DiaCore

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Policy Dialogue on the assessment and convergence of RES Policy in EU Member States

D4.2: RES market values and the merit-order effect

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PREFACE

DIA-CORE intends to ensure a continuous assessment of the existing policy mechanisms and to establish a fruitful stakeholder dialogue on future policy needs for renewable electricity (RES-E), heating & cooling (RES-H), and transport (RES-T). The core objective of DIA-CORE is to facilitate convergence in RES support across the EU and enhance investments, cooperation and coordination.
This project shall complement the Commission's monitoring activities of Member States (MSs) success in meeting 2020 RES targets and builds on the approaches developed and successfully applied in the other previous IEE projects.
The strong involvement of all relevant stakeholders will enable a more thorough understanding of the variables at play, an identification and prioritization of necessary policy prerequisites. The dissemination strategy lays a special emphasis on reaching European-wide actors and stakeholders, well, beyond the target area region.

PROJECT PARTNERS

N°	Participant Name	Short Name	Country Code
CO1	Fraunhofer Institute for Systems and Innovations Research	Fraunhofer ISI	DE
CB2	Vienna University of Technology, Energy Economics Group	EEG	AT
CB3	Ecofys Netherlands bv	Ecofys	NL
CB4	Eclareon GmbH	eclareon	DE
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CB6	Lithuanian Energy Institute	LEI	LT
CB7	Centre for European Policy Studies	CEPS	BE
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CB9	University of Utrecht	UU	NL
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Summary

The topical focus of this report is on the assessment of the *merit-order effect* and *market values* of renewable energy sources electricity (RES-E) generation since both are relevant for a correct quantification of net support expenditures for RES in the electricity market. In particular, the analysis focuses on the assessment of these indicators for variable renewable energy sources (vRES), most prominently wind and solar PV. The installed capacity of variable renewable energy sources is being assumed to substantially increase to meet EU RES and climate targets. In case of high deployment shares the feedback effect on electricity markets is expected to reach a significant dimension and therefore indirectly influences the overall cost-benefit analysis. The assessment of both the merit-order effect and market values are conducted from a historical and a future perspective.
Based on historic data an econometric analysis has been performed for selected Member States, which were already at the forefront of RES deployment in the past. The historical price development in these member states represents 73 % of the RES share in Europe's regional electricity markets. To gain insights into the impact of renewable electricity on prices, market values and the merit order effect were calculated using a multivariate regression analysis and ex-post calculations.
The results of the historical analysis show a clear and consistent trend; specifically it can be seen that feed-in of electricity from variable renewables (wind power and photovoltaics) has a negative impact on day-ahead electricity prices. Regression results performed for all Member States confirm this finding. Also, the market value of renewable electricity generation is influenced: we found that an increased share on total load, in particular for wind power, leads to a substantially lower market value per generated MWh. Concretely, looking at normalized market value factors, which relate the revenues of a certain technologies to the ones of a baseload generator, one can see that the market value factor for wind power drops with an increase in the share of wind in total load. The intensity of the drop however varies between member states thus shows that some electricity markets are more able to incorporate fluctuating renewables than others (due to flexibility, interconnection, storage and other forms of demand side management). Outcomes of the econometric analysis looking at the effect of variable renewables on spot prices show decreases of around 0.53 €/MWh for e.g. Germany or 0.8 €/MWh for Spain per additional percent of wind infeed. Scaling this up to a yearly measure translates into 180.7 Million € or 197.7 Million € lower cost of consumed electricity evaluated at wholesale prices. These findings are similar to those found in the literature.
The model-based forward looking analysis finds that an additional amount of RES-E, ceteris paribus, decreases average electricity prices by 2 to 5 percent depending on the actual amount and type of additional RES-E and the corresponding in- and divestments in the conventional generation park.

When it comes to the sensitivity of market revenues of variable renewables to framework conditions in electricity markets this report has shown that additional energy efficiency measures in combination with a more ambitious carbon pricing considerable impacts specific market revenues of RES. The impact depends on the technology in question but can reach up to 15 €/MWh. Further influencing factors are the future development of the high voltage transmission grid, whether additional demand side flexibility can be utilized and which market design will be chosen. The aggregated results show that the market

value of vRES in the EU increases by 0.28 billion EUR in 2030 and by 11.47 billion EUR in 2050 as a result of increased demand side participation through power2heat applications. When international grid development is delayed the overall effect results into lower market values of 0.36 billion EUR in 2030 to 4.90 billion EUR in 2050. If throughout the EU capacity markets were implemented revenues of vRES within wholesale markets are lower by 3.29 and by 6.85 billion EUR in 2030 and 2050, respectively.

Also market revenues are expected to change in between years due to intra-yearly differences in resource availability. These impacts are attributable to variations in meteorological conditions and can cause up to 10 €/MWh variations in specific market revenues of variable renewable generation.

Furthermore, the ratio between potential market revenues of RE generators and baseload generators (the market value factor) considerably drops with increasing penetration, especially for vRES. In the period until 2030 and 2050 the decreasing effect of market value factors becomes apparent. The average of market value factors over all EU countries drops for wind onshore, wind offshore and solar PV with increasing RES penetration by as much as 4 to 12 percentage points as compared to a baseline pathway.

To put the calculations in this paper into a perspective, moreover a market based framework for assessing the effects of RES-E is presented. The framework establishes the merit-order effect and market values of RES-E as distinct benefit measures, which are based on market prices, and from which the benefit RES-E has in the electricity market can be calculated. This framework is applied in the overall cost-benefit analysis of renewable electricity that is presented in project deliverable D4.4 available on the project webpage (http://diacore.eu).

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1 Introduction

The installed capacity of vRES – in particular wind and solar power – is being assumed to substantially increase to meet EU RES and climate long-term targets (EC 2011). Some countries such as Denmark, Germany or Spain have already integrated large shares of renewables into their power systems. However, the integration of vRES into grids and markets creates a number of impacts, from either the technical (operation and planning), economic and regulatory perspective. In case of high shares of these variable RES technologies the feedback effect on electricity markets is expected to reach a significant dimension that should be carefully considered in energy policy. An in-depth analysis of these effects from different perspectives has been conducted within the EU project *beyond2020* (Frías et al. 2013).

One effect of viral importance is that with sufficiently high shares of RES-E in a certain power system the operation of the system and the underlying grids changes. These changes are not fundamental in the sense that they compulsively require completely new market architecture. However, they cause a shift from traditional generation patterns towards a more dynamic operation of conventional power plants and might alter the generation mix of dispatchable plants. As a direct consequence, this changes price dynamics of wholesale electricity markets, which in turn leads to distributional effects between different market participants and alters their in- and divestment incentives. It is important to note that this basically holds regardless of whether RES-E are fully integrated in markets and thus directly marketed in these wholesale markets or if they impact markets only indirectly via residual load profiles. However, if renewable generation units market their output directly they probably can realize higher market revenues through innovative business models.

In any case, the overall price dynamics of wholesale markets and potential revenues from selling their generation on markets is of great importance for the overall cost-benefit analysis of renewables. On the one hand, market price changes go hand in hand with the costs of serving wholesale demand within a certain period of time. These changes influence producer and consumer rents during that period and have the potential to drive the market towards a different equilibrium. The corresponding distributional effects during such transition phases induced by renewable deployment can impact the amount of RES-E support expenditures and consumer electricity prices. On the other hand, under perfect framework conditions support costs for RES-E are determined by the gap between expenditures needed for investment and potential market earnings. The higher market earnings the less support expenditures are needed to ensure investments in RES-E. As a consequence, current designs of renewable support policies get more market-oriented via setting incentives for RES-E generators to switch from protected markets into common balancing groups and directly market their energy in electricity markets. Furthermore, on the one hand, the share of RES-E generation that runs out of support and thus has to participate in electricity markets gets progressively higher and, on the other hand, some of the RES-E technologies are about to reach grid parity in the near future. Even in the case of a support cost assessment for support systems where generators are not responsible for market integration (e.g. fixed feed-in tariffs) it is important to establish a relation between the deployment of RES and the resulting influence on electricity markets to accurately calculate the required monetary transfer caused by the policy intervention for RES in the electricity market from the consumer/societal point of view.

The focus of this report is to shed light on these key effects of large-scale RES-E integration in electricity markets. First, we analyse how price dynamics in wholesale markets induced by RES-E deployment have changed in the past and are expected to change based on a number of scenarios. These changes are summarized under the term *merit-order effect* of RES-E in the relevant literature (cf. Sensfuß et.al, 2008). Second, a closer look is taken on potential earnings of RES-E stemming from electricity markets. Within this report we refer to the term *market value* of RES-E as the sum of revenues earned from RES-E plant operators through the marketing of generated electricity in spot markets.

The remainder of the report is organized as follows. Chapter 2 introduces the above described market figures more formally and provides additional information on the assumptions taken within the assessment. Also, as basis for the incorporation of these figures in the subsequent support cost assessment, an appropriate cost-benefit framework is introduced in chapter 3. In chapter 4 results of ex-post calculated historical market values and an econometric analysis of the merit-order effect for selected countries are documented. Specifically, the most important countries with regard to RES expansion of wind and solar power are analysed by looking at impacts of RES infeed on their respective electricity spot prices and corresponding market values. All results are contrasted against the findings from other relevant studies in order to contribute to existing literature in this field. Finally, in chapter 5 a comprehensive modelling set-up for the assessment of the merit-order effect and RES market values under changing framework conditions is presented. The report closes with a summary chapter on preliminary findings and conclusions.

2 Background

As in all markets the fundamental variables in liberalized electricity markets are prices. Electricity prices are distinguished in retail and wholesale prices. Retail prices are the average cost of electricity plus taxes, surcharges (e.g. the RES surcharge) and grid fees. Retail prices for different consumers are different depending on their supplier, the type of consumer (household or industry), the yearly amount of electricity that is consumed and the location of electricity withdrawal. The share of energy cost of the total electricity price varies among countries. Figure 2-1 and Figure 2-2 summarize the composition of electricity retail prices for consumers and industry for selected European countries. It can be seen that the share of energy accounts on average for 41% in household prices and for 36% in industry prices, whereas it varies considerably more for households in different countries. However, it can be seen that the energy share makes up a significant part of the price. Electricity taxes are in the range of 30% on average of overall prices and the remainder accrues from the provision of grid services.

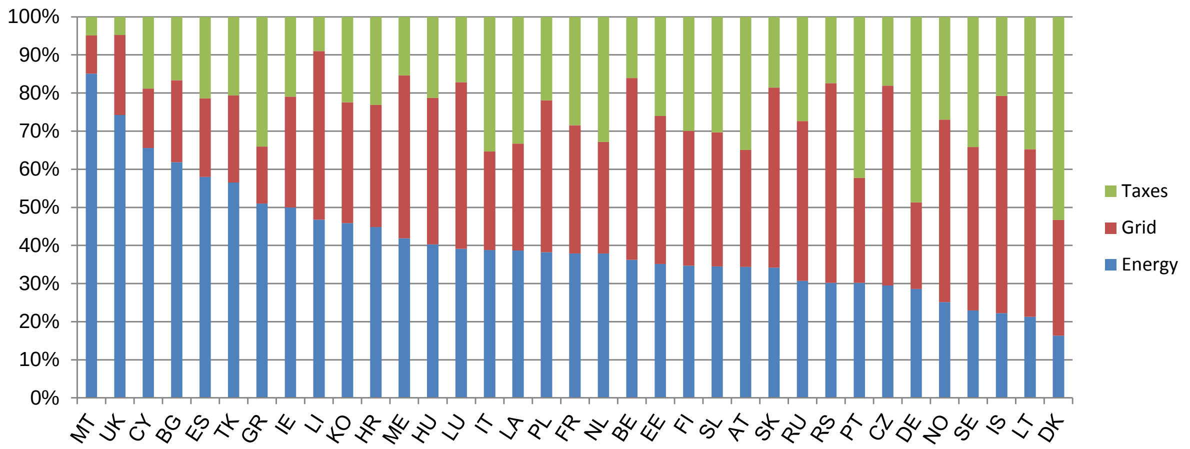


Figure 2-1 Components of electricity retail prices of households in selected countries (Source: Eurostat)

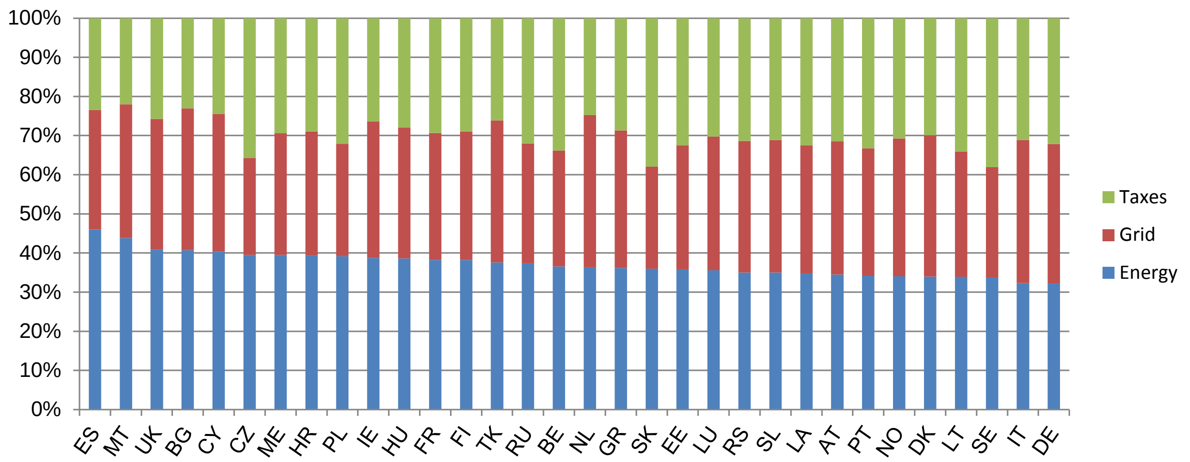


Figure 2-2 Components of retail electricity prices for industry in selected countries (Source: Eurostat)

In the long run, average retail electricity prices should cover all costs and levies that arise in the course of supplying consumers with electricity. Therefore, they also comprise the costs of supporting and generating electricity from renewable sources (RES-E). Table 2-1 shows a further subcategorization of retail electricity prices. Since the focus of this analysis is laid on the impacts of renewable electricity on prices and costs, RES surcharges are separated from other taxes to make them a distinct category.

Table 2-1 Subdivided composition of retail electricity prices

Energy costs	Energy-only wholesale markets
	Capacity markets
Grid costs (System usage charge)	Distribution grid
	Transmission grid
	Balancing costs
	Other system services
Taxes	Levies on production, transport and sale
RES surcharge	Generation costs
	RES market value and support costs
	Support design

Energy costs comprise the total costs of electricity generation from conventional energy sources. They include variable and fix costs. In liberalized markets generators, traders and large consumers compete in wholesale markets for the interregional provision and delivery of electricity. At the moment, the main share of total electricity generation costs is covered by revenues stemming from energy-only wholesale markets. Depending on the concrete market design a certain share of fixed costs can be earned from capacity markets. The second part of the price consists of the remuneration for costs that comprise all services provided by grid operators. These are among others the reliable operation and maintenance of existing grids as well as investments in new infrastructure and equipment. Taxes comprise e.g. poverty, environmental and consumption taxes, which differ in type and size from country to country (cf. Figure 2-1 and Figure 2-2). Finally, the RES surcharge covers all expenditures arising from the gap between long-run generation costs and market revenues of RES-E. The size of necessary support expenditures for RES strongly depends on the design details of the implemented support instrument(-s) (Ragwitz et al. 2014). The support of RES-E and the subsequent integration in electricity markets and grids causes costs and benefits that appear at several points in the above mentioned price categories. To what extent and at what point in time these costs and benefits actually materialize in retail prices depends on many factors including system inherent time lags, the level of competition and the regulatory framework. In this report we take a step back and analyse impacts of RES-E on wholesale electricity markets and what RES-E generators can earn from these markets. These two market figures significantly impact energy costs as well as RES surcharges and thus total electricity costs to be borne by consumers.

3 Definitions and key assumptions

3.1 General approach

The aim of this report is to deliver numerical insights into two distinct benefits of renewable electricity generation in electricity wholesale markets. The first benefit concerns the price-damping effect of renewable infeed, which has been termed the *merit-order effect* in the literature (cf. Sensfuss et al. 2008). The second quantifies the market value of renewable generation itself. Both figures are closely related to each other. In the following the relation of these two benefits of RES are formally characterized and incorporated in a general cost-benefit framework of the electricity sector.

The merit-order effect concerns the relation between wholesale electricity market prices and renewable electricity generation. This relation is multi-facetted and can be expressed through various measures. For example, it depends on which concrete prices are taken into account, on what characteristics of prices it is focused on and over what period of time the analysis is performed. Furthermore, whereas empirical approaches are limited by the availability of data, model results are strongly influenced by the applied modelling approach and assumptions on framework conditions. For this reason, we are approaching the assessment of the merit-order effect from several directions. First, we provide a formal definition of the merit-order effect, which is embedded in a more general framework developed for the cost-benefit analysis of RES-E based on electricity markets. The framework is set up in a way that the results can be directly transferred into the assessment of net support expenditures of RES-E. Secondly, we perform a comprehensive empirical analysis of observed merit-order effects in several EU countries by applying different econometric models, which are oriented on the state-of-the-art in the relevant literature. The results of this analysis are again contrasted and interpreted with respect to the existing literature. Thirdly, we use a hybrid modelling approach to model the merit-order effect under different framework conditions. In order to account for robustness checks of the results we perform sensitivity analyses of the most important input assumptions. To show the implications of a simultaneous change of various framework parameters we carry out pathway scenarios.

3.2 Formal notation conventions

In this section we provide some basic definitions of variables and indicators that will be used throughout the paper. We apply the convention that absolute values as sum over a certain time period (in EUR/a) are denoted by capital letters and marginal values that relate a certain cost or benefit to the amount of energy generated or consumed (in EUR/MWh) by lower case letters. Energy contents are always given in MWh per corresponding time period. Table 3-1: Selected notation gives and overview on the main variables, which are used in the following in order to formally describe how the merit-order effect and market values play together in a general cost-benefit framework of the electricity sector.

Table 3-1: Selected notation

MOE	... Absolute Merit-Order Effect	in EUR/a
MV	... Absolute Market Value	in EUR/a
mv	... Relative Market Value	in EUR/MWh
mvf	... Market value factor	in interval [0,1]
p	... (Wholesale) electricity price	in EUR/MWh
q	... Electricity consumed/generated	in MWh per hour
Q	... Cumulated electricity consumed/generated	in MWh per year
C	... Yearly fixed electricity generation costs	in EUR/a
c	... Variable electricity generation costs	in EUR/MWh
B	... Net benefit of additional RES deployment	in EUR/a
$Conv$	... Index indicating conventional electricity generation	
Res	... Index indicating renewable electricity generation	
Dem	... Index indicating total electricity consumed	

3.3 The merit-order effect

We interpret the merit-order effect in its general form as the relation between wholesale electricity prices and renewable electricity generation. This relation is quantified as differential change of price characteristics as response to additional RES deployment. Therefore one has to contrast two system states to each other. We define **system state (1)** as our reference case with a certain RES deployment. In contrast to that **system state (2)** characterises the same power system, however with a greater share of RES on demand. Thus, both system states describe a certain power system in its equilibrium, whereas the states are differing in the share of RES on gross electricity demand. We mark the relevant variables with indices (1) and (2), respectively, to state whether they refer to system state (1) or (2).

With regard to prices we have to recognize that there are plenty of prices subject to three distinct dimensions. A price $p_{t,l,\delta}$ refers to a point in time t, a certain location l and to a future point in time δ when the electricity is physically delivered (gate closure). The concrete market design defines products that discretize this 3-dimensional price space, since not for each time, location and gate closure point a priced product can be traded. Within this report we abstract from this and consider only the day-ahead wholesale prices within a certain country to assess market values and the merit-order effect. For a certain country the merit-order effect will be calculated as

$$MOE = \sum_{t=1}^{t=8760} \left(p_t^{(1)} - p_t^{(2)} \right) \cdot q_t^D \quad . \tag{0}$$

Therein, the MOE effect is calculated as the sum of system-state differences in price-weighted electricity demand over one year. In other words, the merit-order effect quantifies how the market value of consumption changes when additional RES is deployed.

3.4 Market Values

In principle, the market value of RES-E generation comprises all segments where this generation is eligible to be marketed. Generally, for a more profound assessment of market values the amount of potential profits that can be achieved by RES-E generators has to be analysed in detail. Since the various RES-E technologies differ significantly in some for the markets relevant characteristics (e.g. generation profile / dispatchability, capacity credit, cost structure, locational needs, etc.) each technology has to be analysed separately.

A simplified estimation of the *market value* of RES-E generation can be calculated by multiplying the electricity production by the day-ahead electricity market price in a certain price zone as shown in eq. (2).

$$MV = \sum_{t=1}^{T} p_t \cdot q_t^{Res} \tag{1}$$

Division by the cumulative generation leads to the relative market value

$$mv = \frac{\sum_{t=1}^{T} p_t \cdot q_t^{Res}}{\sum_{t=1}^{T} q_t^{Res}} \ . \tag{1}$$

The base price of day-ahead electricity prices are the average over the year

$$p_{base} = \frac{1}{8760} \sum_{t=1}^{T} p_t \ . \tag{2}$$

The ratio between the relative market value of a certain technology and the corresponding base price in the same price zone is called the *market value factor*

$$mvf = \frac{mv}{p_{base}} \tag{3}$$

This factor is important to compare relative market revenue changes of certain technologies between different countries / price zones.

3.5 Accounting framework for the electricity sector for cost benefit analysis

In this section we describe a framework for assessing the effects of RES-E in terms of costs and benefits in the electricity sector. Thereby we discuss the effects under the following propositions:

- By direct or indirect relationships all costs are reflected by prices, how costs materialize into prices depends on the applied market design.
- As the output – a unit of electricity - is a homogeneous good, benefits are reflected in cost savings.

In the electricity sector the costs for the supply of electricity divide into fixed and variable costs of electricity generation. These costs are priced in different market segments that are either organized competitively or regulated. In the absence of market power, in the long-term equilibrium the revenues from the different market segments are sufficient to cover the long-term costs (capacity and energy) of generation, though technical constraints such as limited potential may induce rents for some generation technologies. Structural changes in the composition of revenues in one market segment therefore, ceteris paribus, imply unabatedly immediate or time-lagged changes in the composition of revenues in other market segments so that in the long-term equilibrium all costs are covered. Thus the long-term retail price for electricity, composed of the wholesale price and all surcharges equals the long-term average system costs.

Now we discuss the impacts of RES-E on the electricity sector in more detail. We do this with the help of Figure 3-1. A legend for Figure 3-1 is provided in Table 3-2. We assume that in Figure 3-1 costs, revenues and prices are shown as yearly weighted average. Moreover we assume that marginal costs are constant so that marginal costs equal average costs.

In our simple model two types of generating technologies are available: a conventional fossil peak power plant (F) that serves as benchmark and a RES-E power plant (R) with volatile output. The two types of technologies distinguish in how their costs of electricity generation are divided into costs for energy (1a-1d) and costs for capacity (1e). Whereas peak power plants are characterized by high variable costs relative to their capacity costs due to their low full-load-hours, RES-E plants have variable costs close to zero and their generation costs almost exclusively derive from the costs of the generating capacity.

Now when a new unit of RES-E generating capacity is added it creates benefits (3a+3b) within the power system by displacing both energy and capacity from the conventional benchmark power plant. Due to its variability in output there are system states in a year where the RES-E capacity is not available to displace conventional generating capacity. This effect takes place on several time scales (cf. Hirth, Ueckerdt, und Edenhofer 2015; Nicolosi 2012):

- In the short run (2a+2b) additional energy from the conventional benchmark technology is required due to the need for additional system flexibility (ramping, cycling, part-load).
- In the long term the RES-E power plant decreases the amount of energy produced by conventional generators much more than reducing the need for installed capacity so that additional conventional capacity with low utilisation needs to be installed (2c).

Thus the system integration costs are the additional costs of the conventional benchmark technology that cannot be displaced by the RES-E power plant. The RES-E generator “sees” these integration costs as reduction in market value (Hirth, Ueckerdt, und Edenhofer 2015). The aggregated benefit of the new RES-E capacity across all market segments determines its market value (3c). The investment costs of a new RES-E project net of its market value determine the support costs that need to be covered outside the wholesale electricity market.

The different components of costs and benefits discussed so far are reflected by prices in different segments of the electricity market (Spot, Balancing, Capacity, Support Scheme). We distinguish between electricity wholesale spot markets and other market segments; while on spot markets generally a price emerges that determines the exchange of quantities between the supply and the demand side, the other segments are often characterized by only one party forming the demand side, so that they are either operated as procurement auctions or regulated and the resulting costs of the demand are usually passed on as surcharges on the retail prices for electricity.

In the short term the marginal costs (1a-1c) of the last generating unit needed to satisfy the demand set the price on the wholesale electricity market (4a). These prices are however not sufficient to cover the costs of capacity. Two options exist to finance this cost gap: an energy only market with scarcity prices (4b) or a market for capacity (5b). As can be seen from Figure 3-1 in a market environment with perfect information both options for pricing capacity should lead to the same mark up on average, i.e. while price spikes occur less frequently they are generally higher in magnitude than capacity prices, but apportioned to a MWh. both options should lead to the same price.

The costs for the provision of balancing energy of the conventional power plant are reimbursed on the balancing market. This does not imply that the RES-E power plant cannot provide balancing energy; we however only display here the additional amount of balancing energy resulting from the variability compared to the conventional benchmark.

Finally, the RES-E power plant asks for its financing gap to be recovered through a support premium. Ultimately, in one way or the other, this financing gap is passed on to consumers as support costs (③). This financing gap arises as the RES-E plant cannot (yet) achieve the same market value as the more efficient benchmark technology (neglecting positive externalities outside the electricity sector). Thus the market value (①) that will be analysed in more detail in this paper is an important indicator for the competitiveness of RES-E power plants in the electricity market.

We recall from above that the market value of RES-E depends on the costs of the alternative benchmark technology that it displaces. With increasing penetration of RES-E capacity however the number of hours where the costs of conventional generation are displaced will also go down. In extreme cases with a very high availability of RES-E capacity, new RES-E capacity would only displace other existing RES-E capacity. This shift in the generation mix through pushing more costly generation out of the market is referred to as the merit-order effect (②). The consequence is that the wholesale price level will go down and given that the surcharges stay constant also the retail price for electricity has to go down, unless retailers do not pass on the decreased costs for the purchase of electricity to the consumers. However, as we operate in a closed system where all costs have to be recovered in the long term, the investment gap will have to be recovered less smoothly in fewer time steps, either by means of more extreme scarcity prices in the wholesale market, or by means of higher surcharges in the other market segments, depending on the applicable market design. Thus the reader may observe that in the long-term equilibrium the average retail price for electricity has to equal the average system costs, which are composed of the average costs of the benchmark technology (1a-1e), plus the support costs of the not yet efficient RES-E technology.

Next we present our conceptual discussion from above in a more formal framework. The objective is to dismantle the interrelationships between the different RES-E impacts we are interested in.

Cost perspective

As we have argued above the output of the electricity value chain – a unit of electricity – is a homogeneous good and therefore benefits in the electricity sector can be expressed as cost differences between different system configurations (in our case system state (1) and (2)). In both states we assume a system that is supplied by a certain mix of conventional and renewable electricity generation. The total system costs are simply given by the sum of fixed and variable costs of generation

$$C_{total} = C_{fix} + c_{var} \cdot q \; = C_{fix}^{Conv} + c_{var}^{Conv} \cdot q^{Conv} + C_{fix}^{Res} + c_{var}^{Res} \cdot q^{Res} \,. \quad (4)$$

Adding renewable electricity generation to this reference system lowers the costs of conventional generation by the amount they are displaced by renewable generation and adds additional fixed and variable costs on part of renewable generation to the total costs. Thus, additional costs of switching from system state (1) to (2) can be calculated by subtracting total system costs of both system configurations. Due to the fact that in the end all costs are translated into electricity prices and potential additional side payments that have to be borne by consumers, the cost difference of both states also represents the net-benefit of RES

$$B^{(1-2)} = C_{total}^{(1)} - C_{total}^{(2)} \,. \quad (5)$$

When renewable generation has relatively higher costs than conventional generation the net-benefit is negative.

