Contract N°: IEE/12/833/SI2.645735

Project Acronym: DIA-CORE

Policy Dialogue on the Assessment and Convergence of RES Policy in EU Member States

Final Report

Project Coordinator: **Fraunhofer ISI**

July 2016

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1 Introduction

The foundations of a policy framework for renewable energy sources until 2020 were laid by the European Parliament and Council in 2009, with Directive 2009/28/EC. This Directive advocated an overall, EU-wide target of 20% renewables by 2020. This target was broken down into legally binding national targets. National policy instruments have since been created and adapted to support the deployment of renewable energy sources (RES) at member state level. There is clear evidence of progress towards the 2020 target: the EU-wide share of renewables in gross final energy consumption increased from 8.5% in 2004 to 16.0% in 2014.

Yet both the effectiveness and the economic efficiency of the various national support policies vary greatly from country to country. Effective policy instruments are able to trigger investments in the targeted amount of renewables while economically efficient policies ensure that the target is met at low cost. It is in this context, that the DiaCore project has been set up.

The DiaCore project

DiaCore stands for *Policy Dialogue on the assessment and convergence of RES policy in EU member states*. The focus of the project is to ensure a continuous assessment of existing policy mechanisms for renewables, thereby complementing the monitoring activities of the European Commission. Moreover, the project intends to establish an active stakeholder dialogue on future policy needs for renewable electricity, heating and cooling, and transport.

The specific aims of DiaCore are to:

- Provide detailed performance assessments of existing policy mechanisms, with cross-country policy evaluations.
- Present indicators on effectiveness and efficiency of existing policies for renewables.
- Highlight additional policy needs to achieve the 2020 targets.
- Prepare key findings and recommendations to facilitate convergence in renewables support across the EU and to enhance investment, cooperation and coordination.

This report synthesises the main findings of DiaCore and is structured along the lines of the five key themes analysed in the project.

Theme 1: Coordinating efforts to reach the 2020 targets considers how to ensure effectiveness and efficiency by converging national policies towards best practices and creating a level playing field for renewable energy generators.

Theme 2: Integrating renewables into markets looks at the challenge for policy-makers to find a cost-effective balance between risk exposure and market integration.

Theme 3: Financing renewables and risk allocation explores the variations in capital costs across Europe. As a consequence of the cost structure of renewables, with high upfront costs, financing costs have a higher impact on their total costs than on the total costs of conventional technologies. It is thus crucial to keep investment risk at a minimum.

Theme 4: Coordinating EU renewables policy with global market developments, namely technological advancement, observes the interplay between national policies and global trends. Thereby, we focus on two renewable technologies: biomass and solar PV. Biomass is increasingly imported and used for energy generation, thus coordination within the EU is required to ensure sustainable deployment. For solar PV, a technology which has shown a highly dynamic cost development in the past, coordination mechanisms and information exchange regarding technology developments are discussed, particularly in relation to timely tariff regressions.

Theme 5: Keeping policy costs for renewables at an acceptable level uses quantitative policy analysis to indicate the impact of policy choices on related policy costs and the effects of mitigating non-economic barriers.

The final section of this report summarises the **Central Policy Recommendations** derived from the project.

2 Coordinating efforts to reach the 2020 targets

2.1 Policy context

Across the EU MS, various policy instruments have been implemented to promote the use of renewable energy sources (RES). Although there are already substantial experiences with the use of support schemes, the dynamic framework conditions have led to a continuous need for reforming the applied policies. Also policy priorities have changed in most MS. Whilst the policy effectiveness or the ability of support instruments to trigger new investments was a main policy target, when RES-share was still negligible, economic efficiency has become increasingly important in the light of higher shares of RES, rising support costs and the financial crisis. In particular the strong growth of Solar PV in some MS has enhanced this change of policy priorities. The stronger focus on cost control mechanisms has led to a revival of tender or auction mechanisms to control the additional RES-capacity eligible for support and to determine support levels in a competitive bidding procedure. Another highly relevant issue regarding renewables support is related to the increasing share of intermittent RES leading to evolving requirements for effective electricity market design. While initially fair remuneration of RES power in the market should be a priority for market design, a more systemic focus on system flexibility should be adopted with a rising share of RES. This is reflected in several market design parameters, e.g. how the system matches temporal profiles of different generation and load types and how it accommodates the spatial profile of intermittent RES generation.

