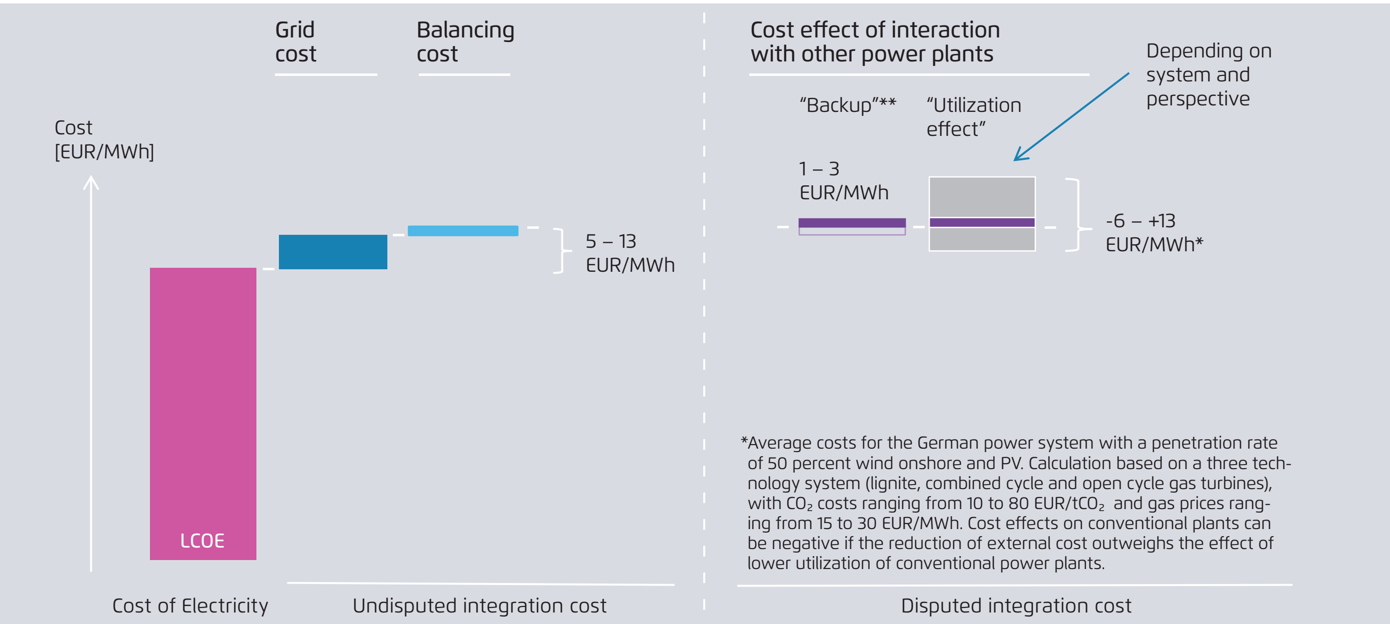
largest controversies concern the value of past investments (value of existing power plants) and the consideration of external effects (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident).

The most important areas of discussion and the key controversies appearing when integration costs are calculated are summarized in Figure 1. These are based on existing studies and discussions at workshops conducted in Berlin and Paris.

When **calculating** integration costs, probably most controversial discussion concerns the perspective taken. For instance, are we talking about the costs for the owners of existing assets or for consumers? Depending on the chosen perspective, the calculation can result in very different valuations for the capital invested in existing power plants ("sunk costs"), which is often the single largest integration cost component. As in any other market, entrance of a new producer tends to have a negative impact on the return on investment of existing producers. From the perspective of consumers, who do not have to pay for capital invested into existing power plants, the new entrant may appear as a positive effect if it induces lower power prices on the market. From the perspective of the owner of an existing power plant, reduced utilization will be a negative effect, leading to lost revenues and reducing the plant's value. From the perspective of an environmental agency, a change in power plant structure that reduces, for example, the utilization of lignite power plant and their emissions represents a benefit, not a cost. In quantifying costs for grids and balancing, large differences may result when looking at optimal or "worst case" cost estimations. Long-term estimations of integration costs depend largely on assumptions about the long-term future. The most pertinent question here is whether to assume a future system similar to today's or a long-term transformation of the entire power system.

newable energies are assumed to "fall from the sky" (see section 5.4.1). Lower values may result in systems with growing electricity demand and at low penetration levels.

Overview of components discussed under "integration costs" Figure 2



Own illustration **included in „utilization effect". In reality, quantifying the cost of backup alone, without considering the change of utilization of the entire power plant fleet, is misleading and does not capture key points of the controversies. The back-up calculation presented here is only illustrative. It is assumed that the addition of 300 TWh of wind and solar PV in Germany (~50% of electricity demand) requires 20 GW more capacity compared to an alternative addition (300 TWh) of new base load capacity. The calculation assumes this back-up would be provided by new open cycle gas turbines.

The **attribution** of some or all cost components to new and existing technologies within a changing power plant mix is a source of controversy. While some argue that all costs introduced by new market entrants should be attributed to the new entrants, others argue that costs incurred from changes to the power plant mix must be attributed to the overall transformation process. As changes to the power plant mix result from a complex interaction between policymaking, technology development and market competition, this question will certainly remain disputed in both academic and policy circles for many years to come.

While an objective **definition** of "integration" may be challenging, an objective definition of "cost" is likely to be impossible. Quantification of costs require a definition of the system considered – whether, in particular, costs are understood as the price paid by the customer for a good delivered (e.g. electricity at the wholesale market) or the cost for the producer to deliver the good; and whether societal costs are included in the calculation. Societal costs can include additional costs for the health system due to pollution from coal power plants, future costs to cope with global warming due to greenhouse gas emissions, an implicit risk insurance in case of a nuclear accident and costs that arise from the reduced value of picturesque landscape marred by wind turbines. In Europe, the "cost" of the right to emit one metric ton of CO_2 into the atmosphere is currently 7.5 EUR. While some argue this should be counted as CO_2 cost (making the cost of power produced by lignite to be around 40 EUR/MWh), others argue that the real cost of a ton of CO_2 is 80 EUR (and would calculate cost of power produced by lignite as approx. 110 EUR/MWh).

A certain risk of confusion can arise based on the **context of the debate**. In economic theory, marginal costs (the costs of adding one incremental unit) are required as an input parameter for analysis; when evaluating different power sector development pathways, average costs are an appropriate comparison tool.

Last but not least, a central aspect that often leads to confusion is the **focus of analysis**, or the question that is asked.

While in some instances the objective may be to calculate integration costs as the costs of integrating a certain amount of a specific technology into a system in transition, in other instances the objective may be to calculate (and allocate) the effect that a certain amount of a specific technology has on a system *after* transition.

2. Integration costs for grids and balancing are well defined and rather low

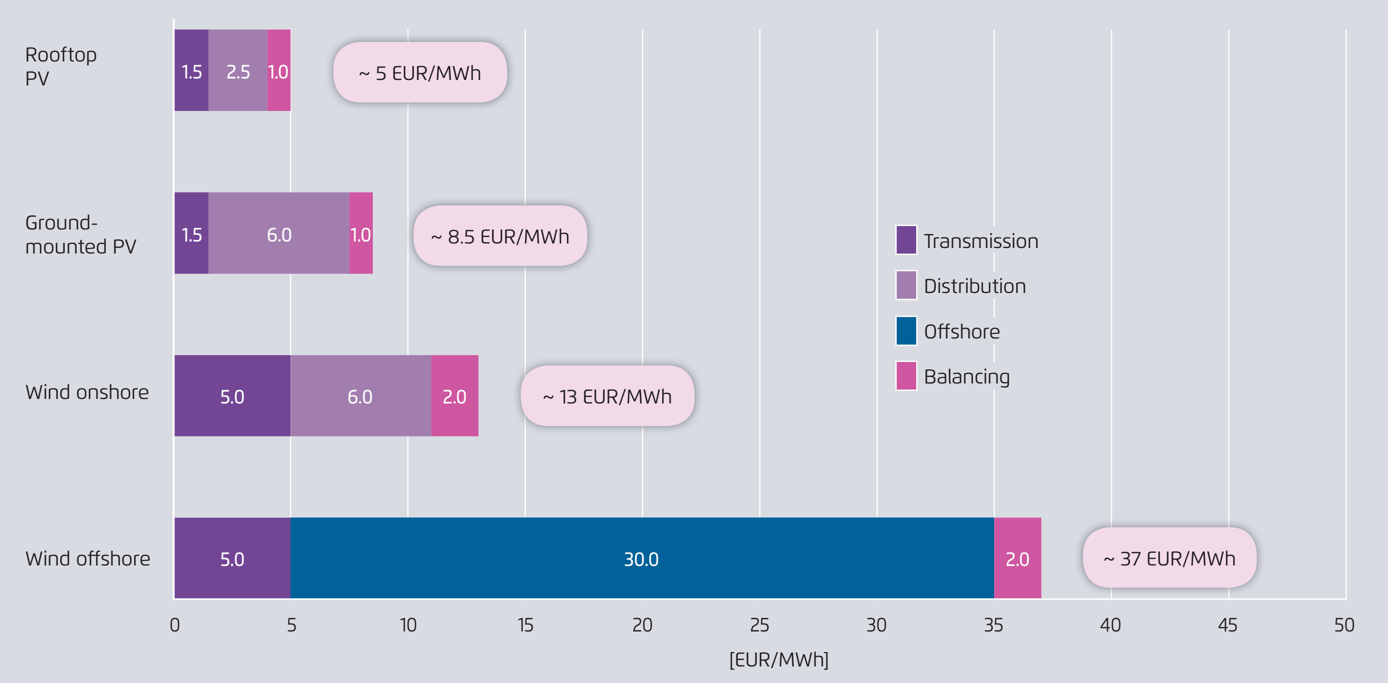
Certain costs for building electricity grids and balancing can be attributed without much discussion to the addition of new capacities in power systems. For example, building a wind park in a remote location close to the shore will require a low voltage grid connection (distribution grid) to the nearest high-voltage (transmission) grid and may require an upgrade to the transmission grid if demand for electricity is not located within the production area. This is no different than if a new coal or nuclear power plant were built at the same location.

The result of an analysis of several grid expansion studies in Germany and Europe (including distribution and transmission grids), as well as a review of the research on balancing cost, are summarized in Figure 3.[4] Grids and balancing costs reach approximately 5 EUR/MWh for rooftop solar PV, approximately 9 EUR/MWh for ground-mounted solar PV, approx. 13 EUR/MWh for wind onshore and approx. 37 EUR/MWh for offshore wind.

A first key challenge in quantifying costs for grid expansion is distinguishing them from generation costs. In real power systems, the priority is usually given to reducing power generation costs, such as by locating power plants at the sites with good resources (wind in windy spots, coal power plants where coal prices are lower). This reduces costs for power generation but increases costs for transporting power to the centers of demand.

4 These are representative values of the average cost per MWh of wind and solar power added to the system from a number of studies for the European and German power system, including penetration rates up to 65 percent for wind and solar power.

Representative grid and balancing costs for wind and solar power — Figure 3



see Appendix

Another trade-off takes place with curtailment (the use of less wind or solar power than is available at a given point in time). By dimensioning the grid connection of a solar PV power plant to, say, only 70 percent of its peak capacity, power generation costs increases by approximately 2 percent (as about 2 percent of the energy produced by the PV power plants would be curtailed), yet grid connection costs drop by 30 percent.

A second key challenge is that grid cost can be very case specific. An illustrative example: a small solar PV power plant on the roof of an inhabited house in a city is likely not to require any grid upgrade at all – while a large solar PV power plant on the roof of an uninhabited house in the middle of a forest might require significant upgrade of the distribution grid.

The cost for balancing induced by integrating wind and solar power amount to between 1 and 2 EUR/MWh, based on an analysis of various scenarios summarized in section 4. A closer look at the German experience with balancing market development in the last decade (in 2014, the share of renewables in Germany is at 27 percent of the power production) reveals that other factors, such as changes in the geographical scope of the market and increasing competition, may have a significantly larger impact on balancing costs than the integration of renewable energy does.

3. Experts disagree on whether the "utilization effect" can (and should) be considered as integration costs.

Adding any type of new power plant reduces the utilization of existing power plants. It has been debated whether this effect can (and should) be considered as an integration cost and how the value of power plants and/or lost revenues of operators can be quantified. At high penetration rates, the effect from new wind and solar power plants may differ significantly from those of new baseload power plants. The former requires more dispatchable capacity in the system and a changed pattern of residual demand, leading to a shift of power production from base load to mid-merit and peak load power plants. Quantifying the cost of these effects depends largely on the perspective taken, on the system considered and on the definition of costs applied. In the following, these differences are explained using two power systems as examples, one labeled "best case" and the other one "worst case," as depicted in figure 4.

Different integration costs in different power systems

The two graphs in Figure 4 illustrate the addition of solar power plants in the two power systems. In each graph, the power production of thermal power plants over 24 hours is depicted before and after adding solar PV:

→ The best-case example is illustrated on the left: a system with a strong correlation of solar irradiation and electricity demand, which may occur in countries with high amounts of air conditioning. When adding solar PV to this system, less total installed thermal power plant capacity is required (assuming a constant demand) and generation by thermal power plants during peak loads – usually the most expensive electricity within a system – is reduced.
→ The effect of adding solar PV in the worst-case example on the right hand side is quite different. The highest demand occurs in the evening hours after sunset, which may arise in winter times in countries with a cold climate. Adding very high shares of solar PV would not help the system during the highest load. The total thermal power plant capacity required is the same as before solar PV.

A comparison between the two systems illustrates the system-specific differences in quantifying integration costs. While in the best case, solar PV reduces the amount of thermal power plants needed, in the worst case the same amount of power plants is needed as before. This leads to a different effect on the average cost per unit of electricity produced by thermal power plants (lower cost in the best case on the left and higher cost in the worst case on the right). The quantification of this effect on the rest of the power system may thus result in negative costs (or benefits) in the best-case scenario, while significant additional cost may occur in the worst-case scenario.

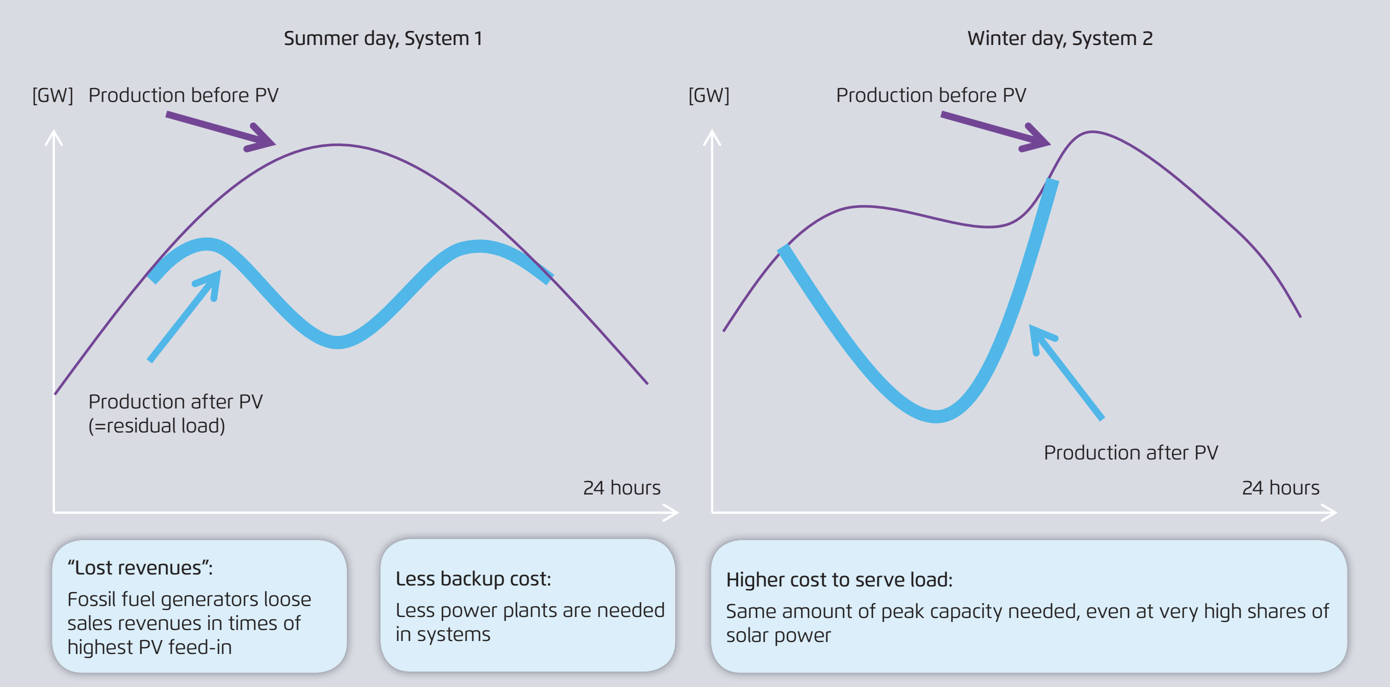
The key driver of these differences in cost is the higher capacity of thermal power plants needed in the worst-case situation and the cost for having these available despite their lower utilization. The cost of having the thermal power plant capacity available remains unchanged (before and after introduction of solar PV), and it is spread out over fewer full load hours (as solar PV replaces much production during daytime hours). As a result, capital cost per unit of electricity increases.

Integration costs depend on one's perspective

The best-case example on the left of Figure 4 illustrates the challenges in quantifying "integration costs," depending on the perspective taken. While fewer thermal power plants are needed after solar PV is added, these thermal power plants might already exist, or they might be under construction (because, say, the decision to invest in a new facility was made several years before solar PV appeared in the system). This is a typical example of sunk cost. The owner of these thermal power plants will thus fully take into account expected losses (in revenues or invested capital) as a component of "integration costs," and may ask for compensation as a result. Consumers, on the other hand, may not even notice the closure of power plants no longer needed by the system. Associated sunk costs therefore would most likely not be seen as "integration costs." Based on these different perspectives, the quantification of the cost effect on the residual power plant fleet would lead to different results. From the perspective of the owner of the power plant, costs would accrue both in the best-case and the worst-case scenarios. From the perspective of the consumer, costs would accrue only in the worst-case scenario, while the best-case scenario would lead to cost reductions.

While the division between consumer's and producer's perspectives merely serves as a thought experiment here, these differing perspectives are at the heart of the controversy surrounding integration costs. To make matters more complex, the consumer's and producer's perspectives may be closely intertwined in markets with little competition or with regulated prices for end consumers. In such situations, tension in the discussions may be more difficult to disentangle.

Schematic representation of power production by thermal power plants, before and after adding solar PV — Figure 4



Own illustration

Integration costs depend on which external effects are considered

In real power systems, the effect of wind and solar PV on the cost of producing the remaining electricity depends not only on the type of power plants within the system but also on the definition of cost applied.

For example, in a future German power system with high share of wind and solar PV, a shift in power production may occur from lignite to gas, driven by the structural impact of wind and solar on the pattern of residual load. This shift may result in very high integration costs when externalities, especially the costs of CO_2 emissions, are not considered. (When the price of CO_2 emissions is low, power generation by gas is significantly more expensive than by lignite.) If externalities are considered at a high value, the same calculation may result in a very low or even a negative value of integration costs (or "integration benefits"), induced by a change in residual power generation.

This example illustrates how the definition of generation costs, including the externalities that are considered (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident), can alter the calculation of integration costs. This discussion is therefore closely related to the overall definition of cost boundaries, which are by nature not objective entities, but reflect social preferences and perceptions within a changing environment.

The role of system adaptation

When aiming to quantify the long-term effects and costs of integrating wind and solar PV into power systems, a number of other developments also need to be considered such as power-plant closures (or reinvestment needs) and structural changes in the demand for electricity driven by a growing population or the electrification of energy systems (i.e. electric vehicles or heat pumps).

The effect of such developments is illustrated in Figure 5. It presents the case of Germany at a penetration of 50 percent wind and solar PV. On the left, the residual load in Germany is depicted with the shares "base load," "mid-merit" and "peak load." This first situation (sometimes referred to as the "legacy system") represents an extreme case in which 50 percent of electricity from wind and solar would "suddenly fall from the sky" while the power plant mix remains the same. Demand for "peak load" and "mid-merit" power is almost entirely diminished, leaving few hours in the year when existing power plants must satisfy this demand. The demand for "base load" power is also significantly reduced. In such a situation, thermal power plants built to provide base load demand 24 hours a day are being used only at an average of approximately 12 hours a day, incurring significantly higher specific costs (i.e. cost per unit of electricity produced).

In a real system, 50 percent of new power from wind and solar PV does not fall from the sky; it is added over decades to a system in transition, with other, traditional power plants being possibly shut down as renewable power is increased. The center of Figure 5 illustrates the effect of such an adaptation. It focuses on the modification of the power plant fleet and assumes that 20 GW of baseload power plants are closed down by the time that wind and solar PV provide 50 percent of electricity. This increases the utilization of all remaining power plants, which stays below the level before wind and solar PV were added.

If the entire power system is adapted (Figure 5, right), the utilization of the remaining power plant fleet may stay at a level similar to today's: additional flexible demand increases the demand for base load power, while only slightly (or not at all) increasing peak demand. Such a development may be driven by the introduction of new technologies (e.g. electric vehicles or heat pumps), but also by price volatility. For instance, electricity may become cheap in times when sun and wind are plentiful and expensive in times when they are not. Over 20 years, say, electricity consumption might adapt to resource availability – like the shift towards night-time heating that took place after the introduction of new base load power plant technologies in the last century. The utilization of all power plants in this adapted system may be similar to the starting point. As a result, the specific power generation costs of the residual load would be similar to those in the initial power system.

This example shows that an assessment of future power system scenarios and their overall costs requires many assumptions and predictions about a distant future in 20 or even in 50 years – not only assumptions about cost and technologies, but also assumptions about how electricity demand and supply may evolve over several decades.

Quantifying the cost effects on the residual power plant fleet

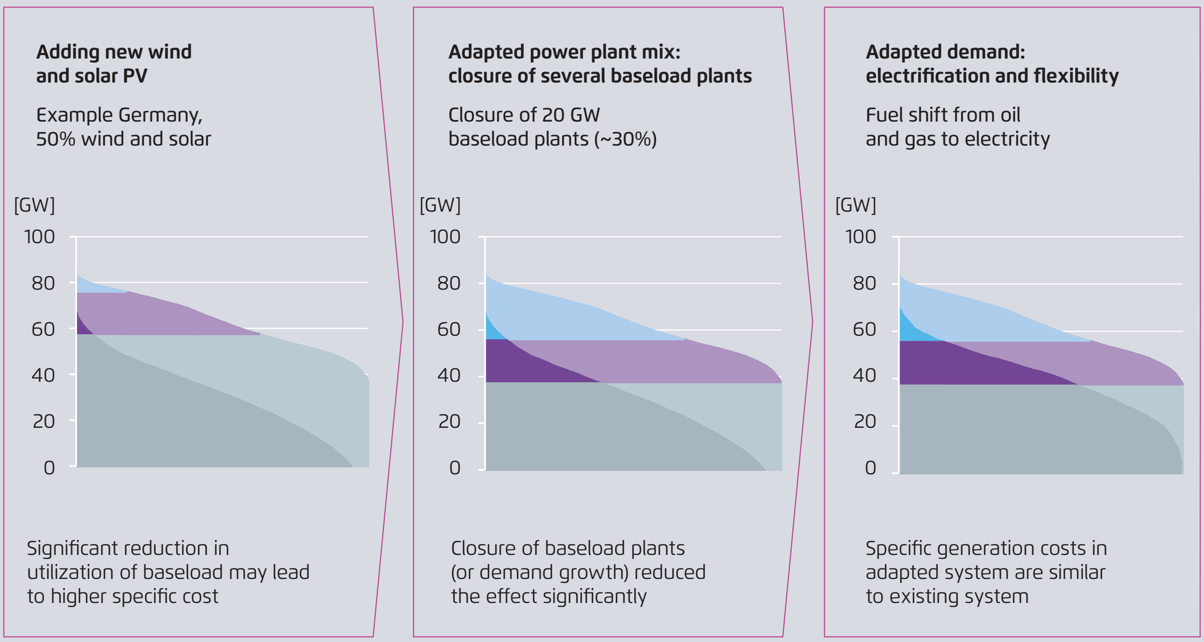
A calculation of the impact of renewables on the cost of the residual power plant fleet varies significantly depending on the power system, perspective and assumptions. Consider a power system that uses multiple technologies into which wind and solar power are introduced at a rate of a few percent per year (so as to allow the residual power plant fleet to adapt) up to a 50 percent penetration rate. In this case, values range between 5 and 12 EUR/MWh in a two-technology system[5] and if we ignore external costs (see section 5.3.4.2), and may range between -6 and +13 EUR/MWh[6] in a three-technology system (see section 5.3.6 and 5.3.7) and when considering external costs.

Lower positive values at the same penetration rate of 50 percent can occur when electricity demand becomes more flexible or grows (see qualitative discussion in section 5.4), when capital costs are low or when external effects of base load power plants are quantified with high costs (section 5.3). Negative values (benefits) result from lower pen-

5 The lower value assumes a mix of CCGT and OCGT gas turbines. The higher value assumes a mix of lignite and OCGT gas power plants. Both values use a historic residual load duration curve in Germany and do not consider adaptation in demand pattern.

6 These values reflect a calculation of a three-technology system (lignite, combined cycle and open cycle gas turbines) using a residual load duration curve in Germany and assuming adaption in the power plant fleet. The calculation does not consider interconnections with neighboring countries, and does not assume adaption in demand patterns, flexibility options or further electrification. It fully considers costs of capital invested ("producer perspective"). In the case of a high valuation of external effects, an imperfect market is assumed that does not fully internalize external effects.

Residual load after adding wind and solar power – in non-adapted and adapted systems — Figure 5



Own illustration

etration rates (up to -13 EUR/MWh; see section 5.3.4) and in case of an imperfect market combined with a high evaluation of external costs (up to -6 EUR/MWh, at 50 percent penetration rate; see section 5.3.6 and 5.3.7).

The highest values at the same penetration rate of 50 percent result when a system consisting of only one technology is assumed and if this is a base load technology used also for meeting peak load (up to 27 EUR/MWh; see section 5.3.4), or if very high penetration rates of wind and solar power occur without an adaptation in the rest of the power system (see the qualitative discussion in section 5.4).

4. Comparing total system costs of different scenarios would be a more appropriate approach.

The concept of integration costs aims at answering the question "How can different power generation technologies be compared?" While debates surrounding this question will persist, in the reality of the 21st century, this question risks being rephrased as "What approach and assumptions are necessary to make one technology look more competitive than another?" Lucky enough, the questions for policymakers in charge of long-term power sector development is not "What is the best concept for comparing different power generating technologies?" but "What are the implications of choosing path A or path B?"

For political decision-making, the comparison of total system costs in different scenarios can be a more appropriate tool. Unfortunately, various methodological challenges persist, most importantly how to define system boundaries and how to consider externalities. Yet establishing a relevant and transparent analysis is much easier, as is the discussion of key sensitivities and implications. In the following, we describe an approach for comparing scenarios with high and low shares of renewables.

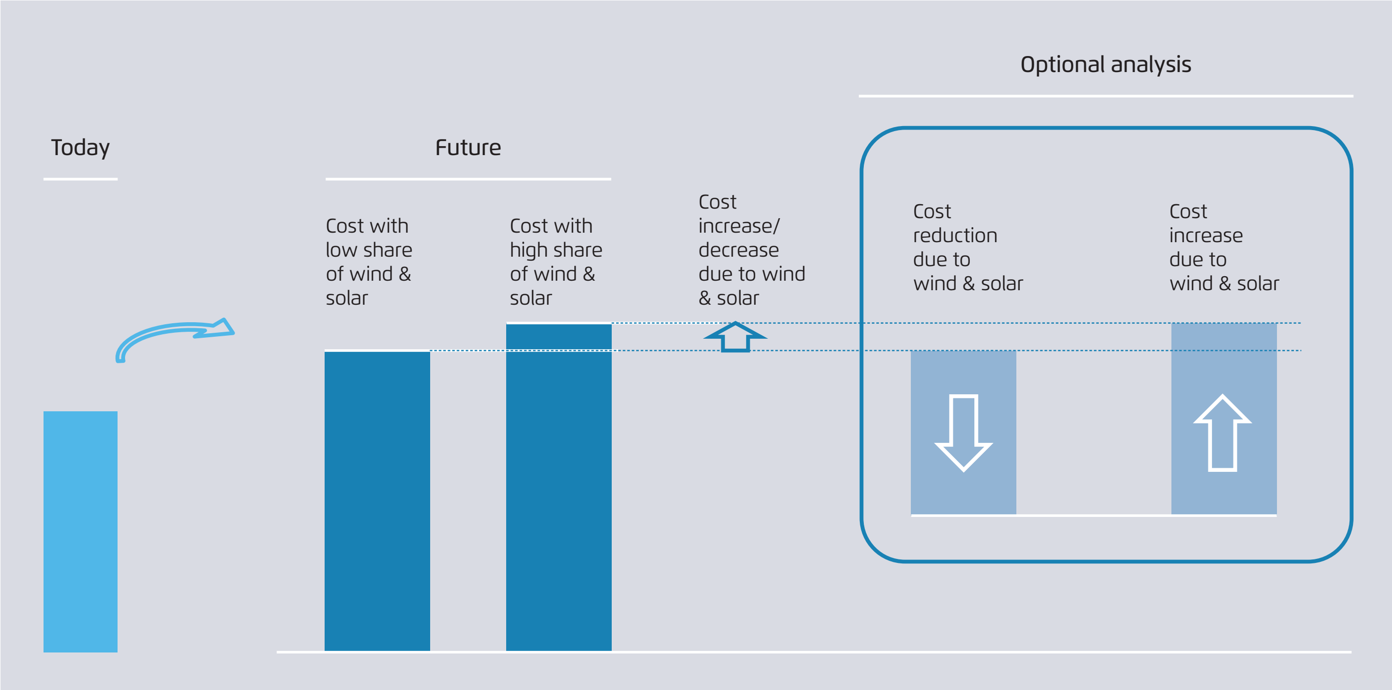
We start by constructing two or more scenarios that include different shares of renewables in the future, say in 2035. Each of these scenarios must be equal from a technical point of view. That is to say, the same level of security of supply (i.e. loss of load expectation) must be achieved and all components should be reasonably adapted to the respective mix of renewable energies. Based on an initial definition of costs, which may or may not include the costs of externalities, the total costs for power generation are calculated for each scenario. This must include costs for power generation by renewable and non-renewable technologies as well as all costs for grids and for the balancing of supply and demand.

The approach detailed in figure 6 may be applied to compare a scenario with a high share of renewable energy to one with a low share of renewable energy. A straightforward comparison of the total system costs is possible between the two scenarios. Optionally, one can also analyze the interaction effects and the attribution of different cost components to different technologies. For example, cost reductions (fewer fossil fuel imports, lower investment needs in thermal power plants) and cost increases (investment in renewable capacity, new grids) can be identified by comparing the scenarios. Yet these optional analysis and assumptions on cost causation are not necessary for the analysis of different pathways.

The resulting cost increase or cost decrease within the power system must be subject to an extensive and transparent sensitivity analysis and accompanied by a further assessment of economic impact. Key sensitivities to be considered are summarized in Figure 7. They are based on experiences with scenario analysis conducted in Germany. On a technical level, key sensitivities to analyze are assumptions about the type of renewable energy used and future cost development. For instance, a renewable energy expansion largely based on wind offshore and biomass is likely to result in significantly higher costs than building a scenario on wind onshore and solar PV. A similarly significant effect may result from the assumption that electricity demand will not change compared with the past vs. the assumption that electricity demand will adapt to new supply structures.

A second key sensitivity is the impact of different cost definition on the results. Because the valuation of different impacts on health, environment and risk of accidents is more a political than an academic question, there is certainly more

Total system cost approach for comparing different renewable energy penetration scenarios — Figure 6



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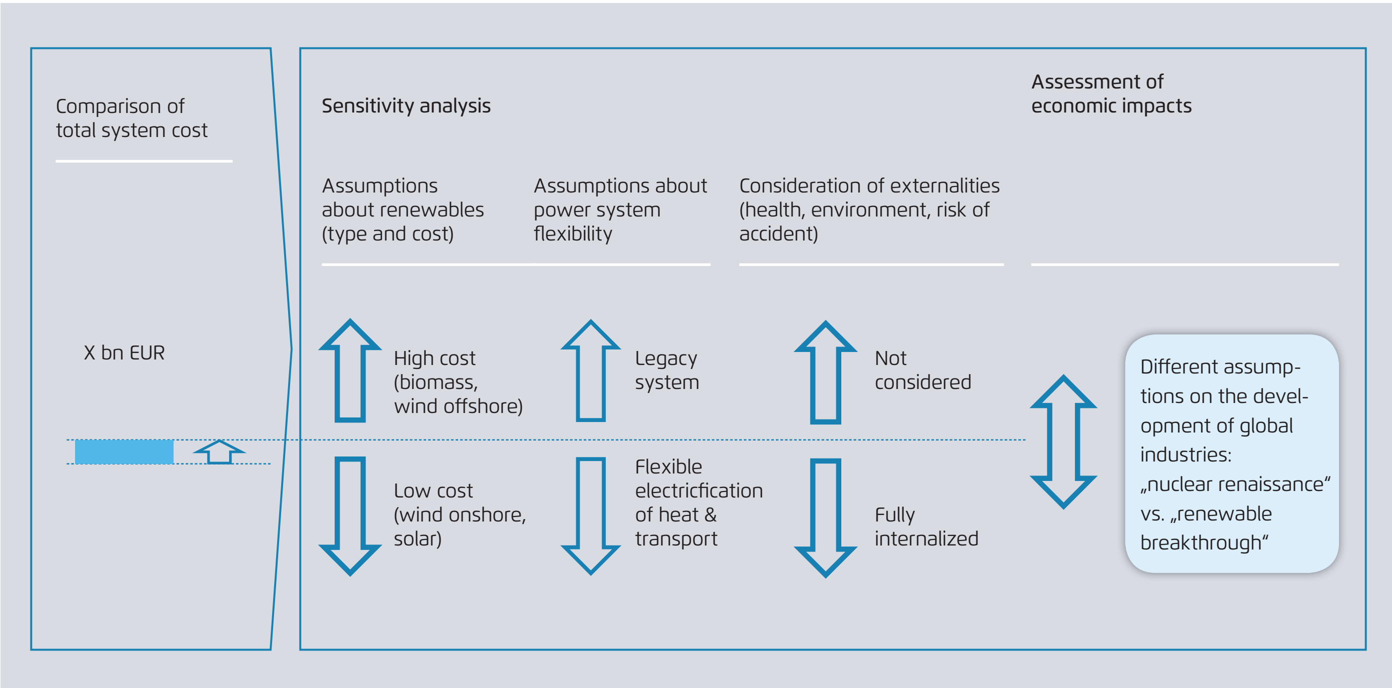
Overview of key sensitivity analysis and impact assessments to accompany total system cost comparisons — Figure 7



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than one truth; yet a transparent discussions about implications is required to support political decision-making.