Cost recovery conditions

We have postulated that in the long-term competitive equilibrium all costs are covered by a combination of market revenues in case of an energy-only market (EOM) or by a combination of market revenues (EM) and premium payments outside the electricity market in case of distinct mechanisms for energy and capacity remuneration (CM). In the following we assume for the sake of notational simplicity an “energy-only” market design for conventional generation whereas the renewable generation can receive a premium a premium outside the electricity market on top of the electricity market revenues. Within the subsequent modelling activities we differentiate all relevant configurations. Thus, the cost recovery conditions translate into

$$\overbrace{mv^{Res} \cdot Q^{Res}}^{EOM} + \overbrace{pr^{Res} \cdot Q^{Res}}^{Additional\ premium\ for\ RES} = C_{fix}^{Res} + c_{var}^{Res} \cdot Q^{Res}, \qquad \forall\ Res$$
$$\overbrace{mv^{Conv} \cdot Q^{Conv}}^{EOM} = C_{fix}^{Conv} + c_{var}^{Conv} \cdot Q^{Conv}, \qquad \forall\ Conv. \tag{6}$$

Value perspective

The total market value of demand, i.e. all market revenues in the wholesale market, can be split up in market revenues from conventional and renewable generators.

$$mv^{Dem} \cdot Q^{Dem} = mv^{Conv} \cdot Q^{Conv} + mv^{Res} \cdot Q^{Res} \tag{7}$$

If we add up both cost recovery conditions from (8) we receive

$$C_{total} = mv^{Res} \cdot Q^{Res} + pr^{Res} \cdot Q^{Res} + mv^{Conv} \cdot Q^{Conv} \tag{8}$$

The revenues of conventional generators can be expressed via eq. (9), which leads to

$$C_{total} = mv^{Dem} \cdot Q^{Dem} + pr^{Res} \cdot Q^{Res}. \tag{9}$$

Equation (11) describes the total power system cost as function of the market value of demand plus a premium to be paid to renewable generators. This equation is valid for both system states. Thus, we can thus describe the net-benefit defined in eq. (7) as

$$B^{(1-2)} = \overbrace{(mv^{Dem,(1)} - mv^{Dem,(2)}) \cdot Q^{Dem}}^{MOE} + \overbrace{(pr^{Res,(1)} \cdot Q^{Res,(1)} - pr^{Res,(2)} \cdot Q^{Res,(2)})}^{Change\ in\ support\ payments} \tag{10}$$

In doing so, we established a relationship between the net-benefit of renewables and the merit-order effect together with a change in required support payments to renewables.

Finally, the support payments to renewables from eq. (12) can be split up in costs and revenues via eq. (8) into

$$pr^{Res,(1)} \cdot Q^{Res,(1)} - pr^{Res,(2)} \cdot Q^{Res,(2)} = \overbrace{(mv^{Res,(1)} \cdot Q^{Res,(1)} - mv^{Res,(2)} \cdot Q^{Res,(2)})}^{Change\ in\ market\ value} + \ldots$$
$$\ldots \overbrace{-c_{var}^{Res,(1)} \cdot Q^{Res,(1)} + c_{var}^{Res,(2)} \cdot Q^{Res,(2)} - C_{fix}^{Res,(1)} + C_{fix}^{Res,(2)}}^{Change\ in\ generation\ cost}. \tag{11}$$

In the remainder of this report the merit-order effect (MOE) and corresponding changes in market values (MV) of wind onshore, wind offshore and solar PV will be quantified for a number of scenarios. In order to fully assess changes in support payments, and therefore calculate the overall net-benefits, the effect of e.g. learning rates, resource quality and other impacts on generation costs need to be taken into account as well. Therefore, total changes in support costs will be conducted in the overall cost-benefit analysis documented in deliverable D4.4 available on the project webpage (http://diacore.eu).

Table 3-2: Legend for Figure 3-1.

System costs	(1a)	(1b)	(1c)
	Variable costs	CO_2 costs	Fuel costs
	(1d)	(1e)	
	Balancing costs	Capacity costs	
System integration costs	(2a)	(2b)	(2c)
	flexibility effect	forecast error	utilisation effect
Market value (Benefits)	(3a)	(3b)	(3a + 3b)
	Displ. Var. costs	Displ. Cap. Costs	Market value
Market design			
	Energy olny	Energy and cap.	
Wholesale electricity price	(4a)	(4b)	
	Base price	Avg.scarcity rent	
Surcharges on electricity price	(5a)	(5b)	(5c)
	Grid surchage	Capacity price	RES-e premium
Impacts of RES-e	1	2	3
	Merit order effect	Market value	Support Costs

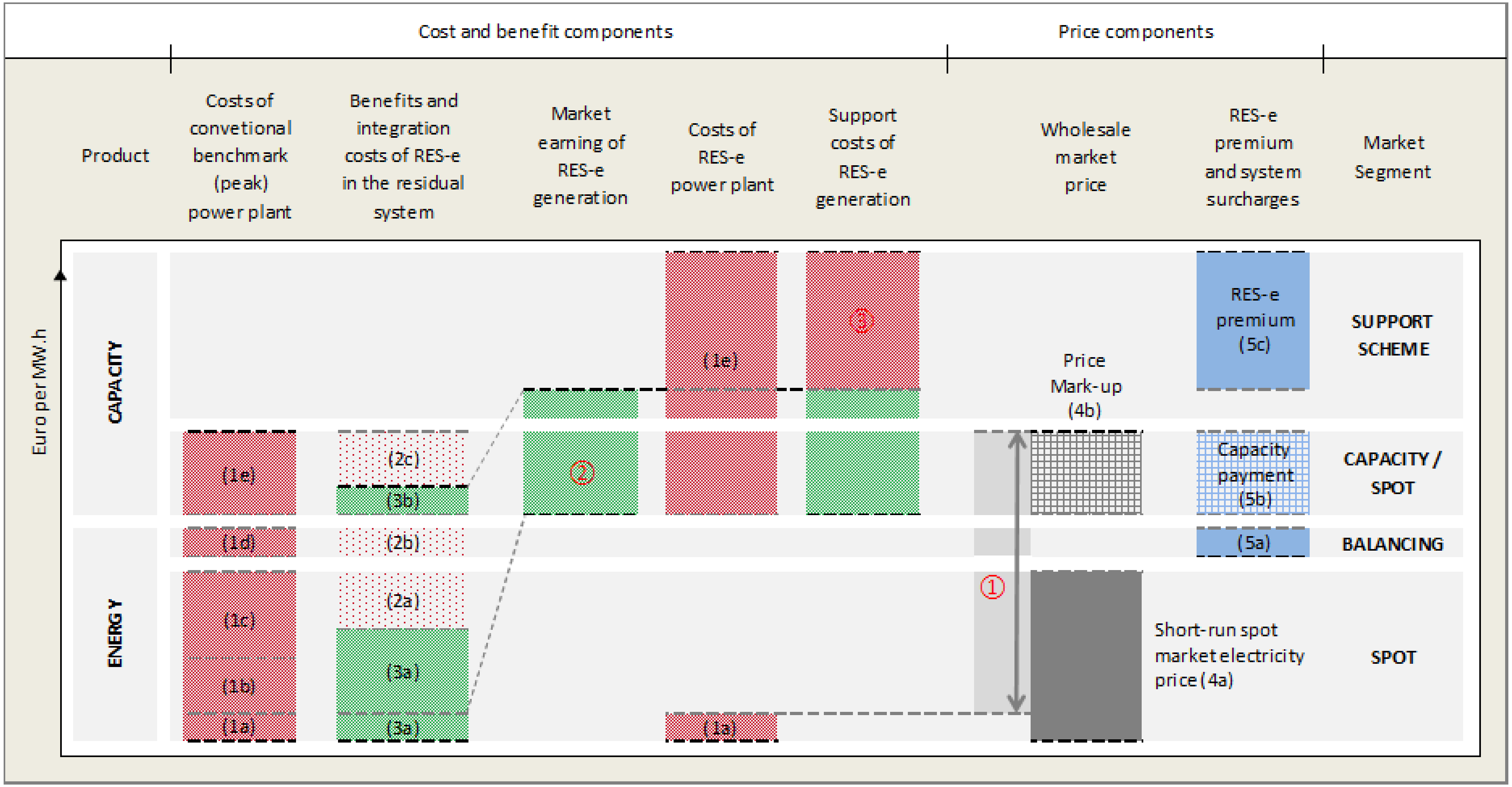


Figure 3-1: Assessment framework for the electricity sector.

4 Assessment from a historical perspective

In this first subtask an assessment of both the merit-order effect and market values has been conducted from a historical perspective. Building on the literature review conducted, light will be shed on Europe's regional electricity markets.

A clear distinction has been made between market values and the merit-order effect, thus covering both the system- and investor-perspective. Finally, for variable RES-technologies (i.e. wind and solar) market values will be analysed in depth. The analysis includes a calculation of the market values on the basis of historical data for generation of variable RES and the corresponding spot market prices.

4.1 Literature review of existing studies

As starting point of the historical analysis, a literature review on existing definitions, approaches, results and criticisms will be presented: The literature analysing empirical effects of renewables infeed on the electricity spot price and thus implications for merit order and market value is very diverse and covers a variation of methodologies and countries. To our knowledge, nevertheless, a Europe-wide study of these effects, covering as many countries as the following has not been executed so far. This literature review gives a broad overview of empirical approaches used to analyse merit order and market value effects of renewables during the last years. In the methodology section, some specific studies that inspired the methodology used in this approach are examined in more detail.

The German electricity market has experienced an exceptional growth of RES during the past decade and has been analysed quite frequently. Pham and Lemoine, 2015, for example apply a GARCH framework and model the effect of wind power and photovoltaics separately on the German electricity spot price in the period of 2009 to 2012. They use maximum likelihood and discover a price depressing effect of increased renewables feed-in. Cludius et al. (2014) also take Germany into focus and look at the merit order effect of wind and photovoltaics. Using OLS (ordinary least squares) regressions in different specifications, they find that each additional GWh of renewables fed into the grid would lead the price of electricity on the day-ahead market to fall by 1.1 to 1.3 €/MWh. The derived merit order effect takes on a value of 5 €/MWh in 2010 and rises to over 11 €/MWh in 2012 according to their calculations. Weber et al. (2006) find similar effects for **Germany** in the period between 2004 and 2005: they estimate a fall in the day-ahead price of electricity by 1.89 €/MWh for each additional GWh of wind power by applying a univariate regression model.

Two further studies that look into the German and Austrian power sector simultaneously have been conducted by Würzburg et al. (2013) and Hildmann et al. (2015). While Würzburg et al. (2013) apply a multivariate regression approach for the years of 2010 to 2012 and also find a substantial merit order effect of renewables (wind power and photovoltaics taken as a joint explanatory variable). They estimate a decrease of around one euro per additional GWh of electricity and thus calculate a merit order effect of 7.6 €/MWh on average from these results. Hildmann et al. (2015) also analyse the spot market and marginal production costs of RES production – they nevertheless present a more critical approach of calculating a merit order effect from the infeed of RES electricity. Concretely they state that neither zero marginal operation costs nor zero grid integration costs for RES, which are assumed in most studies analysing the merit order effect or market values of RES, are entirely correct. This provides interesting insights and a new perspective in the discussion on these developments and should be considered when interpreting and comparing previous findings.

Another country that has been analysed by several authors is **Spain**. A study by Gelabert et al. (2011) looking at day-ahead electricity prices between 2005 and 2009 finds that "a marginal increase of 1 GWh of electricity production using renewables and cogeneration is associated with a reduction of almost 2€ per MWh in electricity prices (around 4% of the average price for the analyzed period)" (Gelabert, Labandeira, and Linares 2011). The methodology of this study has been applied partly for the following analysis of different European electricity markets. Gil et al. (2012) analyse the effect of large-scale wind power integration into the Spanish electricity market in the years 2007 to 2010. They apply a conditional probability approach and find that the price of electricity would have been around 9.7 €/MWh or 18% higher without wind production. Using an an artificial intelligence-based technique (M5P algorithm) to determine the influence of wind power technology on the spot market, Azofra et al. (2014) also analyse historical data for Spain in the year 2012. They find that "wind power depressed the spot prices between 7.42 and 10.94 €/MW h for a wind power production of 90% and 110% of the real one, respectively" (Azofra et al. 2014).

Two further studies analyse developments on the Danish electricity market. Østergaard et al. (2006) analyse data for the year 2005 and find that electricity spot prices would have been lower in **Denmark** without any wind electricity generation – namely by 1 €/MWh in 2004, 4 €/MWh in 2005 and 2.5 €/MWh in 2006. Jónsson et al. (2010) apply a non-parametric regression model and look at the effect of day-ahead wind power forecasts on electricity spot prices between 2006 and 2007. As the Danish electricity market has specific characteristics, namely being relatively small and exhibiting a large wind penetration, variation and price effects estimated there are especially high. Concretely, in times of high wind feed-in a downward effect of 55-50 €/MWh. This describes an overall effect, which is induced by "large shares" of wind feed-in of total electricity generation and not normalised to e.g. one GWh of additional wind power generated. All in all, Jónsson et al. (2010) say that about 40% of variation in the Danish electricity prices can be assigned to wind power infeed – an important finding as variation in prices is also an important determinant, e.g. for profitability of electricity storage – an effect that should also be taken into account when looking at the effect of variable RES infeed on electricity prices.

Further European countries where market values and/or merit order effects of variable RES have been assessed are the **Netherlands**, **Italy** and **Ireland**. In Ireland for instance, O'Mahoney and Denny (2011) have analysed the merit order effect of wind generation in the Irish electricity market. Applying a OLS multiple regression model, they find that wind power induced a coefficient on wind of -0.0099 in their analysis for the year of 2009 – scaled up to the market outcomes in this year, this implies that prices would have been 12% higher without wind generation, or phrased differently, that savings through wind generation amount to 141 million €. Nieuwenhout and Brand (2011) study the impact of wind power on electricity prices in the Netherlands. This empirical study primarily compares different wind generation intervals according to historical weather data in the years 2006-2009. They find that average day-ahead prices on the Dutch electricity market have been around 5% higher during no-wind intervals in comparison to the rest of the analysed period. A more recent study on the Italian electricity market – a further relevant European market in terms of installed variable RES capacities – has been conducted by Clò et al. (2015). Applying a multivariate linear regression model for the years 2005 to 2013, they find an impact of variable RES (photovoltaics and wind power) on the Italian electricity spot prices. Looking into the two technologies separately, the authors conclude that "an increase of 1 GWh in the hourly average of daily production from solar and wind sources has, on average, reduced wholesale electricity prices by respectively 2.3€/MWh and 4.2€/MWh and has amplified their volatility" (Clò, Cataldi, and Zoppoli 2015). This study is interesting due to the fact that it analyses almost a decade and that it furthermore also takes variability into account.

Finally, to complete the overall literature review and to open up the geographical scope, some literature from the United States is presented. Woo et al. (Woo et al. 2011) use a stationary AR-process to model the effect of wind generation on balancing energy prices and variance in Texas for the years 2007 to 2010. The four-zone Electricity Reliability Council of Texas (ERCOT) works with 15-min balancing energy market prices, which allow an extremely high-resolution study of the market. The authors find that "a 1 GW increase in wind generation (during 15 min) decreased Texas balancing electricity prices between 13 and 44 US$/MWh." (Woo et al. 2011). Nicholson, et al. (2010) also analyse the ERCOT market, with a focus on balancing energy. The authors estimate an ARMAX model and find decreasing effects of wind generation on balancing energy prices of 0.67 to 16.4 US$/MWh per additional GW of wind power (depending on the year, time of the day, and the area in the Texas network). A report by Hresko and Goggin (2015), elaborated for AWEA (the American Wind Energy Association) looks into electricity price developments in another area, specifically the **PJM** region which serves serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Using a different approach, they just analyse how prices developed during the two days of the polar vortex, which brought about extreme weather circumstances. The authors show that "Wind energy protected Mid-Atlantic and Great Lakes consumers from extreme price spikes during the polar vortex event in early January 2014, saving consumers over US$ 1 billion on their electric bills" (Hresko and Goggin 2015).

The overall conclusion that can be drawn from this literature review is that variable renewables have a visible effect on electricity prices and can induce a merit order effect. Moreover, market values of RES are largely influenced by their share of the overall electricity generation and by the respective time of day in which the variable RES feed in takes place. Nevertheless it is also important to consider that wind and solar power lead to substantial variation in electricity prices. It is also not entirely correct to assume that these technologies operate at zero marginal costs – implying that effects that have been observed so far could be overestimated to a certain extent. Overall, however the downward effect of variable RES infeed on electricity spot prices seems to be very unambiguous.

4.2 Empirical Approach

The approach followed in our analysis is oriented along the lines of the papers by (Gelabert, Labandeira, and Linares 2011) and (Würzburg, Labandeira, and Linares 2013). The independent or outcome variable is the electricity price, measured as the hourly spot price on the country's respective electricity exchange platform. We then assess, as explained before, how this price changes in hours with different levels of variable RES infeed.

The Regression Model

The influence of variable renewables on electricity spot prices is modelled by a multivariate regression in different specifications. As the electricity price is determined to a large extent by demand, the load, also measured in an hourly resolution, is introduced as a main control variable. As the electricity generated does not exclusively stay in the respective country, cross-border flows of the electricity, if available improve the accuracy of the estimated relationship.

As different seasons of the year exhibit significantly different levels of demand, monthly dummies are introduced to represent this pattern, which can be especially relevant in countries where use of electricity is strongly weather dependent, as e.g. France, where a substantial amount of heating stems from electric heaters, such that demand in winter is a lot higher than in the summer time. For the same reason, weekly dummies are used as to account for different levels of electricity demand due to the structure of a given week. As the day-ahead electricity price is a variable that depends strongly on the price that occurred a day earlier, lags of the electricity price of 24 hours behind were also introduced as a control factor.

$$\textbf{Baseline Regression}: \boldsymbol{P_h} = \boldsymbol{ß_0} + \boldsymbol{ß_1 LOAD_h} + \boldsymbol{ß_2 RE_h} + \boldsymbol{ß_3 ExIm_h} + \boldsymbol{ß_4 lagp_h} + \boldsymbol{ß_5 dummies} + \boldsymbol{\varepsilon_h}$$

The Durbin Watson test indicated positive autocorrelation among the residuals, such that robust (heteroscedasticity consistent) standard errors were computed. A second variation to account for this factor was performed by differencing the regression. This regression could only be executed if the dependent variables were also forecasts, i.e. if load and infeed were available as a 24 h ahead estimation. Only the difference to the preceding (i.e. 24 hour behind) value is estimated by implementing this regression specification.

First differencing of the variables yields very similar results on the coefficient estimates. Taking exemplarily the year 2010 in Germany, the regression coefficient on wind infeed is -0.00098 as compared to -0.00097 for explanatory variables in levels. As the regression making use of variables in levels has more explanatory power (adjusted R_2 of 0.804 compared to 0.607), we keep the specified form as before.

4.2.1 Robustness Checks and Variations

As a first robustness check, following the methodology of Gelabert et al. (2011) a regression specification was performed using daily averages to cancel out unwanted noise through strong fluctuations during the day.

$$\textbf{Daily averages}: \boldsymbol{P_d} = \boldsymbol{ß_0} + \boldsymbol{ß_1 LOAD_d} + \boldsymbol{ß_2 RE_d} + \boldsymbol{ß_3 ExIm_d} + \boldsymbol{ß_4 lagp_h} + \boldsymbol{ß_5 dummies} + \boldsymbol{\varepsilon_d}$$

Furthermore, the regression was varied by aggregating RES infeed and total load. The so-called residual load is calculated by subtracting all electricity generated by renewables and thus leaves as a value the load that was covered by conventional power plants. Whereas it is now no longer possible to disaggregate the different types of RES infeed and the exact value, the regression equation does provide a more correct representation of the actual relationship observed at the electricity market.

$$\textbf{Residual load}: \Delta\boldsymbol{P_d} = \boldsymbol{ß_0} + \boldsymbol{ß_1}\Delta\boldsymbol{residual\ LOAD_d} + \boldsymbol{ß_3}\Delta\boldsymbol{ExIm_d} + \boldsymbol{ß_4 dummies} + \boldsymbol{\varepsilon_d}$$

Following (Swinand and O'Mahoney 2015) another variation of the regression was to approximate load as a non-linear variable to account for different levels of price elasticity at different levels of demand. In general, demand has a positive effect on the price, as an increase causes a movement up the merit order curve to more expensive technologies and thus inducing a price increase, according to (Swinand and O'Mahoney 2015) among others. I.e. this sensitivity should improve the model fit by including its non-linear relationship.The same sensitivity was performed for the RES infeed, i.e. it was tested whether wind or PV infeed benefit from approximating them with a non-linear variable.

$$\textbf{Non-linear load}: \Delta\boldsymbol{P_d} = \boldsymbol{ß_0} + \boldsymbol{ß_1}\Delta\boldsymbol{LOAD_d} + \boldsymbol{ß_2}\Delta\boldsymbol{LOAD^2_d} + \boldsymbol{ß_3}\Delta\boldsymbol{RE_d} + \boldsymbol{ß_4}\Delta\boldsymbol{ExIm_d} + + \boldsymbol{ß_5 dummies} + \boldsymbol{\varepsilon_d}$$

In the results section, the different sensitivities were compared and their benefits and disadvantages discussed, to give an indication as to which one best approximates the relationship of interest. It has to be kept in mind nevertheless, that different countries could benefit from different approximations due to their differently structured electricity markets.

Analysing alternative specifications of the model

Allowing load and/or infeed of RES to take on a non-linear shape by including a squared term, changes the regression results only marginally. The squared term for load or wind/solar PV is neither statistically nor economically significant, and it does not improve the model's explanatory power.

Implementing residual load (as the load served by the remaining technologies – subtracting the hourly generation of solar PV and wind power) yields a significant positive value. In a test for Germany, e.g. a coefficient of 0.0009431 implied that an increase in residual load by one GWh, lets the electricity price increase by €0.94. Or, phrased differently, a decrease in the load served by variable renewable technologies of one GWh per hour lets the electricity price rise by roughly one €. Again, also with residual load, implementing a non-linear form of the variable does not improve the model fit.

First differences of the variables (explanatory as well as dependent) yield very similar results on the different coefficients. Taking exemplarily the year 2010 in Germany, the regression coefficient on wind infeed is -0.00098 as compared to -0.00097 for the specification where the explanatory variables are introduced in levels and not as a difference to their 24 h lagged value. As the regression making use of variables in levels has more explanatory power (adjusted R_2 of 0.804 compared to 0.607), we keep the specified form as before.

Finally, looking into the first sensitivity, i.e. aggregating hourly values to daily averages, this model provides similar results with a slightly higher explanatory power (R2). As the results from our main specification include a higher resolution and allow us to analyse intra-day variation of the spot price and the dependent variables, we decide to accept the slightly lower R2 as well as the potential unwanted noise as a trade-off for higher resolution data and insights into daily profiles of the variables of interest.

4.2.2 Calculation of absolute effects

Absolute effects are calculated by taking the average hourly load of the respective Member state and scaling it up:

$$\textbf{Hourly load}\,(MWh)\,x\,24\left(\frac{hours}{day}\right)x\,365\left(\frac{days}{year}\right)x\;\boldsymbol{ß_2 RE_{hwind}} = \textbf{average annual savings}$$

The change in the price induced from an increase of an additional percent wind/solar power of the average hourly load, i.e. the coefficient on wind infeed ($ß_2\boldsymbol{RE_{h_{wind}}}$) multiplied by said share of average hourly load, is taken as a factor to calculate these costs.

4.3 Data

The data underlying the following regressions stems from various sources. Specifically, spot prices from different electricity trade platforms, load data from ENTSO-E, Nordpool and other country-specific sources have been gathered as well as cross-border flows from ENTSO-E and wind and PV-infeed from other national sources. Furthermore, the input data for the EMMA model (Hirth 2015) provided useful input data prepared from ERA weather data to approximate infeed for especially earlier years where no data was available otherwise. Furthermore, Eurostat Data served as a source, especially concerning installed capacity. The detailed list of sources can be found in the Annex. This data has an hourly resolution and has been matched country wise. As data availability is limited, it was not possible to assess the same periods of time in all respective Member States, nor was it even possible to assess the impact of renewables on the electricity price, i.e. their market value in all of the given Member States. On the one hand, RES penetration in some countries is still relatively negligible, whereas others, exhibiting a high level of RES penetration, lacked the data necessary for the analysis. Nevertheless, roughly 73 % of all installed variable RES capacity are covered by the following analysis (68.8% of PV and 75.1% of wind power) – i.e. the most important markets were analysed and results can surely be interpolated to markets in other Member States.

First of all, data at hand is in hourly resolution. To deal with leap years, the respective 29th of February was just introduced as a regular date. Daylight saving time poses a problem, as two values occur at the same time at one point, i.e. a 25 hour day. To deal with this problem, the first of the two values was then deleted.

We are interested in how **electricity spot prices** are influenced by different levels of variable renewables feed-in (wind and photovoltaics). The price used is always the day-ahead price, which serves as a basis for purchasing and selling decisions on the day-ahead market (Würzburg, Labandeira, and Linares 2013). The authors further argue that this price has a more significant impact in terms of traded volumes when compared to the intra-day price.

Hourly **RES infeed** is our main dependent variable of interest. We want to observe, how electricity prices are changed by different levels of renewables fed into the grid. As the dependent variable is the day-ahead price, ideally RES infeed should be represented as a day ahead-forecast variable as well. In most cases, only actual infeed data could be obtained.

Hourly **load** – is one of the most important determinants of electricity spot prices as it represents the demand that has to be served in the respective hour. In periods of high demand, prices are usually higher. This can change, nevertheless if those periods coincide with high levels of RES infeed – as variable renewables basically have zero marginal costs they can strongly influence prices in time of strong infeed. Load, as well as RES infeed would be ideally represented as a forecast variable. In most cases, only actual load data could be obtained.

Cross-border flows: If available, this variable was also introduced. Cross-border flows improve the explanatory power of the model as they show how the supplied electricity was distributed, as far as an electricity outflow to a neighbouring country took place, or rather if additional electricity was needed in that particular hour such that electricity was imported from a neighbouring Member State. A net effect was calculated, i.e. inflows were subtracted from outflows to best approximate actual levels of demand in the respective Member State at the given point in time.

Dummy variables to account for seasonality (monthly dummies) and fluctuations during the week (weekly dummies) were also included into the regression.

4.4 Historical market values of RES

In this section the historic market value factors of wind onshore and solar PV are presented based on actual hourly day-ahead prices and corresponding RES generation. Figure 4-1 shows that in general, the market value of PV is higher than that of wind. This is due to the effect that the sun usually shines at peak demand times, where in the past high demand used to trigger higher electricity prices and thus lead to a higher value for electricity generated by photovoltaic power plants. Furthermore, as the subset of analysed years presented is quite early with a comparably low installed capacity, a merit-order effect induced through photovoltaics is also not very likely due to its substantially small share. As will be seen in the model-based analysis, larger capacities and thus higher infeed can lead to a substantial drop in the market value of PV.

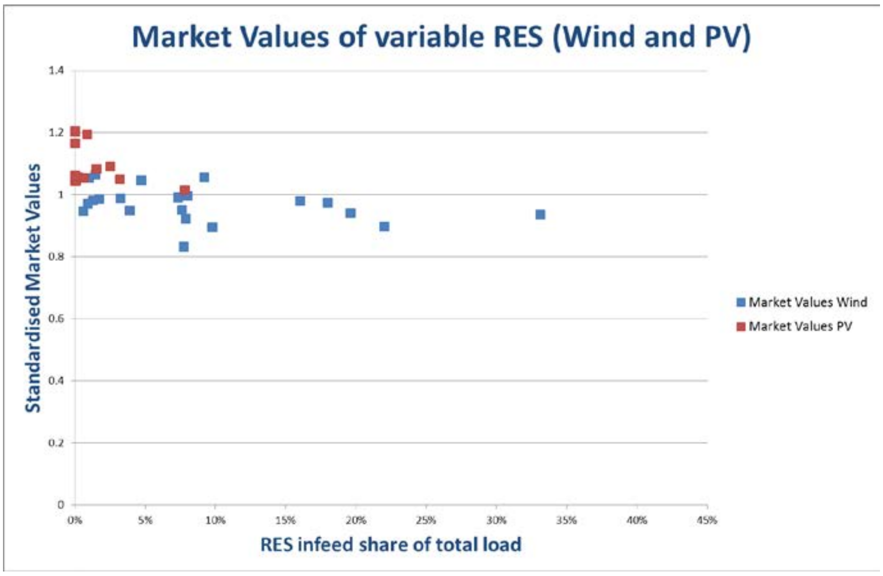


Figure 4-1: Market Values of variable RES (wind and photovoltaics)

The market value factors for wind grouped by countries can be seen in Figure 4-2. It can be seen that there were no clear trends observable with regard to the development of market value factors with varying penetration levels in several countries.

Looking at different years in the same country, i.e. in Ireland, one can see that a drop in the market value can occur with increased share of total load. Specifically, as total share of wind infeed of load increased from 17.9 to 19.6 % between 2013 and 2014, the market value of wind power fell from 0.97 to 0.94 in the same period. Whether the increase in the share of load was a determinant of this drop or whether other factors were influential as well is nevertheless not obvious from this calculation. At lower levels of wind infeed in earlier years (2008-2010), Member States do not exhibit clear patterns – as can be seen, i.e. for the Netherlands, France or Germany. In this case, nevertheless, the impacts of the financial crisis in 2009 also have to be taken into account when interpreting the specific values. Overall, one can say that additional data and more background information on the specific electricity markets is needed to make sense of the different values and their behaviour. It is furthermore crucial to keep in mind that several other factors determine the behaviour of the market value as is calculated in the present analysis: As wind (or more generally speaking) variable RES infeed as a share of total load is used as a value, one cannot distinguish whether a drop in this share is due to a bad wind year (rather than little or no new installed capacity) or whether demand increased disproportionately such that it had to be served from other electricity sources and thus decreasing the RES share even though generation had increased or at least remained stable in comparison to the previous year. When going into detail in the Member State perspective, these effects will be discussed by analysing additional historic data to complement the market values calculated for the given year.

