Dialogue on a RES policy framework for 2030

towards2030

D3.2.1

Appropriate policy portfolios for (nearly) mature RES-E technologies

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About the project

The aim of **towards2030-*dialogue*** is to facilitate and guide the RES policy dialogue for the period towards 2030. This strategic initiative aims for an intense stakeholder dialogue that establishes a European vision of a joint future RES policy framework.

The dialogue process will be coupled with in-depth and continuous analysis of relevant topics that include RES in all energy sectors but with more detailed analyses for renewable electricity. The work will be based on results from the IEE project beyond 2020 (www.res-policy-beyond2020.eu), where policy pathways with different degrees of harmonisation have been analysed for the post 2020 period. **towards2030-*dialogue*** will directly build on these outcomes: complement, adapt and extend the assessment to the evolving policy process in Europe. The added value of **towards2030-*dialogue*** includes the analysis of alternative policy pathways for 2030, such as the (partial) opening of national support schemes, the clustering of regional support schemes as well as options to coordinate and align national schemes. Additionally, this project offers also an impact assessment of different target setting options for 2030, discussing advanced concepts for related effort sharing.

Who we are?

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This report

Until now, in particular PV and wind have experienced substantial cost reductions that brought them close to levelised cost of electricity generation from conventional generation technologies. Now, it is necessary to offer investors attractive framework conditions for these mature RES-E technologies while ensuring minimal costs for society, in order to attain the targets for RES-E deployment that were formulated by the EU.

This report aims to identify challenges faced by investors of mature RES-E technologies, and to suggest policy options to tackle these challenges. The challenges addressed in this report are related to factors which affect RES-E deployment in a 2030 timeframe in the EU. The analysis will focus on policy design options that have been proposed in the recent policy discussion. The method will be based on qualitative comparisons between different alternatives for each challenge. Thereby, we substantiate the analysis of the challenges and possible solutions with selected country case studies.

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1 Introduction

The European Union has decided to transform the European energy system for reasons of sustainability, cost-competitiveness and security of supply. The large scale deployment of renewable energy sources for electricity generation (RES-E) represents a major pillar of the strategy to decarbonise the electricity sector. Until now, in particular PV and wind have experienced substantial cost reductions that brought them close to levelised cost of electricity generation (LCOE) from conventional generation technologies. Now, it is necessary to offer investors attractive framework conditions for these mature RES-E technologies while ensuring minimal costs for society, in order to attain the targets for RES-E deployment that were formulated by the EU. This can e.g. be realised by keeping the risk premium for investments low. This report aims on the one hand to identify challenges faced by RES-E investors triggering an increase of the risk premium and, on the other hand, to suggest policy options to tackle these challenges.

More specifically, the RES-E policy challenges addressed in this report comply with two conditions: First, they are directly and indirectly related to factors which affect RES-E deployment in a 2030 timeframe in the EU through increased market exposure and thus higher risk premia for potential investors. Second, these challenges shall be addressable by RES-E policy.[1] The analysis will focus on policy design options that have been proposed in the recent policy discussion. The method will be based on qualitative comparisons between different alternatives for each challenge. Thereby, we substantiate the analysis of the challenges and possible solutions with selected country case studies.

The report starts with some basic information on the identification and description of mature technologies and shortly summarises the key challenges to policy support for mature RES-E technologies. The structure of the remainder is two-part: The first part (Chapter 3) contains an overview of challenges for RES-E investors that occur across many or a majority of Member States (MS) in the EU. The second part (Chapter 4) shows then examples of the general challenges, but that are specific to individual EU MS. The report closes with a short summary and policy recommendations.

[1] Those challenges which are related to the general functioning of electricity markets and, in particular, issues related to market integration and grid integration of RES-E are not addressed in this report. Challenges related to external developments will not be addressed in this report either.

2 Basic information

This chapter defines which RES-E technologies are regarded as mature. It further provides an overview of challenges arising for RES-E technologies.

2.1 Identification and description of mature technologies

Following the economics of innovation, a technology's level of maturity depends on the position in the S-curve and the stage of the innovation process (see Figure 1). In the course of technology evolution, immature technologies are located at the stage of development of robust prototypes and demonstration projects (RD&D). The major challenge for these technologies consists of the incremental decrease of levelised costs of electricity generation (LCOE). Mature technologies instead have reached a certain level of commercialisation and cost-efficiency. The final stage of the technology evolution process consists of large scale deployment despite decreasing technology support.

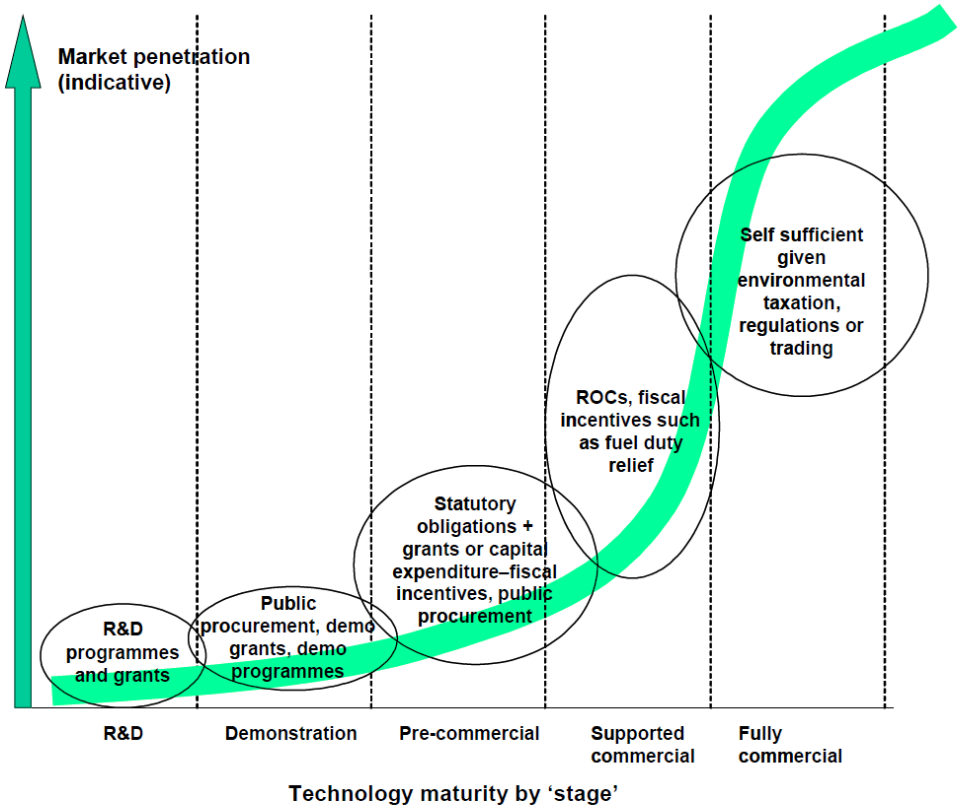


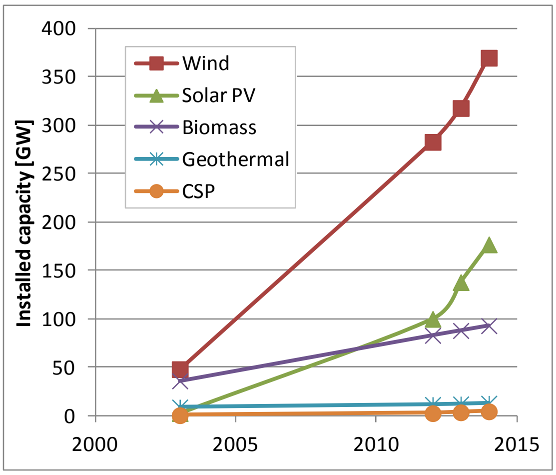
Figure 1: S curve of technological development and policy instruments. Source: (Foxon, 2005)

Unlike other commercial products, it is somewhat difficult to precisely locate the different RES-E technologies in the S-curve as they usually receive support from the government or public agencies (Usha Rao, 2010). However, there are specific indicators that can be used to determine and compare the stage of technological innovation of individual RES-E technologies. They include primarily the LCOE and the overall globally installed capacity.

Table 1 provides an overview of the globally installed RES-E capacities. It is evident that hydropower presents by far the most significant capacity. Wind power, solar PV and biomass represent already substantial capacities and can thus also be considered as mature technologies. However, as outlined in the chart integrated in Table 1, wind and solar PV currently experience exponential growth (at the global level), whereas biomass is characterised by a rather linear capacity increase (on average). In contrast, geothermal and concentrated solar power (CSP) only feature small numbers of installed capacities. These technologies could thus be assigned to the phase of pre-commercial or supported commercial maturity.

Table 1: Globally installed capacities of RES-E technologies. Source (REN21, 2015)

[GW]	2003	2012	2013	2014
Hydro	715	960	1018	1055
Wind	48	283	318	370
Solar PV	2.6	100	138	177
Biomass	36	83	88	93
Geothermal	8.9	11.5	12.1	12.8
CSP	0.4	2.5	3.4	4.4



The evolution of LCOE of different RES-E technologies between 2010 and 2014 is outlined in Figure 2. It is pertinent to note that LCOE for hydro-based electricity generation are in the range of conventional power generators, similar to biomass-based power plants. Solar PV has experienced significant growth in installed capacity and a substantial drop in costs that makes PV competitive with conventional power generators. A similar evolution can be observed for wind on-shore, attaining even lower levels of LCOE. Comparatively higher levels of LCOE and a substantially lower number of large-scale installations are characteristic for geothermal and wind-offshore, indicating a lower degree of maturity. Electricity generation from CSP features a reduction in LCOE but is still far from being competitive.

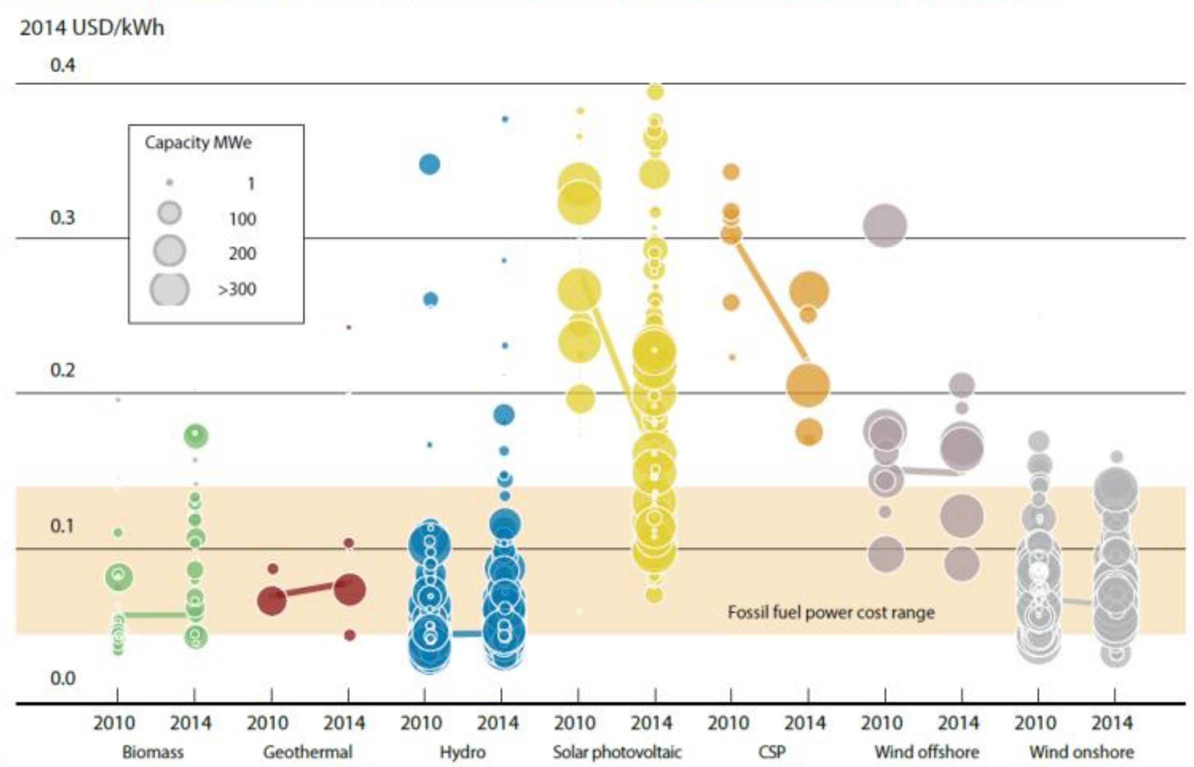


Figure 2: The levelised cost of electricity from utility-scale renewable technologies, 2010 and 2014. Source: (IRENA, 2014)

Based on this assessment we identify CSP, geothermal and wind-offshore as immature technologies. Solar PV and wind onshore can be considered as mature technologies at the phase of supported commercial use. Hydropower generation is regarded to be fully commercial. In addition, on the European level, hydro is not expected to experience substantial further growth in the future. Biomass technologies are partly fully commercial, but there are still non-mature technologies such as gasification plants. Since the range of biomass technologies covered is very broad, we do not consider biomass as one already mature RES-E technology. Instead, we focus on solar PV and wind onshore.

2.2 Short summary of key challenges

Work carried out in this project has identified key challenges for European renewable electricity policy in a 2030 perspective, based mostly on a literature review (del Río and Peñasco, 2014). The starting assumption is that the perspectives of policy makers are reflected in policy documents, both European and from MS. Publicly available EU documents and information sources at MS level have been consulted. In addition to those official documents, country case studies in energy and energy policy journals, relevant information in the "grey literature" and reports from other EU-funded projects have been taken into account (see del Río and Peñasco, 2014, for further details on the methodology).

The resulting list of documents and articles allowed us to identify relevant challenges, which have been classified in different categories: technology-related, macroeconomic-related, related to current policy discussions, administrative barriers and social acceptance. However, we have not tried to rank the relevance of those challenges. The perspective adopted is mostly that of renewable energy policy-making at MS level.

2.2.1 Technology-related policy challenges

Technological development determines whether renewable electricity sources are available on the market (Boie et al., 2014). Renewable electricity deployment critically depends on technology development and cost reductions (European Commission, 2013). A set of challenges is related to the evolution of the costs and maturity of the technologies. In this respect, the most important technologies to take into account are renewable energy technologies themselves.

Adapting support level to trends in technology costs

Adapting support levels to the evolution of technology costs in order to avoid overcompensation (or too low support) represents a challenge for policy makers. Likewise, the costs of renewable electricity deployment may also be affected by changes in material prices. For example, variations in the price of silicon and steel were important in explaining those changes in the past in the case of solar PV and wind (Panzer, 2012). There are also concerns that shortages of rare earth metals (such as indium, tellurium and silver for the deployment of PV technologies) and carbon fibre (for the offshore wind industry) are likely to drive up the prices and hence will escalate installation costs in the short to medium term (Zyadin et al., 2014). All these trends would certainly affect deployment of renewable electricity.

Appropriate combination of R&D support and deployment support for less mature renewable electricity technologies

Policy-makers have to adapt the type of renewable electricity policy to the specifics of the technology in question in order to induce cost reductions and innovation in renewable energy technologies. Some of these will require more emphasis being put on R&D investments, whereas for others mass deployment will still make more sense. The balance between R&D support and deployment support for less mature technologies represents a critical challenge, both at the EU and MS levels.

Adapting to the uncertain evolution of factors affecting the competitiveness of renewable energy technologies: resource potentials, fossil fuel prices and costs of competing technologies

Since EU renewable energy targets are set as a percentage of final energy consumption, they are affected by variables either influencing renewable electricity generation or electricity demand. Renewable electricity generation would be affected by resource endowment. A lower than expected quality of renewable energy resources (wind speeds, levels of solar radiation, rainfall levels…) would entail a lower than expected electricity production, ceteris paribus. It is a challenge to estimate with absolute precision the amount of those resources a long time ahead, although this is probably not a major factor, i.e. its relative importance is lower compared to other variables. An important variable, although also mostly beyond renewable electricity policy, are fossil fuel and carbon prices. Their influence on renewable electricity deployment can be substantial as they determine the relative profitability of renewables compared to those technologies fired by fossil fuels. While it is beyond the boundaries and scope of renewable electricity policy, those prices have to be taken into account when setting policies for renewable electricity. It is certainly a challenge to predict the trends in those prices, so that support costs for renewables are neither too low nor too high but simply provide a reasonable comparative cost advantage compared to fossil fuels. The challenge is compounded by the fact that different types of renewable electricity and fossil fuel sources are substitutable to different degrees regarding peak and base loads. A somehow related topic is the trend in the costs of competing non-renewable technologies. While, again, clearly beyond the realm of renewable electricity policy, an accurate calculation and prediction of the evolution of these costs should be made in order to appropriately set support levels for renewable electricity, a challenge on its own. A particularly relevant factor for renewable electricity deployment is the price of gas.

2.2.2 Macroeconomic-related policy challenges

Providing support under strict fiscal conditions

The austerity programs adopted to cope with the public deficits have involved a reduction of budget-financed renewable electricity support, although in most countries renewable electricity is predominantly supported through a surcharge on electricity bills. The degree of the uncertain economic recovery in the short and medium terms will influence renewable electricity policy and, thus, renewable electricity deployment. A main challenge for renewable electricity policy makers is to provide continuity of support but consider limited budget at the same time. This will certainly increase pressure for policymakers to adopt cost-effective policies.