The results from comparing total system costs in different pathways can later be accompanied by an in-depth analysis of macroeconomic impacts. This may include impacts on power prices by different national and international electricity consumers, or economic benefit of a strong technological and industrial advantage for certain technologies (e.g. wind turbines, solar panels or nuclear reactors). It should be noted, however, that such an analysis is once again likely to depend largely on assumptions, such as whether the growing global demand for electricity in the next decades will be provided by wind energy, solar PV or nuclear technologies.

1 Background and Objective

1.1 Debate on integration costs

In comparing the costs of different power generation technologies, the levelized cost of electricity (LCOE) is commonly used. This metric answers the question "How much does it cost to produce a unit of electricity with a certain type of technology?" But it does not consider when and where the unit of electricity is produced. As customers of electricity require electricity at their homes and during the time they use their appliances – such as a TV or a cooking stove – the significance of the comparison by LCOE is often questioned.

In order to achieve a more meaningful comparison of the cost of different power generation technologies, various expansions to the concept of LCOE have been suggested and discussed. These concepts aim to enable a comparison of the cost not only to produce electricity, but also to deliver it to the customer at the desired location and time. These additional costs, which are not captured by the concept of LCOE yet are relevant for comparing different power generation technologies, are often referred to as "integration costs."[7]

Various authors have quantified integration costs both in theoretical systems as well as in county-specific case studies. The appendix provides a non-exhaustive overview of the literature published on the topic.

1.2 Background, objective and focus

In view of the exceptional developments in the technology and cost of wind and solar power plants, and given their massive deployment in several countries, the challenge of comparing the cost of these power generation technologies with conventional power generation technologies has received increasing attention over the past years.

As the energy sector worldwide is largely dependent on political decisions involving a wide range of actors and interest groups, it comes with little surprise that such integration costs have been a source of much debate in academia, stakeholders and policymakers. Quantifications of integration costs that are calculated by different stakeholder groups may range from negative numbers to very high numbers.

This report aims to contribute to the debate on integration costs in three ways. First and most importantly, it clarifies what's at stake and explains the different results that appear in quantifications of integration costs. Second, it provides new analysis based on recent case studies from Germany and Europe (focusing on grid costs). Third, it suggests an approach for comparing the costs of different energy policy pathways that avoids some, though not all, of the pitfalls in quantifying integration costs.

It is important to emphasize that it is not the objective of this report to solve the question of integration costs, or to suggest one "correct" understanding. Neither it is to summarize or synthesize the large and growing body of literature on this subject. (For the interested reader, an overview of literature is provided in the appendix.)

This report focuses on the integration costs debate in regard to the differences between variable wind and solar photovoltaic power plants on the one hand and base load coal, lignite and nuclear power plants on the other. We believe that this is the politically most relevant – and controversial – comparison. The findings are likely to be relevant as well for other types of weather-dependent renewable energies – such as hydropower – and other types of thermal power plants.

7 In addition to a comparison of cost, comparison of the market value of electricity produced by different power generation technologies – depending on the specific regulatory environment – has also been suggested.

In terms of the time horizon and the penetration rate of wind and solar power, this report focuses on the next 10 to 30 years and penetration levels of 25 percent to 75 percent. Depending on the country, such penetration levels of wind and solar power may correspond to renewable penetration levels – including hydro power and/or biomass – of 90 percent or more.

1.3 Report organization

The remainder of this report is structured as followed: Section 2 gives an overview of the discussion on integration costs and the key challenges involved, ranging from country-specific technical aspects to different evaluations of externalities (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident) that involve purely political discussions. To allow quantitative analysis within this report, we introduce a way to quantify integration costs based on a comparison of different scenarios. While this method aims to improve the comparative assessment of different technologies, it has a number of shortcomings that has led to controversial debates.

Section 3 and 4 focus on the easier elements of the integration costs debate – the costs for grids and balancing. Important challenges and influencing factors are discussed and quantification from case studies presented. In the case of grid cost, we also include our own analysis of recent case studies in Germany and Europe.

Section 5 focuses on the most difficult element of the integration costs debate – the effect that new power plants (wind and PV or baseload) have on the cost of other power plants in the system. The aim of this section is to help understand why integration cost calculations may lead to very high or very low results even within the same power system.

In Section 6, an alternative approach is suggested to compare the costs of different policy pathways. This approach, we submit, avoids some, though not all, of the pitfalls of quantifying integration costs.

2 Integration costs – what are they?

2.1 Overview of integration costs

Typically, three components are discussed under the term "integration costs" (Figure 8):

→ 1. Grid cost: Costs to bring the electricity to where it is demanded
→ 2. Balancing cost: Cost to offset differences between actual production and forecasts
→ 3. Costs (or benefits) from interaction with other power plants, most significantly, the increase in the specific generation costs of other power plants due to the reduction of their full load hours [8]

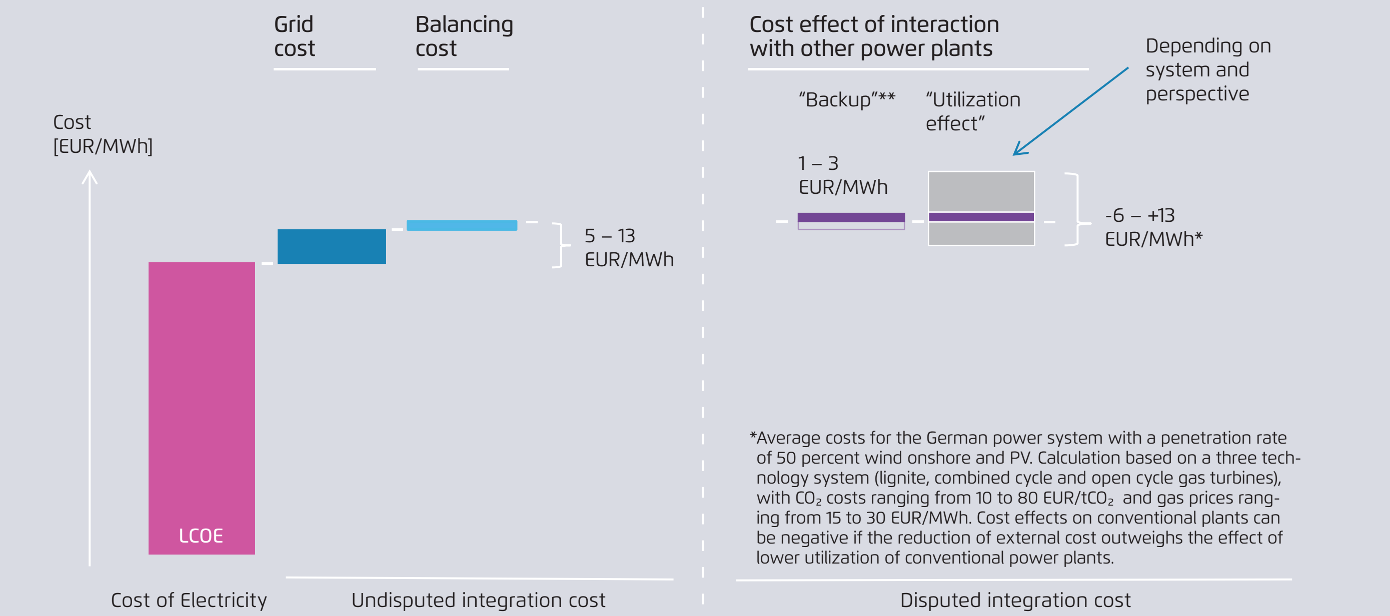
In principle, each of these costs occur when a new power plant is added to a power system. When a new wind turbine or coal fired power plant is built, it is not built in the middle of a city but where all required resources are available. Electricity grids are thus needed to transport power to where it is consumed.

Measures must also be taken in case the actual production of the power plant is not as expected in a given moment. In the case of wind, this may be due to incorrect forecast of wind speeds or technical outages; in the case of coal power plants, this may be due to the risk of technical failures or disruptions in the coal supply chain.

Last but not least, the addition of a new wind or coal power plant to the electricity system is likely to impact other power plants. Unless the demand for electricity increases significantly, the electricity produced by the new power

8 This issue has been previously discussed under the terms "backup cost," "adequacy cost," "profile cost," "utilization effect" and "capacity-factor effect."

Overview of components discussed under "integration costs" Figure 8



Own illustration **included in „utilization effect". In reality, quantifying the cost of backup alone, without considering the change of utilization of the entire power plant fleet, is misleading and does not capture key points of the controversies. The back-up calculation presented here is only illustrative. It is assumed that the addition of 300 TWh of wind and solar PV in Germany (~50% of electricity demand) requires 20 GW more capacity compared to an alternative addition (300 TWh) of new base load capacity. The calculation assumes this back-up would be provided by new open cycle gas turbines.

plant may replace the electricity previously produced by other power plants. Full load hours of existing power plants may thus decrease and their specific power generation costs may increase.

Due to their specific, weather-dependent generation profile, wind turbines and solar PV have different integration costs from those of conventional power plants. Power production follows the weather rather than demand, leaving it to other parts in the system to provide electricity when there is little wind or sun. This creates a greater need for backup power plants in the system.

A more detailed description of the three components of integration costs, the relevant differences between wind and solar power and other power plants, as well as the challenges in quantifying the cost components is provided in sections 3, 4 and 5.

2.2 Conceptual differences and controversies

In the following, key challenges in quantifying integration costs are described. This overview is largely based on discussions at two workshops held in Berlin and Paris, bringing together experts from academia, industry and policy. It is far from providing a complete and exhaustive summary of the perspectives and methodologies on offer today.

2.2.1 Definition of system boundaries and costs

Quantifying integration costs requires a definition of the system in question as well as a definition of costs. This first challenge may be the most difficult and controversial, yet it is a crucial aspect to good policy.

Figure 9 gives an overview of system boundaries and the types of costs included within a narrower or wider understanding of costs.[9]

A very narrow understanding of cost may be described as direct cost of electricity, which could be the actual money that the investor of a power plant has to pay to buy and use the technical equipment and the fuel needed to produce electricity.

A wider understanding of cost may as well include external cost of electricity: Besides the technical equipment, the investor of a power plant will most likely also use other limited resources and cause so-called external effects. This may range from land use for the construction of the power plant to emissions of particles and potential damage in case of an accident induced by the operation of the power plant. The cost of such external effects may or may not be included in the analysis. If they are included, their quantification may also vary significantly.

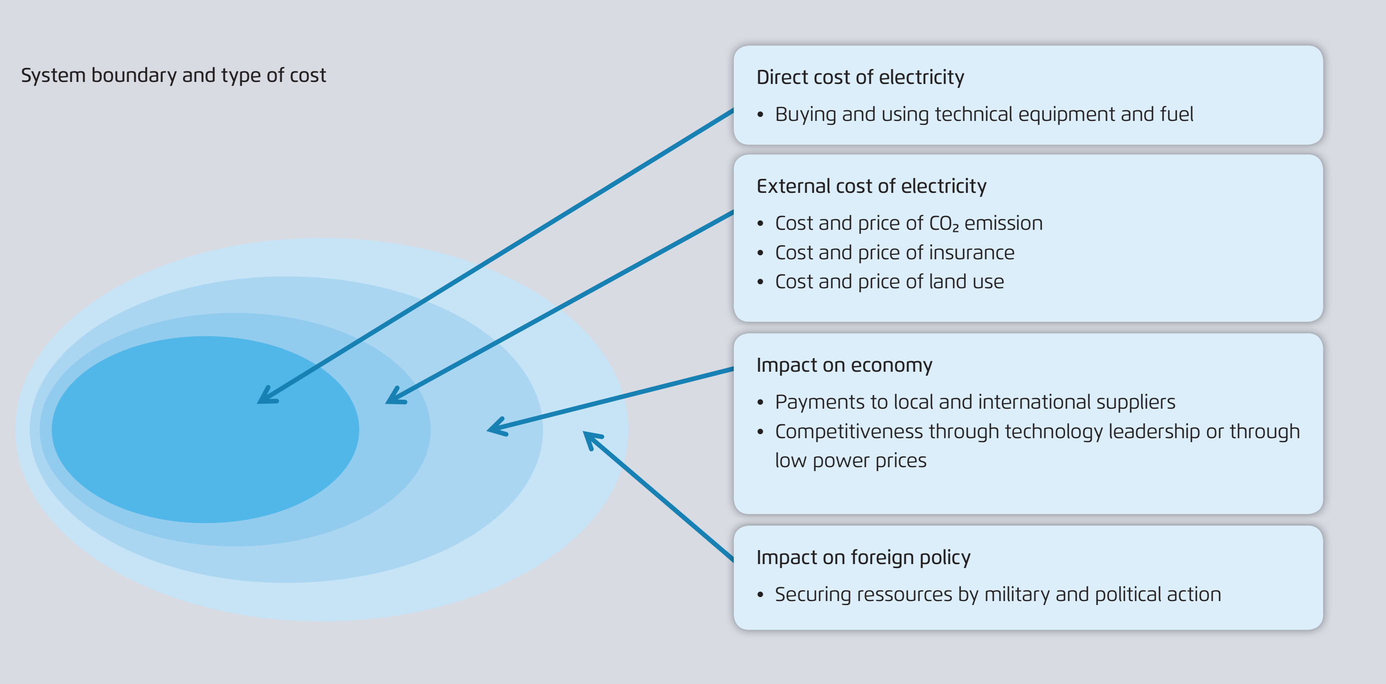
An even wider understanding of cost may include **macroeconomic** impacts as well. While "cost" is quite a straightforward concept from a business perspective, from the perspective of a countries' economy a payment from one investor to a supplier may be a "cost" and "income" at the same time, depending on where the supplier is located. In the realm of policymaking, the analysis of policy choices often focus on overall economic impacts. Such impacts may depend on where the equipment and fuel for electricity production are bought. Such assessments may also reach the realm of industrial policymaking, where the effects on the competitiveness of a country's industry are considered. Such effects may appear within the energy intensive industrial sector, where competitiveness is improved by a low-cost electricity supply, or within the industrial and high tech sector that produces electricity generation equipment for the national and international market, where competitiveness is improved by technology leadership.

Last but not least, the **impact on foreign policy** may be a factor when analyzing policy options about electricity generation systems. As electricity security supply could depend on an uninterrupted provision of the fuel required (e.g. oil, gas, coal, uranium), different technology choices may affect the foreign policy of a country, as well as the direct or indirect costs incurred by such foreign policy, in different ways.

In theory, any of these different types of costs may be internalized in the prices paid in the power market of a specific

9 The illustration is adapted from the NEA (2012).

Overview of possible system boundaries and types of costs and benefits | Figure 9



adapted from NEA (2012)

country, depending on market and regulatory design. For example, a business generating electricity by burning coal may or may not be charged with a tax (or obliged to purchase emission certificates), depending on whether policymakers disincentivize CO_2 emissions. Similarly, a business that generates electricity by wind turbines may or may not be obliged to compensate local citizens for harming the quality of the landscape in their neighborhood.[10]

Analysis conducted to understand and/or predict market developments in the power sector often consider the direct costs of electricity and the external costs of electricity only to the extent they are internalized. Analysis conducted to compare different policy options considers broader external effects and macroeconomic impact. While the economic impact is mostly analyzed separately from power system costs, external effects may either be analyzed separately or included in the analysis of power system costs.

2.2.1.1 Supplemental discussion: The external cost of electricity

The externalities of electricity production are probably the most controversial issue in discussions surrounding policy choices for power system development. Since integration costs may include changes in the specific cost of power production by the residual power plant fleet, external costs can have a significant impact on the quantification. (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident. See section 5 for further discussion on this point.)

The external cost of power production by lignite on both the environment and the health of the population has been a source of controversy in Germany. With an emission of 0.9 – 1.3 t CO_2 per megawatt hour, power production by lignite has the strongest impact on global warming of all generation technologies. Some stakeholders may argue that

10 One could also imagine a taxation system in which costs for securing the supply of a certain type of resource is charged to consumers of this resource via a dedicated tax.

the price paid for the right to emit carbon dioxide, currently 7.5 EUR/tCO_2, is an appropriate reflection of the external costs because it is determined on the basis of a functioning market. Other stakeholders may argue that the real cost of emissions is 80 EUR/tCO_2, because this, they argue, is the price that society will have to pay to cope with the damage done by emissions on global warming. A similar controversy exists on health impact. Here some see a negative impact of mercury emissions on the health of the population (leading to additional costs in the healthcare system), while others do not see such a direct effect, as they believe in well-functioning air quality regulations.

A similar controversy exists regarding the risk and associated costs of a nuclear accident. Why some calculate the cost of a potential nuclear accident based on the probability of the occurrence of such an accident and its subsequent cost,[11] others doubt the appropriateness of such a calculation, emphasizing that no one but a public entity would be willing to insure a nuclear power plant at a cost that would allow its continued operation. Quantifying a theoretical premium to insure nuclear reactors against the risk of a nuclear accident can therefore lead to very different results, ranging from 1 EUR/MWh to 140 EUR/MWh or even 2360 EUR/MWh[12].

External effects are also a source of controversy in the case of wind and solar power plants. While not having a significant impact on carbon emissions, such installations may impact the aesthetic of the landscape and have a negative impact on wildlife (such as birds in the case of wind turbines).

2.2.2 Different perspectives for calculating costs

Business vs. policymaker

From the point of view of a business, the framework of analysis is determined by the specific regulatory regime (including market rules and taxation) that determines whether or not any specific type of cost is internalized.

From the point of view of a policymaker (in economic theory also referred to as "social planner"), a specific regulatory regime at a specific point in time – or assumptions about a future regulatory regime – does not determine the "right" system boundaries or cost definition. An appropriate definition of cost depends rather on the question asked. For example, a system planner that aims to achieve an overall optimized system may wish to perform calculations that fully account for all external effects and incorporate macroeconomic impact in its analysis. A technical planer that aims to optimize the power sector alone may only count the direct cost and the external cost that are internalized in the power system. By contrast, an environmental agency may consider the external effects on the environment (e.g. CO_2 emissions) in accordance with their own quantification of these costs and may consider an incomplete internalization of these as a market failure that needs to be corrected.

As the last example shows, the calculation of costs may be influenced by the evaluation and prioritization of different effects, which may depend on political orientation. For example, energy policy actors may have different views on how to consider and quantify effects on global warming when evaluating different policy choices in the power sector – regardless of current regulatory regimes.

Producer vs. power customer

Closely linked to the definition of the system and the understanding of cost is the question of the perspective taken when performing the analysis. In one scenario a business may spend an average of 100 EUR/MWh to produce and transport electricity and sell it at an average price of 110 EUR/MWh. The cost of electricity would thus be 110 EUR/MWh from the perspective of the customer, and 100 EUR/MWh from the perspective of the producer. In a different scenario, a business may spend the same to produce electricity, but due to the competitive situation the customer may pay an average price of only 70 EUR/MWh – which may compensate the business for operational costs, but not allow the business to recover the investment cost fully.

In economic theory and with perfect markets, the difference in perspective can be easily solved by looking at a long-term

11 An excellent overview of nuclear power costs, including the controversy on the probability of accidents and the perception of risk is provided in Leveque (2015).

12 Versicherungsforen Leipzig (2011).

equilibrium situation, where differences between consumer and producer perspectives cease to exist.[13] In real power systems, where the time between an investment decision and the first electricity generation of a power plant may exceed 10 years and where political decisions have significant impact on the competitive situation (introduction of certain types of power plants, measures to reduce electricity consumption, market coupling), the question of perspective is related to a number of controversial issues.

To illustrate this controversy, one may think about a power system in which an investor decides to build a number of new coal-fired power plants. After ten years, the construction is completed, yet it turns out that demand for electricity has declined and what is needed is not coal-fired power plants that run at 4000 hours a year but gas turbines that run at 400 hours a year instead. Calculating the cost of electricity production from the perspective of the producer would include the investment cost of the coal-fired power plants. (Because the producer has to repay his loan; if this is not possible, he may face bankruptcy). Taking the perspective of the customer, it may be difficult to argue why he should pay for a non-optimal investment decision of an investor. Hence, the calculation of electricity production costs may either build on the cost of avoiding the closure of existing coal-fired power plants or on the price that would be paid to create a new cost-optimal solution with open-cycle gas turbines.

As this example shows, the question of perspective is closely related to a different question, namely, whether to calculate the cost of integration while assuming a "brownfield" or a "greenfield" system, or whether to use an "optimized" or "non-optimized" system. These issues are discussed below (section 5.4).

13 Due to the long planning period and lifetime of physical assets in electricity generation and transmission, power markets can be out of equilibrium for quite some time, potentially for decades. This is pronounced in markets that do not grow significantly, such as most European markets.

National power systems vs. interconnected systems
A similar perspective challenge occurs when analyzing power systems that are part of a larger interconnected system. As an example, take a country in the interconnected European power system that imports 10 percent of its electricity demand from a neighboring country.

From the perspective of the importing country, it may appear reasonable to calculate the cost of electricity imports based on the prices paid during those hours in which electricity is imported. The price paid may not correspond to the cost of the power production in the exporting country because, say, market prices in these hours only partly reflect the initial investment cost of the power plants used (as these may be partly financed by a "feed-in tariff" or a "contract for difference").

From the perspective of the exporting country, the cost of power produced may include both the investment as well as the operational cost and thus significantly differ from the perspective of the importing country (similar to the case of the producer and the consumer). Finding a "consistent" methodology for calculating the cost of electricity imports from the perspective of the importing country would require assumptions about which power plants in the exporting country produced the electrons that crossed the border.

2.2.2.1 Supplemental discussion: The valuation of past investments

The cost of building a power plant, commonly called investment cost or capital cost, is a key driver of integration costs. This is further elaborated in section 5.

In the case of a new power plant, such quantification may be quite straightforward and can be easily drawn from published studies, based on the price paid for the equipment as well as on the cost of capital during the construction and depreciation period. Properly quantifying the value of an existing power plant is challenging; a "right" or "wrong" certainly does not exist. Two possible approaches are presented below, with the first one focusing on the policy perspective and the latter focusing on a business perspective.

One possible approach focuses on the history of the investment, assuming that the value of a power plant equals 100 percent of the initial investment cost at the time of construction and is then reduced over the depreciation period of the power plant or over its technical lifetime. A challenge with such an approach arises when power plants are used beyond the depreciation period or exceed the expected technical lifetime. In such a case the cost is calculated as zero, though the power plant still has significant value for the power system.

Another possible approach focuses on the current value of a power plant, such as the price a business could expect if it were to sell the power plant to a different investor. Such a value could be determined based on future revenues expected from the ownership of the power plan. A challenge with such an approach lies in its connection to policymaking, as well as preferences of the population in democratic countries. As an extreme example, imagine that the entire population of a democratic country wakes up one day and decides to abandon a certain technology altogether. In this event, the price that an investor would be willing to pay for a specific power plant would change dramatically.

2.2.2.2 Supplemental discussion: Different perspectives on the same cost component

Empirically, the three components of integration costs (grid, balancing and interaction with other power plants) do not necessarily appear as "costs" in a bookkeeping sense. Depending on the perspective, they may also appear as depressed electricity prices and reduced revenues. Figure 10 shows how costs may appear in the perspective of system planners and investors. Take the example of grid costs. A system planner will account for these expenses as costs. Depending on the regulatory environment, an investor of a power plant might see these as costs (if producers pay grid fees), as reduced revenues (in a market with local prices) or as no costs at all (if consumers pay grid fees).

Different perspectives on integration cost components — Figure 10

Perspective	Integration cost component		
	Grid	Balancing	"Utilization effect" on other power plants
System planer	increased costs for grids	increased costs for ramping, cycling, etc	decreased utilization of thermal plants, higher specific cost
Investor*	decreased locational spot revenue; higher grid fees	increased imbalance costs (imbalance charge, intraday trading)	decreased spot market revenue

Own illustration

*depending on market design

2.2.3 Cost causation and attribution of costs

As we have seen, the definition and quantification of integration costs is a controversial subject. Another disputed topic is the attribution of some or all of the cost components to new and existing technologies.

Within research and policymaking circles, there has been debate whether or not integration costs can and should be attributed to new capacities (e.g. wind and solar power plants). While some argue that costs for system adaptation is caused by the technologies that cause the adaptation, others argue that system adaptation inherently occurs in power systems and thus cannot be attributed directly to specific new technologies.

This may, for example, raise the question whether the reduced profitability of an existing power plant is the fault of new entrants, or if it is the fault of the inflexibility of the specific power plant.

Another example is balancing costs. These arise because errors in forecasts of wind or solar generation need to be balanced with fossil-fired power plants. They also arise because conventional plants are costly to ramp up or down. If conventional plants were perfectly flexible, forecast errors would not cause any costs. It is the interaction between forecast error and power system inflexibility that causes costs. These costs must be attributed to both factors, not to a single one.

2.3 Technical differences and controversies

Below we provide an overview of further methodological challenges related to integration cost analysis. We underline how these costs differ depending on present and future power system characteristics.

2.3.1 Power system features

Power systems across the world vary greatly, and with them the integration costs of wind and solar power plants. For example, one country may have a very strong electricity grid and new wind and solar power plants may be easily connected; in another country a new dedicated power grid needs to be built for every new installation.

In still another country, new wind and solar power plants may be built while the demand for electricity shrinks, so that the impact on other power plants is very strong. In a different country, by contrast, power demand may increase at the same time that new wind and solar power plants are built, so that the effect on other power plants may be insignificant.

Calculating a value for integration costs for a certain technology that applies to all countries across the world is thus not possible. What is needed is a case-by-case analysis. Key power system characteristics that influence the quantification of integration costs are described in sections 3, 4 and 5.

2.3.2 “Brownfield” vs. “greenfield”

Calculating integration cost requires a specification of the system where new technologies are integrated. Integration may either be assumed to take place in an entirely new system, commonly called a “greenfield,” or in an already existing system, commonly called “brownfield.” The key difference between these two approaches is that in the first case, the entire system may be designed in the most cost-optimal way, including all interaction effects between different technologies. In the latter case, a cost-optimal design of the existing system is not possible, which likely will lead to an altogether sub-optimal solution.

In reality, one might look at a power system as a combination of two situations: An existing power system with relatively stable demand (the case in many European countries) could be considered a pure “brownfield” at a given time. As over the years more and more power plants are closed down or require reinvestment to remain functional, the system will develop a combination of “brownfields” and “greenfields,” converging towards a complete greenfield situation. Following this line of thought, an increase in electricity demand has the same effect. New demand might add to a “greenfield” situation, while a reduction in demand might add to a “brownfield” situation. Countries with a high growth in electricity demand (such as India) may currently come close to a “greenfield” situation.

2.3.3 Future assumptions

Integration costs are often calculated based on future scenarios, such as increasing penetration levels of wind and solar power. As in any such analysis, a significant amount of assumptions are required – forecasts about how the future will look in terms of available technologies, the behavior of people and regulatory design. Obviously, uncertainties increase with the length of the time considered.

In the following, three key aspects are highlighted with a significant impact on the results of a quantification of integration costs – as in all assumptions about the future, a simple "right" or "wrong" does not exist.

Technology and costs

Probably the most straightforward unknown that affects the quantification of integration costs is the future cost of technologies. For example, the cost of building an electricity grid directly depends on which type of hardware is available at what cost (e.g. new HVDC technologies or controllable transformers for distribution networks). Less obvious but equally important are assumptions about technologies that consume electricity – for example if cars in 2050 are fueled by oil, electricity or hydrogen, and if buildings are warmed by gas or heat pumps.

Optimized vs. non-optimized planning

Besides assumptions about the cost of technologies used, assumptions about planning approach may have a significant effect on integration costs. For example, building a 100 MW electricity grid to connect a 100 MW coal fired power plant may be a cost effective planning approach, but applying the same planning approach to a solar power plant is unlikely to be a cost optimal solution. (See section 3 for an explanation.) Whether or not a cost-optimal planning approach is applied may be an assumption about future regulatory design (in the case that the grid planning is under the authority of a government) or an assumption about business decision making (in the case that the grid is planned and paid for by a private business).

A second example that may have a significant influence on integration costs is the amount of storage assumed in future scenarios. While some analysis may assume a cost-optimal expansion of storage (driven by a system planner, say), others may assume non-optimal investment in storage technologies, leading to significantly higher cost.

System adaptation

The integration of small amounts of a new type of technology is unlikely to have an impact on the rest of the power system in the short term. Adding large amounts of a new type of technology may fundamentally change the entire power system in the long term, ranging from the way electricity is consumed to the rules and regulations in place to enable a functioning market.

For example, the addition of large amounts of nuclear or lignite power plants in the second half of the 20th century has led to very low prices of electricity at night, incentivizing the construction of pumped hydro storage capacities and increasing electricity consumption during night-time, including for heating appliances. If, for example, photovoltaic power plants experience further cost drops in the first half of the 21st century, it is very likely that over the years the pattern of electricity demand could fundamentally change as more and more people and businesses find ways to make use of low electricity prices in times when sunlight is plentiful (such as with electric vehicles or warehouse cooling).

2.4 One possible approach for calculating integration costs

This section presents one possible way of defining and calculating integration costs. While this approach is used in the remainder of this report for a quantitative discussion, it is important to emphasize that the method has been questioned by several stakeholders. Its use here is not intended to implicitly support or not support any of the positions in the debates described above.

The approach takes a top-down perspective, using total system costs as a starting point.[14] We compare two differ-

14 The approach presented here is similar to that proposed by Ueckerdt et al. (2013).

ent future scenarios of a power system (Figure 11). The scenarios differ by the share of renewable energies (RES), and are called "Low RES" and "High RES."[15] For each given share of renewable energies, the power systems are assumed to be fully functional (having sufficient capacity at any time and any location).

We calculate integration costs as the sum of three components. The first two items are the additional costs for balancing services and electricity grids. The third item is the cost effect that RES have on the conventional power plants, which is likely to be a less-than-proportional decrease in their generation costs (see example below). Generation costs for RES have no impact on the calculation of integration costs but they are depicted in several of the following graphs, which display the total costs of the system.

15 The renewable energies (RES) are used to describe wind and solar power here – in line with the focus of this report

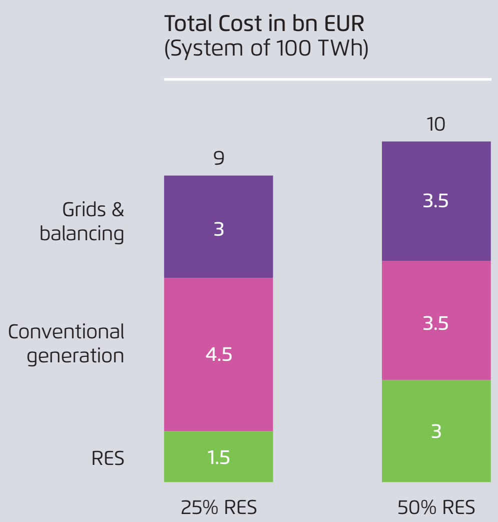
Take the following numbers as an example (see Figure 11). A power system with a yearly electricity consumption of 100 TWh costs €9 bn annually at 25 percent RES (Low RES), of which €3 bn are for balancing and grids and €4.5 bn are for conventional generation.