It is widely acknowledged that enhanced cooperation and coordination of RES policies across the EU MS increases the likelihood of meeting the 2020 targets and reduces the associated costs (see European Commission (2013)). However, to facilitate policy learning and the dissemination of best practices regarding RES policy, a close monitoring and continuous evaluation of RES frameworks and their impact on RES diffusion in the EU MS are necessary.

2.2 Objectives of the analysis

It is one major objective of the DIA-CORE project to facilitate policy learning and to promote a better coordination of policy design across the EU MS. Transparent approaches and tools for evaluating RES policies and regulatory frameworks for the support of renewable energy technologies (RET) in practice are a central precondition in this regard. Therefore, in order to provide traceable and reliable monitoring tools for RES frameworks in the EU MS, the DIA-CORE project develops and improves indicators for measuring RES policy and electricity market performance.

Thereby, in the frame of this project, established indicators to assess the performance of renewable energy support policies (indicators developed in the context of the OPTRES and RE-SHAPING project, cf. (European Commission 2005; European Commission 2008; Ragwitz et al. 2007, Steinhilber et al. 2011) are updated and developed further but also completely new indicators are developed.

In doing so, reliable evaluation criteria covering various aspects of renewable support policies have to be defined. These aspects include the effectiveness of the policies used to measure the degree of target achievement and the costs for society resulting from the support of renewable energies (static efficiency). In addition, a comparison of the economic incentives provided for a certain RET and the average generation costs (relative remuneration levels), helps to monitor whether financial support levels are well suited to the actual support requirements of a technology. Further, the status of the market deployment of different RES technologies and the openness of the respective power systems for integrating RES-E in the EU MS have to be evaluated.

A further objective of the project relates to a better understanding of the role of the broader regulatory framework for RES deployment. Here, especially the role of non-economic framework factors, such as administrative- or grid-related barriers, is in focus of the analysis to allow for a more holistic evaluation of RES frameworks. To this end, a new composite indicator is developed which serves for assessing the expected future RES deployment under given regulatory framework conditions.

2.3 Approach

To measure the performance of policies supporting the deployment of renewables in the EU a set of indicators is developed in the frame of this project: a policy effectiveness indicator, a market deployment status indicator, a comparison of economic incentives and conversion costs and an indicator measuring the preparedness of the electricity market to integrate RES. Additionally, we introduce a new forward looking indicator for evaluating the expected future RES diffusion under different regulatory framework conditions.

With the ***Policy Effectiveness Indicator*** we measure the impact of a policy on the deployment of renewables by setting the increase in renewable energy supply – normalized by weather-related fluctuation – in relation to a suitable reference quantity. The reference quantity chosen is the additional available resource potential considered to be realizable by 2030. This definition of the Policy Effectiveness Indicator has the advantage of giving an unbiased indicator with regard to the available potentials of a specific country for individual technologies. Member States need to develop specific renewable energy sources proportionally to the given potential to show comparable effectiveness of their instruments.

The ***Deployment Status Indicator*** compiles information reflecting how advanced the renewables market in each EU country is for a certain technology: the higher the value, the higher the maturity of that specific technology market in that country. Thereby, we differentiate three general types of deployment status: Immature RET markets characterized by small market sizes, a low number of market players and low growth rates associated with typical market entry barriers; Intermediate RET markets with increasing market sizes, a strong market growth and entry of new market players and growing experience with RET development. However, in case of very fast market growth, growth-related barriers (e.g. related to scarcity of infrastructure, financing or administrative capacity) might occur; Advanced RET markets characterized by established market players and mature technologies. At this stage, market growth may start to slow down and market players may encounter barriers related to growing competition for sites, resources or infrastructure (e.g. curtailment). The indicator consists of four sub-indicators: Production of RES technology as share in the respective sector (electricity/heat) consumption, production as share of 2030 realisable potential and installed capacity of RET. The Deployment Status Indicator allows for a more nuanced policy evaluation when doing macro-level comparisons of large groups of Member States and/or technologies as the effectiveness of a policy is influenced by the maturity of the respective RET market