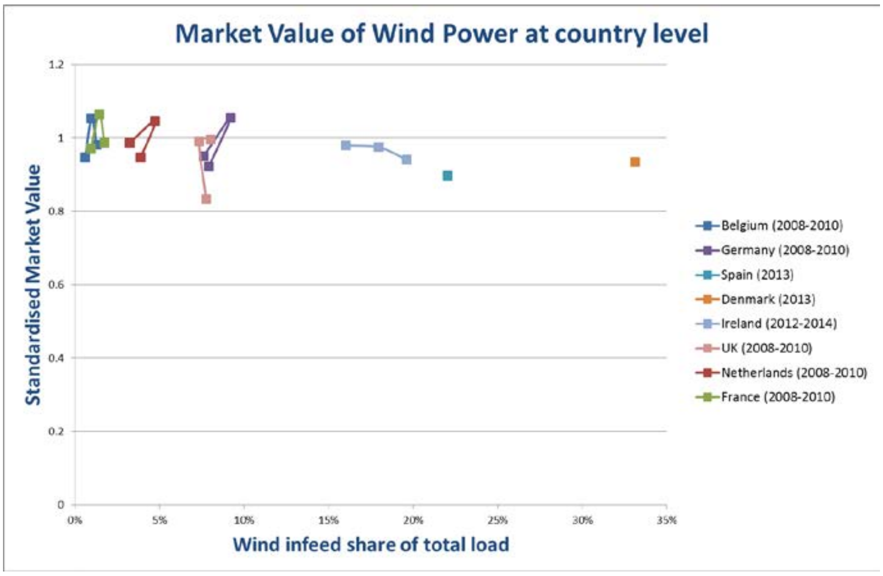


Figure 4-2: Market Values of Wind for the analysed countries in the given years

Error! Reference source not found. depicts the market value of electricity generated from photovoltaic power plants. The variation among countries with regard to the market value factor is not as strong as in the case of wind power, which is, as explained beforehand, primarily due to the specific characteristics of photovoltaics, producing especially during peak demand hours for electricity during the day. Nevertheless, a drop of the market value is correlated with an increase in the share of photovoltaics of the total load.

Again, the crucial year of the financial crisis, 2009, seems to have a stronger influence on the market value than the share of total load of the variable electricity produced – it can be seen that in France and in Germany, the market value slightly increases between 2009 and 2010 even though installed capacity is increased during that time. This could likely be due to a catch-up effect, partly compensating for the losses in the previous year.

4.5 Results of the empirical analysis

Table 4-1 presents a comparison of regression outcomes for the year 2008 in several European countries. It is clearly visible that all explanatory variables are statistically significant and that the model applied seems to be a good "one size fits all" approach at first sight. It yields adjusted R^2 of 0.7 to 0.81.

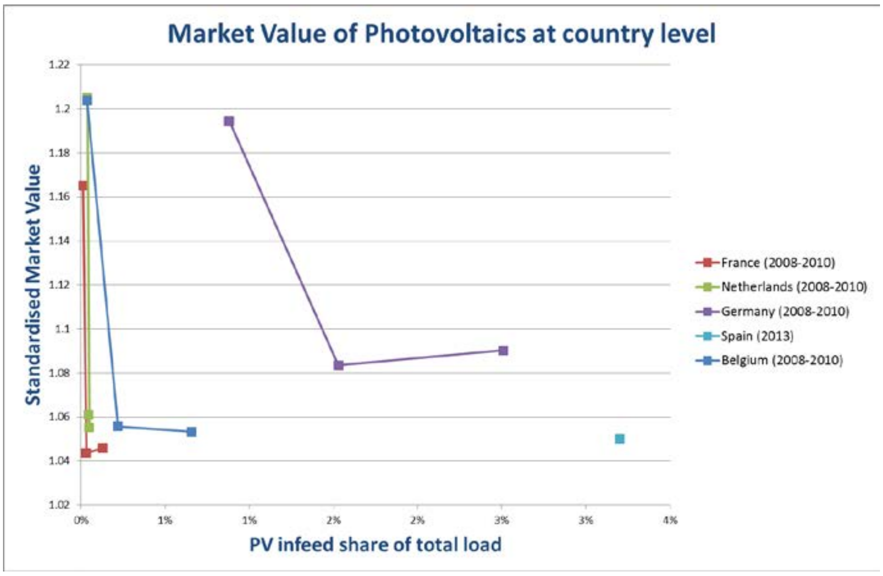


Figure 4-3: Market Values of PV for the analysed countries in the given year

Table 4-1: Regression outcomes of the effect of infeed of variable RES on the day-ahead spot price in earlier years

	Germany	Belgium	France	Netherlands	UK
Load	**0.0020983**	**0.015268**	**0.0025147**	**0.0073827**	**0.00036527**
	(0.000020337)	(0.00019212)	(0.000024843)	(0.00009812)	(0.0000257170)
Wind infeed	**-0.0020042**	**-0.051258**	**-0.0024276**	**-0.012803**	**-0.00080692**
	(0.000040607)	(0.0035567)	(0.00030201)	(0.00046732)	(0.00025199)
PV infeed	**0.00064324**	**0.27547**	**0.2305**	**0.30829**	
	(0.00024065)	(0.038755)	(0.015553)	(0.0077475)	
24 h lagged spot price	**0.22128**	**0.23987**	**0.27386**	**7.2565**	**0.44611**
	(0.0066929)	(0.0077914)	(0.0066532)	(0.86259)	(0.0091832)
Monthly dummies	✓	✓	✓	✓	✓
Weekly dummies	✓	✓	✓	✓	✓
Year	2008	2008	2009	2008	2009
Observations	8736	8736	8760	8736	8699
Adjusted R2	0.798	0.703	0.817	0.7	0.81

OLS-Estimation of hourly changes in electricity prices (incl. 24 h price lag)

Later years are more interesting for the analysis, as they are characterised by much higher levels of RES deployment and substantial feed-in of variable RES into the grid. Exemplarily, Table 4-2 shows selected recent years in Germany and Spain (countries with substantial wind power and solar PV deployment) as well as Ireland and Denmark which also generate a substantial share of their electricity from wind power.

Table 4-2: Regression outcomes of the effect of infeed of variable RES on the day-ahead spot price (later years)

	Germany	Ireland	Denmark	Spain
Load	**0.00045846**	**0.0048125**	**0.0080714**	**0.0020531**
	(0.000016985)	(0.00014112)	(0.00016509)	(0.00002713)
Cross-border flows	**-0.0013211**			
	(0.000036044)			
Wind infeed	**-0.00016011**	**-0.0022512**	**-0.0047187**	**-0.0028472**
	(0.000025069)	(0.00022197)	(0.00010867)	(0.00003482)
PV infeed	**-0.000051778**			**-0.0028387**
	(0.000039878)			(0.00009386)
24 h lagged spot price	**0.46986**	**0.36962**	**0.27302**	**0.31939**
	(0.0071222)	(0.0097878)	(0.010785)	(0.006631)
Monthly dummies	✓	✓	✓	✓
Weekly dummies	✓	✓	✓	✓
Year	2012	2012	2013	2013
Observations	8760	8758	8330	8736
Adjusted R2	0.625	0.529	0.693	0.818

OLS-Estimation of hourly changes in electricity prices (incl. 24 h price lag)

One can see that the adjusted R^2 differs between the different countries, indicating that potentially some regions would benefit from modelling the respective relationship differently. Nevertheless the coefficients on wind and solar PV infeed are economically and statistically significant and all remaining explanatory variables also perform well in all the multivariate regression analysis performed for the different countries. Cross border flows, only available for Germany in 2012 also show a significant effect – increased outflows of electricity, indicating a potential oversupply on the German electricity market, decrease electricity spot prices.

Country Case Studies

The following section presents country case studies to give insights into different European spot markets and to allow interpretation of the regression outcomes and the calculated market values. A diverse geographical spread is represented, totalling 73% of installed RES capacity in the EU. Please further note, for simplicity, the yearly total of the decreased electricity spot prices is referred to as savings. Per definition, these savings are the a decline of market revenues for generators, which in turn are savings for consumers in terms of a transfer from non-RES producers.

4.5.1 Belgium

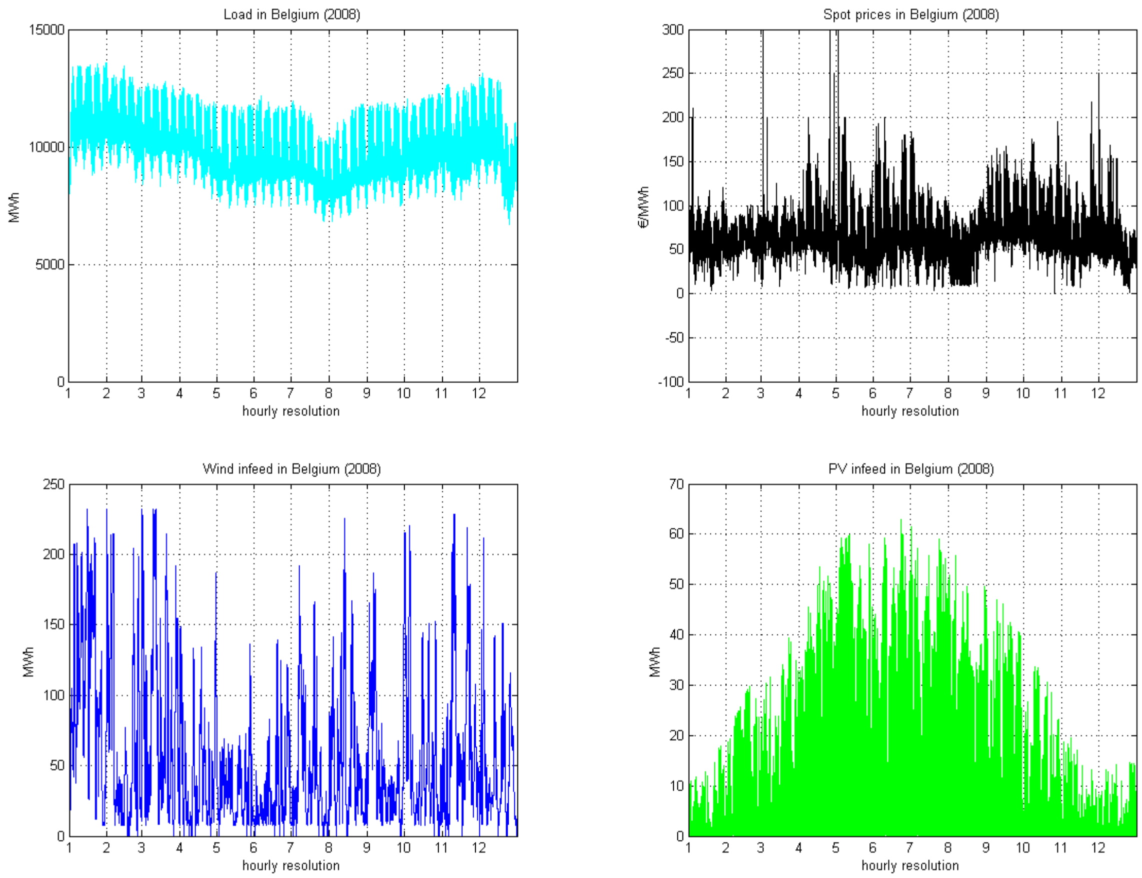


Figure 4-4: Electricity Market Variables for Belgium (analysed year: 2008)

In Belgium, the year 2008 is presented exemplarily for the historic assessment of the impact of variable renewables on electricity prices. On first view, a strong variation in spot prices can be observed, with peaks of up to 500 € and drops down to a value of zero. The mean price lies at 70.36 €.

Wind infeed also fluctuates strongly throughout the year. The installed capacity of 280 MW leads to peaks of 232.24 MW of hourly feed in, whereas at times, zero infeed is measured. The mean value lies at 57 MWh.

For photovoltaic infeed one can observe that unsurprisingly the summer months exhibit higher values of feed in. Of the installed capacity of 100 MW in 2008, peaks of around 62 MWh can be observed. In times of low performance, again zero infeed is measured – across the year, this leads to a mean of 9.41 MWh. Mean hourly load is around 10,002 MWh, whereas peak load can rise up to 13,584 MWh and hours of low load can fall to a demand of only 6,696 MWh.

Wind infeed and spot prices are weakly negatively correlated, whereas the coefficient does not have any statistical significance. To further explore a potential relationship between the two factors, the baseline regression (1) was applied. The results for the year 2008 are shown in the Member State overview in Table 4-1. The regression coefficients indicate an economically and statistically significant negative effect of wind infeed on the day-ahead electricity spot price. As the results have to be taken with caution – due to the only one year observation period and due to potential bias through missing variables (as e.g. a high resolution gas price to approximate the technological alternative to variable RES-E infeed), it has to be kept in mind that the relationship might well be causal but that the coefficient's size is likely subject to variation depending on the model.

Nevertheless it can be observed, that at a 99% significance level, an increase of RES by 1% share of the average demand for electricity (around 100 MWh) generated by wind power in Belgium would reduce the day-ahead spot price by 4.43 €/MWh on average. The influence of PV infeed on the spot price is on average positive, but the coefficient has to be interpreted with caution – this is due to the fact that little PV capacity has been installed in Belgium in 2008, i.e. an effect on spot price from a share that small is rather questionable. The positive value is rather due to the fact that peak generation time of PV plants coincides with (in 2008 prevalent) peak demand hours where prices were generally high. In later years where substantially more PV was installed, a curb in this peak demand due to solar power infeed could be observed and the size and even direction of the coefficient is likely to change.

Merit Order (Regression Results)

- Significant impact of wind infeed on day-ahead spot price (**4.43 €/MWh** reduction through increase of wind power by 1% of average load) in 2008
- An increase of one percent of the load on average of wind generation would thus yield savings of around **398.8 Mio. €** in 2008

Market Value (Ex-Post Calculation)

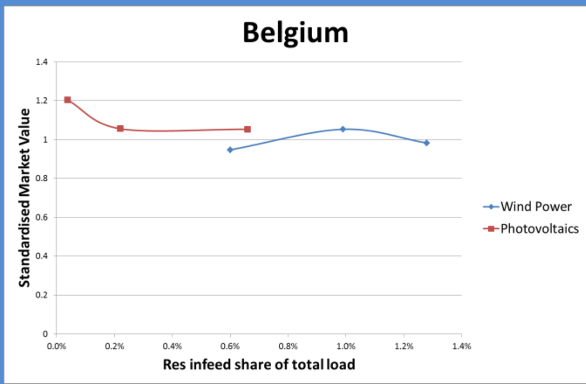
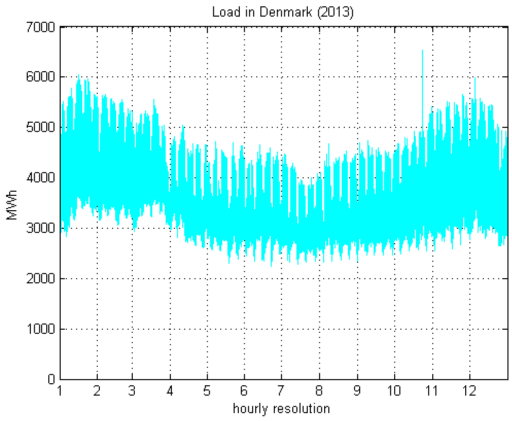


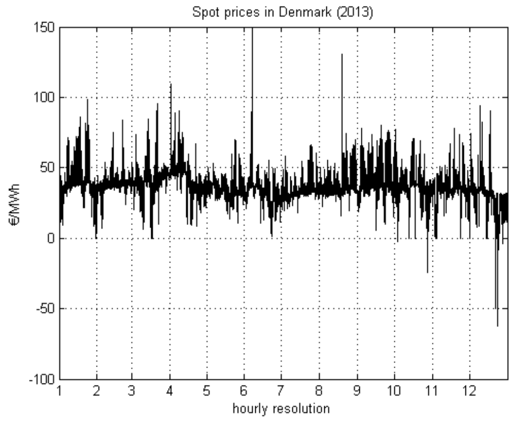
Figure 4-5: Main results Belgium

The market value of wind power and solar PV in Belgium is presented in Figure 4-5Figure 4-5 alongside with the primary findings on the merit order effect. To calculate the market value, the approach used is straightforward. At the same time it is important to discuss further effects that are likely to have influenced the market value in the respective years. In 2008, the financial crisis is quite certain to have had an influence on prices in general, most probably depressing all electricity prices and thus potentially undervaluing the price of wind and solar PV.

It is furthermore important to see what kind of weather was prevalent in the respective year analysed. A good indicator for the weather is looking at the full load hours of the respective technology, i.e. how many hours of the year the plant generated electricity as compared to its actual capacity. In 2008, wind power ran with 1,793 full load hours, which is relatively high in comparison to the following years. Interestingly, the standardised market value of wind power was below the value of one for this particular year, which could be an indication for high infeed of wind power depressing its own market value in the respective peak hours. To make a definite statement, nevertheless, historical data for more consecutive years would be useful.

4.5.2 Denmark





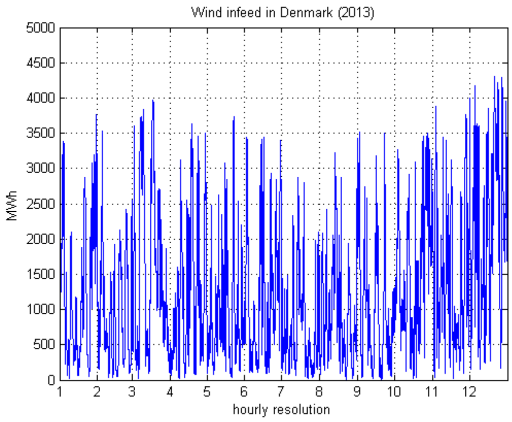


Figure 4-6: Electricity Market Variables for Denmark (analysed year: 2013)

In Denmark, a negative but non-significant correlation between spot prices and wind infeed can be observed in the year 2013 which is presented in Figure 4-6. Wind infeed varies between 12 and 4,310 MW per hour, constituting an average of 1,266.9 MWh in 2013. Load has an average of 3,824 MWh in Denmark, with peak values of up to 6,538 MWh and minima of lowest 2,241 MWh. Spot prices peak at 107 €/MWh and can become zero or slightly negative (-0.07 €/MWh). The annual mean electricity spot price is 39.9 €/MWh in 2013.

Looking at regression results for Denmark in the year 2013, one can observe an effect that is statistically and economically significant: Wind power fed into the grid in 2013 led to decreased day ahead prices for electricity according to the regression results. Specifically, an increase of wind infeed representing one percent of average hourly load, would lead the spot price to fall by 0.18 €/MWh on average. As wind infeed in Denmark – as visible in Figure 4-6 sometimes reaches values of over 100% of average load, the impact on prices can thus be quite significant.

The strong variability of the electricity price induces further economic effects. Large price spreads lead to higher profitability of electricity storage and demand side applications (e.g. batteries, power to heat (P2H) applications). If these effects persist over a longer period of time, this sets incentives for increased investments into storage technology. This is a co-effect of the price variability which is partly attributable to high levels of variable RES infeed. In turn this has several implications: First of all, variable RES would be complemented by storage technology and price spikes would be smoothed out. In the longer term, this would again affect the profitability of the storage systems as they depend on the price spreads to be able to store electricity beneficially. Correlation coefficients between the spot prices of Denmark and its neighbouring countries also show a relatively high interdependence. In 2015, net cross-border-flows made up 16.7% of the total load in Denmark. Inflows of electricity even amounted to a share of 22.9%. This shows on the one hand the strong interconnection of Denmark, which also increases the flexibility of its electricity market and at the same time shows how electricity spot prices in neighbouring member states should have a significant role in price formation on the Danish electricity market. These impacts will be discussed later on.

The market value for wind power in the year 2013 is roughly 0.93, at a load share of wind infeed of almost 35%. Full load hours in 2013 lay at 2,665 h/a – the year was a normally performing wind year according to this number as well as official sources as e.g. (Kjaer 2015). The historical data analysed for this study does not present the year 2013 as a year of especially high or low demand. Therefore, as weather and load did not behave uncharacteristically, one can assume that the market value of wind power according to our measure is largely attributable to wind power's own increased share of electricity generation in Denmark.

Merit Order (Regression Results)

- Significant impact of wind infeed on day-ahead spot price (**0.18 €/MWh** reduction through a one percent increase of wind power of average hourly load) in 2013. As wind feed-in sometimes even overshoots average hourly load, this effect can be quite substantial.

- Overall savings would i.e. be **6 Million €,** if one percent of wind infeed would be introduced on average

Market Value (Ex-Post Calculation)

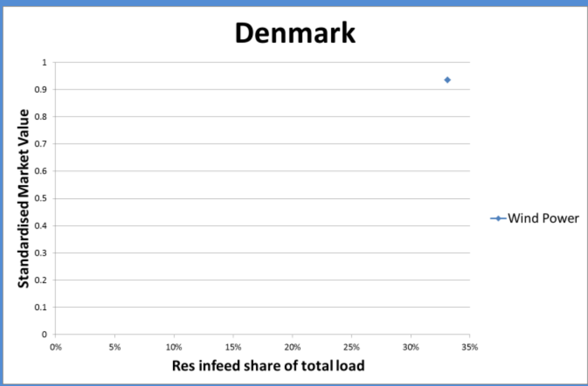


Figure 4-7: Main results Denmark

Figure 4-7 presents the most important outcomes of the analysis for Denmark. Market value for wind power in the year 2013 is roughly 0.93, at a share of RES infeed of almost 35% of wind infeed of the total load. Full load hours in 2013 lie at 2,665 h/a.

4.5.3 France

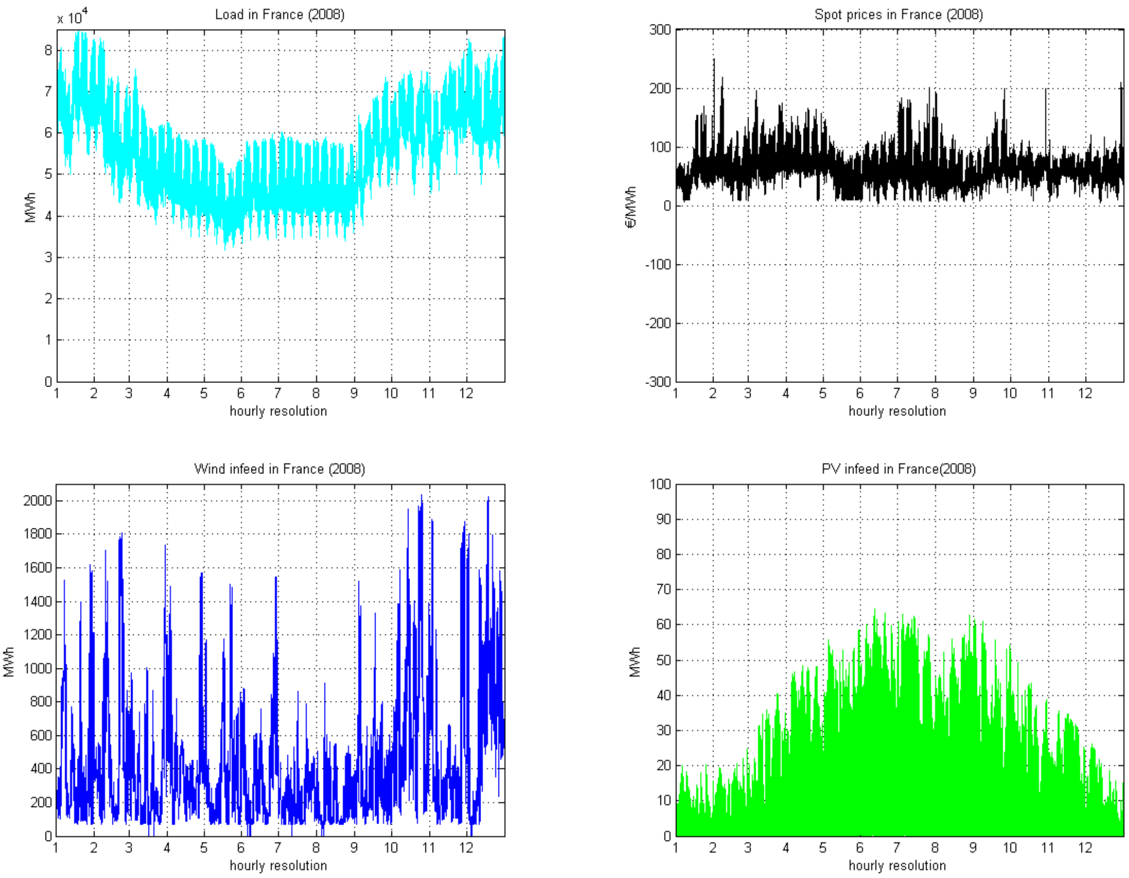


Figure 4-8: Electricity Market Variables for France (analysed year: 2008)

In France, no significant correlation is observed between spot prices and hourly infeed of electricity from wind power or photovoltaics in the year 2008, which is exemplarily depicted in Figure 4-8. Spot prices vary substantially between 3.5 and 250 €. Wind feed-in peaks at over 2,000 MWh whereas solar PV (due to a substantially lower installed capacity) only reaches peaks of around 64 MWh in the summer months. This is quite a low share when one looks at the overall load in France – which reached a maximum of 84,730 MWh in 2008. Load exhibits an especially high variation in France, not least due to the large share of electric heating which increases demand substantially during winter months. Minimum values, during the summer months go as low as 31,618 MWh, whereas the yearly average lies at around 56,202 MWh.

The regression results looking at the impact of the feed-in of variable renewables show that wind power decreases the electricity spot price. Specifically, in 2008, an increase of wind power by one percent of total load would yield a decrease of the electricity spot price by 1.56 €/MWh.

The coefficient on photovoltaics cannot be evaluated in this context as its economic significance is largely questionable, as the share of PV is too small to actually induce an effect. Again, rather a correlation between more expensive hours of peak demand during the day and hours of strong PV infeed rather than a causal relationship is likely to be captured by the given coefficient.

Merit Order (Regression Results)

- Significant impact of wind infeed on day-ahead spot price (**1.56 € / MWh** reduction through one percent increase of wind power in terms of average hourly load)
- Quantified as total savings over the year 2008 if introducing one more percent of wind feed-in as share of the load on average, this yields **761.5 Mio. €**

Market Value (Ex-Post Calculation)

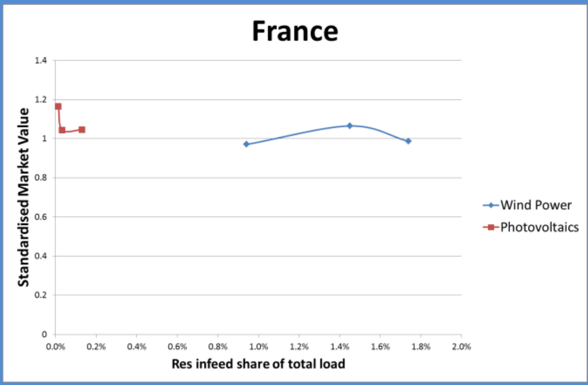


Figure 4-9: Main results France

4.5.4 Germany

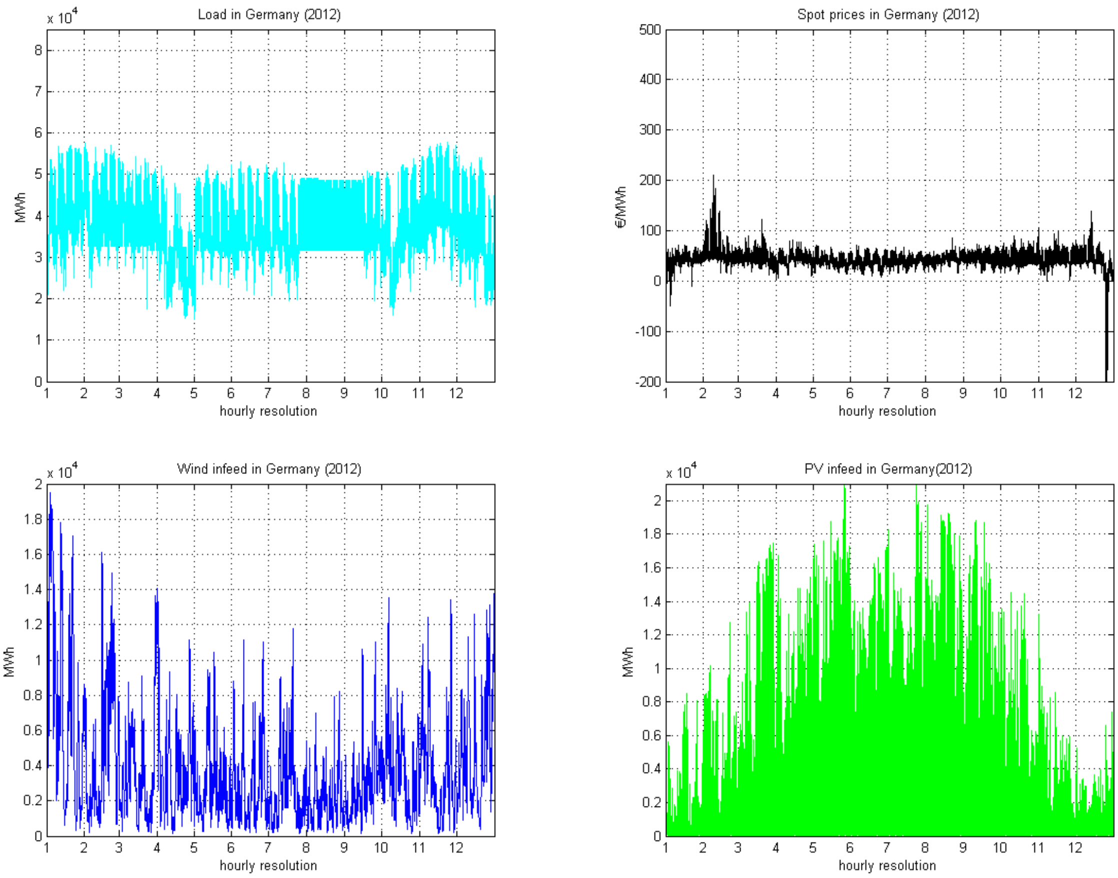


Figure 4-4-10: Electricity Market Variables for Germany (analysed year: 2012)

In Germany, the year 2012 is used to exemplify the electricity market. In this year, spot prices ranged between a maximum of 210 €/MWh and a minimum of -221 €/MWh, i.e. they exhibited a very large spread. The implications on the variability of prices are the same as described beforehand in the case of Denmark. The average annual spot price in 2012 was 44.8 €/MWh. The annual average of hourly wind infeed was 3,832 MWh in Germany in 2012, whereas maxima of up to 19,497 MWh occurred at times. Hourly photovoltaic infeed peaked at 20,985 MWh and exhibited an annual average of 3,061 MWh in 2012. Hourly load in Germany ranged between 14,975 and 57,767 MWh and has an annual average of 39,170 MWh.