At 50 percent RES (High RES), balancing and grid costs are €0.5 bn higher. Conventional generation costs are €1 bn lower. However, if specific (EUR/MWh) costs of conventional generation would have stayed the same, costs had decreased by €1.5 bn[16]. Hence, conventional generation costs decreased by €0.5 bn less than expected. While absolute conventional generation costs declined, specific costs increased from 60 EUR/MWh to 70 EUR/MWh. Increasing the

16 This value is calculated as follow: €4.5 bn (generation costs in the Low RES scenario) divided by 75 TWh (conventional generation in the Low RES scenario) multiplied by 50 TWh (conventional generation in the High RES scenario)

An example of integration costs calculated from additional costs and less than proportional decreased costs

Figure 11

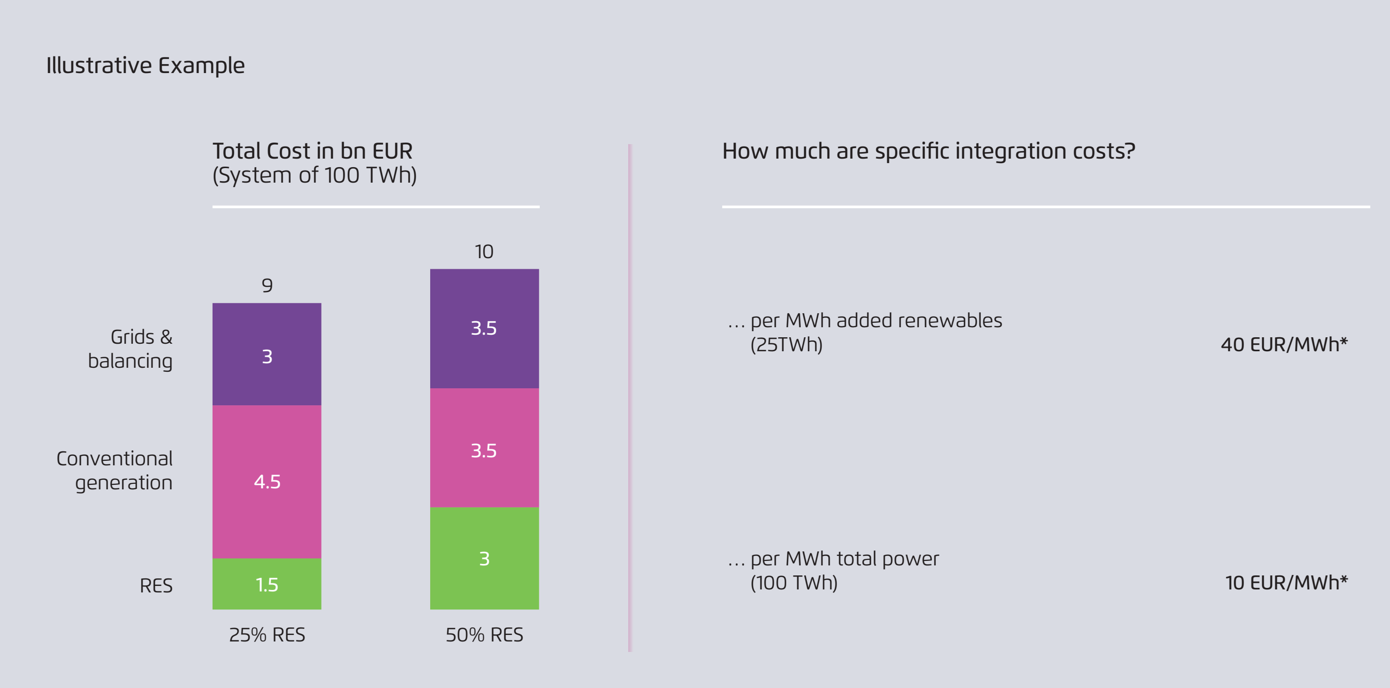


Description of effect	Contribution to integration costs in bn EUR
Additional cost for grids & balancing	0.5
Less then proportional decrease in cost of conventional generation	0.5*
Proportional increase in cost for renewables	–
	Integration cost: 1 bn EUR

Own illustration

*example here: fully considering higher specific generation cost as integration cost, assuming that specific cost of conventional generation increase from 60 to 70 EUR/MWh, multiplied by 50 TWh (alternative calculation: 3,5 bn EUR – 4,5 bn EUR / 75 TWH * 50 TWH)

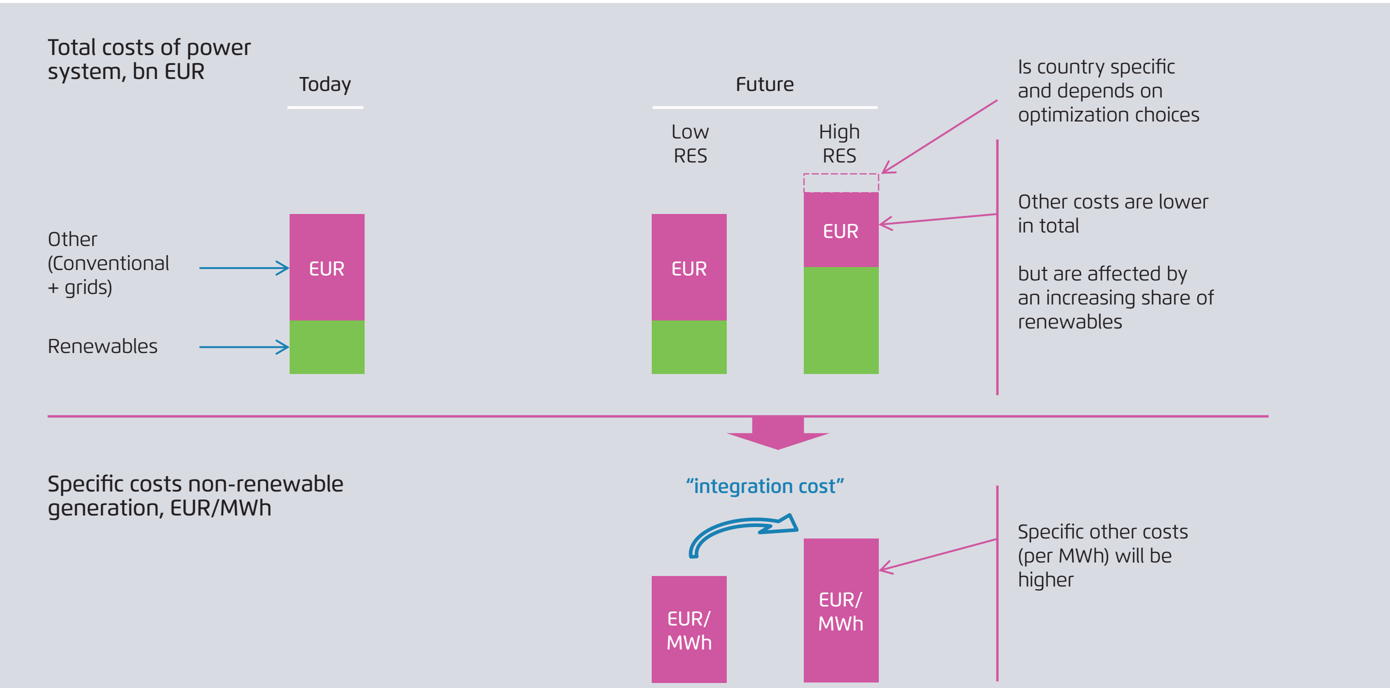
Different approaches for calculating specific (per-MWh) integration costs — Figure 12



Own illustration

*example here: that is to say, when dividing 1 bn EUR total integration costs by different denominators

Increase of the specific costs of the non-VRE part of the power system — Figure 13



Own illustration

share of RES changed the pattern of residual load in such a way that it became more costly to serve.

Absolute integration costs are €1 bn, €0.5 bn from additional grid and balancing costs and €0.5 bn from less than proportional decreased residual generation costs.

Often, it is convenient to express integration costs in specific (per MWh) terms, for which different denominators may be chosen. To illustrate the relevance of the choice of the denominator values are presented on the right side of Figure 12. When absolute costs are divided by total electricity consumption (100 TWh), specific integration costs are calculated to be 10 EUR/MWh; when they are divided by the added renewables they are calculated to be 40 EUR/MWh. In our quantification, we will use "added renewables" as a denominator and calculate the average cost for integrating these renewables.

When calculating integration costs by comparing the total system costs in two scenarios, we need to ensure that the share of renewable energy is the only driver of differences between the two scenarios. A comparison of a future scenario with a scenario of today is unlikely to provide such a case. Accordingly, two future scenarios need to be established, as illustrated in Figure 13. Integration costs reflect the rise in specific costs in the non-RES part of the power system when comparing these two future scenarios.

3 Grid costs

Grid costs are the costs for transmission and distribution networks that are related to the construction of a new power plant. For example, if a renewables project yields 100 MWh per year and requires grid investments worth €500 per year in annualized terms, grid costs are 5 EUR/MWh.

Compared with other integration cost components, defining grid costs is relatively straightforward and uncontroversial. Yet four significant challenges arise when calculating these costs:

- → Defining the boundaries of the category "grid costs" is not always clear-cut. Some costs might be count as grid, generation, or balancing costs. Careful accounting is necessary to avoid double-counting.
- → Future grid expansion is driven by many factors. Extracting the amount that is caused by renewables can be challenging.
- → Grid costs can be specific to systems and projects. Calculating average or typical costs can be difficult, especially for distribution grids.
- → New technologies and planning approaches that can reduce grid costs significantly and may or may not be considered in analysis.

These difficulties help explain the large variation of grid costs that studies find.

3.1 Overview of grid costs

In the context of this report, "grid costs" are generally understood as the costs for building or upgrading electricity networks that are related to renewables expansion. Grid costs include investment costs, power losses and expenses for certain ancillary services. They occur on the transmission grid level (380 kV, 220 kV) and on the distribution grid level (below 220 kV), as well as for offshore grids.

Investment costs (capital costs) are often the largest component of grid costs. These include the costs for building new or upgrading existing lines – overhead lines, underground cables, transformers and substations – but they might also include the costs of building voltage support equipment (e.g., static VAR compensators) or active power flow management (e.g. FACTS). Losses that occur in the transport of power can contribute to grid costs for both distribution and transmission grids. Grid costs may also include the costs of system (ancillary) services that system operators buy on the market, such as the provision of balancing reserves, voltage support, black-start capability or re-dispatch – a number of components that might as well be included in a calculation of balancing and generation costs.

Which actors bear the grid costs depends on the regulatory environment of a given market. In nodal pricing schemes, grid costs are recovered from price differences between locations. In most European countries, grid costs are distributed over loads and/or generators, and sometimes vary regionally. In Germany, electricity consumers pay grid costs.

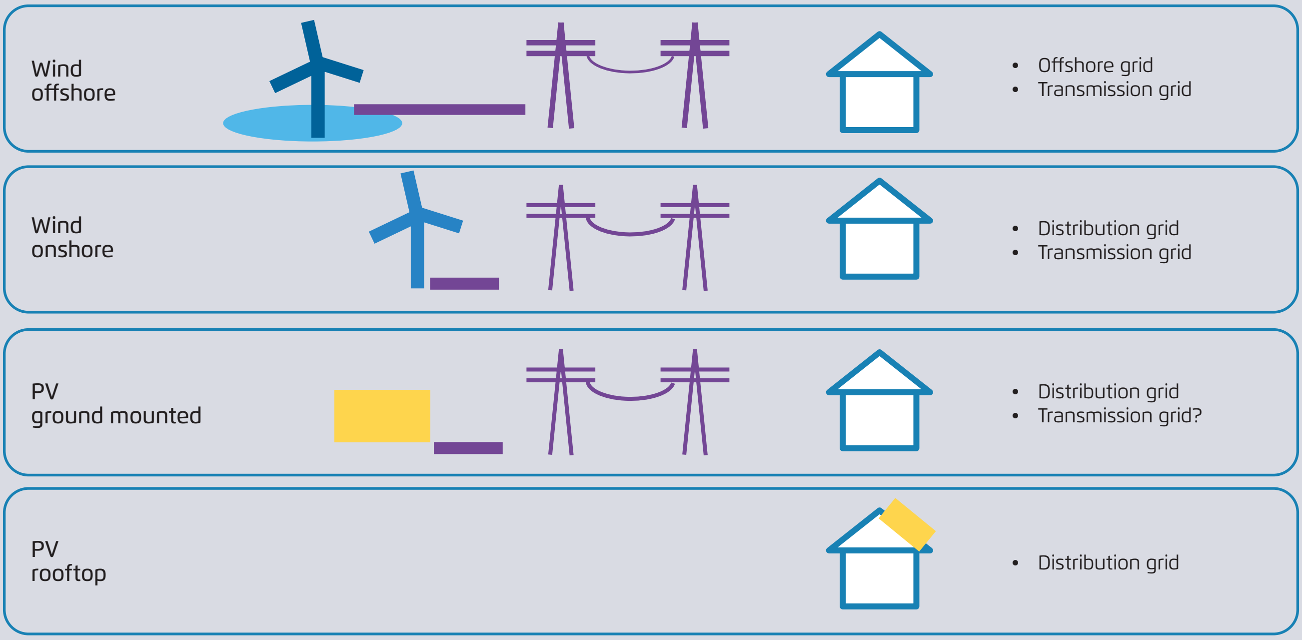
3.1.1 Grid costs for different types of renewable technologies

Different types of grid costs are more relevant for some technologies than for others. An overview of the major grid costs for the different types of wind and solar power plants is given in Figure 14.

Offshore wind power requires an offshore grid as well as an expansion of transmission grid onshore. Onshore wind farms and ground-mounted solar power plants are mostly connected to the distribution grid; direct connection to the transmission grid may occur as well. Major grid costs for these technologies are distribution grid costs and costs for the transmission grid, the latter depending largely on the distance of the power plants from centers of demand. Rooftop solar power plants may induce none or significant cost in the distribution grid, depending on the location. (This is discussed in more detail below.) As their location is generally in direct proximity to demand, an expansion of the transmission grid is unlikely to be required.

Overview of grid costs for different renewable energy technologies

Figure 14



Own illustration

3.1.2 Differences between renewable technologies and other technologies

In principle, grid costs related to new wind and solar power plants are very similar to those related to the construction of any other type of power plant. A new coal fired or nuclear power plant may require investments in grid connection and expansion, especially in case its location is not in proximity to the centers of demand. Yet certain differences exist when adding wind and solar:

→ The connection is to the distribution grid not the transmission grid due to smaller average size of generating units (typically 0.1 to 100 MW as compared with >500 MW for conventional power plants).
→ The average utilization of connecting grids is lower due to the lower average utilization factor of the generator (typically 10 percent to 45 percent compared with 20 percent to 85 percent for dispatchable generators).
→ Sites with the best resources may be located far away from demand and the process of selecting sites may not consider cost for power transport (depending on the regulatory environment, this may also apply to fossil power plants).

3.2 Challenges in quantifying grid costs

3.2.1 Separating grid costs from other cost components

Drawing a line between grid costs and other cost components is not always clear-cut, especially in three cases:

→ Curtailing peak in-feed of renewables can reduce grid costs but increase generation costs.
→ The costs of system services can be attributed to grid, balancing, or generation costs.
→ (Shallow) connection costs are sometimes count as grid costs, but often generation costs.

Curtailing the maximum in-feed of wind and solar power generators can reduce the costs for grids (more below). At the same time, it increases generation costs, as either more wind and solar power generators are needed to produce the same amount of electricity, or the curtailed electricity is replaced by power from other generators in the system. Some studies may count these curtailment costs as grid costs; others, as generation costs.

The costs of ancillary (system) services are recovered through different channels depending on the market. In some markets, some services, including balancing reserves, are bought by system operators and costs are recovered via grid fees. Accordingly, these costs sometimes count as grid costs. In other cases, costs are recovered via imbalance charges. Consequently, costs might count as balancing costs. Finally, the provision of system services is sometimes imposed on generators by network codes, without direct compensation. In this case, costs may occur as generation costs. None of these approaches should be considered as "right" or "wrong"; each is based on a specific regulatory environment that may exist in a certain market at a given time. This example shows that the boundary between grid costs, balancing costs and generation costs is arbitrary to some degree.

Grid costs are often separated into grid connection costs and grid expansion costs. Grid expansion costs are commonly understood as the costs of upgrading the "hinterland" network – such as improving distribution grid transformers and building North-South transmission corridors in Germany. (Shallow) connection costs are commonly understood as the costs of constructing a line from the project site to the next substation or transformer. They can in most cases be easily attributed to the project. In most European countries, the project developer has to pay for these costs; hence they are included in generation costs, not grid costs. Different countries draw the line between connection and expansion costs differently (ENTSO-E 2014). Depending on the regulatory environment, connection costs may include a component for grid expansion. These are called "deep" connection costs.

The ambiguity of these components makes the comparisons and generalizations difficult. At any rate, one should avoid double-counting curtailment, ancillary services and connection costs.

3.2.2 Extracting grid costs from scenarios

Grid expansion studies typically estimate grid costs 10 to 20 years in the future. It would be wrong to attribute the entire increase in grid costs to renewable expansion. Other factors might drive grid costs as well, such as demand growth or a geographic shift of conventional capacity. Ideally, one would compare two future scenarios of the same year that differ only in the VRE penetration rate as represented in Figure 15.

When comparing grid costs between different years, many factors might have an impact on grid requirements and costs. For example, the nuclear phase-out in Germany increased the utilization of the transmission grid, as the southern part of the country was left with a larger electricity balance deficit. Similarly, a change in fuel prices that favors construction of power plants disproportionally located in the north of Germany (e.g., hard coal plants) might increase grid costs. Finally, grid upgrades might be required to support the market integration foreseen by the European power market.

Identifying the portion of grid costs driven by the deployment of wind and solar power alone requires a comparison of scenarios that differ only in this respect, with everything else unchanged.

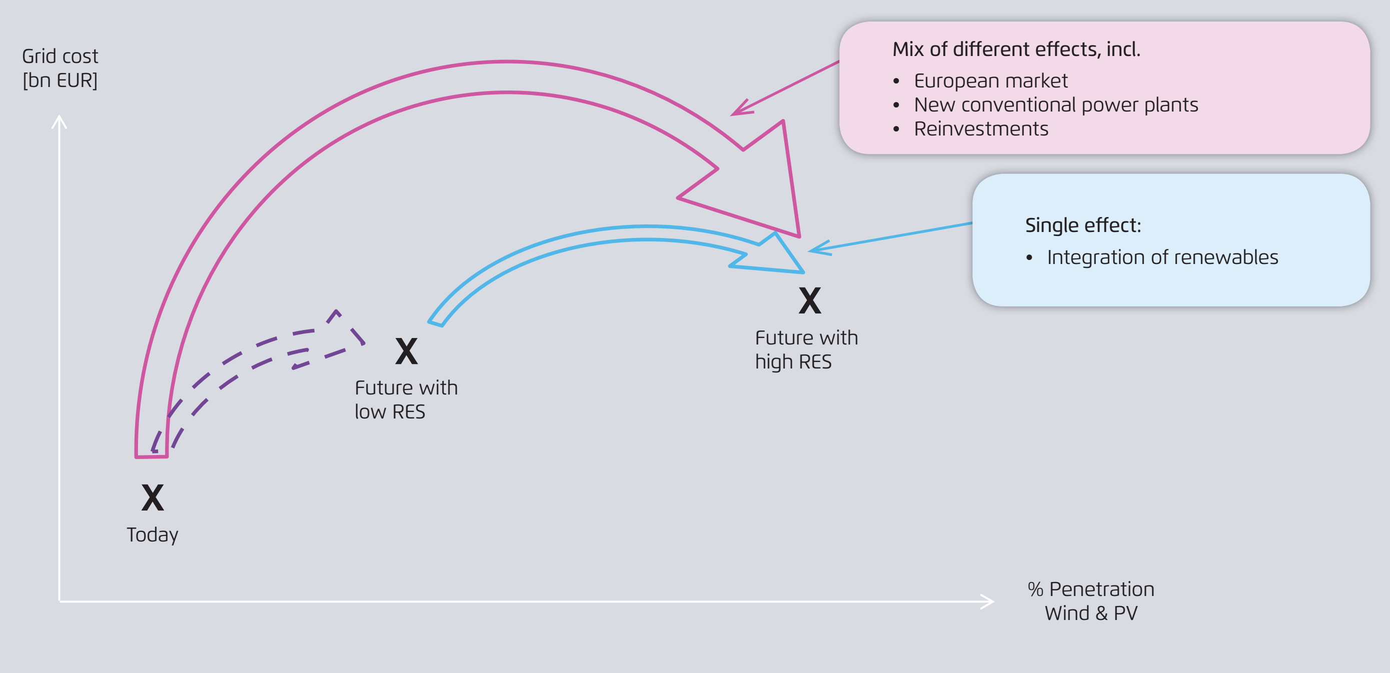
3.2.3 Technology and case-specific grid costs

Grid costs vary significantly between renewable energy technologies and even between individual projects. The types of grid costs that are most relevant for different technologies have been described above. Yet even within a single technology, grid costs can vary substantially, as can be shown using rooftop solar power plants (figure 16). In the best case, small-scale rooftop solar PV in towns or cities may not require any grid investment, as existing grid infrastructure can be used.[17] In the worst case, a relatively large rooftop solar power plant located in a more remote location – for example an uninhabited barn outside a village – may require a significant distribution grid upgrade. A recent case

17 Even negative grid costs may appear when power losses are reduced in existing distribution grids or a smaller peak demand reduces the required grid connection capacity.

Different approaches for calculating grid costs based on different future scenarios

Figure 15



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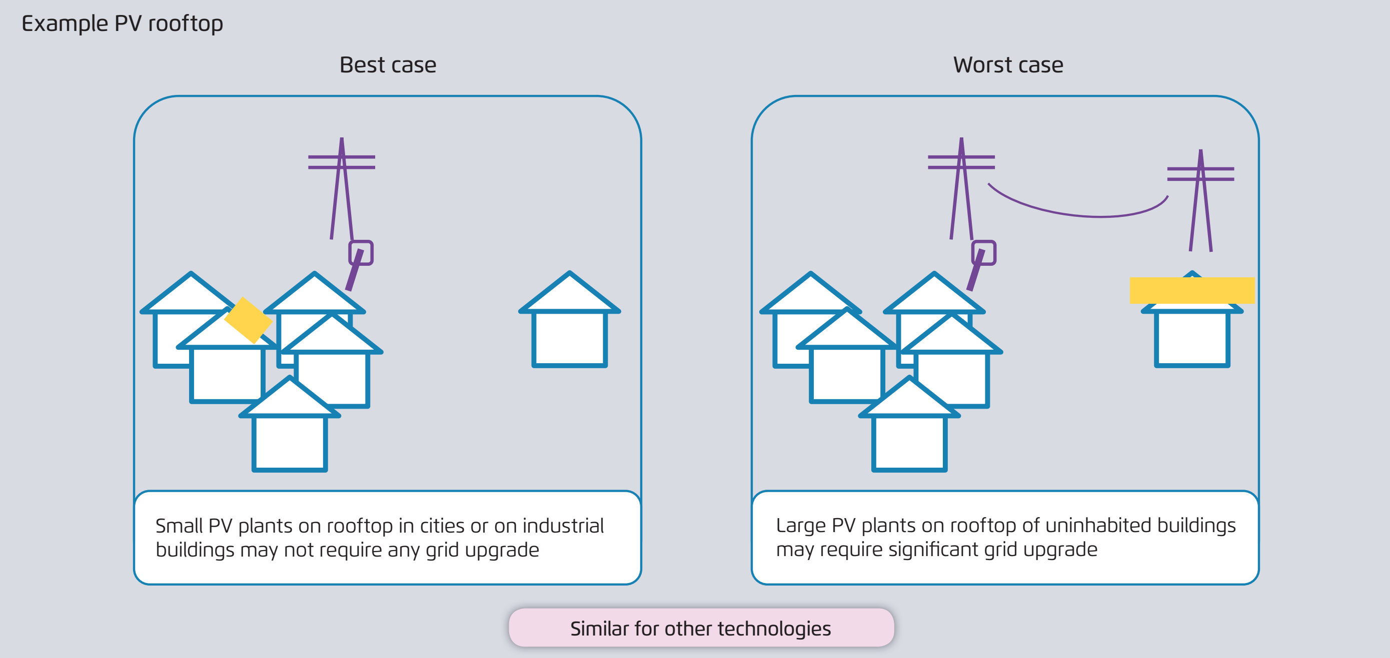
Best-case and worst-case examples of grid costs for rooftop solar PV

Figure 16



Own illustration

study from eastern Germany (Dieckert et al. 2014) reports average distribution grid costs of 150 €/kW for solar PV, with about half of all projects featuring negligible costs, and individual projects amounting to 600 €/kW and more.

3.2.4 New technologies and optimized planning approaches

Many studies find that grid costs can be substantially reduced if innovative technologies, regulation or planning approaches are used. Such "optimized" grid costs are often reported to be much lower than those under "business-as-usual" assumptions. For example, flexible demand is frequently reported to have a major impact (Pudjianto et al. 2013). So too is smart distribution grid equipment (DENA 2012), transmission grid temperature monitoring (DENA 2010) and the curtailing of in-feed peaks (IAEW et al. 2014).

The degree to which studies account for these options affects cost estimates. Sometimes the costs of these options are included in grid costs; sometimes they are not.

3.3 Grid cost estimates

Major analytical efforts have been conducted recently to estimate grid (expansion) costs in various European countries. An overview of the findings is presented in the following. The results are organized by technology and grid types.

While many of the most elaborate studies (such as national grid development plans) calculate the costs incurred in grid expansion in different scenarios, they do not calculate the specific grid costs per unit of wind and solar power added. In the following, the grid cost component of integration costs (in EUR/MWh) is calculated when not otherwise provided. For this, the approach for separating out the effect of wind and solar power plants described in section 3.2.2 is applied as well as the method for calculating average integration costs described in section 2.4. Investment costs were annualized.[18] Operational expenses (OPEX) of the additional grid components were assumed to be 1.5 percent of total investment cost per year (following commonly used assumptions). The costs of the curtailment of VRE generation[19] were also included whenever indicated. In some of the studies considered, e.g. (KEMA et. al 2014), significant differences in the development of electricity demand occurred in the scenarios. Based on the insights gained in Prognos/IAEW (2014), a roughly proportional increase in grid costs was assumed in the case of increasing electricity demand between two scenarios. Scenario results were adapted accordingly so the effect of wind and PV only could be estimated. A detailed list of the set of scenarios used for each of the calculations is given in appendix.

3.3.1 Grid cost estimates from recent German studies

The quantification of grid costs for the case of Germany is based on three different studies:

- the annual grid development plans from 2014 for the transmission (NEP 2024) and offshore grid (O-NEP 2024) by German transmission system operators and the German regulator BNetzA
- a distribution grid study commissioned by the German Economic Ministry in 2014 realized by IAEW/E-Bridge/Offis (IAEW/E-Bridge/Offis 2032)
- an analysis of the cost optimal expansion of renewable energies in Germany, covering both distribution and transmission grids, commissioned by Agora Energiewende in 2013 and realized by Consentec (Consentec 2033)

Based on this analysis, the costs for transmission grids in Germany are calculated as approximately 5 EUR/MWh of additional wind or solar power (Figure 17). A strict attribution of the transmission grid costs to individual technologies (wind onshore, wind offshore and solar PV) is not possible based on the scenarios available. Due to the various deployment of wind power in the different scenarios (with a 97 TWh difference between the scenarios) vs. solar PV (with

18 Transmission/Offshore grid – lifetime of 60a, WACC of 7 percent; distribution grid – lifetime of 40a, WACC of 7 percent.

19 The costs for curtailment were assumed to be 50 EUR/MWh. This is the average cost for replacing the renewable electricity lost with an equal amount of electricity produced when wind and/or solar power plants are curtailed. This assumption is based on ef.Ruhr et al. (2014)

a 3 TWh difference between the scenarios), it appears safe to assume that the differences in transmission grid costs between the scenarios are largely attributable to the expansion of wind power in Germany.

Much easier is the attribution of the costs for offshore grids, which are clearly driven by the expansion of offshore wind farms. The costs for offshore grid extension are calculated to be approximately 30 EUR/MWh (Figure 17).

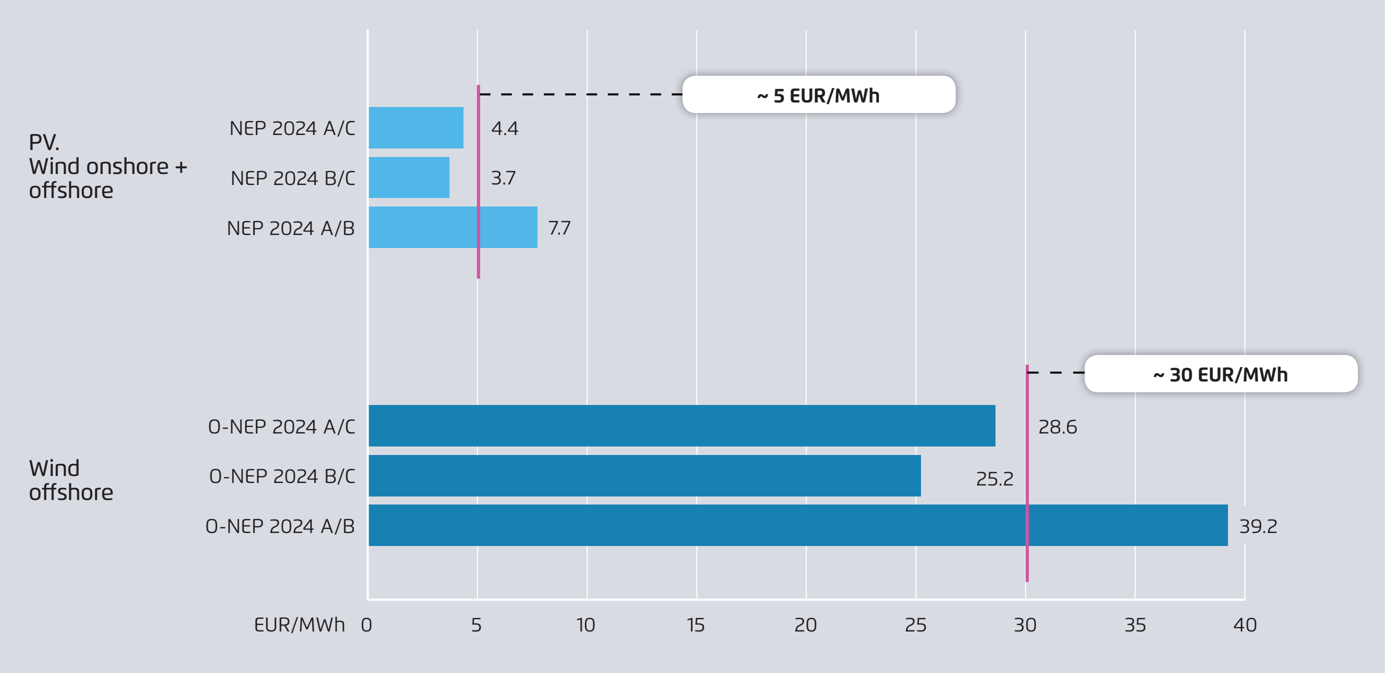
The costs for building and upgrading the distribution grid as a consequence of v-RES development in Germany are between approximately 6 and approximately 14 EUR/MWh (Figure 18). Significant differences exist between scenarios in which an optimized approach of distribution grid expansion is chosen instead of a non-optimized "business as usual" approach. In the study by Agora/Consentec, a cost-optimal level of curtailment by wind onshore and solar PV is assumed (reducing the maximum feed-in of solar PV by up to 30 percent of its maximal capacity and wind onshore by between 0 percent and 12 percent). The results of BMWi distribution grid scenarios do not consider these approaches for reducing distribution grid costs. Various technologies and changes in planning approaches that would lead to significant cost reductions have been noted, but have not been quantified in their effect.

3.3.2 Grid cost estimations from recent European studies

The following European-scale studies were analyzed:

- → a study of grid integration costs of PV commissioned by the European Commission in 2014 and carried out by the Imperial College London (Scenario names: PV Parity 2020, PV Parity 2030)
- → a study of the integration of the RES commissioned by the European Commission in 2014 carried out by KEMA/Imperial College London/NERA/DNV GL (Scenario names: KEMA 2020, KEMA 2025, KEMA 2030)
- → a study of the system effects of RES for different countries commissioned by the OECD in 2012 and carried out by the Nuclear Energy Agency (Scenario name: NEA)

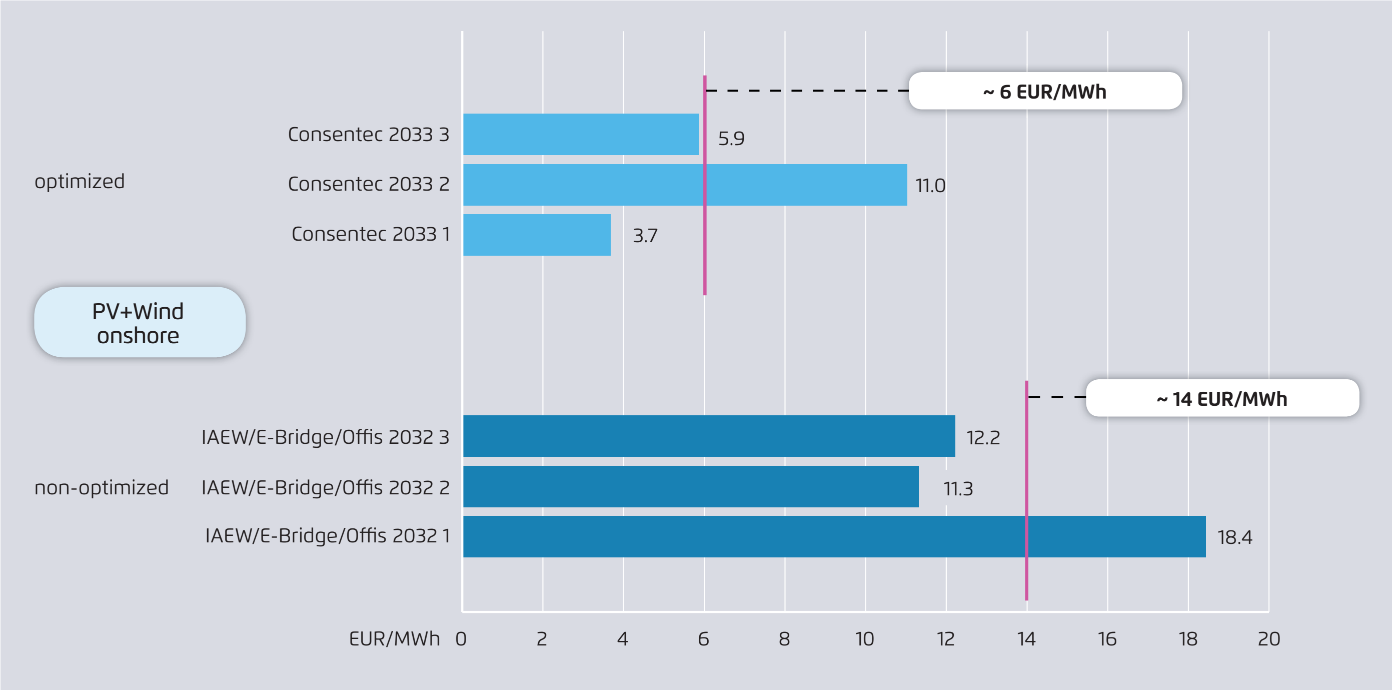
Quantification of transmission and offshore grid costs in Germany — Figure 17



See appendix

Quantification of distribution grid costs in Germany

Figure 18



See appendix

For the analysis of European transmission grid costs, a differentiation between wind and PV is possible based on the results of the PV parity study, which calculates specific transmission grid costs for PV. The PV parity study mainly suggests almost insignificant transmission grid costs of less than 0.5 EUR/MWh for solar power in 2020, increasing to 2.8 EUR/MWh in 2030 (Figure 18).

