Cost and revenue related impacts of integrating electricity from variable renewable energy into the power system - A review of recent literature

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May 2014
ECN--E-14-022

Acknowledgement

The author would like to thank the ECN senior group managers Paul Koutstaal and Eppe Luken for their feedback on a previous version of this paper.

At ECN, the activities regarding this paper are registered under project number 52803.03.01.

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Abstract

The major purpose of the paper is to review a set of recent publications on the cost and revenue related impacts of integrating rising shares of electricity from variable renewable energy (VRE) in the power system. More specifically, besides discussing some methodological issues on assessing VRE integration impacts and costs, the paper review some thirty recent publications on different categories of VRE integration impacts and costs, including (i) balancing impacts and costs, (ii) grid-related impacts and costs, (iii) system adequacy impacts and costs – and, finally, some VRE-induced impacts on wholesale electricity prices, generators' revenues and the profitability or competitiveness of VRE and non-VRE generators.

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Summary of major findings and conclusions

Power generation from variable renewable energy (VRE), such as wind or solar, has grown rapidly over the past two decades. Electricity output from VRE generators, however, has a number of specific characteristics (i.e. it is variable, uncertain, location-specific, modular and low short-run cost), that cause a variety of cost and revenue related impacts on the power system, in particular when the share of VRE power generation rises rapidly and becomes quite substantial.

Regarding the cost related impacts of integrating VRE output into the power system, three categories are usually distinguished:

- *Balancing impacts and costs,* i.e. the impacts and costs due to the short-term variability and uncertainty of VRE generation output, including the costs arising from the need to hold and use more system operating reserves against higher uncertainty (errors) in forecasting output from VRE generators, as well as from the (related) increase in ramping, cycling or other, less cost-effective operations of other power plants.
- *Grid-related impacts and costs,* i.e. the impacts of VRE deployment on transmission and distribution needs and the associated costs to extend and reinforce the network in order to meet these needs (including occasional benefits of lower grid needs and lower network losses at lower VRE penetration rates).
- *Adequacy impacts and costs,* i.e. increasing VRE deployment reduces the deployment – or utilisation – of conventional, non-VRE generators (*the utilisation effect*) but hardly reduces the need for conventional capacity to safeguard system adequacy (*the capacity credit effect*). Adequacy impacts of VRE deployment refer to these effects, while adequacy costs refer to the associated costs.

Based on a review of recent studies and surveys on these cost related impacts of integrating VRE into the power system, the major findings and conclusions include:

(1) The deployment of wind and solar power causes significant integration costs, in particular at higher penetration levels (>10%). At 10-30% penetration, these costs range from 10-30 €/MWh for wind and from 25-50 €/MWh for solar. As a

percentage of their LCOE, these amounts correspond to a range of 15-40% for wind and of 15-35% for solar.

(2) Balancing costs are generally the lowest component of total VRE system integration costs, ranging from 1-6 €/MWh, i.e. 5-15% of total integration costs. The largest component consists of either grid-related costs or adequacy costs, depending on the specific case or study considered.

(3) Apart from the cost definition and methodology used, estimates of the size and composition of VRE integration costs are location-specific, varying from country to country and from power system to power system, depending on a complex interaction of factors such as VRE characteristics (power output profiles, load factors, penetration rates), electricity load characteristics (magnitude of peak load, load profiles, correlation with VRE output), generation plant mix, geographical and balancing area size, transmission connections with neighbouring regions, designs of the distribution networks, time perspective, etc.

(4) Integration costs per MWh of VRE output tend to increase with growing penetration rates. Integration costs may even be negative (benefits) at low penetration levels (1-3%), but costs often become significant and tend to show a steep increase at 5-10% VRE penetration. At even higher shares of VRE deployment, the increase in integration costs seems to level off gradually.

(5) At a given (fixed) penetration rate, integration costs per MWh of VRE output tend to decrease over time depending on the adaptation or transformation of the power system, including options to enhance the overall flexibility of the power system such as improving the flexibility of the power plant mix, enhancing demand responsiveness, extending and enforcing the grid infrastructure, introducing more flexible system and market operations, etc.

In addition to a variety of impacts affecting system costs, VRE deployment has some (related) impacts on generators' output prices and, hence, on their market revenues and operational surpluses, as well as on the profitability and competitiveness of VRE and non-VRE generators, their ability to recover their fixed investment costs and their willingness to invest in new generation capacity.

In brief, regarding these revenue related impacts of integrating VRE output into the power system, the major findings and conclusions include:

(6) Due to its low short-run marginal costs, increasing output from VRE deployment decreases wholesale electricity prices (*the wholesale price effect*). In the short and medium term, at higher VRE penetration levels, this effect is likely rather substantial (e.g. at 30% wind penetration, the VRE-induced price reduction effect probably varies between 15-35 €/MWh). In the long run, however, the wholesale price effect is likely significantly lower, depending on the adaptation of the power system.

(7) Increasing VRE deployment increases the short-term volatility of wholesale prices and, hence, enhances the risk of power generation.

(8) VRE output curtailment has, up to now, been relatively low in European countries, but model simulations show that at higher VRE penetration levels (20-50%), VRE curtailment as a fraction of potentially generated power becomes higher (up to 5%), implying higher output (revenues) for non-VRE generators, but lower output (revenues) for VRE generators and lower benefits – or cost savings (fuels, emissions) in the non-VRE system.

(9) Due to the wholesale price effect, it gets harder – and perhaps even impossible – for VRE technologies, despite their learning rates, to become profitable and market competitive (without VRE support), i.e. to cover their fixed investment costs and, hence, these technologies may become increasingly dependent on subsidies in order to meet rising, ambitious RE targets. This applies particularly for the short and medium term. In the long run, the wholesale price effect may be significantly lower – or even largely disappear – depending on the adaptation of the power system. Moreover, the profitability or competitiveness of VRE technologies depends also on other factors such as the prices of fossil fuels and CO_2 emissions.

(10) Due to the wholesale price effect and the utilisation effect, increasing VRE deployment reduces the generation revenues and operational surpluses of conventional power plants, notably of mid-merit and peak-load units with relatively high short-run marginal costs, such as gas-fired turbines. This may result in plant closures and a lack of incentives to invest in maintaining and expanding generation capacity. Once again, this applies particularly in the short and medium term, but may be less significant in the long run depending on the adaptation of the power system (notably the shift towards a more optimal plant mix).

(11) More generally, assuming there is a so-called 'missing money problem' in liberalised, energy-only markets (i.e. a lack of operational surpluses to cover investment costs), increasing VRE deployment exacerbates this problem through both the revenue-decreasing impact and the price-volatility, risk-increasing impact of VRE deployment on conventional power plants, in particular in the short and medium term. In the long run, however, these impacts on the missing money problem – including the related system adequacy problem – may be lower, or even largely disappear, depending on the long-term transformation of the power system.

1 Introduction

Over the past two decades, power generation from variable renewable energy sources – in particular from wind and solar – has increased substantially in several EU Member States. In order to meet long-term, ambitious climate and other sustainability targets, it is expected that the share of variable renewable energy (VRE) in total electricity use will rise even more significantly in the coming decades. Power generation from VRE, however, has a number of specific characteristics that cause a variety of impacts on the power system, in particular when the share of VRE power generation rises rapidly and becomes quite substantial.

Recently, the IEA has identified and discussed several specific characteristics of power generation from VRE that appear to be relevant from a system integration perspective (IEA, 2014). In brief, focussing on the main characteristics relevant to this paper, electricity output from VRE generators is:[1]

- *Variable,* i.e. power output fluctuates depending on the availability of the renewable energy source, notably on the weather conditions affecting wind speed and sun radiation. As a result, output from VRE (‘*intermittent’*) generators cannot be controlled or economically dispatched by system operators based on traditional economic criteria, in contrast to output from most conventional (‘*dispatchable’*) generators that can be turned on and off based on their economic attractiveness at every point in time to supply electricity and other system services – e.g. reliability – according to real-time power demand and other system needs (Joskow, 2011).
- *Uncertain,* i.e. due to deficiencies in forecasting weather conditions, output from VRE generators is less predictable and, hence, less certain than other, controllable generators.
- *Location-specific,* i.e. VRE resources are not evenly distributed geographically and, in contrast to conventional fuels, cannot be transported to other locations. This may affect siting decisions and transmission needs as generation sites with high VRE output potentials may be located far from areas of high electricity demand.
- *Modular,* i.e. the scale of an individual VRE production unit (wind turbine, solar panel) is much smaller than of a conventional (fossil-fuel, nuclear or large-hydro)

1 In addition, IEA (2014) discusses another technical property of VRE generation, i.e. it is non-synchronous. For a further discussion of this and other system-specific characteristics of VRE power production, see IEA (2014), as well as Sims et al. (2011) and Pérez-Arriaga (2011).

generator. The increasing amount of smaller, distributed generation from VRE has a major impact on the structure and operation of the transmission and distribution network.
- *Low short-run cost,* i.e. once built VRE generators can produce electricity at very little costs as their short-run, marginal costs are close to zero (IEA, 2014).

As mentioned, due to the specific properties of electricity from VRE, deploying higher, rapidly rising shares of VRE in total generation has a variety of impacts on the power system. In brief, these cost and revenue related impacts include among others:
- Costs resulting from impacts on balancing (short-term) power demand and supply, safeguarding (long-term) system adequacy and meeting grid-related needs.
- Impacts on wholesale electricity prices, generators' revenues and the profitability or competitiveness of VRE versus other generators.

Over the past two decades, these impacts have been amply analysed and discussed by a large, rapidly growing amount of scientific and policy-oriented publications.[2] The major purpose of the present paper is to review a set of recent publications on the cost and revenue related impacts of integrating rising shares of VRE generation in the power system, in particular to present and discuss the major findings and conclusions of these publications.

The structure of this paper runs as follows. Section 2 discusses some methodological issues on assessing VRE integration impacts and costs. Subsequently, Sections 3 up to 7 review the major findings of some recent publications on different groups or categories of VRE integration impacts and related costs and revenues, including balancing impacts and costs (Section 3), grid-related impacts and costs (Section 4), system adequacy impacts and costs (Section 5), total VRE integration costs (Section 6) and, finally, some VRE-induced impacts on wholesale electricity prices, generators' revenues and the profitability or competitiveness of VRE and non-VRE generators (Section 7).

[2] References of the full list of publications reviewed are included at the end of this paper..

2

Some methodological issues[3]

2.1 The LCOE approach

A common metric to assess the costs or economic attractiveness of different generation technologies is the concept of *levelised costs of electricity* (LCOE). LCOE is calculated at the plant level by summing up the present (discounted) value of all lifetime fixed and variable costs of a generation technology – including costs of investments, fuel, operation, maintenance, etc. – and dividing it by the amount of electricity the plant will produce. It is usually expressed in average generation costs per unit produced, for instance in €/MWh.

LCOE, however, is a flawed metric for assessing or comparing the economic attractiveness of VRE generators versus conventional, dispatchable power plants, basically because "LCOE as a measure is blind to the when, where and how of power generation" (IEA, 2014). More specifically, the basic flaws or shortcomings of the LCOE approach to assess the economic value (attractiveness) of VRE versus other generation technologies include (Joskow, 2011; Hirth, 2012 and 2013; Ueckerdt et al., 2013; Edenhofer et al., 2013; IEA, 2014):

- It does not consider *when* electricity is produced, i.e. the value or wholesale price of electricity varies widely throughout the day, week and year. As a result, the market value of electricity from VRE technologies can vary widely depending when the electricity is produced. In particular, other things equal, the classic LCOE approach tends to overvalue generation from wind – as its output is more heavily weighted to off-peak periods when electricity prices are relatively low – and to undervalue power production from solar, as it usually generates relatively more electricity during periods of the day when prices are relatively high (Joskow, 2011).
- It does not consider *where* electricity is produced, i.e. due to grid-related costs and constraints the value of electricity differs depending on where it is produced. In particular, other things equal, the value of electricity from off-shore wind – which is

[3] This section is based on and follows Chapter 4 of IEA (2014), supplemented by other recent publications mentioned in the text.

often far located from high power demand centres – is usually significantly lower than the electricity from solar PV produced at the end-user level.
- It does not consider *how* electricity is produced, i.e. due to certain system-specific characteristics of VRE generators (variable, uncertain, non-synchronous, etc.), the value of electricity from these generators is – other things equal – usually lower than the value of electricity from conventional technologies as specific system costs result from addressing the impacts of these characteristics (such as system adequacy, reliability, frequency or balancing costs; see IEA, 2014 and Sections 3 and 5 below).

Hence, whenever technologies differ in the when, where or how of their generation, an assessment based on LCOE is no longer valid and may be misleading as it implicitly assumes that electricity generated from different sources has the same value (IEA, 2014). Consequently, to assess the economic value or attractiveness of different generation technologies from a social or power system perspective, the LCOE of a technology needs to be compared with its (marginal) economic value, which depends on when, where and how the electricity is produced (Edenhofer et al., 2013; see also the section on the value of VRE generation below).