The ***Economic Incentives and Conversion Costs Indicator*** assesses the attractiveness of the economic incentives for RET investors and compares annualized support payments over the lifetime of a RET plant to the actual generation costs, the levelised costs of electricity generation (LCOE). The level of financial support paid to the supplier of renewable energy is a core characteristic of a support policy. Besides its direct influences on the policy cost, it also influences the policy effectiveness. The objective of this indicator is to analyse whether payments are adequate to stimulate investments without providing excessive windfall profits for investors. Comparing the support level available for the different technologies in each MS contributes to the identification of best policy practices that have been the most successful in encouraging market growth at preferably low costs. However, as the actual support levels are not comparable since they do not reflect the duration of support payments. For this reason, the available remuneration level during the whole lifetime of a RET plant is taken into account. The remuneration level contains the final energy price if the support payments expire after a certain time horizon, but the RET plant continues in operation. To ensure comparability of the remuneration levels, time series of the expected support payments or final energy prices, respectively, are created and the net present value is calculated. The net present value represents the current value of the overall support payments discounted. Finally, the annualised remuneration level is calculated based on the net present value. The advantage of the presented indicator is that it allows a global picture of the financial remuneration offered by a certain support mechanism during the whole lifetime of a RET. The comparison is carried out on an aggregated level per technology category. The tariffs within one technology category can differ significantly when several tariffs are available for one technology.

For the electricity sector we provide a *combined illustration of the Policy Effectiveness Indicator* and the Economic Incentives and Conversion Costs Indicator to facilitate analyses and to show whether a high profit level generally involves higher policy effectiveness.

The **E*lectricity Market Preparedness Indicator*** measures the preparedness of the electricity market to flexibly integrate RES-E and to meet the needs of generation based on fluctuating RES. With rising shares of intermittent RES larger variations in generation patterns will occur and generation will be less predictable at day-ahead stage than traditionally. These variations increase the value of flexibility from load and all generation assets. As European power markets have historically not been designed for these requirements, it is essential to assess and, where necessary, adjust the power market designs and operational paradigms to meet the emerging requirements so as to ensure intermittent RES provide full value to the power system to avoid unnecessary wind/solar spill (curtailment). With increasing shares of RES, also cost efficient solutions for market integration are becoming more important to minimise costs for consumers. Direct marketing can incentivise private actors to develop strategies to maximise revenue from selling RES. Further, a full internalisation of physical constraints of different generation assets in the market price and integration of markets for energy and system services is necessary to ensure a fair remuneration of RES while capturing synergies across all elements of the power system and ensuring system security. Sub-indicators currently used for the Electricity Market Preparedness Indicator relate to the liquidity of electricity markets, the market gate closure times, the level of market coupling (day-ahead and intraday), the economic burden sharing for grid connection (connection charges) and to the utilization of transmission capacity.

Complementary to the update and further development of the above described indicators for ex-post evaluation of RES support policies, we perform an analysis of expected future RES deployment trajectories through the development of a ***Short-term Forward Looking Indicator for RES Diffusion*** in EU Member States. Thereby, the assessment focuses on the most dynamically developing RES-E technologies on EU level, namely onshore wind and PV. The analysis provides estimations of the expected growth of the technology markets based on a comprehensive assessment of the regulatory framework conditions on country level. This short-term assessment allows for a refined estimation of the effects of individual policy measures or adaptations of the regulatory environment on the short-term RES market development on Member State level. The diffusion indicator can be used as a tool for monitoring the potential attainment of RES targets (i.e. the 2020 targets) as well for reviewing and improving the regulatory frameworks for RES on MS level to enhance their effectiveness and improve the cost-efficiency of measures promoting RES diffusion.

A detailed description of the methodology and data sources for all indicators is provided in Boie et al (2015).

2.4 Results

2.4.1 Monitoring the development of RES markets and policies in the EU

Support schemes in Europe are already showing increased convergence towards the best practices outlined in this project (see Held et al. 2014): countries with fixed feed-in tariffs increasingly choose feed-in premiums to incentivise operational decisions according to market signals.[1] Quota schemes have sometimes been modified to include price floors so that the price risk is reduced. Finally, auctioning is progressively being introduced in EU member states (cf. Figure 1).