Difficulties in access to finance

On the other hand, the financial crisis has led to credit restrictions which have affected all types of productive investments and, particularly, renewable electricity investments. The cost of capital has risen in some MS (European Commission, 2013, and Noothout et al., 2016). This has involved a difficulty to access loans in order to finance those investments and/or substantially increase total capital costs[2]. In some countries, and particularly in the South of Europe (such as Portugal, Spain), capital is relatively more expensive. A main challenge for renewable electricity policy is to mitigate these restrictions and facilitate access to affordable finance for renewable electricity investors and, particularly, for the smaller ones.

2.2.3 Administrative policy challenges

Improving and reducing the duration of the administrative procedures

Administrative barriers crucially affect the uptake of renewable electricity. Their relevance has been highlighted by several EU-funded projects and by the European Commission itself. This issue is further addressed below (see 3.2).

2.2.4 Social-acceptance related policy challenges

Mitigating the not-in-my-backyard (NIMBY) of renewable electricity projects

Public opinion is of particular importance for the deployment of renewable electricity (Boie et al., 2014). The social acceptance of renewable electricity in a 2030 perspective has two sides. On the one hand, it may refer to the not-in-my-backyard (NIMBY) phenomena for renewable electricity deployment. Renewable energy projects bring, both, benefits for the local population and costs. The former may refer to an increase in employment levels and rural/regional development opportunities. The latter is usually associated to negative environmental impacts, i.e. visual intrusion, soil occupancy etc. This issue would become more problematic with an increasing penetration of renewable electricity, which would be the case in 2030 if there was a concentration of renewable electricity deployment in certain places and for certain technologies. A key challenge for policy makers lies in developing effective public participation strategies, and in gaining a better understanding of local attitudes and how participatory approaches in renewable electricity planning can facilitate further deployment of renewable electricity.

[2] According to Bloomberg/NEF, investment in renewables reached a peak in 2011 of 123$Mlrd and decreased thereafter to 53$Mlrd in 2013.

Addressing social rejection to high or escalating support costs

On the other hand, social acceptance may be related to the costs of public support. If these are too high or experience a substantial increase in a given year, this would lead to a social backlash against the renewable electricity deployment support scheme. This suggests that a major challenge for policy-makers is to keep the costs of renewable electricity policy within reasonable levels. Social acceptance may not only be related to the total amount of policy costs, but on their distribution among different actors (i.e. equity). If those costs fall disproportionately on a given group of the population, social rejection is more likely, especially if this group is well-organised and has considerable negotiation power. Certainly, a challenge for governments is to appropriately inform the people about the costs and benefits associated to the public promotion of renewable electricity deployment.

2.2.5 Challenges for policy design

Institutional adaptation to the implementation of market-based instruments

The Guidelines on State aid for environmental protection and energy 2014-2020 (European Commission, 2014) state that renewable support schemes should normally be market-based. Market-based instruments are expected to increase cost-effectiveness and mitigate the distortions on competition. Competitive bidding (i.e. auctions) will have to be implemented in order to provide support to most of the new installations from 2017 onwards[3]. Arguably, this move to market-based instruments in general and auctions in particular will represent a challenge for policy makers, i.e. the institutional adaptation to a new instrument.

How to design auctions to lead to effective and efficient deployment of renewable electricity

In addition, the choice of design elements for the new market-based instruments in general and auctions in particular, in order to ensure an effective and efficient deployment of renewable electricity represents a main challenge. This last point is highly relevant since auctions for renewable electricity can be designed in many different ways (del Río and Linares, 2014).

Bindingness of targets

The existence of a binding EU target without binding national targets in a context in which the responsibility for renewable electricity policy instruments remains solely at the MS level raises the issue of how those MS policies can be expected to contribute to the EU target when there is no responsibility for a national amount of renewable electricity deployment. Lack of national targets may increase uncertainty (at least initially) in relation to proportions of renewable electricity on the system (CEER, 2013). This would affect the whole value chain for renewable energy technologies, including technology providers and project developers. Obviously, the alternatives (i.e. MS targets and an EU-wide target) also bring challenges, mostly in terms of cost-effective deployment across the EU, if the renewable electricity targets are set only partially considering renewable

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[3]According to the Guidelines (126 and 127), aid for at least 5 % of the planned new electricity capacity from renewable energy sources should be granted in a competitive bidding in the transitional phase 2015-2016. From 1 January 2017, aid should be granted in a competitive bidding process unless Member States demonstrate that only one or a very limited number of projects or sites could be eligible or that higher support levels or low project realisation rates would result from the competitive bidding process. The bidding process can be limited to specific technologies where a process open to all generators would lead to a suboptimal result which cannot be addressed in the process design in view of, in particular: the longer-term potential of a given new and innovative technology; the need to achieve diversification; network constraints and grid stability; system (integration) costs or the need to avoid distortions on the raw material markets from biomass support. Aid may be granted without a competitive bidding process to installations with an installed electricity capacity of less than 1 MW (6 MW for wind installations), or demonstration projects.

energy resource potentials in MS (i.e. when they are mostly set according to the economic capacity of countries).

The impact of market values on the competitiveness of renewable energy technologies

Furthermore, it is usually argued that past and future reductions in the costs of solar PV and wind will make these technologies cost-competitive with respect to their competing alternatives in the medium or long-term (Piria et al., 2013). For some, this means that support schemes for wind and solar should be phased out. However, there is still a challenge for policy makers to encourage renewable electricity investments with the expected move to market-based instruments, since part of the revenues are received through the wholesale market and prices are reduced when a greater penetration of renewable electricity takes place (so-called "merit order effect", see Sensfuß et al., 2008). Therefore, even where the full costs of (variable) renewables are lower than average market prices, policy intervention may be needed to ensure that sufficient investment is attracted to renewable electricity projects (Piria et al., 2013).

Balancing stability and flexibility in renewable electricity support

Finally, a fundamental challenge for policy-makers is to balance the trade-off between improved stability for investors and flexibility of the support scheme to adapt to changing circumstances in order to avoid overcompensation to renewable electricity generators.

The above discussion has identified the main challenges which are common to most technologies, i.e. to renewable electricity in general. However, for reasons of simplicity it has not focused on the technology-specific challenges. These might be relevant. For example, the future of biomass is subject to uncertainties such as lack of biomass markets, transportation infrastructure and supply chains. In addition, requirements in terms of efficiency improvements and application of new combustion technologies will limit a strong deployment of this technology (Boie et al., 2014). In addition, challenges are likely to differ per region within the EU. For example, as mentioned above, some are likely to have more credit restrictions and budget constrains than others. Feedback from stakeholders on those technology-specific and regional-specific barriers would be useful.

3 Similar challenges across all EU member states

From an investor's perspective, mature RES-E technologies face a number of challenges that potentially hinder the further deployment in a scenario of decreasing public financial support. Some of these challenges occur similarly across all EU member states. They include:

- high risk premia due to different factors increasing investment **uncertainty**,
- **shrinking market values** of RES-E and
- **non-economic barriers**.

One key problem regarding the challenges identified is that reducing the risk premia typically counteracts the increased market compatibility of RES-E support required for increasingly competitive RES-E technologies. Each type of challenge and potential policies to remove or at least attenuate these challenges are addressed in more detail in the following sections. Each section includes a short description of the challenge, describes the respective policy options (instruments, design elements, combinations of instruments) to tackle the challenge and outlines their strengths and weaknesses.

3.1 Investment uncertainty and rising risk premia

To ensure profitability of a utility scale RES-E project, the key challenge for an investor is to reduce the cost of capital (also referred to as weighted average cost of capital, WACC). The cost of capital is substantially influenced by the risk premium that represents costs related to the uncertainty in the occurrence of future revenues and costs. The level of uncertainty and thus the related risk premia are highly heterogeneous across the EU as they depend on country specific framework conditions. Consequently, also the urgency of introducing de-risking policies varies across EU member states. From the DIA-CORE project we know that such policies are implemented in some member states but there are substantial difficulties in many other (EPU-NTUA et al., 2015). Thus, selected revenue risk challenges and policy designs are outlined in the following.

3.1.1 Market-based curtailment

3.1.1.1 Description of the challenge

Currently, the EU renewable energy Directive (European Commission, 2009) requires MS to ensure priority dispatch for RES-E in so far a secure operation of the power system is ensured. With increasing RES-E in the power system, special situations characterised by a highly inflexible must-run electricity generation in combination with low demand have increasingly occurred in European electricity markets. These situations can be signalled by negative prices, if market design does not prohibit their occurrence. We briefly assess the frequency of negative prices at the EEX/EPEX day-ahead as an indicator for situations with high electricity supply and low demand that may require curtailing RES-E. In recent years, **negative prices** were observed during a limited number of hours at the different European day-ahead markets. Figure 3 shows the number of hours with negative prices or effective price floor (in case no negative prices are allowed) for different countries of the EU. In such situations, the RES-E operator or marketer has no incentive to sell his electricity on the market if (1) the electricity is marketed directly under a market premium scheme and if (2) if the market price drops below the negative value of the market premium. This behaviour of restrained bidding is also referred to as "market-based curtailment"[4].

Negative prices and market-based curtailment affect likewise conventional and renewable power generators. However, it should be noted that the impact on the profitability of renewable power plants is more severe given the differences in their cost structures. As especially wind and solar PV feature substantial capital costs but no fuel costs, the capital costs can only be covered by maximising electricity generation, which is already limited by the availability of the respective natural resource. Curtailing generation would further cut the revenue potential beyond the limits of the natural potential. Conventional generators instead are characterised by higher variable costs and avoiding these costs can reduce the financial impact of curtailment (Bird et al., 2014).

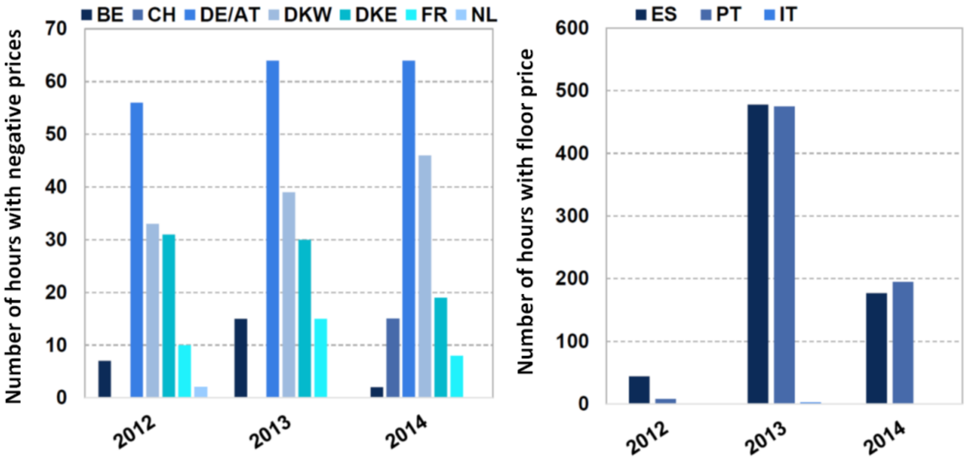

Figure 3: Number of hours with negative prices or with effective floor price. Source: (Fraunhofer ISI et al., 2015a)

With respect to future investments, a risk for investors arises from the difficulty to properly assess how often negative prices will occur in the future and at which (negative) price levels. Estimates of the future occurrence of negative prices in the current literature vary substantially. For instance, for the EEX/EPEX day-ahead market the German think tank Agora Energiewende (2014) expects up to 1,200 hours per year in 2022 with negative prices (assuming that the share of RES-E exceeds 65% of the hourly demand) whereas Fraunhofer ISI et al. (2015a) expect approximately 250 hours until 2025. Current investors face even higher uncertainty since forecasts are required beyond 2025, given the average life time of RES-E assets of about 20 years.

In order to design appropriate policies that reduce the risk of market-based curtailment, it is essential to obtain a thorough understanding of the reasons for negative prices. One assumption is that negative prices typically occur at hours with high shares of RES-based electricity generation and low levels of demand. However, according to the analysis of electricity prices at the EEX/EPEX day-ahead market in 2012 and 2013, carried out by Agora Energiewende (2014), the share of RES-E never exceeded 65% of electricity consumption in all hours with negative prices. That is, negative prices do not only occur when demand is fully covered by renewable electricity generation. Instead, even in hours with negative prices (or hours with positive prices, but below the marginal generation costs of nuclear and lignite power plants) conventional generation capacities, featuring marginal generation costs superior to zero, account for a substantial share of the total generation mix. The two major reasons to explain this phenomenon, introduced by Agora Energiewende (2014), are explained in the following:

(1) Certain conventional power plants (in particular base load capacities) are characterised by **technical restrictions** that prevent them from shutting down and starting up very quickly or for a short number of hours. In situations of relatively low demand and/or a high share of RES-based generation lasting only for a few hours, the operator of such an inflexible power plant has to choose between shutting

[4] Market-based curtailment should not be mixed up with grid-related curtailment, where congested grids require the curtailment of electricity.

down the plant or keeping it running despite market prices being inferior to his marginal generation costs. In the first case the operator encounters the respective costs for shut-down, start-up and potential opportunity costs if the minimum shutdown time exceeds the duration of the low price period. In the second case, he encounters the costs related to the price difference between his marginal costs and the actual market price, but he benefits from the ability to run the plant in a profitable manner as soon as the low price period is over. Comparing both options delivers a certain price threshold where the continuous utilisation of the plant starts being more profitable. This is the minimum price at which the operator bids his generation at the market. Depending on the length of the low price period and the type of power plant, this price can be negative.

(2) Operators of conventional capacities can also be required to sell electricity at the market at low prices if they have to fulfil **additional contractual obligations**. Reserve capacities sold at the ancillary services market require the operation of a power plant according to the original schedule despite very low or negative market prices to ensure short-time positive or negative adjustment in power output in the contractually agreed period of time. Similar obligations apply to the operators of combined heat and power (CHP) plants that must supply a contractually agreed amount of heat and are thus forced to sell the electricity generated simultaneously. In both cases, operators place bids at (negative) prices corresponding to the opportunity cost related to a breach of contract, in order to sell their electricity at the market.

3.1.1.2 Preventive policies

Based on the assessment of the reasons for negative prices the following section proposes policies to overcome risks related to market-based curtailment. However, it is important to note that negative prices as such do not represent a disadvantageous feature of the market design. In contrary, negative prices (similar to extremely high prices) give a clear indication of situations with deficient system flexibility (assuming a properly functioning market). Thus, the policy suggestions do not aim to disable this market mechanism of negative prices. Instead, the aim is (1) to avoid the frequent occurrence of situations with negative prices and (2) to make the impacts of such situations more manageable for RES-E operators.

In order to **avoid situations with negative prices** the following measures can be envisaged and triggered by policies:

(1) The **reduction of the must-run capacity block** would diminish the capacity of power plants that potentially place negative bids at the market in order to fulfil additional contractual obligations. Reducing the amount of spinning reserve could be realised by providing RES-E generators better **access to the ancillary services market** (e.g. through shortened auctioning periods that are compatible with the RES-E forecast horizon and adapted prequalification requirements). Incentivising **more flexibility in the heat sector** can be realised by supporting the introduction of so-called power-to-heat measures (that enable a short term substitution of CHP-based heat generation through a RES-E-powered resistance heater[5]) and heat storage capacities (that permit a more flexible operation of the CHP plants).

(2) An **expansion of transmission capacities** between EU countries can facilitate the convergence of spot market electricity prices and thus reduce the frequency of hours with negative prices as well as the overall price level (Haas, 2008). This effect can be enhanced by a further implementation of the internal energy market (possibly also in the context of the overarching target of an Energy Union, envisaged by the European Commission (2015a) that strives for the utilisation of interconnectors without any technical or regulatory barriers). A similar effect can be observed through **increased storage capacities** (Kondziella and Bruckner, 2012). However, the question is whether price spreads are sufficient to ensure the economic efficiency of storage plants and whether there is enough social ac-

[5] It should be noted that resistance heater should only be used for heat generation in hours of particularly high shares of RES-E, in order to avoid an increase of carbon emissions by substituting low-carbon natural gas through carbon-intensive base load electricity.

ceptance for large scale projects. In particular the latter issue can be addressed by policy through the introduction of local benefit schemes, participation programs and information campaigns.

(3) If end consumer prices for electricity reflect the variation in spot market prices (as it is for instance the case in Sweden), in particular negative prices could induce a shift of demand into the respective low-price hours, lifting the price level (load management). To increase the **flexibility of electricity demand**, adequate policies should pave the way for the introduction of time variable tariffs and possibly provide the regulatory framework for the rollout of the corresponding infrastructure (smart meters). A **re-design of end-consumer prices** (in particular in the residential and commercial sector) can ensure that charges and taxes (for the network and financing of RES-E support) do not prevent from load management by making negative price signals "invisible". Instead, a dynamic design of these components can provide additional incentives to consumers to consume electricity in hours of high generation from RES-E. Further information on the impact of demand flexibility on RES-E is provided in Section 3.2.

3.1.1.3 Reactive policies

In the case that **market prices lead to a curtailment** of RES-E generation there is the option to treat market-related curtailment as the provision of ancillary services and (partially) compensate any losses in revenue. In this case curtailment could be understood as an ancillary service in terms of providing downward reserve capacity or balancing energy (EWEA, 2013). This measure would fully eliminate the risk of market-based curtailment.

3.1.1.4 Short appraisal

All measures suggested to reduce the occurrence of hours with negative prices basically lead to a general improvement of the functioning of the electricity market. They enhance flexibility in the electricity system, increase price elasticity of electricity demand at the spot market and thus lead to reduced price levels that are beneficial for consumers and the economic competitiveness. However, the suggested measures require further analysis in order to estimate the involved costs and compare these to the achieved benefits.