In order to address the shortcomings of the LCOE approach, two alternative approaches have been developed to assess the system costs and economic attractiveness of, particularly, VRE generation. One approach consists of calculating so-called *system integration costs* and the other of calculating *total system costs*, and based on this, calculating the *system value* of VRE output generation (Miligan et al., 2011; Edenhofer et al., 2013; IEA, 2014).

2.2 Integration costs of VRE generation

In the case of VRE power generation, (system) integration costs have been defined in different ways, for instance as “the extra investment and operational cost of the non-wind part of the power system when wind power is integrated” (Holttinen, et al., 2011), as “the additional cost of accommodating wind and solar” (Miligan et al., 2011), as “the marginal impact that additional wind or solar power has on the costs of the residual system” (Hirth, 2012), or as “additional system costs induced by VRE that are not directly related to their generation costs” (Ueckerdt et al., 2013).[4] Moreover, integration costs have often been decomposed in different sub-categories – such as ‘balancing costs’, ‘grid-related cost’, ‘adequacy costs’ or ‘profile costs’ – often decomposed and defined differently across different studies (see, for instance, NEA, 2012; Hirth, 2012 and 2013, Ueckerdt et al., 2013, Pudjianto et al., 2013, and Holttinen et al., 2013). In addition, these costs have been calculated in different ways using a large variety of methodologies, tools and underlying assumptions (Brouwer et al., 2014).

[4] Other definitions of integration costs or similar concepts, such as ‘additional system costs’, can be found in, for instance, NEA (2012) and IEA (2014).

In general, calculating integration costs of VRE generation technologies is done by setting up and comparing two scenarios. One scenario includes the technology in question and one does not include it at all or includes it at a lower penetration level. Cost differences between these scenarios are calculated and, subsequently, allocated to the technology in question (IEA, 2014).

Calculating, assessing or comparing integration costs of VRE generation technologies, however, raises some methodological complications.

Firstly, to single out integration costs that are due to certain specific system properties, for instance the variability and uncertainty of a VRE technology, one needs to compare this technology with another technology that is identical in terms of all system aspects – i.e. the when, where and how of power generation – with the only exception that this reference technology is neither 'variable' nor 'uncertain' (IEA, 2014). Constructing such a proxy or benchmark technology, however, can be quite challenging and complicated, resulting in inadequate outcomes (Miligan et al., 2011; Ueckerdt et al., 2013). Therefore, establishing a single benchmark to compare and assess different generation technologies can result in comparing apples and pears and in inaccurately estimating – i.e. under- or overestimating – integration costs of VRE generation technologies (Miligan et al., 2011; Ueckerdt et al., 2013; IEA, 2014).

Secondly, besides assessing or comparing the 'true' or 'full' costs of VRE versus other generation technologies, integration costs are sometimes calculated in order to design a system tariff to recover the additional costs that a VRE technology causes to the power system. This aim refers to questions such as "Who causes what costs and who should pay for them?" and raises issues even more complicated to solve than developing a benchmark technology. In particular, the complex myriad of effects mediated through the power grid – and integrated simultaneously into a single, system-level outcome – can make the attribution of causality extremely challenging and rather misleading (IEA, 2014).

Thirdly, when calculating integration costs, the analysis is usually done separately according to different cost categories such as balancing, adequacy and grid-related costs (see Sections 3-5 below). These categories, however, are not independent of each other. For instance, additional grid investments may smooth the variability of VRE at the system level and, hence, reduce balancing and adequacy costs. Similarly, a longer-term adaptation of the generation mix towards more flexible units will lower balancing costs, but may also affect adequacy costs. Hence, a rigorous decomposition and calculation of integration costs into the above-mentioned categories is generally not possible. Moreover, as these cost components are not independent of each other, caution is needed when adding up components, notably if they have been obtained from different modelling exercises using different reference technologies (IEA, 2014).

Finally, there are at least two main reasons why estimates of VRE integration costs are difficult to compare across different studies and inherently include a high degree of uncertainty. Firstly, VRE integration impacts and costs depend on the specific power system, which differs across countries and regions, while changing over time. Hence, the system-specific nature of VRE integration impacts results in a wide range of cost estimates – see Sections 3-6 below – and complicates the comparison of these estimates across different studies focusing on different countries, regions or time intervals. Secondly, the wide range of cost estimates – and the difficulty to compare these estimates – also results from the large variety of different methodologies that have been used to estimate VRE integration impacts and costs, including the use of different modelling exercises, scenario assumptions, reference technologies and calculation tools (Brouwer et al., 2014; IEA, 2014).

The methodological complications and qualifications mentioned above should be considered when assessing the findings on integration cost estimates reviewed in Sections 3-6 below.

2.3 Total system costs and the value of VRE

Another approach – compared to both the LCOE approach and the integration cost approach – is to calculate total system costs and, based on this, the value of electricity from VRE technologies. By focusing on (changes in) total system costs, the major advantage of this approach is that it avoids the complications of, on the one hand, decomposing integration costs in different categories and, on the other hand, developing an appropriate benchmark technology to determine these costs. In particular, when adding VRE generation to the system, two types or groups of changes in system costs can be distinguished (IEA, 2014):

- An *increase* in some costs, such as an increase in balancing or grid-related costs and the costs of VRE deployment itself. This group of changes can be termed *additional costs* of VRE deployment.
- A *reduction* in other costs, such as reduced fuel costs, reduced need for other generation capacity, reduced grid losses and reduced carbon or other emission costs (as far as these costs have been internalized into the power system, for instance through a carbon tax or emissions trading scheme). This group of changes can be termed *benefits* or *avoided costs* of VRE deployment.

By comparing (or adding up) these two groups of cost changes, the economic attractiveness of VRE deployment can be simply determined. If the avoided costs (benefits) of VRE deployment are higher than its additional costs, total system costs decrease due to VRE deployment and, hence, this deployment is economically attractive from a system perspective. On the other hand, if the avoided costs are lower than the additional costs, total system costs increase and, hence, VRE deployment is not attractive.

Actually, as it is sometimes complicated to determine which costs are avoided and which costs are additional – for instance, because they are closely related or may change over time from avoided to additional costs, and vice versa – it may even be more simple to calculate total system costs only for two scenarios, i.e. one including and one excluding VRE deployment, and just compare the two outcomes to assess the economic attractiveness of VRE deployment.

As indicated, based on calculating changes in system costs, the value of VRE generation can be determined and compared with the generation costs of electricity from VRE. More specifically, the (economic or system) value of VRE deployment corresponds to its net benefits to the residual system, i.e. avoided costs minus increased costs, excluding the investment and operational costs of VRE generation itself. This value – or, more precisely, the set of underlying cost changes – is influenced by a number of factors such as (i) the temporal and locational match between electricity demand and VRE generation, i.e. the when and where of this generation, (ii) the penetration rate and mix of VRE technologies, (iii) the flexibility of the power system and generation portfolio, and (iv) the degree of system adaptation over time to rising and higher levels of VRE penetration rates (IEA, 2014). For instance, at a higher degree of system adaptation over time, the additional costs of VRE generation at a certain penetration rate may be lower in the medium or long run while the avoided costs may be higher, resulting in higher net benefits (or lower 'net integration costs') and, hence, a higher value of VRE generation (see Sections 3-7 below for a further discussion of the factors affecting the system costs and value of VRE deployment).

A major advantage of the system value approach is that the value of adding VRE generation output to the system can be compared to the investment and operational costs of VRE generation itself, including different levels of aggregation (i.e., for instance, at the total or average level of VRE output, and either at the individual technology or plant level or for a range of VRE technologies and plants as a whole). If expressed in average output per VRE technology (e.g., on a per MWh basis) the system value of VRE generation can even be directly compared to its levelised costs (LCOE). If the value of additional VRE generation is larger than its LCOE, further increasing the deployment of VRE is economically attractive and helps to decrease total system costs (IEA, 2014). The opposite applies, however, if the value of additional VRE generation is smaller than its LCOE. From a system perspective, the optimal level of VRE deployment is reached if the (marginal economic) value of additional VRE generation is equal to its levelised costs (Hirth, 2012; Ueckerdt et al., 2012; Edenhofer et al., 2013).

2.4 Other perspectives: other costs and benefits

Most of the (scientific) literature using one of the approaches above – i.e. either based on LCOE, integration costs, total system costs or system value – assesses costs and benefits of VRE generation from a so-called power system perspective.[5] These costs and benefits, however, can also be considered from a wider social perspective, for instance from the perspective of the total energy system or from society as a whole, including the impact of VRE generation on other (energy) sectors and/or other (social, environmental) aspects (IEA, 2014). In that case, the assessment of VRE deployment includes also other (additional) costs and benefits outside the power system such as (i) changes (decreases) in fossil fuel prices and resulting changes (increases) in fuel use outside the power sector (due to the VRE-induced lower demand for fossil fuels by the power sector), (ii) changes in economic activities and employment, or (iii) changes in

[5] This applies also for most of the literature reviewed in Sections 3-6 below, unless stated otherwise.

emissions and other pollutants (as far as these emissions or pollutants have not already been internalized by the power sector).

In addition, costs and benefits of VRE deployment can also be considered from a (more narrow) private perspective. In that case, the assessment takes account of only those costs and benefits that an investor actually pays and receives, including (discounted) investment and operational costs, as well as (discounted) market revenues, subsidies and other forms of public support to VRE deployment.

Findings and conclusions from assessing VRE generation may vary significantly depending on the perspective (system, social, private) and the approach (LCOE, integration costs, system costs, system value) taken. This can be illustrated by means of **Table 1**, which presents a fictive numerical example of the costs and benefits of two VRE technologies – wind and solar – according to three different perspectives (power system, social, private) and the cost/benefit approaches outlined above.

Table 1: Fictive numerical example of assessing VRE generation technologies from different perspectives

	System perspective		Social perspective		Private perspective	
	Wind	Solar	Wind	Solar	Wind	Solar
1. Benefits (avoided costs)	60	110	80	130	40	70
2. Additional costs	20	10	20	10	0	0
3. Value (1 - 2)	40	100	60	120	40	70
4. LCOE	50	90	50	90	35	75
5. Net value (3 - 4)	-10	10	10	30	5	-5

For instance, **Table 1** shows that, from a power system perspective, the LCOE is 50 €/MWh for wind and 90 €/MWh for solar (which, according to the LCOE approach, may lead to the – dubious – conclusion that wind is 'more attractive' than solar). However, as the additional system costs of solar are lower than of wind (10 and 20 €/MWh, respectively) while the respective benefits are higher (110 and 60 €/MWh, respectively) – for instance, due to lower grid-related costs and higher (peak) electricity prices for solar – the system value is higher for solar than for wind (100 and 40 €/MWh, respectively). Comparing this value with the respective LCOE of these technologies results in a net value of +10 €/MWh for solar and of -10 €/MWh for wind. Hence, from a system value perspective, solar would be economically attractive while wind would be unattractive.

From a (wider) social perspective, however, an assessment of the two technologies leads to the conclusion that the net value of these technologies is significantly higher than from a power system perspective, although solar is still more attractive than wind (i.e. 30 and 10 €/MWh, respectively; see **Table 1**). This is due to the fact that in the (fictive, numerical) example of **Table 1** the benefits of both solar and wind are assumed to be higher from a social perspective, e.g. due to lower external environmental effects resulting from these technologies.

Finally, from a private perspective, it can be observed from **Table 1** that (i) the additional system costs of VRE deployment – e.g., for transmission, system adequacy and balancing – are zero for both solar and wind, i.e. they are assumed to be socialized and passed on to electricity end-users rather than allocated to power producers, (ii) on the other hand, compared to the power system and social perspective, benefits are lower for investors, notably in solar, e.g. because certain system or social benefits, such as lower grid losses or lower external effects, are not accruing to these investors, (iii) due to public support to VRE investment, the LCOE of both wind and solar is reduced by, on average, 15 €/MWh for each technology to 35 and 75 €/MWh, respectively, and (iv) as a result, the net value is +5 €/MWh (profit) for wind and -5 €/MWh (loss) for solar.[6]

In the case of complete and perfect markets, the (net) value of a VRE technology from a private perspective is equal to its (net) value from both a system and social perspective. In the fictive example of **Table 1** (as in reality) this is, however, not the case due to the fact that not all costs and benefits of VRE deployment are fully internalised and passed on to private investors.

The example outlined above illustrates that the findings and conclusions of economic assessments of VRE deployment depend highly on both the cost-benefit approach and the cost-benefit perspective of these assessment (besides the wide range of specific methodologies and tools used within each approach/perspective). Therefore, authors and analysts conducting such assessments should be aware of the implications of applying a certain cost-benefit approach/perspective and report the most relevant implications of their approach/perspective in an adequate way. Moreover, these implications – and the other methodological complications and qualifications outlined in this section – should be acknowledged when reading the sections below on the impacts and costs of VRE deployment.