Average grid costs for wind power based on KEMA are approximately 7 EUR/MWh (Figure 19). However, they vary significantly, which alerts us to the need for further analysis and a better understanding of both drivers of grid costs as well as cost reduction potentials. These figures seem consistent with results from the German analysis, as transmission grid costs for wind and PV were calculated to be around 5 EUR/MWh.

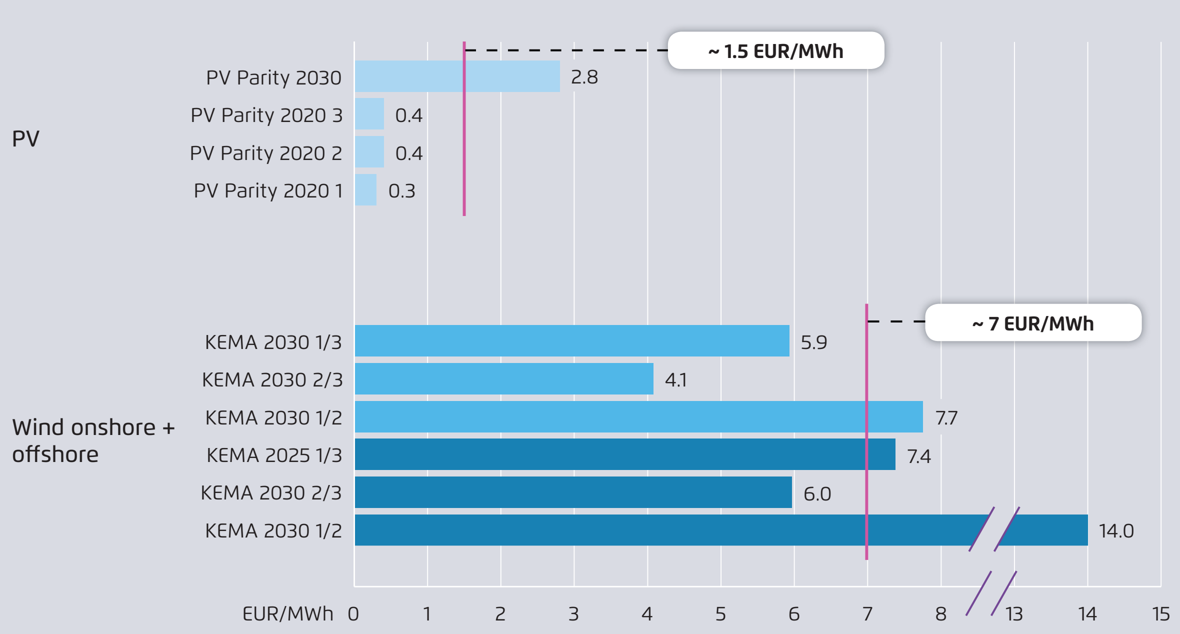
The results for distribution grid costs (presented in Figure 20) are characterized by very high variations, reflecting the case-specific and system-specific nature of these costs.

The results depicted from the analysis show that significant differences in distribution grid costs exist not only between different countries but also between different scenarios within the same country. The two results of the analysis conducted in the PV parity project depicted in the graph, -25.0 EUR/MWh of solar PV added in Greece compared to 8.8 EUR/MWh of solar PV added in Belgium, may be considered a good representation of best-case and worst-case examples similar to those illustrated in Figure 16. These results are based on the same methodology; other studies reach even higher values, up to 47 EUR/MWh. These may result from different assumptions about the specific situation under analysis or from different calculation methods.

The analysis of different distribution grid cost estimates confirms that a single cost figure does not provide an accurate assessment of distribution grid costs. Nevertheless, the figure of 6 EUR/MWh, obtained from the optimized scenarios in Germany, appears to be representative.

Quantification of transmission grid costs in Europe

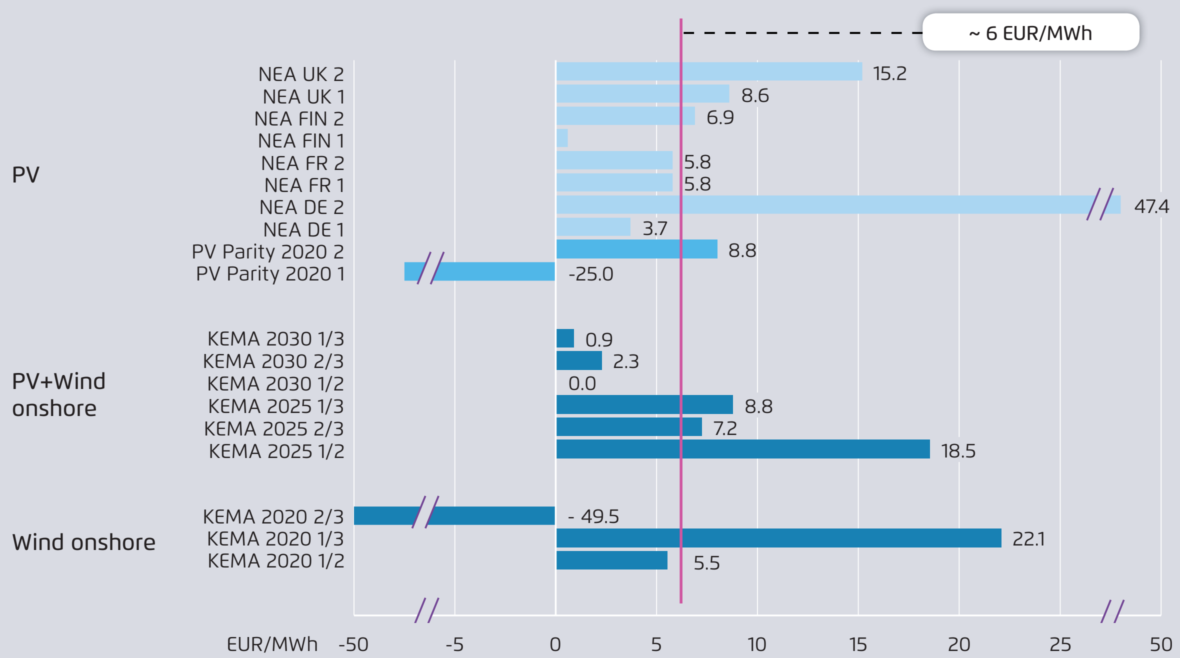
Figure 19



See appendix

Quantification of distribution grid costs in Europe

Figure 20



See Appendix

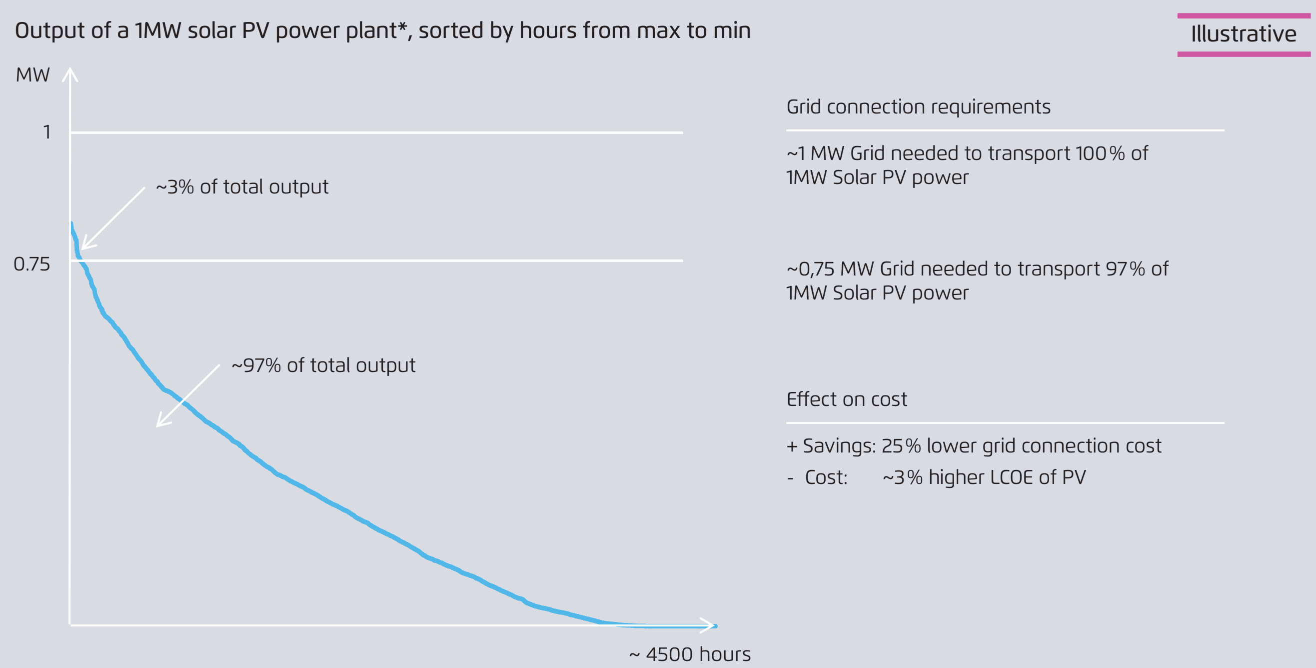
3.4 Options for limiting grid costs

Planning and building cost effective grids for future wind and solar PV requires different approaches from conventional grid planning. Grids built for dispatchable power plants are designed to transmit the maximal output of the plant, as this might be needed to provide power during the peak-load hour of the year.

Grids that connect wind and solar PV power plants do not necessarily need to be designed to transport the maximum power output; no one could guarantee that the plant would produce at maximum output during the hour of highest demand. Their design may focus on transporting the power produced by wind and solar PV as cost effectively as possible. In other words, a cost optimal grid design for wind and solar PV power plants may look at the total cost of the generation and grid connection, and accept that a small share of (potential) generation is lost for the sake of lower grid cost. The example calculated in Figure 21 shows the effect of such an optimization based on the feed-in data of an individual solar power plant.[20] In this case, curtailing solar feed-in at 75 percent of rated capacity leads to a curtailment of only 3 percent of potential generation. Thus while grid cost may be reduced by 25 percent, generation costs are increased by only 3 percent. Finding an economic optimum that includes cost of generation and grid will obviously depend on the specific costs of both. While a cost optimal level of curtailment is likely to be rather low today (2-3 percent of generation is often given as a point of reference), this level may increase significantly in case the cost of solar modules collapses.

20 The data is from a solar power plant located in southern Germany with a sun elevation angle of 180°, an azimuth of 40. It is provided by EEG TU Wien (http://portal.tugraz.at/portal/page/portal/Files/i4340/eninnov2014/files/lf/LF_Hartner.pdf). The value for installed capacity is based on module capacity; the calculation of output takes into account losses due to reflections, inverter, etc.

Cost effects of curtailing maximum in-feed of solar power — Figure 21



* Based on data of a solar power plant located in southern Germany, provided by EEG TU Wien

There are further options for limiting grid costs, including the following:

- → The avoidance of local hotspots: encourage new investments only in areas where grids have sparse capacity or can be upgraded at moderate costs.
- → Technical capabilities of wind and solar generators: grid codes need to account for a high share of wind and solar power and require, say, fault ride-through capability (e.g., avoid the 50.2 Hz issue) and voltage support.
- → Improving the operation of distribution grids. This can be performed by using regulated distribution transformers that improve distribution grid voltage support and allow larger in-feed without exceeding voltage limits.
- → Advanced inventive regulation that awards smart technologies, innovation and cost-efficient investments.

More in-depth discussion of options can be found in IEA (2014, section 5) and IAEW (2014).

4 Balancing costs

Balancing costs are the costs incurred in balancing deviations of actual generation from the forecasted generation (Figure 22). For example, if a renewables project that yields 100 MWh per year requires balancing services that cost 200 €, then balancing costs are 2 EUR/MWh.

As for grid costs, the definition of balancing costs is relatively straightforward and uncontroversial. However, three major challenges exist when calculating balancing costs:

- → Some studies include the costs of holding balancing reserves; others don't.
- → Imbalance prices that generators pay today are often not cost reflective.
- → Studies vary in how they define "short-term" balancing.

Furthermore, as discussed above, the allocation of balancing reservation costs to grid, balancing or generation costs is not always clear-cut.

4.1 Overview of balancing costs

Balancing power is used to stabilize the active power balance of integrated power systems on short-time scales (from seconds to hours). In AC power systems, the demand-supply balance has to hold at every instant of time to ensure frequency stability at, usually, 50 Hz or 60 Hz. Frequency deviations have a number of problematic consequences, one being that they can mechanically destroy rotating machines such as generators.

In today's power markets, these costs appear as the imbalance charge that investors pay to system operators for deviating from submitted schedules. Depending on the definition, they might also include additional costs for intra-day trading and portfolio management.

4.1.1 Balancing costs of renewable technologies

VRE generators, being weather-dependent, are subject to forecast errors. Forecast errors increase the need for holding and deploying balancing reserves, in order to balance deviations. Obviously, the occurrence of such deviations depends on the quality of the forecast and the time horizon for which the forecast is made. While forecast errors are likely to be significant when made over a period of several hours or a day, they are likely to be close to zero if made for a period below an hour. The relative size of the deviation is likely to decline with the increasing geographical distribution of renewable power plants.

4.1.2 Differences between renewable and other technologies

Balancing requirements induced by wind and solar power plants differ from those induced by the construction of other types of power plants.

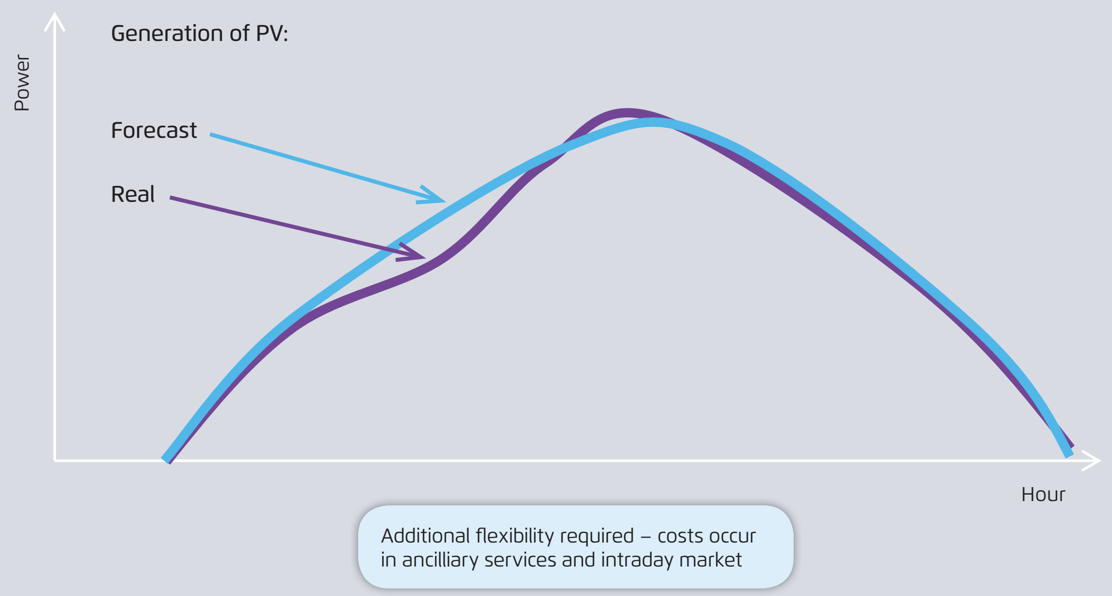
The power production of wind and solar depends on the weather rather than on signals from the power plant control room, and may thus only be forecasted, not controlled (with the exception of curtailment, which is always possible). In order to ensure system stability, reserves are required to offset the errors incurred in forecasting wind and solar generation that do not occur for other types of power plants. The impact on the amount of reserves requires increases with the penetration level of renewables.

Another effect occurs because of the smaller size of single renewable generators (typically below 5 MW) relative to that of other types of power plants (typically above 500 MW). This smaller size reduces the impact that technical failures of a generator have on the rest of the system. In order to ensure system stability, far fewer reserves are required to offset the failure of renewable generators than in the case of large power plants.

These differences on the resulting balancing requirements in a power system may not be as straightforward as it seems. For example, the effect of forecast errors of renewables may in some hours of the year be insignificant relative

Forecasted and real power production by solar PV

Figure 22



Own illustration

to forecast errors of demand or the need to be prepared for an outage of the largest generator connected to the grid.

4.2 Challenges when quantifying balancing costs

Most balancing power markets have two components: reservation of balancing reserves and activation of these reserves. Reserving capacity is often remunerated with a capacity price; activating capacity, with an energy price. Some studies count both these cost components, other studies count just one. Studies that rely on observed balancing prices often do not account for the costs of holding reserves, as these costs are not including in prices. Take Germany. The costs of holding reserves is recovered via the grid tariff and hence paid for by electricity customers on a pro-rata basis. The costs of activating reserves, via the imbalance price (or "imbalance charge"), are placed on generators, retailers, and consumers (balance responsible parties) that caused the imbalance.

The imbalance prices paid for balancing services do not always reflect costs, and balancing power markets cannot always be regarded as competitive. If these markets are subject to market power, prices tend to be above costs. What is more, the cost of holding reserves is sometimes not included, and pricing rules regularly do not reflect marginal costs.

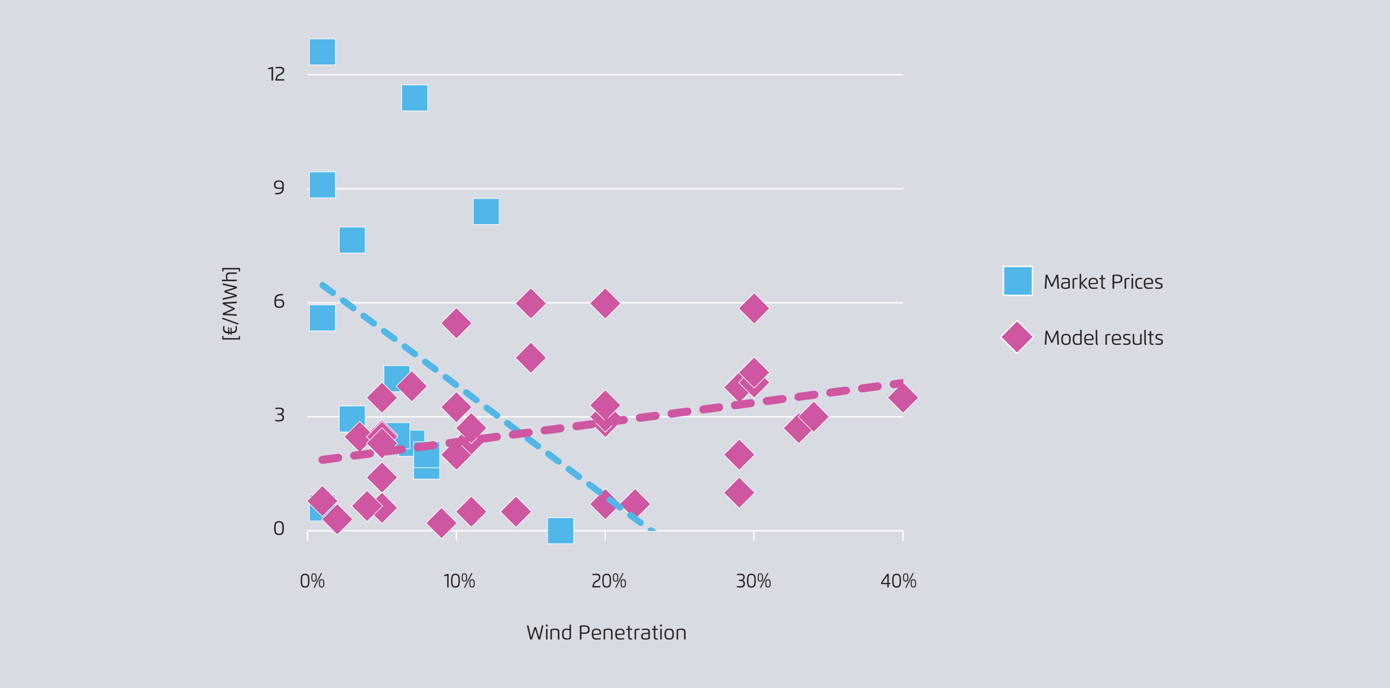
Another challenge is the definition of "short term" in the quantification of costs. Some studies include only costs for balancing power; others include the costs for intra-day trading and portfolio management (all costs occurring after the closure of day-ahead markets).

4.3 Balancing cost estimates

4.3.1 Balancing cost estimates from the literature

There are many studies that estimate balancing costs. Some studies assess cost based on observed market prices; others calculate costs based on models that include the cost for reserves. Studies that assess costs based on market data sometimes find very high costs in the double-digit

Balancing cost estimates from the academic literature | Figure 23



Adapted from Hirth et al. (2015)

EUR/MWh range. One example is Austria, where costs were above 11 EUR/MWh in 2014 (e3 consult 2014). By contrast, balancing costs in Germany are currently around 2 EUR/MWh (Hirth et al. 2015). These estimates are subject to the caveats discussed above.

Model-based studies find balancing costs that are quite low. Ideally, such studies account for both the additional costs of holding and using reserves, but not all do. In power systems with mostly thermal plants, balancing costs are estimated to between zero and 6 EUR/MWh, even at wind penetration rates of up to 40 percent. In power systems with significant shares of flexible thermal generation, such as the Nordic region, balancing costs are even lower (Figure 23).

While many studies estimate the balancing costs for wind power, studies on solar power are much less common. Pudjianto et al. (2013) estimate the balancing costs of solar PV to be between 0.5 EUR/MWh and 1 EUR/MWh.

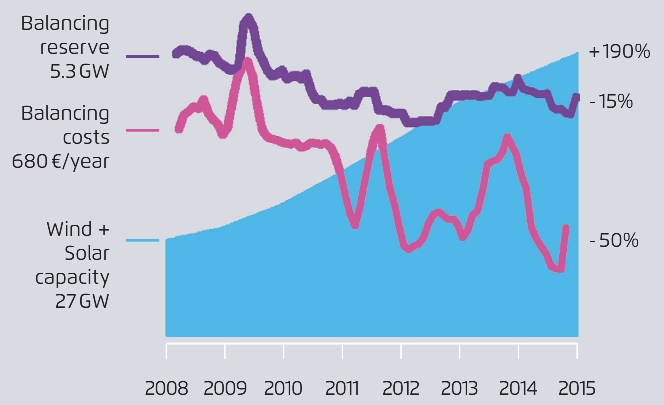
4.3.2 The German balancing power experience

There is much debate about the stress that wind and solar power forecast errors put on balancing systems. However, there are many other sources of system imbalances, including load forecast errors and outages of conventional plants and interconnectors. The German experience illustrates that wind and solar expansion does not necessarily play a major role for balancing costs: Since 2008, combined wind and solar capacity tripled – but the amount of capacity that was reserved for balancing power declined by 15 percent, and the costs of holding that reserve declined by 50 percent (Figure 24).

Of course this finding does not imply that additional wind and solar power will reduce the balancing reserve requirement. What it does show is that other factors must have overcompensated the VRE expansion, depressing the requirement for balancing or the price of the reserve. There are several candidates for these factors: TSO cooperation, more competitive balancing power markets, improvement

Balancing reserve and cost development in Germany since 2008

Figure 24



Hirth & Ziegenhagen (2015)
Note: Balancing costs do not include the costs of using the reserves

of forecasts, more liquid spot markets, and the economic recession:

- → TSOs cooperation in reserve sizing. In 2009/10, German TSOs established a balancing power cooperation (*Netzregelverbund*). Today, both reserve sizing and activation is done jointly such that Germany can in practice be treated as a single balancing area. Since 2012, the Danish, Dutch, Swiss, Belgium, Czech and Austrian TSOs have joined to form the "International Grid Control Cooperation" (IGCC). At this stage, the members outside Germany cooperate (imbalance netting) but size reserves individually.
- → Balancing markets became more competitive, possibly triggered by market design changes and regulatory intervention. The number of suppliers for primary and secondary balancing power increased from five in 2007 to between 20 and 30 in 2015. Forecasts of wind and solar generation, or load forecasts, may have improved. Since the introduction of the feed-in premium, in 2012, plant owners have had an incentive to improve their forecasts.
- → Intra-day market liquidity improved and 15-minute trading on power exchanges became common, allowing better portfolio management.
- → Supply shocks hit the balancing power market, such as the nuclear phase-out that reduced balancing power supply. Then came the recession, which increased balancing power supply by leaving the wholesale market with more overcapacity, which could enter balancing power markets. The net effect of these two shocks is unclear.
- → Lower margins on spot markets changed opportunity costs for thermal plants, reducing costs generally, especially for upward balancing power reservation.

4.4 Options for limiting balancing costs

A variety of options exist for reducing balancing costs. The options can be clustered into three groups: improving forecasts; improving balancing markets and European integration; and improving short-term spot markets.

Smaller wind and solar power forecast errors mean less balancing costs. Wind and solar power forecast is a relatively new field, and many experts argue that there is vast room for improvements, especially in the area of short-term forecasting (with forecast horizons limited to a few hours). Reducing forecast errors by half in the coming ten years seems to be realistic. Such improvements will happen only if the economic incentives are set right, however. The economic incentive for improving forecasts is the price paid for forecast errors. This is known as the imbalance price[21]. It is only since the introduction of the feed-in-premium support scheme for renewables in Germany in 2012 that renewable energy plant owners pay for forecast deviations. Some argue that the German imbalance price is inefficiently low (Hirth & Ziegenhagen 2015); a higher price would trigger more forecast improvements.

Many options exist for improving balancing markets. The sizing of balancing reserves could be adjusted according to the current state of the power system. For example, if a

21 In Germany, it is called the *regelzonenübergreifender einheitlicher Ausgleichsenergiepreis*, or *Ausgleichsenergiepreis* for short.

wind front is expected to arrive the next day, additional reserves could be procured (dynamic sizing, Fraunhofer IWES 2015). Increased international cooperation among TSOs, such as imbalance netting, reduces balancing costs (Fattler & Pellinger 2015). Market design of balancing power markets could be adjusted so that more market participants could supply these services. Frequent auctions (e.g., daily) and short contract duration (e.g. of one hour) could enable balancing power is provided not only from the demand side, but also from wind and solar power. This would not only generate an additional income stream for these actors; it would also reduce balancing power prices.

The larger the balancing area, the more forecast errors from individual plants balance each other out. Integrating the four German balancing areas into a single zone by introducing the *Netzregelverbund* was an important step. Currently, two different processes are under the way to further integrate balancing areas beyond the German borders. On the one hand, the European process of framework guidelines and network codes aims at creating an integrated European balancing market as part of the European target model. On the other hand, groups of TSO cooperate in a bottom-up process to make balancing more efficient. The "International Grid Control Cooperation" of western-central European TSOs expands the idea of the *Netzregelverbund*. Apart from other benefits, larger balancing areas help keep the balancing costs of wind and solar power low.

More liquid intra-day spot markets with shorter gate-closure times and reduced trading intervals (15 minutes, say) help VRE generators manage forecast errors without relying on balancing systems.

5 Effects of variable renewables on existing power plant utilization

Probably the most controversial and complicated aspect of assessing integration costs relates to the effects that wind and solar power have on the rest of the power plant fleet. The aim of this section is to contribute to an improved understanding of this topic by describing technical effects (section 5.2) and economic effects (section 5.3) as well as the key parameters and assumptions that underlie quantitative assessments.

Analysis of this aspect of integration costs will invariably include parameters that are specific to the country and situation considered. This makes it difficult to apply insights obtained in one country to another. The result of the analysis will depend on a variety of factors and perspectives that are subject to controversial debate. Specifically, no consensus exists concerning how to quantify the generation costs of different technologies (particularly how to consider externalities), whether one should view costs from the perspective of the consumer or producer, or the circumstances that will prevail in the future (e.g. concerning the types of power plants that will exist when a certain penetration of renewables is reached). The following aims to highlight how different assumptions influence the results, rather than arguing for a specific set of assumptions as the "correct" one.

5.1 Overview of impacts on existing conventional power plants

When introducing additional capacity to a system – whether wind or solar, or any other power plant – the output as well as the revenues of other power plants tend to be reduced. In contrast to dispatchable power plants, wind and solar power plants produce electricity when the wind blows or the sun shines. This means that their output does not react to demand for electricity and is not constant, but rather variable, with a comparatively low average utilization.

Compared to the addition of conventional power plants, the effect of adding wind or solar capacity thus differs in two respects:

→ First, other power plants may need to provide the capacity needed at times of high demand, no matter how many wind and solar power plants are built. This is often described as a need for "backup capacity" or, technically more correct,[22] as the reduced average utilization of the other power plants.
→ Second, the structure of the remaining demand is changed (i.e. the temporal pattern during a day as well as during the year), leading to different use of existing power plants and, if changes in the power plant fleet over time are considered, a different cost-optimal mix of residual power plants also results. This is often described as a shift from "base load" to "mid-merit and peak load".

These differences may have an impact on the specific generation costs of the other power plants of the system:

→ First, the reduced average utilization of the other power plants leads to a higher specific cost (EUR/MWh) of the invested capital, leading to an increase in their average generation cost.
→ Second, a shift between the technologies providing residual demand may occur: Not only are more dispatchable power plants needed, but also the more expensive power plants will be used more and the cheapest power plants less (e.g. less lignite and nuclear and more natural gas or biogas power plants). This shift impacts capital and operational costs. In a perfect market, the change in op-

22 Technically speaking, the addition of wind and solar PV in an existing system does not require backup capacity. Yet compared to the case of adding base load power plants, a system with new wind and solar PV must keep more capacity in the system. In the latter case, the average utilization of all residual power plants is thus lower.

erational cost will increase the average generation cost of the other power plants. In an imperfect market and using a wider understanding of cost (e.g. considering all externalities), the shift from base load to mid-merit and peak load may lead, among other things, to a decrease in average costs.

The challenges in quantifying this integration cost component are manifold and will be the focus of this section. A short summary should be provided at the outset: From a technical perspective, the costs are very system specific and depend on the type and amount of renewables added, the flexibility of the power system and the type of other power plants. Controversies regarding the quantification of these effects, especially the increase in specific capital costs of the residual power plants, focus on the types of power plants assumed to exist in the future as well as the perspective taken when performing the calculation. Controversies regarding the quantification of the higher operational cost focus on the quantification of external effects, and to which extent these externalities should be considered when analyzing power system costs.

5.2 Technical analysis of effects on existing power plant utilization

The following section describes technical effects. These effects impact the economic assessment, which is the subject of section 5.3. The separation aims to separate the technical analysis, which is less controversial, from the more controversial economic analysis. Before key sensitivities are discussed, an overview of our approach is provided.

5.2.1 Effects on the residual load curves induced by new power plants

5.2.1.1 Introduction to residual load duration curves

The residual load duration curve is a tool which can be used to illustrate the effects induced by new power plants on the rest of the power system. As this tool is used in the following, we first introduce and explain it in some detail.

We define residual load as the load remaining after new power plants are added – these may be new wind and solar power plants or new base load power plants.[23] This is important for our analysis in order to emphasize the difference between these two cases.

The starting point for calculating the residual load is the "load" in a given power system, which is a common term used for the demand for electricity in a certain region (such as a country) in a given hour. The second key parameter is the generation by certain power plants, for example a certain number of new solar PV power plants, in the same hour. Neither the load nor generation of solar PV are constant over time but vary over the day, depending on the activities of the people who consume electricity as well as the intensity of the sunshine. As an example, electricity demand in Germany during the first Monday in July 2014 is depicted on the left hand side of figure 25 - together with a simulation of the power generated by solar PV during the same day, assuming that 50 GW of solar PV is installed in Germany.

The residual load per hour is then calculated by subtracting during each hour the generation by the new power plant – in this case solar PV – from total demand. From the perspective of the existing power plants in a given system, this residual load is a very important parameter – for within each hour, this is the residual "market" into which they can sell the electricity produced. Comparing the resulting residual load in Germany during the day in July with the original load (depicted in the middle of Figure 25) one can see that the remaining "market" is unchanged during the night but reduced significantly during daytime hours. While the total load during the day initially varied between ~50 and 70 GW, the residual load now only varies between ~50 and 60 GW.