Regression results for Germany in the year 2012 show a statistically and economically significant effect of wind power feed-in on day-ahead electricity prices. A price reduction of around 0.53 €/MWh would occur according to the findings per one percent of average hourly load generated from wind power. Introducing forecast variables for wind and photovoltaics, the value increases. The coefficient on PV in 2012 is lower, indicating a decrease of around 0.05 €/MWh.

The market value of wind power in Germany in 2012 amounts to 0.89, whereas that of photovoltaics takes on a value of 1.06. In 2012, the capacity factors of wind and solar, i.e. the utilisation of wind and PV systems were comparatively low – this could be an indication that the market value of both technologies is higher than usual in this particular year, as a high capacity factor usually leads to lower market values. As one can see in the figure below, the market value for PV continuously drops with an increased share of the total load. For wind power a similar pattern is observable but it has outliers and does not follow a linear trend (possibly due to several of the years observed being during the financial crisis and thus exhibiting irregularities).

Performing a sensitivity analysis using coal prices (daily closing prices at the EPEX spot), slightly decreases the coefficients on wind and solar PV. This shows that fossil fuel prices for the relevant technologies also impact the day-ahead electricity prices. The decrease in the coefficients is however economically not strongly significant, showing that even including an important conventional technology into the equation does not diminish the influence of variable renewables on electricity spot prices. This adds further robustness to our findings for Germany. It would be interesting to add relevant fossil fuel prices to other Member State's equations in future research as well.

Merit Order (Regression Results)

- Significant impact of wind infeed on day-ahead spot price (**0.51 €/MWh** reduction through one percent increase of wind power as share of average load) in 2012
- Overall savings of an additional percent generated by wind power on average would thus be around **180.7 Million €** in 2012

Market Value (Ex-Post Calculation)

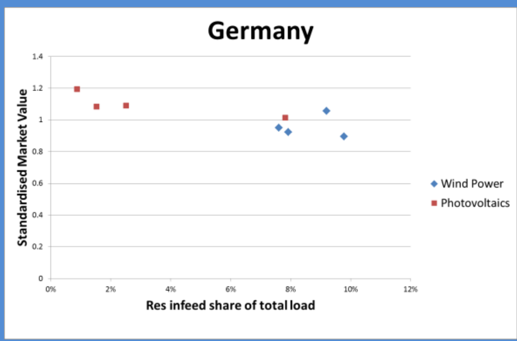
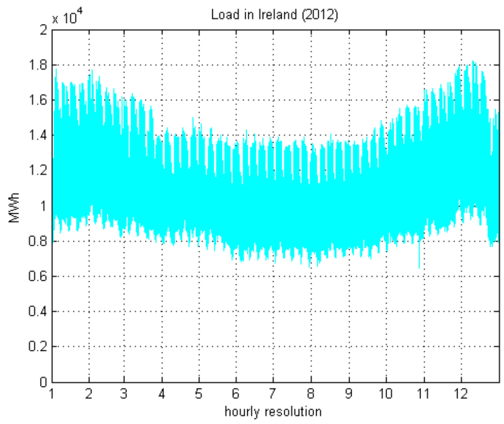
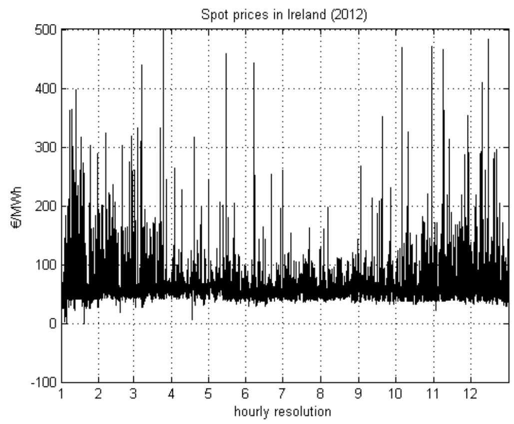


Figure 4-11: Main results Germany

4.5.5 Ireland





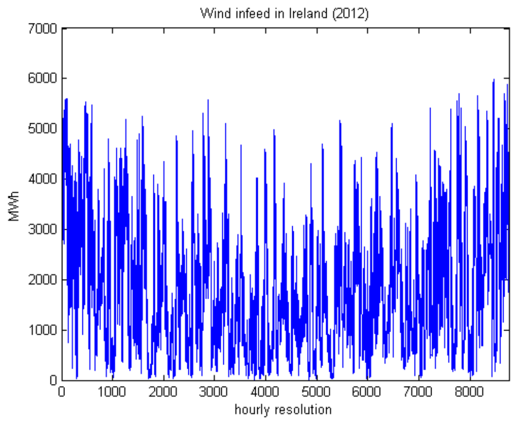


Figure 4-12: Electricity Market Variables for Ireland (analysed year: 2012)

The Irish hourly electricity spot prices in 2012 exhibit substantial fluctuations between 0 and over 500 €/MWh. The mean value takes on 62.6 €/MWh. Wind infeed peaked at up to 6522 MWh. The annual average in 2012 was 1868.5 MWh. Values for load in Ireland vary between 0 and 18,213 MWh and take on an average of 11,667 MWh in 2012.

Looking into regression results, a significant negative effect of wind infeed on Irish electricity spot prices can be observed. Specifically, one can say that one percent more of load generated by wind power would induce the day-ahead spot price to fall by 0.17 €/MWh. Quantifying this effect for a hypothetical additional percent in the year 2012, shows that cost savings due to the decreased electricity spot price would amount to 17.4 Mio € in Ireland. In 2013, this effect increases, i.e. one percent additional average load generated by wind power leads to an average price drop of 0.19 €/MWh in the electricity spot price. In 2014, this effect is even stronger at – 0.31 €/MWh for one percent of the average hourly load generated by wind power.

The historic market value of wind power in Ireland in the years 2012 to 2014 shows a clear trend of declining with increased share of the load. Specifically, the market value drops from 0.98 to 0.94 with an increase of the share of wind feed-in from 33 to 40 percent.

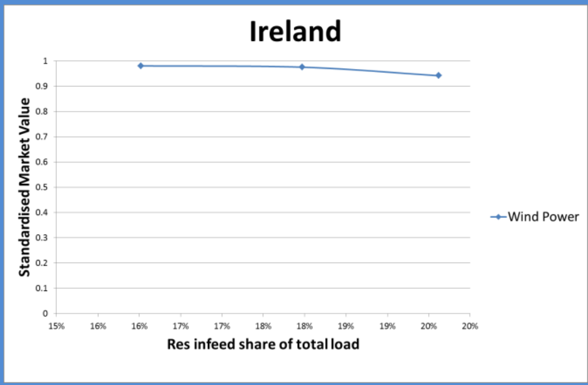
Merit Order (Regression Results)	Market Value (Ex-Post Calculation)
• A significant negative effect of infeed of electricity generated from wind power can be observed on electricity spot prices: A drop of **0.17 €/MWh** if feed-in is increased by one percent of average hourly load in 2012 • **17.4 Million €** could have potentially been saved, if on average one additional percent of average hourly load would have been generated from wind infeed in 2012	

Figure 4-13: Main results Ireland

4.5.6 Netherlands

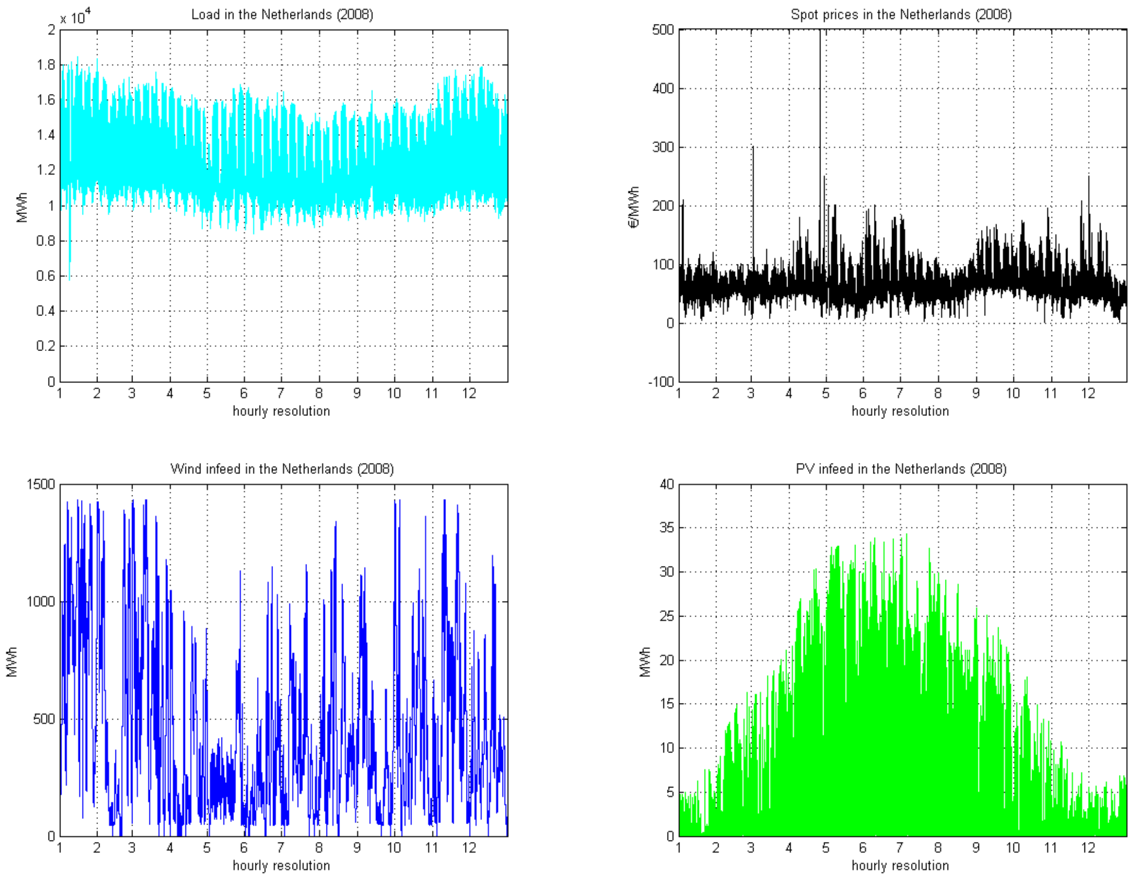


Figure 4-14: Electricity Market Variables for the Netherlands (analysed year: 2008)

In the Netherlands, as in all previous cases, simple correlation coefficients do not indicate an obvious relationship between wind and PV infeed and electricity spot prices. In 2008, spot prices spread out between 0 and 500 €/MWh and took on an average value of 70 €/MWh. Wind infeed ranged between 0 and 1,430 MWh while it took on an average value of 449 MWh. Installed capacity of photovoltaics being substantially lower, PV infeed had maximum values of 34 and an average of 5.3 MWh in 2008. Load in the Netherlands is quite evenly distributed over the year. Maximum values are 18,465 MWh and minima are at as low as 5,767 MWh. On average the curve shows a very balanced distribution over the year at a mean of 13,010 MWh.

Regression results show that one percent additional wind infeed of the average daily load would lead to a decrease in the Dutch electricity spot price of 0.49 €/MWh in 2008. For the total year, the amount of savings would have been comparatively low, namely amounting to 85,846.43 € in total for the year 2008.

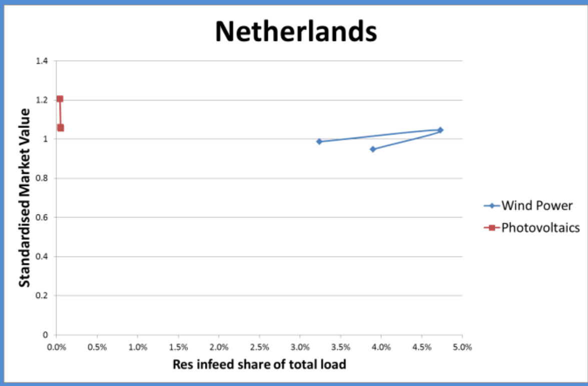
Merit Order (Regression Results)	Market Value (Ex-Post Calculation)
• A negative effect but economically insignificant effect of wind infeed on electricity spot prices was calculated in the regression for the Netherlands in 2008. Specifically, prices would merely drop by **0.007 €/MWh** if an additional percent of average hourly load were fed in from wind power • In total **85,846.43 €** would have been saved in 2008, if an additional percent would have been fed into the grid from wind generation	

Figure 4-15: Main results Netherlands

4.5.7 Spain

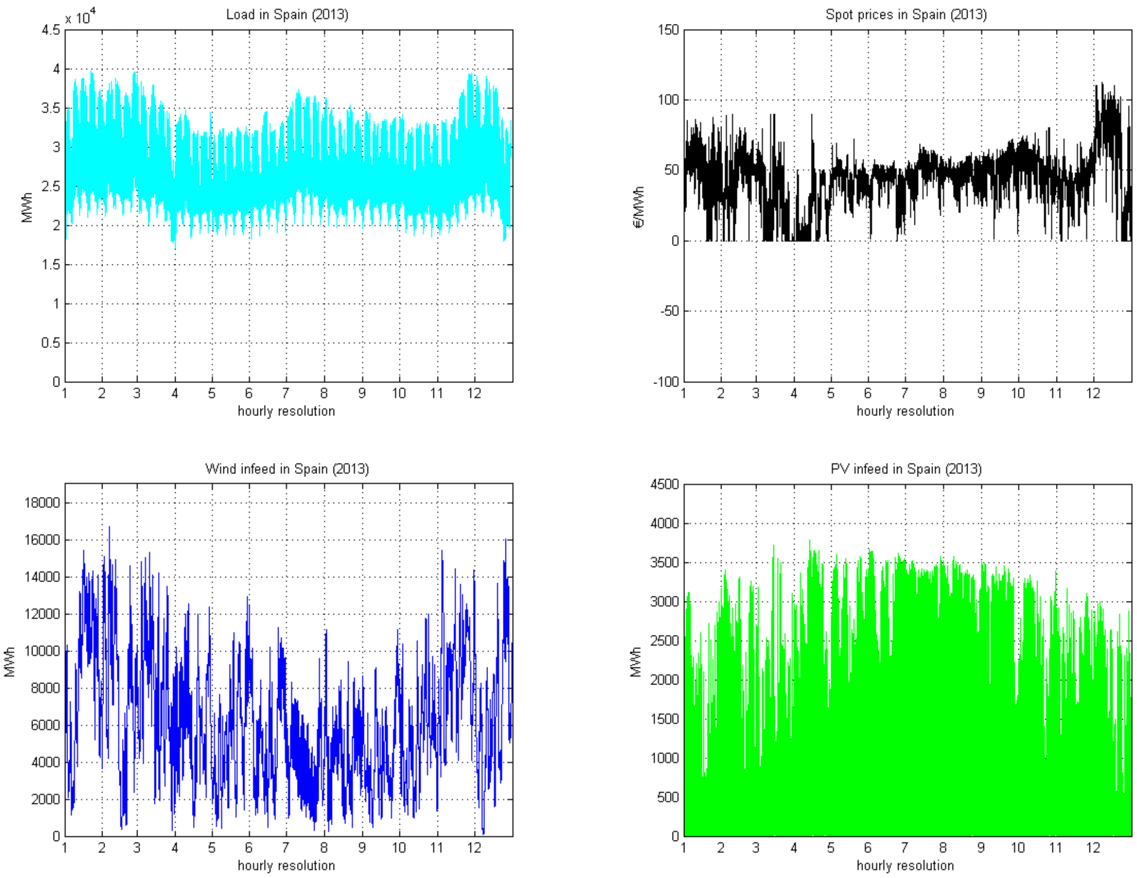


Figure 4-16: Electricity Market Variables for Spain (analysed year: 2013)

A negative and significant correlation between Spanish spot prices and wind infeed can be observed for the year 2013. In 2013, spot prices on the electricity market in Spain varied between 0 and 112 €/MWh, exhibiting visible drops especially in spring time (see Figure 4-16). Values between 70 and 16,672 MW were fed in on an hourly basis by wind power in 2013 at a yearly average of 6196 MW per hour. Hourly PV infeed was more constant throughout the year, ranging between zero and 3781.7 MW. Load in Spain is also relatively constant throughout the year, at a mean of 28,140 MW per hour and spreading out to maxima of up to 39,633 and down to 17,096 MWh at times.

In 2013, wind infeed has a negative effect on electricity spot prices according to the regression results for Spain. An additional percent of wind power as a share of average hourly load would lower spot prices on average by 0.8 €/MWh in 2013. A similar effect can be observed for photovoltaics. An increase of hourly infeed by one GWh would induce prices to fall by roughly 0.8 €/MWh. In 2013, savings from an additional percent would have amounted to 197.5 Million € for wind and about the same amount for an increase of PV infeed. To scale up this effect and present an example, in 2013, savings induced by an additional GWh of hourly infeed would have amounted to 700 Million € for wind, and similar savings could be expected for an additional GWh of hourly PV infeed.

In 2013, the market value of PV in Spain was 1.05, for wind power it took on a value of 0.9. This outcome does not seem to be driven by other irregularities that occurred during the year, but appears to mainly reflect how wind and solar power contribute to their respective own market value.

Merit Order (Regression Results)

- Wind infeed has a negative effect on electricity spot prices according to the regression results for Spain in 2013. An additional percentage share of wind power in terms of average load would lower spot prices by 0.8 €/MWh in 2013. A similar effect can be observed for photovoltaics (also a decrease by roughly 0.8 €/MWh).
- In 2013, induced by an additional percent savings would have amounted to **197.5 Million** € for wind and about the same amount for an increase of PV infeed.

Market Value (Ex-Post Calculation)

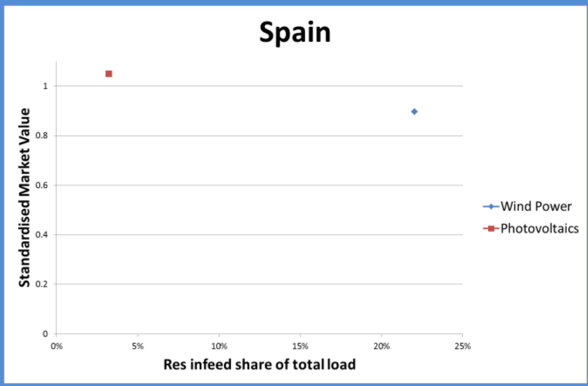
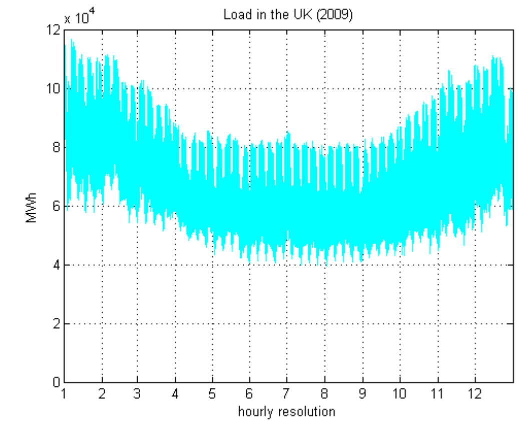
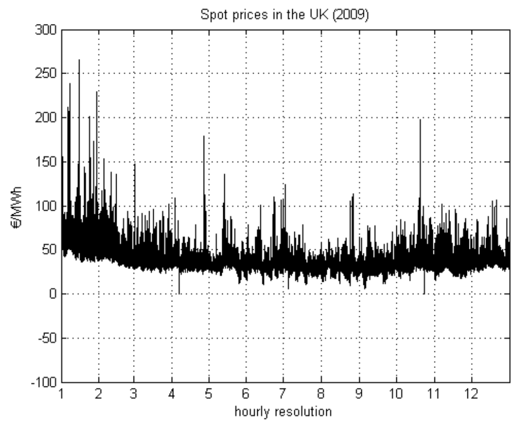


Figure 4-17 Main results Spain

4.5.8 UK





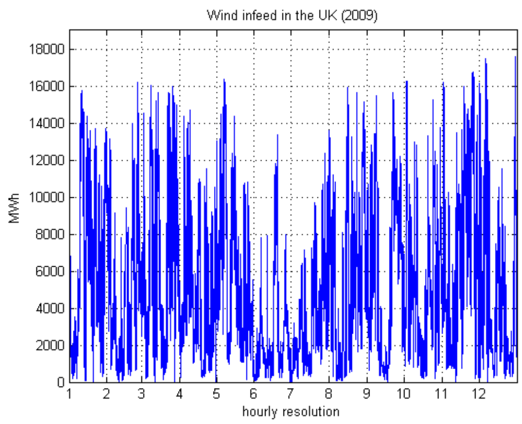


Figure 4-18: Electricity Market Variables for the UK (analysed year: 2009)

In the UK's electricity market, a substantial penetration of RES due to a high installed capacity of wind power plants can be observed in the yearpresented, 2009. Even though the correlation between wind feed in and spot prices is not significant there is good reason to believe that there is an influence of high infeed on spot prices, especially as the spot prices exhibit a huge dispersion. The maximum spot price in 2009 in the UK was 578.9 €/MWh, whereas at times the price took on a value of zero. The mean price in 2009 was 42.4 €/MWh. Maximum infeed of electricity generated by wind power plants was 17566 MWh in 2009 whereas the annualised average is 5,277.6 MWh. Load in the UK is especially high during the winter months, where peak values of 116,579 MWh werereached in 2009. Minimal values are as low as 34,476 MWh. Average load in 2009 was 71,814 MWh.

In the UK, regression results show quite a small influence of wind power infeed on the electricity spot price. In 2009, the price of one MWh would have decreased by 0.55 € if an additional percent of the load would have been generated from wind power on average. For a total year, as demand is relatively high in the UK, this would have summed up to overall cost savings of 381.6 Mio €. Nevertheless the effect remains quite small in comparison to other countries, as well as when one looks at the UK's spot market with peak prices of up to 578.9 €/MWh and an average price of 42.4 €/MWh. At the same time, more years are necessary to determine whether the effect is really that small or if rather other occurrences during that particular year determined this small coefficient.

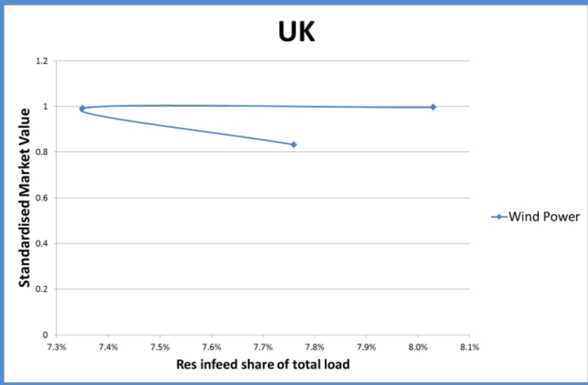
Merit Order (Regression Results)	Market Value (Ex-Post Calculation)
• In the UK, an economically small effect of wind power on electricity spot prices could be observed. A decrease of **0.55 €/MWh** on average was observed for the increase of wind infeed by one percent of average hourly load • In terms of total savings for the year 2009, this would sum up to **381.6 Mio €** if this additional one percent would have been continuously generated from wind power	

Figure 4-19: Main results UK

4.6 Discussion and Comparison with the Literature

Figure 5-1 illustrates the results of our econometric approach for the geographical scope covered by our analysis. In this figure, price effects are related to the size of the respective country's electricity market: An increase in variable RES generation in the dimension of a one percent share of the average load of that country was used as a unit of reference for the price change. This approach is the most suitable for an overall comparison between Member States as they do differ in size (RES targets are also set in relative terms for this reason). Apart from a few outliers, there is a clear trend that a higher load share of variable RES leads to lower electricity prices, and can thus induce a merit order effect. This trend is even more apparent in more recent years, whereas earlier years show more dispersion, possibly due to other unobserved effects that also influence electricity spot prices.

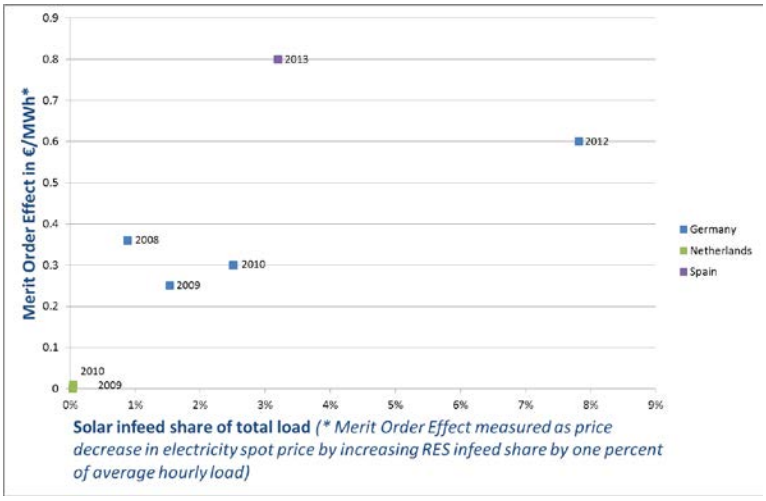


Figure 5-1: Merit Order Effect for Wind Power and Solar Photovoltaics - Comparison of price changes induced by feed -in of variable RES (2008-2013)

The literature on the merit order effect and historical market values of variable renewables, as discussed above, features diverse approaches and spans a large bandwidth of outcomes. In the following, results from the literature are compared more specifically with the three case study regions assessed here. In the literature, an effect was mostly calculated for an additional GWh of variable RES per hour. To be able to compare our findings with those from the literature, we scaled up our outcomes for Denmark, Spain and Germany to this measure as an example.

Scaling up our results led to outcomes similar to the literature for Germany, i.e. 1.49 €/MWh (2012) compared to around 2 €/MWh for wind and solar PV together (2010-2012) (Würzburg, Labandeira, and Linares 2013). For Spain, Gelabert, Labandeira, and Linares (2011) estimated a downward effect of around 2 €/MWh on average for the years 2005 to 2009. For 2012, downward effects of wind power on electricity spot prices of over 10

€/MWh have been found in the literature (Azofra et al. 2014). Our finding of a decrease by 5.68 €/MWh for one additional GWh of RES (if the coefficients for wind and solar PV are combined) is lower, but a direct comparison is not possible as a different measure was applied in Jónsson, Pinson, and Madsen (2010). The same problem exists for Denmark, as the approaches applied in the literature are quite different to ours and not directly comparable. Results from the literature describe a Danish market with or without wind power and a paper from 2010 claims that 40 % in price variation is attributed to wind power (Jónsson, Pinson, and Madsen 2010). Our result shows an average price decrease of 4.7 €/MWh if one additional GWh were generated by wind power – the actual hourly price effect is also subject to large fluctuations due to the high level of wind penetration in the Danish market.

To summarize, our results are robust to different specifications, yield significant coefficients and do not differ substantially from findings in the literature. The multi-country approach seems to be quite suitable for an analysis of the whole of Europe, although the drawbacks mentioned earlier must be considered. The main lessons learned from the multi-country analysis are that, first of all, effects differ over countries, showing that different electricity markets are more or less able to incorporate large shares of RES. In Spain, for instance, the merit order effect is relatively high. This effect is also visible in the relatively low market value for wind power and PV (compared to other European countries). In Denmark, on the other hand, average effects are not as substantial and the market value for wind power is also quite high considering the large share of total electricity demand it meets. This could be due to more flexible demand-side management that incorporates large shares of renewable electricity into the heating system if necessary (Ea 2015). In Germany, when looking at generation profiles, it can be assumed that a balanced mix of renewables leads to a more stable infeed pattern of renewable electricity. This could prevent the extreme fluctuations that occur if only one technology is predominant, and could also be a possibility to prevent extreme impacts of fluctuating renewables on electricity prices. Looking at the different strategies applied to incorporate large shares of renewables into different electricity markets yields interesting insights for other Member States that have not yet expanded their RES share to such an extent.

Studying the historical data available, shows that a downward trend of electricity spot prices was induced by feed-in of variable renewables. This finding holds in all the European Member States analyzed. At the same time, the market values of renewables decreased with their increasing share in total electricity demand. Focusing on three case study countries, these effects were discussed in more detail and contrasted with other regression specifications, as well as with historical market values of renewables. This confirmed the effect. Taking into account the drawbacks of a “macro” approach in comparison to country-specific analyses such as those discussed in the literature review, our study provides an integrated picture of Europe’s electricity markets and outcomes for Member States that have not been analyzed to this extent before.