[6] Note that the figures in **Table 1** are fictive numbers for illustrative purposes only and do not necessarily relate to reality.

3

Balancing impacts and costs

3.1 Balancing impacts

Due to the variability and uncertainty of VRE generation output, an increase in the share of VRE deployment generally tends to lead to (i) an increase in the magnitude and frequency of changes in net load, i.e. an increase in the short-term variability of total load minus VRE output, ranging from minutes up to a timescale of one or two days, and (ii) an increase in the risk and incidence of forecast errors. Consequently, in order to address these effects and safeguard a reliable, short-term balancing of power demand and supply, an increase in VRE deployment implies (a) an increase in reserve requirements, i.e. a higher need for balancing and other short-term, system-operating reserves, and (b) a higher need for flexibility of other, non-VRE generators including, for instance, a need for higher levels of plant cycling, ramping, part-load operations and idle capacities of these generators. These impacts of increasing VRE deployment translate into additional costs due to holding and operating more reserves, the increased ramping and cycling of conventional, non-VRE power plants, including higher costs resulting from higher wear-and-tear, forced outage rates, shorter plant lifetimes, lower fuel efficiencies or, more generally, less cost-effective investments and operations of these non-VRE power plants.

While the above-mentioned impacts due to the short-term variability and uncertainty of VRE deployment are usually grouped together under the heading *'balancing impacts'* or *'balancing effects'*, the associated costs are generally labelled as *'balancing costs'*.[7]

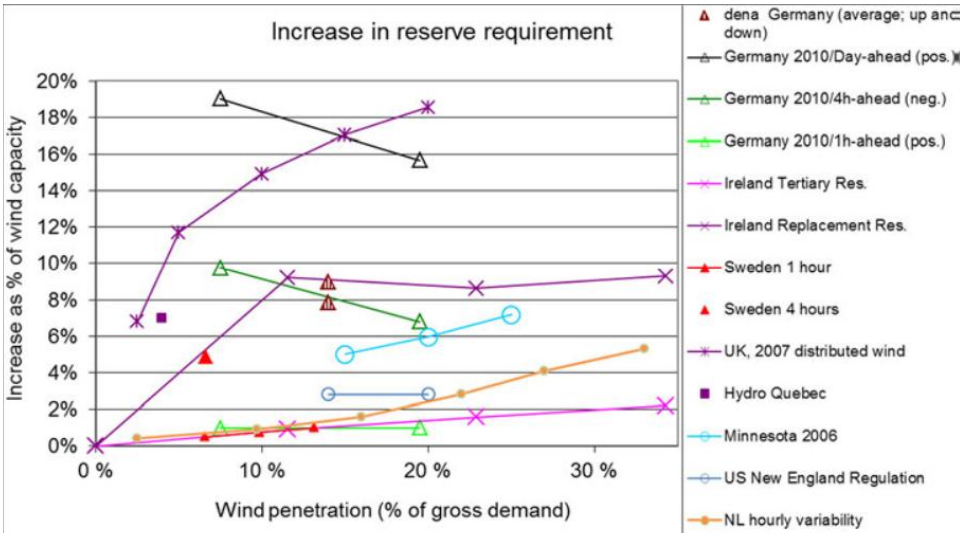
[7] Occasionally balancing costs are called *'imbalance costs'*. For more (technical) details on balancing impacts and costs of VRE deployment, see Gross et al. (2006), Holttinen et al. (2011 and 2012), Pérez-Arriaga (2011), Pérez-Arriaga and Battle (2012), Hirth (2012) and IEA (2014).

3.2 Reserve requirements

Holding and operating reserves are required to maintain the short-term balance between power generation and load in an electricity system. Across countries, there is a wide variety of types, categories and labels of reserves differentiated by (i) the type of event they respond to (contingencies, forecast errors, etc.), (ii) the timescale of the response (seconds, minutes, hours), (iii) the direction of the response (upward, downward), and (iv) the type of required response (instantaneously – i.e. automatically – or manually activated within a short time period; see Pérez-Arriaga, 2011). For instance, primary and secondary reserves are usually activated automatically within timeframes of seconds and minutes, while tertiary and hourly reserves are activated manually within timeframes shorter and larger than one hour, respectively.[8]

As noted, increasing VRE deployment tends to lead to increased reserve requirements as the risks of forecasts errors on generation output increases. Recently, both Holttinen et al. (2011 and 2013) and Brouwer et al. (2014) reviewed a large variety of studies on the increase in reserve requirements resulting from higher shares of VRE deployment, notably of wind power. They show that estimates of increases in reserve requirements due to increases in VRE deployment vary widely. Apart from differences in methodology and other factors determining reserve requirements (see below), this variety of estimates is mainly due to differences in timescales of uncertainty taken into account in different studies. This is illustrated in **Figure 1**, obtained from Holttinen et al. (2013), showing increases in reserve requirements as a function of wind power penetration, estimated by studies using different timeframes of uncertainty in forecasting wind power.

Figure 1: Increase of reserve requirements as a function of wind power penetration



Source: Holttinen et al. (2013).

8 For a further discussion of different types and definitions of operating reserves in power systems across different countries, see Gross et al. (2006), Pérez-Arriaga (2011) and Holttinen et al. (2011 and 2013).

More specifically, the studies reviewed by Holttinen et al. (2013) show that:

- If only hourly variability of wind is taken into account when estimating the increase in short-term reserve requirement, the results are 3% of installed wind capacity or less, with penetrations below 20% of power demand.
- When 4-hour forecast errors of wind power are taken into account, an increase in short-term reserve requirement of up to 9–10% of installed wind capacity has been reported for penetration levels of 7–20% of power demand (Holttinen et al., 2013).

In general, the size of the increase in reserve requirements is significantly higher if the timeframe of VRE output uncertainty is larger (Holttinen et al., 2013; Brouwer et al., 2014). This is caused by the larger correlation in VRE power production at larger timeframes, resulting in larger forecast errors and, hence, in a higher need for reserves (Brouwer et al., 2014). Moreover, regardless the timeframe of uncertainty, almost all studies reviewed by Holttinen et al. (2013) and Brouwer et al. (2014) show that the relative reserve size increases at higher rates of VRE penetration (see **Figure 1** and similar graphs in Brouwer et al., 2014). The curves of the relative reserve requirements (in % of installed VRE capacity) show a steep increase at lower VRE penetration levels (5-10%), which gradually levels off at higher shares of VRE deployment (as the relative level of forecasting errors and resulting VRE output uncertainties becomes smaller if the number of VRE generators increases and becomes more geographically spread across the power system).

An increase in reserve requirements does not necessarily imply new investments in reserve capacity. As the amount of VRE-caused reserves is at its highest when VRE generation is at a high output level, the other power plants are usually operated at a low level, i.e. they can act as reserves and increase their output if VRE generation decreases (Holttinen et al., 2011). This implies, however, that these non-VRE power plants have to operate at a higher level of flexibility (more cycling, higher ramping rates, etc.), thereby raising operational inefficiencies and costs. At higher VRE penetration rates, however, there may be a need for investments in additional reserve capacity of more flexible plants in order to better address the balancing impacts of higher VRE deployment and, hence, to reduce the costs of these impacts.

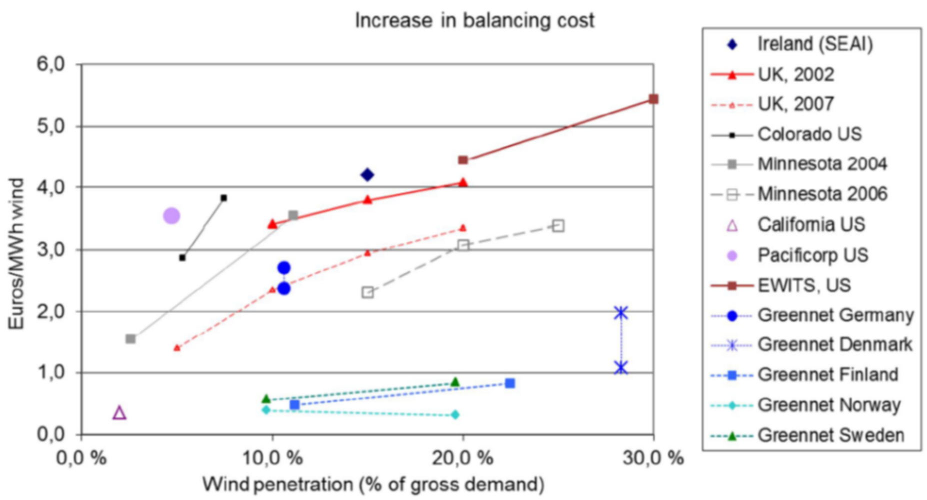
3.3 Balancing costs

As noted, balancing costs due to VRE deployment arise from the need to hold and use more system operating reserves against higher uncertainty (errors) in forecasting output from VRE generators, as well as from the (related) increase in ramping, cycling or other, less cost-effective operations of other power plants due to the VRE-induced increase in short-term variability and uncertainty of net load (IEA, 2014). These balancing costs have been estimated by a large variety of studies, as surveyed by, amongst others, Gross et al. (2006), Holttinen et al. (2011 and 2013), and Hirth (2012). The major findings of these studies and surveys include:

- For wind penetrations up to 30% of power demand, model estimates of balancing costs range from 1-5 €/MWh, depending on penetration rate and system context of the countries studied (see **Figure 2**, obtained from Holttinen et al., 2013). This is approximately 10% or less of the wholesale value of the generated wind power. Other surveys (Gross et al., 2006; Hirth, 2012) show similar ranges of estimated balancing costs.

- Similar to the increase in reserve requirements (as discussed above), several studies show that balancing costs tend to increase at higher rates of wind penetration, in particular at lower intervals (5-10%), but seem to level off at higher penetration levels.
- NEA (2012) has estimated balancing costs in selected OECD countries for three VRE technologies (onshore wind, offshore wind and solar) and three conventional technologies (coal, gas and nuclear) at different penetration levels (10% and 30%). These costs are similar for each VRE technology but range from 1.3 to 3.5 €/MWh in France (at penetration rates of 10% and 30%, respectively), from 2.3 to 4.5 €/MWh in Germany and from 5.3 to 9.9 €/MWh in the UK.[9] Comparable balancing costs for the conventional technologies in these countries are significantly lower, ranging from 0.0 to 0.6 €/MWh (NEA, 2012).
- In addition to model estimates, there is some evidence on actual balancing costs of wind power from electricity (balancing) markets, i.e. 0.6 €/MWh at a wind penetration level of 4% in the Netherlands, 1.3-1.5 €/MWh for 16% wind penetration in Spain, and 1.4-2.5 €/MWh for 24% wind penetration in West-Denmark (Holttinen et al., 2013).

Figure 2: Comparison of modelled balancing costs from different integration studies



Source: Holttinen et al. (2013).

In general, estimates of balancing costs per MWh of VRE generation are relatively low, notably at low penetration levels, but vary widely across studies and power systems, and tend to become more significant at higher penetration levels. In addition to differences in penetration rates and estimation methodologies (including differences in cost definitions), the variation in cost estimates is due to a variety of other system-specific factors such as (i) the method and quality of forecasting VRE generation output, (ii) the timeframe of scheduling market (gate) closure and balancing operations (day-ahead, intra-day, one or two hours before real time) and, hence, the related timeframe

9 US dollars have been converted to Euros at a rate of 0.7 €/US$.

of uncertainty in forecasting VRE generation output, (iii) the size of the balancing area and, more generally, (iv) the overall variability and flexibility of the power system (Pérez-Arriaga, 2011; Holttinen et al., 2011 and 2013; IEA, 2014). More specifically, at a given penetration rate, important factors identified to reduce balancing costs of VRE deployment are (i) aggregating VRE generation output over large geographical regions, (ii) operating larger balancing areas, including the use of interconnection capacity for balancing purposes, (iii) improving forecasting methods, (iv) utilizing shorter market (gate) closure times and, hence, shorter scheduling intervals for balancing operations, i.e. closer to real-time delivery hour, and (v) increasing the share of more flexible generation units (Idem; see also Section 6 below).