23 This definition and the approach chosen here works well for the focus of the analysis (i.e. wind, solar as well as nuclear and lignite power plants). This is because all of these plants feature lower marginal costs (within the current regulatory regime) than other existing power plants. Analysis of the interaction effects may be more complex in the case of new coal or gas fired power plants featuring higher marginal costs than some of the existing power plants.

The residual load duration curve is then established by calculating the residual load in every single hour of a year (8760 hours) and sorting every hour from the highest to the lowest value, as depicted on the right hand side of figure 25. This residual load duration curve provides an overview of the residual market for the other power plants during the entire year – including the maximum demand for electricity on the left side of the curve, and the lowest demand of electricity (or even excess supply) on the right end of the curve. As we can see, the residual load on the Monday night that is depicted on the left and middle part of figure 25 features one of the lower values of residual load within the entire year of 2014, yet by far not the lowest. As the yearly load duration curve shows, the hour with the lowest residual load (on the right end of the curve) features a residual load of only approximately 30 GW. The daily peak appearing during the Monday from our example, of around 60 GW, is also far below the highest value of residual load during the year (around 80 GW).

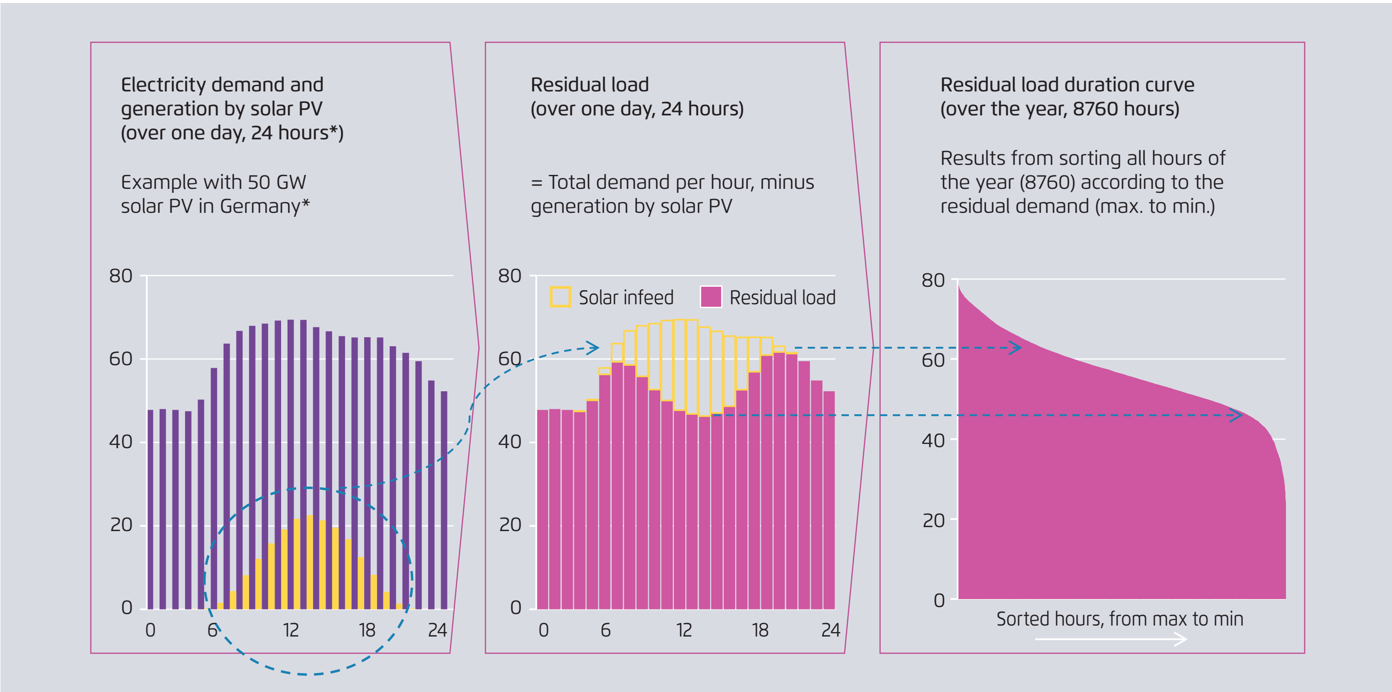
5.2.1.2 Limitations to analysis based on residual load duration curves

While the concept of residual load duration curves is very helpful for illustrating certain effects, there are two key limitations to its use in power system analysis, which are discussed in this subsection: It tends to neglect structural change to patterns in electricity demand and is unable to capture interdependencies between interconnected markets. Due to these limitations, long term system analysis aimed at supporting political decision-making should be based instead on a bottom-up simulation of electricity demand (see section 6). For illustrative purposes, the concept will nevertheless be used in the following.

Residual load and changes in electricity demand patterns

In real power systems, electricity demand interacts with electricity generation, via the market price signal, both in the short term (operation decisions) and the long term (investment decisions). For example, a pumped hydro power plant will use electricity for pumping in times of low prices, and provide electricity to the system in times of high prices. If

Explaining the residual load duration curve (Part 1): adding solar PV to a power system — Figure 25



* Example Germany, Monday in July with ~50 GW PV (~8% of electricity demand)

investors foresee structural price spreads between market prices at night and during the day, new pumped hydro power systems may be built. Another example is electric heating: when electricity prices are low, people may prefer electric heating over oil- or gas-based heating, leading to an increase in electricity demand. If prices are low at night only, people may prefer specific electric heating appliances that consume electricity at night only.[24] Depending on the design of the market, the market price for electricity at different times of the day may differ according to the technologies used. In north-western Europe, the construction of lignite and nuclear power plants has led to very low electricity prices at night, when demand for electricity tends to be lower.

An analysis that is based on a historic pattern of electricity demand neglects such interaction effects between electricity demand and generation. A look at a residual load duration curve in the case of 150 GW of solar PV in Germany (in next subsection, assuming this would be reached in 2030) illustrates the challenges involved. Quite irrespective of how the rest of the power system and market design are constructed, it seems quite safe to assume that the price of electricity would be very low between 11 a.m. and 2 p.m. during every day in the summer, with strong indications this will remain the same in 2031, 2032, etc. In view of such a perspective, industrial, commercial and private consumers of electricity may identify ways to profit from this structural change in electricity prices. Thus, analyzing future power systems that exhibit a high penetration of wind and PV based on historical load curves is problematic, and requires further assessment.

Residual load and interconnection

In reality, European markets are interdependent through electricity grids and market coupling. The load duration curve of one single country is thus not relevant for the power plants located in this country, as load may be served as well by power plants located in a neighboring country. Furthermore, power plants may produce electricity to serve the load in another country, provided that sufficient interconnection is available. When analyzing impacts on the residual load duration curve of one country, it is important to be aware that such impacts may be overshadowed by other effects that are occurring in foreign power systems.

Further limitations to the residual load approach

A further limitation to residual load duration curve is that it neglects the need for power system flexibility within a given timespan (e.g. 15 minutes or 4 hours). A yearly load duration curve provides no insight into how much flexibility is needed within such time intervals.[25]

5.2.1.3 Adding new power plants and its effects on residual load

Adding new generation capacity to the power system affects the residual load curve. While this applies to the addition of wind and solar PV as well as new baseload (nuclear or lignite), significant differences may appear, which are illustrated in Figure 26 and 27.

Figure 26 illustrates the effect of adding a large amount of solar PV into the German power system (150 GW installed capacity, equivalent to ~25 percent of electricity demand, and about three times more than the maximum foreseen by current long-term scenarios). Figure 27 illustrates the effect of adding the same amount of electricity (over the entire year) produced by a new base load power plant.

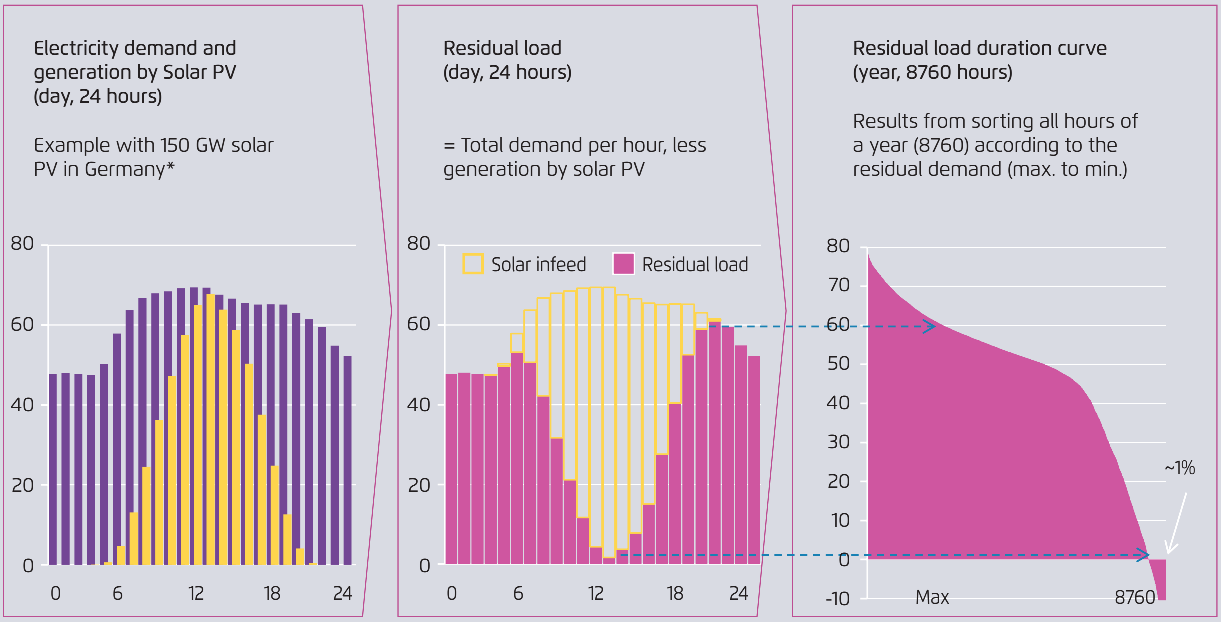
In the case of adding solar PV, the residual load during the depicted Monday of July would reach its daily minimum during day time at close to 0 GW (assuming that the demand does not react to the new type of supply). The maximum residual load occurs in the evening hours at around 60 GW. The "market" for the existing power plants would therefore be significantly reduced during daytime hours, but would remain unchanged during night time hours. A closer look at the residual load duration curve (right hand side of Fig-

24 Depending on the regulatory environment, different consumer groups may have different incentives to adjust their electricity consumption patterns. While the market price for electricity may contribute only some 10–20 percent to the total price of electricity paid by household customers, it may represent 80–90 percent of the total price paid by large industrial customers.

25 Fraunhofer IWES (2015) provides an analysis of such requirements and effects in the area of France, Germany, Benelux, Austria, and Switzerland.

Explaining the residual load duration curve (Part 2): adding significant solar PV to a system

Figure 26



* Example Germany, Monday in July with ~150 GW solar PV, assuming non-optimized solar PV plant design based on real infeed data 2014 by EEX (~25% of electricity demand).

ure 26) reveals that in such a scenario, residual load would be negative during several hundred hours within the year, leading to curtailment of approximately 1 percent of electricity produced by solar PV (unless a structural change in the demand pattern is realized by the time 150 GW of solar PV are installed). The highest residual load within the year would continue to be around 80 GW.

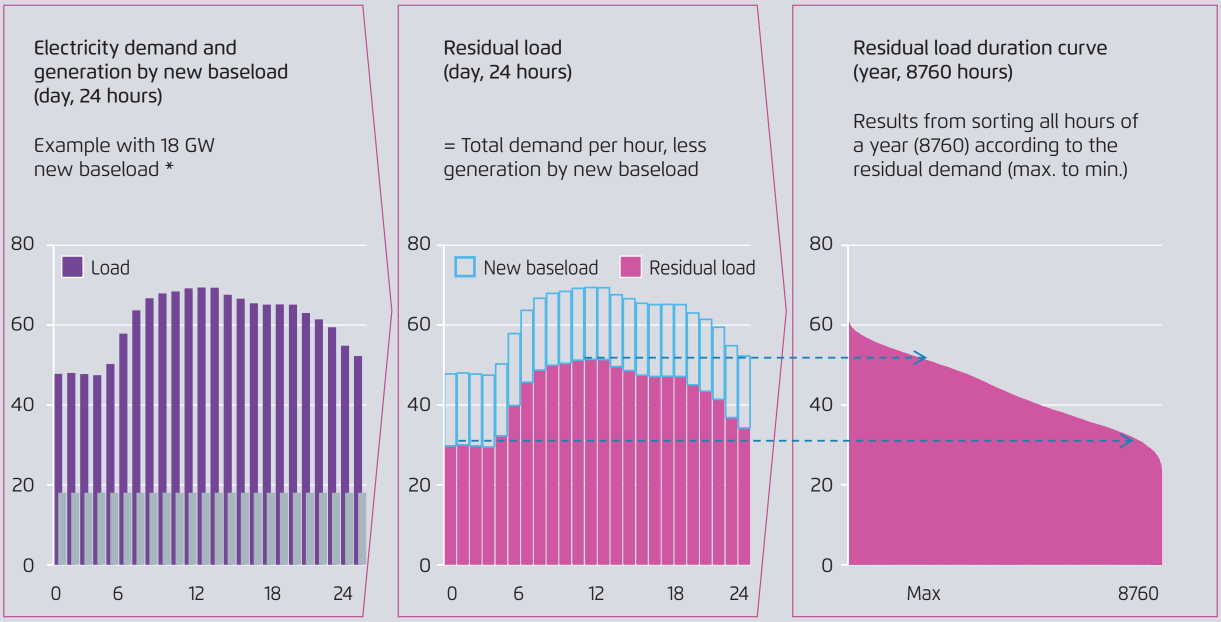
When adding a similar amount of electricity from new base load power plants to the power system (see Figure 27), the variations in residual load follow quite exactly the variations in load, assuming constant power production by the new base load plant. The remaining "market" for the existing power plants is thus reduced by a constant ~20 GW within each hour. In contrast to the case of adding a significant amount of solar PV, daily variation in residual load is lower (varying only between 30 and 50 GW during the Monday depicted here). The residual load duration curve over the entire year (on the right hand side of Figure 27) features a lower maximum (~ 60 GW) and does not have negative values, even in the hours with the lowest residual load.

5.2.1.4 Adding wind & solar vs. new base load

To compare the different effects of adding a mix of new wind and solar PV vs. new base load power plants in more detail, Figure 28 illustrates key impacts to the daily load and residual load duration curves. These curves repeat the examples given above (figures 26 and 27), although instead of a high penetration of solar PV only a mix of variable renewable energy is depicted,[26] and a different graphic representation is used.

26 All further analysis presented in this section are based on a detailed simulation of the feed-in of variable renewable energy in Germany for the year 2030, using real weather data from 2011. These data are available for each hour of the year within the Excel tool accompanying this publication and is further described in Fraunhofer IWES (2015). Because the simulations include certain shares of inflexible run-of-river hydro as well as inflexible shares of power generation by biomass, the terminology "variable renewable energy" would be more accurate than "wind and solar PV" – the latter of which is used in the following, as wind and solar PV represent over 85 percent of variable renewable energy in Germany.

Explaining the residual load duration curve (Part 3): adding new baseload to a system — Figure 27



* Assuming 18 GW new baseload power plants, with equivalent power production of 150 GW non-optimized solar PV in Germany

In the case of adding new base load power (lower graphs in figure 28), residual load is reduced constantly, leading to a parallel downward shift in both the daily residual load as well as the yearly residual load duration curves. In the case of new wind and solar PV capacity (upper graphs in figure 28), load is reduced only in the hours when either the sun is shining or the wind is blowing. As this is not necessarily the case in the hour of the highest demand, the highest residual load within the year may be the same as the highest load before adding wind and solar PV. Due to the occurrence of periods with large amounts of wind power or sunshine (as illustrated in the extreme case for solar PV above), the amount of hours with very low, or even negative, residual load may increase. The shape of the residual load duration is not only shifted downward, but also pivots clockwise, compared to the parallel downward shift in the case of new base load power.

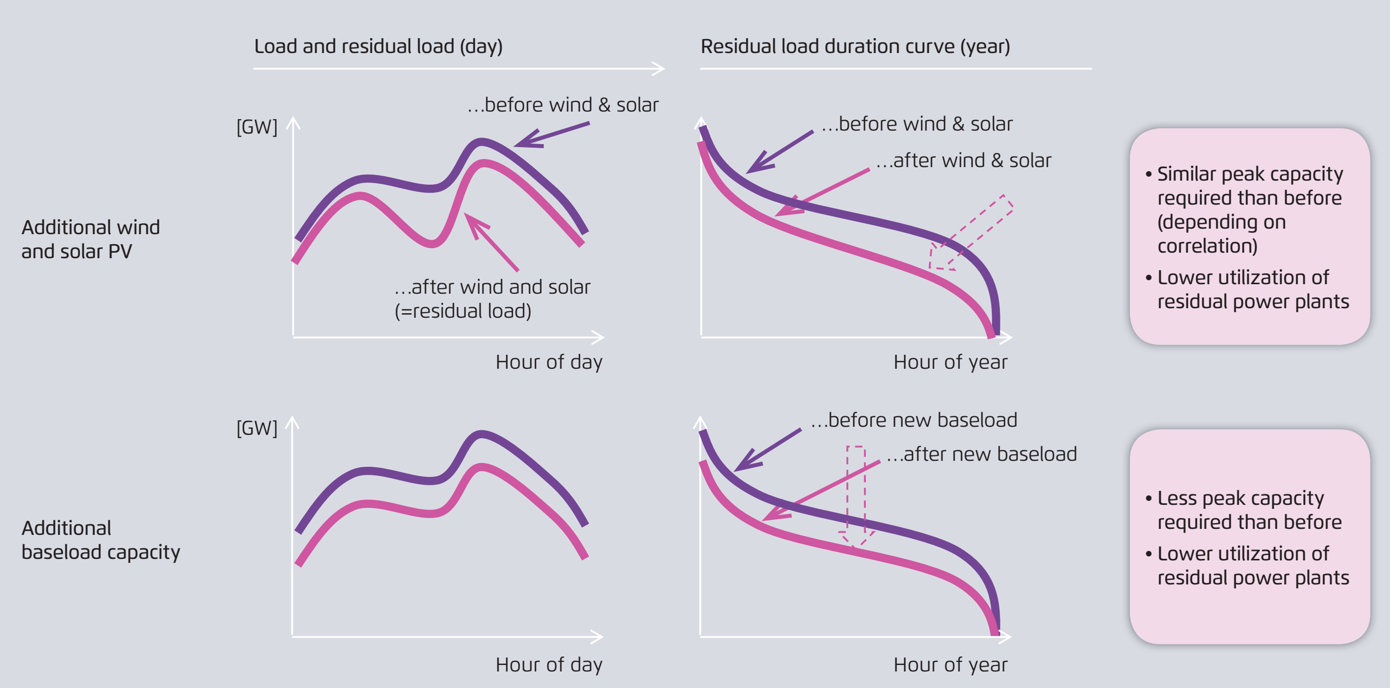
Considering the effects on an existing power plant fleet, the key similarity is that the utilization of the other power plants is reduced in both cases. A first difference is the lower need for peak capacity in the case of new base load generation, compared to the case of new wind and solar PV[27] (the highest residual demand on the left side of the curve is lower). A second difference is the disproportionally large reduction in base load demand (the area covered by the residual load curve on the right side is reduced more than on the left side), leading to a shift from base load power demand toward more mid-merit and peak power demand. The cost effects of these two differences will be discussed in detail in section 5.3.

5.2.2 Key sensitivities in the system analyzed

The effort to quantify integration costs should begin with an analysis of technical effects, which depend largely on the specific power system that is being considered. The following presents the most important factors influencing such a technical analysis. While many parameters directly depend on the specific case analyzed – and thus are likely to be less

27 Adding wind and solar PV may as well reduce the peak capacity requirement, albeit typically not to the same degree.

Effect of adding wind and solar PV or base load capacities to a power system — Figure 28



Own illustration

controversial – other parameters may largely depending on assumptions about the future – and may thus be more controversial, especially if they concern a distant future.

5.2.2.1 The effects of increasing penetration levels

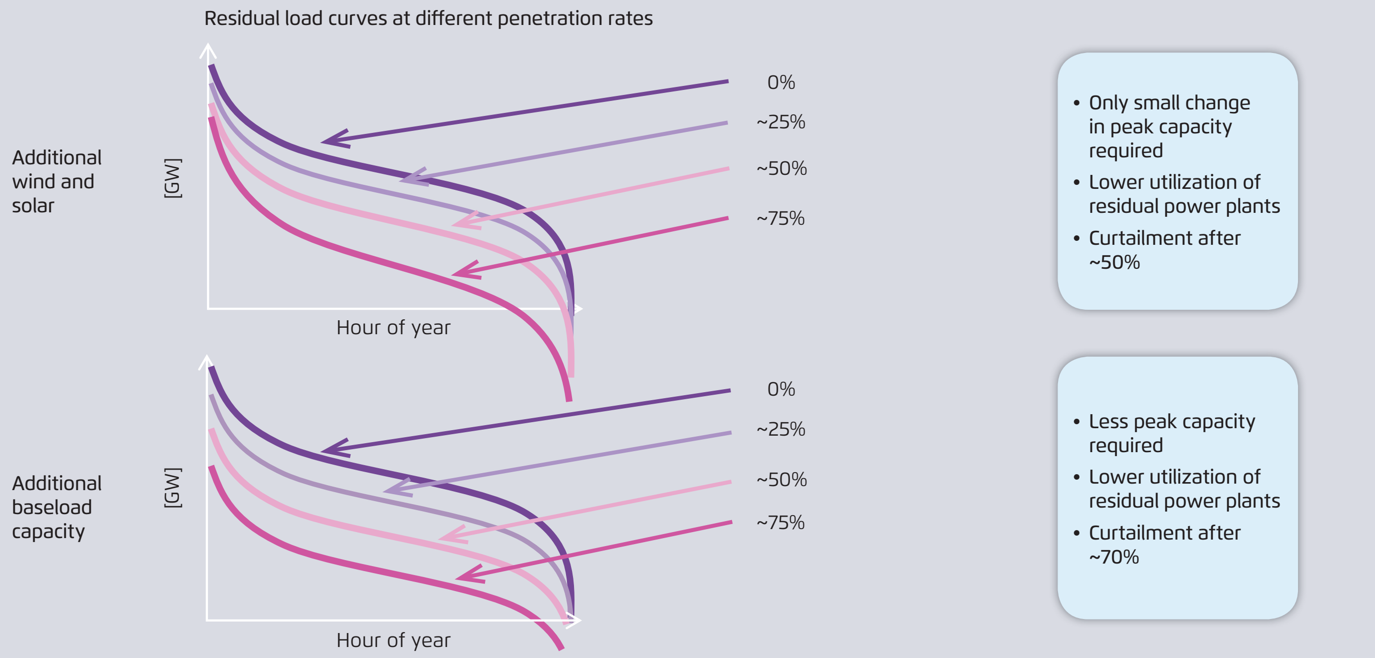
At higher renewable penetration levels, the residual load effects of adding wind and solar PV versus adding new base load power plants become increasingly divergent. Figure 29 illustrates the impact of adding an increasing amount of new electricity to an existing power system. The graphs depict typical effects on a northern European power system when new capacities that produce 25 percent, 50 percent or 75 percent of total electricity demand are added either as wind and solar PV (upper graph) or as new base load power plants (lower graph). This illustration of effects assumes that electricity demand patterns remain unchanged over the time the new capacity is added and ignores the existence of other potentially inflexible generation.

The left end of the upper graph illustrates that even very high levels of wind and solar do not reduce the peak load significantly, at least not in the case of a northern European power system. The right end of the graph illustrates the occurrence of renewables curtailment (i.e. residual load becomes negative in some hours of the year), which starts to be relevant at penetration levels around 50 percent of wind and solar PV and becomes significant at penetration levels of 75 percent.

The left end of the lower graph illustrates how the highest residual load is continuously reduced in the case of an increasing share of new base load capacity. Similar to the case of adding wind and solar PV, curtailment of new base load capacity appears at high penetration rates.[28] Yet because the residual load is reduced constantly (parallel shift downward

28 The understanding of curtailment used here is that of a potential power production that exceeds the demand in a given hour. While this is sometimes applied only to the case of new wind and solar power plants, it may be equally applied to new lignite or nuclear power plants, for which the greatest share of costs accrue during power plant construction (investment costs), irrespective of their use.

Effects on residual load of increasing penetration of wind & solar vs. new baseload — Figure 29



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instead of pivoting clockwise in the case of wind and solar), curtailment appears only at much higher penetration levels and to a lesser extent.

Figure 30 provides a closer look at the differences of adding wind and solar PV versus new base load power in Germany, based on data from Fraunhofer IWES (2015) and assuming no adaptation of power demand patterns. At 25 percent penetration, the differences between the two cases are rather small. At a 50 percent penetration rate, the difference becomes apparent within the extreme hours – with higher maximum residual load and lower minimum residual load when wind and solar PV are added. In a real power system with 50 percent wind and PV, this would require more peak power capacity or demand side flexibility for the hours of high residual load, as well as flexibility options to avoid curtailment (or the acceptance of such).

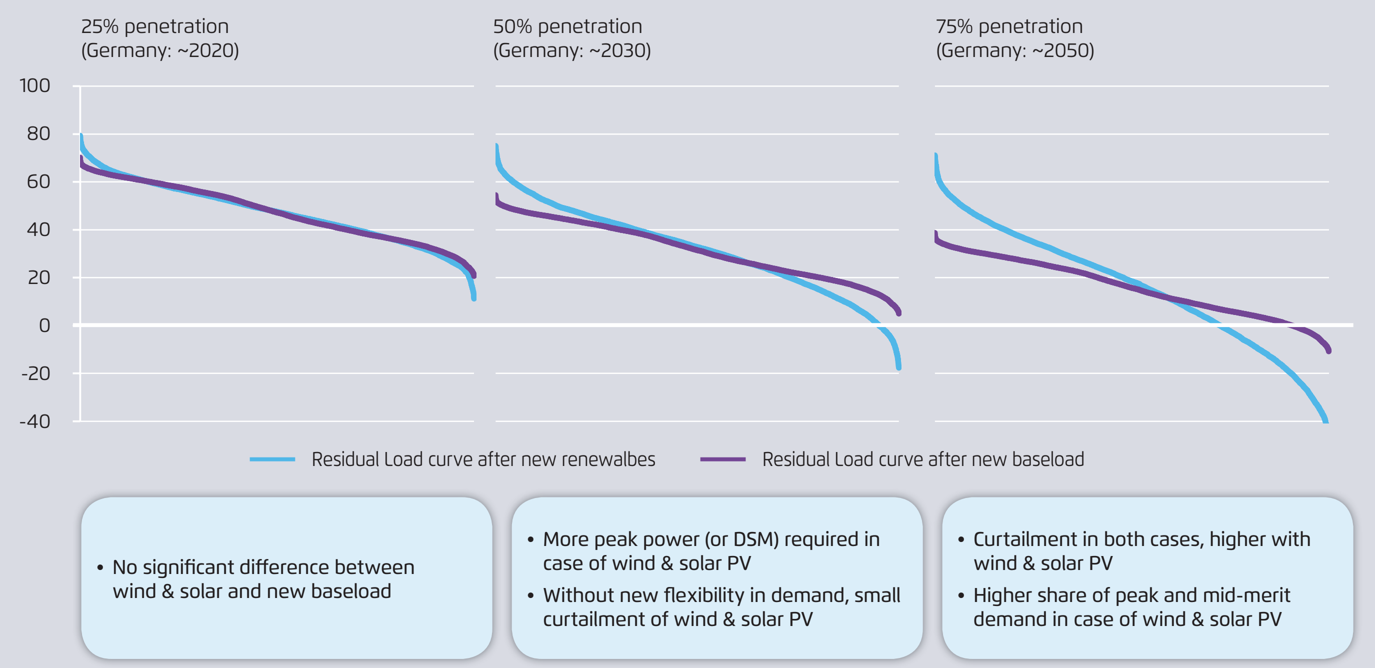
Significant differences appear at a 75 percent penetration rate. From a long term perspective, this difference would likely result in a significantly different cost-optimal mix of power plants – i.e. more peak and mid-merit power plants in the case of wind and solar – as well as more difficulty in avoiding (or accepting) curtailment.

5.2.3 Correlation of wind & solar with load

Power production from wind and solar PV is unlikely to ever perfectly match the changes in consumer electricity demand. Thus, while demand-driven production of wind and solar PV can be ruled-out, it is possible to conceive a certain level of a correlation between variable renewables production and demand. Countries with a hot climate and a high share of electricity demand for cooling (e.g. air conditioning of buildings) are a prime example of how electricity peak demand and production by solar PV can be correlated. Similar correlations may occur in countries with higher demand for electrical-based heating on cold and windy days.

Figure 31 illustrates the effect that such a correlation on the residual load duration curve (upper graph). In contrast to the worst-case example (lower graph), the maximum residual load is reduced in that case. In a real power system, less peak

Effects of wind & solar vs. new baseload power generation on the residual load duration curve in Germany Figure 30



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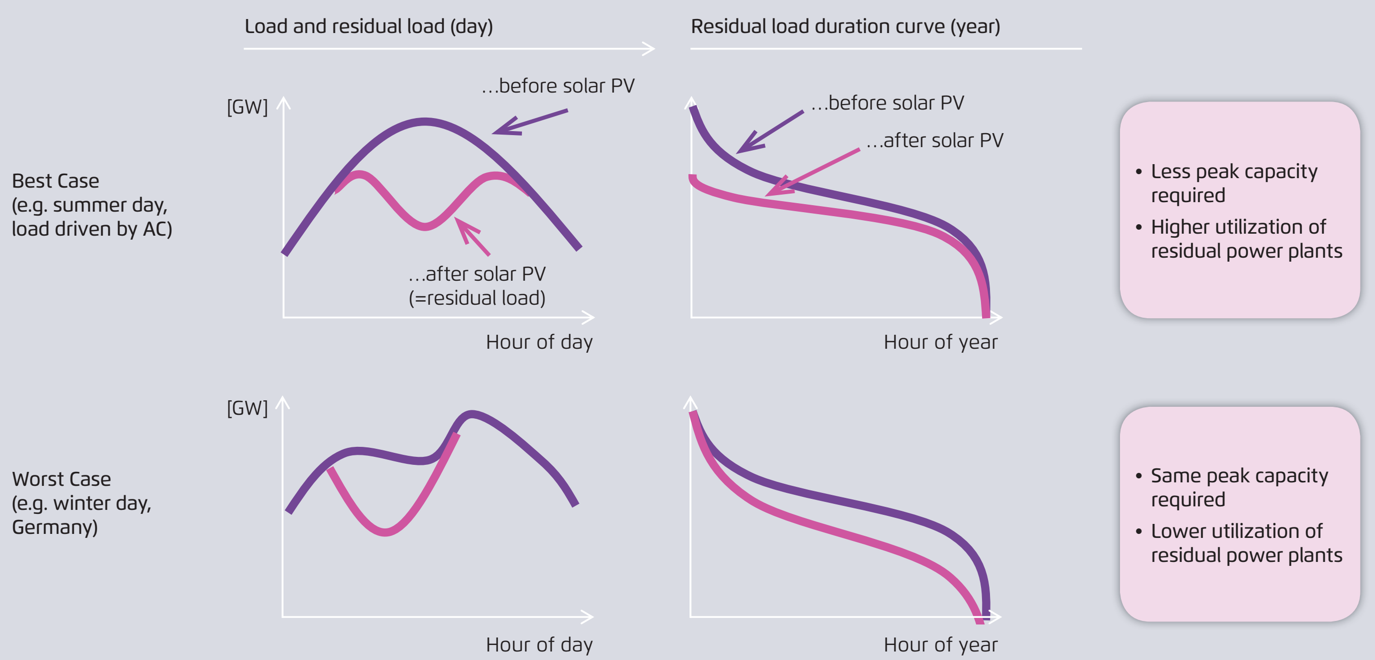
Effects of correlation between wind & solar power generation and electricity demand Figure 31



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capacity would be required and the average utilization of the other power plants may increase instead of decrease. Negative residual load (or curtailment) might in such a case not appear until extremely high penetration levels.

5.2.4 The effects of a mixture of wind & solar

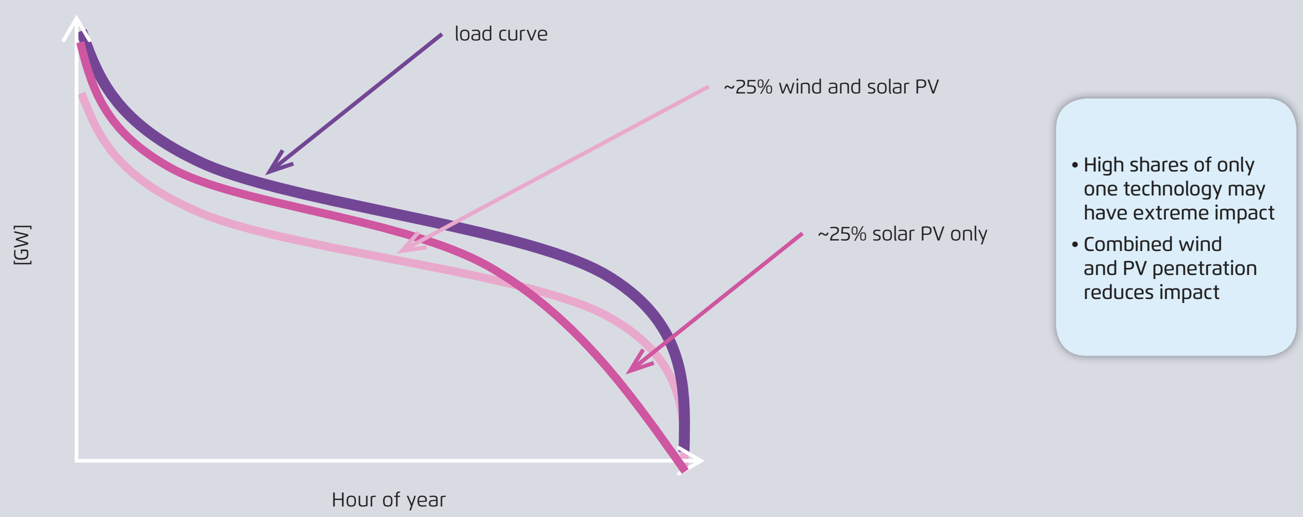
Power production by wind and solar PV depends on the amount of wind blowing and the intensity of sunshine within a given hour. While interactions between these two phenomena certainly exist, the two phenomena are not perfectly correlated with each other. In central Europe, solar generation and wind generation are roughly uncorrelated. Therefore a mix of power produced by wind and solar PV will always provide a more balanced feed-in than a mix consisting of one technology only.