Providing compensation payments for curtailed RES-E generation in hours of negative prices should only be introduced after all alternative measures have been taken. Compensation payments disincentivise an economic utilisation of the RES-E generation capacities and cause additional costs that would need to be borne by the consumer.

However, the question comes up how to deal with negative prices, when they occur more frequently due to an over-supply from RES-E generation that exceeds overall demand. In this case, new remuneration elements are likely to be required in addition to the pure market price to ensure further investments in RES-E capacities. For example when assuming a transformation of current feed-in tariff schemes based on administrative price setting to tender schemes any potential losses during periods of negative prices will be internalised in the level of the bids, therefore an automatic adaptation of remuneration levels occurs. However, such situations will only arise in the long run, when RES-E dominates the overall electricity generation mix.

3.1.2 Grid-related curtailment

3.1.2.1 Description of challenge

In addition to market-based curtailment, RES-E generators face loss of income through congestion management and grid related curtailment. Uncertainty about the frequency of congestion situations thus represents an additional driver for the risk premium.

There are at least two major reasons for grid related curtailment (see for instance Jacobsen and Schröder, 2012):

(1) **Network constraints**: Curtailment can take place temporarily (occasionally during several weeks or months) if the expansion of grid infrastructure is delayed relative to the installation of generation capacity. Curtailment may also occur more permanently if a distribution or transmission system operator (DSO or TSO) intentionally hinders grid reinforcement due to substantial additional costs that cannot be justified by the marginal amount of additionally integrated RES-E generation. The rationale behind this behaviour is the purpose to avoid overinvestment in grid capacity if the related costs substantially exceed the costs for lost RES-E generation. That means curtailment is considered as a solution for the optimisation of capacity investments in the grid.[6][7]

(2) **Network security and inertia**: In contrast to the first aspect, curtailment may also be required at very short time scales when network security is at risk. In this case, grid capacity is sufficient to accommodate all RES-E generation but fast changes in RES-E generation, grid faults or limitations in other factors (such as reactive power or frequency) threaten the stability of the grid. If fast shut-downs of important RES-E capacities are foreseeable, precautionary curtailment ahead of the expected drop can ensure a controlled reduction in generation and the connection of additional spinning reserve. Curtailment may also be required in situations of grid faults and grid maintenance, when RES-E generation cannot be integrated by the grid. Last, a high share of RES-E generation can trigger e.g. frequency problems in the grid which require curtailment and the connection of conventional units providing additional inertia in the system.

The reasons for curtailment outlined above do not necessarily imply a risk for investors, as curtailment may happen **voluntarily**. In this case, RES-E operators and DSOs or TSOs agree on a reduction in generation output in pre-defined situations and under certain established procedures and compensation schemes (EWEA, 2013). However, if the curtailment happens **involuntarily**, it can be understood as a major driver for the risk premium due to the uncertainty in estimating the potential future loss of income through grid-based curtailment. In this context it has to be kept in mind that the uncertainty of curtailment does not only depend on the grid management but also on all other actors linked to the grid. These actors include other renewable capacities and conventional installations as well as consumers with their individual consumption behaviour that can influence the occurrence of grid-based curtailment.

In order to get an impression of the scale of grid related curtailment observed in the past, Figure 4 illustrates the amount of curtailed RES-E generation and the respective share relative to overall RES-E generation for selected EU countries. Italy is characterised by a decline of curtailment over the past years from nearly 9% to less than 1% (due to substantial grid upgrades and extensions, according to Steurer et al., 2014), all other countries feature an increase in curtailment (Spain only in 2013). In the most recent years, the share of curtailed energy ranges between 0.3% and 2.1%.[8]

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[6] Ochoa et al. (2010) determine in their simplified network simulations that accepting curtailment of 2% allows doubling wind power penetration to 29%. This share rises to more than 40% if 10% curtailment is allowed. The German Energy Agency, Dena (2012), determined that curtailing wind and PV generation by 2% would reduce required investment by 13%-21%, depending on the voltage level, until the year 2030.

[7] In Germany, grid operators are allowed to curtail RES-E generation when grid stability is jeopardized. RES-E operators are compensated for 95% of the lost profit (Bundesnetzagentur, 2014)

[8] With regard to Spain, for the period January to April 2013 curtailment translates into economic losses of €70 m (Martinez et al., 2015). For Germany, the costs for the entire year 2013 sum up to nearly €44 m (Next Kraftwerke, 2015).

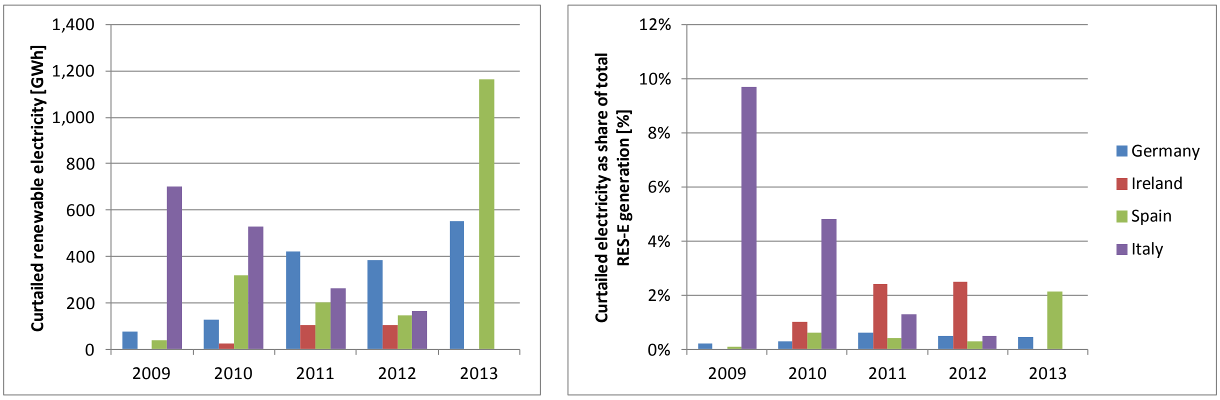

Figure 4: Grid related curtailment of RES-E generation in selected EU Member States (left) and share of total renewable generation (right). Values for 2013 are only available for Germany and Spain. The Spanish value for 2013 only relates to wind energy. Source: (Steurer et al., 2014, Martinez et al., 2015, Fraunhofer ISI et al., 2015b)

3.1.2.2 Preventive policies

Similar to the market-based curtailment, the risk of grid-related curtailment can primarily be reduced by implementing measures that avoid or at least reduce the frequency of situations where the grid is congested or system stability at risk. If, however, curtailment is inevitable for reasons of congestion management, adequate policies are required that minimise the monetary impacts for investors.

To **avoid or reduce grid-related curtailment**, a wide range of measures are conceivable that could be triggered by respective policies.

(1) The **expansion and upgrade of the transmission and distribution grid** (including interconnectors and transformer stations between grids of different voltage levels) represent one of the most effective measures to reduce curtailment. Policies can support and accelerate grid reinforcement by reducing regulatory barriers, initiating grid planning processes in relevant areas well ahead of RES-E capacity expansion and supporting education campaigns to raise public acceptance. Further, DSOs and TSOs could be obliged by law to realise sufficient grid access for RES-E generators as long as they cannot justify that curtailment is economically more viable from a macro-economic perspective.

(2) The **optimised operation of grids, RES-E capacities and reserves** can ensure the improved utilisation of existing grid infrastructure. TSO and DSO can make better use of their grids, for instance, through dynamic line rating[9]. The curtailment of RES-E generation can be shortened through automated curtailment. Improved forecasting methods reduce the need for precautionary curtailment. Curtailed RES-E generation may be used to provide positive reserves to use the energy that would otherwise be curtailed. Further, maintenance of conventional capacities could be scheduled into periods of high RES-E generation to avoid oversupply. Policies can incentivise better utilisation of the existing grid resources by allocating part of the costs from compensation payments for RES-E curtailment to grid operators, RES-E operators and generators. Last, enhancing the share of RES-E self-consumption in periods of curtailment through an adequate design of network charges can further alleviate the need to curtail RES-E generation.

(3) Partial compensation payments for RES-E operators can also trigger the **installation of new RES-E sites in curtailment poor regions** where grid reinforcement costs are low. While the selection of the plant site must be primarily based on the prospective energy generation potential, partial or regionally dif-

[9] Dynamic line rating relates to a real-time monitoring of physical parameters of transmission system lines to assess the actual transmission capacity, which can substantially exceed the nominal capacity determined under static line rating and worst case conditions.

ferentiated compensation payments can increase the relevance of grid conditions in the investment decision.

3.1.2.3 Reactive policies

As outlined above, grid-related curtailment is likely to become more frequent in the future due to the ongoing expansion of RES-E capacities. **To mitigate the revenue risk** for RES-E investors or to compensate for loss in revenue through current grid-related curtailment, compensation payments can cover the complete profits lost. However, as previously outlined, partial compensation payments potentially make sense to incentivise grid-compatible RES-E investments. In addition, transparency of curtailment decisions and clear calculation methodology for the amount of spilled energy and potential compensation payments are a necessary prerequisite to ensure that curtailment is a measure of last resort.

3.1.2.4 Short appraisal

In general, policies should facilitate a cost-efficient integration of RES-E in the power system. Thereby, the question is whether this can be done rather by extending the electricity network or by curtailing RES-E generation in situations of congested grids. Grid-related curtailment applied to a certain extent can make sense in order to keep costs for the required grid expansion at a reasonable level.

Similar to the re-design of electricity consumer prices suggested in Section 3.1.1, a dynamic design of compensation payments or the re-allocation of the related costs across the different actors of the energy system entails the previous advantages. However, it should be borne in mind that the introduction of such dynamic mechanisms potentially makes the overall regulatory system more complex and may, thus, represent an additional barrier for (in particular small) RES-E investors, instead of the required simplification.

3.1.3 Retroactivity

3.1.3.1 Description of the challenge

Political uncertainty and instability puts at risk predictable funding schemes required for a continuous and stable extension of RES-E capacities.

The main point here is that, as governments are concerned about the increasing total policy support costs of mature technologies, given their increasing penetration (in spite of lower unitary costs), they may **reduce support retroactively**, affecting the stability and viability of existing RES-E installations in a number of European countries and, thus, seriously damaging the investment climate for these technologies. In turn, this would have two effects: a lower deployment than would be the case and, higher deployment costs (since higher risks translate into higher financing costs). Although these regulations are for existing plants, they may have an impact on the economics of new plants. This is a relatively widespread issue across Europe (EPIA, 2013).

In this context, the **Spanish case** with solar PV illustrates how retroactivity developed and its consequences.[10] It illustrates a main problem of feed-in laws: since they set a price (support level) and let renewable energy investors and generators respond to this price, uncontrolled increases in renewable energy capacity or generation may result. In turn, this may lead to a strong increase in total support costs. The setting of the level of remuneration by the government depends on knowledge about the costs of the technologies, which is mainly in the hands of RES-E investors. These have an incentive to inflate those costs in order to receive a higher remuneration. This well-known problem of asymmetric information may lead to higher than necessary support costs.

The increase in the support costs can be especially dramatic for technologies with a significant potential for cost reductions over time, such as solar PV. This has been the case in Spain. The solar PV sector experienced an

[10] Retroactive changes likewise took place in other European countries, such as Bulgaria or the Czech Republic.

unprecedented spike in investment between 2007 and 2008. Solar PV generation capacity increased from 146 MW in 2006 to 3,398 MW in 2008, with investment in Spain's solar PV market accounting for more than 40 percent of the world's total solar installations in 2008. The boom in PV capacity led to a parallel upsurge in costs. Total support costs for solar PV increased thirteen-fold between 2007 and 2009, from 194 M€ to 2629 M€ and the unitary costs of support increased from 39 €/MWh in 2007 to 42 €/MWh in 2009. In 2009, solar PV received 56% of all support provided to renewable electricity in Spain, despite providing only 12% of Spain's renewable electricity. A main, although certainly not the only factor leading to this boom was the support policy that had been implemented, i.e., a FIT system[11]. This has certainly put a burden on electricity consumers. The government reacted by adopting policy measures aimed at reducing those total costs.

In September 2008, a new decree aiming at cost-containment was enacted. First, a centralised administrative procedure for registering the solar PV capacity, which was also capped to 500 MW/year, was established. Second, an allocation system involving four calls a year on a first-come, first-serve basis was set up. Finally, FITs were reduced and attached to a degression mechanism (which implied an inter-annual reduction of 10% for new installations).

In spite of the new regulation, the costs of solar PV promotion continued to increase. Concerns about these escalating costs triggered an even stronger reaction by the government, leading to the adoption of several cost-containment policy measures (see del Río and Mir-Artigues, 2014, for further details):

(1) **Shortening the support period**: The length of the subsidy period was reduced to 25 years for RES-E plants already deployed (instead of lifetime). Beyond this period, plants would still be able to sell their electricity to the grid, but at wholesale prices.

(2) **Cap on the full load hours of generation which are eligible for support**: A cap on the eligible full load hours which could be remunerated with a FIT for plants installed under previous laws was established.

(3) **The grid access charge**: Since January 1st 2011, RES-E generators would have to pay a 0.5€/MWh fee for the use of the grid.

(4) **The generation charge**: The value of this charge is 7% of energy sales. Although this charge falls on all electricity generation sources, note that those generators which receive RES-E support through FITs cannot pass the amount of this fee to customers and, thus, should assume the additional costs fully.

(5) **Change in the tariff-updating mechanism**: The new law set a new criterion for the annual updating of the tariffs. From January 1st 2013 onwards, tariffs and premiums would be yearly updated according to the underlying inflation rate (i.e., the consumer production index, CPI) minus the prices of food and energy products), instead of using the CPI, effectively reducing the remuneration of RES-E plants since the underlying inflation rate is lower than the CPI.

A moratorium on support for new renewable energy capacity was adopted in January 2012. The postponement of the support policy was labelled as temporary. The energy reform establishing a new mechanism for RES-E support was passed in 2013; however, the details of the new retribution system, markedly the support levels per technology were only approved in June 2014 (RD 413/2014). This new regulation abolishes a former regulation (RD 661/2007) and therefore affects existing as well as new RES-E plants.

Spain's changes to the FIT regulations have implications for those solar PV projects already up and running, as in some cases the financial viability of existing projects has been threatened. Industry associations, solar PV investors, generators and environmental NGOs have strongly criticised these measures for being retroactive. Industry associations filed claims against the Spanish government in different courts, including the Spanish Supreme Court and the European Court of Justice.

[11] The combination of fixed and updated preferential prices yielding high internal rates of return, coupled with an abrupt although distant end of the tariff framework, boosted a rush for the submission of proposals. Moreover, two external factors contributed to this race: the end of the housing market boom and the easy access to credit (del Río and Mir-Artigues, 2014).

However, the Spanish Supreme Court has rejected calls for the suspension of the royal decree RD 1565/2010 which led to the shortening of the support period (i.e., number 1 above). It has ruled that shortening the support period would only have an impact on the future cash-flows but not in earnings accumulated before such regulation was approved in 2010. In this sense, the Court has stated that RD 1565/2010 cannot be considered retroactive (Tribunal Supremo de España, 2014).

The fallout from the solar PV boom and bust had wider implications for Spain, creating uncertainty amongst investors about the stability of Spain's regulatory environment for renewable energy in general.

3.1.3.2 Preventive policies

A main challenge for policy-makers is to balance the trade-off between higher stability for investors on the one hand and flexibility of the support scheme to adapt to changing circumstances in order to avoid overcompensation to RES-E generators on the other hand. RES-E investors usually demand **predictability and stability** of the support scheme. This is critical to ensure lower risks for investors and, thus, the effectiveness and even the efficiency of the support scheme. However, unexpected trends in, e.g., technology costs may result in a greater support level than initially envisaged. This overcompensation may result in a greater deployment level and, thus, much higher support costs than expected and those needed to trigger a certain RES-E capacity. Obviously, ex-post changes by the government in the support levels leading to retroactive cuts strongly increase risks for investors and lead to an unstable investment climate (del Río and Peñasco, 2014). As stated by the European Commission (2013), changes that reduce the return on investments already made alter the legitimate expectations of business and discourage investments.

Therefore, retroactivity should be avoided to the extent possible. The best manner in which the recourse to retroactive changes would be made unnecessary is to adopt **instruments and design elements which limit the skyrocketing of support costs**. Retroactive changes have mostly taken place in countries with FITs and usually related to the support of solar PV. One of the well-known problems of these instruments is that, since they do not inherently cap the total quantity of RES-E being supported, costs of promotion may significantly increase if the quantity of electricity quickly responds to very attractive support levels. However, several cost-containment mechanisms exist that allow to control the costs of support under FITs, such as capacity caps (the amount of capacity installed in a given period is limited), generation caps (maximum number of full-load hours being supported), periodic revisions (support levels are revised for new plants periodically), total budget caps (maximum amount of total financial support for a given period), traditional degression (pre-set reduction of support levels over time for new plants), flexible degression (the reduction in support levels over time depends on the total installed capacity in a previous period) (del Río and Mir-Artigues, 2014). Another option to restrict support costs is the use of tender schemes instead of feed-in tariffs or premiums with caps.

3.1.3.3 Reactive policies

Retroactivity should be avoided in advance, an ex post correction of retroactive measures could possibly mitigate the existing uncertainty for investors to a certain extent, but it is probably not sufficient to restore investors' confidence.