4

Grid-related impacts and costs

4.1 Grid-related impacts

Due to some system-specific properties of VRE deployment, notably its location-specific and modular (small-scale) characteristics (see Section 1), increasing VRE deployment has a variety of impacts on the power system in general and the transmission/distribution grid in particular. In brief, depending on these characteristics (location, scale), the major grid-related impacts of VRE deployment include:

- Some VRE generators are located and concentrated in areas far away from high load centres, for instance at windy sites with cheap land and lower acceptance issues (both onshore and offshore wind parks) or in areas with high sun radiation levels (concentrated solar power, CSP). This implies that large, variable amounts of output from these generators increase load flows, which in turn enhance transmission needs, increase network losses and tighten grid constraints (congestion). These effects can be mitigated or addressed through operational measures such as re-dispatch, including curtailment of VRE output, or through grid investments, notably by extending and reinforcing the transmission network. The costs of these measures are the reason for grid-related costs due to VRE deployment (Hirth, 2012).
- Other VRE generators, however, are closely located to households or other (small) electricity end-users and operate in small, individual units that are connected to and spread across the distribution network (i.e. distributed generation, notably from solar PV). Depending on the penetration level of solar PV, amongst other factors, the impacts of PV deployment can be positive (benefits) or negative (costs) to the system. For example, PV may release some capacity of the network, reducing network losses and allowing load growth without necessarily incurring network investments. On the other hand, at higher penetration levels, PV may trigger distribution problems such as reverse power flows, over-voltages due to voltage rise

effects, thermal overloading and higher network losses.[10] In this case, distribution networks may need to be reinforced, implying additional costs due to the deployment of solar PV (Pudjianto et al., 2013; Nieuwenhout, 2013).[11]

4.2 Grid-related costs

Several studies have estimated grid-related costs of VRE deployment. **Table 2** provides a summary overview of some estimates of grid-related costs due to deploying wind power in EU countries at different penetration levels. The table shows that these estimates generally vary between 1-8 €/MWh of wind power. Besides differences in cost definitions and methodologies applied, the variation in cost estimates seems to be largely due to the (existing) grid system in the countries concerned rather than the penetration level of wind power.

Table 2: Estimates of grid-related costs due to deploying wind power in EU countries

Country	Penetration level (in %)	Costs (in €/MWh)[a]	Source of studies surveyed
Several EU countries	15-20	3.8	Holttinen et al. (2011); Ueckerdt et al. (2013)
Several EU countries	<40	2.0-7.0	Holttinen et al. (2011); Hirth (2012)
Major EU countries	10	0.7	IEA (2014)
Major EU countries	13	3.8	IEA (2014)
Ireland	16	1.5	IEA (2014)
Ireland	59	7.7	IEA (2014)
Germany	35	1.4-5.7	Brouwer et al. (2014)
UK	19	2.3-4.5	Brouwer et al. (2014)

a) US dollars have been converted to Euros at a rate of 0.7 €/US$.

Recently, the PV Parity Project has estimated grid costs related to integrating 480 GW of solar PV by 2030 into the European grid, finding modest transmission network costs. In 2020, at a PV penetration rate of 7%, these costs are estimated at about 0.5 €/MWh, increasing to 2.8 €/MWh by 2030 (at a PV penetration rate of 13-14%). Reinforcing distribution networks to accommodate solar PV would cost up to 9 €/MWh in those Northern European countries, e.g. Belgium, reaching high penetration levels up to 18% (Pudjianto et al., 2013).

Grid-related costs of deploying VRE technologies (onshore wind, offshore wind and solar) at different penetration rates (10-30%) in selected OECD countries have also been estimated by NEA (2012). Grid-related costs have been distinguished between grid

10 Up to a certain penetration level (about 8-10%), increasing PV deployment will reduce network losses. Beyond this level, however, further increases in PV deployment will start increasing these losses (Pudjianto et al., 2013).

11 In addition, increasing PV deployment will have institutional impacts as institutional arrangements and practises will need to be updated to reflect the changing role of distribution networks. For instance, (i) sufficient real-time data has to be collected at the distribution grid level to ensure secure system operations, (ii) better co-ordination between transmission system operators (TSOs) and distribution system operators (DSOs) may become necessary, and (iii) grid planning processes need to be better integrated (IEA, 2014).

reinforcement and extension costs on the one hand and grid connection costs on the other.[12] Estimates of these costs for each of the three VRE technologies in selected EU countries – France, Germany and the UK – are included as part of **Table 5** (See Section 6 below). Compared to similar estimates for wind or solar deployment mentioned above, estimates of total grid-related costs presented in **Table 5** are generally much higher, varying from 5 €/MWh for onshore wind in the UK (10% penetration) to 40 €/MWh for solar in Germany (30% penetration). Grid connection costs are generally higher for offshore wind than for onshore wind and solar, whereas grid reinforcement and extension costs are usually higher for solar than offshore and onshore wind. While total grid-related costs are similar at the 10% and 30% penetration level for all three VRE technologies in France, they are generally slightly higher at the 30% level – compared to the 10% level – in the UK, but significantly higher in Germany, in particular for onshore wind and solar (**Table 5**).

The cost estimates by NEA (2012) have been criticised by Holttinen (2012) and Söder (2012), in particular the cost definition and methodology used to estimate grid connection costs for wind, resulting in an overestimation of these costs.[13] More generally, assessments and comparisons of grid-related (and other VRE integration) costs have to be treated with due care as – besides the cost definition and methodology used – they depend highly on the system context and the existing grid performance, in particular whether the existing grid is already characterised by severe grid constraints or not.

[12] *Grid connection* (to the closest point in the existing grid) refers to extension of the grid to plants *outside* the current grid area, notably offshore wind farms. *Grid reinforcement* refers to upgrading the current grid in terms of voltage or load-carrying capability. *Grid extension* refers to extension of the existing grid to plants *inside* the current grid (NEA, 2012).

[13] For further details on the methodology, cost definitions and data used, see NEA (2012), Holttinen (2012) and Söder (2012).

5

Adequacy impacts and costs

5.1 Adequacy impacts

System adequacy refers to the ability of the power system to meet electricity demand at all times, including peak load hours, taking into account the fluctuations in supply and demand, reasonably expected outages of system components, projected retirements of generating facilities, and so forth (NEA, 2012; IEA, 2014; Brouwer et al., 2014). Increasing the capacity of VRE generation contributes hardly or not to safeguarding system adequacy at peak times as its so-called '*capacity credit*' is low – or even zero (see below). Hence, even if VRE generation capacity is increasing, the capacity of other, non-VRE generators has to be largely maintained in order to secure system adequacy. However, VRE generators' output can be substantial – or even abundant – during many hours of the day, which requires other generators to reduce their output and, hence, the utilisation of their plants.[14] This increases average production costs of these other generators as they have to cover the same capacity (investment) costs with reduced load factors.[15] These so-called '*capacity credit effect*' and *'utilisation effect'* of VRE deployment – including associated costs – will be further considered below.

5.2 The capacity credit of VRE deployment

The capacity credit (or capacity value) of a power plant can be defined as the amount of additional peak load that can be served due to the addition of the plant, while

[14] This impact of VRE generators' output on the load factors (full load hours) of other generators is sometimes called the '*utilisation effect'* (see Nicolosi, 2011; Hirth, 2012; Ueckerdt et al., 2013; IEA, 2014; as well as in the main text below). In addition, VRE output generation has an impact on the wholesale electricity price offered to both VRE and other generators (the so-called *'wholesale price effect'*. In some cases, e.g. during off-peak periods, abundant VRE power generation may even lead to extremely low (negative prices and/or the need to curtail VRE output (*'VRE curtailment effect'*). Both the wholesale price effect and the VRE curtailment effect will be considered further in Section 7.

[15] In addition, increasing VRE deployment decreases generation revenues and operational surpluses of other, non-VRE generators (as discussed in Section 7).

maintaining the same level of system reliability (NEA, 2012; IEA, 2014). It is usually expressed as a percentage of a plant's nominal capacity. In case of VRE generators, the capacity credit reflects the firm capacity of other, conventional plants that can be replaced by these generators (Gross et al., 2006; Pudjianto et al., 2013).

The capacity credit of a power plant depends on several factors (NEA, 2012; IEA, 2014; Brouwer et al., 2014). The most important factor is the correlation of generation output with peak demand. For instance, solar technologies may have a high capacity credit in countries where peak demand is in summer around mid-day – due to air conditioning – when solar output is maximal. On the other hand, the capacity credit of solar technologies may be relatively low or practically zero in countries where peak load occurs during winter evenings, when solar output is minimal, as in several Northern European countries, notably those relying on electric heating such as France (NEA, 2012; Pudjianto, 2013).

Another key factor affecting the capacity credit of a power plant is the correlation of its output with the so-called '*peak net load*', i.e. the output of the rest of the generating system during high demand periods (IEA, 2014). For instance, the output of dispatchable plants such as coal or nuclear is weakly correlated with peak net load, while these plants are supposed to be available during periods of high electricity demand. Hence, the capacity credit of these plants is usually rather high, often fairly close to one (NEA, 2012). On the other hand, output from VRE generators relying on the same natural source is closely correlated (e.g., one wind turbine is likely to stop turning the very moment other turbines in the same area stop turning). At higher correlations and higher penetration levels of VRE output, adding more VRE generation to the system increases the chance that little or no additional output will be produced during peak hours. Therefore, when the penetration level of a VRE technology increases, its capacity credit decreases, often to low values – or even to zero (NEA, 2012; IEA, 2014; Brouwer et al., 2014).[16]

Calculating capacity credits is a complex undertaking with requires the use of advanced modelling (NEA, 2012). For wind, the values of the estimated capacity credits show a wide range from 40% of installed wind power capacity – in situations with low wind penetration and a strong correlation of wind power production with times of peak load – to 5% in higher penetration scenarios or if the wind power output profile correlates negatively with the system load profile (Holttinen et al., 2011 and 2013; Brouwer et al., 2014). For solar PV, capacity credits in a Southern European country such as Greece have been estimated at relatively high values (65-95% of PV nameplate capacity) at low penetration levels (2-4% of electricity demand), but they decline steadily to lower values (18-20%) at higher penetration rates (16-18%). In North-western European countries such as France, Germany or the UK, the capacity credit of solar is already very low (about 5% or less) at low penetration levels (2-4%) and moves closer to zero at higher penetration levels (Pudjianto et al., 2013).

Table 3 presents values of capacity credits (in %) of both VRE and non-VRE technologies at different penetration levels (10% and 30%) in France, Germany and the UK, as

[16] Output correlation is usually lower – or even negative – when a VRE technology is spread across large geographical areas, or when output is diversified over a mix of VRE technologies (e.g., both onshore wind, offshore wind and solar), resulting in higher credit rates.

estimated by NEA (2012). It shows, among others, that (i) the capacity credits of VRE technologies (wind onshore, wind offshore and solar) are significantly lower (0-30%) than the capacity credits of conventional, non-VRE technologies (coal, gas and nuclear, i.e. 96-97%), (ii) the capacity credits of VRE technologies are significantly lower at the 30% penetration level than at the 10% level, (iii) the capacity credits for solar (0.1-0.4%) are much lower than for wind (6-30%), (iv) the capacity credits for offshore wind (10-30%) are higher than for onshore wind (6-22%), and (v) the capacity credits for wind are significantly higher in the UK (15-30%) than in France (6-11%) or in Germany (6-15%).

Table 3: Estimates of capacity credits (in %) of VRE and non-VRE technologies in selected EU countries

	France		Germany		UK	
Penetration rate	10%	30%	10%	30%	10%	30%
Coal	96.2	96.2	96.2	96.2	96.2	96.2
Gas	97.0	97.0	97.0	97.0	97.0	97.0
Nuclear	97.0	97.0	97.0	97.0	97.0	97.0
Wind onshore	7.0	5.9	8.0	6.0	22.0	15.0
Wind offshore	11.4	9.6	15.0	11.2	29.9	20.4
Solar	0.4	0.1	0.4	0.1	0.4	0.1

Source: NEA (2012).

5.3 The utilisation effect

As noted above, due to the generally low capacity credits of VRE technologies – in particular at higher penetration levels – adding VRE deployment contributes hardly or not to safeguarding system adequacy at peak load hours or, to phrase it slightly different, adding VRE capacity contributes hardly or not to replacing non-VRE capacity while maintaining the same level of system adequacy. At higher penetration levels, however, electricity output from VRE generators can be substantial – or even abundant – during many hours of the day, which requires other, non-VRE generators to reduce their output and, hence the utilization of their plants.

This impact of the deployment of VRE generators on the deployment of other, non-VRE generators has been called the '*utilisation effect*' (Nicolosi, 2011; see also Hirth, 2012; and Ueckerdt et al., 2013). Recently, this concept has been further explored by the IEA (2014) and distinguished into two sub-concepts:

- *The transitional utilisation effect.* This effect refers to the VRE-induced displacement of non-VRE generators, mostly those with highest short-run costs, and thus see a reduction in their capacity factors and market shares. As the name implies, the transitional utilisation effect is a transitory effect. When a large amount of VRE generation is added to a power system in a relatively short period, it is usually not possible to adapt the overall power plant mix simultaneously with the rising share of VRE deployment. As a result, power plants that may have been designed to operate as mid-merit plants will have to operate as peaking plants.[17] This implies a reduction in their capacity factor and a change in the way they are operated (e.g. more frequent start/stops, more frequent ramping and long periods stopped). Similarly, at sufficiently high-VRE shares, base load power plants will need to operate as mid-merit plants (assuming this type of utilisation is not prevented by technical constraints). This situation is referred to as the transitional utilisation effect. It occurs when the power plant mix is not adjusted to the change in net load, i.e. load minus VRE output (IEA, 2014).