It would also be interesting and important to include fossil fuel prices for more countries aside of Germany, as well as the CO_2 price into the different analyses, to enable a more complete understanding of the respective electricity markets. While this was beyond the scope of this analysis, the sensitivities for Germany did show that including historic spot prices for coal does not lead to significant changes in effects of wind or solar PV infeed on day-ahead spot prices. In the following section which shows future market values and merit order effect, both CO_2 and fossil fuel prices have been accounted for.

In terms of further research, it would be interesting to study the effects and determinants of increased price variability in more detail, as well as cross-country impacts between strongly interconnected regions. In the following analysis of future market values and merit order effect induced by variable renewables, specific country clusters of interconnected areas will be analysed in more detail to see how the interconnection of countries influences their respective price developments. Specifically, three large clusters were identified across Europe which are interconnected and thus exhibit similar developments as well as interdependencies to a certain extent.

5 Model-based assessment

5.1 Method of approach

In the previous chapter the merit-order effect caused by RES-E and market values of RES-E have been analysed empirically. The aim of this task is to complement the historical perspective by model-based analyses of these two key indicators and to assess their sensitivity to changed framework conditions in order to provide a holistic picture for the subsequent assessment of costs and benefits of RES deployment.

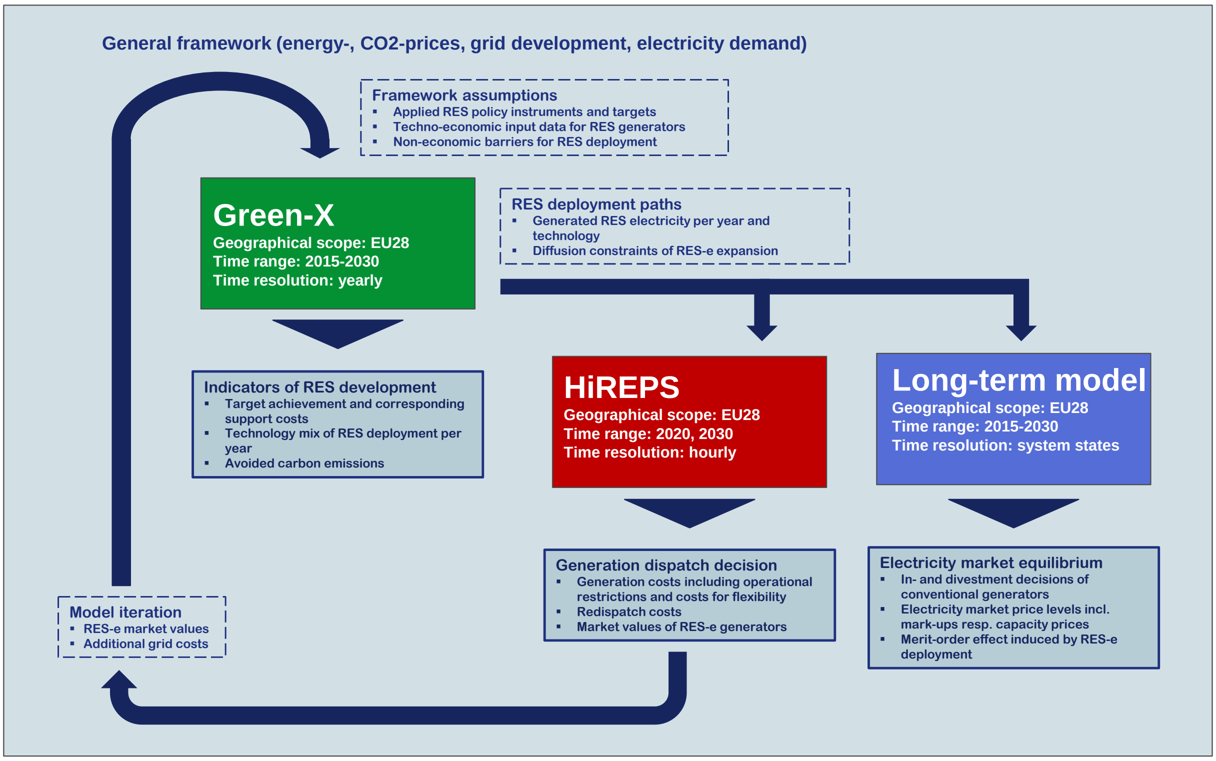


Figure 5-1: Schematic overview of the applied modelling set-up

The appropriate modelling of impacts of RES-E on electricity markets requires the interplay of several models with different focus and complementing features. The investment decision of RES-E generators is dominantly driven by the support schemes in place, existing non-economic barriers and the technological development. Common investment models with a focus on electricity markets do not reflect these peculiarities in the investment decision of RES-E, or even consider RES development only exogenously. The RES-investment model Green-X endogenously reflects all these relevant framework conditions in detail and delivers disaggregated results on RES deployment paths per year, technology and country.

In order to assess the impact of RES-E on electricity markets we use a short-term and a long-term model of the European electricity market in order to point out different effects that can be better represented in the one or the other model. Both models receive from the Green-X model the level of RES-E generation in the corresponding scenario and then analyse how the residual power system reacts to these quantities.

In order to get insights in the actual costs and benefits of integrating variable renewables into power systems including transmission constraints it is of crucial importance to capture their timely and spatial generation characteristics and the ability of a certain power system to react on this generation infeed. For this purpose, the high resolution power system model HiREPS is used to deliver the hourly power plant dispatch and transmission grid flows in order to estimate costs and market values of RES-E generation. This market value is then again passed on to the Green-X model in order to assess the effect on investment incentives for RES-E; the iteration is performed until no more deviation takes place, respectively it is below a certain threshold.

The deployment of RES-E impacts in turn the long-run equilibrium of electricity markets. In- and divestment decisions of conventional generators are influenced by their present and expected future market earnings and full-load hours. The annual revenue streams of generators will also depend on the future market design and the prices, which will evolve from these markets. Therefore, an investment model that explicitly covers the long-run perspective is necessary in the modelling set-up. Unless otherwise noted, all results presented in the following are derived from the short-term model.

5.2 Applied models

In this section a short characterization of the applied models is given.

5.2.1 Green-X

The ***Green-X*** model is used in this study to perform a detailed assessment on the future deployment of renewable energies in the European Union. The Green-X model is a well-known software tool with respect to forecasting the deployment of RES in a real-world policy context. This tool has been successfully applied for the European Commission within several tenders and research projects on renewable energies and corresponding energy policies, e.g. FORRES 2020, OPTRES, RE-Shaping, EMPLOYRES, RES-FINANCING and has been used by Commission Services in the “20% RE by 2020” target discussion. It fulfils all requirements to explore the prospects of renewable energy technologies:

- It currently covers geographically the EU-27 (all sectors) as well as Croatia, Switzerland, Norway (limited to renewable electricity) and can easily be extended to other countries or regions.
- It allows investigating the future deployment of RE as well as accompanying generation costs and transfer payments (due to the support for RE) within each energy sector (electricity, heat and transport) on country- and technology-level on a yearly basis up to a time-horizon of 2030 (2050).

The modelling approach to describe supply-side generation technologies is to derive dynamic cost-resource curves by RE option, allowing besides the formal description of potentials and costs a suitable representation of dynamic aspects such as technological learning and technology diffusion.

It is perfectly suitable to investigate the impact of applying different energy policy instruments (e.g. quota obligations based on tradable green certificates, (premium) feed-in tariffs, tax incentives, investment subsidies) and non-cost diffusion barriers.

Within the Green-X model, the allocation of biomass feedstock to feasible technologies and sectors is fully internalised into the overall calculation procedure, allowing an appropriate representation of trade and competition between sectors, technologies and countries. Moreover, Green-X was recently extended to allow an endogenous modelling of sustainability regulations for the energetic use of biomass.

Within Green-X a broad set of results can be gained for each simulated year on a country-, sector-, and technology-level:

- RE generation and installed capacity,
- RE share in total electricity / heat / transport / final energy demand,
- Generation costs of RE (including O&M),
- Capital expenditures for RE,
- Impact of RE support on transfer costs for society / consumer (support expenditures),
- Impact of enhanced RE deployment on climate change (i.e. avoided CO2 emissions)
- Impact of enhanced RE deployment on supply security (i.e. avoided primary energy)

Modelling support policies:

With Green-X a thorough assessment of impacts of various forms of energy policy interventions on RES deployment can be performed. The model is perfectly suitable to investigate the impact of applying different energy policy instruments to facilitate the market deployment of low carbon energy supply technologies – e.g. quota obligations based on tradable green certificates, (premium) feed-in tariffs, tax incentives, investment subsidies as well as the impact of non-cost diffusion barriers. The model contains a support policy database of all current RES support policy instruments, including their concrete implementation via design elements, for the EU28, Switzerland, Norway, the Western Balkan countries, North Africa and Turkey.

Green-X database:

The input database of the Green-X model provides a detailed depiction of the past and present development of the individual RES technologies - in particular with regard to costs and penetration in terms of installed capacities or actual & potential generation. Besides also data describing the technological progress such as learning rates is available which serves as crucial input to further macro-economic analysis.

5.2.2 The long-term electricity market model

The long-term electricity market model_is a stylized, intertemporal numerical dispatch and investment model of the European electricity market. Economically speaking, it is a partial equilibrium model that considers several electricity market actors' (representative conventional electricity generator, representative renewable electricity generator, electricity market coupler, capacity auctioneer) interrelated optimization problems, that jointly constitute a Nash game between the actors. In the current set-up all actors behave fully competitive, i.e. they do not anticipate an influence of their actions on the prices and see prices as parameters – this leads to the competitive market solution being implemented. In the model all operational and investment decisions by all actors are taken simultaneously for all model periods, i.e. perfect foresight is assumed. The current time horizon of the model is up to 2050 in five year steps. The installed generating capacity for the start year of the model (currently 2015) is given as parameter, but within the forward looking time horizon of the model, changes to the capacity stock are decided endogenously. Generating capacity, generation and demand are assigned to different nodes in a network, whereby each node represents a Member State and electricity exchange between nodes is limited by net transfer capacities (NTC`s).

Actors in the lower stage are represented explicitly by their optimization problems. In order to reduce mathematical complexity and keep the model at one level the actor in the upper stage, the capacity auctioneer is represented implicitly by his market clearing constraint. The price for electricity and the capacity premium are derived from the shadow prices (dual variables) of the market clearing constraints. The model is created by deriving the first order conditions of each actors´ optimization problem and adding these to the constraints and the market clearing conditions. The model is formulated as mixed complementarity problem (MCP), coded in GAMS and solved with the Path solver.

5.2.3 HiREPS

The **Hi**gh **Re**solution **P**ower **S**ystem (HiREPS) model is a dynamical power system simulation and optimization model that also includes the heat sector. The focus of the model is to analyze the integration of variable renewable electricity generation into power systems - by specifically including a detailed representation of all relevant operational system constraints.

The HiREPS model addresses these aspects through the detailed representation of

- **RES-E electricity generation**: The HiREPS model uses historical weather data, to calculate for an assumed distribution of wind turbines, solar photovoltaic and solar thermal power plants the local renewable power generation across Europe in a 7x7 km spatial resolution. This localized renewable power generation is then used in the unit-commitment and load-flow simulations. The wind speed data source for HiREPS is the COSMO-EU model of the German Weather Service DWD. The solar irradiation data is taken from the SOLEMI database of the German Aerospace Agency DLR.
- **Conventional power plants:** HiREPS dynamically simulates the unit commitment of the thermal power plants by including the technical and economical limitations. The technical constraints are for example maximum ramp rates, efficiency reduction at part loaded operation, minimum stable output, minimum on and off times. Economical constraints are for example start-up costs, fuel costs and CO2 costs.
- **Hydro power grids:** Hydro power storages are a key option to enable the efficient integration of variable renewable electricity generation from solar and wind energy. Therefore HiREPS includes a detailed modelling of the hydropower sector in Europe. All countries with significant amounts of hydropower in the EU, like France, Italy, Austria, Switzerland, Germany, Norway, Sweden and Spain, are modeled in detail. This includes a detailed modelling of hydrological constraints, e.g. the consideration of hydro power cascades, the fill-levels of water reservoirs and hourly water inflows through run-of-river plants and into reservoirs. For other European countries a more aggregated model of hydropower is used.

- **Load-flow simulations:** The model can either be operated as market model (ignoring power-grid limitations within market areas) or as power system model incorporating the high-voltage transmission grid of ENTSO-E and neighboring regions. The model can simulate the impact of cross-border and intra-country grid expansions on prices and redispatch costs.
- **Demand side flexibility options:** A substantial amount of demand-side management options are included in the model. The options are typically cross-sectoral and comprise e.g. Power2Heat, heat storages, Power2Gas, compressed air storages and load shifting and shedding in selected industries and households.

The model has been applied in numerous EU and national projects e.g. PRESENCE, Define, PowerStore2050, SolarGrids and BETTER.

5.3 Modelling assumptions and data input

In order to ensure maximum consistency with existing EU scenarios and projections various input parameters of the scenarios are derived from PRIMES modelling. More precisely, the PRIMES scenario used is the PRIMES *reference scenario* as of 2013 (EC, 2013)[1]. The main data source for RES-specific parameter is the Green-X database – this concerns for example information on the status quo of RES deployment, future RES potentials and related costs as well as other country-specific parameter concerning non-economic barriers that limit an accelerated uptake of RES. Thus, Table 5-1 provides a concise overview on which parameters are based on PRIMES, on the Green-X database or which have been defined for this assessment.

Table 5-1: Main input sources for scenario parameters

Based on PRIMES	Based on Green-X database	Defined for this assessment
Primary energy prices	RES cost (investment, fuel, O&M)	RES policy and carbon pricing framework
Energy demand by sector (EU countries)	RES potential	Electricity transmission grid development
Conventional supply portfolio and conversion efficiencies (EU countries)	Biomass trade specification	Electricity market design
CO_2 intensity of sectors (EU countries)	Technology diffusion / Non-economic barriers	Demand-side participation
	Learning rates	Phase-out timeline of existing power plants

Figure 5-2 shows some of the price assumptions that have been used for the modelling. On the left hand side fuel price assumptions are shown, whereby the dotted line indicates the 2013 Primes reference scenario. It can be seen that for the different fossil fuel carriers a continuous increase of prices has been foreseen. For comparison, the solid lines indicate the price developments that have been assumed for the recent 2016 Primes reference scenario. We can see that the price levels are altogether lower reflecting recent downward movements in international markets for fuels. On the right hand side are shown the CO2 price developments again for the 2013 and 2016 forecasts. We observe for the reference 2013 scenario a lower price level for most of the period compared to the High RES case and only towards the end of the period the price in the reference scenario surpasses the price of high RES scenario.

[1] At the time the modelling work has been conducted the more recent Primes reference scenario as of 2016 has not yet been available.

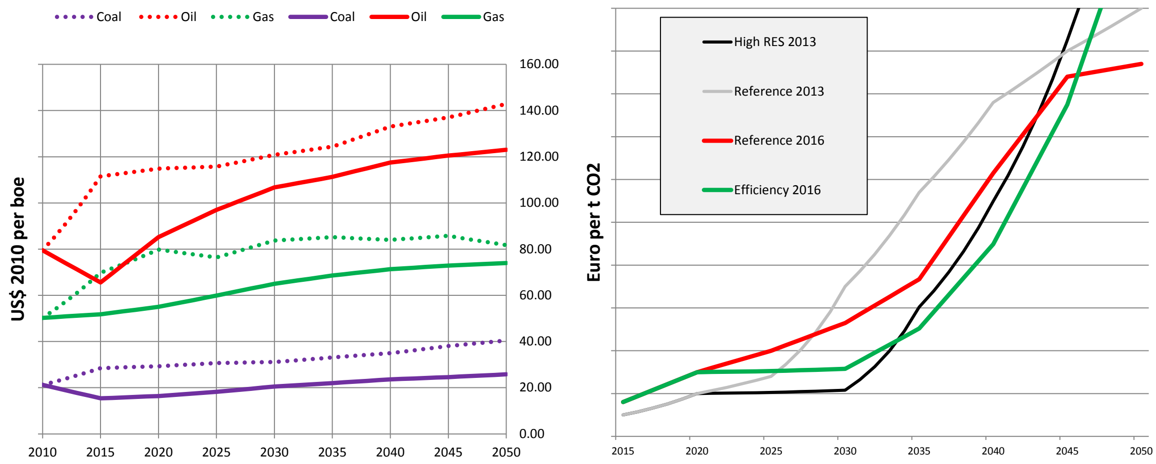


Figure 5-2: Development of fuel (left) and CO_2 (right) prices according to PRIMES scenarios.

The development of installed capacities and costs of generation technologies is derived from the power plant database of TU Wien, EEG. For nuclear power plant early decommissioning has been assumed where this has been announced, the effect of which is displayed in Figure 5-3. The yellow bar indicates the cumulative installed capacities with decommissioning, whereas the other bars indicate the capacities that would have been available to the market when technical lifetimes would be considered.

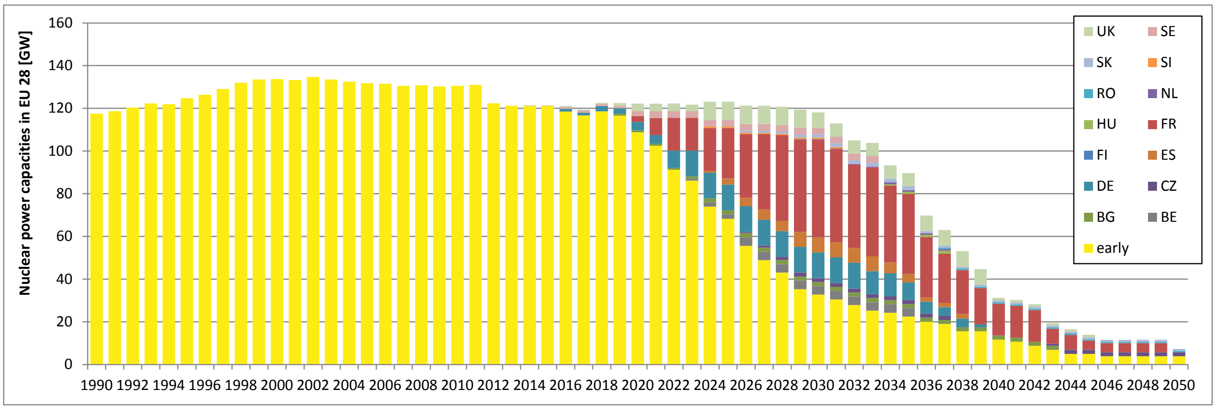


Figure 5-3: Development of nuclear power generation capacities (GW) based on TU Wien / EEG power plant database, Eurostat, Platts.

The electricity transmission grid development is updated according to the assumptions of the Ten Year Network Development Plan (ENTSO-e 2014).

5.4 Scenarios

In order to study possible future developments of market values of renewable energy technologies (RET) and the merit-order effect caused by the deployment of increasing RES shares a comprehensive scenario analysis has been carried out within the course of this work package. The geographical coverage of the analysis comprises the EU28 member states and the time scope of the scenarios ranges from 2015 until the year 2050. We study the impacts of changing framework conditions on market values according to several key dimensions that are described in the following. The merit-order effect per definition only refers to a change in RES policy whereby all other parameters are kept constant.

1. **RES policy:** The ambition level and the concrete design of future RES support policies will strongly influence the resulting RES shares in different countries up to 2030 (cf. Figure 5-4). Both, the market values and the merit-order effect are closely linked to RES deployment in general and to the composition of the evolving RES portfolio in particular. Therefore, besides the reference assumption of a 27% RES target for the EU in 2030, a more pessimistic and a more optimistic RES ambition level will be studied.
2. **Electricity transmission grid:** EU legislation has mandated the European Network of Transmission System Operators for Electricity (ENTSO-E) with the delivery of a Ten-Year Network Development Plan (TYNDP) in every two years. On the one hand ENTSO-E has to consider several RES development scenarios within their network planning process, on the other hand it has turned out in the past that actual infrastructure building tend to lag behind plans[2]. To adequately consider this development we assume a reference scenario, where TYNDP projects can be realized in time and a more pessimistic scenario, in which some share of the projects are delayed in construction.
3. **Electricity market design:** The future evolvement of electricity market design within the EU is far from being clear. One important aspect with regard to market values of RES and the merit-order effect is the trend towards the establishment of capacity markets in addition to energy markets versus energy-only markets with strategic reserves. To study the effects of this development we will consider two extreme scenarios, one reflecting an energy-only market across the EU and another assuming the establishment of national or international capacity markets.
4. **Carbon pricing:** The supply shock of emission allowances in the ETS caused by the financial crisis and a couple of other factors led to low carbon prices and thus no long-term incentives for additional investments. The recently announced structural reform of ETS makes the future development of carbon prices uncertain. Due to the fact that the carbon price strongly impacts the market competitiveness and thus the necessary support expenditures of RES we will study the impacts of two distinct carbon price trajectories.
5. **Demand-Side response:** The inability of consumers to adjust their demand based on (short-term) variations in market prices has been known to be a major flaw of electricity markets since their establishment. Whereas in the public debate it is sometimes claimed that increased demand-side participation will solve many of existing problems, we will specifically address this issue via building on existing research identifying bottom-up potentials and costs of demand side shedding and shifting options across the EU and assess their impact on the viability of RES and resulting effects in electricity markets.

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[2] According to TYNDP 2014 "… more than one third of investments are delayed compared to the initial schedule, mostly because of social resistance and longer than initially expected permitting procedures, possibly leading to project reengineering."

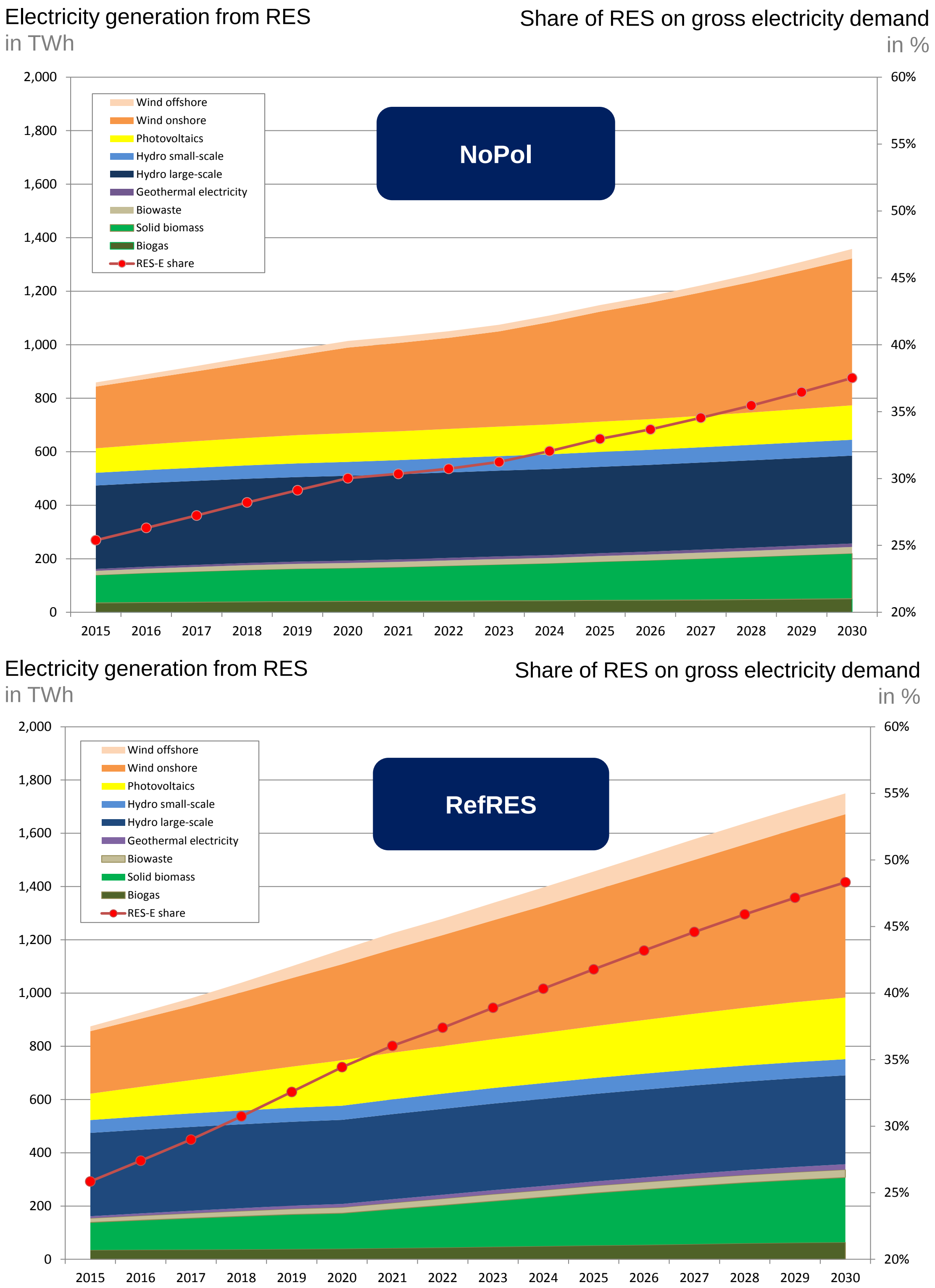

Figure 5-4: Development of RES-E capacities in no-policy (upper) and reference (lower) scenario. These two scenarios are contrasted in order to assess merit-order effect.

In principle, all of these dimensions can evolve independently from each other. In order to derive insights on the relative importance of each of the dimensions it is therefore necessary to study a variation in a certain dimension without changing the others (ceteris paribus condition). However, this methodology identifies the importance of a certain dimension, but do not give insights of the impact of a simultaneous variation in more than one dimension. This is important given that some of the dimensions substituting each other, and others are complements (e.g. higher demand-side response substitutes additional needs for grid infrastructure, whereas higher RES shares make changes in electricity market design more probable). Due to the fact that a comprehensive consideration of all possible variations of outcomes would exceed current modelling capabilities, we follow a mixed approach. We divide the assessed scenarios in two groups.

We use **pathway scenarios** to reflect the evolvement of a certain mix of possible future developments in all dimensions that could most likely occur simultaneously. We developed three distinct pathway scenarios; A business-as-usual scenario aims to reflect the most probable development in all of the before mentioned scenarios and will be used as reference scenario to be compared to all other scenarios. Besides that two alternative pathways comprised by a consistent set of variations in all dimensions are considered as well. Together, these three pathway scenarios allow us to derive a bandwidth of potential future market values of RES and the merit-order effect by explicitly considering substitutional and complementary effects, respectively.

On the other hand **sensitivity scenarios** are carried out to assess the impact of a dedicated development in one dimension in isolation of the others. This enables us to understand the relative importance of key developments with regard to impacts on RES market values and how it influences the merit-order effect. We limit the number of modelled scenarios by only considering two options per dimension, which are meant to spread up the bandwidth between a reference development and either a more pessimistic or optimistic development.

Table 5-2 summarizes the considered scenarios for the assessment of market values and the merit-order effect. The scenarios in the table are grouped according to their type, e.g. either pathway or sensitivity scenario. A detailed description of the sub-categories within the key dimensions is given in section 0.

Table 5-2: Overview of modelled scenarios

Nr.	Type	Acronym	RES policy			Grid development		Electricity market design		Demand-Side response		Energy efficiency and carbon pricing		Fuel prices	
			LOW	REF	HIGH	REF	DELAY	EOM	CM	REF	HIGH	REF	HIGH	REF	LOW
❶	Pathway	P-NoPolicy	●			●		●		●		●		●	
❷	Pathway	P-Reference		●		●		●		●		●		●	
❸	Pathway	P-High-RES			●	●		●		●			●	●	
❹	Sensitivity	S-Grid		●			●	●		●		●		●	
❺	Sensitivity	S-Market		●		●			●	●		●		●	
❻	Sensitivity	S-Carbon		●		●		●		●			●		●
❼	Sensitivity	S-Demand		●		●		●			●	●		●	

5.5 Results of the modelling

In this chapter the evaluation of the potential future merit-order effect induced by RES-E as well as the corresponding market values of RES-E are evaluated and summarised based on the modelling results gathered within this project. The results are presented in relative, as well as absolute terms to allow for a differentiation of price and volume effects.

5.5.1 Relative effects

The growing share of RES-E in electricity markets increasingly impacts electricity prices. These prices in turn have a feedback effect on the market revenues RES-E generators are able to earn. In this section both, the impact of additional RES-E on electricity prices as well as the feedback on their specific returns is shown.

5.5.1.1 Decreasing wholesale electricity prices

In order to filter the impact of additional RES-E generation on electricity prices two model runs, which only differ in their RES-E share, are contrasted with each other. The first of these scenarios is the P-NoPolicy scenario, which assumes that the EU ETS is the only source of support in place and no dedicated RES target will be achieved in 2030. In contrast to that the P-Reference scenario represents a world in which the RES target of 27% is reached by 2030 through the implementation of a dedicated RES support scheme.