3.1.3.4 Short appraisal

Retroactivity should be avoided in any case in order not to destroy the investors' confidence. Problems of rising policy costs have occurred in particular in feed-in systems and should preferably be handled before costs rise too much. Thus, issues related to exorbitant policy costs should be tackled preferably by means of preventive policies, such as using volume restrictions (caps in case of feed-in systems or using tender procedures instead). Other design elements suitable to avoid excessive policy costs in particular for highly dynamic technologies are different types of degression mechanisms. In future years, tender schemes will be a key policy to combine quantity control and competitive measures for price determination.

3.1.4 Risks arising from support scheme design

The landscape of RES-E support schemes applied in the different countries of the EU is quite diverse (cf. Figure 5). In addition, the European Commission requires member states to support RES-E predominantly by applying a **competitive auction process** from 2017 onwards (see the guidelines, sec. 3.2.2.1, (126), in European Commission, 2014). Here the question arises, how the different support schemes and in particular auctions affect the different market actors / investors and who of the actors concerned is best able to cope with the respective risks. In general, the support scheme cannot reduce or mitigate all existing risks related to the development of RES-E, but it can influence the allocation of risks to the respective actors. Dealing with these risks involves certain costs and a support scheme should ideally allocate risks to the actor who is best able to cope with the respective risk category. However, it can also make sense not to allocate risks according to the economic efficiency criterion, but to expose an actor to a certain risk category in order to promote learning. Handling risks of RES-E development with support schemes involves the question whether a risk should be borne by the public or the private investors. In this context, we distinguish between productive and unproductive risks. Whilst productive risks can be influenced actively by the respective actor, unproductive risks are outside the actors' control.

In the following, a short review gives an overview of different types of support schemes, the design of related instruments and how they affect the risk for investors. Subsequently, the different schemes and instruments are evaluated and specific designs are formulated to effectively handle these risks.

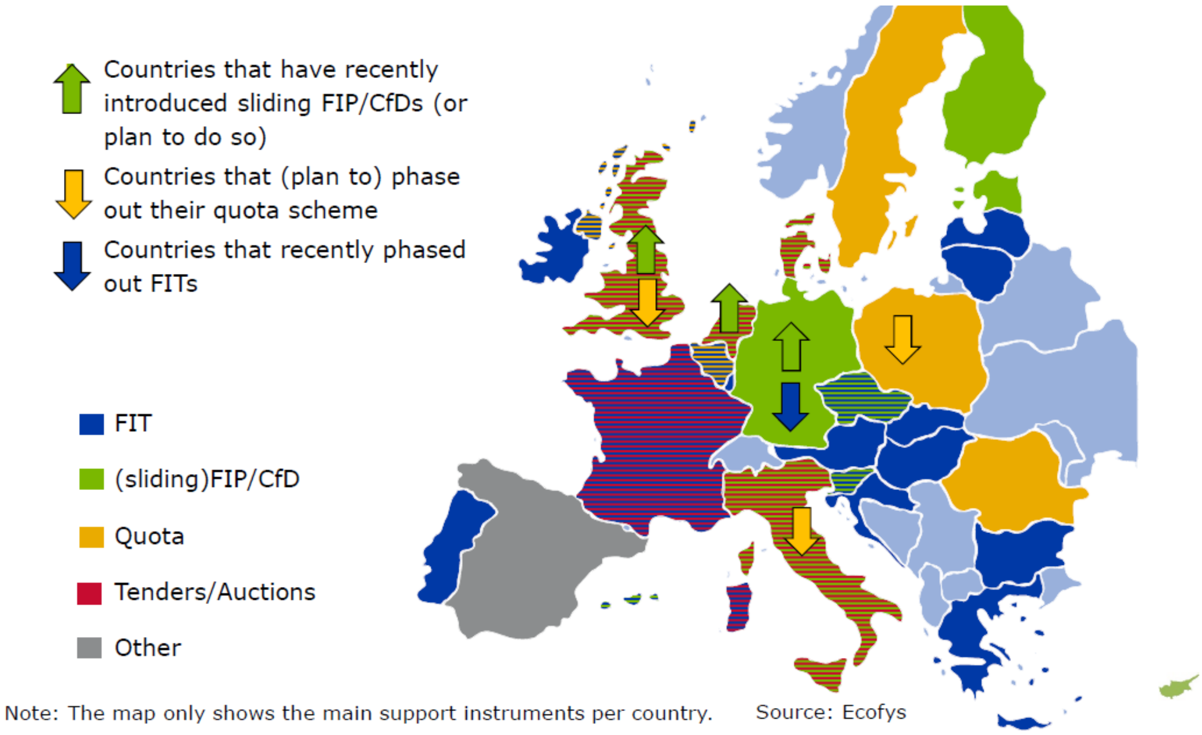

Figure 5: RES-E support schemes applied in EU member states. Source: (Klessmann, 2014)

3.1.4.1 Description of the challenge

In terms of support schemes, Fraunhofer ISI et al. (2014) distinguish five major types:

- **Fixed feed-in tariff**
  Fixed feed-in tariffs (FiT) represent a guaranteed payment for each unit of energy generated for a predetermined period of time (e.g. 20 years). Under a FiT scheme, investors only face risks that are directly related to the investment (technical and management risks, completion and operation risks, resource risks). At the same time, FiT are not well suited to improve the market integration of more ma-

ture RES-E. They can be replaced by alternative, more market-based instruments, as outlined in the following.

- **Sliding market premium**
  If RES-E generators are reimbursed by a sliding market premium, they have to sell their electricity on the market. Average revenues (market value) are compared to a benchmark remuneration level. The sliding market premium compensates RES-E operators for the differences of the benchmark remuneration level and the average revenues from the power market. It is usually determined on a monthly basis, e.g. in Germany, or annually, e.g. in the Netherlands, and incentivises RES-E operators to sell their electricity at the market at the most efficient manner (i.e. primarily at hours of elevated market prices).
  Through the sliding market premium, the price risk and the sales risk are partially transferred to the RES-E operator. The sliding market premium ensures an optimised generation pattern of RES-E generators (e.g. through improved generation forecasts) but the investment incentive is still based on the benchmark remuneration and not on the market signal.
- **Fixed market premium**
  In contrast to the sliding market premium which is calculated on a regular basis, the fixed market premium is determined once at the very beginning of an investment, likewise relative to a given level of remuneration. It remains constant throughout the entire funding period and thus transfers the overall risk resulting from the variations in wholesale electricity prices to the RES-E investor.
- **Capacity payment**
  Capacity payments that compensate part of the investment costs can be designed, similar to the market premium, in a sliding or constant version. The risks imposed to the RES-E investor are the same as for the generation-based fixed market premium.
- **Quota obligations**
  Quota obligations constitute a support scheme different from the before-mentioned price-based instruments. RES-E operators receive certificates for their green electricity generation. These certificates may be sold to other market actors that are obliged to fulfil a certain quota obligations of green certificates. Selling the certificate on the respective market provides an additional income to the RES-E operator, in addition to the income from selling the electricity on the market. RES-E investors face twofold price risks given the uncertain development of the prices on the electricity and the certificate market.

As mentioned earlier, the European Commission requires Member States to extend existing RES-E support schemes by applying a competitive **auction** process from 2017 onwards (European Commission, 2014). The auction process is not to be understood as a distinct support category but as an instrument to determine support levels for support schemes in a competitive bidding procedure. A price or volume-based auction transfers the sales risk to the RES-E investor, as costs for planning occur prior to the actual auction process and might end up as sunk costs. These potential sunk costs further increase the risk premium, the bids and the final remuneration being granted.

3.1.4.2 Preventive policies

When evaluating the different support schemes with respect to the risks for RES-E investors, fixed market premia or capacity payments tend to increase risk due to the fact that the RES-E investors face the risk of the long term price development which reduces the cost-efficiency of market integration of RES-E generators (so-called unproductive risks). Quota obligations particularly increase risks for investors due to the uncertainty resulting from price variations on two separate markets (electricity and certificates). Thus, sliding market premia should be given priority as the related risks are productive in the sense that they trigger market-based behaviour (electricity sales at hours of high prices) and improved integration (e.g. enhanced forecasts and thus reduced need for reserve capacity).

Applying auctions to determine the support level can potentially increase the productive risks for RES-E investors, by giving a strong impetus for investors to better assess and control their cost structures, thus reducing the overall costs for funding.

Thus, in the following, a number of risks related to the auction process and recommendations for an appropriate, risk-minimising design are provided (del Rio and Linares, 2014):

- **Inclusion of pre-approved RES-E sites for large-scale technologies (such as offshore wind)**
  Performing auctions for a list of pre-approved technology specific RES-E sites makes it necessary to involve regional governments and stakeholders in the identification of the respective sites and thus mitigate NIMBY problems that potentially increase investor risks.
  In addition, if the pre-approved list of sites includes information on local resources, this will additionally minimise transaction and administrative costs for investors and remove part of the information failure for small bidders, as investors do not need to approve sites prior to the bidding procedure and thus do not risk sunk costs.
- **Frequent, pre-defined auction schedule**
  Regular, long-term and high frequency auctions provide investors certainty about future markets, thus reducing the barrier for investors to invest in the investigation of appropriate sites (if not pre-approved by the regulator) and the planning process.
- **Excessive price rules**
  A low number of bidders in an auction may result in excessively high prices. Seller concentration may avoid such situations. However, they should not include a cancellation of the bidding process through arbitrary administrative decision as this would imply significant investor risks. Instead, efficient seller concentration rules should cap the number and size of bids or the revenue per bidder.
- **Deadlines for construction and penalties for non-compliance**
  Deadlines for construction and penalties for non-compliance represent instruments to ensure a timely construction through investors after winning the auction. However, if there is a substantial risk for not complying, the penalty may be included in the bid price. Speculative behaviour and unreasonably low bids can be effectively mitigated through progressive penalties (that increase with increasing delay of construction) or performance bonds (similar to a deposit a bidder has to provide to proof his serious interest in realising the RES-E project) that the state can cash in in case of non-compliance. Deadlines should be set-up long enough to avoid that investors' risk are increased.

3.1.4.3 Reactive policies

Reactive policies cannot be suggested as the support mechanism design builds upon the respective regulation conceived by the policy makers.

3.1.4.4 Short appraisal

From a government perspective, auctions represent a powerful tool to determine the required level of support while controlling the total costs of support. They are particularly well applicable for large-scale projects (such as wind offshore or solar thermal power) and some of the suggestions previously listed have a positive impact on further reducing the unproductive risks. The payment should take the form of feed-in premiums in order to facilitate market integration. From our point of view, the sliding premium would be the preferred alternative[12], since non-productive risks for investors are avoided, whilst market participation provides learning effect for RES-E developers.

In contrast, other instruments than auctions are likely to be more appropriate to promote smaller bidders (such as cooperatives) and the respective technologies (e.g. decentralised small scale wind and PV).

[12] Of course, the sliding premium is not free of inconvenient, e.g. it does not tackle the issue of negative prices.

3.2 Shrinking market values

3.2.1 Description of the challenge

The most recent trends in the design of support schemes aim to incentivise operators of mature RES-E technologies to sell major shares of their electricity directly at the market. By doing so, RES-E providers shall become more market oriented, react to price signals from the market and relieve public support schemes that need to be financed by the public.

The potential revenue that RES-E providers can generate at the market is expressed by the market value. The **market value** equals the average hourly wholesale electricity price weighted by the respective RES-E generation. If RES-E generation primarily occurs in peak hours, the market value exceeds the average wholesale price (and thus the relative market value is superior to one), whereas generation in off-peak hours implies a market value inferior to the average wholesale price. That means, the market value depends on the temporal coincidence of RES-E generation with high or low market prices. It is, thus, affected by the actual electricity generation profile as well as by the temporal variation of the electricity price which, in turn, depends on the shape of the residual load and the merit order curve.[13]

Following Pudlik et al. (2015), there are a number of factors that influence the market value (see Figure 6). Policy suggestions to increase the market value of mature RES-E are designed considering these factors; the latter are explained in more detail in the following.

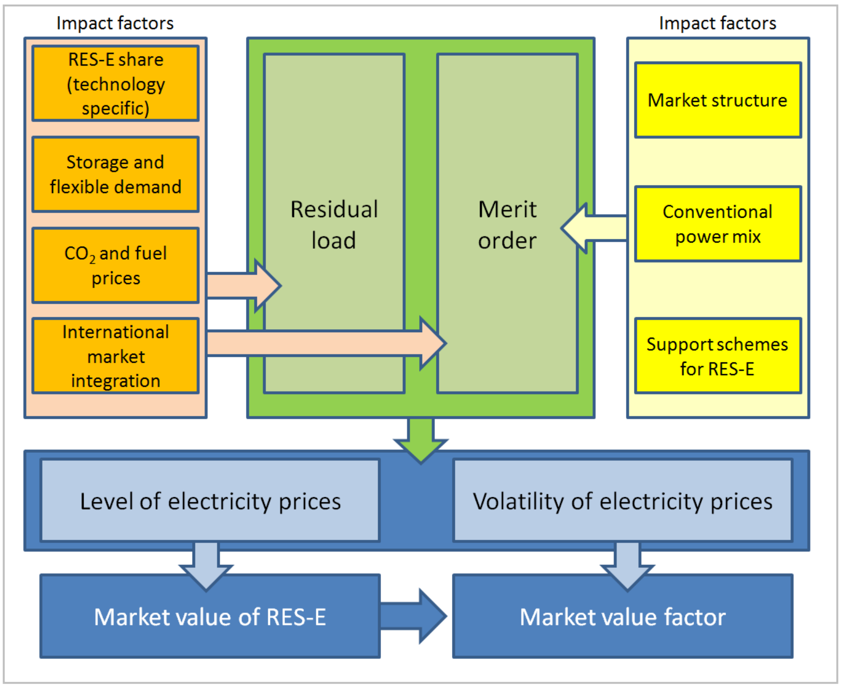

Figure 6: Overview of factors influencing the market value. Source: (Pudlik et al., 2015)

The market share of RES-E technologies, the availability of storage and flexible demand, carbon and fuel prices as well as the international market integration affect the residual load and the merit order, as illustrated in

[13] The residual load equals the overall electricity demand less the generation from (fluctuating) renewable energy sources. Hours with high shares of RES-E generation are typically characterised by low levels of residual load. The merit order represents the ranking of bids (in ascending order) from electricity generators at the electricity spot market. The bids correspond to the short-term marginal electricity generation costs. Based on the merit order the supply curve is generated which is used to determine the clearing price. The clearing price is set by the last bid that is required to cover demand.

Figure 6. In contrast, the direct, short-term impact of the market structure, the conventional power mix and the RES-E support is limited to the merit order.[14]

The **RES-E share** has a substantial impact on the residual load and thus on the market price. Given that PV and wind feature nearly zero marginal generation costs (and that they benefit from priority dispatch in many countries), they cause a reduction of the market price in hours of high RES-E generation as they push more expensive generators out of the merit order. Thereby, they trigger a deterioration of their own market value. This phenomenon is usually referred to as the "merit order effect".

The interrelationship between market share and market value was empirically observed by Pudlik et al. (2015) for Germany (see Figure 7). It becomes obvious that PV features a more substantial drop in relative market value s with rising share of generation than wind. This can be explained by the fact that PV generation is characterised by high temporal correlation whereas wind generation takes place more randomly.

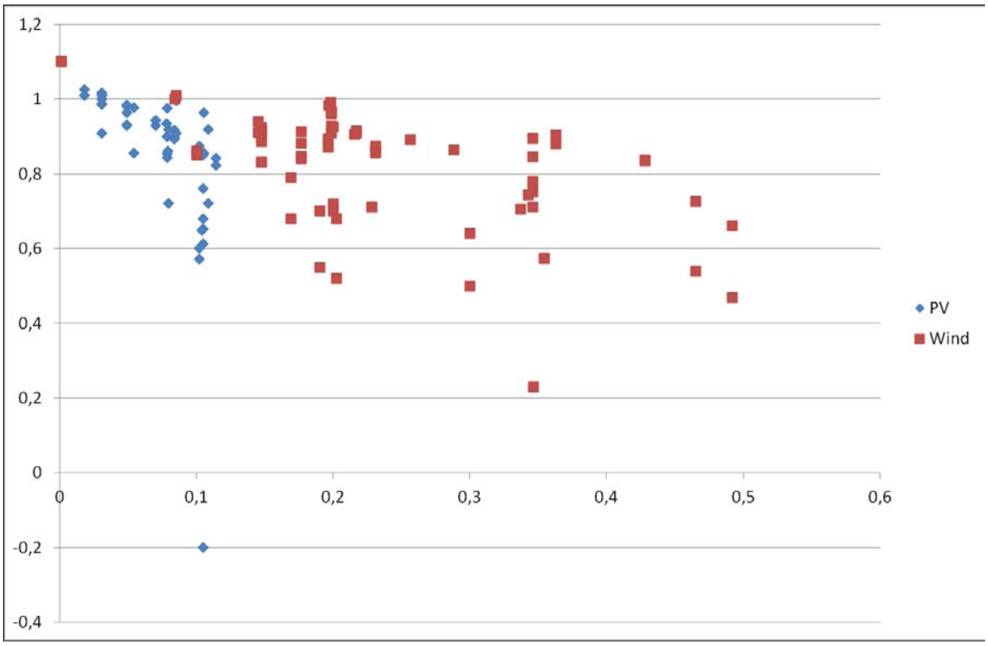

Figure 7: Evolution of relative market values in Germany as function of market share. Source (Pudlik et al., 2015)

Storage capacities or **demand side flexibility** can potentially contribute to a smoothing of the residual load and thus of market price amplitudes as they enable a shift of generation from off-peak to peak hours and of load from peak to off-peak hours. Thus, they can partially counteract the merit order effect. In this regard, short-term storage devices can raise the market value of PV by shifting the electricity generation from midday to morning and evening hours. For wind, long-term storage is required to overcome seasonal variations in generation.[15]

Extension of international net transfer capacities (NTC) and **international market coupling** can have a market value enhancing effect. This applies in particular to wind, as regional distribution of RES-E can be more diverse in larger market areas and, thus, imply a reduced fluctuation of RES-E generation that weakens the merit order effect. Further, market values can be increased in one country if the other, newly connected country features lower RES-E shares or higher wholesale prices.