- *The persistent utilisation effect.* This effect refers to the structural shift of the cost-optimal mix of non-VRE, dispatchable generators towards more mid-merit and peaking generation. The transitional utilisation effect does not lead to a long-run, cost-optimal situation. Over time, the dispatchable power plant mix is likely to adapt to the changed shape of the VRE-induced change in the net load duration curve and the likely more variable operational pattern of the power system.[18] Once such an adaptation has taken place, the actual utilisation of power plants will match their design again, i.e. there will be fewer base load plants installed while the share of mid-merit and peaking generation will increase in the dispatchable plant mix. Moreover, dispatchable plants will also see 'normal' capacity factors again. This structural shift towards mid-merit and peaking plants is termed the persistent utilisation effect (IEA, 2014)

Regardless whether the utilisation effect is transitional or persistent, increasing VRE deployment implies that the *average* production costs (per MWh) will be higher in the residual generation system (although average costs will be less higher after the adaptation or structural transformation of the power generation system; see IEA, 2014; as well as Section 6 below).[19] Because capital costs occur also when capacity is idle, decreasing utilization increases the average costs of the residual generation mix. This can be alleviated over time by adapting the dispatchable power plant mix, i.e. a shift towards less capital-intensive technologies (Hirth, 2012).

But even if the system responds optimally by shifting the capacity mix from base load towards peak load technologies, the average generation costs in the residual system still increase because the residual mix contains a lower share of base load and a higher share of mid-merit and peak load generation. On an average (MWh) basis, mid-merit and peak load generation is generally more expensive than base load generation. Hence, even if the system adapts over time, average generation costs will still be higher in the residual system (Hirth, 2012; Ueckerdt et al., 2013; IEA, 2014).

[17] Due to their cost structure (relatively high investment costs and low operational costs), *base load plants* are those plants that are cheapest when running practically all the time, i.e. at high capacity factors. *Peak load ('peaking') plants* (relatively low investment costs and high operational costs) are those plants that are cheapest at a low capacity factor. *Mid-merit plants* are those power plants that are cheapest in an intermediate range of capacity factor (IEA, 2014).

[18] The persistent utilisation effect will favour technologies that are cost-effective operating at capacity factors that are typical for peaking and merit-order generation. In addition, the balancing effect (see Section 2) will favour technologies that are more flexible, i.e. that can start/stop operations frequently as well ramp quickly in a wide range. Hence, both effects favour similar technologies such as flexible combined-cycle gas turbines (IEA, 2014).

[19] *Total* generation costs in the residual power system, however, will be *lower* as the increase in VRE output results in less residual (non-VRE) generation and, hence, in less operational (e.g. fuel) costs in the residual system.

5.4 Adequacy costs

Compared to the large amount of studies that have estimated the increase in balancing/grid-related costs due to VRE deployment, estimates of VRE-induced adequacy costs are scarce.[20] Recently, however, a few studies have estimated the increase in adequacy costs due to VRE deployment or, more specifically, the increase in average generation costs in the residual system due to the utilisation effect. For instance, a recent report by the IEA provides an indicative calculation of the economic significance of the utilisation effect (IEA, 2014). The analysis assumes that the residual generation mix is fully adapted to the deployment of VRE technologies (long-term, persistent utilisation effect). In addition, it assumes that base load generation costs approximately 42 €/MWh, mid-merit generation about 56 €/MWh and peak load generation circa 112 €/MWh. At a zero VRE penetration rate, assuming 81% base load generation, 17% mid-merit generation and 2% peak generation, this results in an average, levelised cost of electricity (LCOE) of about 46 €/MWh. Under these assumptions, the impact of increasing VRE penetration on the average generation costs in the residual system can be calculated directly.[21]

The result of this indicative calculation are summarised in **Table 4** for three cases of VRE deployment indicated as '*Wind power only*', '*Solar power only*' and '*2/3 wind power and 1/3 solar power*'.[22] The table shows the increase in average generation costs (LCOE) for the residual plant mix due to the deployment of VRE technologies at different penetration levels, both in terms of cost increase per MWh generated in the residual, non-VRE system (i.e. in €/$MWh_{residual}$) and per MWh generated in the VRE system (i.e. in €/MWh_{VRE}). For instance, the upper part of **Table 4** shows that, in the case of wind power only, at a penetration rate of 20%, the average generation costs in the residual system increase by 2.5 €/MWh in terms of residual output (i.e. these costs increase from about 46 €/MWh at zero VRE penetration to approximately 48.5 €/MWh at 10% wind penetration). In the case of 20% solar PV only, this increase is slightly higher (2.6 €/MWh). However, a mix of 2/3 wind and 1/3 solar PV implies a much lower increase, i.e. 1.3 €/MWh at 20% VRE penetration, mainly due to the lower correlation of mixed VRE output with peak net load).

The above-mentioned increase in per MWh costs can also be expressed in terms of added VRE generation. At a 20% penetration level, this corresponds to an increase of 9.8 €/MWh of wind power only, 10.4 €/MWh of solar PV only and 5.3 €/MWh of 2/3 wind and 1/3 solar PV (see lower part of **Table 4**).[23]

20 For instance, a recent and extensive survey of wind integration studies includes estimates of capacity credits of wind power but no estimates of adequacy costs (Holttinen et al., 2013). An older survey, which reviews more than 200 VRE integration studies and reports from around the world (Gross et al., 2006), only gives four estimates of the 'reliability costs' of integrating wind power, ranging from 2.4-4.8 UK£/MWh of wind output at a penetration level of 10% and from 3.3-4.8 UK£/MWh at 20% wind penetration.

21 IEA (2014) also calculates the impact of increasing VRE penetration on total generation costs in the residual system. As indicated in footnote 19 above, these total costs decrease in all cases due to the lower output and, hence, the lower operational costs in the residual system.

22 Note that absolute values are highly sensitive to assumptions on generation costs (LCOE) and, hence, are indicative only (IEA, 2014).

23 The results in the lower part of **Table 4** can be easily derived through multiplying the results in the upper part by the ratio between residual and VRE generation. For instance, at a 10% VRE penetration level, this ratio is 9 (90/10) and at a 20% level it is 4 (80/20).

Table 4: Indicative increase in average generation costs (LCOE) for the residual plant mix due to the deployment of VRE technologies at different penetration rates[a]

Penetration level	10%	20%	30%	40%
	in €/$MWh_{residual}$			
Wind power only	0.8	2.5	4.8	7.8
Solar PV only	0.7	2.6	6.2	10.2
2/3 wind power and 1/3 solar PV	0.3	1.3	3.2	5.7
	in €/MWh_{VRE}			
Wind power only	7.3	9.8	11.1	11.6
Solar PV only	6.2	10.4	14.5	15.3
2/3 wind power and 1/3 solar PV	2.7	5.3	7.4	8.6

a) All values in US dollars have been converted to Euros at a rate of 0.7 €/US$.

Source: IEA (2014).

At growing penetration levels, however, the utilisation effect becomes more significant (IEA, 2014). For instance, at 40% penetration, the numbers mentioned above become 11.6 €/MWh for wind power only, 15.3 €/MWh for solar PV only and 8.6 €/MWh for 2/3 wind power and 1/3 solar PV (see last column at the lower part of **Table 4**).[24]

The above-mentioned, fictive results of IEA (2014) compare reasonably well with the ranges of similar adequacy ('back-up') costs of various generation technologies at different penetration rates in selected OECD countries, as estimated by NEA (2012).[25] **Table 5** (see Section 6 below) presents a selection of these NEA estimates, i.e. the adequacy costs per MWh of VRE output for three technologies (wind onshore, wind offshore and solar) at two penetration levels (10% and 30%) in three selected EU countries (France, Germany and the UK). In brief, the table shows, amongst others, that (i) adequacy costs range from 3 €/MWh (10% wind) to 19 €/MWh (30% solar) in the UK, and from 6 €/MWh (10% wind) to 14 €/MWh (30% solar) in both France and Germany, (ii) the increase in adequacy costs due to an increase in VRE generation is generally relatively small, except for wind in the UK where these costs increase from 3 €/MWh (10%) to 5 €/MWh (30%), (iii) in all three EU countries, adequacy costs are much higher for solar (14-19 €/MWh) than for wind (3-6 €/MWh), and (iv) in all three EU countries, adequacy costs for wind onshore are similar to those for wind offshore.

Finally, the PV Parity Project has recently also estimated adequacy costs due to VRE deployment, in particular so-called 'back-up capacity costs' due to PV deployment in several EU countries (Pudjianto et al., 2013). One of the major findings is that in most countries, particularly in Northern Europe, these costs are approximately 14-16 €/MWh_{PV} flat across all penetration levels (ranging from 2% to 18%). In these countries,

[24] For comparative reasons, the IEA has also calculated the utilisation effect for a reference technology, i.e. the cost increase of adding a constant flat block of base load energy. In terms of residual output generation, the utilisation effect of this technology increases from 0.4 €/MWh at 10% penetration to 2.7 €/MWh at 40% penetration, while it remains more or less flat at approximately 4.0 €/MWh in terms of output generated by this technology (IEA, 2014).

[25] The estimates by IEA (2014) compare also reasonably well with the fictive results obtained by Hirth (2012), varying from a cost increase due to the utilisation effect of 10 €/MWh_{VRE} at 10% VRE penetration to 24 €/MWh at 40% penetration.

the capacity credit of PV is very limited due to a low correlation factor between PV output and peak demand. Only in some Southern European countries, back-up capacity cost of PV are lower and may even be negative (benefits), as in the case of Greece, due to a strong correlation between PV output and peak demand conditions occurring during summer periods (Pudjianto et al., 2013).

6

Total VRE system integration costs

Estimates of total VRE system integration costs – including the three components of balancing costs, grid-related costs and adequacy costs – are scarce. Two major, recent exceptions are the study by NEA (2012), covering both wind and solar in selected OECD countries, and the study by the Grid Parity Project (Pudjianto et al., 2013), covering solar in various selected EU countries. Details of these studies regarding the three components of VRE integration costs have already been discussed in the previous Sections 3 to 5.

Table 5 provides a summary overview of total integration costs – including the three constituent components – for three VRE technologies (wind offshore, wind onshore and solar) at two penetration levels (10% and 30%) in three selected EU countries (France, Germany and the UK), as estimated by NEA (2012). The table shows among others:

- Total integration costs range from 13 €/MWh (10% wind in the UK) to 58 €/MWh (30% solar in Germany).
- Total integration costs are higher for solar (25-58 €/MWh) than for wind (13-32 €/MWh).
- Total integration costs are higher for offshore wind (20-32 €/MWh) than for onshore wind (13-31 €/MWh), except for Germany at 30% wind penetration.
- Total integration costs are generally higher at the 30% generation level than at the 10% level. When moving from 10% to 30% VRE, however, the increase in total integration costs is relatively modest in France (+10-15%), very substantial in Germany (+50-130%), while the UK takes an intermediate position (25-60%).
- In general, the major component of total VRE integration costs is accounted for by grid-related costs (ranging from about 45-65% of total costs), followed by adequacy costs (20-35%) and balancing costs (15-20%). In individual cases, however, there are some striking differences and exceptions. For instance, in the case of 30% wind in the UK, balancing costs account for almost half of total integration costs, while grid-related costs account for a share of approximately 30%. In the case of 10% solar in Germany, adequacy costs account for about 55% of total integration costs, compared to a share of circa 35% for grid-related costs.

Table 5: Estimates of VRE system integration costs in selected EU countries (in €/MWh)[a]

		Wind onshore		Wind offshore		Solar	
	Penetration rate	10%	30%	10%	30%	10%	30%
France	Grid connection[b]	4.9	4.9	13.0	13.0	11.2	11.2
	Grid reinforcement and extension[c]	2.5	2.5	1.5	1.5	4.0	4.0
	Total grid-related costs	*7.3*	*7.3*	*14.6*	*14.6*	*15.2*	*15.2*
	Adequacy (back-up) costs	5.7	6.1	5.7	6.1	13.6	13.9
	Balancing costs	1.3	3.5	1.3	3.5	1.3	3.5
	Total system integration costs	**14.3**	**16.9**	**21.6**	**24.1**	**30.1**	**32.6**
Germany	Grid connection	4.5	4.5	11.0	11.0	6.6	6.6
	Grid reinforcement and extension	1.2	15.6	0.6	8.3	2.6	33.2
	Total grid-related costs	*5.7*	*20.0*	*11.6*	*19.3*	*9.2*	*39.8*
	Adequacy (back-up) costs	5.6	6.2	5.6	6.2	13.5	13.8
	Balancing costs	2.3	4.5	2.3	4.5	2.3	4.5
	Total system integration costs	**13.6**	**30.7**	**19.5**	**30.0**	**25.0**	**58.1**
UK	Grid connection	2.8	2.8	13.9	13.9	10.9	10.9
	Grid reinforcement and extension	2.1	3.6	1.8	3.2	6.0	10.6
	Total grid-related costs	*4.8*	*6.4*	*15.7*	*17.0*	*16.9*	*21.5*
	Adequacy (back-up) costs	2.8	4.8	2.8	4.8	18.3	18.8
	Balancing costs	5.3	9.9	5.3	9.9	5.3	9.9
	Total system integration costs	**13.0**	**21.2**	**23.8**	**31.8**	**40.5**	**50.2**

a) US dollars have been converted to Euros at a rate of 0.7 €/US$. NEA (2012) has also estimated comparable system integration costs for conventional generation technologies such as coal, gas and nuclear. In general, these costs are much lower, ranging from 0.35 €/MWh for gas to 1.7 €/MWh for nuclear.

b) *Grid connection* (to the closest point in the existing grid) refers to extension of the grid to plants *outside* the current grid area, notably offshore wind farms.

c) *Grid reinforcement* refers to upgrading the current grid in terms of voltage or load-carrying capability. *Grid extension* refers to extension of the existing grid to plans *inside* the current grid.