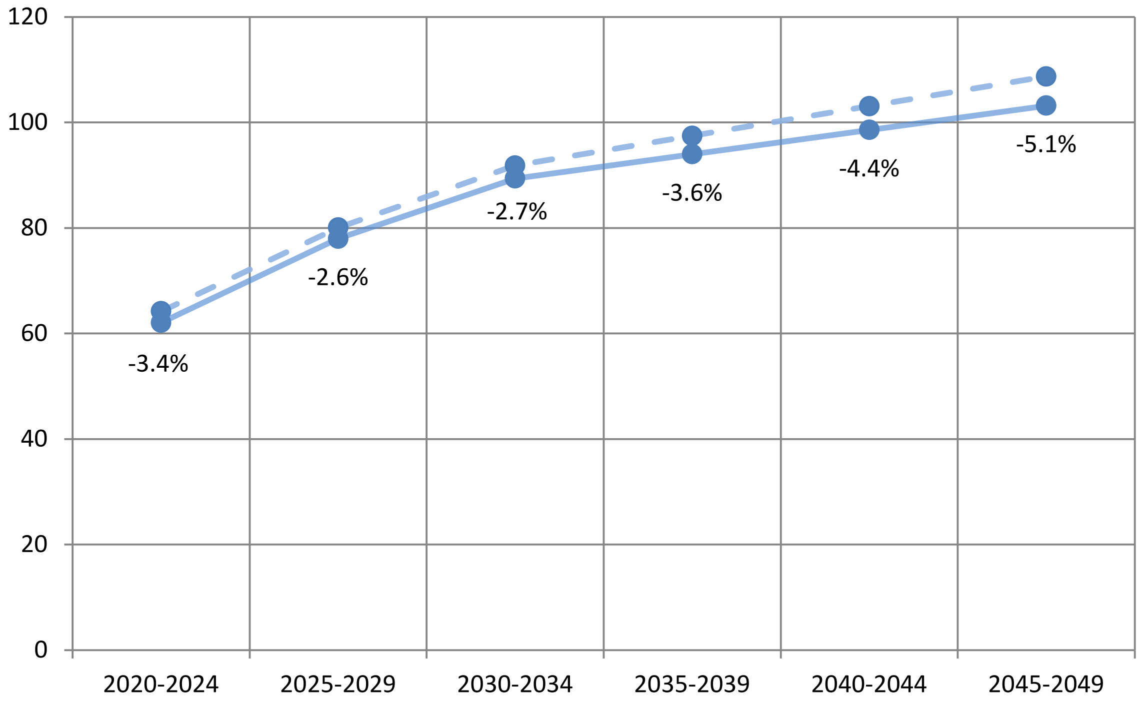

Figure 5-5: Average day-ahead electricity prices in the EU in the P-NoPolicy scenario (dashed line) and the P-Reference scenario (solid line).

Figure 5-5 shows the resulting day-ahead electricity price of both scenarios as an EU average. It can be seen that in each period of time the prices of the P-Reference scenario are below the ones in the P-NoPolicy scenario. This indicates that an additional amount of

RES-E, ceteris paribus, decreases average electricity prices by 2 to 5 percent depending on the actual amount and type of additional RES-E and the corresponding in- and divestments in the conventional generation park. It has been assumed in the modelling that all conventional generators fully recover their total costs based on market revenues. However, it should be stressed that this analysis has been performed under the ceteris paribus condition. In reality, electricity markets are almost never in equilibrium and prices vary according to a large number of independent influences. This analysis has thus shown that given everything else remains constant, additional RES-E lowers average electricity prices.

The resulting prices do not equally drop within the EU. Price drops are more significant in Member States where relatively expensive generation technologies can be substituted and those adjacent states, whose markets are comparably well coupled to it. Figure 5-6 shows the spatial distribution of electricity prices across the EU in the year 2030. It has been assumed that that all Member States have implemented electricity markets and that all markets are implicitly coupled via current NTC values plus the extensions proposed in the TYNDP of ENTSO-E.

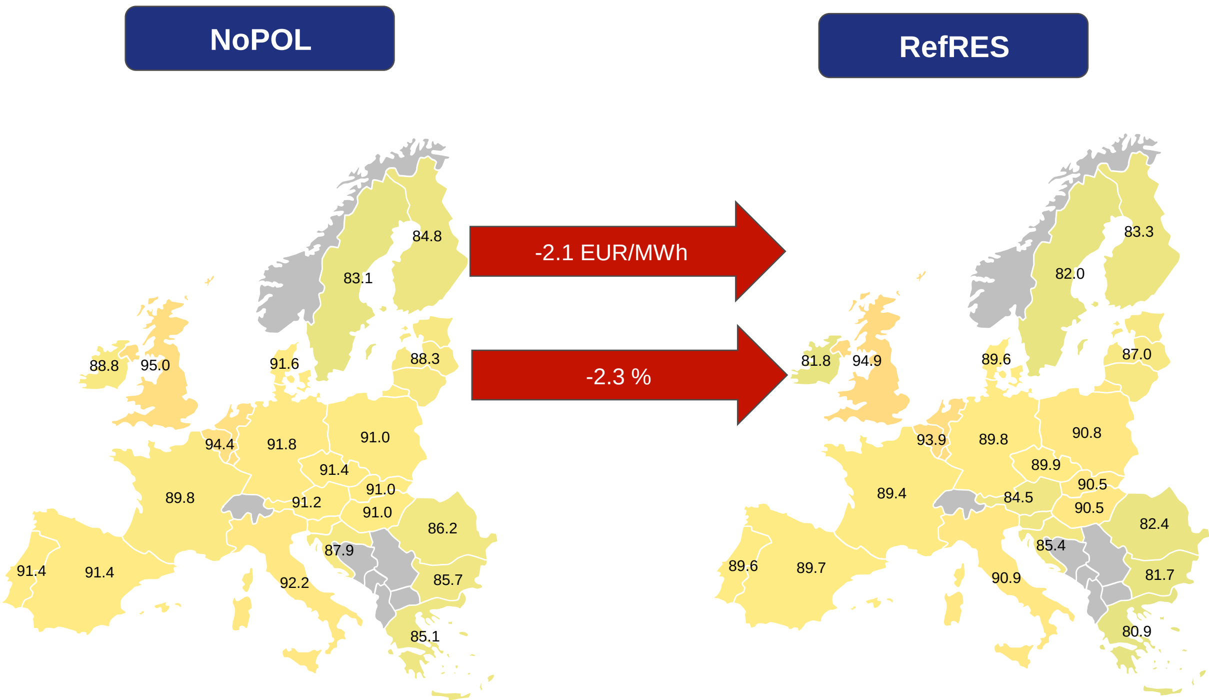

Figure 5-6: Average day-ahead electricity prices of the P-NoPolicy scenario (NoPOL) and the P-Reference scenarios (RefRES) across the EU in 2030.

Over all EU countries prices dropped in the P-Reference scenario by 2.1 EUR/MWh, or by 2.3% as compared to the P-NoPolicy scenario. Most obvious is the price drop in the Western Balkan region that accounts for the substitution of expensive fossil fuels by renewables. Due to the assumption of implicit market coupling in this region the lower prices in Western Balkans also lead to a significant drop of average prices in Austria. This finding reveals another import aspect of coupled electricity markets. Depending on the level of market coupling, RES investments in one state lead to costs and benefits in adjacent states and thus induce incentives for free riding.

Figure 5-7 shows the impacts of sensitivities on scarcity price mark-ups. With respect to the level of scarcity prices it has to be noted that their absolute level is determined by the frequency of scarcity situations. The more often scarcity situations occur the lower the price mark-ups need to be; The investment cost gap that needs to be recovered stays in sum the same. In our dataset we assumed one scarcity event in each Member State per five year period, since this is a typical amortisation period within the sector. However, this is due to the fact that our model framework is deterministic. In a stochastic model setting scarcity prices would occur more often at times with a high probability of scarcity. Such an analysis is recommended for future work as this has again a crucial impact on potential market revenues of renewables.

On the left hand side we compare the impact of increased demand elasticity against the reference case. At first we compare the impact of additional demand elasticity potential that is constantly available against the reference case. We can observe that it decreases the price level of price mark-ups required to finance investments into new generating capacity, since less peak capacity is required; it does not however solve the peak pricing problem since the marginal capacity unit still depends on price mark-ups, which is a natural condition of the energy-only market design. On the other hand demand elasticity that is not constantly available (s_demand_b) has a different effect: in the hours where it is available it can avoid high scarcity prices. However, since it is not constantly available it cannot displace capacity. Therefore the absolute scarcity price level is even higher due to the lower contribution margin in hours where elasticity avoids scarcity prices. This effect can be thought to be similar to the effect of volatile RES-E generation, which is not constantly available.

On the right hand side of Figure 5-7 we see the impact of delayed grid expansion on scarcity prices. We see that grid expansion not only has an impact on variable costs when it comes to the most efficient dispatch, but can also help to save generation capacities and thus price mark-ups if existent capacities are shared more efficiently between Member States.

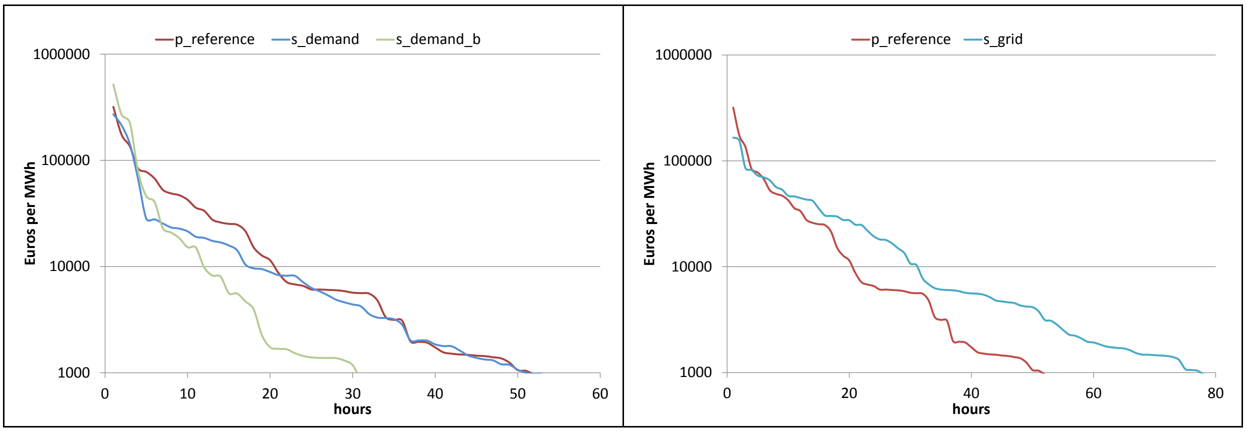

Figure 5-7: Sensitivities on scarcity price mark-ups (logarithmical scale) based on the long-term model. Mark-ups for demand elasticity sensitivity on the left; mark-ups for grid development sensitivity on the right.

5.5.1.2 Decreasing market value factors of variable renewables

The ratio between potential market revenues of RE generators and baseload generators considerably drops with increasing penetration, especially for variable RES (vRES). This peculiarity can partly be explained through a special characteristic of variable RE generation, which is marketed (and thus valued) in energy-only electricity markets. The marginal value of its generated electricity decrease with increasing market penetration, because less high priced generation is substituted at higher infeed levels. Therefore, market prices are low when (nearly zero priced) renewable electricity infeed is high and vice versa. This is a competitive disadvantage of variable (or non-dispatchable) electricity generation compared to dispatchable generation, which materialises in the form of relatively lower market revenues as compared to revenues of the same amount of constant electricity generation. To study the size of this effect the three scenarios P-NoPolicy, P-Reference and P-HighRES have been contrasted with each other. The NoPolicy scenario and the Reference scenario only differ in their RES-share, whereas the HighRES scenario also assumes a considerable amount of additional energy efficiency measures. The absolute levels are not much higher than in the Reference scenario. In the following the relative market value factor will be shown for these scenarios and different time frames.

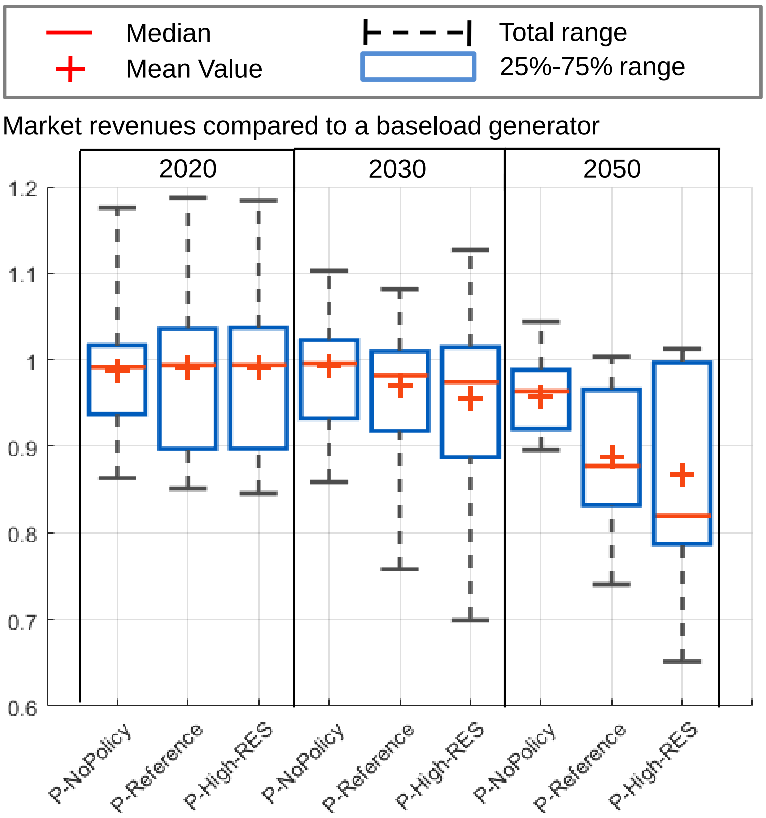

Figure 5-8: Market value factor of wind onshore within the EU for different RES scenarios.

Figure 5-8 shows boxplots that each contains the market value factors of all EU member states in the respective scenario. In the year 2020 the absolute amount of RES between the different scenarios does not significantly differ. However, they differ in their RES-E generation mix and the location of RES investments.

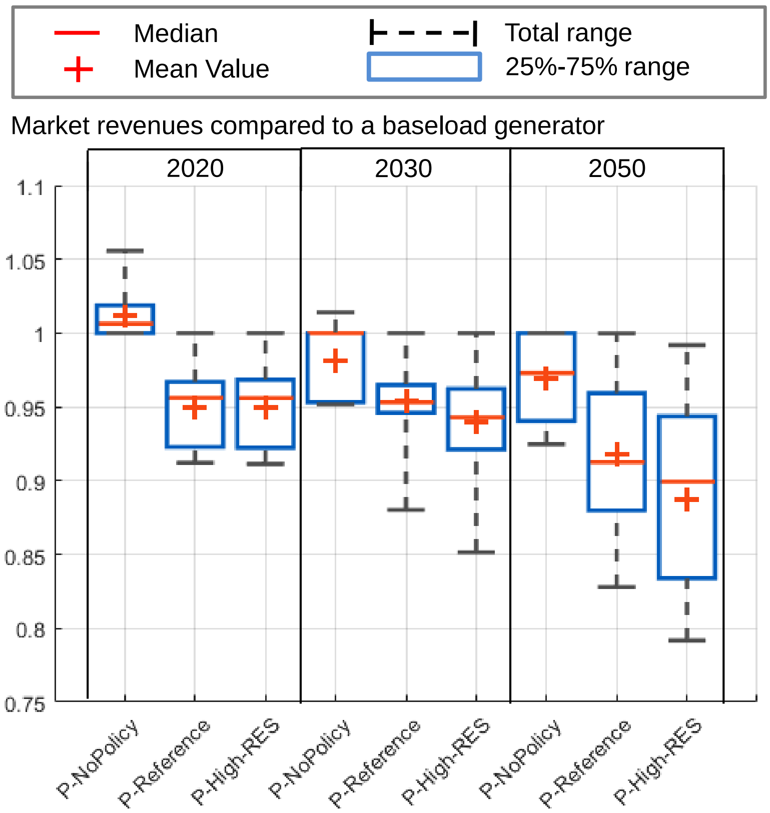

Figure 5-9: Market value factor of wind offshore within the EU for different RES scenarios.

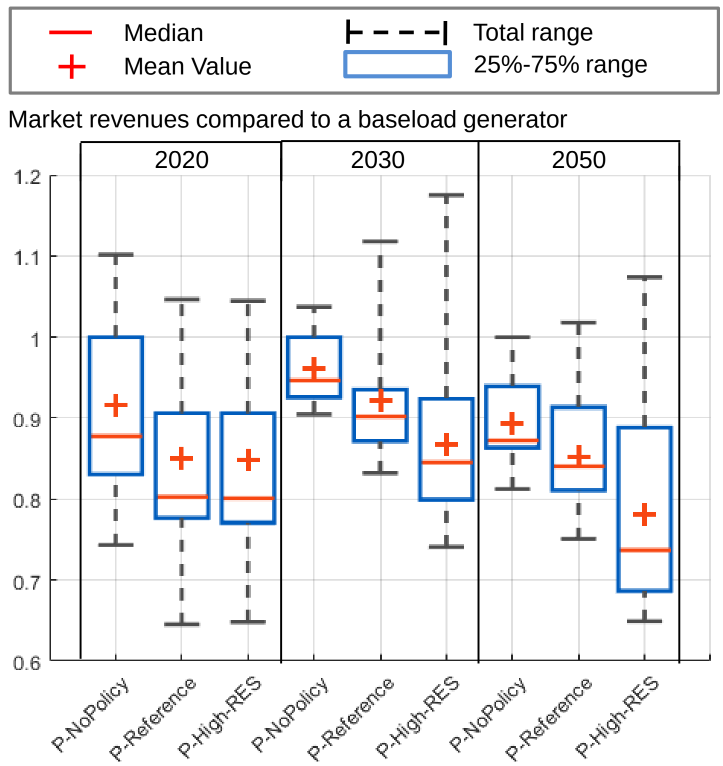

Figure 5-10: Market value factor of PV within the EU for different RES scenarios.

The first three boxplots in Figure 5-8 illustrate the aforementioned effect. Even the absolute amount of RES-E is the same across the EU, investment at locations with higher market values or the total mix of variable renewables (in this case additional PV) can change the value of the generation profile in a way that relative revenues increase. In the period of 2030 and 2050 the decreasing effect of market value factors becomes apparent. Not only the median values decrease from nearly 100% down to around 80% with higher RES-E penetration, but also both minimum and maximum value factors drop in the lower range.

The same holds for wind offshore. It can be seen in Figure 5-9 that market value factors of wind offshore can even be above the revenues of a baseload generator at low penetration levels. With higher penetration also the relative market values drop, however less step than they do for wind onshore. The strongest decline in relative market revenues can be observed for the case of PV (cf. Figure 5-10).

5.5.1.3 Sensitivity of market values caused by external factors

In general, electricity prices are strongly influenced by economical and technical framework conditions. As a consequence, also revenues of RES-E are impacted by these conditions. Basically, there are two opposing sets of conditions that influence the level of market value factors of vRES. The first set of conditions is adding variability to the market. This is e.g. the case if additional vRES are installed, which has been discussed in the previous section, but it can be any other addition of inflexibility as well. Under such conditions the market value factors of vRES decrease. The other set of conditions add flexibility to markets. These are, e.g. well-known measures as additional storages, demand-side management, energy sector-coupling, making conventional generation units more flexible, or expanding transmission grids. By adding flexibility to the market the market values of vRES increase. In order to assess the magnitude of such influences several sensitivity scenarios have been evaluated with regard to their impact on market values of wind onshore, wind offshore and solar PV. The results of this evaluation can be seen in figuresFigure 5-11Figure 5-16. We compare each of the sensitivity scenarios to the reference scenario (P-Reference) in order to assess the impact of framework conditions on market values.

The first sensitivity (S-Carbon) accounts for additional energy efficiency measures and increased carbon prices. Two opposing trends can be observed in this scenario. In 2030 the lower demand reduces electricity prices and thus market values. In 2050 the higher carbon prices outweigh this effect and electricity prices and market values considerable rise.

The demand scenario adds flexibility to the market. It assumes additional investments in power2heat units. It becomes evident that within the timeframe of 2030 this measure is not utilized very much. In the long-run up to 2050 when gas prices rises the application of power2heat significantly increases market values of all technologies.

The S-Grid scenario assumes a delayed grid expansion as compared to the TYNDP of ENTSO-E across Europe. This mainly influences the market values of wind onshore in 2050. In the S-market scenario the assumption was taken that each country has implemented a national capacity market.

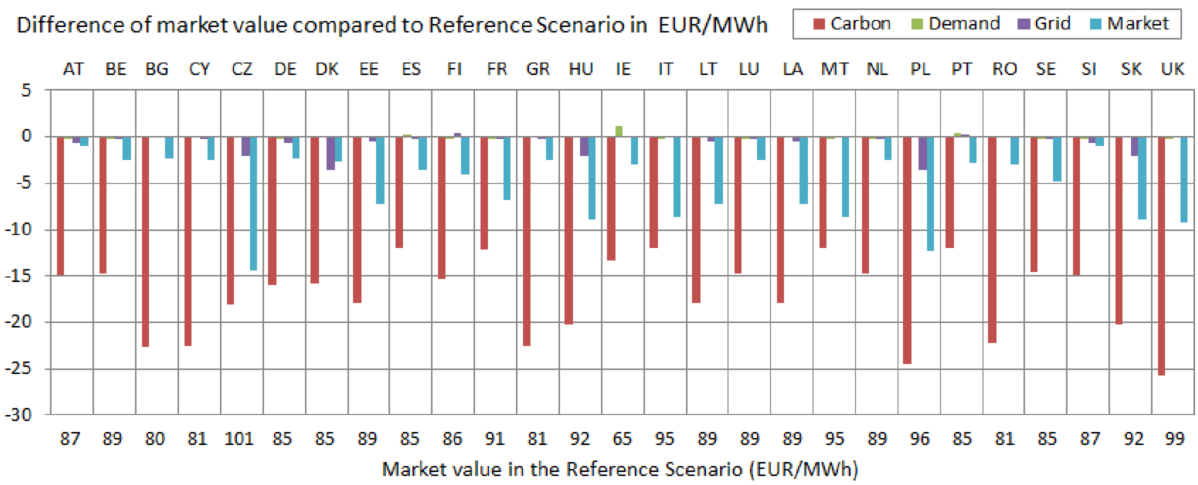

Figure 5-11: Change in market values of wind onshore as compared to the Reference Scenario in 2030

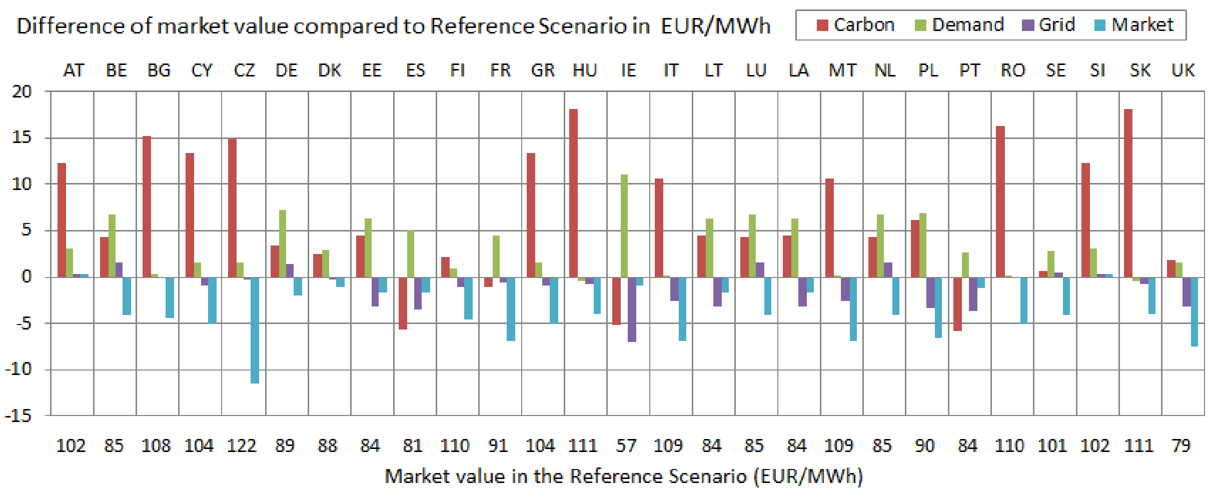

Figure 5-12: Change in market values of wind onshore as compared to the Reference Scenario in 2050

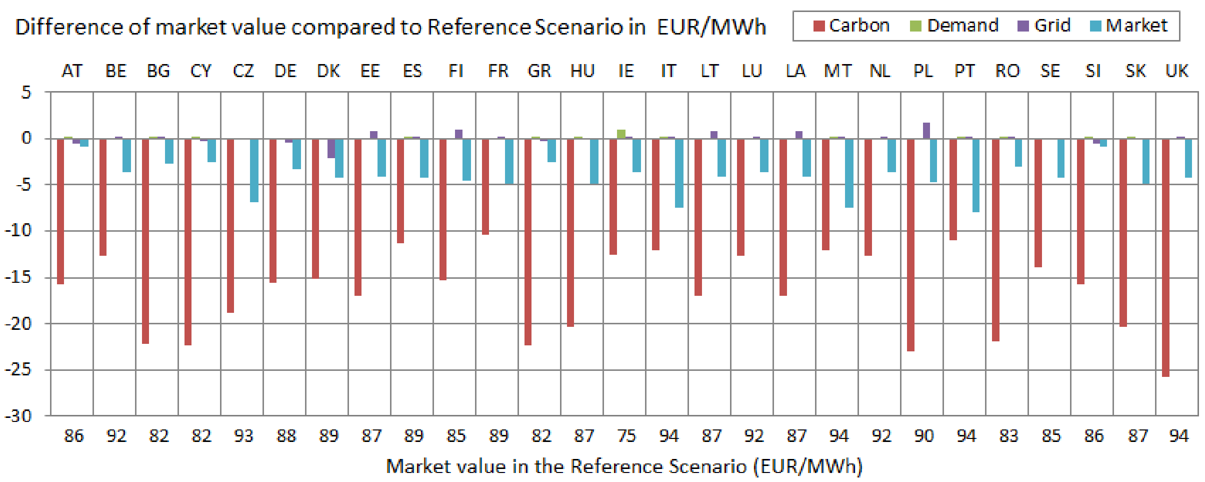

Figure 5-13: Change in market values of wind offshore as compared to the Reference Scenario in 2030

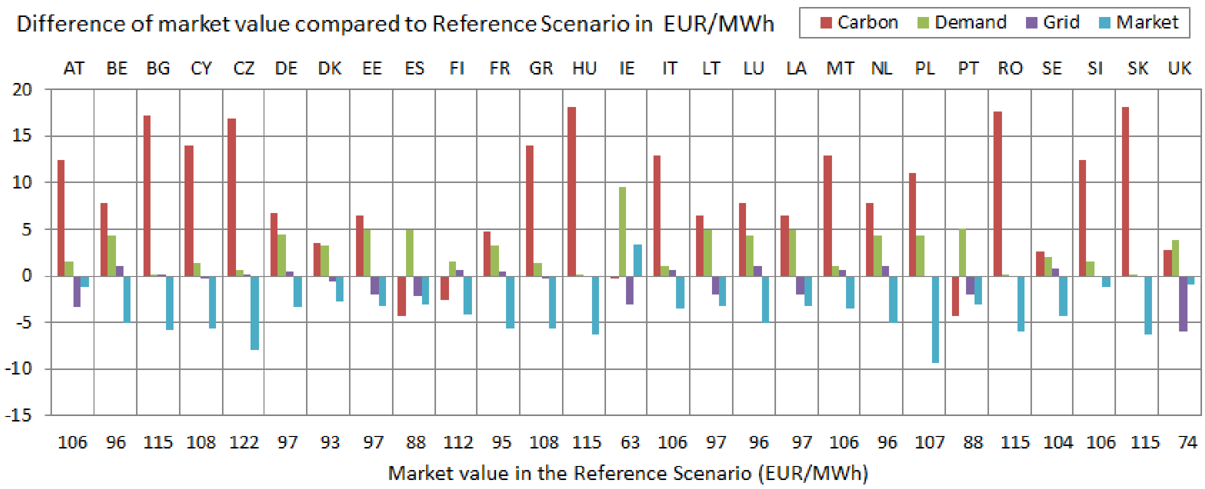

Figure 5-14: Change in market values of wind offshore as compared to the Reference Scenario in 2050

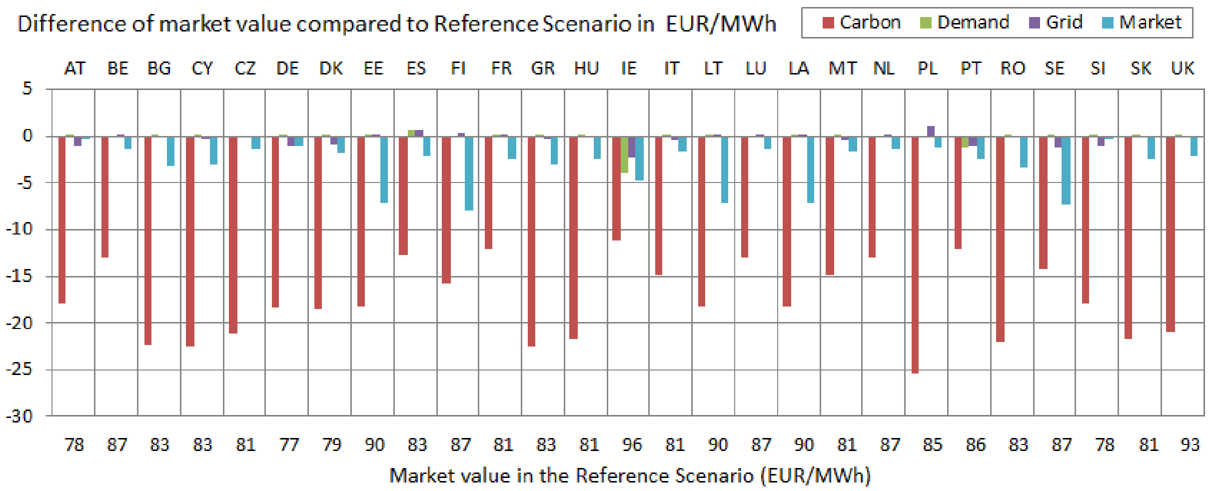

Figure 5-15: Change in market values of solar PV as compared to the Reference Scenario in 2030

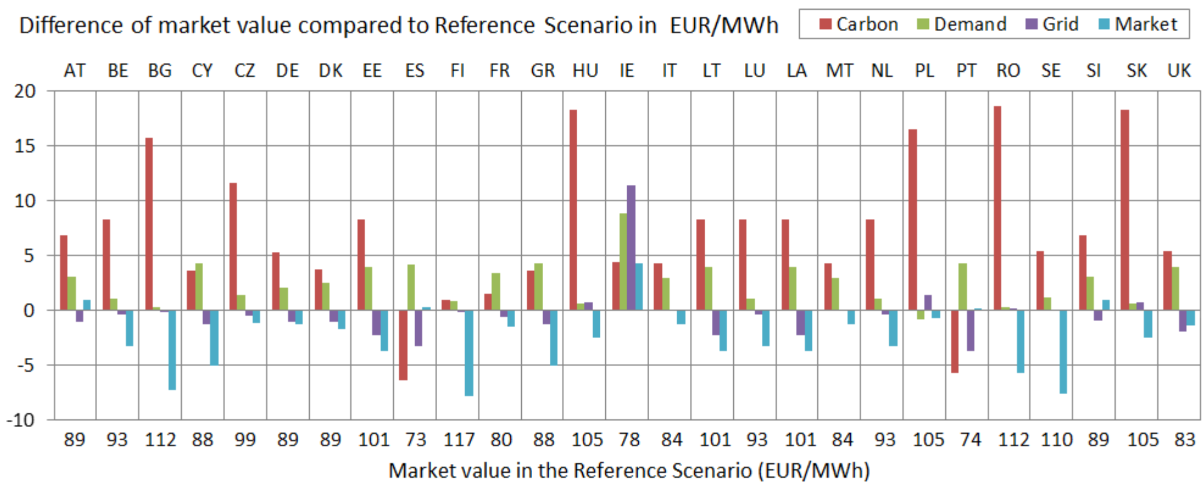

Figure 5-16: Change in market values of solar PV as compared to the Reference Scenario in 2050

This market design suppresses price peaks in scarcity events and thus lowers average electricity prices in electricity wholesale markets. In this case generators receive besides the revenues from electricity wholesale markets additional revenues from capacity markets. These markets value firm capacity and are intended to incentivize necessary investments. To this end the peak prices, which are a necessity in energy-only markets disappear and thus average prices in these markets drop. Due to the fact that vRES generators have a high chance of not producing in times of scarcity when peak prices occur, their market revenues remain more or less the same, whereas the energy-only part of revenues from conventional generators decreases as do average electricity prices. The market values of RES decrease according to their actual generation in times of scarcity. However, this strongly depends on whether vRES would be able to catch peak prices or not, and on the other hand on the capacity credit of vRES and thus their additional potential revenues from capacity markets. Therefore, this issue has to be studied more deeply in future research.