[14] Of course, market structure and RES-E support schemes also affect the share of RES-E technologies and thus the residual load. However, this mid- to long-term effect is not specifically considered in this analysis.

[15] However, Winkler et al. (2015) argue that a reinforcement of transnational net transfer capacities is more cost-effective than storage as the latter requires massive capacities to obtain the same results as grid reinforcement.

Changes in **fuel and CO_2 prices** may lead to a restructuring of the merit order. The impact of rising CO_2 prices on the position of generators in the merit order correlates with their carbon intensity. Changes in fuel prices affect only those generators using the respective fuel. Generally speaking, both imply a rise in the overall market price level and a steeper rise of the upper end of the merit order. However, the impact on the market value of RES-E is relatively limited as the raised peak prices do rarely occur in situations with large amounts of RES-E generation.

With respect to factors influencing merely the merit order, the actual **structuring of the market** can influence the market value in two ways: on the one hand, market power can enable the use of mark-ups that cause an increase in market prices and market values.[16] At the same time, scarcity prices may appear in markets being short of supply. However, RES-E generators benefit to a substantially lower extent from scarcity prices than conventional generators, as scarcity prices rarely coincide with high shares of RES-E generation.

The **conventional power generation mix** may lower the market value if it contains a substantial stock of large inflexible power plants and must-run capacities that cannot be shut down at low market prices due to thermal inflexibility or obligations at other markets (reserve market, heat market, see also Section 3.1.1). They set bids at the market below their actual marginal generation costs and thus lower prices (even below zero) and therefore market values of RES-E.

The actual design of the **RES-E support scheme** affects the bidding strategy of RES-E generators and thus the market value. In particular the price at which RES-E reduce their own generation (see Section 3.1.1) depends on the type and level of support.

Apart from the residual load and the merit order, the RES-E generation profile is decisive for the market value. As wind and PV depend on the availability of the respective natural resources, the electricity output cannot be controlled as a function of prices. However, at the time of installation a **plant configuration** can be chosen that allows attaining higher market values. This includes eastern or western orientation of PV modules and tracking systems to generate electricity at hours of high demand and time-delayed to the bulk of PV generation with southern exposure. Wind turbines can be designed to make better use of low wind speed situations (and thus higher generation at hours with higher residual load, as depicted in Figure 8) and to allow more continuous generation. Further, the selection of the installation site can be chosen considering the local wind patterns in comparison to the national average and the market price patterns. Once the installation is completed, the operator has no more opportunities to influence the market value.

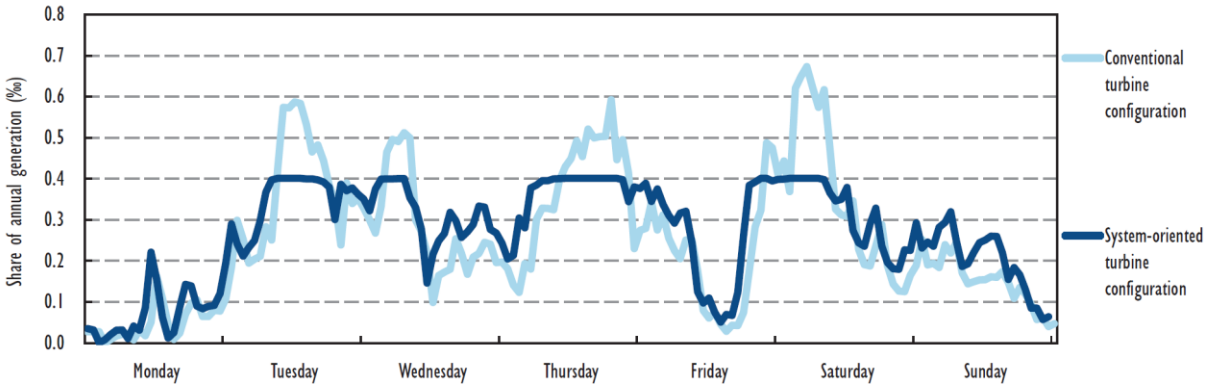

Figure 8: Comparison of electricity generation from two different wind turbine designs. Source (IEA, 2014a)

[16] This argument builds upon the hypothesis that electricity providers with significant market power can place bids at the wholesale market that actually exceed their marginal electricity generation costs and thus generate additional income.

To sum up, it is certain that rising RES-E shares imply a reduction of market values through the merit order effect. In addition, there are a number of additional drivers for low market values:

- lack of flexibility in demand, insufficient storage or grid capacities
- lack of market coupling and grid infrastructure
- inflexible power plants and must run capacities

Their individual impacts are difficult to assess as they strongly depend on the country specific circumstances. In the following we suggest policy measures to keep higher market values for RES-E.

3.2.2 Policy design options

3.2.2.1 Preventive policies

The merit order effect can be understood as major driver for the decline in market values through rising shares of RES-E generation. At the same time it is somewhat immanent to the integration of RES-E electricity in power markets due to the nearly zero marginal costs of RES-E technologies. The negative impact of the merit order effect on RES-E investors could thus only be obviated through fixed feed-in tariffs, which are not considered to be an efficient support mechanism for mature technologies (see Section 3.1.4). However, the negative impact on the market value would persist also under feed-in tariff support. Consequently, it is necessary to design policies addressing all other factors influencing the market value, in order to mitigate the impact of the merit order effect on RES investments.

Price **elasticity of electricity demand** can be increased through policies that facilitate the introduction of time-variable tariffs. In particular with respect to commercial and residential customers, a dynamic design of charges and taxes (for the network or RES-E support) can provide additional incentives for load management. Apart from flexibilisation of existing consumers, the coupling of the electricity sector with other sectors can lift demand and thus market values. Sector coupling can in particular be envisaged through electrification of the heat and transport sector (by incentivising the use of heat pumps and electric vehicles) as well as the intensified use of electricity to generate industrial products (e.g. electric arc furnace instead of blast furnace steel generation) and synthetic matters (hydrogen and methanol). Of course, the shift from the conventional fuel to electricity should primarily contribute to emission reduction. If this is the case, electrification can also be envisaged from the market value perspective, through policies that provide a framework that is conducive to the technological transition of the respective sectors.[17] However, it is important to note that the electrification of the heat sector (usually referred to as power-to-heat) is particularly suitable for raising the market value of wind and much less for the market value of PV, as heat demand dominantly takes place in winter months whereas the bulk of PV generation occurs in summer time.[18]

Extending large scale **storage** facilities can deliver similar benefits than demand side flexibility (and expansion of NTC). However, recent studies (e.g. Winkler et al., 2015) come to the conclusion that the expansion of NTC and demand side flexibility are more effective than storage expansion as the latter requires massive capacities to obtain the same results. In the end, the country specific characteristics must be decisive for the selection for the adequate flexibility measures.

The expansion of international net transfer capacities and the further **coupling** of the European electricity markets allow countries to make use of flexibility options from foreign countries. Further, the simultaneity of RES-E

[17] The market value enhancing effect of electrification and demand response can potentially be mitigated by grid reinforcement and the expansion of NTC.

[18] In contrast, the increased equipment of commercial and residential buildings with air-conditioning (A/C) devices represents a growing portion of electricity demand that coincides with PV generation (especially in Southern European countries). However, demand flexibility of A/C is limited to approx. one hour (if it is not equipped with a cold storage device), as the indoor temperature corridor in buildings is relatively narrow and, thus, does not allow for a substantial deviation from the conventional cooling schedule.

generation can be reduced given larger geographical distribution of sites. Thus, on a European level member states should further work on the establishment of an internal European energy market, following the idea of a European Energy Union (see for instance, Held et al., 2015).

In the short run, higher **fuel and CO_2 prices** increase the market value. Thus, ambitious CO_2 prices (implemented through the European Emissions Trading Scheme ETS or carbon taxes) should be implemented. However, the long-term impacts of rising CO_2 prices on future investments in new power generation capacities and their impact on the market value are difficult to assess and require further research.

To avoid the reduction of market values through **must-run capacities**, policies should provide access for RES-E generators to ancillary service markets. Also, the promotion of power-to-heat and heat storage devices can increase flexibility in the heat sector and thus reduce the need for CHP plants to place bids in the market below their marginal generation costs (similar to the measures envisaged to avoid market based curtailment, see Section 3.1.1).

Last, policy frameworks should incentivise that RES-E investors aim for highest market values achievable and not only for the lowest LCOE. In this sense, RES-E investors would include the potential prospect of market values to be generated in their investment decision. If this incentive is not set automatically by the market, policies can assist in drawing attention to this issue.

3.2.2.2 Reactive policies

Given that the reduction of the market value is a continuous process that already started and is going to take place over the years to come (through further diffusion of RES-E generation) there is no need to distinguish between preventive and reactive policies. Instead, all measures previously listed are able to increase the market value of existing and future RES-E generation plants (apart from the aspect on including market values in the investment decision).

3.2.3 Short appraisal

In conclusion, the implementation of an internal European energy market and the reduction of must-run capacities can be understood as no regret options, given their positive impacts on market values as well as on other challenges for mature RES-E technologies (e.g. market-based curtailment, see Section 3.1.1). To the same extent, flexibility represents an indispensable tool to keep market values up and compensate for the merit order effect. However, the selection of the right flexibility measure significantly depends on the national circumstances and potentials. In this context it should be kept in mind that it is crucial to design a well-balanced portfolio of the different options as demand side flexibility, storage and NTC expansion influence each other's profitability (Pudlik et al., 2015). Nevertheless, the expansion of net transfer capacities and demand side flexibility represent the most promising options, as they do not only increase market values but also facilitate market coupling and increase price elasticity of demand, thus enhancing the function of the market.

3.3 Non-economic barriers

3.3.1 Description of the challenge

Besides the relevance of economic framework conditions as one key driver for RES-E development, non-economic and other regulatory factors pose an important challenge for the RES-E diffusion. According to Ecorys (2010) examples for the most severe types of non-economic barriers are:

- **Administrative barriers** including problems regarding the planning and authorisation procedure of RES-E projects (delays, high efforts for project developers to obtain the needed permissions or problems related to spatial planning)
- Problems with regard to **grid connections** (inconvenient grid access conditions, long lead times and low transparency)
- **Social acceptance** problems and public opposition from locals against RES-E projects (Not-in-my-backyard NIMBY)

The relevance of non-economic barriers has been highlighted in various research projects, scientific literature and by the European Commission.

On a policy level, the EC pointed out the negative effect of administrative barriers on RES-E deployment and exhorted Member States to take action to reduce them already back in 2001 in its RES-E Directive (see Article 6 in European Commission, 2001). The European Commission (2005) assessed the (inadequate) progress made in reducing these barriers in most Member States and made five precise **recommendations**. These were for Member States to establish, among others:

(1) **One-stop authorisation** agencies to take charge of processing authorisation applications and providing assistance to applicants;
(2) Clear **guidelines for authorisation procedures** with a clear attribution of responsibilities[19] and;
(3) **Pre-planning mechanisms** in which regions and municipalities are required to assign locations for the different renewable energies.

However, subsequently, little progress has been made in most Member States in the follow-up and the effectiveness of support schemes has been seriously affected by the existence of those barriers. Therefore, the EC urged Member States to continue to implement measures to reduce non-economic barriers (European Commission, 2008). The Renewable Energy Directive (European Commission, 2009) requires Member States to take adequate measures to achieve national overall targets, including cooperation between local, regional and national authorities" (art. 4) and lays down rules for administrative procedures (art. 13). In particular, article 13 states that, Member States shall take appropriate steps to ensure that: "administrative procedures are streamlined and expedited at the appropriate administrative level and rules governing authorisation, certification and licensing are objective, transparent, proportionate, do not discriminate between applicants and take fully into account the particularities of individual renewable energy technologies" (European Commission, 2009). In addition, Member States have to report on the progress in reducing these non-cost barriers in the biennial progress report. In their most recent communication on the "Renewable energy progress report" the European Commission still judges the progress in simplifying procedures to be slow and highlights the need for some Member States to address non-cost barriers in particular for large infrastructure projects (e.g. wind offshore) (European Commission, 2015b). At the same time the European Commission recognises some slow progress in the simplification of procedures.

The **role of non-economic barriers** for the diffusion of renewable energy technologies has been taken up by several research projects. At EU-level, the project AEON assessed the role of non-economic barriers for all renewable energy technologies (Ecorys, 2010). In addition, "keep-on-track!" evaluated the Member States' progress regarding RES-E development with a focus on the identification of existing administrative, financial and technical barriers on national level (http://www.keepontrack.eu). Results indicate that barriers in the area of administrative processes are still an important issue, but their relevance has decreased over the last years (Spitzley et al., 2015). Other projects focus on analyzing barriers for certain technologies. In particular, the European research project DIA-CORE provides a standardised comprehensive framework to investigate the

[19] Authorisation procedures must be based on objective, non- discriminatory criteria which are known in advance to the undertakings concerned, in such a way as to circumscribe the exercise of the national authorities´ discretion, so that it is not used arbitrarily.

determinants for the diffusion of RES-E from an investor's perspective and applies this concept to Solar PV and Wind. Identified determinants are classified according to the following four categories (Boie et al., 2015):

- Political and economic framework
- Electricity market structure and regulation
- Grid infrastructure and grid regulation
- Administrative procedures for RES-E projects

These determinants are then evaluated according to their relevance for future RES-E development by applying an extensive stakeholder consultation process with a focus on RES-E investors and project developers.

The project "wind barriers" analyzed the status of administrative and grid barriers for wind power and "PV-Legal" and its successor "PV-Grid" focused on the role of barriers for the development of Solar PV technologies and created an online database for evaluating the non-economic framework conditions for PV development in the EU Member States[20]. Focusing on the analysis of administrative procedures for onshore and offshore wind, the Intelligent Energy Europe project Good practice wind (GP WIND Project) identifies good practices and provides a good practice guide and toolkit for developers (http://project-gpwind.eu/).

To sum up, several research project as well as past European Commission documents and Directives keep on insisting that administrative procedures are a barrier for the penetration of RES-E. There is no reason to think that this would not be a barrier in a 2030 horizon, especially if sustainability criteria become more important with increasing land occupation. Thus, a main challenge for policy-makers is to improve and streamline these procedures in order to facilitate the uptake of RES-E.

3.3.2 Policy design options

3.3.2.1 Preventive policies

Taking into account the increasing use of competitive tenders to determine the financial support for mature RES-E technologies, non-economic barriers are becoming increasingly important. In particular in the light of a potential future opening up of national support schemes across EU-countries the nationally or even regionally determined non-economic framework conditions including administrative and grid-related procedures would distort competition between RES-E project developers. Thus, Ragwitz et al. (2015) suggest mitigating non-economic barriers to reduce risks and ensure a fair competition between all bidders in the following way:

- Create a **stable and reliable policy framework** for administrative processes and spatial planning
- Enhance the diffusion of **best practices** e.g. through guidelines
- Harmonise **spatial planning regulations** and provide uniform national standards
- Introduce **time limits** for permit approval
- Support **local administration**

3.3.2.2 Reactive policies

Tackling non-economic barriers should preferably be addressed by creating favourable conditions when designing RES-E support policies in terms of preventive policies. However, corrective measures reducing non-economic barriers should be undertaken, if the need to do so is recognised. In addition, we recommend realising a **strategic review** of the existing procedures before a tendering procedure is introduced in order to avoid problems with realisation rates of the tendering process.

[20] Information on "wind barriers" is available at http://windbarriers.eu including the publication of Ceña et al. (2010), whilst http://www.pvlegal.eu and http://www.pvgrid.eu provide information on the projects dealing with barriers for Solar PV development.

3.3.3 Short appraisal

Various studies have shown that non-economic factors play a key role for the diffusion of renewable energy technologies. This means that a favourable economic framework based on support policies is not sufficient to stimulate market growth of RES-E. Non-economic barriers may hamper the market uptake of RES-E or increase policy costs and should be mitigated in order enable the planned RES-E development. The role of non-economic factors increases for mature technologies with the increasing use of tender procedures and a potential opening up of support schemes across Member States. Therefore, it is essential to create enabling non-economic framework conditions with a level playing field for all RES-E project developers.

4 Country-specific challenges

Certain challenges for investors of mature RES-E technologies strongly depend on national peculiarities. Based on case-studies, we describe situations in selected European member states that relate to the overall challenges identified in the previous chapter (see Table 2), but include the particular national situations and suggest potential policy design options.

Table 2: Assignment of case studies to EU-wide challenges from Chapter 3

	Risk premium	Non-economic barriers	Market value
Spain: over-capacity and retroactivity	x		
UK: Lacking social acceptance		x	
Germany: No RES-E support in hours with negative prices	x		x

4.1 Spain: Over-capacities are a barrier to the uptake of new RES-E installations

Starting in the mid-90s, Spain was one of the first EU Member States in adopting effective support schemes for renewable energy in the power sector. By the time the current EU renewable energy Directive (European Commission, 2009) was adopted, Spain had already deployed more than 16GW of wind power and more than 3GW of solar photovoltaics, being one of the EU countries with a higher degree of penetration of renewables in its power system.