Nevertheless, substantial differences persist between support schemes. In support schemes based on a feed-in premium, for example, regulatory fragmentation remains in how reference prices are calculated (e.g. yearly, monthly, daily or hourly). Moreover, the way in which maximum strike prices are defined differs depending on the exact approach used for the calculation of levelised cost of electricity (LCOE). Auctions are also applied in many different ways throughout Europe, reflecting the limited experience with this instrument. Likewise, the way tariffs are revised (in the case of administratively defined tariffs) differs significantly among countries. In support schemes based on quota obligations, several countries such as Belgium, Italy and the United Kingdom opted to introduce technology banding in their previously technology-neutral quota systems, while Poland and Sweden retained their technology-neutral quota. In general, there is a trend towards EU countries substituting quota obligations through alternative support schemes, such as feed-in premiums combined with competitive bidding procedures (Italy, Poland, and the UK).

The differences observed suggest two major problems: first, numerous support schemes deviate from acknowledged best practices, which limits their effectiveness and efficiency (see Boie et al. (2015)) and provides a sub-optimal balance between market compatibility and investment security. Second, differences in support scheme design lead to a fragmented market within Europe. Creating an internal market implies overcoming this fragmentation, however, which in turn requires greater convergence on support scheme design.

[1] Presently many feed-in premiums and feed-in tariffs are an asymmetric risk sharing instrument, hedging RE producers against low power prices, but not electricity consumers against high power prices. Hence a mutual hedging dimension will be essential for RE for the further development of feed-in premiums und tariffs. For feed-in premiums that means that the premium could become negative in case of high electricity prices.