5.5.1.4 Sensitivity of market values caused by varying meteorological conditions

The market revenues of variable renewable electricity generation significantly depend on the absolute amount of generated electricity as well as the actual generation profile of units. Both aspects vary in space (thus differentiate several wind parks) and in time. Within this analysis we focus on the latter characteristic and study the sensitivity of market values of aggregated generation from wind onshore and solar PV by performing additional model runs with the weather years 2006 to 2009. In order to work out the impact of a changed generation profile, we present two sets of model runs. In the first scenario we took the generation profiles of RES and the hourly demand curve from different years, but scaled it to the mid-term yearly average of generation and demand as it has happened in an average year and also has been used in the main modelling runs. In doing so we can isolate the effect of a changed generation profile whereas the generation share and the full-load hours, respectively, remained the same.

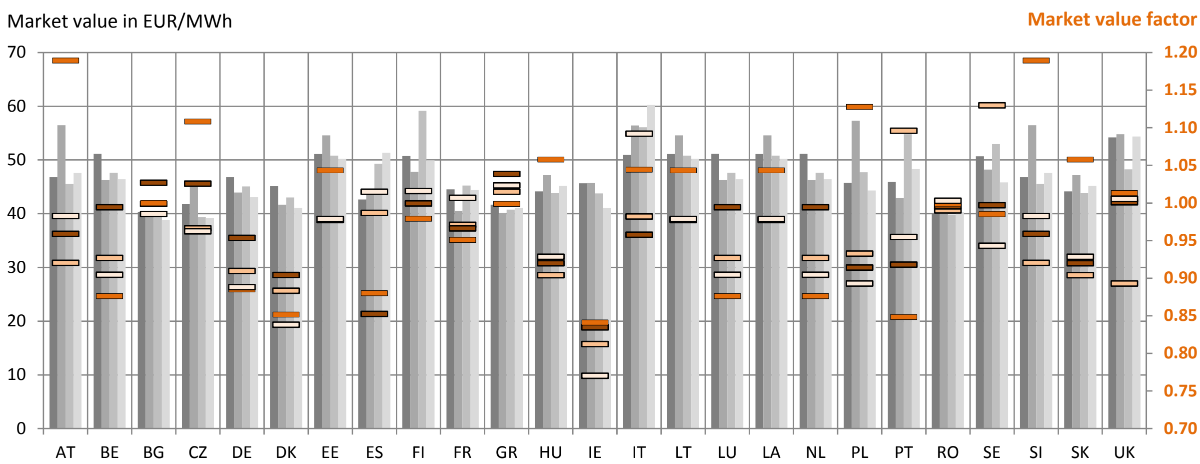

Figure 5-17: Changes in market values and value factors in 2020 due to different generation profiles of wind onshore based on the weather years 2006 to 2009. (Each weather year corresponds to a (cross-)bar; The shading in both colour schemes match each other)

In the second set of model runs we again exchanged generation profiles and demand curves, but scaled them in a way that we do not only reflect the changed generation profiles but also the mid-term changes in yearly electricity generation and demand. Note, that due to the economic crisis the electricity demand in 2009 also impacts the results in the sense that it was unusually low compared to previous years and thus the vRES share was relatively higher as well.

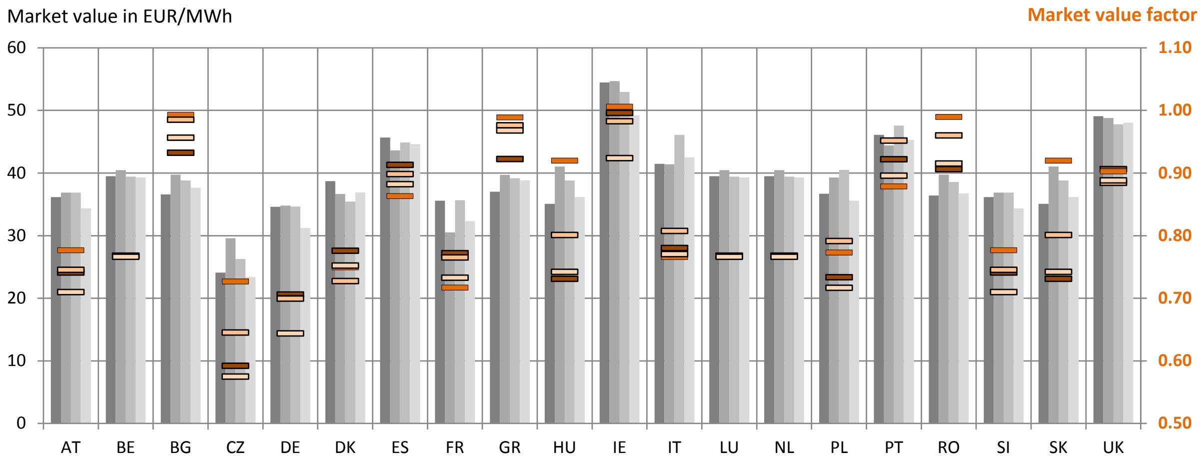

Figure 5-18: Changes in market values and value factors in 2020 due to different generation profiles of solar PV based on the weather years 2006 to 2009. (Each weather year corresponds to a (cross-)bar; The shading in both colour schemes match each other)

The results of how generation profiles impact market values are presented in Figure 5-17 and Figure 5-18, which show the changes in market values in EUR/MWh and corresponding market value factors (share of market revenues as compared to a constant generation profile with the same energy content) for wind onshore (5-13) and solar PV (Figure 5-18) in the model year 2020. In general, it can be observed that wind onshore shows a greater sensitivity to changes in generation profiles than solar PV. In the case of wind onshore there are outliers in several countries, which indicate that wind onshore is able to earn revenues from peak prices in scarcity situations in certain weather years. For, example in Austria wind onshore has a market value factor of 1.19 in the generation profile of 2007 and a factor below 1 in all other years. This finding is important as it indicates that generation from vRES is not necessarily zero in times of scarcity. However, further analysis should put more emphasis on how frequent certain events and weather years occur in order to derive statistically robust findings on expected variations of market values due to meteorological events.

If also the impact of mid-term variations due to changing resource availability of RES generation is considered the results are more robust. Figure 5-19 and Figure 5-20 contain the market values that result from different generation patterns including changed full-load hours for the weather years 2006 to 2009. The first thing that can be noticed is that overall the variations in market values and corresponding value factors are not so much different as compared to the scenarios where only the profiles have been changed, however the differences over years are not so pronounced anymore. As stated above, with regard to future works it is important to study more the concrete statistics of such variations, as they directly impact necessary support payments on a yearly basis.

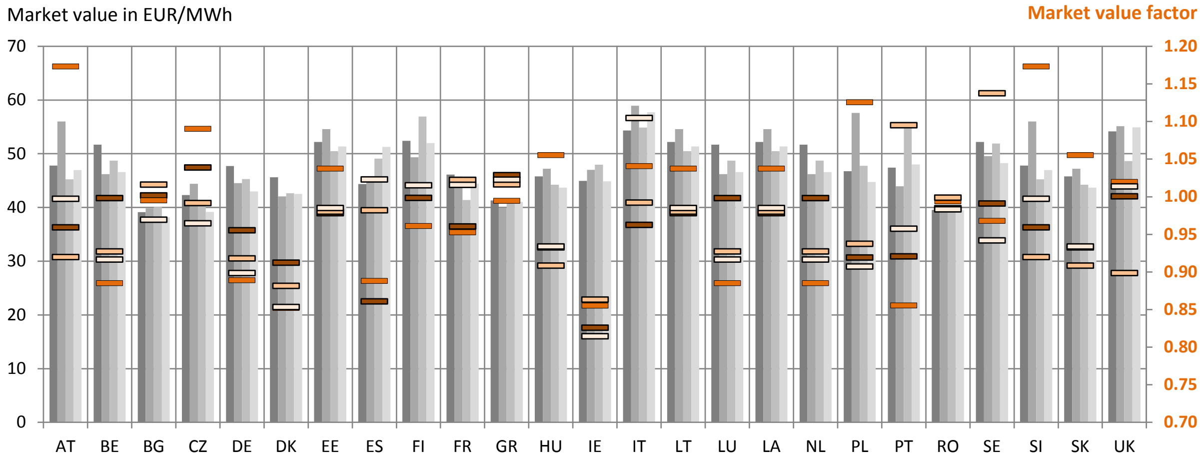

Figure 5-19: Changes in market values and value factors in 2020 due to different generation (profile and full-load hours) of wind onshore based on the weather years 2006 to 2009. (The shading in both colour schemes match each other)

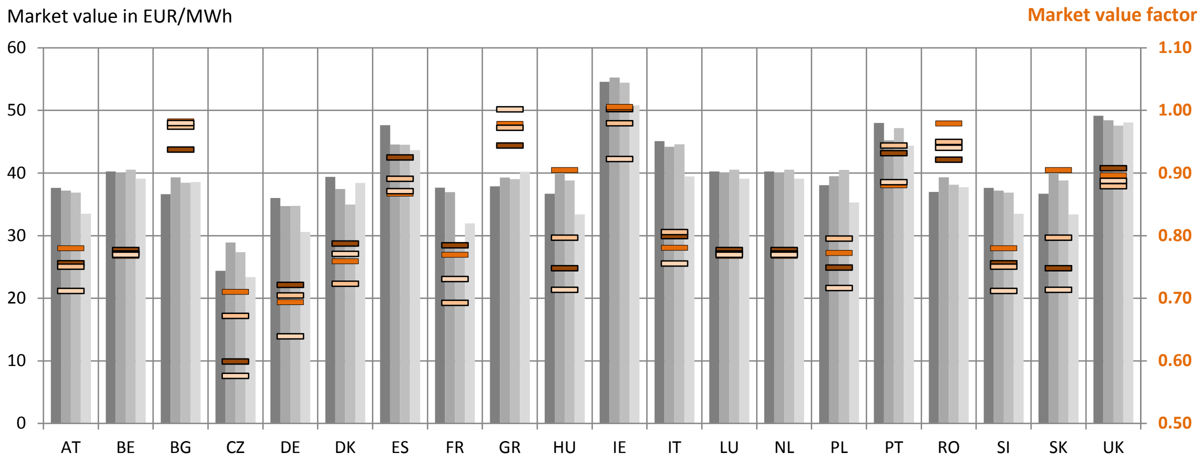

Figure 5-20: Changes in market values and value factors in 2020 due to different generation (profile and full-load hours) of solar PV based on the weather years 2006 to 2009. (The shading in both colour schemes match each other)

5.5.2 Absolute effects

Above described price effects turn into costs and benefits when multiplied with the corresponding amount of energy. These figures then flow into the main cost-benefit-analysis performed in subsequent work packages of this project. In order to gauge the significance of the costs/benefits in selected cases they are related to reference values.

5.5.2.1 Decreasing costs of residual demand

The (wholesale) price damping effect of RES-E ultimately results in lower costs of the residual demand, i.e. the remaining share of demand that is not covered by RES-E generation. It should be noted that these results were derived under the condition that all conventional generators are still able to fully recover their total costs. The savings mainly occur through substitution of generation technologies with high fixed costs (e.g. nuclear, coal) with technologies that have lower fixed costs (e.g. CCGT, gas turbines, …). The effect is moderated by the fuel switch from low cost fuels to high cost fuels. However, the size of this effect again depends on the actual carbon price.

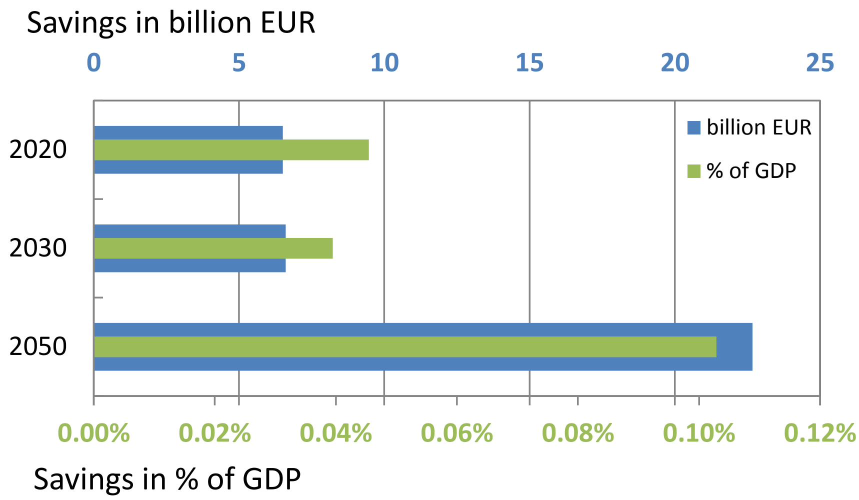

Figure 5-21: Aggregated merit-order effect of the EU in 2020, 2030 and 2050.

The absolute amount of cost savings that occurred in the P-Reference scenario as compared to the P-NoPolicy scenario are shown in Figure 5-21. The savings induced by additional RES deployment in 2020 and 2030 with 6.50 and 6.61 billion EUR are almost the in the same range. Both amount to about 0.04% of the EU´s expected GDP in these years. Note that here the impact of additional RES deployment on the GDP has not been considered. In 2050 the effect already reaches a considerable amount of 22.67 billion EUR savings, which accounts for 0.1% of EU´s expected GDP. Other interesting measures to put this figure into relation would be the total amount of investments in the EU, or the total support costs of RES whose generation accounts for this price drop. This assessment will be performed in the overall cost-benefit analysis presented in project deliverable D4.4 (cf. http://diacore.eu).

Figure 5-22 shows a region-specific split of the overall merit-order effect for the time periods 2020-2030 and 2030-2040. The numbers are presented in percentage of average expected GDP of this region and moreover related to the amount of additional RES-E that has been installed in this area. The first figure indicates the actual benefits that occurred within the corresponding region. The second figure gives insights in how much benefits occurred as related to the own contribution of the region in terms of additional investments. Whereas in the period from 2020 to 2030 the countries in the Balkan Region mainly profits from price decreases in the period up to 2040 a more scattered picture across Europe depending appears, where additional investments occur and the kind of generation technologies they substitute.

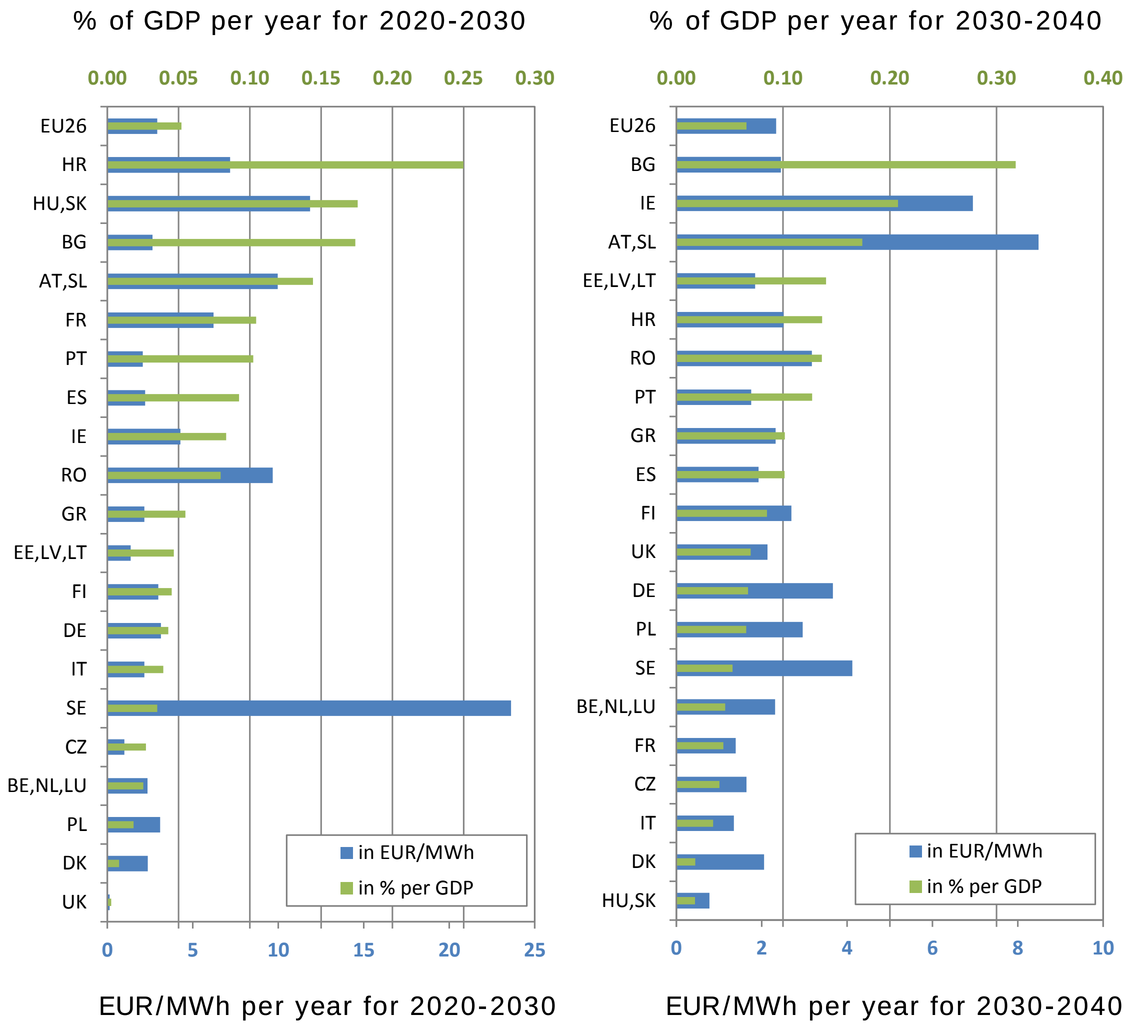

Figure 5-22: Average yearly merit-order effect of additional RES-E generation for the time period of 2020-2030 (left chart) and 2030-2040 (right chart).

When looking at the energy related figures it becomes obvious that the ranking among regions change. This reveals an important feature of interconnected energy markets. Benefits in one country are spilling over into other countries subject to organisational and technical framework conditions. The case of Sweden is very pronounced in Figure 5-22. Whereas Sweden only moderately benefits from price drops compared to its GDP it ranks first with regard to benefits related to additional RES-E investments, because Sweden is among those regions with the lowest additional investments in the period from 2020 to 2030. Therefore, it can be argued that Sweden profited comparably well compared to what they actually contributed to the additional investments. Figure 5-23 contains equal figures for the later period 2040 to 2050 and average numbers for the whole period from 2020 to 2050.

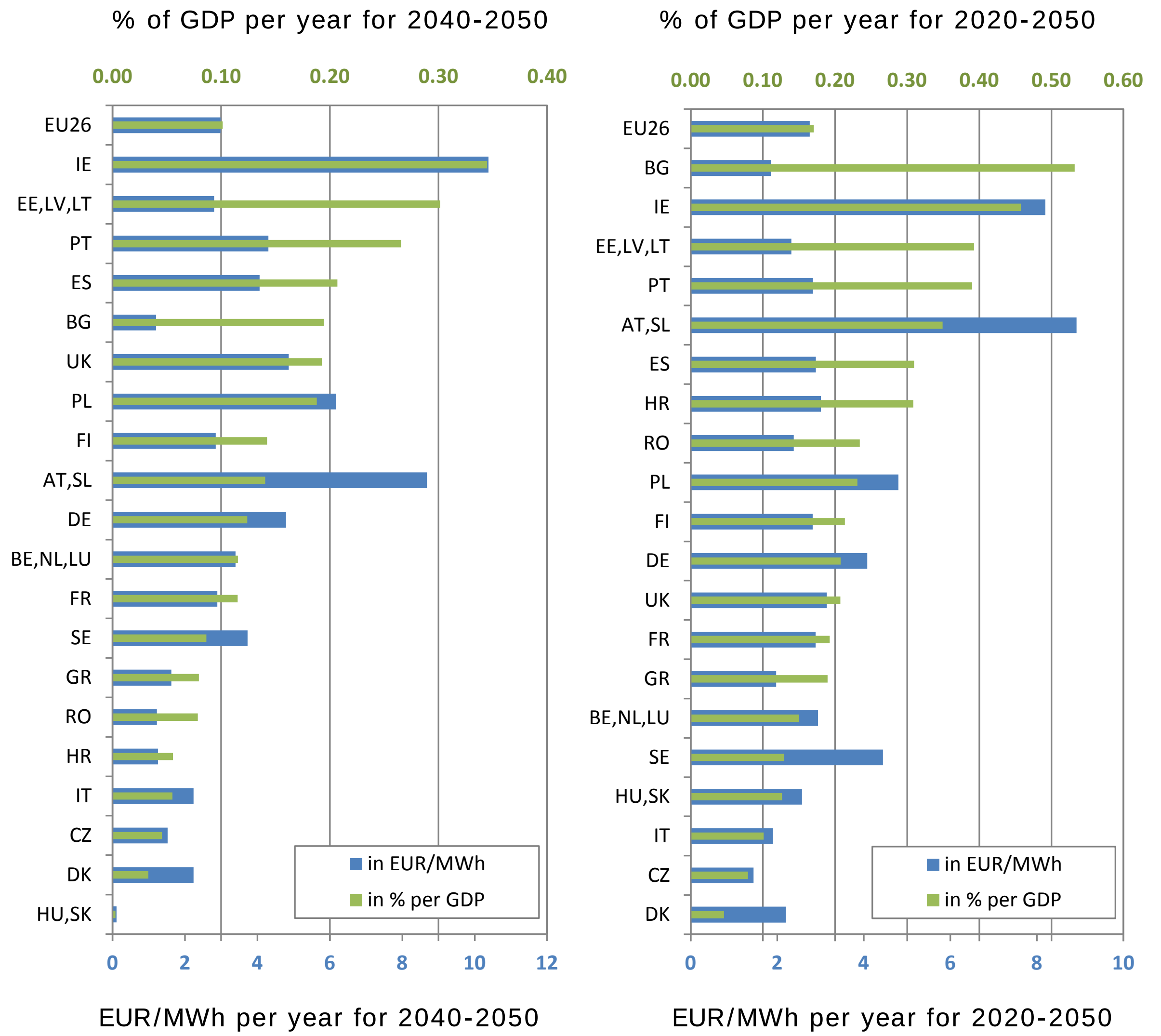

Figure 5-23: Average yearly merit-order effect of additional RES-E generation for the time period of 2040-2050 (left chart) and 2020-2050 (right chart).

Figure 5-24 shows how the merit-order effect has an impact on prices in the long-term electricity market equilibrium. With respect to the level of scarcity prices it has to be noted that their absolute level is determined by the frequency of scarcity situations. The more often scarcity situations occur the lower the price mark ups need to be, however investment cost gap that needs to be recovered stays the same in sum. In our dataset we had one scarcity event in each Member State per five year period.

On the left hand side it can be observed that the merit-order effect leads to reductions in all price levels up to 140 € per MWh, which as can be seen from the horizontal axis, account for the major share of price levels that occurred during the observation period between 2015 and 2050. The range of price level thereby reflects mostly the variable costs of conventional generation that has been displaced by the additional renewable generation. The right hand side of Figure 5-24shows the 50 highest price levels that occurred during the observation period. Here we can observe that the merit-order effect is much less pronounced and not always positive. The explanation is that the renewable generation is much less capable to displace conventional generating capacity [MW] that it is capable to displace conventional generation [MWh], so that the highest scarcity price levels cannot be avoided.

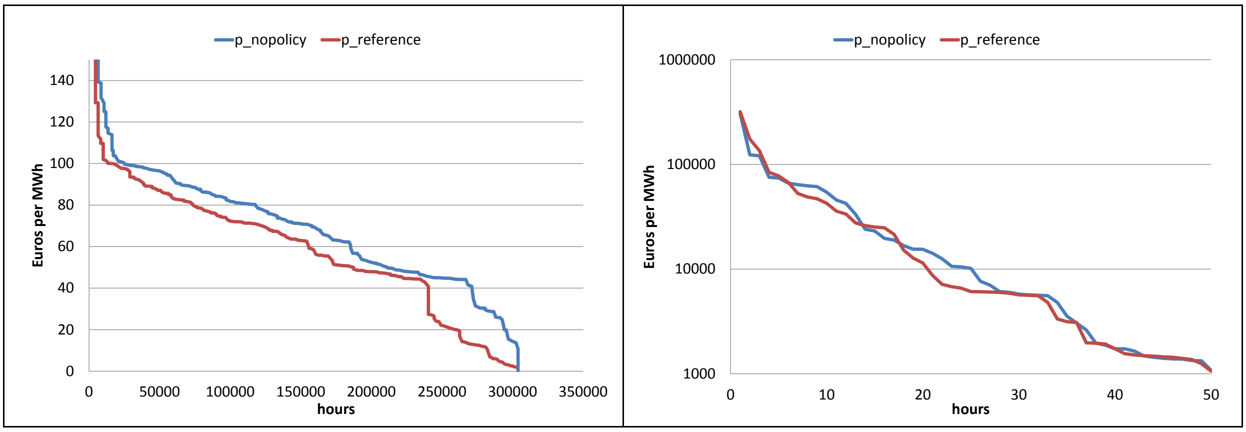

Figure 5-24: Merit-order effect of long-term price development based on long term model. Prices based on short-run costs on the left; scarcity prices (logarithmic scale) on the right.

5.5.2.2 *Impacts on support costs of variable renewables*

The level of required support premiums for renewable energy generators ultimately depends on the gap between their generation costs (incl. risk premiums) and potential revenues they can earn from markets. Thus, when revenues drop with increasing RES deployment as discussed in section 5.5.1.2 the support costs proportionally increase as well. On the other hand, with increased flexibility introduced into markets, revenues of RES rise as a result of higher prices in times of more RES infeed (demand increases in low-price periods, therefore prices tend to increase as well). Figure 5-25 shows the amount of additional costs or benefits caused by the changed framework conditions with regard to market revenues of variable RES-E.