In 2010 Spain started a period of several profound energy policy changes in the direction of reducing support for RES-E. In January 2012 the Spanish government decided to stop registration of new RES-E installations[21]. In 2013 the Energy Reform was announced, introducing a completely new retribution scheme for RES-E which included **retroactive cuts in economic support for already existing installations**[22]. These policy changes have resulted in a de-facto halt in RES-E deployment in the country (see also 3.1.3.1).

The main argument used to justify these decisions has been the **need to contain the increasing costs of support** for RES-E in order to correct the 'tariff deficit'[23] affecting the Spanish power system. However, an often less mentioned contributing factor for this change in policy may be the fact that the Spanish power system suffers from a serious excess of generation capacity.

In the sections below we analyse how Spain arrived to this situation, the severity of the overcapacity problem and how this affects the deployment of new RES-E capacities, as well as the possible policy solutions that may be applied.

In order to do so, we rely on several sources of information. First, in order to identify the extent of the problem, official data on the electricity generation capacity and electricity demand have been used. Second, a deep literature review on the causes and consequences of this problem, relying on the views of a wide array of

[21] Real Decreto-ley 1/2012, January 27th, 2012.

[22] Real Decreto 413/2014, June 6th, 2014.

[23] The tariff deficit refers to revenues (electricity prices) not covering regulated costs over the period. This tariff deficit reached 30,000 million € in 2013, about 3% of Spain's GDP.

stakeholders, has been performed. Finally, a draft text was produced with the above mentioned sources. It was sent to several stakeholders and their feed-back and views were incorporated in the text.

The next section discusses the degree of the problem, i.e., how much overcapacity exists in the Spanish electricity system. Section 4.1.1 is dedicated to the analysis of the causes and the main consequences of overcapacity. Section 4.1.2 considers several policy options to address this problem.

4.1.1 Description of the challenge

The electricity generation capacity installed in the last 15 years has increased significantly, and virtually doubled between 2001 and 2014, from 55GW in 2001 to 102 GW in 2014. This increase has been above the rise in electricity demand over the same period.

Most new generation capacity came mainly from two generation technologies: wind power and natural gas-fuelled combined cycle gas turbines (CCGTs). Between 2003 and 2010, Spain installed 25.3 GW of natural gas-fuelled generation plants. From 2010 to 2014 the CCGT capacity has remained roughly constant. Over the same overall period 2003-2014, installed wind power increased from 6.2GW to 22.8GW. Investment in new conventional generation was mostly driven by expectations of a substantial future increase in power demand as a result of high economic growth rates. The focus on gas-fuelled plants was perceived as a low risk investment due to their relatively low investment costs, shorter construction periods and lower carbon risk as compared to coal plants.

However, what seems more relevant is to compare the **evolution of the installed capacity** with the maximum electricity demand, which provides an indicator of the security of supply which the system has to safeguard.

Figure 9 below shows the evolution of the installed generation capacity compared to the evolution of the hourly peak demand in the country[24]. The gap between the two has been steadily growing in the last 10 years. The excess dispatchable capacity has also increased significantly over the same period.

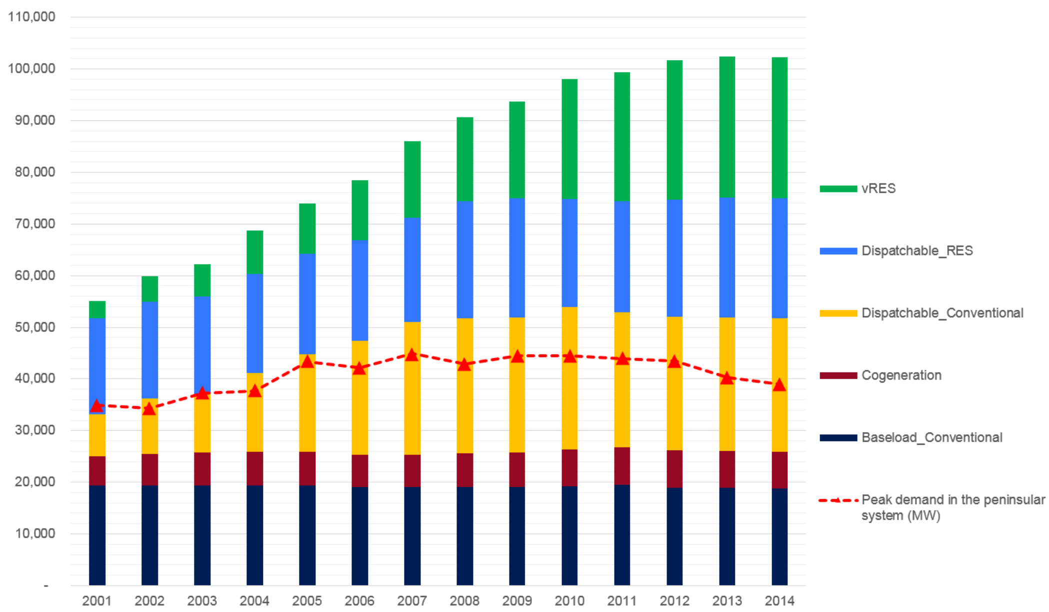

Figure 9: Peak power demand vs. available capacity (MW). Source: Own elaboration. Data source: Red Eléctrica de España.

Back in 2001, the peak demand was roughly the same as the sum of all conventional installed capacity[25]. The 18GW of dispatchable RES-E capacity available (mostly hydro) provided a 'safety buffer' to guarantee security of supply. Additionally, there was an incipient – but already growing – amount of variable RES-E in the system.

[24] In the peninsular system.

In 2014, the situation was radically different. Conventional capacity alone exceeded the peak demand, which remained roughly at 2001 levels, by 13 GW. Additionally, there are 23 GW of dispatchable RES-E capacity and 27GW of variable RES-E capacity in the system. The installed capacity of RES-E in 2014 is even much higher than the historical peak demand, which occurred in 2007. The most recent data show that installed power capacity more than doubles maximum peak demand in the day with the maximum electricity demand in the Spanish system (4 February 2014, between 8 p.m. and 9 p.m.).

This overcapacity has to be put in a European context. There have been overcapacity problems in other EU countries. According to the "Leistungsbilanz" report (50Hertz et al., 2014), the day with the maximum load in Germany was December 5th 2013. On that day, the "secured capacity" was 116.3 GW and the maximum load was 79.1 GW. Therefore, there was an overcapacity of 37.3 GW or 47%. According to the Spanish Ministry of Industry (2013), using the methodology of the European Network of Transmission System Operators for Electricity (ENTSO-E) a coverage ratio of 1.73 times would be a "desirable coverage index" in Spain. This same indicator is 1.28 for Italy, 1.21 for Germany, 1.15 for U.K. and 1.09 for France.

4.1.1.1 Factors behind overcapacity

At a very general level, the causes of overcapacity are related to the factors affecting both sides of the problem, the supply and the demand side, i.e., factors influencing the substantial increase in capacity and other factors behind the stagnant evolution of electricity demand. Therefore, the following causes can be noted. Some of these factors are interrelated to some extent.

Risks related to security of supply in the late 1990s

A major risk in a context of highly increasing electricity demand is that it outpaces the installed generation capacity, leading to security of supply problems in the form of black outs.

In the second half of the 90s the gap between the 'firm' generation capacity available (base load and dispatchable plants) in the Spanish system and the peak hourly demand was closing at a very fast pace. This resulted in some situations of elevated risk of blackouts in some regions of the country.

Macroeconomic factors

Until 2008 banks were eager to lend money at relatively low interest rates, which favoured investments in electricity generation capacity.

Spain went under an economic boom in the late 1990s until 2007 and a deep **economic crisis** thereafter. Obviously, this has had a large impact on a highly increasing electricity demand (triggering the aforementioned concern of the government about the possibility of black-outs) and a stagnant and, eventually decreasing electricity demand since 2008. Both industrial and residential demand increased significantly.

In contrast to the developments in installed capacity, the **power demand forecasts** done in the early 2000s turned out to be too optimistic. The 2005 revision of the Spanish Plan for Power and Gas Infrastructure 2002 – 2011 (Spanish Government, 2005) estimated that peak power demand would grow by 24% in 6 years (from 43 GW in 2005 to 53 GW by 2011). These estimations, however, did not materialise in practice. The Spanish economy started to decelerate in 2007 and after the global financial crisis in 2008, Spain entered a period of economic stagnation / recession. Actual peak power demand in 2011 was 44 GW (17.5% below estimations). Since 2011, the peak power demand has further decreased to 39 GW in 2014, a number comparable to the maximums reached a decade earlier. There was a lack of appropriate coordination/monitoring of long-term power system requirements (capacity needs dependent on demand projections) between long-term renewable de-

[25] Including nuclear, coal, gas and cogeneration plants

ployment objectives and developments in the conventional generation sector. According to the Ministry of Industry (2013), GDP and electricity demand were forecasted to increase by an accumulated 25% and 24%, respectively, in 2013 compared to 2005 levels. In contrast, GDP grew by only 2% and electricity demand was reduced by 1% in such period. Electricity demand growth rates in the last years have generally been negative.

Government investment signals

Through regulations or the approval of planning documents, the government has undeniably influenced the expectations of investors in specific technologies. In particular, this has been the case with the two technological categories undergoing the greatest growth rates in the 2000s: CCGTs and RES-E. The aim was to force an energy transition towards less polluting fuels and more efficient plants and away from coal and fuel-oil plants.

CCGTs were the main option of utilities to respond to the increasing electricity demand, in a context of cheap financing, plants which were less risky, easy, fast and relatively cheap to build than other alternatives. The Plan for Electricity and Gas Infrastructures 2002-2011 gave an undeniable backing for the investment in CCGTs. This plan envisaged the construction of 14.8 GW of CCGTs. This target was increased to 30 GW in 2005. It was an indicative target, i.e. not binding (neither for the state nor for firms).

Two main planning documents for RES-E were the Renewable Energy Plans in 1999 (IDAE 1999) and 2005 (IDAE, 2005). Both had objectives for RES-E in 2010 (30,355 MW and 42,494 MW, respectively) which have been clearly surpassed.

Easy granting of administrative authorisations

The regions, which had competencies on the siting of electricity generation plants, were eager to grant permits to these plants. Administrative permits for RES-E plants were easily and quickly granted by the regions, given the high level of perceived local benefits and the fact that the costs were shared by all electricity consumers nationally (Iglesias et al., 2013).

Overcapacity as an inherent issue in systems with high RES-E penetration

Given the relatively low capacity factor of RES-E and the need for back-up capacity from conventional electricity sources, electricity systems with a large penetration of RES-E might be inherently more capacity-intensive than others in order to produce a given amount of electricity and ensure the security of supply at all times during the day (base-load and peak-load).

4.1.1.2 Effects of overcapacity

The huge overcapacity present in the system has palpable economic consequences at system level (societal perspective) and for power market actors (both conventional and renewable generators). At the system level, overcapacity results in **underutilisation of assets** which in turn results in a sub-optimal allocation of economic resources. Market actors also suffer the consequences of overinvestment. Natural gas-fuelled plants have seen a radical reduction in their utilisation factor over the last years. For renewable generators, overcapacity results in two main negative effects: Firstly, the **downward pressure on wholesale power prices**, results in an increased competiveness gap (difference between the RES-E generation costs and the revenues obtained from the market), increasing the need for support per unit of energy generated. Secondly, **overcapacity hinders further penetration of renewables** in the system, since in such conditions it is difficult to justify politically the provision of economic support for new RES-E plants, which are not needed from a strict ‘security of supply’ point of view.

Interview-based survey among Spanish stakeholders

A survey among stakeholders was launched in October-November 2015. Its aim was to know the **opinion of these stakeholders** about the causes and consequences of overcapacity of electricity generation as well as policies to address this problem.

An e-mail interview with structured responses was sent to different types of stakeholders. These included energy experts, energy regulators and the renewable energy associations. 15 people were contacted, with no aim of representativeness, whereof 11 accepted to respond to the interview. Three interviewees were from electric utilities, four were energy regulators, three were energy experts and one came from a renewable energy association.

Most interviewees considered that **lack of planning** could be blamed for overcapacity in Spain. After that, the economic boom leading to a considerable increase in demand was pointed out as a main factor behind this problem.

The eleven interviewees unanimously indicated that overcapacity would lead to a suboptimal allocation of economic resources. Overcapacity was clearly identified as a highly relevant barrier for further investments in renewable energy technologies.

Finally, regarding the **policies to address this problem**, two types of policies were differentiated, depending on their short-term (effectiveness of already implemented measures) or long-term scope (what to do in order to mitigate the problem in the long-term). Regarding the short-term policies, most of the interviews (6) considered that the improvement in the interconnection capacity with other countries could mitigate the problem. This was followed by "hibernation of CCGT plants" (3 interviewees) and "the moratorium to RES-E electricity generation" could mitigate this problem (2 interviewees).

Regarding what to do to solve the problem in the long-term, five interviewees argue that this is an opportunity to discourage the operation of more polluting power plants. Three claim that a better long-term energy planning could have improved this problem in the first place. Providing incentives for electrification of the transport and heat sectors and removing capacity payments for dispatchable power plants are not regarded as a solution to the problem.

4.1.2 Policy design options

Given the dimensions of the problem described above, it seems very likely that its effects will last long and the adjustments required to stabilise the situation will be deep. Spain is equipped with a relatively young power plant fleet (Fichtner, 2012)[26]. During the last ten years, massive investments have been made in new natural gas-fired power plants. Almost no new coal power plants have been brought on line in Spain for at least twenty years and also no new nuclear power plants (Fichtner, 2012).

While it can be expected that the recovery of the Spanish economy will result in increasing levels of demand which will contribute to the correction of this issue in the long term, short term energy policy decisions need to carefully take into account the current situation.

4.1.2.1 Measures adopted so far

Energy policy decisions in Spain seem indeed to have been influenced by this issue in the last few years:

The abrupt **cancellation of economic support** for all new RES-E plants in early 2012 - aimed at containing increasing RES-E support costs - resulted also in an effective halt in new RES-E deployments in the country. Alt-

[26] According to Fichtner (2012), the retirement rate in the 2010-2020 period is about 24% (installed capacity in 2010 amounted to 98,000 MW, whereas expected retirement in the period would be 23834 MW).

hough a new RES-E support scheme is in place since 2014, this has not triggered a recovery in investments in the renewable sector so far.

In the Energy Reform of 2013 the Spanish Government tabled a regulatory framework for the '**hibernation'** (temporary closing) of combined cycle gas plants. Although the regulation has not been approved so far, the Spanish Government is considering the temporary closing of 6 GW of CCGTs in its infrastructure plan for the period 2015-2020 (MINETUR, 2014).

The Spanish Government has also been pushing actively in recent years for an **expansion of the interconnection** capacity with France, which could possibly result in increased electricity exports to northern EU countries, partially mitigating the effects of the Spanish overcapacity.

While these measures may help mitigate the effects of overcapacity in the short term, a long-term sustainable solution to the issue - enabling further penetration of renewable generation in line with 2030 RES-E objectives – would require a broader list of policy measures.

4.1.2.2 Preventive policies

It is important to incorporate the lessons learned about the past conditions that created the current overcapacity problem into future long-term energy policy decisions.

In order to avoid building new overcapacities in the future, developments on the conventional generation side need to be carefully coordinated with national renewable energy deployment objectives. Actual levels of deployment, both on the conventional and the renewable side need to be frequently monitored. In this point it is critical that national authorities – in charge of long-term energy planning – and local and regional authorities – usually in charge of permitting procedures - coordinate very closely.

4.1.2.3 Reactive policies

Overcapacity is a serious short-term problem; however, the possible solutions to this problem may also open opportunities to accelerate a broader long-term transition to a low-carbon energy system. The excess generation capacity can be corrected by adopting measures both on the demand and supply side:

On the demand side, setting up policy incentives to increase domestic demand of electricity seems at first incompatible with EU energy efficiency and climate strategy and commitments; however, these policies could be justified if they offset primary energy consumption in other sectors. In this sense, the overcapacity in the electricity system may be an opportunity to accelerate the **electrification of the heat and transport sectors**, which is arguably a main trend for the decarbonisation of the whole economy (IEA, 2014a). However, care should be taken when considering this as a simple solution. The (marginal) emission factor of electricity has to be compared to the emission factor of the reference energy carrier (i.e. petrol, diesel in the transport sector and gas or oil in the heat sector). Furthermore, whether this is a sensible strategy in terms of CO_2 abatement efficiency depends on the CO_2 abatements costs in the different sectors.

The supply side can also contribute to the correction. If the excess generation capacity has a positive side is that the most polluting plants remaining in the system are no longer critical to guarantee security of supply. Overcapacities could serve as a reason to realise a **gradual coal phase-out** in the medium term, e.g. de-incentivise the continuation of the most polluting plants e.g. by establishing stricter environmental standards for combustion plants and removing existing subsidies for the consumption of domestic coal.

In situations of overcapacities, it should be reconsidered to possibly **remove or adapt existing capacity payments** for dispatchable generation plants. In the Spanish case, these payments exist, with the rationale to incentivise investment in new plants. However, the original objective to guarantee generation adequacy is not a concern in situations of overcapacity. Spain has currently the opposite problem. Capacity payments are hardly justified in these conditions except for strategic plants e.g. those placed in specific network hubs with additional need for dispatchable capacity.