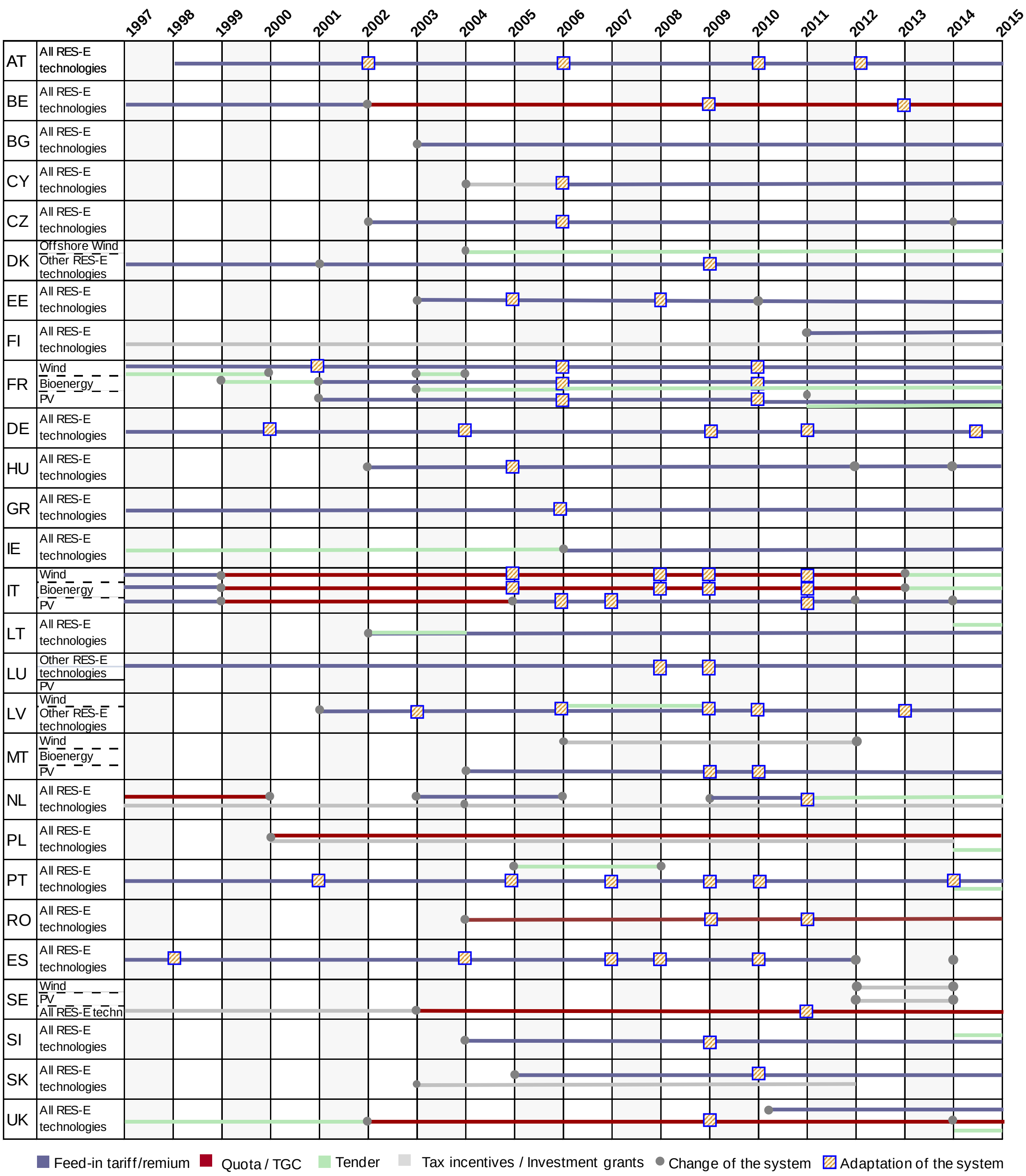


Figure 1: Evolution of the main support instruments in EU28 Member States

Figure 2 and Figure 3 exemplarily display the Deployment Status Indicator and the Policy Effectiveness Indicator for onshore wind. Onshore wind remains the most mature RES-E technology besides hydro. Since the last update in 2013, Romania and Sweden joined the five Member States which had advanced deployment status (Denmark, Germany, Portugal, Spain, and Ireland). Fourteen Member States reach intermediate deployment status. The majority of MS meets or exceeds the 100 MW threshold to achieve maximum score in the sub-indicator of installed capacity, with the exception of Luxemburg, Latvia, Slovakia, Slovenia and Malta. Only 7 Member States remain immature with regard to onshore wind deployment.