Figure 32 illustrates the effect on the residual load duration curve when a 25 percent share of solar PV is added, in contrast to the effect of adding a mixture of both wind and solar PV producing an equivalent amount of electricity. Most striking is the difference on the right side of the graph, during the hours with the lowest residual load. When adding only solar PV, significantly more hours occur in which the residual load is very low or even negative. The obvious reason is that the 25 percent solar PV share is only produced during sunny hours – while the 25 percent mix share is produced during hours with sunshine and/or wind, and is thus more evenly distributed.

5.2.4.1 Supplemental discussion: The cost-optimal mix of wind and solar

When discussing the cost optimal mix of renewable energy technologies, the effect on the residual load duration curve is often considered a key factor. Such a comparison of indirect effects may certainly be relevant when considering long-term technology mixes (e.g. if a 100 percent renewable system consists of 75 percent wind or 75 percent solar) and even more so in small island systems. However, analysis of a large system within interconnected markets, such as Germany's power system, may find that such effects are not relevant for lower penetration shares (say, 30 percent wind and solar), as differences in the levelized cost of electric-

Residual load curves with different technological mixes Figure 32



Own illustration

ity between renewable energy technologies may be far more relevant than the indirect effects driven by changes in the residual load duration curve (see Consentec 2013).

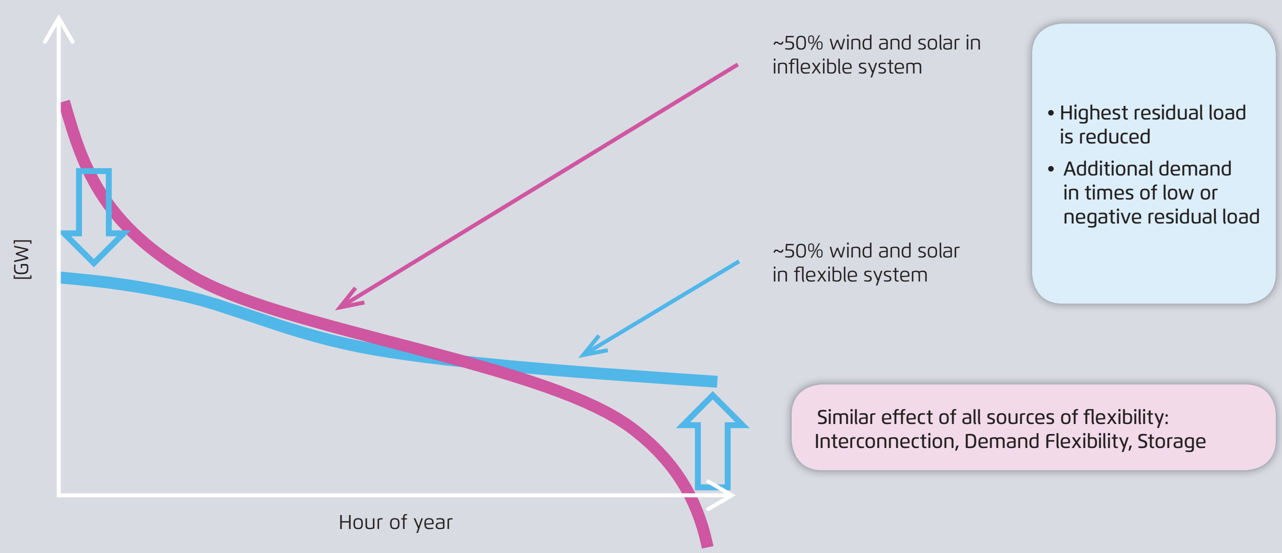
5.2.5 The effect of flexibility options

Demand for electricity largely depends on consumer behavior (e.g. household, commercial, and industrial electricity demand patterns). In order to reduce the cost of providing electricity to meet this demand, a number of measures have been introduced in recent decades as a supplement to the construction of new power plants. Pumped hydro storage capacities have been built; power systems within and between countries have been connected; and incentives have been provided to electricity customers to shift their consumption patterns from peak hours to off-peak hours. Such measures are today often called flexibility options.

Figure 33 illustrates the effect of such flexibility options on the residual load duration curve. Residual load is reduced during times of high residual load, reducing the need for peak capacity (and saving costs that would other arise for alternative options to serve peak demand, such as gas turbines). At the same time, residual load is increased during times of low residual load, allowing for higher utilization of power plants with the lowest (marginal) costs. Storage systems are probably the most well-known and straight-forward flexibility option, and include pumped hydro storage, small scale lithium-ion batteries and power-to-gas. Additional interconnector capacity (e.g. connecting Germany and Norway) and additional demand side flexibility (e.g. a steel factory using electric arc welding at times of low electricity prices) have very similar effects.

As described above, changes in the load duration curve occur when adding new wind and solar PV capacity compared to adding new base load capacity. In both cases, additional flexibility helps to integrate especially higher penetration rates and to reduce the cost of serving the demand for electricity. An optimal mix of flexibility options will largely depend on the load pattern as well as the feed-in pattern of the respective technology (i.e. wind/solar PV, or base load)

Effects of flexibility on residual load duration curve — Figure 33



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as well as the respective cost to build and operate flexibility options.

5.2.6 The effects of electrification

It is expected that long term ambitions to reduce carbon dioxide emissions in Europe (and many other parts of the world), as well as efforts to reduce import dependencies will lead to a fuel shift in many parts of the energy system, carbon-free technologies such as wind, solar PV and nuclear increasingly replacing fossil fuels. Probably the most relevant examples are electric vehicles (which represent a switch from gasoline to electricity) and new heating applications (that use heat pumps instead of natural gas). Long-term visions include the production of fuels and chemicals via power-to-gas and other applications.

Figure 34 illustrates the effects that such a fuel shift towards electrification has on the residual load duration curve. This figure assumes that the new applications enter as flexible consumers of electricity. The peak demand is therefore not increased, but rather the demand increases in times of low residual load when sufficient wind and solar PV (or new base load power) are available. How new electricity customers will consume electricity in reality is certainly difficult to predict and will depend largely on how regulations and the markets are designed.

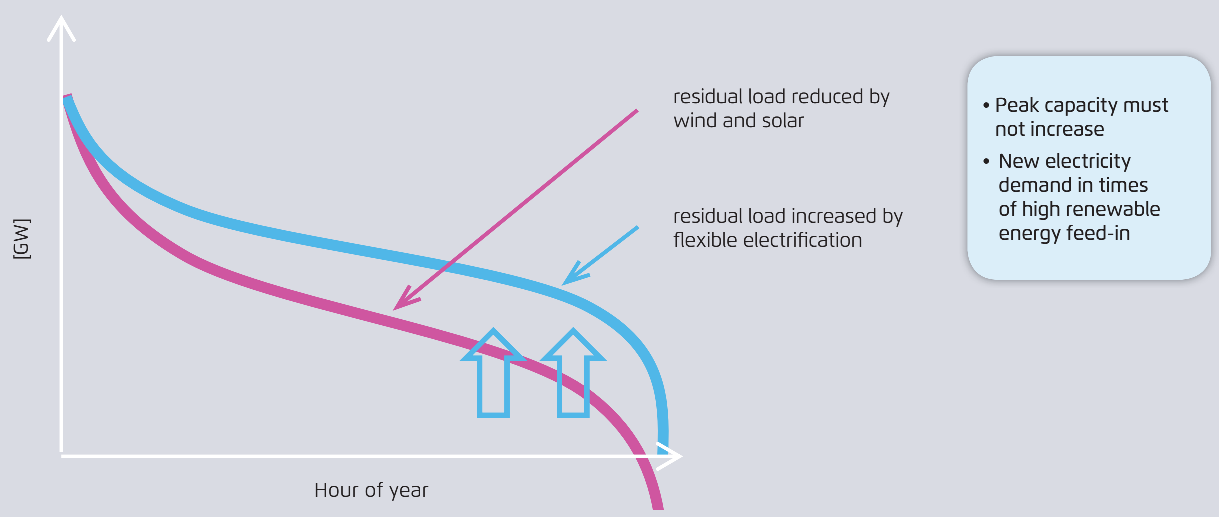
5.3 Economic analysis of the effects on existing power plant utilization

The previous subsection focused on the technical impacts that variable renewables have on other power plants in the system. This second part will focus on the economic assessment of these effects.

5.3.1 Introduction to analyzing the cost of reduced power plant utilization

Figure 35 provides an overview of the differences between adding wind and solar or new base load capacity into a power system. It illustrates the key resulting cost drivers in the residual generation, as well as two possible approaches to quantify the effects on integration costs.

Effects of flexible electrification on residual load — Figure 34



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The type of capacity added leads to two types of divergent impacts on the residual load duration curve. First, when wind and solar PV capacity are added, more total dispatchable capacity is required than when new base load is added. Secondly, when wind and solar PV capacity are added, larger shifts in residual load away from base load to mid-merit and peak load are experienced.

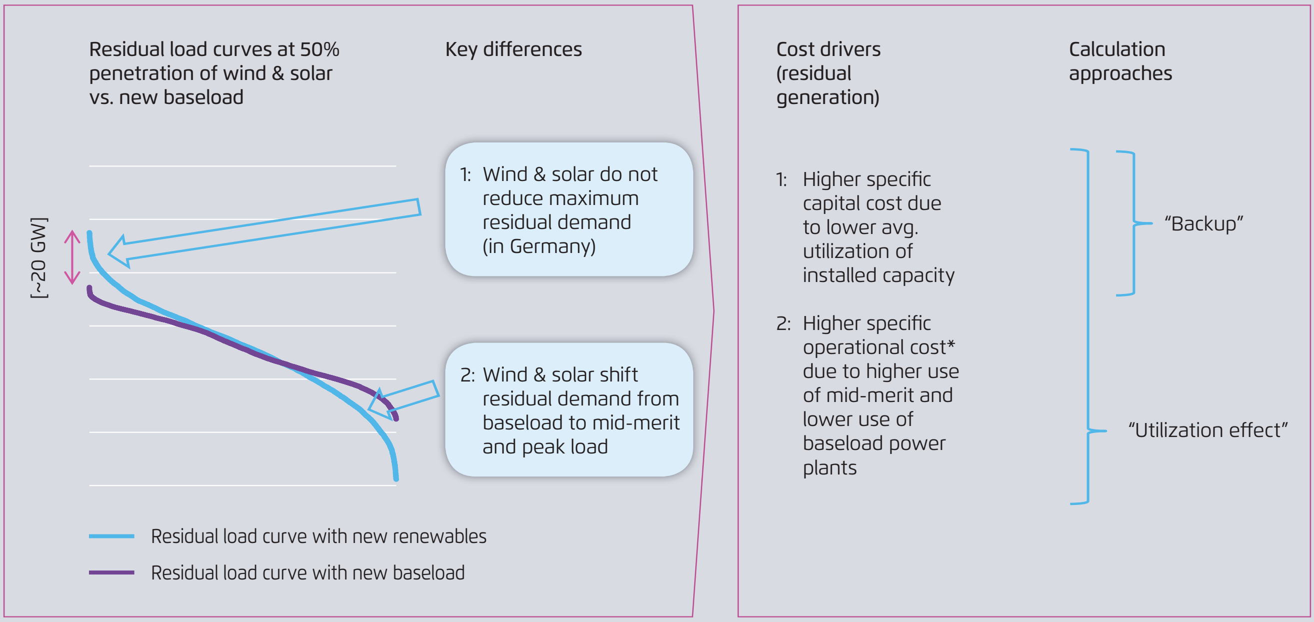
These differences have a twofold effect on the costs of providing residual load. First, there is a larger need for residual power plant capacity when more solar and PV are added. (In the example of Figure 35, 50 percent variable renewables require about 20 GW more residual capacity than if 50 percent new baseload would be added). As a consequence, higher specific capital costs occur for the residual generation, due to lower average utilization of installed capacities. Second, with a higher share of power produced by mid-merit and peak power plants there is a reduction in the contribution made by base load power plants. This leads to an increase in specific generation costs (EUR/MWh) whenever these generation costs are higher for mid-merit and peak power plants than those of base load power plants.

An intuitive approach for quantifying the costs of the first effect can be called the "backup" approach. Such an approach aims solely to identify the additional capacity (and its costs) required when wind and solar PV are added in comparison to the addition of new base load capacity. However, this approach neglects the cost effects involved in the different utilization of such "backup" power plants and is thus not appropriate for the quantification. Nevertheless, for the purpose of illustration, such a calculation will be presented in section 5.3.2.

In order to capture the effect on both the amount of capacity required as well as changes in the utilization of this capacity, a different approach is needed. Such an approach can be called the "utilization effect" approach and is presented in section 5.3.3. While this method aims to improve the comparative assessment of different technologies, it has been

Key differences, cost drivers and calculation approaches for analysing cost effects on residual power generation

Figure 35



Own illustration

* inclu. fuel costs and external costs

questioned by several stakeholders and led to controversial debates.

5.3.2 An approach NOT to follow: Calculating backup costs

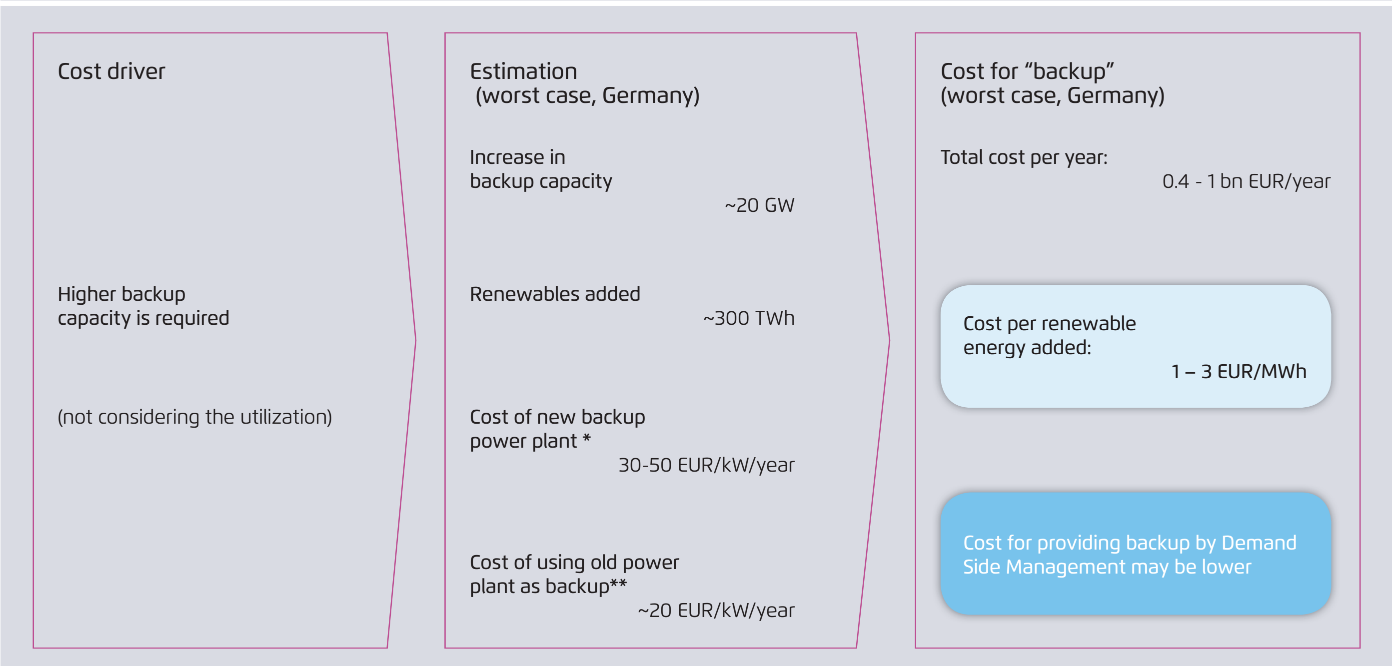
As explained above, quantifying the effects of additional backup requirements needed due to the addition of wind and solar PV capacity (as compared to the addition of new base load capacity) may appear intuitive, but is not an appropriate way to capture the relevant cost effects. Such a calculation is nevertheless presented here, for the purpose of illustration.

As an example, it is assumed that the addition of 300 TWh of wind and solar PV in Germany (~50 percent of electricity demand) requires 20 GW more backup capacity, as compared to an alternative addition (300 TWh) of new base load capacity[29]. Assuming that this backup would be provided by new open cycle gas turbines (OCGT) at a cost of 300 to 500 EUR/kW, this would result in cost of 0.6 to 1 billion EUR per year, or approximately 2 EUR/MWh of electricity produced by wind and solar PV. Assuming that the backup capacity required would be provided by old combined cycle gas turbines (or old hard coal power plants), for which investment cost would not be paid but only the cost to keep the power plants available to the system, the cost would be 0.4 bn EUR per year, or approximately 1 EUR/MWh of wind and solar PV added. Depending on assumptions related to technologies and markets, the results may be higher (e.g. assuming that cost for OCGT are higher or CCGTs would be used) or lower (e.g. assuming that demand-side management would compete at a lower cost).

While these numbers are only illustrative, they help to emphasize that quantifying the cost of "backup" alone, without considering the utilization of the entire power plant fleet, is misleading and does not capture key points of dispute with a view to "integration costs." As shown by this calculation, the "backup" costs – i.e. costs necessary for keeping suffi-

29 Realistic approximation based on calculation performed on data from Fraunhofer IWES (2015). (See also section 5.2.2).

Calculating back-up costs - an approach not to follow — Figure 36



*Assuming investment cost of 300 – 500 EUR/kW and fixed operating expenses of 2% per year for Open Cycle Gas Turbine
**Assuming depreciated Combined Cycle Power Plant with operating cost of 20 EUR/kW per year

cient capacity within the system in order to ensure its adequacy – are not significant per se, but the costs associated to the reduced utilization of the existing assets may be larger. This will be discussed in the next section.

5.3.3 An approach for quantifying the "utilization effect"

A possible approach for quantifying the effects that the addition of new capacity will have on the remaining power plants may be called "utilization effect" approach. While this method aims to improve the comparative assessment of different technologies, it has been questioned by several stakeholders and led to controversial debates. We discuss this approach in the following.

The approach is based on the methodology introduced in section 2.4 and requires calculation of the residual generation cost in two scenarios: (1) a scenario without the addition of the new capacity and (2) a scenario in which new capacity is added (which may be either new wind and solar or new base load). The specific residual generation costs in the first scenario (EUR/MWh) are multiplied by the residual generation (TWh) in the second scenario. This value represents the costs (€ bn) of the residual electricity in the second scenario if the specific cost of electricity would be delivered by the generation mix of the first scenario. This result is then subtracted from the real cost of providing electricity in the second scenario. The difference is divided by the amount of new generation added in the system (either wind and solar, or base load). This value is the specific cost of the "utilization effect" per unit of wind and solar (see numerical example on figure 11, section 2.4).

The remainder of this section is dedicated to describing the results obtained by applying this approach to quantifying the integration costs experienced in different power systems under various assumptions and perspectives. The objective of this discussion is to contribute to a better understanding of why some calculations of this integration cost component yield very high results while other yield very low – or even negative – results, even when analyzing the same system and situation.

The two key cost drivers and challenges in quantification will be discussed in detail in two separate quantitative subsections.[30] The first subsection will focus on the role of capital costs as a driver of higher integration costs. This will be based on a highly simplified thought experiment with a single- and a two- technology system (5.3.4).

The second section (5.3.5) will focus on how the shift from base load to mid-merit and peak generation operates as a cost driver. This discussion is based on a more elaborate three-technology system. The two quantitative discussions are enhanced by a qualitative discussion of different ways of accounting for changes in the power system, which are challenging to capture with the concept of residual load duration curves.

5.3.4 Quantifying the effects of lower utilization of capital invested in other power plants

5.3.4.1 Calculations for a one-technology system

Calculating integration costs in a one-technology system, while obviously unrealistic, is relatively easy and may be sufficient for illustrating essential aspects of the integration cost debate. The approach described above is used, assuming that the entire residual load would be provided by only one type of technology (only lignite, nuclear or gas power plants). Calculations are performed on the basis of the historic load data and a simulation of the production of wind and solar power plants in Germany, both of which are described in detail in Fraunhofer IWES (2015). We assume a cumulative penetration level of up to 50 percent and for illustrative purposes compare it to a 0 percent wind and solar scenario.

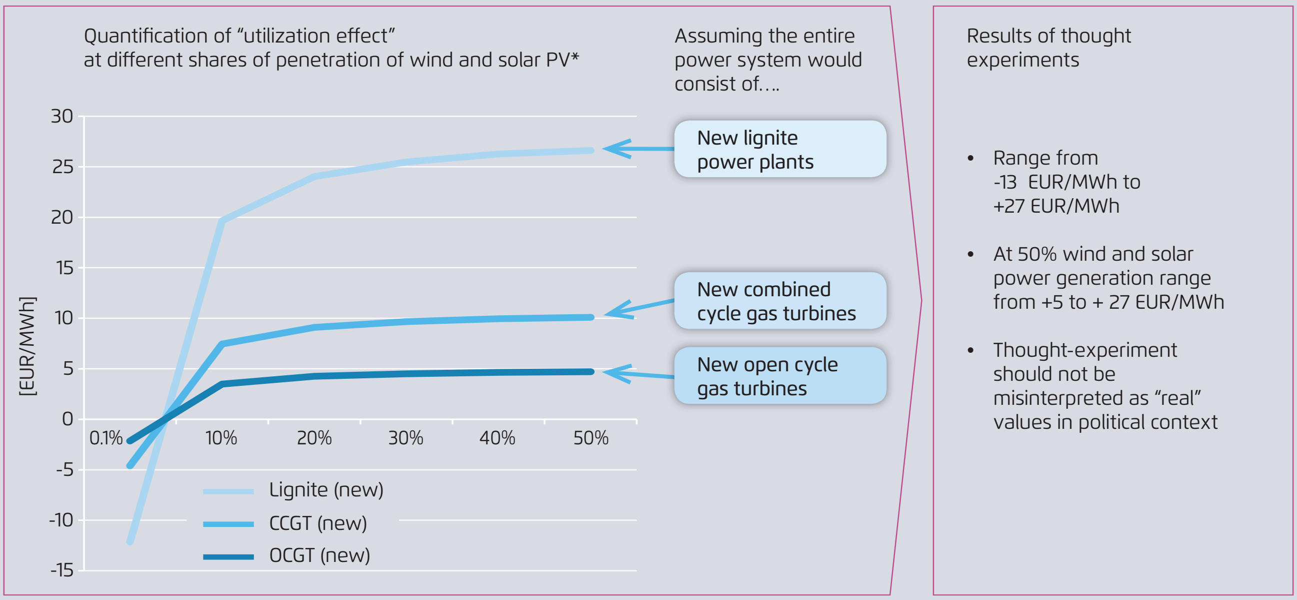
30 The analysis performed above is based on an Excel tool that can be sent to the reader upon request (write an email to info@agora-energiewende.de). This tool enables thought experiments for different one-, two-or three- technology systems, based on simulations for variable renewable energy generation and load in Germany, France, and the Pentalateral region (Germany, France, Benelux, UK, Austria and Switzerland). In an expert mode, all assumptions concerning technology and fuel costs can be can modified.

Figure 37 illustrates the results of the calculations, depending on the technology assumed to serve the residual load and the penetration rate of wind and solar power. The results show the large differences on the "utilization effect" depending on the thermal power plant that are assumed in this theoretical one-technology residual system. The highest resulting value is achieved by assuming that the entire system would consist of new lignite power plants (fully considering the annuity cost of the initial investment), with calculations of the "utilization effect" ranging up to 27 EUR/MWh per unit of wind and solar PV added. When assuming that the entire system would consist only of new gas fired CCGT power plants, the quantification of the utilization effect in the same system would result in significantly lower values of up to 10 EUR/MWh, assuming a system of only new OCGT power plants in values up to 5 EUR/MWh. A quantification of the resulting value in the case of a system consisting only of nuclear power plants was not performed, as appropriate figures for estimating the investment costs of nuclear power plants were not available. Because the cost structure is comparable to those of lignite power plants (high initial investment cost and low operational cost), it may be expected that such calculations would yield similar results to those that use lignite power plants as a basis.

The large difference in results is driven by differing capital costs for the power plants needed to serve the residual load. Assuming a technology with a high initial investment cost (e.g. lignite with a fixed cost of approx. 200 EUR/kW/year) will lead to significantly higher results than assuming a technology with very low investment cost (e.g. OCGT with a fixed cost of approx. 40 EUR/kW/year).

At very low penetration levels, integration cost calculations yield negative values. This is driven by the phenomenon that some wind and solar power plants generate during the times of peak demand, thus reducing the remaining power plant capacity required. Depending on the assumed capital costs of the other power plants in the system, this may lead to rather large savings of approx. -12 EUR/MWh when lignite power plant utilization is avoided, or to rather low savings of approx. -5 EUR/MWh when the utilization of open

Cost of interaction between variable renewables and the residual power plants ("utilization effects") - depending on technolgy (in a one-technology system thought experiment) Figure 37



Own illustration

*Example Germany, adding up to 50% of wind and solar PV cycle gas turbines is avoided.[31] While this effect is rather insignificant in northern European power systems, this may not be true of systems in which a significant correlation exists between renewable energy production and electricity demand (e.g. in systems with significant solar power capacity and A/C demand), as discussed in section 5.1.

5.3.4.2 Calculations based on a two-technology system

In reality, a power system is unlikely to be composed solely of base load power plants (lignite or nuclear, being used as well to provide peak power) or peak-load power plants (e.g. OCGT being used as well to provide base load power). We therefore extend our "thought experiment" to a two-technology system, in order to illustrate the impact it has on the quantification of the "utilization effect." We assume that the second technology is an open cycle gas turbines, representing a typical peak load capacity that can be added in any power system within a short time. Based on a rough estimation of the controlable capacity available to cover peak load in the German power system, 30 GW of such power plants are assumed.

Figure 38 presents the results of the calculations, depending on the combination of technologies assumed and the penetration rate of wind and solar. For comparison, the results of the prior thought experiment are included in the graph, representing the cases of a one-technology system consisting either of lignite (upper blue line) or of gas fired CCGT (upper pink line). Assuming that a peak power technology is available (for example, 30 GW of gas fired OCGT), the results of the quantification of the "utilization effect" are reduced by approx. 50 percent both in the case of lignite (lower blue line) and in the case of CCGT (lower pink line), in comparison to the one-technology model. At 50 percent wind and solar PV penetration, the quantified "utilization effect" falls from 27 EUR/MWh to 12 EUR/MWh in the case of lignite as a base load technology, and from 10 EUR/MWh to 5 EUR/MWh in the case of gas fired CCGT as a base load technology.

The difference between the one- and two-technology systems is driven by the phenomenon that with increasing penetration rates of wind and solar the highest peaks in residual demand occur only during very few hours a year (see section 5.2). While the one-technology model assumes that lignite or CCGT power plant would, unrealistically, cover even these extreme peaks, the two-technology system assumes that these peaks would be more cost efficiently covered by open cycle gas turbines.

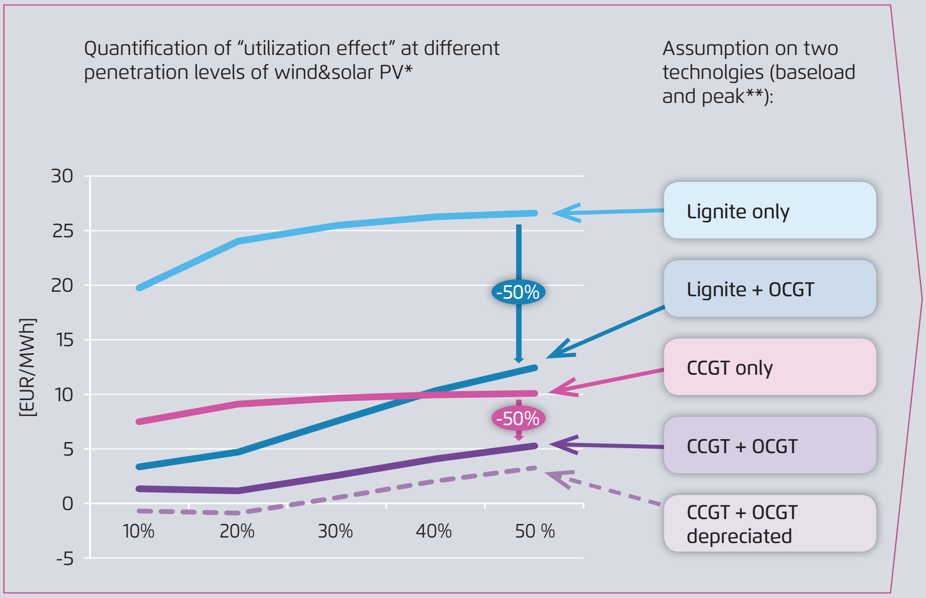
To illustrate the importance of how the system is defined and the perspective applied, an additional dotted line is included in figure 38. This line depicts the results of a two-technology system in which base load is provided by new CCGT and peak load is provided by depreciated open cycle gas turbines, the latter of which represents a technology with virtually no capital costs. Depending on the perspective taken in calculating integration costs, such a technology may appear in calculations of power systems in the form of interconnections to neighboring countries, when only the price paid for the import of electricity is considered (further discussed in section 2). Assuming that a peak power technology with close to zero fixed annual costs is available, the calculated "utilization effect" is just 3 EUR/MWh.

5.3.4.3 Supplemental discussion: Marginal versus average costs

In political debates concerning different pathways for power system development, discussion tends to focus on the overall implications of going from a given situation X toward one of various possible situations Y or Z in the future. In the framework of the "utilization effect" quantification, this naturally leads to comparison of the total effects that occur between the situation X and the respective future state Y or Z, and dividing these effects by the amount of electricity added in between. This provides an indication of the average cost effect of every additional unit of wind and solar PV on the road from X to Y.

31 This phenomenon may have led to misunderstanding in very early analysis on the topic in Germany during the 1980s, which found that approximately 4 percent of wind and solar power are the maximum contribution these technologies can provide to the German power system.

Cost of interaction between variable renewables and the residual power plants (“utilization effects”) – differences between a one- and two-technologies system (thought experiment) Figure 38



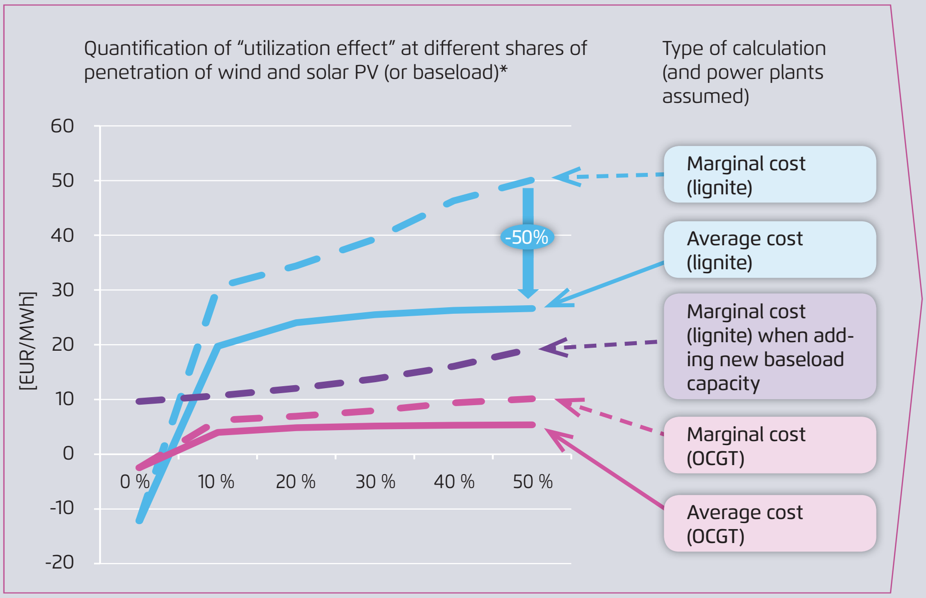
Results of thought experiments

- “utilization effect” in the two-technologies system is significantly lower than in a one-technology system
- Assuming existing, depreciated peak load capacities reduce the “utilization effect” in both case.