If overcapacity occurs in combination with limited cross-border transfer capacities, these could be improved in order to have the option of increasing electricity export. Thus, the goal set up in the **Energy Union** Package of a minimum interconnection target set for electricity at 10% of installed electricity production capacity of the Member States by 2020 and 15% by 2030 could certainly provide an opportunity for Spain to deliver electricity to other countries, where a clear lack of generation capacity can be observed. In fact, interviews carried out for this project show that the improvement in interconnection capacity is regarded as a main option to mitigate the overcapacity problem (see text box at the end of Section 4.1.1).

4.1.3 Short appraisal

Overcapacity of electricity generation capacity in Spain, caused by several factors, can certainly be considered a barrier for the future deployment of RES-E. Several policy alternatives have been proposed to deal with this problem, either in a short-term or a long-term horizon.

4.2 Germany: No RES-E support in hours with negative prices

4.2.1 Description of the challenge

4.2.1.1 Background and problem definition

As outlined in Section 3.1.1, the number of hours with negative prices is likely to increase in the future, increasing the risk premium for RES-E investors through market-based curtailment. In addition, the state aid guidelines for environmental protection and energy (sec. 3.2.2.1, (124a)) of the European Commission (2014) require Member States from 1 January 2016 to put in place measures that "ensure that generators have **no incentive to generate electricity under negative prices**". In the framework of the last update of the German Renewable Energy Act (EEG) the government has added the new article §24 to comply with these requirements (BMWi, 2014). §24 specifies that for wind turbines with an output of at least 3 MW and other plants with an output of at least 500 kW (and which will be in operation as of 1 January 2016) the reference value to be applied for the determination of the feed-in premium is to be reduced to zero if "the value of the single-hour contracts for the price zone Germany/Austria on the spot market of the electricity exchange EPEX Spot SE in Paris is negative for at least six consecutive hours". A reduction of the value to zero in the above-mentioned situations means that for these hours no market premium is paid.

Thus, security of investment in wind and solar capacities is not only endangered by negative prices but, in the German case, additionally by a **forced shut down at times of maximum RES-E production** (given the high correlation between RES-E generation and negative wholesale prices at the spot market). The key question is to what extent §24 can cause revenue risks and additional risk surcharges and which policy options can mitigate these risks.

4.2.1.2 Past occurrences of negative electricity prices in Germany and other European countries

Since 2008, in more than 10 hours every year, prices dropped below zero at the day-ahead market at EPEX-Spot (see Table 3 and the analysis carried out in Section 3.1.1). The maximum of 71 hours with negative prices was reached in 2009. Afterwards this number fell again due to the market coupling with Germany's neighbouring countries. Since 2012 it follows an increasing trend due to the further expansion of RES-E capacities, reaching in 2013/2014 nearly the level of 2009. In those two latest years the annual minima of the market prices have stabilised at a level which corresponds to the negative market premium of wind parks with the lowest support. Intervals with negative electricity prices which lasted for a minimum of 6 hours have mainly occurred since 2012 (see Figure 10). Between 2012 and 2014 a total of 10 intervals with negative electricity prices which lasted for at least 6 hours occurred.

Table 3: Number of hours with negative prices and annual minima of electricity wholesale prices on the day-ahead market at EPEX Spot, 2008-2014

	2008	2009	2010	2011	2012	2013	2014
Number of hours	15	71	12	15	56	64	64
Annual minima [€/MWh]	-101,52	-500,02	-20,45	-36,82	-221,99	-100,03	-65,03

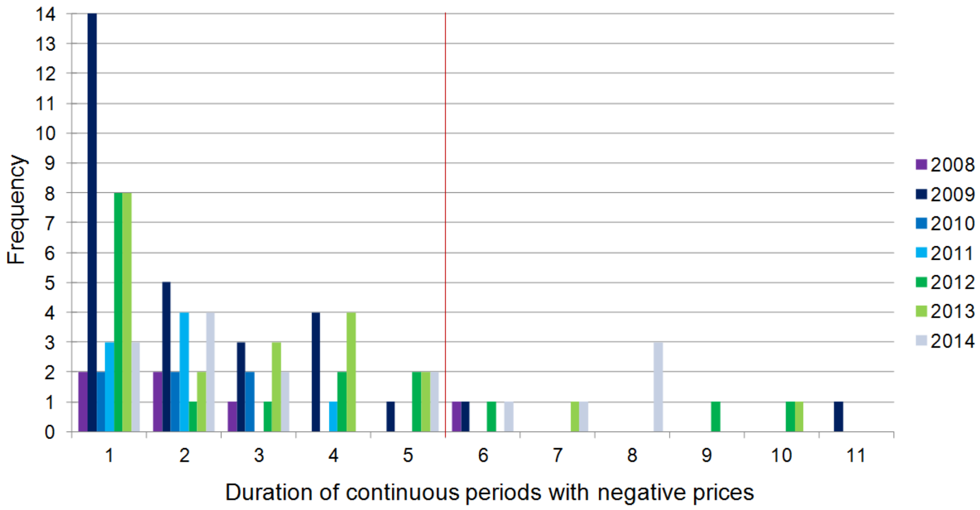

Figure 10: Duration of continuous periods with negative wholesale prices on the day-ahead market of EPEX Spot. Source: (Fraunhofer ISI et al., 2015a)

4.2.1.3 Future development of negative electricity prices

In the past, the frequency of situations with negative prices that last for at least six hours has played a minor role in the electricity wholesale market (see Figure 10). Thus, the regulation of § 24 EEG would have had a marginal effect on the earnings of operators of RES-E installations. However, due to further expansion of RES-E capacities, such §24 situations are expected to occur more frequently in the future. To quantify their future occurrence a quantitative assessment was performed by Fraunhofer ISI et al. (2015a) with the aid of a **residual load analysis**. The calculated RES-E development until 2030 is based on the respective target of a 55-60% share in gross electricity production. It is further assumed that the capacity of must-run assets drops from currently 18 GW to 5 GW until 2030 by developing flexibility on both the production and the demand side. The RES-E feed-in and load are based upon nine different historic weather years (WY, 2006-2014) and an additional synthetic WY that considers a RES-E generation profile which was adapted to the future RES-E generation mix in order to better take into consideration weak wind turbines and thus providing a flattened generation profile (i.e. higher generation during low wind periods but less pronounced generation peaks in wind intense periods).

Figure 11 shows the development of hours with surplus electricity relevant for §24 as an indicator for the hours with negative prices until 2030. One can observe that the number of surplus hours relevant for §24 will rise despite the increase in flexibility of the energy system. Whereas in 2020 the average number of hours across all WY is about 85 hours, it increases to 267 hours until the year 2030. It is also important to note the impact of the weather year on the number of surplus hours which ranges (in 2030) between 180 and 520 hours. The effect is even more significant when including the adapted generation profile in the comparison where the number of surplus hours is minor to 80 hours per year. In total, the average number of surplus hours in 2030 corresponds to approx. 3% of the overall number of hours per year (which is 8760). The number of intervals with surplus electricity generation will rise between 2020 and 2030 on average from 9 to about 25, with the average surplus period lasting for about 9 hours in 2020 and 11 hours in 2030.

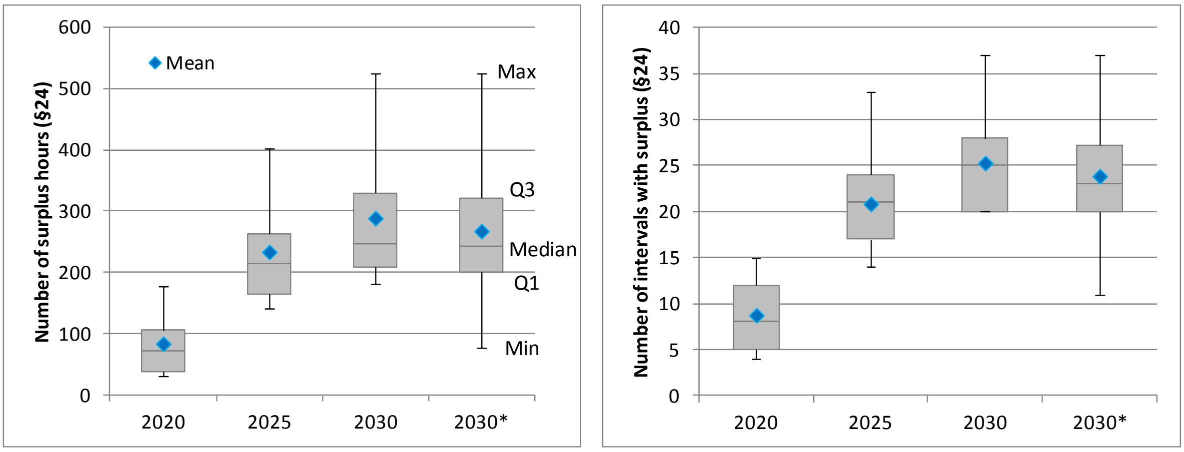

Figure 11: Evolution of the annual number of hours with negative prices (left) and the respective number of intervals (right) across the different weather years. 2030* contains the adapted generation profile. Source: (Fraunhofer ISI et al., 2015a)

The respective amounts of RES-E generation which would be produced in situations falling within §24 (i.e. more than 6 consecutive hours of negative prices) sum up on average to about 3.4 TWh in 2030 (see Figure 12). This is the equivalent of 3% of the total electricity generated in RES-E installations affected by §24 (i.e. commissioned as of 2016). However, in extreme cases the curtailed electricity generation may be more than twice as high, equalling up to 7 TWh or 6% of total RES-E generation.

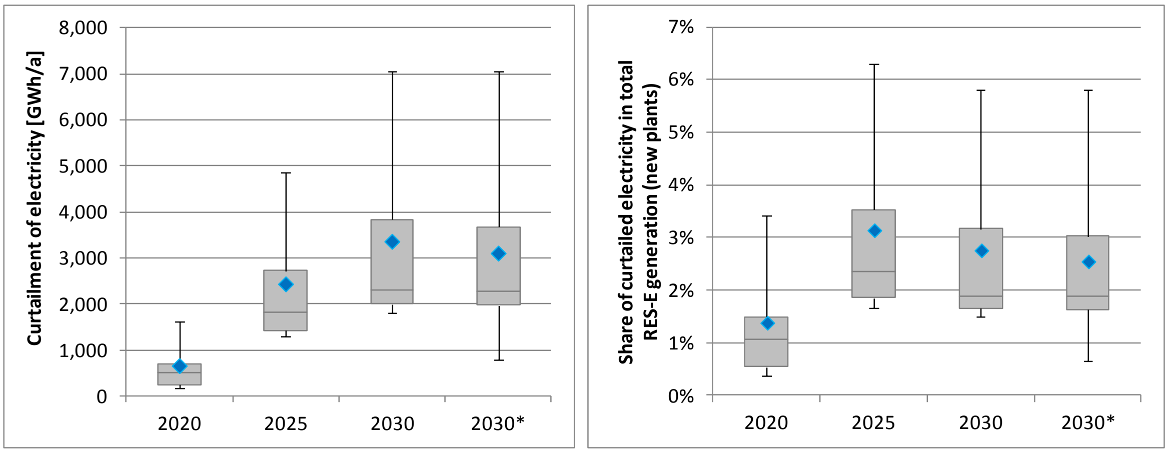

Figure 12: Evolution of future amount of curtailed electricity (left) and share in total electricity generation (right) across the different weather years. Source: (Fraunhofer ISI et al., 2015a)

4.2.1.4 Impacts of §24

If marketers expect a §24 EEG situation they probably adjust their bids in order to **counteract a loss of revenue**. It is most probable that they do not submit their bids at the price of the negative market premium[27] but of

[27] The usual behaviour of bidding at the price of the negative market premium is explained by the fact that this is the lowest price at which income can be generated, as the income consists of the market price and the actual market premium.

0 €/MWh on the day-ahead market. Electricity that was not marketed on the day-ahead market would then be put on the intraday market (if this is within the regulation for managing regional balancing zones).

Alternatively, §24 could incentivise marketers to behave in a questionable way with respect to anti-trust and competition law: Marketers might aim to prevent §24 situations by **avoiding a negative market price** in the sixth hour through a coordinated strategy. Possibly the activities of just one marketer are sufficient if he has a correspondingly large market share during the hours in question.

Both strategies are questionable with respect to the efficiency of the wholesale price signal and could, thus, ultimately jeopardise the operability of the market as a whole. In addition, a reduced amount of energy sold and a reduced market premium imply losses of revenue for plant operators and marketers.

These revenue losses are all the more increasing the risk for investors and operators, as they may vary significantly in scale. On the one hand there is the risk of an incorrect forecast of the occurrence of §24 situations ("management risks"). This can induce marketers to adapt their bidding strategy although this may not have been necessary or vice versa. On the other hand the there is considerable uncertainty regarding the exact extent of the future occurrence of §24 situations, implying additional "revenue risks" for plant operators affected by §24 EEG.

In this context, the question arises whether the occurrence of negative prices indicates inefficient market activities. Fraunhofer ISI et al. (2015) state that the occurrence of negative prices may inter alia be caused by the regulatory framework for RES-E but it is not necessarily a proof of inefficient market situations. Considering that the market premium reflects the "green" value of the RES-E for target achievement, negative prices up to the market premium do not necessarily indicate market failure. Thus, a system with negative prices up the value of the market premium may be considered to be economically efficient if the "green kWh" is associated to an environmental value added. In surplus situations marketers / plant operators reduce their feed-in if the negative market revenues over-compensate the granted market premium.

4.2.2 Policy design options

The policy options conceivable to address the previously outlined risks comprise (1) the abolition of § 24 EEG without substitution, (2) compensation payments for marketers or plant operators for revenues lost due to §24 EEG, or (3) coupling of day-ahead and intraday market to cushion the risk-conducive impacts of §24.

4.2.2.1 Absolute risk avoidance: Abolition of §24

Fraunhofer ISI et al. (2015a) come to the conclusion that §24 EEG does not increase market efficiency but particularly raises the risks for RES-E investors. From an economic and energy-industry perspective it is therefore recommended that **§ 24 EEG is abolished without substitution**. Negative prices are an incentive for both additional flexibility and shutting down additional conventional generation in times of high renewable feed-in. The rules under § 24 give the opposite incentive and therefore lead to inefficiencies. Suspending remuneration under §24 creates additional risks particularly for operators of RES-E facilities to which they cannot react productively. Given this background it appears highly appropriate to further develop the state aid guidelines (European Commission, 2014) or interpret them differently. Abolishing §24 EEG without substitution is the only policy option which avoids all negative consequences of the current regulation.

4.2.2.2 Second best solution: Compensation for losses of revenue and special conditional bids

If the recommended solution cannot be implemented other policy options can be considered, even though none is able to outperform the others when addressing the negative impacts of the current regulation. It is therefore necessary to weight the policy options in order to rank them.

Reducing revenue risks and inefficient management risks are key issues. Both risks, however, depend on the further development of the energy system. In order to avoid risk premiums which result from the frequency of negative prices it is sensible to **compensate losses of revenue**. At the same time, in order avoid the described management risks and related efficiency risks it is recommended to introduce **particular, conditional bids** at EPEX Spot which are tailored to §24 EEG (similar to the “linked block” or “flexible block” orders at the Nord Pool Spot). These conditional bids would enable operators to sell their electricity only if no §24 situation occurs. This would not increase costs of the RES-E expansion by additional risk premiums (which would remain relevant in case of calls for tender). Furthermore, it is recommended **tying compensation payments to conditional bids**. This would give marketers a clear incentive to make use of conditional bids and to avoid incentives for collusive behaviour. Further, putting the efficiency of the market price signal at risk would be minimised.

In order to effectively reduce risk premiums, timely compensation payments are advantageous for liquidity reasons. Explicit financial compensation analogous to feed-in management is to be preferred to an additional quantitative quota at the end of the support period. This proposal is cost-neutral for the support costs as it can be assumed that the compensation payments will avoid risk premiums to finance the project.

4.2.2.3 Other solution: Coupling of day-ahead and intraday market

If compensation payments or conditional bidding cannot be implemented in the short term, coupling the day-ahead with the intraday market as a reference market for the identification of §24 situations represents an interim policy option. This would limit the occurrence of §24 situations to very few situations or at best avoid it entirely which would drastically reduce possible losses of revenue. Coupling the markets makes operational implementation (particularly with a view to marketers’ bidding strategy and therefore also the management risk) more complex. At the same time the price signal between day-ahead and intraday market is distorted in the medium term just as under the present regulation if (despite the coupling) §24 situations occur frequently. This market coupling is therefore only to be recommended as long as it is highly probable that no or very few §24 situations occur. However, there is uncertainty if such an adjustment would withstand a state aid audit.

4.2.3 Short appraisal

The full abolition of §24 is considered as most promising measure to reduce additional risks for RES-E investors arising from the particular decrease of the market premium to zero in the relevant situations. However, it remains uncertain whether the German government reject §24 given the requirements from the European state aid guidelines. Against this background, we suggest to design policies that enable conditional bids or allow for compensation payments.

4.3 UK: Lacking social acceptance for new wind parks

The UK had a cumulative installed wind power capacity (both onshore and offshore combined) of 12.4 GW at the end of 2014 (EWEA, 2015). This is equivalent to 9% of the total EU capacity (ibid). Currently, wind makes up on average ca. 5-6% of total electricity demand in the UK. Yet, significant **potential for further development remains available**. Despite this, the deployment of wind energy, in particular onshore wind, is smaller than in other European countries with less favourable wind resources. As of September 2015, installed capacity of onshore wind in the UK was 8,258 MW (Renewables UK, 2015). In its National Renewable Energy Action Plan, the UK established an objective of 14,890 MW installed of onshore wind by 2020, so significant deployment will be needed in the next 5 years to meet this target. Further deployment will be required in the period 2020-2030 to meet common EU objectives.