The graphs show the difference in aggregated market revenues of wind onshore, wind offshore and solar PV of the sensitivity scenarios S-Demand, S-Grid and S-Market compared to the P-Reference scenario. In all scenarios the amount of RES generation can slightly differ between countries and technologies due to changed market values and electricity prices. However, the EU-wide amount of RES generation is similar in all scenarios, therefore aggregated figures for the EU and all variable technologies are shown. In this way the total impact of changed framework conditions represented by sensitivities can be isolated from other factors.

The S-Demand scenario assumes a certain amount of additional flexibility in the form of power2heat applications in Europe´s electricity generation mix. Obviously, these options are only applicable in countries with heat demand. The aggregated results show that the market value of vRES increases 0.28 billion EUR in 2030 and by 11.47 billion EUR in 2050 as a result of increased demand side participation through power2heat applications.

In the S-Grid sensitivity scenario it is assumed that the grid expansion in Europe is delayed as compared to the TYNDP. The scenario assumes a certain delay that has been derived from historic delays in grid investment that have been observed. The overall effect results into lower market values of 0.36 billion EUR in 2030 to 4.90 billion EUR in 2050.

Finally, the S-Market scenario assumes the implementation of capacity markets across the EU. This leads to electricity prices in day-ahead markets that do only reflect the variable generation costs. Thus, electricity prices fall as compared to the reference case, which also contains price peaks above marginal generation costs in times of scarcity. The question that is relevant with regard to market revenues of RES is which amount of RES generation has been available at times of scarcity and could thus profit from peak prices. If RES infeed was low at times of scarcity revenues would more or less remain the same in both cases and vice versa the higher the corresponding infeed in times of scarcity the higher is the difference in market revenues. In the case of wind onshore and wind offshore the model results have shown that both technologies have had certain availability at scarcity prices, whereas in the case of PV the results do not show a general trend among EU countries. The aggregated effect is that in both years the (energy-only) market revenues are lower by 3.29 and 6.85 billion EUR, respectively.

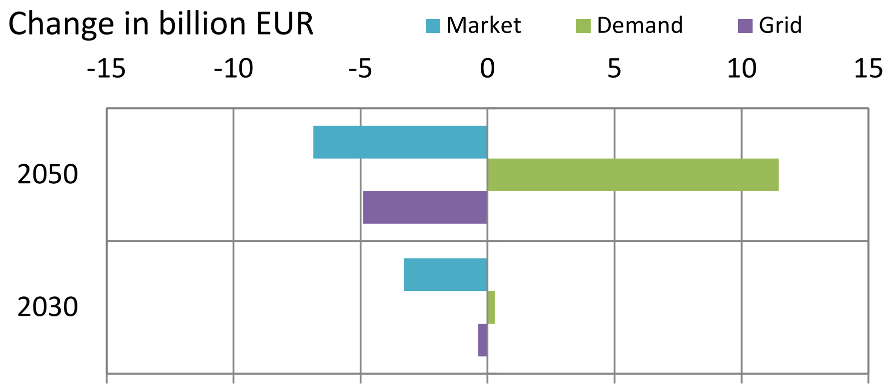

Figure 5-25: Difference in total market revenues of variable RES in the EU (wind onshore, wind offshore and solar PV) of sensitivity scenarios compared to the reference scenario.

6 Overall findings and Outlook

The aim of this report is to deliver numerical insights into two distinct benefits of renewable electricity generation in electricity wholesale markets. The first benefit concerns the price-damping effect of renewable infeed, which has been termed the *merit-order effect* in the literature (cf. Sensfuss et al. 2008). The second quantifies the market value of renewable generation itself. Both figures are closely related to each other. This chapter provides a brief summary of the main finding and conclusions of this report.

In chapter 3 a market-based framework for assessing the costs and benefits of RES-E in the electricity market has been presented. The framework established the merit-order effect and market values of RES-E as distinct benefit categories from which the benefit of RES-E in the (wholesale) electricity sector can be derived and be contrasted with support costs in order to arrive at the net benefit.
Historical benefits of RES-E have been quantified via applying an empirical model. The results show a clear and consistent trend; specifically it can be seen that feed-in of electricity from variable renewables (wind power and photovoltaics) have had a negative impact on (day-ahead) electricity prices. Regression results for all Member States analysed confirm this finding. This influences the market value of the renewables themselves: with increased shares, especially for wind power, lead to a substantially lower market value of electricity generated by said technology. The intensity of the drop however varies between member states, which shows that some electricity markets are more able to incorporate fluctuating renewables than others (due to flexibility, interconnection, storage and other forms of demand side management). Outcomes of the econometric analysis looking at the effect of variable renewables on spot prices show decreases of around 0.53 €/MWh for e.g. Germany or 0.8 €/MWh for Spain for one additional percent of wind infeed. Scaling this up to a yearly measure would have meant 180.7 Million € or 197.7 Million € of additional costs of consumption without additional RES generation. These findings are similar to those found in the literature.

As discussed widely in more recent studies, it is nevertheless important to consider other factors influencing electricity spot prices, taking account of the complexity and the multiplicity of variables interacting on the electricity market.

In chapter 5 of this report the evaluation of the potential future merit-order effect induced by RES-E as well as the corresponding market values of RES-E have been described for the time period until 2050. We have found that an additional amount of RES-E, ceteris paribus, decreases average electricity prices by 2 to 5 percent depending on the actual amount and type of additional RES-E and the corresponding in- and divestments in the conventional generation park. To put this into perspective, this translates into around 0.04% of Europe´s GDP in terms of cheaper electricity consumption evaluated in wholesale prices.

The resulting prices do not equally drop within the EU. Price drops are more significant in Member States where relatively expensive generation technologies can be substituted. Often this goes along with power flows across markets areas and Member States. Therefore, the transition towards renewables leads to spill-over effects in Europe’s electricity markets.

Furthermore, the ratio between potential market revenues of RE generators and baseload generators (the market value factor) considerably drops with increasing penetration, especially for variable RES (vRES). In the period until 2030 and 2050 the decreasing effect of market value factors becomes apparent. The average of market value factors over all EU countries drops for wind onshore, wind offshore and solar PV with increasing RES penetration by as much as 4 to 12 percentage points as compared to a baseline pathway. In particular, in certain countries drops can reach a dimension of 15 to 30 percentage points. These market value factor drops translate into a 1 to 2 €/MWh higher support costs for total renewable generation per year. In the modelled scenarios they are offset by a decline in average wholesale electricity prices in the range of around 3 €/MWh. However, these figures can considerably change over time, depending on the assumptions being taken and thus should be interpreted with appropriate care.

When it comes to the sensitivity of market revenues of variable renewables to framework conditions in electricity markets this report has shown that additional energy efficiency measures in combination with a more ambitious carbon pricing considerable impacts specific market revenues of RES. The impact depends on the technology in question but can reach up to 15 €/MWh. Further influencing factors are the future development of the high voltage transmission grid, whether additional demand side flexibility can be utilized and which market design will be chosen. The aggregated results show that the market value of vRES in the EU increases by 0.28 billion EUR in 2030 and by 11.47 billion EUR in 2050 as a result of increased demand side participation through power2heat applications. When international grid development is delayed the overall effect results into lower market values of 0.36 billion EUR in 2030 to 4.90 billion EUR in 2050. If throughout the EU capacity markets were implemented revenues of vRES within wholesale markets are lower by 3.29 and by 6.85 billion EUR in 2030 and 2050, respectively.

Also market revenues are expected to change in between years due to intra-yearly differences in resource availability. These impacts are attributable to variations in meteorological conditions and can cause up to 10 €/MWh variations in specific market revenues of variable renewable generation.

Finally, the long-term modelling with endogenous capacity stock has revealed that RES-E generation is much more capable to displace conventional electricity generation other than conventional capacity. The implication is that short-run marginal costs are lowered by the mechanism of the merit-order effect whereas price mark-ups to finance additional capacity can hardly be avoided, as fixed costs still have to be recovered. Price peaks induced by scarcity situations occur less often and at different times, but are relatively larger as compared to the reference case. It is crucial to which extent renewables contribute to meet demand in such situations, as this significantly impacts their market value.

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Annex

Annex Table 1: Data sources

Spot price - Data sources			
AT	Austria	EPEX & EXAA	http://www.epexspot.com/de/ http://www.exaa.at
BE	Belgium	Belpex, EMMA	http://www.belpex.be/index.php?id=79; http://neon-energie.de/emma/
CZ	Czech Republic	PXE	http://www.ote-cr.cz/statistics/yearly-market-report/page_report_62_162 https://www.pxe.cz/?language=english
DE	Germany	EPEX, EMMA	http://www.epexspot.com/de/, http://neon-energie.de/emma/
DK	Denmark	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/, EMMA
EE	Estonia		http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table
FI	Finland	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/
FR	France	EPEX	http://www.epexspot.com/de/, http://neon-energie.de/emma/, http://www.green-x.at/
IE	Ireland	?	
IT	Italy	GME, EMMA	http://www.mercatoelettrico.org/En/Statistiche/ME/DatiSintesi.aspx, http://neon-energie.de/emma/
LV	Latvia	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/
LT	Lithuania	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/
NL	Netherlands		http://www.apxendex.com/marketdata/powernl/public/data_charts/monthly_avg_price.gif, EMMA
NO	Norway	EMMA	http://neon-energie.de/emma/
PL	Poland	PolPX, EMMA,	http://tge.pl/en/155/monthly-market-reports, http://neon-energie.de/emma/,
ES	Spain	OMIE	http://www.omie.es/files/flash/ResultadosMercado.swf
SE	Sweden	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/

UK	United Kingdom	APX, EMMA	http://www.apxgroup.com/trading-clearing/apx-power-uk/, http://neon-energie.de/emma/

Data sources for explanatory variables			
EU28	European Union	Eurostat	http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_and_natural_gas_price_statistics
AT	Austria	OEMAG	http://www.oem-ag.at/de/home/, https://transparency.entsoe.eu/
BE	Belgium	ELIA	http://www.elia.be/en/grid-data/power-generation/wind-power, http://neon-energie.de/emma/, http://www.green-x.at/, https://transparency.entsoe.eu/
CZ	Czech Republic	CEPS	http://www.ceps.cz/ENG/Data/Vsechna-data/Pages/Vyroba.aspx, https://transparency.entsoe.eu/
DE	Germany		http://neon-energie.de/emma/, https://transparency.entsoe.eu/,
DK	Denmark	energinet	DK: http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx, https://transparency.entsoe.eu/
EE	Estonia	elering	EE: http://elering.ee/data-archive/; http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table, https://transparency.entsoe.eu/,
FI	Finland		https://transparency.entsoe.eu/,
FR	France	rte-france	http://clients.rte-france.com/lang/an/visiteurs/vie/previsions_eoliennes.jsp, https://transparency.entsoe.eu/, http://neon-energie.de/emma/, http://www.green-x.at/
IE	Ireland	eirgrid	http://www.eirgrid.com/operations/systemperformancedata/windgeneration/, https://transparency.entsoe.eu/
IT	Italy	GME	http://neon-energie.de/emma/, http://www.green-x.at/, http://www.mercatoelettrico.org/En/Statistiche/ME/DatiSintesi.aspx,
LV	Latvia	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table, https://transparency.entsoe.eu/
LT	Lithuania	Nordpool	http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table, https://transparency.entsoe.eu/
NL	Netherlands		https://transparency.entsoe.eu/, http://neon-energie.de/emma/, http://www.green-x.at/,
NO	Norway		https://transparency.entsoe.eu/

PL	Poland		https://transparency.entsoe.eu/, http://neon-energie.de/emma/, http://www.green-x.at/,
ES	Spain	REE	http://www.esios.ree.es/web-publica/, https://transparency.entsoe.eu/
SE	Sweden	SVK	http://svk.se/Drift-och-marknad/Statistik/Elstatistik-per-elomrade/
UK	United Kingdom	ELEXON	https://www.elexonportal.co.uk/article/view/216?cachebust=p7hybpanya, https://transparency.entsoe.eu/, http://neon-energie.de/emma/, http://www.green-x.at/,

Annex Table 2: Literature Review

Paper	Method	Variables	Years (Unit)	Country	Results
EMPIRICAL APPROACHES					
Ostergaard et al. (2006): Vindkraftensbetydning for elprisen i Danmark	n/a	Analyse data of on Danish electricity prices and wind generation. Distinguish between those hours with wind and those hours without it.	2004-2006	Denmark	They find that Danish electricity prices would have been higher without any wind electricity generation (1 €/MWh in 2004; 4 €/MWh in 2005; and 2.5 €/MWh in 2006).
Jonsson et al. (2010): On the market impact of wind energy forecasts	non-parametric regression model	how day-ahead electricity spot prices are affected by day-ahead wind power forecasts	2006-2007 (hourly)	Denmark	Strongest price-reducing effects during times of high wind production. price differences between low wind (55–50 €/MWh during the day, 30 €/MWh at night) and high wind (30 €/MWh during the day, 18 €/MWh at night) situations. approximate 40% electricity price variation (specific characteristics of Denmark: high penetration and small market!)
Pham et al (2014): Impacts of Renewable Electricity Generation on Spot Market Prices in Germany	GARCH framework- maximum likelihood technique.	Model separately wind and photovoltaic effect on electricity spot prices using Price drivers: Load; Gas price, exchanges with France, dummy variables.	2009-2012 (hourly)	Germany	Lower prices but consumers do not seem to benefit (distributional aspects have to be considered, i.e. merit order effect priced into consumer prices)

Hildmann et al. (2015): Empirical Analysis of the Merit-Order Effect and the Missing Money Problem in Power Markets With High RES Shares	analysis of the spot market and of marginal production costs of RES production	Cost components of variable RES units, spot market prices, RES generation volumes	2011-2013	Germany and Austria	market distortions that hinder proper market functioning, namely 1) the gap between the electricity volume actually traded at day-ahead spot markets versus the overall electricity consumption, and 2) the regulatory assumption that variable RES generation, i.e., wind and photovoltaic (PV), truly has zero marginal operation and grid integration costs. In this paper, we show that both effects over-amplify the well-known merit-order effect of RES feed-in, and indirectly also the missing-money problem beyond a level that is explainable by underlying physical realities.
Würzburg, Labandeira, Linares (2013): Renewable generation and electricity prices: Taking stock and new evidence for Germany and Austria	multivariate regression model	electricity price is the dependent variable, and the explanatory variables are the demand for electricity, the renewable electricity production from solar and wind, the gas price, and the exports and imports of electricity	2010-2012 (hourly daily basis averaged)	Germany and Austria	Ceteris paribus, day ahead electricity prices for Germany and Austria decrease by roughly 1 €/MWh for each additional expected GWh produced by renewable sources (solar and wind). Given that the average hourly renewable generation during the period of investigation was close to 7.6 GW, this gives an average price decrease, in absolute terms, of approximately 7.6 €/MWh.
Cludius, Hermann, Matthes CEEM (2013): The Merit Order Effect of Wind and Photovoltaic Electricity Generation in Germany 2008-2012	OLS in different specifications	Merit order effect of wind and photovoltaic: electricity price as dependent on a constant *c*, the feed-in of wind and photovoltaics and total load as an indicator for total demand.	2008-2012 (hourly)	Germany	each additional GWh of renewables fed into the grid, the price of electricity on the day ahead market is reduced by 1.10 to 1.30 €/MWh. The total merit order effect of wind and PV ranges from 5 €/MWh in 2010 to more than 11 €/MWh in 2012.
Neubarth et al. (2006): Beeinflussung der Spotmarktpreise durch	univariate regression model	effect of wind power production on day-ahead spot prices in Germany	2004-2005 (hourly)	Germany	The day-ahead electricity price falls by 1.89 €/MWh for each additional GW of wind power.

Windstromerzeugung					
Clò, Cataldi, Zoppoli (2014): The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices	Multivariate linear regression model	PUN as dependent variable Load, solar and wind generation as main explanatory variables, gas price traded in the Dutch Title Transfer Facility (TTF) trading point	2005-2013 (hourly, daily basis averaged)	Italy	Over the period 2005–2013 an increase of 1 GWh in the hourly average of daily production from solar and wind sources has, on average, reduced wholesale electricity prices by respectively 2.3€/MWh and 4.2€/MWh and has amplified their volatility.
O'Mahoney, Denny (2011): The Merit Order Effect of Wind Generation in the Irish Electricity Market	OLS regression model (times series multiple regression model)	**Shadow price** as marginal cost of the most expensive unit required to meet demand in the same period (as a dependent variable); dependent variables are net demand, wind infeed, **fuel prices**, i.e. coal, gas, oil and carbon price (lagged 24 h behind → influence on forecast); **marginal capacity** difference between the maximum rated number of megawatts a unit is able to supply and their actual availability in a given hour divided by demand; to see if a scarcity premium is significant	2009 (hourly)	Ireland	value of wind to the market dispatch has resulted in savings of €141 million to the market dispatch. We find that the total costs to the market would have been in the region of 12% higher over the course of the year had no wind output been available.
Nieuwenhout and Brand (2011): The Impact of Wind Power on Day-ahead Electricity Prices in the Netherlands	use wind and weather data to reconstruct day-ahead wind generation figures and divide the data to create groups that correspond to	Day ahead prices; four wind classes: a) forecasted wind generation below 200 MWh per hour, b) between 200-700 MWh per hour, c) between 700-1200 MWh per hour, and d) more than 1200 MWh per hour.	2006–2009 (hourly)	Netherlands	Average day-ahead prices at the Dutch electricity exchange were roughly 5% higher during the no-wind intervals with respect to the average of the entire sample for the analysed period.

	low or no-wind production intervals.				
Gelabert et al. (2011): An ex-post analysis of the effect of renewables and cogeneration on Spanish electricity prices	Multivariate regression model	Average effect of a marginal change in the special regime on electricity prices. Daily average is used to cancel out unwanted noise. Exclude hydro power because it can be stored, shifted and therefore has a positive opportunity cost.	2005-2009 (hourly, daily basis averaged)	Spain	A marginal increase of 1 GWh of electricity production using renewables and cogeneration is associated with a reduction of almost 2€ per MWh in electricity prices (around 4% of the average price for the analysed period).
Azofra, Jiménez, Martínez, Blanco, Saenz-Díez (2014): Wind power merit-order and feed-in-tariffs effect: A variability analysis of the Spanish electricity market	an artificial intelligence-based technique (M5P algorithm) is applied to empirical hourly data to determine the influence of wind power technology on the spot market for different levels of wind resource	Total generation; generation in hydraulic power plants, in nuclear power plants, in coal-fired thermal power plants, combined cycle thermal power plants Available capacity by means of nuclear power plants , combined cycle thermal power plants	2012 (hourly)	Spain	Wind power depressed the spot prices between 7.42 and 10.94 €/MW h for a wind power production of 90% and 110% of the real one, respectively.
Gil et al. (2012): Large-scale wind power integration and wholesale electricity trading benefits: estimation via an ex post approach.	conditional probability approach	how much the market penetration of wind generation influenced day ahead electricity prices	2007 to 2010	Spain	On average, the electricity price without wind production is 9.7 €/MWh or 18% higher than it is with wind production.

Nicholson et al. (2010): The Relationship between Wind Generation and Balancing-Energy Market Prices in ERCOT:2007–2009	ARMAX model	hourly zonal balancing-energy market price as the dependent variable - Effect of wind generation on electricity prices; explanatory variables that include wind generation, production from gas plants, temperature, and past values of the electricity price	2007–2009	Texas (US)	Range of decreasing effects of wind generation on balancing electricity prices of 0.67 to 16.4 US$/MWh per additional GW of wind power (depending on the year, time of the day, and the area in the Texas network).
Woo et al. (2011): The impact of wind generation on the electricity spot-market price level and variance: The Texas experience	Stationary AR-process	Price as dependent variable, nuclear generation, system load, price of gas, and a set of time dummies as additional explanatory variables	2007–2010	Texas (US)	While rising wind generation does Indeed tend to reduce the level of spot prices, it is also likely to enlarge the spot-price variance. a 1 GW increase in wind generation (during 15 min) decreased Texas balancing electricity prices between 13 and 44 US$/MWh
American Wind Energy Association (2015): Wind energy saves consumers money during the polar vortex	n/a	Comparison of price peaks during the polar vortex and prices that would have occurred without the supply of wind power (no econometric estimation technique)	6th and 7th of January 2014 (hourly)	PJM states (US)	Wind energy protected Mid-Atlantic and Great Lakes consumers from extreme price spikes during the polar vortex event in early January 2014, saving consumers over $1 billion on their electric bills.
MODELLING APPROACHES					
Deane et al (2015) quantify the merit order effect in 2030 and 2050 in European electricity wholesale markets by comparing electricity systems in a Reference and Mitigation Scenario for both years.	The objective function is to minimise total costs over the year across the full system. This includes operational costs, consisting of fuel costs and carbon costs;	A power plant portfolio is constructed for each Member State for each scenario (Reference and Mitigation) and each year (2030 and 2050). In all, approximately 2,220 individual thermal power plants are included in the model. Power plant capacities, efficiencies and fuel types are based on outputs from the PRIMES model.	2030 and 2050	Europe	The reduction in wholesale electricity price between scenarios is on average €1.6/MWh and €4.2/MWh for 2030 and 2050 respectively.

	start-up costs consisting of a fuel offtake at start-up of a unit and a fixed unit start-up cost.				
McConnell et al (2013): Retrospective modelling of the merit-order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market	calculate the likely reduction of wholesale prices through the merit order effect on the Australian National Electricity Market.		2009-2010	Australia	for 5 GW of capacity, comparable to the present per capita installation of photovoltaics in Germany, the reduction in wholesale prices would have been worth in excess of A$1.8 billion over 2009 and 2010, all other factors being equal
Miera et al (2008): Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain	Empirical Analysis: analyse the market in 3 consecutive days with similar levels of electricity demand in order to isolate the impact of wind generation from the other factors affecting the market price. Alternative		2005-2007	Spain	reduction in prices is greater than the increase in the costs for the consumers arising from the RES-E support scheme (the feed-in tariffs), which are charged to the final consumer

	approach: quantify the direct effect to simulate the merit order (dispatch) and the electricity price in the absence of wind generation.				
Von Roon and Huber (2010): Modelling Spot Market Pricing with the Residual Load	Linear estimation model	*load:* ENTSO-E, *wind power:* Net Operator values, *CHP:* FfE Modelling Tool, *PV:* Vattenfall Transmission 2008, *other RES:* Not considered	2007-2009	Germany	The authors have identified the residual load (calculated as the load profile minus the feed-in from renewable energy sources (RES)) as significant factor on spot market pricing.
Elberg, Hagespiel (2014): Spatial dependencies of wind power and interrelations with spot price dynamics	Stochastic simulation model	using copulas, incorporated into a supply and demand based model for the electricity spot price.		Germany	the specific location of a turbine – i.e., its spatial dependence with respect to the aggregated wind power in the system – is of high relevance for its value.
Hildmann (2013): Revisiting the Merit-Order Effect of Renewable Energy Sources			2011-2012 (hourly resolution)	Germany	Given base load power plants that have sufficient operational flexibility in terms of fast ramping, start/stop times and minimum operation point requirements, energy only markets seem to work even for high RES penetration scenarios.
Hirth (2012): The market value of variable renewables: The effect of solar wind power variability on their relative price	simple regression model is applied to estimate the impact of increasing penetration	market share of wind power, a dummy for thermal system that interacts with the share (such that the impact of market share in thermal systems is β1 and in thermal system β1+β2), and time dummies as control variables		Germany	value of wind power to fall from 110% of the average power price to 50–80% as wind penetration increases from zero to 30% of total electricity consumption. For solar power, similarly low value levels are reached already at 15% penetration

	rates on value factors.	to capture supply and demand shocks			
Sensfuß, Ragwitz, Genoese (2008): The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany	results generated by an agent-based simulation platform (Power ACE); model provides detailed representation of the German electricity sector and simulates reserve markets and the spot market		2001; 2004-2006 (hourly)	Germany	the impact of renewable electricity generation on spot market prices. The results generated by an agent-based simulation platform financial volume of price reduction is considerable. In the short run, this gives rise to a distributional effect which creates savings for the demand side by reducing generator profits

ANNEX A

Explaining the baseline estimation on the basis of the German Electricity Market

Using the example of Germany in the year 2008, in the following it is briefly shown how the determinants chosen for the baseline regression model have been introduced into the model and how they changed the regression fit and the adjusted R^2. One can observe, that while the explanatory power of the model increases with all additional control or explanatory variables, introducing PV in the fifth model specification does not further increase the R^2. This is due to the fact that PV capacity was comparably low in Germany in 2008 – an effect that also becomes visible for other Member States during that period. In more recent years, the economic significance of solar power increases.

In the model specification (1) it can be seen, that weekly and seasonal variation explain around 15 % of price changes. The load – unsurprisingly – determines the main share of the electricity price and has a positive coefficient: Increased demand induces electricity prices to rise, according to basic market reasoning: If demand increases and supply remains unchanged, a shortage occurs, leading to a higher equilibrium price.

Annex Table 2: Different Model Specifications to estimate the effect of RES feed-in on day-ahead prices in Germany

	Model 1	Model 2	Model 3	Model 4	Model 5
Load		**0.0024084**	**0.0019253**	**0.00211**	**0.0020983**
		(0.000018818)	(0.00002208)	(0.000019873)	(0.000020337)
Wind infeed				**-0.0020057**	**-0.0020042**
				(0.000040617)	(0.000040607)
PV infeed					**0.00064324**
					-0.00024065
24 h lagged spot price			**0.27071**	**0.22424**	**0.22128**
			(0.0073928)	(0.0066027)	(0.0066929)
Monthly dummies	✓	✓	✓	✓	✓
Weekly dummies	✓	✓	✓	✓	✓
Year	2008	2008	2008	2008	2008
Observations	8760	8760	8736	8736	8736
Adjusted R2	0.149	0.7	0.741	0.798	0.798

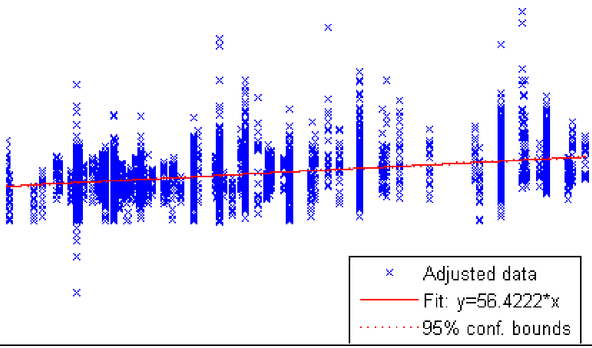
OLS Estimation of hourly changes in electricity prices (Germany)

As electricity spot prices are nonstationary, the lagged value (24 h behind) was further introduced as a control variable. The lagged price is also highly significant and an increase of one € in the lagged price seems to induce the day-ahead price of the same hour in the following day to be on average 0.27 € higher.

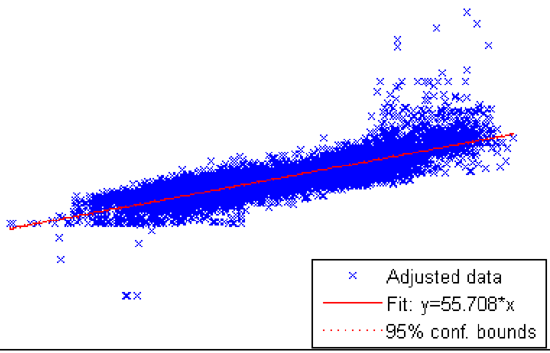
The fit of the model further improves when introducing wind infeed as a determinant of electricity prices. PV infeed, at least in the year 2008 for Germany, does not improve the fit further but it does yield a significant coefficient.

Annex Table 3: Model fits for the different Regression Specifications (Germany, 2008)

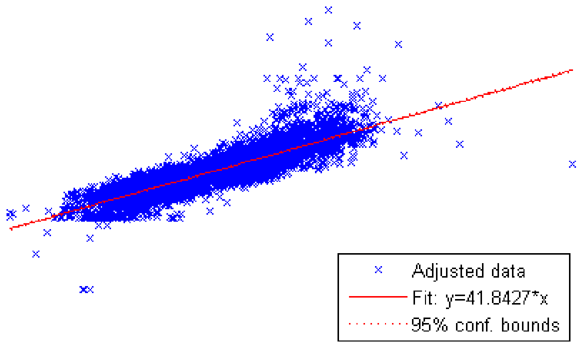
Model1



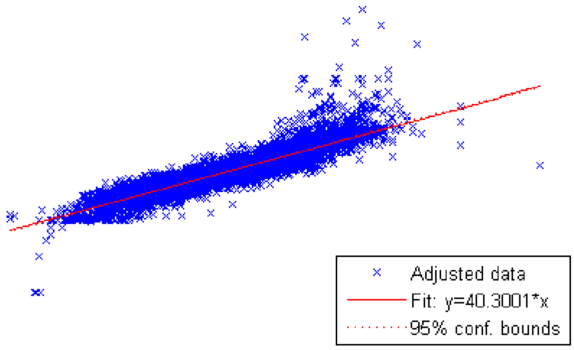
Model 2



Model 3



Model 4



Model 5