Own illustration

*Example Germany, adding up to 50% of wind and solar PV
**assuming 30 GW of OCGT are available as peak load technology

Cost of interaction between variable renewables and the residual power plants (“utilization effects”) – differences in quantifying “marginal” vs. “average” values Figure 39



Marginal cost

- indicates the cost of adding an extra MWh of renewables beyond a penetration rate of X%, assuming that this MWh must bear all the costs of its integration

Average cost

- indicates the cost of integrating renewables up to a penetration rate of X%, assuming that the cost is spread over all renewable energy MWh

Own illustration

*Example Germany, adding up to 50% of wind and solar PV, or new basload capacity

Such an approach may significantly differ from the approach that is commonly applied in economic theory, where not average costs between a point in time X and Y are the focus of analysis, but rather the marginal change of adding an extra unit of wind and solar PV at the point in time X or Y.

Figure 39 illustrates the difference in the results of the analysis when either the average costs or the marginal costs are calculated. For illustrative purposes, this calculation builds again on the first thought experiment, assuming a one-technology system, and presents the two extreme cases, i.e. a system only with new lignite power plants or a system consisting only of new OCGT power plants. Assuming a system consisting only of new lignite power plants, the marginal cost of adding wind and solar PV can rise to 50 EUR/MWh, almost twice as high as the average cost at 50 percent wind and PV penetration, which is 27 EUR/MWh. The same effect occurs at a much lower level when one compares the marginal cost and average cost of adding wind and solar PV in a new OCGT power plant system. They range in that case between 5 and 10 EUR/MWh.

For an illustrative comparison, we also calculate the utilization effect of adding new base load power plants to the one-technology system consisting of lignite power plants: At a penetration rate of 50 percent, the marginal cost of integrating new base load power plants reaches 19 EUR/MWh (at this penetration level, average costs are once again ~50 percent lower).

5.3.4.4 Summary of findings on the role of capital costs

To avoid misinterpretation it should be emphasized that the theoretical models presented in the previous sections are far from appropriate for analyzing real power systems and informing political debates. Nevertheless, the calculations do generate four key insights:

First, the "utilization effect" occurs when adding wind and solar PV to a power system (in the absence of a structural response in electricity demand), irrespective of the assumptions on the technology available: the average utilization of required capacity is reduced, leading to a rise in the costs of the residual load.

Second, the quantification of the "utilization effect" depends largely on the capital costs of the residual technologies, with the annualized investment cost being the key driver of the results. This obviously leads to the challenge of identifying the "right" residual technologies to consider – which may depend both on the system's features and the perspective taken.

Third, when moving towards more diversified systems (in this case, from a one-technology to a two-technology system), the resulting "utilization effect" is smaller (twice as small as in our theoretical models).

Fourth, the analysis shows how important it is to understand thow the "utilization effect" is calculated: Marginal costs may be twice as high as average costs, depending on the calculation method.

5.3.5 Quantifying the effect of a shift from base load to mid-merit and peak load

While a one- or two-technology system is enough to illustrate the cost effects of lower utilization of the residual power plants, it is not enough to quantify the effect of a shift from base load to mid-merit and peak load, which is required to illustrate how different considerations of external effects may have on the results. To perform such analysis, at least a three-technology system is needed, whith one technology serving the base load, one technology serving mid-merit, and one technology providing peak load demand.

5.3.5.1 Theoretical background: Cost optimal provision of electricity demand

When analyzing a three-technology system, the contribution made by the different technologies to total capacity is an important parameter. A commonly used approach for determining a cost-effective supply share for each technology given a specific residual load duration curve is introduced in this section (figure 40).

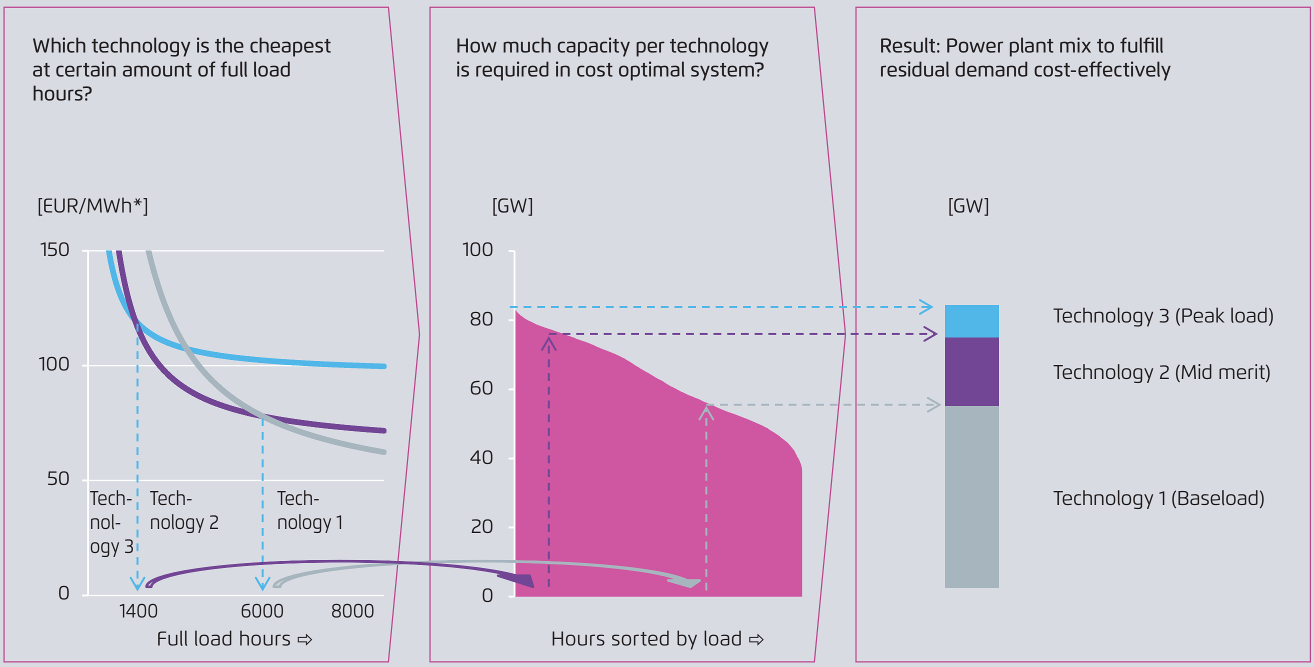
First, the levelized cost of electricity produced by the different power plant technologies available are calculated as a function of the yearly utilization (from 1 to 8760 hours). The key factors considered in this calculation are investment costs (calculated as yearly annuity costs), other annual fixed costs, as well as costs that depend directly on utilization levels, including fuel and variable operating costs. Depending on how costs are defined, external costs (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident) may be ignored or priced (with current or future expected values) based on various approaches.

In the example presented here, three technologies are considered for the German power system: lignite, combined cycle open gas turbines (CCGT), and open cycle gas turbines (OCGT). Based on the cost curves that result from the above calculations, the lowest cost technology can be determined for any number of full load hours, as well as the full load hours during which a change in the cost-optimal technology takes place. In the example presented, lignite is the cost optimal technology at utilization between 8760 and 6000 full load hours per year, CCGT between 6000 and 1400 hours, and OCGT at utilization below 1400 full load hours.

In a second step, the cost-optimal capacity mix is determined based on a cost analysis of the different technologies available. In our example, the cost optimal technology for providing electricity to meet residual demand during more than 6000 hours per year is lignite. Thus, the cost-optimal capacity of lignite, based on assumptions used here, would be 56 GW. The cost-optimal technology to provide the demand that is needed between 1400 and 6000 hours per year is CCGT. Because 77 GW or more of capacity are needed to meet residual demand during 1400 hours of the year, the cost-optimal capacity of CCGT is 21 GW (i.e. the difference between 77 GW and 56 GW). To serve the additional demand during the 1400 hours, up to the highest residual load of 87 GW, an additional capacity of 10 GW OCGT would be cost-optimal.

The different technologies used to meet the residual demand for electricity are often called "base load," "mid-merit" or

Background: Theoretical approach for calculating a cost optimal residual power plant mix — Figure 40



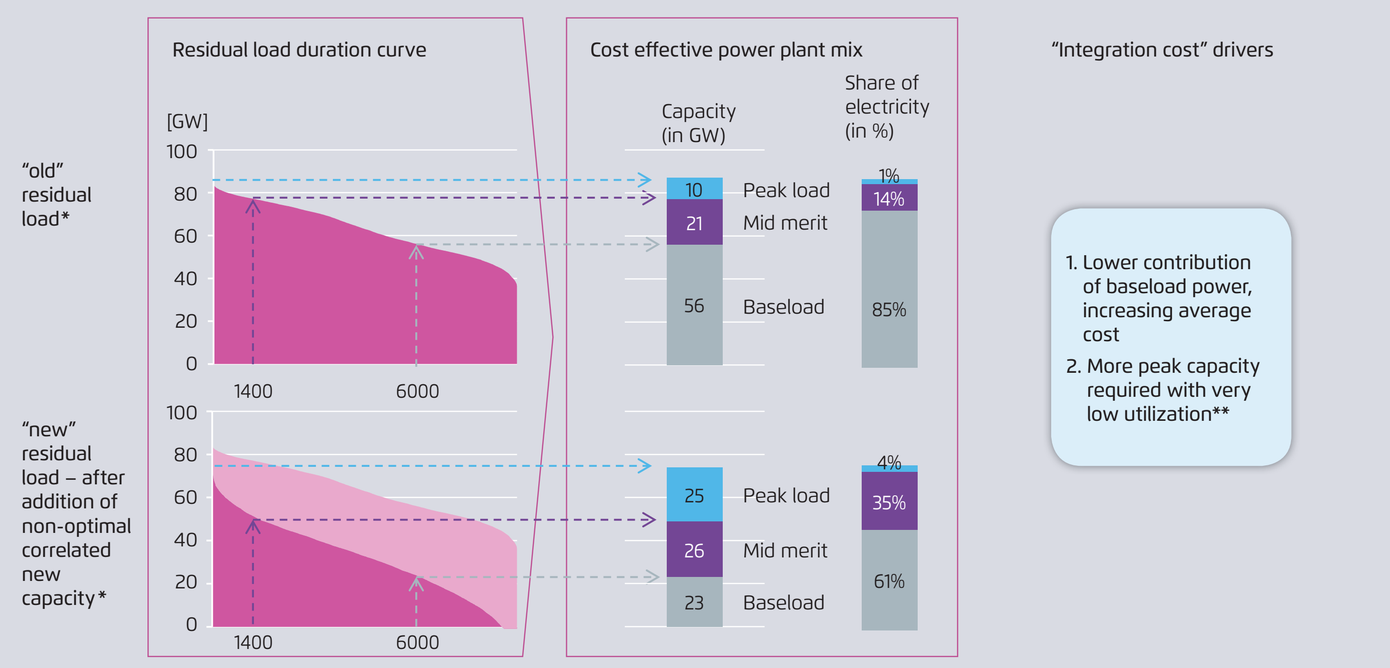
Own illustration * Key assumptions used here for illustration: Technologies available are lignite, CCGT, OCGT, CO_2 price 30 EUR/tCO_2, gas price 30 EUR/MWhth "peak load" capacities, depending on the section of the residual load duration curve for which they provide the cost-optimal solution.

5.3.6 Step 1: Quantifying the shift from base load to mid-merit and peak load

The approach outlined above allows one to translate the change in the shape of the residual load duration curve discussed in section 5.2 into a specific shift in the amount of power contributed by different technologies. This is required to quantify the cost effect of such a shift.

Figure 41 illustrates the effect that the addition of new capacity has on the residual load and the effect it has on the cost-effective mix of power plants to provide this residual load, including their respective utilization levels. Applying the approach described above, the cost effective mix of technologies can be derived for both the residual load duration curve before (upper graph) and after (lower graph) the addition of new capacity. In the example here (representing the case of adding 50 percent of new electricity generation using wind and solar PV in Germany), and using the same assumptions concerning technologies and costs detailed above, the resulting cost- optimal mix of power plants would be 23 GW of base load, 26 GW of mid-merit, and 25 GW of peak power plants. As expected, the cost-optimal amount of base load power is significantly reduced, while the demand for mid-merit and peak power capacity is increased. This change in the mix of cost-optimal capacity is also reflected by a change in the share of electricity provided: While base load capacity contributed 85 percent electricity before, this share is reduced to 61 percent (of residual electricity demand) after the introduction of new wind and solar PV. In contrast, the contribution of mid-merit and peak load capacities is increased. While the example here illustrates the impact of new wind and solar PV capacities on the residual load, the same effect occurs when adding any type of new capacity that is not a "perfect power plant."

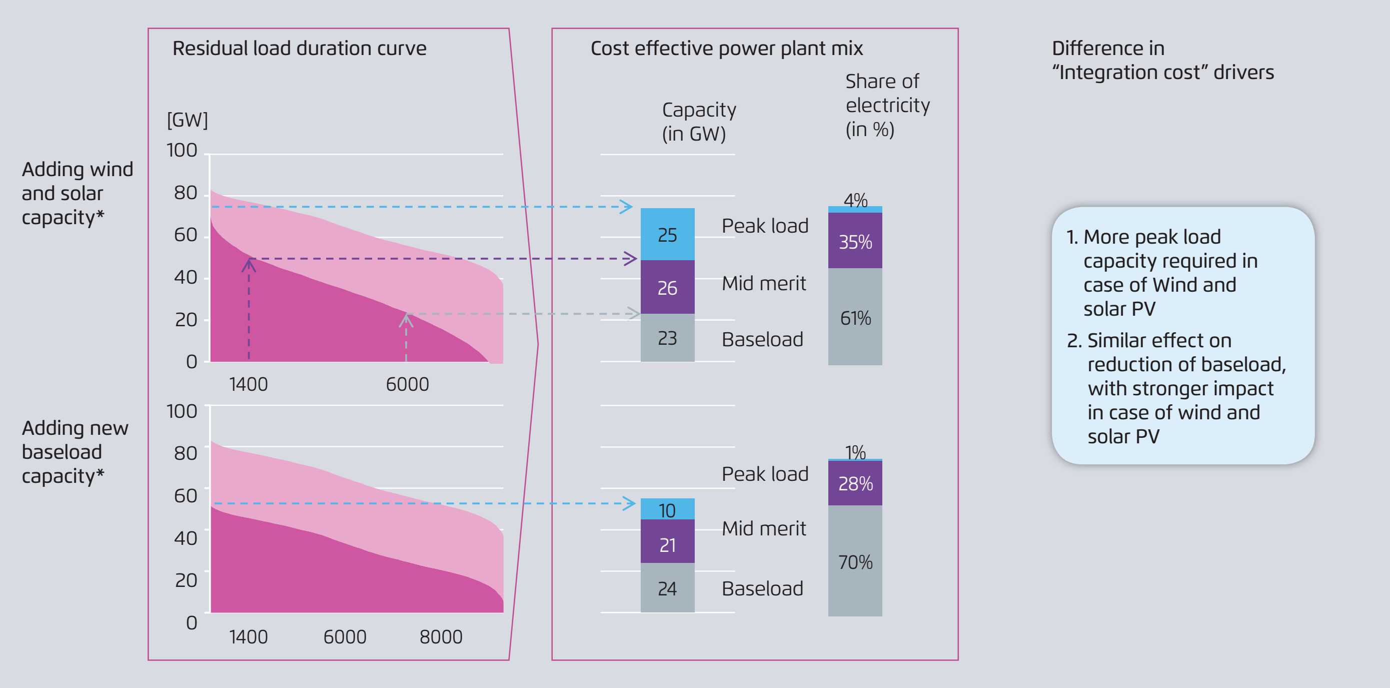
Cost-effective power plant mix before and after addition of new wind and solar power generation — Figure 41



Own illustration

*Example Germany, adding 50% of wind and solar PV
** in case of wind & PV, depending on correlation with load

Different cost-effective power plant mix in case of adding wind and solar vs new baseload capacity — Figure 42



Own illustration — *Example Germany, adding 50% new electricity

Figure 42 illustrates different cost effective power plant mixes when adding, either wind and solar (upper graph) or new base load (lower graph). In both cases, the effects on the cost-optimal amount of base load capacity is very similar: While 23 GW of the base load technology are cost-optimal after the addition of 50 percent new wind and solar PV capacity, 24 GW of base load technology are cost optimal after the addition of 50 percent new base load capacity. The effect on mid-merit capacity required changes slightly, with 26 GW in the case of new wind and solar PV compared to 21 GW in the case of new base load. As expected, the most significant effect occurs on the demand for peak capacity: 25 GW are required in the case of new wind and solar PV compared to 10 GW in the case of new base load. Furthermore, a major reduction in the share of electricity produced by base load can be observed in both cases considered here (compared to the siutation before new capacity was added), with an increase in the contribution by mid-merit and peak load power plants. In the case of additional wind and solar PV, the share of peak load power production is significantly higher (4 percent vs. 1 percent), the share of mid-merit is higher (35 percent vs. 28 percent), and the share of base load is lower (61 percent vs. 70 percent).

5.3.7 Step 2: Quantifying the cost of shifting from base load to mid-merit and peak load

Based on the calculations concerning the optimal mix of technologies used to serve residual load, the cost of providing the residual load can be calculated in the two scenarios (before and after the addition of new power plants, either new wind and solar or new base load).

In the example of the three-technology system considered here, a shift occurs from power production from lignite to power production from natural gas. This is associated with a change in generation costs, as the two technologies have differing fixed and marginal costs.

The relevant cost components affected by this shift will thus be cost of fuel, especially the cost of natural gas, as well as costs for carbon dioxide emissions (emissions per unit of electricity produced by lignite are approximately four times that of gas). As discussed in section 2, estimates of the true cost of carbon dioxide emissions may diverge significantly depending on who is conducting the calculations. Also, forecasts differ concerning the future price of natural gas.

Figure 43 illustrates how integration cost estimates are impacted by different assumptions regarding the cost of emitting carbon dioxide as well as the cost of natural gas. We use the same example residual load in Germany before and after adding 50 percent wind and solar PV capacity, but vary our assumptions concerning natural gas and CO_2 prices. The graphs in the middle of Figure 43 illustrate how variance in these costs impact the estimated levelized cost of electricity produced by the three considered technologies (lignite, CCGT, OCGT). To reduce complexity, the calculations performed here assume that change in the cost assumptions do not influence the utilization of the power plant fleet, which may be understood as an imperfect market where not all costs are fully internalized (e.g. from the point of view of an environmental agency). In a more perfect market that takes externalities into account, with emissions costs of, say, 80 EUR/tCO_2 emissions, lignite is fully replaced by natural gas, simplifying the calculation of integration costs, as the scenario is reduced to two-technologies.

Assuming a low cost of CO_2 and a high cost of natural gas, electricity produced by the base load technology (here, lignite) is significantly cheaper than the electricity produced by the mid-merit technology (here, gas in a CCGT power plant). The shift from the base load to the mid-merit technology that results to meet residual electricity demand is thus associated with significantly higher costs to provide the residual load, equal to an increase of 24 percent or 13 EUR per added MWh of wind and solar PV.

Assuming higher costs for CO_2 and lower costs for natural gas, the levelized cost of electricity generated by lignite and gas-fired power plants is approximately equal at very high utilization rates. If one assumes that the power generation mix is unchanged (ie. that some costs for CO_2 emissions exist but are not internalized in the market and thus have no impact on the power plant dispatch[32]), this leads to a much smaller impact on the cost to provide the residual load. The resulting increase in specific cost is only +2 percent, or 2 EUR per added MWh of wind and solar PV.

Assuming that the real cost of CO_2 emissions is 80 EUR/tCO_2 (as an environmental agency may suggest[33]) as well as natural gas costs of 15 EUR/MWh, the specific cost would be reduced by -5 percent, or -6 EUR/MWh of wind and solar PV added. In such a case (which may only result when assuming an imperfect market for external effects, as is the situation in Europe today), the shift in generation between different technologies outweighs the increase in the capital costs.

5.3.7.1 Summary of findings concerning shifts from base load to mid-merit and peak-load demand

Once again, it is important to emphasize that the calculations presented here do not intend to suggest that any one assumption is "right" or "wrong." Instead, the aim is to illustrate how these assumptions impact the results.

Our calculations point to two key insights:

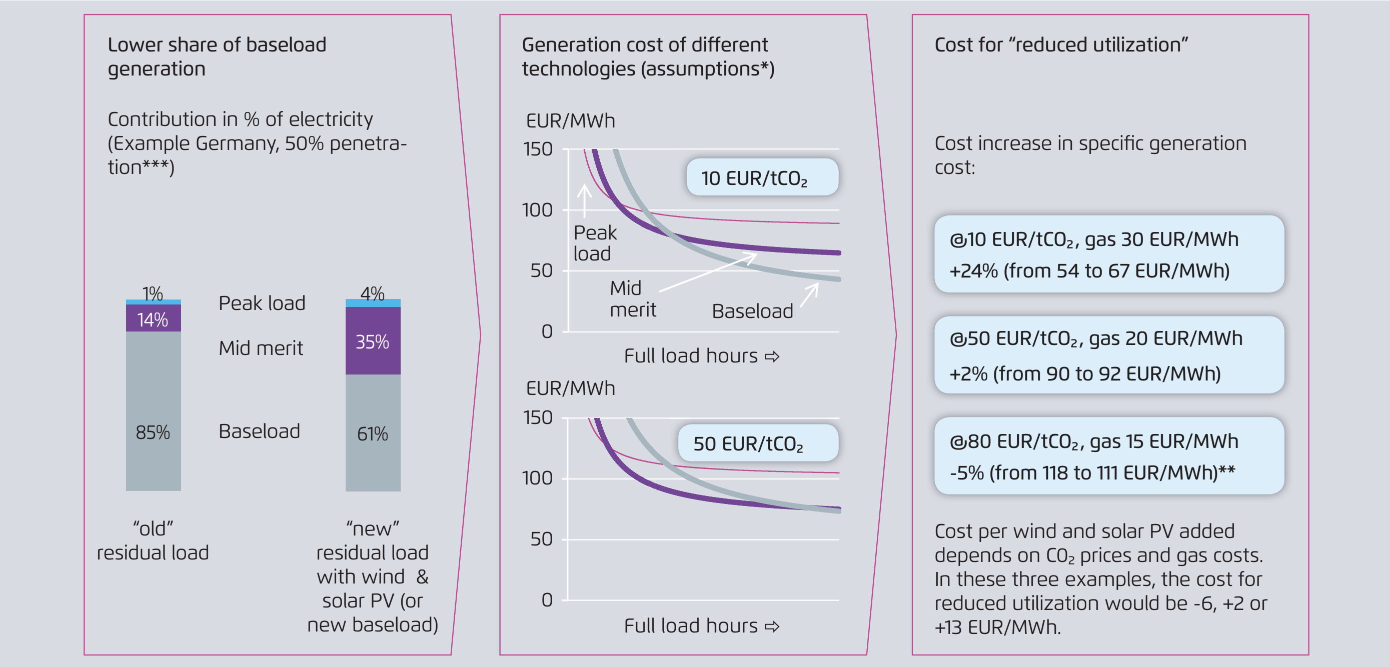
First, the change in operational costs induced by a shift from base load to mid-merit and peak load technologies is associated with increasing specific costs, as described above. This occurs both when new wind and solar power are added and when new base load power is added, although the effects are more pronounced with wind and solar.

Second, the quantification of this effect is largely driven by assumptions concerning fuel costs and the pricing of externalities. In a perfect market, base load technologies are by

32 In fact, if the cost of CO_2 emissions is internalized in the market, the resulting cost-optimal mix would change both before and after the addition of wind and solar PV. Implicitly, the example calculations presented here thus assume an imperfect market, in which the costs of CO_2 emissions occur but are not priced into the power system.

33 80 EUR/tCO_2 are used here as an illustrative value, based on the higher range of the costs recommended by Dietz and Stern (2014), where total costs range from 25 to 80 EUR/tCO_2.

How CO_2 and natural gas assumptions drive the cost of "reduced utilization" Figure 43



Own illustration
*Assuming lignite, CCGT and OCGT as base/mid-merit and peak technologies, natural gas price of 30 EUR/MWhth
**Illustrative calculation, assuming the same generation mix as above (ie cost for CO_2 are not internalized and have no impact on power plant dispatch)
***optimized technology mix @ 30 EUR/tCO_2, gas 30 EUR/MWh

definition cheaper than mid-merit and peak load technologies and the induced shift will increase integration costs. If external costs are not internalized, estimation of this effect may yield negative results and may even compensate for increased specific capital costs.

While the example presented here – which uses lignite as a base load technology – may appear highly specific to Germany, in fact it is easy to extrapolate the findings to other countries, such as France. Nuclear power plants have a cost structure that is similar to lignite power plants, and both produce externalities that are difficult to quantify.

5.4 Legacy systems and system transformation

In academic settings, discussions regarding power systems tend to distinguish between "greenfield" and "brownfield" systems, as well as between short- and long-term effects (see section 2). For the discussion of integration costs, these categories are highly relevant, and many diverging views can be reconciled once clarity concerning the underlying perspective is achieved. Unfortunately, a clear-cut separation between short- and long-term effects is very difficult to achieve in real power systems. Furthermore, the "greenfield" development of a power system is more of a theoretical construct than reality in most parts of the world today (see section 2)

The calculations presented above may be understood as informed by the "greenfield" and "long term" perspectives, while fully neglecting the development of demand over time. In the following, the effects of applying different perspectives (or assumptions) regarding the future development of both the supply and demand side of a power system are illustrated.

5.4.1 Short-term perspective: If 50 percent new electricity fell from the sky

Figure 44 illustrates the effects that would result to the residual load duration curve if 50 percent of electricity produced by new capacity "fell from the sky" and was added to an existing power system (either through new wind and solar PV or new base load power[34]). Assuming that a cost-optimal mix of the three power plant technologies exists in the situation before the new capacity is added (identified by the approach outlined above and using the same assumptions on CO_2 and natural gas costs), the average utilization of the base load technology (here: lignite) is 95 percent,[35] the average utilization of mid-merit technology (here: CCGT) is 43 percent, and that of the peak technology (here: OCGT) is 4 percent. The contribution made by the different technologies to providing the residual load before the addition of new capacity is represented on the left hand side of figure 44 with different colors.

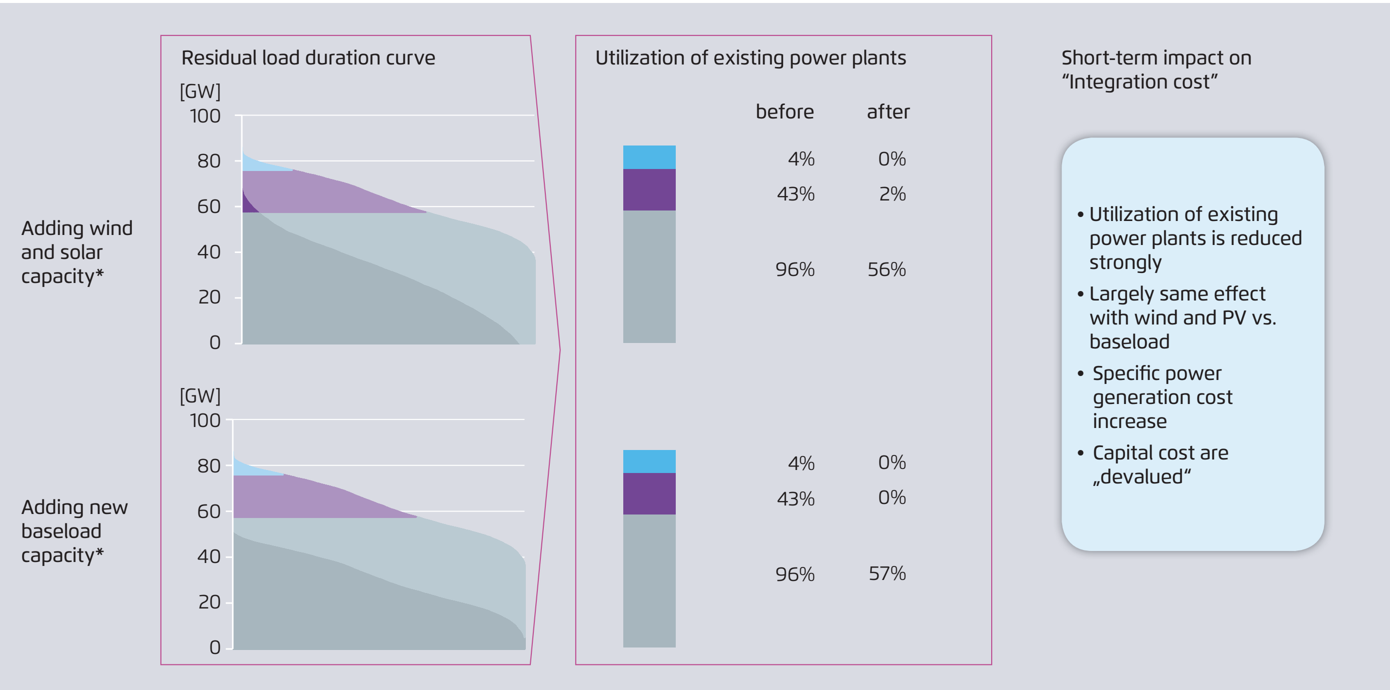
After the addition of wind and solar PV capacity "overnight," the utilization of base load power plants is reduced to 56 percent, that of mid-merit to 2 percent, and that of peak power plants to 0 percent. The effect of adding new base load capacity is quite similar, leading to a reduction in the utilization of the residual base load power plants to 58 percent and fully reducing the utilization of mid-merit and peak load power plants to 0 percent.

However, it is rather unlikely that power plants would "fall from the sky" and increase capacity by 50 percent. Instead, this capacity would be gradually added over a period of several years or even decades. At the same time, such an effect is not something entirely uncommon in real power systems: After the time required to commission a new power plant has elapsed (in many cases 7 years or more after the initial

34 The example presented here builds on the same analysis of the German power system presented above.

35 This very high level utilization results from the analysis of the residual load duration curve which does not account for an imperfect availability of real power plants due to maintenance etc. If such effects would be considered, required capacities of all technologies would be somewhat higher and utilization rates lower.

Utilization of existing power plants when 50% electricity is produced by new capacity "falling from the sky" Figure 44



* Example of adding 50% electricity by either wind and solar PV or new baseload power plants in Germany

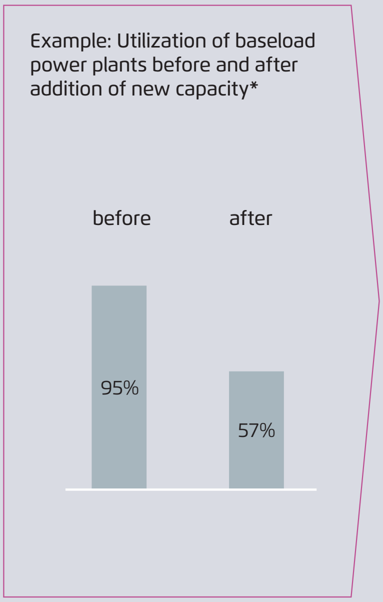
investment decision), demand for electricity may be lower than expected or unexpected competitive capacities may have entered the market (including the expansion of wind and solar PV due to policy-driven incentives). Furthermore, interconnecting markets with each other, as has occurred in Europe in recent years, may be perceived as having a similar effect on the residual load duration curve of a country. In a real power system, such a change in utilization patterns can be expected when power plants originally built to provide base load demand are used to provide mid-merit demand, and those built to provide mid-merit demand end up providing peak demand for just a few hours each year. From a short-term perspective, the addition of new capacity directly leads to a devaluation of the capital invested in the existing power plants. The challenges involved in quantifying the value of existing power plants – as well as the controversial political discussions involved – are discussed in section 2.

Figure 45 illustrates the effect that the addition of new capacities "falling from the sky" have on the specific generation cost of the base load power that is produced by different technologies. In the event that base load power is produced by gas-fired CCGT, the reduced utililization has a rather low impact on generation costs, increasing the cost per unit of electricity produced by approx. 12 percent. A similar effect appears when base load power is produced by lignite and the cost of CO_2 emissions is assumed to be 80 EUR/tCO_2: these assumptions lead to an increase in specific generation costs of 15 percent. Only modifying the assumptions on the cost of CO_2 emissions changes the picture entirely: Assuming that base load power is produced by lignite and the cost of CO_2 emissions is 10 EUR/tCO_2, the increase in specific costs is 39 percent.

The key driver of the difference in specific generation cost, as discussed above, is the capital intensity of the considered power plant technology. The results of the calculations here show that the definition of system boundaries, which may result in significant differences in the overall power generation costs, can have an almost equally significant effect on the relative difference in specific generation costs.

Specific generation costs of existing power plants when 50% electricity is produced by new capacity "falling from the sky"

Figure 45



Assumptions for calculation	Short-term impact on specific generation cost, EUR/MWh @95% utilization	@57% utilization	Diff.
Type of power plant and CO_2 cost			
• Combined Cycle Gas Turbine (@25EUR/MWhth)	56	63	+12%
• Lignite (@80 EUR/tCO_2)	115	132	+15%
• Lignite (@10 EUR/tCO_2)	44	61	+39%
• Nuclear (rebuild**)	65	99	+53%
Perspective on value of capital (Example CCGT)			
• Producer (full consideration of capital value)	56	63	+12%
• Consumer (no consideration of capital value)	49	50	+3%

Own illustration

* Example of adding 50% electricity by either wind and solar PV or new baseload power plants in Germany
** Assuming cost for rebuilding of 2500 EUR/kW, 6 years construction time, WACC of 9%

5.4.2 Mid-term perspective: Nothing stays the same

In real power systems, the addition of new capacity is likely to take place over a period of several years or even decades. During this time, some of the existing power plants are likely to reach the end of their technical lifetime or require investment to keep running.[36] Furthermore, demand for energy may respond to changes in the energy supply.