Source: NEA (2012).

As noted in Section 4, the cost estimates by NEA (2012) have been criticised by Holttinen (2012) and Söder (2012), in particular the cost definition and methodology used to estimate grid connection costs for wind, resulting in an overestimation of these costs. More generally, the outcomes of estimating, comparing, decomposing or adding-up VRE integration costs have to be treated with due care as – besides the cost definition and methodology used – they depend highly on the system context and the level of VRE penetration. In addition, obtaining these outcomes raises several other methodological complications (as outlined in Section 2).

Table 6: Comparative summary of VRE integration cost studies

VRE technology	Wind		Solar	
Source	NEA (2012)[a]	Other studies	NEA (2012)[a]	Pudjianto et al. (2013)
Penetration rate	10-30%	Diverse	10-30%	2-18%
	In €/MWh$_{VRE}$			
Balancing costs	3-6	1-5[b]	3-6	0.5-1.0
Grid-related costs	6-17	1-8[c]	14-26	10-12
Adequacy costs	5-6	7-12[d]	15-16	14-16
Total integration costs	13-29	9-25	32-48	25-28
	In % of total VRE integration costs			
Balancing costs	15-20	10-20	10-15	0-5
Grid-related costs	45-65	10-30	45-55	40-45
Adequacy costs	20-35	50-80	35-45	50-60
Total integration costs	100	100	100	100
	In % of levelised generation cost of electricity (LCOE)[e]			
Total integration costs	20-40	15-35	20-35	15-20

a) Figures refer to three selected EU countries (i.e. France, Germany and the UK; see Section 6, **Table 5**).
b) Holttinen et al. (2013); penetration rate: up to 30% (see Section 3, **Figure 2**).
c) Various; penetration rate: up to 60% (see Section 4, **Table 2**).
d) IEA (2014); penetration rate: 10-40% (see Section 5, **Table 4**).
e) Assuming an average LCOE of 70 €/MWh for wind and 140 €/MWh for solar.

With this general disclaimer in mind, **Table 6** gives a comparative summary of VRE integration costs studies, as discussed in the sections above. The table shows, among others, that:

- For wind, total integration cost are slightly higher in NEA (2012), i.e. about 13-29 €/MWh (at 10-30 wind penetration), compared to the total integration costs added-up from varies studies and surveys reviewed in Sections 3-5 (i.e. approximately 9-25 €/MWh, up to 60% wind penetration; see left-upper part of **Table 6** and notes mentioned there). This difference is due to the higher grid-related costs in NEA (2012), which is partly compensated by the lower adequacy costs in NEA (2012), compared to the sample of other studies. Consequently, whereas grid-related costs are the major component in NEA (2012), accounting for about 45-65% of total wind integration costs, adequacy costs rank, on average, highest in the sample of other studies (i.e. approximately 50-80%; see left-middle part of **Table 6**).
- For solar, the range of total integration costs is also higher – notably the upper bound – in NEA (2012), i.e. 32-48 €/MWh (at 10-30% penetration), compared to the total costs estimated by the PV Parity Project (Pudjianto et al., 2013), i.e. circa 25-28 €/MWh (see right-upper part of **Table 6**). This difference is mainly due to the higher grid-related costs in NEA (2012). Consequently, whereas grid-related costs of integrating solar – similar to these costs for wind – are the major cost component in NEA (2012), accounting for circa 45-55% of total solar integration costs, adequacy costs rank highest in Pudjianto et al. (2013), i.e. approximately 50-60% (see right-middle part of **Table 6**).

- As a percentage of the levelised generation costs of electricity (LCOE), total integration costs of wind power are estimated to be slightly higher in NEA (20-40%) than in the sample of other studies and surveys reviewed in Sections 3-5. For solar power, these rates amount to 20-35% in NEA (2012) and 15-20% in Pudjianto et al. (2013; see lower part of **Table 6**).

6.1 Major conclusions on VRE integration costs

Based on **Table 6** and the studies reviewed in the sections above, the major conclusions on VRE integration costs include:[26]

(1) The deployment of wind and solar power causes significant integration costs, in particular at higher penetration levels (>10%). At 10-30% penetration, these costs range from 10-30 €/MWh for wind and from 25-50 €/MWh for solar. As a percentage of their LCOE, these amounts correspond to a range of 15-40% for wind and of 15-35% for solar.

(2) Balancing costs are generally the lowest component of total VRE system integration costs, ranging from 1-6 €/MWh, i.e. 5-15% of total integration costs. The largest component consists of either grid-related costs or adequacy costs, depending on the specific case or study considered.

(3) Apart from the cost definition and methodology used, estimates of the size and composition of VRE integration costs are location-specific, varying from country to country and from power system to power system, depending on a complex interaction of factors such as VRE characteristics (power output profiles, load factors, penetration rates), electricity load characteristics (magnitude of peak load, load profiles, correlation with VRE output), generation plant mix, geographical and balancing area size, transmission connections with neighbouring regions, designs of the distribution networks, time perspective, etc.

(4) Integration costs per MWh of VRE output tend to increase with growing penetration rates. Integration costs may even be negative (benefits) at low penetration levels (1-3%), but costs often become significant and tend to show a steep increase at 5-10% VRE penetration. At even higher shares of VRE deployment, the increase in integration costs seems to level off gradually.

(5) At a given (fixed) penetration rate, integration costs per MWh of VRE output tend to decrease over time depending on the adaptation or transformation of the power system.

The latter conclusion will be further explored briefly below.

[26] Similar conclusions have been drawn by other studies or surveys on VRE integration costs, e.g. by Hirth (2012), Ueckerdt et al. (2013) and Pudjianto et al. (2012).

6.2 Integration costs at high levels of VRE penetration and system transformation

Recently, the IEA has assessed VRE deployment and system integration at high levels of VRE penetration. It concludes that, from a technical perspective, annual shares of 25-40 VRE penetration can be achieved without major problems, assuming current levels of system flexibility and the availability of sufficient grid capacity inside the power system. This share can be increased further, reaching levels above 50% in very flexible systems, if a small amount of VRE curtailment is accepted to limit extreme variability events (IEA, 2014).

A similar finding has recently been reached by the PV Parity Project. It shows that the EU grid system is able to integrate large amounts of solar PV (up to 28% of power demand). This is in addition to power generation from other VRE technologies (wind) and other low carbon technologies. At higher PV penetration rates, the reliability of electricity supply and the economic efficiency of power system operations can still be maintained, indicated by a low level – less than 0.4% - of VRE curtailment (Pudjianto et al., 2013).

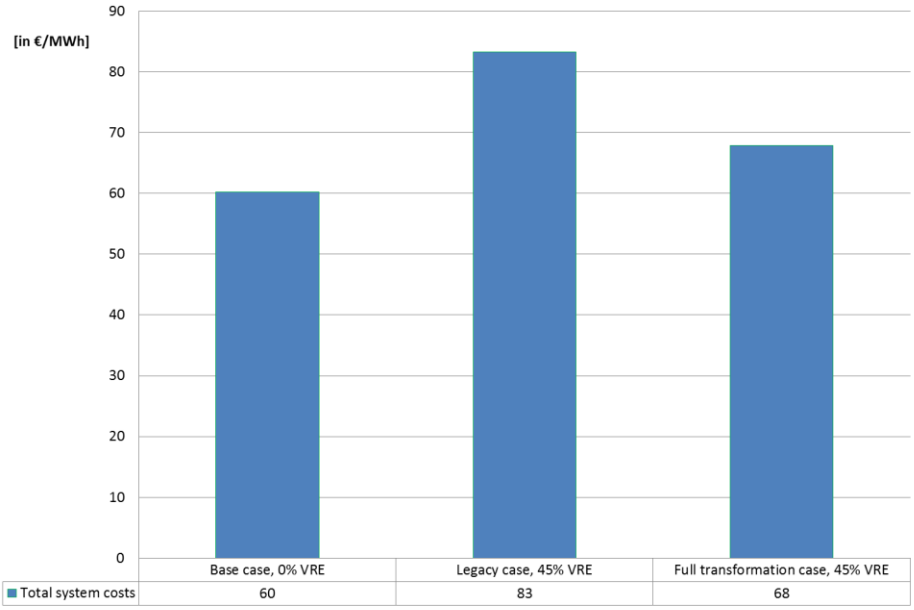
In addition to the technical assessment, IEA (2014) has also evaluated the economic implications of large-scale VRE deployment, in particular the change in total system costs due to a share of 45% VRE in annual electricity generation – 15% solar PV and 30% onshore wind – at different degrees of system transformation. Using a test system, some extreme and purely hypothetical cases were investigated. The main findings of these cases are presented in **Figure 3** and discussed below.

In the 'B*ase case'*, with 0% VRE, the total system costs are estimated at, on average, 60 €/MWh. In the so-called '*Legacy case'*, a share of 45% VRE in annual generation was added to the system overnight and only the operation of the remaining system was allowed to change. In this case, total system costs increase by 23 €/MWh, from 60 to 83 €/MWh, i.e. an increase of approximately 40%. This increase is the result of three principal drivers (IEA, 2014):[27]

- Additional cost of VRE deployment itself (which is assumed to remain similar to today's levels).
- Additional grid costs associated with connecting distant VRE generation and grid reinforcements.
- Limited avoided costs in the residual system as VRE can only bring operational savings in the form of fuel and emission cost reductions.

[27] The additional (balancing) costs of more flexible operation of existing power plants are not an important element in the increased costs (IEA, 2014).

Figure 3: Total system costs of a test system at 45% VRE deployment and different degrees of system transformation



Source: IEA (2014).

Over time, however, a co-ordinated transformation of the entire system reduces additional costs. This transformation includes a wide range of options such as a structural shift towards a re-optimised power plant mix in the presence of 45% VRE (see Section 5), an extended and adjusted grid infrastructure, a system-friendly deployment of VRE technologies, improved system and market operations, and investments in additional flexible resources.[28]

The test system calculation by the IEA shows that when allowing for full transformation of the entire system, i.e. the full transformation case, a share of 45% VRE in annual electricity generation increases total system costs by only 8 €/MWh, compared to 0% VRE, i.e. an increase of approximately 10-15% (**Figure 3**). Hence, system transformation over time significantly reduces the increase in system costs due to the integration of high shares of VRE deployment.[29]

In the long run, high shares of VRE may even come at zero additional costs (IEA, 2014). In the system test modelling analyses, all cost assumptions are kept constant. However, future VRE generation costs are likely to be lower and the costs of CO_2 emissions higher.[30]

[28] For an extensive discussion of these and other flexibility options, see IEA (2014), as well as, for instance, Frontier Economics (2010), Sims et al. (2012), REP (2012) and Agora (2013).

[29] Similar VRE cost reductions owing to system adaptations over time are recorded by Ueckerdt et al. (2013) and Pudjianto et al. (2013).

[30] A cost decrease in the VRE mix between 30% and 40% would put total system costs in the full transformation case on a par with total system costs in the absence of VRE (Base case). In addition, future CO_2 emission prices are likely to exceed the assumed level of 21 €/tCO_2 (IEA, 2014).

7

Impacts on generators' output prices and profits

In addition to a variety of impacts affecting system costs (as discussed in the previous sections), VRE deployment has some (related) impacts on generators' output prices and, hence, on their market revenues and operational surpluses. In particular, growing shares of VRE deployment will have a negative impact on wholesale electricity prices (called '*the wholesale price effect'*).[31] In times of abundant supplies of VRE output and low off-peak demand, VRE deployment may even result in extremely low (negative) prices, including the need to curtail VRE output ('*the VRE curtailment effect*'). Lower wholesale electricity prices – combined with VRE curtailments and lower load factors for conventional generators (due to the VRE-induced utilisation effect, see Section 5) – result in lower revenues and lower profits for both VRE and non-VRE generators, affecting the competitiveness of these generators, their ability to recover their fixed investment costs as well their willingness to invest in new generation capacity. These VRE-induced impacts on generators' output prices and profits are discussed briefly below.