In June 2015, the UK government decided to halt subsidies to new onshore wind power plants. Levels of **public opposition** to onshore wind power plants in the UK are high. Under these conditions it is not clear whether future levels of deployment will be sufficient to meet renewable energy and climate goals.

4.3.1 Description of the challenge

4.3.1.1 Public opinion towards onshore wind

Even though vast wind resources are available in the UK, onshore wind development is not realising its full potential. An important issue affecting growth is that wind energy, particularly on land, continues to be subject for debate among the public. In regular polls the public is asked about their opinion on energy issues, renewable energies as well as climate change. On a national level, **favourability towards wind power depicts a downward trend**. Support for onshore wind therewith decreased from 76% in 2007 to 68% in 2015.[28] At the same time, opposition had been rising from 2007 until 2013, while in 2014 and 2015 opposition fell back to 10%.

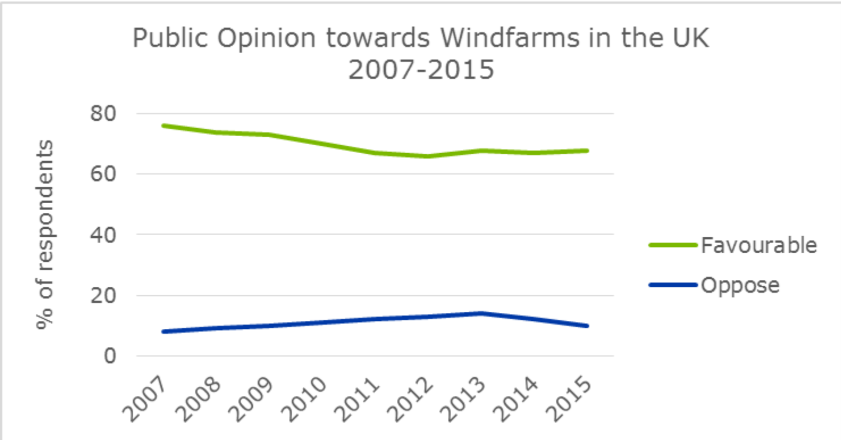

Figure 13: Public Opinion towards Wind Farms. Data based on EDF tracker and DECC public attitudes tracker

Although on a national scale, views towards wind power tend to be more favourable, opposition remains strong at a local level (Jones and Eiser, 2010). This is due to the fact that the view with which respondents answer questions in a poll is different at national level, where issues are perceived to be country-related, taking into consideration energy security and problems of climate change, to a local level where issues are contextualised with home and hence residence and personal impacts of the energy technologies (Pidgeon et al., 2008).[29] In 2009, for example, a **national alliance to oppose windfarms** was formed by thirty local action groups who opposed the siting of wind turbines in their local communities.[30] In 2012, research by The Guardian revealed that local opposition to onshore windfarms had tripled since 2010 when British people were asked whether they would support the building of a windfarm within five miles of their home (Carrington, 2012).

Nevertheless, high levels of support for wind farms, also at local levels, exist in Scotland (Scottish Renewables, 2013). Over the past two years, support for wind power in Scotland has increased alongside the development of onshore wind. A 2015 YouGov survey commissioned by Scottish Renewables finds that 71% of the popula-

[28] Data from 2007 to 2011 based on time series research by YouGov for EDF. Data from 2012 to 2015 based on DECC Public Attitudes Tracker.

[29] For further information on predictors of public opinion on wind and nuclear in the UK see: Förster, S. (2013): British Attitudes to Nuclear and Wind Power. https://yougov.co.uk/news/2013/09/06/british-attitudes-nuclear-and-wind-power/.

[30] http://www.windfarmaction.com/

tion want wind power in the British energy mix, while in 2013 only 64% expressed their support (Scottish Renewables, 2015).

4.3.1.2 Reasons for low public acceptance

Public opinion is a multifaceted issue as the public is a heterogeneous group with varying "interests, experiences, beliefs and values" (Whitmarsh et al., 2011). Despite the advantages that wind power can offer, articles in the media repeating misstatements, emotive language of journalists as well as individual's attachment to the landscape and personal concepts of how the countryside should look are entwined with public oppositions (CSE, 2011). Especially at a local level, opposition is often triggered by the **concern that landscapes are being destroyed** as well as the idea that **property prices will drop** where wind turbines are in view (CSE, 2011). Besides the visual impairment of country sides, residents in close proximity are worried about an unacceptable level of noise that is caused by the movement of blades. This can be conceptualised as **NIMBYISM** ('not in my backyard') which highlights the dichotomy between a public good and an individual's attempt to maximise personal utility. However, drivers of oppositions are not only personal impacts of wind power, but also a gap in understanding how the local windfarm will benefit society as a whole. Additionally, local opposition is frequently the result of a **poorly undertaken public consultation process** and a limited perception of fairness and economic benefits of residents (Jones and Eiser, 2010). At the national level, along with the destruction of landscapes, unreliable electricity supply and increasing electricity costs are major concerns which are driving opposition (Bassi et al., 2012). General believes are that onshore wind is both **expensive and heavily subsidised** by taxpayers. The argument is made that windfarms would not exist without significant subsidies which were paid under the Renewables Obligation, or the exemptions received from the Climate Change Levy (CSE, 2011). Besides the costs aspect, intermitted electricity supply is another argument that is frequently made against onshore wind. Accordingly, it is difficult to match demand and supply, especially given limited storage capacities.

In addition to the outlined arguments which often arise due to misconceptions and a lack of knowledge, several other common concerns about wind power are voiced. These are summarised in the following text box.

Table 4: Further arguments against onshore wind

Frequent arguments used against onshore wind in the UK:

<u>Wind turbines are perceived as not green</u>

Some people (wrongly) believe that a mismatch between energy required in the construction and installation and the actual generation of energy over its lifetime exists. The energy balance is perceived to be negative, while too much carbon is needed during manufacturing.

<u>Wind turbines are not needed in the energy mix</u>

Onshore wind is not seen as a crucial part of the British energy mix as it could be replaced by nuclear energy which is by some perceived as more reliable. Secondly, the UK should not focus on onshore wind but all efforts should be put into further developing offshore wind capacity.

<u>Climate change is not a concern</u>

It has been highlighted in surveys conducted by YouGov that concern for climate change in the UK has decreased, which has also reduced support for onshore wind (YouGov, 2012).

<u>Wind turbines cause shadow flicker and epilepsy</u>

When the rotating blades of a wind turbine cast a shadow on an observer this effect is known as shadow flicker. As the blades move, they cast shadows on nearby grounds or dwellings, which is most noticeable through windows. It is wrongly believed that individuals who suffer from photosensitive epilepsy are likely to have a seizure as a result of this effect (CSE, 2011).

4.3.2 Policy design options

4.3.2.1 Political decisions

In order to understand opposition against windfarms, it is crucial to look at **past and current policy developments** as they are main drivers of public opinion. At the beginning of 2012, 106 Members of Parliament voiced their opposition against onshore wind in a letter to the Prime Minister, asking to cut down on subsidies for wind farm development (letter published in The Telegraph, 05th February 2012). Furthermore, the Conservative Party manifesto for the 2015 elections commits to 'halt the spread of subsidised onshore wind farms' (p.58). In May 2015, an Energy Bill was announced in the Queen's Speech which would remove onshore windfarms from the development consent process, thereby returning decision making power to the local planning authority by removing them from the Nationally Significant Infrastructure Project regime. First only wind projects of over 50 MW will be concerned, yet in due course it will apply to all onshore wind projects (Smith, 2015).

The Renewables Obligation, which has been in operation since 2002 has been the main financial incentive programme for renewable electricity generation. It requires power suppliers to supply a specific proportion of renewable energy. Eligible generators receive Renewables Obligation Certificates (RECs) for each MWh generated. However, the Secretary of State for Energy and Climate Change, Amber Rudd, announced in June 2015 that the Renewables Obligation will be closed to new onshore wind projects from April 2016 (House of Commons, 2015).

The Renewables Obligation was replaced by the **Contracts for Difference** (CfD), an auction scheme for renewable energy for which the results of the first auction round were published in early 2015. However, it is not clear whether onshore wind might also be excluded from the CfD in subsequent auction rounds.[31]

The deployment of small-scale renewable energy is incentivised via a Feed-In Tariff scheme which was introduced in 2010. In 2012 rates were cut while degression triggers were introduced (IEA, 2014b).

4.3.2.2 Policy options

Compared with other European countries, the issue of NIMBYISM seem to be strongest in the UK. A lack of community involvement is seen as a dominant factor in the opposition of windfarm development. As siting decisions are predominantly driven by the private and the commercial sector, **residents do not feel involved** in the planning process nor do they receive a share of economic benefits.

In general public attitudes towards renewables are highly positive, yet local opposition to wind farms also exist in Denmark. Therefore the **Danish Renewable Energy Act** (2009) introduced specific measures for greater citizen involvement and the generation of local economic benefits which helped to ensure a more widespread acceptance of onshore wind. In particular, the Act contains four instruments to promote acceptance of onshore wind farms:

- "a fund to support the financing of **preliminary investigations** by local wind turbine owners' associations or groups;
- a mandatory **auctioning** of a minimum 20 per cent of the shares in a wind turbine **to neighbours** living within a 4.5 km limit of the wind farm project;

[31] http://renews.biz/92129/rudd-stalls-on-cfd-decision/

- a right of property owners to **full compensation for loss of value** to real property due to the siting of wind turbines in their vicinity; and
- a fund to enhance local scenic and recreational values, such as **nature restoration projects** or the installation of renewable energy sources in public buildings" (Olsen, 2013).

A similar picture is drawn in Germany where empirical evidence highlights the correlation between financial participation and acceptance of onshore wind developments (Leuphana University and Nestle, 2014).

These examples could be used to inform policy making in the UK. The creation of a fund, under which **local value added is increased** as well as an encouragement of active participation of the public, can help to overcome local opposition. Besides increasing local value added, fact-based **information campaigns** could help to mitigate the effect on the public opinion of common misconceptions about wind power and highlight the wide range of public benefits of this technology. As the concern for climate change has been decreasing in recent times in the UK, renewables and especially onshore wind could be re-framed as a way of tackling e.g. energy security (Langley and Dickman, 2013), reducing air pollution from fossil-fuelled plants, driving the development of domestic high value added industries and creating jobs.

4.3.3 Short appraisal

The measures suggested above may lead to an increase in the **feeling of ownership** by local communities and therefore to an increase not only specifically in the social acceptance of onshore windfarms but also in the awareness of environmental problems e.g. climate change. In addition to this, the implementation of a fund for local communities could potentially **create various co-benefits** e.g. improve community spaces, reduce energy consumption and carbon emissions or support rural and community development projects.[32]

These measures may stumble upon a number of **obstacles**. The creation of a fund for local communities is not always straightforward and may need a different structure for each wind farm project depending on the community structure and available financial means. On the other hand, the auctioning of part of the shares of the wind farm may be a difficult process for non-professionals and require additional time and resources for local residents to be appropriately informed to participate.

The measures described above are in principle **applicable in other countries** (as we have seen in Denmark and Germany) and to other technologies e.g. PV; however, in the case of the UK, the debate about social acceptability has been more centred in onshore wind due to the large availability of domestic wind resources and the strong opposition for this particular technology.

[32] Of course, these co-benefits potentially entail an increase in project or support costs.

5 Summary and conclusion

This study assesses challenges faced by mature RES-E technologies that may impede further deployment in the run-up to the year 2030. The challenges identified may occur across all EU Member States. The general assessment of these challenges is complemented by three specific case studies that exemplify how these challenges have materialised in practice in specific countries (Germany, Spain and UK). Possible policy options to address these challenges are suggested.

Three key challenges for continuous deployment of mature RES-E technologies were identified:

(1) **Uncertainty** for potential RES-E investors as a consequence of increasing occurrence of (grid and market-based) curtailment, retroactive policy changes and unfavourably designed support schemes. This uncertainty translates into an increase of the revenue risk premium.
(2) Risk of **dropping market values** of RES-E technologies, caused e.g. by the merit-order effect and a lack in system flexibility, resulting in lower profit margins.
(3) **Non-economic barriers**, such as administrative barriers, problems with grid connection or missing social acceptance, that prevent from RES-E investment despite economic profitability.

The competitiveness of mature RES-E technologies is strongly affected by the level of the revenue risk. Smart policies can reduce these risks for RES-E developers while reducing policy support costs. The decreasing market value of variable RES-E generation is a fundamental problem, which pushes further to the future the need for still subsidising mature technologies. At the same time, policies to incentivise the flexibility of power markets (both from the demand and the supply side) will be required in order to accommodate increasing shares RES-E, while keeping system (and support) costs at acceptable levels. Reducing non-economic barriers represent no-regret options that will further gain importance in the period towards 2030 in the context of a better-integrated energy market.

Distinct measures to be integrated in the respective policies are identified in this study. The overview provided in Table 5 summarises the measures identified and reveals which challenge they address. They can be distinguished in terms of implementation on national and European level. The most effective measures are summarised in the following:

Measures on a national level

(1) The relevance of potential RES-E curtailment and the occurrence of negative prices is already a challenge at present in some MS and is expected to further increase with rising shares of non-dispatchable RES-E. The **reduction of must-run capacities** can substantially contribute to the prevention of curtailment and mitigate problems related to negative prices in the short run. Policies should provide **access for RES-E generators to ancillary service markets** and **incentivise enhanced flexibility in the heat sector**. In particular, the occurrence of negative prices in times of over-supply can be reduced. Another co-benefit would be a positive effect on the market value of RES-E.
(2) In a mid-term perspective, the **introduction of time variable levies, grid fees and other tariff components** enhances price elasticity of demand and thus the market value of RES-E. Shrinking market values will become increasingly important with a higher share of variable RES-E in the power system.
(3) The **inclusion of cost-containment elements** in the design of RES-E support schemes can render political retroactivity unnecessary. Thus, the policy scheme should be flexible enough to correct support conditions for new installations and thus control support costs. Using e.g. **auction systems**, which systematically imply a volume control, allows for an early adaptation of the supported RES-E quantity (in the future) while no need to perform retroactive changes is required.
(4) A **well shaped, sliding market premium** (including frequent auctions as well as transparent deadlines and penalties) can further pave the market entry of RES-E generation while reducing the resulting risks and un-

certainties for RES-E investors to a minimum. It presents a good compromise between incentivising market integration of RES-E whilst avoiding exposure of RES-E operators to risks they cannot control (unproductive risks).

(5) In the long run, the **electrification** of additional demand sectors (heat, electricity) and the phase-out or hibernation of fossil fuel plants can substantially contribute to an improved economic viability of RES-E investments.

(6) **Involvement of local communities** in RES-E projects and creation of local value added are effective measures to overcome problems of social acceptance. With regard to addressing the mitigation of non-economic barriers, there is the need to create a level-playing field for RES-E in all EU-MS in terms of providing **stable and reliable policy framework for administrative processes and spatial planning**. This includes a stronger harmonisation of this framework with other EU MS.

Measures on the European level

(1) On the European level, concerted action is required with respect to a creation of a **fully functioning internal energy market**. **Borderless electricity exchange** throughout the EU ensures cross-border flexibility access and reduces the simultaneity of RES-E generation.

(2) The **expansion and upgrade** of the **existing grid infrastructure** (at EU and MS level) can contribute to reduce grid-related curtailment and mitigate the problem of shrinking market values.

(3) The **establishment of an effective European emissions trading scheme** with significant carbon prices make the lower external costs of RES-E generation visible, drive its market value and may therefore reduce the need for financial support from sector-specific RES-E policies.

Table 5: Overview of measures to tackle challenges hindering the deployment of mature RES-E technologies

Measures	Challenges	Risk-related challenges				Non-economic barriers	Market value
Scope	**Measure**	**Market-based curtailment**	**Grid-related curtailment**	**Retroactivity**	**Support schemes**		
Power system and market design	Reduce must-run capacities (short-run)	x	x				x
	Improve internal energy market	x					x
	RES-E access to ancillary services market	x					
	Electrification of heat and transport sector	x	x				x
Environmental policies	Include cost-containment (e.g. through auction or dynamic degression of FITs)			x	x		
	Sliding market premium				x		
	Include pre-approved RES-E sites in auctions				x		
	Frequent auction schedule				x		
	Deadlines and penalties				x		
	Incentivise favourable plant design (PV orientation, wind rotor sizing)	x					x
	Ambitious ETS or carbon price	x					x
	Phase out or hibernation of fossil fuel plants (long-run)	x					x
	Compensation payments for curtailed energy	x	x				
Grids and storage	Grid reinforcement		x				
	Expansion of NTCs	x	(x)				
	Incentivise storage construction	x	(x)				x
	Optimise grid utilisation		x				
	Allocate curtailment costs to grid operators		x				
Design of end user electricity tariffs	Time variable tariffs	x	(x)				x
	Time variable grid cost component		x				
Non-economic framework conditions	Increase local added value of RES-E sites					x	
	Compensation for local communities of RES-E sites					x	
	Mandatory auctioning of RES-E project shares to local communities					x	
	Stable and reliable administrative processes and spatial planning (e.g. time limits for permit approval)					x	

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