Figure 46 illustrates the effects on the utilization of the residual power plants that would result from the simultaneous addition of new capacity and the closure of existing power plants. Using the same example for Germany, it is assumed that the power supply is increased by 50 percent through the addition of new wind and solar PV or new base load capacity, while at the same time 30 GW of base load power plants are closed.[37]

Compared to the thought experiment in which 50 percent new capacity "fell from the sky," the closure of old base load power plants largely counterbalances the effect of adding new capacity. Utilization of the remaining base load power plants is between 82 percent and 90 percent; utilization of the mid-merit power plants between 38 percent and 42 percent; and utilization of the peak power plants between 2 percent and 6 percent. Comparing the case of adding wind and solar PV to that of adding new base load power plants confirms the expectation from above – namely, that the utilization of base load power plants is reduced more significantly in the case of new wind and solar PV, while the utilization of peak load power plants is increased.

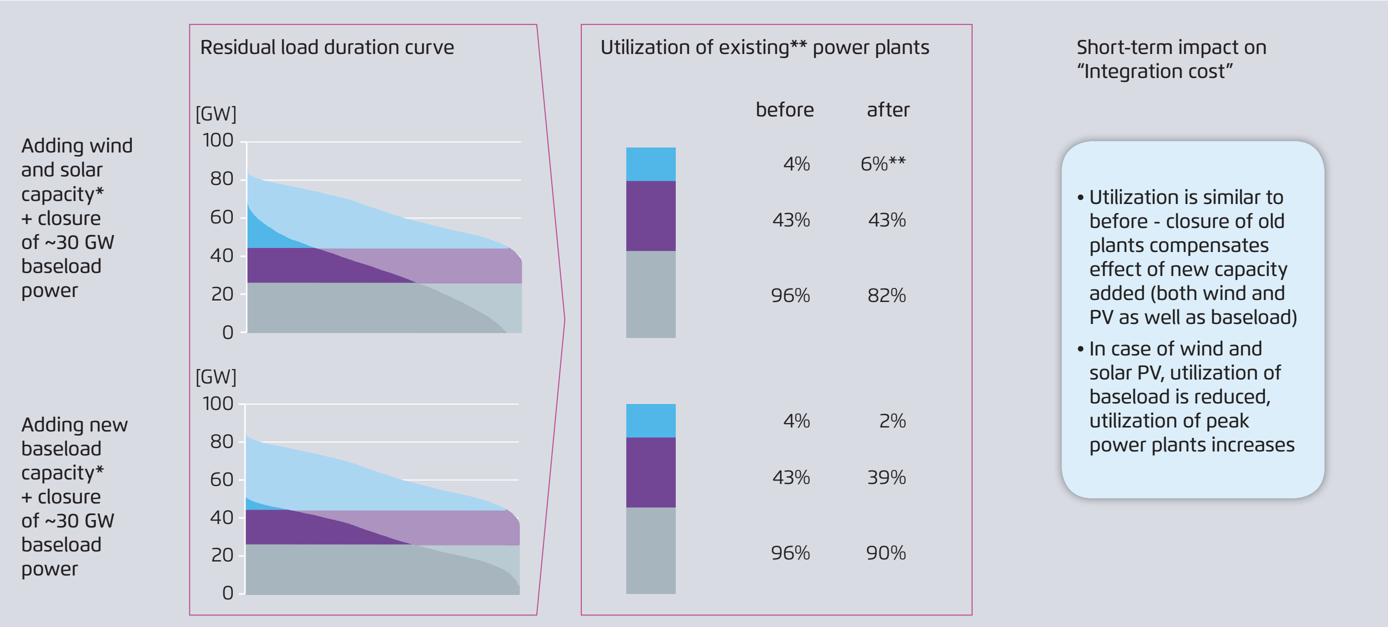
Figure 47 illustrates the effects that would result when new capacity (either wind and PV or new baseload) is added

36 Following the logic of "integration costs," this would make them part of the "new capacity" added rather than part of the residual power plant fleet.

37 This figure roughly corresponds to the scenarios up to 2024 published by the German regulator for the annual grid development planning in 2014. In the case of adding wind and solar, this requires the addition of peak power plant capacity (or demand side activation).

Utilization of existing power plants if power plant closures occur while new wind and solar power generation is added

Figure 46



Own Illustration

* Example of adding 50% electricity by either wind and solar PV or new baseload power plants in Germany

** In the case of adding wind and solar PV, additional peak capacity is required to replace closure of baseload power plants, in the analysis here 18 GW while demand is allowed to respond to structural changes in supply, i.e. new consumers enter the market and the demand for electricity becomes more responsive to changes in supply. To illustrate the effects that result, a highly simplified approach was used to calculate an adapted residual load duration curve, assuming that a constant additional demand of 10 GW (corresponding to ~15 percent of total electricity demand) is added and that 30 GW of demand is flexible and can shift over each 24 hour period. In view of a real power system, new electricity consumers may be understood as, say, electric vehicles and heat pumps, while the additional flexibility may be understood to represent the flexibility provided by new or existing technologies, as well as by increased interconnections between countries or storage systems.

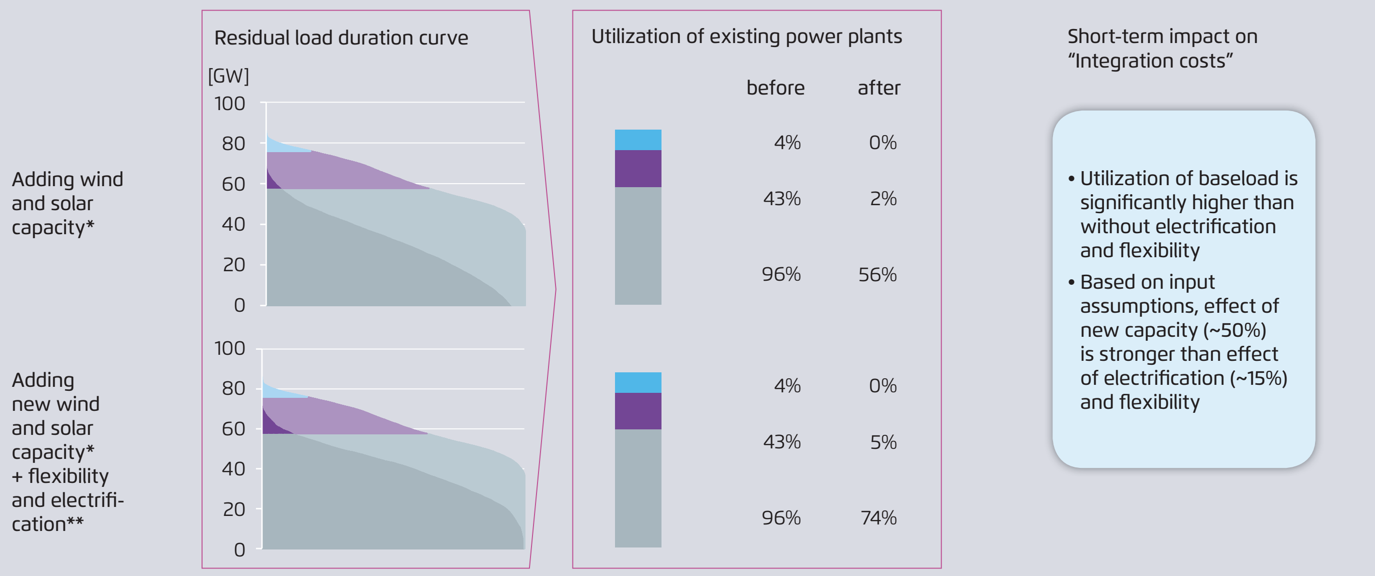
Similar to the effect of power plant closures, increasing flexibility and electrification significantly reduce the negative effect on the utilization of existing base load power plants that results from new wind and solar PV (Figure 47, lower graph). While the utilization of existing base load power plants is reduced to 55 percent in the absence of additional flexibility and electrification, utilization is reduced to only 74 percent when these changes take place simultaneously. It should be emphasized that the relative effect of the changes in the power system considered here are assumed using figures of varying magnitude (e.g. 50 percent new electricity vs. 15 percent new demand). Accordingly, we can only draw the general conclusion that a compensating effect occurs.

5.4.3 Long-term perspective: Power plant closures, electrification, and flexibility

As power systems develop over the long term, supply and demand both undergo change. When new capacity is added, old power plants close and the consumption of electricity may change in terms of specific applications and utilization patterns. Figure 48 illustrates the effects these simultaneous developments can have on the residual load duration curve. For illustrative purposes, a set of assumptions is chosen that leads to a largely constant residual load duration curve: closure of 20 GW of power plant capacity, electrification corre-

Utilization of existing power plants assuming increased flexibility and electrification while new wind and solar power generation are added

Figure 47

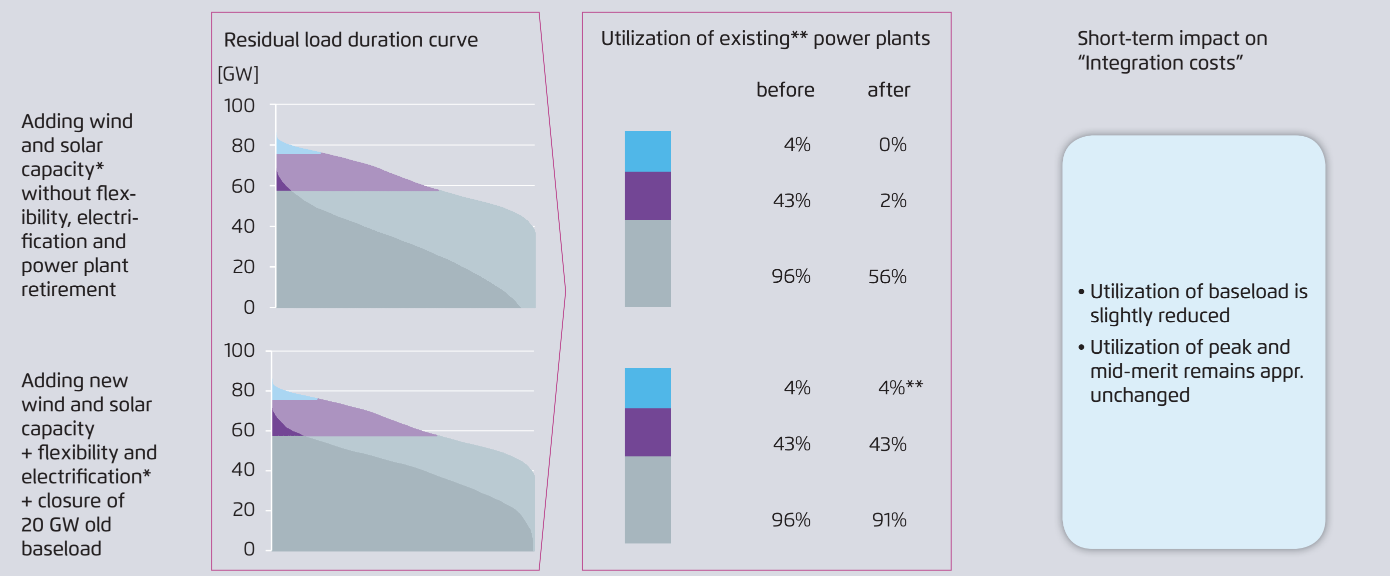


Own illustration

* Example of adding 50% electricity by wind and solar PV power plants in Germany
** Assuming that on average 10 GW additional demand is added (electric vehicles, fuel-generation via electrolysis, heat pumps, etc) and that 30 GW of flexibility are available over 24 hour (interconnection, existing storage, DSM)

Utilization of existing power plants assuming increased flexibility and electrification while new wind and solar power are added

Figure 48



Own illustration

* Example of adding 50% electricity by wind and solar PV power plants in Germany, assuming that on average 10 GW additional demand is added (electric vehicles, fuel-generation via electrolysis, heat pumps, etc) and that 30 GW of flexibility are available over 24 hour (interconnection, existing storage, DSM)

** Additional peak capacity is required to replace closure of baseload power plants, in the analysis here 12 GW

sponding to an average of 10 GW of additional demand, and 30 GW of flexibility achieved through increased electrification and the adaptation of electricity demand. The inclusion of these assumptions almost completely counteracts the reduced utilization that would otherwise result from the addition of 50 percent new wind and solar PV capacity. We only witness a slight reduction in the utilization of base load power plants.

Accordingly, calculation of the "utilization effect" from a long-term perspective based on the assumptions outlined above yields an additional cost of approximately 0 EUR/MWh. This finding holds true irrespective of any assumptions regarding the type of technology used or assumptions on costs, because the cost of providing the residual load is made up of the same cost components, only proportionally reduced.

This analysis should not be misinterpreted as arguing that the "utilization effect" is trivial. Nevertheless, it does illustrate the impact that future adaptive changes in the power system can have on the quantification of "integration costs."

In a real power system, the decision to close a specific power plant or make an investment to extend its lifetime is typically a strategic choice made by the owner of that power plant. This decision may be impacted by a wide range of considerations, and may be more or less "economically logical" in light of available information. In any event, given the human and imperfect nature of such decisions, analyst predictions aiming to quantify the costs of integration will invariably be subject to uncertainty. Such uncertainty also applies to a range of other forecasts, including the future elasticity of demand and the future power mix.

6 Total system costs

Policymaking in the energy sector often requires assessment of various potential pathways for long-term power sector development. Such assessments may be used to reach decisions on overarching objectives, such as decarbonization or security of supply targets, or to adopt technology-specific targets, e.g. for renewable energy. While certainly not the only criterion considered in the political process, economic impacts are an important aspect of fact-based political discussion.

As described above, simply comparing the generation costs of different technologies is far from sufficient for a robust debate. While the concept of "integration costs" aims to improve the comparative assessment of different technologies, it has a number of shortcomings that has led to controversial debates among academics and policymakers alike. In the following, an alternative analytical approach is presented. This approach enables us to sidestep some, yet far from all, controversial aspects of this debate. As a result, it might prove to be a more appropriate tool for supporting political decision-making.

6.1 An overview of the total system cost approach

This approach may be called the "total system cost" approach. It has been used – in different variations – in a large number of studies comparing different long-term power sector development pathways.[38] As the name suggests, the total system cost approach focuses on the total cost of the power system. The key insight informing this approach is that society as a whole must bear the costs of the power system, regardless of redistributive effects and how costs are defined. The detailed categorization and attribution of cost components to certain parts of the power system (i.e. old or new) is not required.

To compare two or more possible pathways, a consistent scenario is defined for each pathway[39] and total costs are calculated for each, allowing a direct comparison of their economic implications. Such a comparison may directly support political decision making when pathways are defined based on considered policy options. A comparison of the cost and benefits of certain components of the system, such as renewables or nuclear power plants, may be additionally performed, but is not required. If this level of detail were added to the analysis, this would create the same challenges and controversies involved in categorizing and attributing costs that were discussed above.

6.2 Integration costs and total system costs

6.2.1 Differences between the two approaches

The "integration cost" concept assesses how different power generation technologies affect the power system. It seeks to answer the question "how can different power generation technologies be compared?" By contrast, the "total system cost" concept assesses the cost of specific power system development scenarios in order to answer the question "how can different scenarios be compared?" In this way, the first approach focuses on comparing technologies, while the second approach focuses on overall costs.

The second main difference between these approaches relates to the need to attribute costs to certain parts of the power system. In order to calculate integration costs, it is necessary to calculate the cost of a specific power system, categorize its component elements and to attribute these components to certain parts of the power system. Calculating total system cost only requires the first step, making categorization and attribution unnecessary. As discussed above, major challenges and controversies exist regarding

38 Including ECF Roadmap 2050 (2010), EU COM Roadmap (2011), McKinsey & Company (2010), Consentec, (2013).

39 In contrast to many scientific studies that use endogenous optimization approaches, key parameters that reflect political pathways, such as the composition of the future power plant mix, may be defined as an input, rather than generated as an output in simulations that optimize investment decisions.

the categorization and attribution of different cost components. These controversies are rendered moot in the total system cost approach.

6.2.2 Different approaches for different questions

When policymakers are faced with choosing between different policy options, the overarching question is "what are the implications of choosing either path A or path B?" To support decision-making in such a case, the total system cost approach may be a more appropriate tool than a comparison based on the concept of integration costs, as the attribution of costs to certain parts of the power system can be highly controversial while having little benefit for decision-making. As discussed above, the attribution of costs may depend on numerous assumptions, including current and future regulatory conditions. The regulatory regime that is in place may be considered the "rules for redistribution" and is ultimately the outcome of political choices. In view of the diverging interests of the stakeholders involved in the power sector, the attribution of costs to certain technologies thus bears the risk of being tendentiously understood as meaning "what approach and assumptions are required to make one or the other technology look more competitive than others?" While comparing a limited number of pathways might appear as a drawback of the total system cost approach, the additional effort involved in analyzing a significant number of scenarios and sensitivities may well be worth going through, in order to avoid controversial debate concerning which cost are rightly attributed where.

The total system cost approach will nevertheless reach its limits when the focus is not to compare real policy options but rather to generally understand the effects of and interdependencies between specific technologies (or when a specific simulation approach requires the parameterization of the system effects of certain technologies). The results of a total system cost analysis may serve as a springboard for the further analysis of technology-specific effects, but it does not allow direct comparison of the cost of different technologies. If the objective is, for example, to develop a simulation tool that endogenously optimizes a long-term power system development scenario, comparing the results of various consistent scenarios may not be possible – and solving all the challenges and controversies described in this report will be required.

6.2.3 Different approaches with similar challenges

The total system cost approach avoids several of the most controversial challenges that arise in the quantification of integration costs, namely those related to the attribution of costs – or, in other words, the question of deciding "who's to blame." At the same time, a significant number of challenges regarding the quantification of total system costs remain, most importantly regarding the definition of the system and its boundaries. Specifically, controversy remains concerning whether or not and how external effects should be considered. Assumptions concerning future technologies and demand behavior also crucially shape the results of the calculations. Furthermore, such assumptions are highly case-specific and difficult to transfer to other countries and situations. Several other challenges remain but have a much lower impact on the results of the analysis. Quantifying the value of existing power plants may remain as a theoretical question, but will not have any impact on results. If, for example, a scenario with a significant amount of investment to extend the lifespan of an aging nuclear fleet is compared with a scenario containing little such investment, only the difference in cost between the scenarios is relevant in the calculations. Thus, the two alternatives can be directly compared, i.e. what is the cost difference between extending the lifespan of the country's nuclear power plants versus investing in renewable energy and all the additional system components that might be required (e.g. grids and secure capacity).

6.3 Comparing scenarios with high and low shares of renewable energy

In the following, a possible application of the total system cost approach to compare scenarios with different shares of renewable energy is described.

As a starting point, two or more scenarios are constructed that include different shares of renewable energy penetration at a given time in the future, for example, in the year 2030. Each of these scenarios must be equal from a technical point of view, i.e. the same level of security of supply (i.e. loss of load expectation) must be achieved at any given location.[40] To establish a reasonable analysis, all components should be reasonably adapted to the respective renewable energy mix, taking into account reasonable assumptions concerning both technological development and consumer behavior. Most importantly, this requires the use of up-to-date assumptions on the cost and type of technologies used for power generation (e.g. assumptions on solar technology from three years ago may already be outdated).

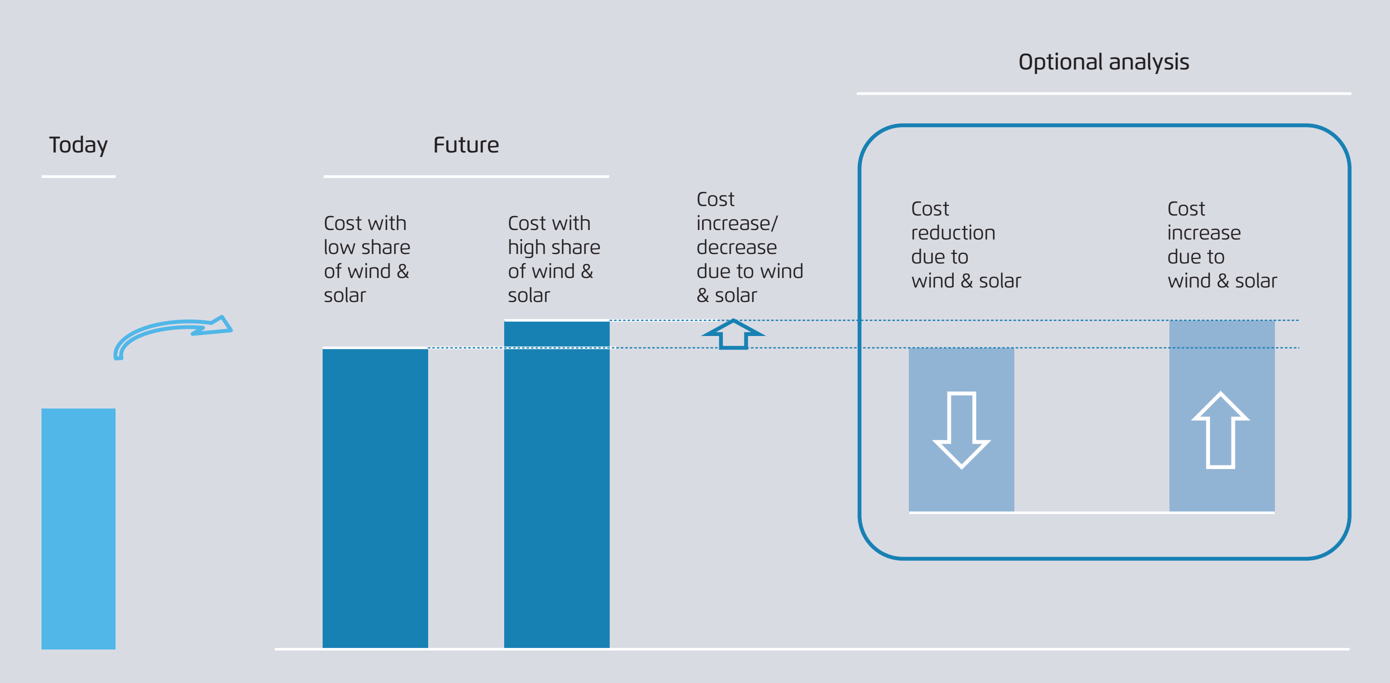
Based on an initial definition of costs, which may or may not include externalities (e.g. healthcare and environmental costs, costs of adapting to climate change or of a nuclear accident), the total cost of power generation are then calculated for each scenario. To enable such analysis, a wide range of power system simulation tools have been developed in recent years. Depending on the year of the scenarios and the penetration rate of renewable energies considered, a realistic simulation of future electricity demand is required for proper analysis.[41]

The calculation of total system costs should include costs for power generation by renewable and non-renewable technologies as well as all costs for grids and the balancing of supply and demand. When the objective is to better understand sensitivities such as a low or high deployment of electric vehicles, a number of scenario variations may be preferred over a combination of various effects within one scenario, to avoid simultaneous occurrence of manifold effects.

40 This may require either sufficient upgrade of the grid infrastructure or alternative measures such as biogas or gas turbines to compensate for an insufficient grid upgrade.

41 For example, while the structural adaptation of electricity demand might be neglected in a scenario that considers 25 percent renewable penetration, an up-to-date analysis of a scenario with 75 percent renewable penetration will certainly require a bottom-up simulation of different electricity demand technologies (e.g. including electric vehicles and heating).

A total system cost approach for comparing different renewable energy penetration scenarios — Figure 49



Own illustration

An optional additional analysis may focus on attributing the total cost increase or decrease that is related to the addition of renewable energy (Figure 49). Such an analysis highlights the total system costs or benefits of wind and solar power. A large share of these cost effects will be rather straightforward – for example, cost reductions due to lower fossil fuel imports, lower investment in thermal power plants, as well as cost increases due to investment in renewable capacity. Certain parts of this optional analysis may be difficult, as it requires costs to be separated into their components (e.g. grid costs need to be distinguished from generating costs), and, most importantly, costs need to be attributed to specific parts of the power system (e.g. grid costs need to be broken down into those driven by market integration and those driven by renewable energy expansion).

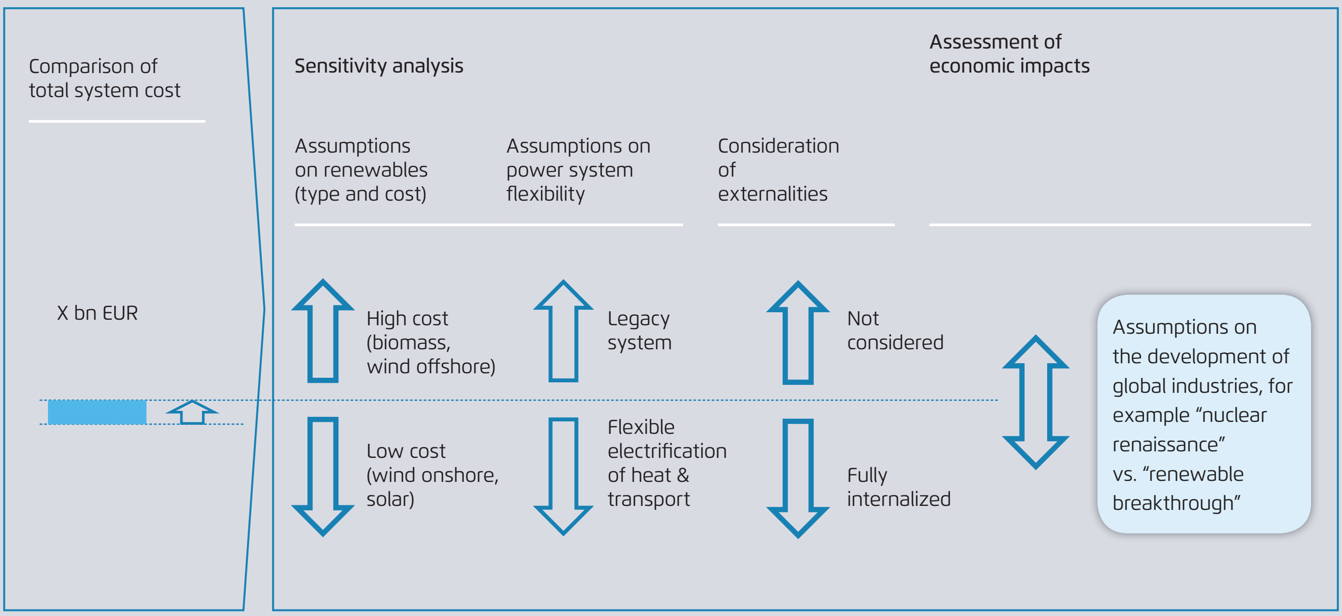
While such an analysis on cost causation remain possible following the calculation of total system costs, it is not necessary for analyzing the impacts of different pathways.

6.4 Key sensitivities and impact analysis

The resulting cost increase or decrease within the power system should be enhanced by an extensive and transparent sensitivity analysis, and can also be accompanied by the further assessment of economic impacts.

Three of the most important sensitivities to be considered are summarized in figure 50, based on experiences with scenario analysis conducted in Germany. On a technical level, the key sensitivities that need to be analyzed are the assumptions concerning the types of renewable energy used and their future cost. For example, a renewable energy expansion largely based on offshore wind and biomass is likely to result in significantly higher costs than a scenario based on onshore wind and solar PV, as the differences in generation costs between these technologies tend to far outweigh the differences in system effects.

Overview of key sensitivity analysis and impact assessments to accompany total system cost comparisons — Figure 50



Own illustration

A similarly significant effect may result from the assumption that electricity demand will be the same as in the past versus the assumption that electricity demand will adapt to new supply structures. Depending on the level of penetration considered, such assumptions may determine to which extent wind and solar power are curtailed, or fully utilized by the system.

A second key sensitivity that must be analyzed is the impact exerted by how costs are defined, including in particular the consideration of externalities. As discussed above, there certainly is not "one best way" to conduct this analysis, yet transparent discussion concerning the implications of each respective evaluation is required to support political decision-making. Depending on the approach taken, factors such as technological risk and environmental impact may be included in the calculated costs or itemized separately. For example, the quantity and effect of carbon dioxide emissions could be incorporated into power system cost estimates or considered within the scope of a separate analysis.

Of course, the results obtained by comparing the total system costs that result from divergent pathways can be accompanied by an in-depth analysis of economic impacts. This may include assessment of how different types of demand, both nationally and internationally, impact power prices, or assessment of the economic benefits that result from having a strong technological and industrial advantage in certain areas (e.g. wind turbines, solar panels, or nuclear reactors). In any event, the findings generated by such assessments will invariably be strongly shaped by their underlying assumptions – including, for example, the shares of growing global demand that will be satisfied by wind, solar, or nuclear power in the next decades.

7 Appendix

7.1 Overview of scenarios used to calculate grid costs

Scenario Name	Source	Compared Scenarios (vRes penetration rate in percent)
NEP 2024 A/B	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario A2024 (28 percent) and Scenario B2024 (31 percent)
NEP 2024 B/C	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario B2024 (31 percent) and Scenario C2024 (42 percent)
NEP 2024 A/C	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario A2024 (28 percent) and Scenario C2024 (42 percent)
ONEP 2024 A/B	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario A2024 (28 percent) and Scenario B2024 (31 percent)
ONEP 2024 B/C	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario B2024 (31 percent) and Scenario C2024 (42 percent)
ONEP 2024 A/C	German transmission system operators (ÜNB) and German Grid Agency (BNetzA), 2014	Scenario A2024 (28 percent) and Scenario C2024 (42 percent)
Consentec 2033 1	Consentec, 2013	Reference Scenario 2033 (64 percent) and Resource-driven Scenario 2033 (64 percent)
Consentec 2033 2	Consentec, 2013	Resource-driven Scenario 2033 (64 percent) and Consumption-driven Scenario 2033 (64 percent)
Consentec 2033 3	Consentec, 2013	Reference Scenario 2033 (64 percent) and Consumption-driven Scenario 2033 (64 percent)
IAEW/E-Bridge/Offis 2032 1	IAEW/E-Bridge/Offis, 2014	Scenario EEG 2014 (N/A) and Scenario NEP 2032 (N/A)
IAEW/E-Bridge/Offis 2032 2	IAEW/E-Bridge/Offis, 2014	Scenario NEP 2032 (N/A) and Scenario Bundesländer 2032 (N/A)
IAEW/E-Bridge/Offis 2032 3	IAEW/E-Bridge/Offis, 2014	Scenario EEG 2014 (N/A) and Bundesländer 2032 (N/A)
PV Parity 2020 1	Imperial College London, 2014	EU 2020 (5 percent)
PV Parity 2020 2	Imperial College London, 2014	EU 2020 (10 percent)
PV Parity 2020 3	Imperial College London, 2014	EU 2020 (15 percent)
PV Parity 2030	Imperial College London, 2014	EU 2030 (5 percent)
KEMA 2020 1/2	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2020 (20 percent) and Scenario 2-2020 (17 percent)
KEMA 2020 2/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 2-2020 (17 percent) and Scenario 3-2020 (18 percent)
KEMA 2020 1/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2020 (20 percent) and Scenario 3-2020 (18 percent)
KEMA 2025 1/2	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2025 (26 percent) and Scenario 2-2025 (25 percent)
KEMA 2025 2/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 2-2025 (25 percent) and Scenario 3-2025 (21 percent)
KEMA 2025 1/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2025 (26 percent) and Scenario 3-2025 (21 percent)
KEMA 2030 1/2	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2030 (41 percent) and Scenario 2-2030 (32 percent)
KEMA 2030 2/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 2-2030 (32 percent) and Scenario 3-2030 (27 percent)
KEMA 2030 1/3	KEMA/Imperial College London/NERA/DNV GL, 2014	Scenario 1-2030 (41 percent) and Scenario 3-2030 (27 percent)
NEA DE 1	NEA, 2012	DE (10 percent PV)
NEA DE 2	NEA, 2012	DE (30 percent PV)
NEA FIN 1	NEA, 2012	FIN (10 percent PV)
NEA FIN 2	NEA, 2012	FIN (30 percent PV)
NEA FR 1	NEA, 2012	FR (10 percent PV)
NEA FR 1	NEA, 2012	FR (30 percent PV)
NEA UK 1	NEA, 2012	UK (10 percent PV)
NEA UK 2	NEA, 2012	UK (30 percent PV)

References and further reading

The list of literature presented here gives an – most likely incomplete – overview of the literature available, structured into four categories: (i) integration of renewables (ii) grid cost (iii) balancing cost (iv) interaction with other power plants and (v) other literature. References explicitly mentioned in this paper are included in the appropriate categories.

(i) Integration of renewables

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Strbac, Goran, Anser Shakoor, Mary Black, Danny Pudjianto & Thomas Bopp (2007): "Impact of wind generation on the operation and development of the UK electricity systems", *Electric Power Systems Research* 77, 1214–1227.

(ii) Grids

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Imperial College London, 2014: Direct Costs Analysis related to Grid Impacts of Photovoltaics, commissioned by the European Commission.

KEMA/Imperial College London/NERA/DNV GL, 2014: Integration of Renewable Energy in Europe, commissioned by the European Commission.

Prognos/IAEW, 2014: Positive Effekte von Energieeffizienz auf den deutschen Stromsektor; commissioned by Agora Energiewende and European Climate Foundation.

(iii) Balancing costs

Carlsson, Fredrik (2011): "Wind power forecast errors. Future volumes and costs", *Elforsk report* 11:01 .

DeMeo, Edgar, Gary Jordan, Clint Kalich, Jack King, Michael Milligan, Cliff Murley, Brett Oakleaf & Matthew Schuerger (2007): "Accomodating Wind's Natural Behavior", IEEE power & energy magazine November/December 2007.

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