[31] Some authors have called this effect '*the merit-order effect*' (see, for instance, Pérez-Arriaga and Battle, 2012; and IEA, 2014). Basically, however, the merit-order effect consists of two related, simultaneous sub-effects, i.e. (i) a quantity effect (called '*the utilisation effect*'; see Section 5), and (ii) a price effect (called '*the wholesale price effect'*). Other authors have called this price effect '*the profile effect*' and the resulting loss in generators' revenues '*profile costs*' (see, for instance, Hirth, 2012 and 2013; Ueckerdt et al., 2013; CPB, 2013; Nieuwenhout, 2013). Some of these authors, however, have defined or used the term 'profile effect' (or 'profile costs') in a broader, ambiguous and multi-interpretable way, including a variety of other VRE-induced effects such as the utilisation effect, the VRE curtailment effect and the flexibility effect (Hirth, 2012 and 2013; Ueckerdt et al., 2013). Other authors (CPB, 2013; Nieuwenhout, 2013) have defined or used the term 'profile effect/costs' only in reference to the VRE-induced impact on the price (and revenues) received by VRE generators, whereas non-VRE generators are also affected by VRE-induced decreases in wholesale electricity prices. Moreover, one may wonder whether, from a social perspective, lower electricity prices and lower generators' revenues can be considered as a cost as they benefit electricity end-users (or traders) and, hence, are basically a transfer of rents ('surplus') from producers to consumers (or traders). For all these reasons, we prefer to use the clear, simple and straightforward term 'wholesale price effect' to indicate the impact of VRE deployment on wholesale electricity prices (and, hence, on generators' revenues, profits, etc.).

7.1 The wholesale price effect

As mentioned in Section 1, a major characteristic of electricity output from VRE generators is that is has low short-run costs, i.e. once built VRE generators can produce electricity at very little costs as their short-run, marginal costs are close to zero. This means that once VRE generation is deployed, it is likely to be among the first technologies in the merit-order. As a result, increasing output from VRE generators has two related 'merit-order' effects (Nicolosi, 2011; IEA, 2014):

- A reduction in load factors and market shares of more expensive generators, mostly those with highest short-run costs, such as gas-fuelled power plants (*the transitional utilisation effect*).
- A reduction in wholesale electricity prices (*the wholesale price effect*).

In principle, these are normal and common effects that also occur in a purely competitive environment when low marginal cost generation is added to the system. The picture becomes more complex, however, in the case of VRE support policies as these policies often contain a performance-based element, i.e. they remunerate and stimulate VRE deployment based on generated output (IEA, 2014). Examples of such policies include feed-in tariffs (FITs), feed-in premiums (FIPs), tradable green certificates (TGCs) or production-based tax incentives such as production tax credits (PTCs). In cases where VRE generators offer their output directly to the market, such policies may create an incentive for these generators to bid below their short-run costs as they receive revenues on top of achieved market prices. Hence, bids may be below zero, resulting in negative prices.[32] This may particularly be the case during periods characterised by off-peak demand, large supplies of VRE output and large supplies from must-run installations, such as CHP, notably in countries with stagnant power demand, a large increase in VRE deployment over a relatively short period and/or a slow adaptation of the residual system.[33]

In addition, FIT support schemes usually have a VRE in-feed obligation for TSOS or, more generally, VRE generators may enjoy so-called '*priority dispatch*', i.e. TSOs (must) give priority to dispatching VRE generators regardless whether this is the most efficient situation or not (Pérez-Arriaga, 2011). Where VRE generators have priority dispatch, their operation can run independent of any market signal. This can lead to even more pronounced lower electricity prices (Nicolosi, 2011; IEA, 2014).

The wholesale price effect of VRE deployment has been estimated by a large number of studies, including model simulations and empirical, historical price data analyses (see particularly the survey of price studies by Hirth, 2012 and 2013, and references cited there). This effect has been estimated in different ways and either expressed in absolute terms, e.g. in €/MWh, i.e. as the difference between the average, VRE output-weighted electricity price received by VRE generators and the average, time-weighted

32 Minimum bids are likely to equal short-run costs of VRE output minus the value of support payments (IEA, 2014). Negative price bids may also come from other, non-VRE generators such as must-run installations (CHP) or other base load power plants with high opportunity costs to cut off production (Nicolosi, 2011).

33 For instance, the European Energy Exchange (EEX) in Leipzig (now called EPEX) closed with a negative power price for the first time in October 2009. By December 2009, 86 hours with negative prices had been observed at the EEX. Among those, 19 hours had significantly negative prices below -100 €/MWh (Nicolosi, 2011).

(reference) power price over a certain period or, alternatively, expressed in relative terms, i.e. as a percentage or ratio – called '*value factor*' – between these two prices. For instance, if the average price received by wind power producers amounts to 49 €/MWh while the average, reference or system-base price over a certain period is estimated at 70 €/MWh, the value factor of wind power is 0.7 (or 70%), while the wholesale price effect is 0.3 (30%) in relative terms and 21 €/MWh in absolute terms.[34]

In a broad survey of about 30 studies, Hirth finds that, at low penetration rates, VRE value factors are close to unity (Hirth, 2012 and 2013). Wind value factors are estimated to drop to, on average, 0.7 at 30% wind penetration, while solar value factors are reported to drop faster, i.e. they reach 0.7 already at 10-15% solar penetration (although there is a large variation in both wind and solar value factors). Based on these findings and a normalised, system-base price of 70 €/MWh in all studies surveyed, Hirth estimates that the wholesale price effect, in absolute terms, probably varies between 15-35 €/MWh at 30% wind penetration (Hirth, 2012 and 2013).

These findings by Hirth are in line with similar findings from other studies. For instance, Ueckerdt et al.(2013) estimates a wholesale price effect of 30 €/MWh at 30% wind penetration (in a model simulation representing typical thermal power systems in Europe). CPB (2013) estimates that in 2015 the average price of wind power amounts to 83% of the reference electricity price of 63 €/MWh in the West-European power market, while – due to the expected increase in wind penetration in this market – it declines to 59% of the reference electricity price of 98 €/MWh in 2040. This corresponds to a wholesale price effect of approximately 11 €/MWh in 2015 and 40 €/MWh in 2040.[35]

The five major factors that determine the size of the wholesale price effect of VRE deployment are the VRE penetration rate, the slope of the merit-order curve, the type of VRE technology (wind or solar), the geographical size of the market area, and the intertemporal flexibility of the power system (Hirth, 2012; IEA, 2014). The wholesale price effects increases with higher VRE penetration rates, because a larger VRE output has a larger impact on prices. It also increases with the slope of the merit-order curve, since a steeper curve leads to a stronger price drop in windy or sunny hours. At higher VRE generation rates, the wholesale price effect is usually higher for solar than for wind as solar generation generally fluctuates more heavily during the day. If a larger geographical area is integrated into one price area, it helps smoothing the wind generation profile, thereby reducing the wholesale price effect at higher penetration rates. Intertemporal flexibility, e.g. from large-scale hydro reserves, has a similar effect, absorbing the fluctuations of VRE generation over time. These and other factors determining the wholesale price effects are discussed in more detail in Hirth (2012 and 2013), Nicolosi (2011) and IEA (2014).

34 In relative terms, the wholesale price effect of VRE deployment – which is sometime called 'the profile effect' – is equal to 1 minus the value factor (CPB, 2013; Nieuwenhout, 2013). In absolute terms, the difference in revenues received by VRE producers due to the wholesale price ('profile') effect is sometimes called 'profile costs' (Hirth, 2012 and 2012; Ueckerdt et al., 2013; Nieuwenhout, 2013). Note that the average, reference (or system-base) power price may be estimated in different ways, i.e. based on wholesale prices over a certain period, which may either include or exclude prices received by VRE producers during certain time intervals or hours of the day.

35 Frontier Economics (2010) has estimated that, if wind capacity in the Netherlands is increased from 6 GW to 12 GW (by 2020), the additional wind in-feed lowers the average base load price level by about 5 €/MWh. In the 12 GW scenario, there are over 160 off-peak hours when the system marginal cost is zero.

In brief, increasing VRE penetrations tends to have a significant, increasing negative impact on wholesale electricity prices, notably in the short and medium term, depending on the factors discussed above. In the long run, however, the wholesale price effects of VRE deployment may be significantly lower, depending on the transformation of the power system. Model results, supported by a review of the literature, however, indicate that at high penetration rates the absolute long-term market value of VRE output is about twice as high as the mid-term value (Hirth, 2013). Besides the height and stability of the long-term system-base price, however, this depends largely on the long-term adaptation of the power system, in particular the structural change of the optimal plant mix, the expansion of transmission interconnections, etc. (see Section 6; Wiser et al., 2011; Hirth, 2013; Ueckerdt et al., 2013; IEA, 2014).

Finally, in addition to an impact on the level of wholesale electricity prices, increasing VRE generation also affects the volatility of these prices, i.e. this volatility generally becomes higher (Frontier Economics, 2010; Wiser et al., 2011; NEA, 2012). This implies that, in general, power prices become more uncertain and, hence, power generation becomes more risky.

7.2 The VRE curtailment effect

In cases of abundant VRE output and extremely low (negative) prices, curtailment of VRE production can be an efficient (or even forced) option. VRE curtailment can be caused by both insufficient transmission capacity and surplus VRE production. When total generation of essential capacity, i.e. must run or reserve-supplying capacity, exceeds residual load – which equals total load minus VRE generation – VRE output production is curtailed (Brouwer et al., 2014).

VRE curtailment has the advantage that it enhances output (revenues) of non-VRE generators and that it may reduce transmission (investment) costs. On the other hand, it reduces potential output (revenues) of curtailed VRE generators and, hence, reduces certain benefits or cost savings in the residual power system (such as less fuel use of less CO_2 emissions). Depending on the specific situation, however, VRE curtailment may be, on balance, the most optimal outcome from a social cost perspective.

Up to now, observed – i.e. historical – VRE curtailment has hardly occurred in high-VRE penetrated, European countries such as Denmark or Germany, whereas European countries with limited transmission interconnections – such as Ireland, Portugal or Spain – experienced some more situations of surplus VRE output, although generally at, on average, relatively low levels (1-2% of potential VRE output; Brouwer et al., 2014). Model simulations, however, show that at higher penetration levels (20-50%) VRE curtailment as a fraction of potentially VRE output becomes higher (up to 5%), implying lower net potential revenues for VRE generators (Hirth, 2012; Ueckerdt et al., 2013; Brouwer et al., 2014).

7.3 Impacts on VRE profitability and competitiveness

The impact of increasing VRE deployment on wholesale electricity prices and VRE curtailments are first of all important for the economics of VRE deployment itself: market prices are reduced and VRE output is curtailed only when VRE plants are generating electricity.[36] As VRE generators face decreasing wholesale prices when they are increasing their output (and do not receive eventual higher prices in hours when they are not producing), this implies that average VRE generation revenues (prices) may even decrease faster than average VRE generation costs (LCOE; due to the learning effect of VRE technologies). Some authors even argue that under current market conditions, i.e. marginal cost-based, energy-only market conditions, (i) VRE deployment – despite its learning rate – will never become profitable or market competitive (i.e. without VRE support, implying that it will never recover its fixed investment costs), and, hence, that (ii) it will become increasingly dependent on subsidies in order to meet rising, ambitious RE targets (Agora 2013; Frenken and Buchner; Hirth, 2013).[37]

This may be correct, notably in the short or medium term, but in the long run the profitability and competitiveness of VRE generation depends, amongst others – i.e. besides its learning rate and some other factors (see below) – on its impact on the wholesale electricity price in the long run (which seems to be significantly smaller in the long term than in the short or medium term, depending on the long-term adaptation of the power system, as indicated above).

One of the factors affecting the profitability and competitiveness of VRE generation is the price of CO_2 emissions. Higher carbon prices increase the cost of fossil-fuel generation, which is supposed to be passed on into higher electricity prices, thereby improving the profitability and competitiveness of VRE generation. Some authors, however, have questioned whether future CO_2 prices will indeed be substantially higher than current levels and, if so, whether higher carbon prices would have a significant impact on the profitability and competitiveness of VRE generation. The main arguments are that (i) higher carbon prices will above all stimulate less expensive, low carbon technologies, such as nuclear or lignite CCS, thereby limiting the increase in carbon and electricity prices and, hence, limiting the effect on the profitability and competitiveness of VRE generation, and (ii) even if carbon and electricity prices become higher, this does not change the fact that VRE technologies have short-run marginal costs close to zero and, hence, will depress output prices during hours with ample VRE supplies while they do not benefit from higher electricity prices during hours when they are not producing (Hirth, 2013; Agora, 2013; Frenken and Buchner, 2013).

36 Some authors have even called this impact of VRE deployment on its own performance '*the cannibalisation effect*', i.e. VRE deployment 'cannibalises' itself by depressing the prices it receives and curtailing its output (Hirth, 2012; Frenken and Buchner, 2013; Agora, 2013), although these are normal practices for low, short-run (marginal) cost activities that expand their output.

37 Apart from the question whether a large proportion of VRE generation can actually ever be profitable and competitive (without VRE support), this issue is related to the more general problem whether 'energy-only' markets will guarantee adequate capacity investments (the so-called 'missing-money problem') and will, therefore, be treated below in the section on this problem. See also Edenhofer et al. (2013).

Hirth (2013) has also investigated some other factors affecting the (market) value and, hence, the profitability and competitiveness of VRE generation. In brief, these factors and his main findings include:

- *Fuel prices.* An increase in the coal price improves the value of VRE generation, but this is less or not necessarily the case when the gas price increases as an increase in the gas price makes the merit-order curve steeper and stimulates the generation by less expensive technologies such as nuclear or new lignite.
- *Interconnector capacity.* Long-term modelling results indicate that long-distance transmission expansion supports the value of wind power in all countries considered, although the size of the effect is small. Mid-term results, however, show that interconnector capacity reduces the mid-term value of wind power in Germany, whereas it increases dramatically in France. This is due to the large existing French nuclear plant fleet. As a result, long-distance transmission prevents French wind power from being locked in with low nuclear prices, but hits German wind power by importing French nuclear power during windy periods.
- *Storage.* The value of both wind and solar power could potentially benefit from pumped hydro storage. At higher VRE penetration rates, however, the beneficial effects is higher for solar than for wind (as solar generation fluctuates more heavily across the day).
- *Flexible conventional generators.* Increasing system and plant flexibilities raises the market value of wind power significantly, up to 40% (Hirth, 2013).

7.4 Impacts on non-VRE generation revenues and profits

Increasing VRE deployment has also important impacts on the economics of conventional, non-VRE generators. In principle, all conventional power plants will be affected by the VRE-induced wholesale price effect, i.e. by lower electricity prices and, hence, lower revenues. This applies in particular for those base load and merit-order plants that are active during the hours in which VRE generators produce substantial amounts of output. In addition, depending on the VRE penetration rate, some conventional generators are also affected by the (transitional) utilisation effect, i.e. by lower load hours, resulting in higher average production costs (see Section 5). At lower penetration rates, this applies particularly for mid-merit plants with relatively high short-run marginal costs, such as gas-fuelled installations. At higher rates, however, it also becomes relevant for base load plants such as nuclear or coal-fired generators. This implies that these plants are actually hit twice by increasing VRE deployment, i.e. both through lower prices and through lower load factors. As a result, these plants face lower sales revenues and lower – or even negative – gross margins, which reduce their profitability and may result in plant closures and a lack of incentives to invest in maintaining and expanding generation capacity.

The above-mentioned impacts of VRE deployment on the economics of conventional generators are confirmed by some recent (modelling) studies.[38] For instance, NEA (2012) has estimated the impacts of VRE deployment on the load factors and profitability of dispatchable technologies. The major short-term results are summarised in **Table 7**.

Table 7: VRE-induced losses in power load and profitability of conventional power plants in the short term[a]

	Wind		Solar	
Penetration level	10%	30%	10%	30%
Conventional plant	Load losses			
Gas turbine (OCGT)	-54%	-87%	-40%	-51%
Gas turbine (CCGT)	-34%	-71%	-26%	-43%
Coal	-27%	-62%	-28%	-44%
Nuclear	-4%	-20%	-5%	-23%
	Profitability losses			
Gas turbine (OCGT)	-54%	-87%	-40%	-51%
Gas turbine (CCGT)	-42%	-79%	-31%	-46%
Coal	-35%	-69%	-30%	-46%
Nuclear	-24%	-55%	-23%	-39%

a) The results presented in this table have been obtained for an optimal (least-cost) dispatchable generation mix, comprising coal, gas and nuclear. Electricity price is assumed to be the cost of the marginal technology plus a mark-up of 7 €/MWh.

Source: NEA (2012).

In brief, **Table 7** shows, among others, that:

a) The short-term impact of VRE deployment on load factors of conventional plants is usually substantial, in particular for gas turbines, including both Combined Cycle Gas Turbines (CCGTs) and, more outspoken, Open Cycle Gas Turbines (OCGTs). Estimated load losses vary from -4% for nuclear at 10% wind penetration to -87% for OCGTs at 30% wind.
b) The impact on generators' profitability is generally even more substantial than the impact on their load factors. Estimated profitability losses vary from -23% for nuclear (at 10% solar) to -87% for OCGTs (30% wind).
c) As expected, load and profitability losses are higher at 30% VRE penetration than at the 10% level.
d) At a given VRE penetration level, load and profitability losses are usually higher for wind power than for solar power.

More recently, ECN has analysed the impact of deploying additional VRE capacity in Northwest Europe on the operation of gas-based units in the Netherlands (Özdemir et al., 2013). More specifically, based on National Renewable Energy Action Plans, the study assumes that between 2010 and 2020 the installed VRE capacity in Germany and the Netherlands increases in total by approximately 64 GW, i.e. about one third of total installed capacity in these countries in 2010. Based on these figures, ECN analyses how

[38] See also the studies mentioned in the sections on the utilisation effect and the wholesale price effect.

the dispatch and the operational surplus of generation units in the Netherlands changes over time.

The analysis shows that by 2020 the deployment of the additional VRE capacity results in a reduction of the full load hours of gas-based units by approximately 55% in the off-peak period and 75% in the peak period, while generation units performing in the super-peak are hardly operating at all. In addition, it leads to a reduction of the so-called '*contribution margin*', i.e. the difference between the revenue and the variable (operational) costs of power generation (in €/MWh), which is aimed to contribute to covering the fixed (investment) costs of a generation unit. Overall, the additional VRE deployment in 2020 results in large reductions of the operational surpluses of gas-based generators to recover the fixed costs of their investments (Özdemir et al., 2013).

Empirically, the impact of VRE deployment on the economics of conventional, gas-fired power plants can presently also be observed in several European countries – such as Germany, Spain and the Netherlands – where the (rapid) increase in VRE deployment over the past years has contributed to lower utilisation rates of these plants, very low – or even negative – gross margins ('spark spreads') for gas-fuelled generation units and (expected) closures of these units (Capgemini, 2013; Frenken and Buchner, 2013; Brouwer et al., 2014).

For instance, in Spain, the utilisation rate of gas-fired plants dropped from 66% in 2004 to 19% in 2012, while the IEA believes that gas plants require a utilisation rate of 57% to be profitable (Capgemini, 2013). In Germany, as CCGT utilisation rates have dropped below 21% in 2012, a study by the Deutsche Bank estimates that utilities may close as much as 6.4 GW of gas stations, i.e. about 25% of the country's gas-fired capacity by 2015. In a recent study (May 2013), IHS estimates that about 130 GW of gas plants across Europe, i.e. circa 60% of the total installed gas-fired generation in the region, are currently not recovering their fixed costs and are at risk of closure by 2016.[39] According to Capgemini (2013), "these plants – that are indispensable to ensure security of supply during peak hours – are being replaced by volatile and non-schedulable renewable energy installations that are heavily subsidized".

It should be noted, however, that the current problems of gas-fired power plants across European countries is not only (or predominantly) caused by the increase in VRE deployment in these countries but also by other factors, in particular (i) the relatively low coal price as well as the low ETS carbon price (which both depress electricity prices and cause a shift from gas- to coal-fired generation), (ii) the economic crisis since 2008 (which limits power demand and further depresses electricity prices), and (iii) the substantial expansion of fossil-fuelled generation capacity over the past years in some countries – e.g. in the Netherlands – and the resulting current surplus capacity, in particular of the relatively more expensive gas plants in these countries (which reduces the utilisation rate and profitability of these plants).

[39] The findings of the Deutsche Bank study (March 2012) and the IHS study (May 2013) are quoted from the European Energy Markets Observatory (Capgemini, 2013).

7.5 The missing money problem

The impact of increasing VRE deployment on the economics of conventional generators – in particular of gas-fired power plants – is linked to a more general issue of current, liberalised 'energy-only' markets, i.e. the so-called '*missing money problem*'. In brief, it states that in a market where electricity is the sole commodity traded ('energy-only' market), the price received for electricity is set by the short-run variable costs of the marginal generation unit. Therefore, the resulting generation revenues are not necessarily sufficient to recover the unit investment costs ('missing money') and, hence, to provide sufficient incentives for investments in generation capacity, in particular in mid-merit and peak-load capacity to meet security of electricity supply during hours of high demand ('long-term system adequacy').

This more general 'missing money problem' of liberalised, energy-only markets – including whether it is indeed a problem, its potential causes and possible solutions – is amply discussed in the literature and will not be repeated here.[40] Assuming there is indeed a missing money problem, the central question addressed here is whether and how increasing levels of VRE deployment affect this problem. In brief, there are at least two ways in which VRE deployment exacerbates the missing money problem:

- Increasing VRE deployment decreases generation revenues and operational surpluses of conventional installations, notably of mid-merit and peak-load (gas-fired) power plants, through lowering electricity prices (the wholesale price effect) and reducing load hours (the transitional utilisation effect). The wholesale price effect applies particularly in the short and medium term, notably during hours with large supplies of VRE output. Conventional generators may benefit, however, from higher electricity prices during hours in which VRE generators are hardly or not producing, especially when generation capacity becomes more scarce (e.g. due to growing demand, plant closures or less new investments). Moreover, over time – depending on the transformation of the power system – the wholesale price effect of VRE deployment may be significantly lower, or even largely disappear, while the dispatchable power plant mix is likely to adapt to the VRE-induced change in the net load duration curve (persistent utilisation effect), as discussed in the previous sections. Hence, the revenue-reducing impact of VRE deployment on the missing money problem is probably much lower – or even largely absent – in the long run compared to the short or medium term.
- Increasing VRE deployment enhances wholesale price volatility and, hence, increases the risk of power generation (Frontier Economics, 2010; Wiser et al., 2011; NEA, 2012; Edenhofer et al., 2013). Moreover, a business case based on making 2000 Euros over 50 hours is less attractive, i.e. more risky, than a business case based on making 20 Euros over 5000 hours (Frenken and Buchner, 2013). A higher risk profile of investments discourages investors or requires a higher return of investment or a higher risk premium. However, there may be a limited market for trading higher risk premiums. Investors in a plant, making 2000 Euros over 50 hours, will try to hedge the risk involved by buying long-term high-price insurance, but the willingness of insurance sellers will be limited due to reasons such as price caps on

[40] For a discussion of the missing money problem – and its links to increasing levels of VRE deployment – see, for instance, Nicolosi (2011); Edenhofer et al. (2013), De Joode et al. (2013), and references cited there.

power exchanges or lack of political or regulatory acceptance of high electricity prices (Frenken and Buchner, 2013). Over time, however, – depending on the transformation of the power system – the VRE induced increase in wholesale price volatility may become less, while markets may develop to better deal with the risk involved. Hence, the price-volatility impact of VRE deployment on the missing money problem, including the related system adequacy problem, may be lower in the long run than in the short or medium term.

Therefore, to conclude, assuming that there is a missing money problem in liberalised energy-only markets, increasing VRE deployment exacerbates this problem through both the revenue-decreasing impact and the price-volatility, risk-increasing impact of VRE deployment on conventional power plants, in particular in the short and medium term.[41] In the long run, however, these impacts on the missing money problem – including the related system adequacy problem – may be lower, or even largely disappear, depending on the long-term transformation of the power system.

To address the (perceived) missing money problem, a variety of specific options are available such as improving the design – or price signals – of energy only markets (concluding long-term contracts; preventing price caps, etc.) or introducing capacity mechanisms such as capacity payments or capacity markets.[42] In addition, there is a large variety of more general options to address the missing money problem as well as other impacts and related problems of increasing VRE deployment, in particular options to enhance the overall flexibility of the power system, such as improving the flexibility of the power plant mix, enhancing demand responsiveness, extending and enforcing the grid infrastructure, introducing more flexible system and market operations, etc.[43] These specific and general options are widely discussed in the literature (see previous two footnotes), and not repeated or reviewed here as they fall beyond the scope of the present paper.

41 This conclusion for the short and medium term is, to some extent, supported by recent (modelling) research, such as the study by ECN (Özdemir et al., 2013), as discussed in the main text above.

42 For a discussion of these and other specific options to address the missing money problem, see e.g. Nicolosi (2011), De Joode et al. (2013), E-Bridge and UMS (2013), Edenhofer et al. (2013), and references cited there.

43 For a discussion of these and other general options to address VRE-induced impacts and related problems, including the missing money problem, see e.g. Frontier Economics (2010), Sims et al. (2011), REP (2012), Agora (2013), De Joode et al. (2013), IEA (2014), and references cited there.

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