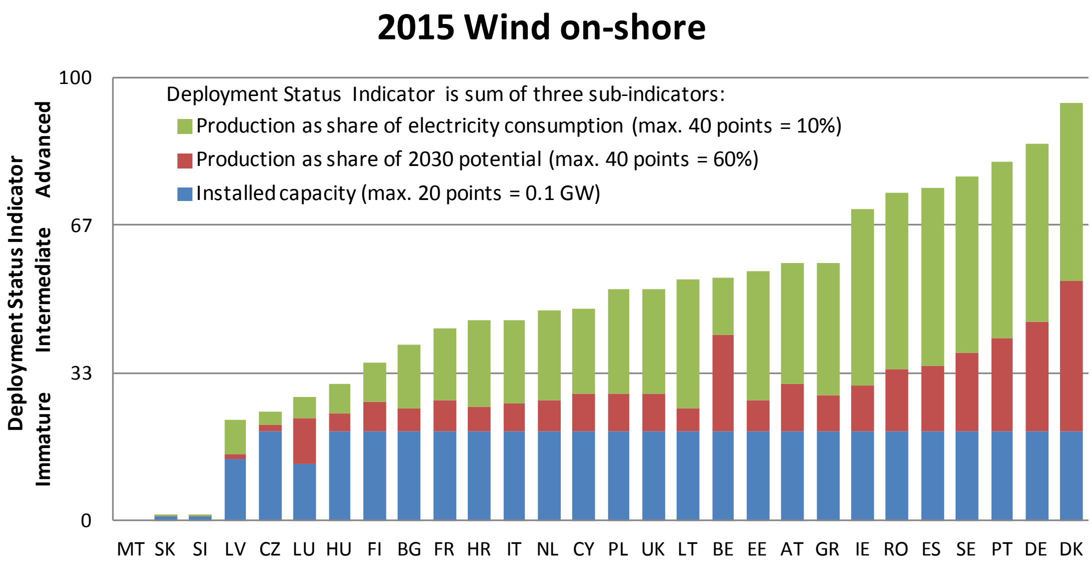


Figure 2: Deployment Status Indicator for onshore wind power plants in 2015

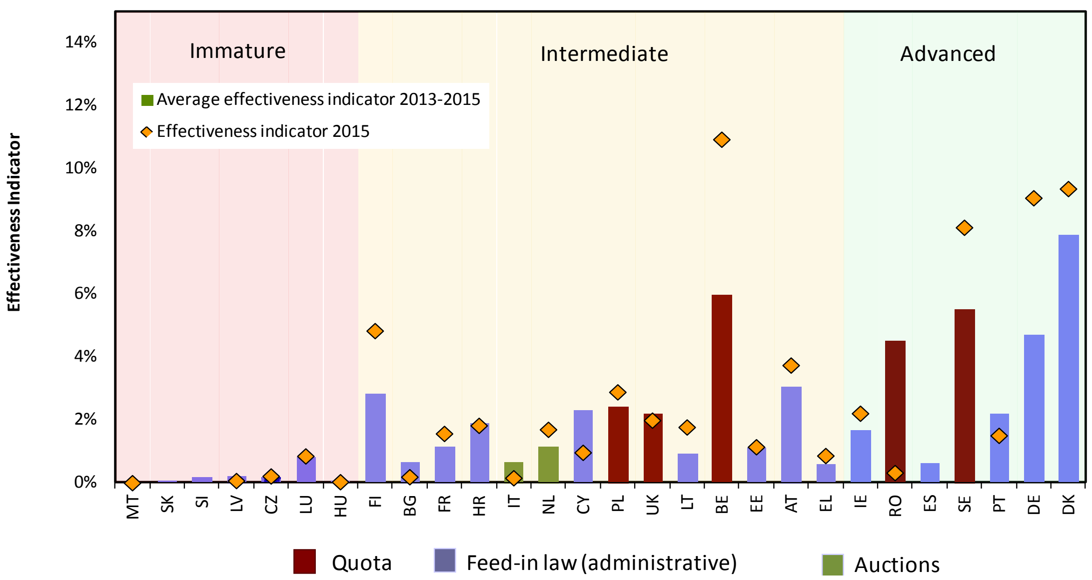


Figure 3: Policy Effectiveness Indicator for onshore wind power plants in the period 2013 – 2015. Countries are sorted according to deployment status indicator.

Regarding policy effectiveness (cf. Figure 3), the 2015 indicator values imply that deployment has picked up again compared to the average of the past three years. Member States with a medium deployment status featuring high effectiveness are Belgium, Finland, and Austria. Among the more developed markets, the effect of the support scheme moratoria in Spain and Portugal can be observed. However, effectiveness in Denmark, Germany, and Sweden was high. Note that wind power in Denmark, especially onshore, has been facing serious public acceptability problems, leading to only 68 MW of new wind installations in 2014, compared to 657 MW in the previous year[2]. Net capacity additions were back up to 125 MW in 2015. Another interesting observation is that MS using quota obligation (Belgium, Romania, and Sweden) have gained momentum compared to MS supporting onshore wind power plants by means of feed-in laws. Onshore wind is one of the lower cost technologies and thus benefits more strongly from technology-neutral quota obligations as implemented in Romania and Sweden than do more costly technologies. Member States which allocated their support via tenders (Italy, the Netherlands, and the UK) all had medium deployment status and medium effectiveness. In the meantime, more MS have introduced auctions. However, these did not yet have effect on the wind deployment of 2015.

Major differences also persist regarding remuneration levels. Figure 4 and Figure 5 compare the average to maximum remuneration with the minimum to average generation costs of onshore wind. Thereby Figure 4 uses the traditional calculation based on uniform weighted average costs of capital (WACC) of 6.5%, whereas Figure 5 is based on the actual country specific costs of capital (WACC figures) for 2015 (see Noothout et al. (2015): DiaCore report “The impact of risks in renewable investments and the role of smart policies”[3]). The analysis reveals that many MS offer just enough or even insufficient remuneration to stimulate investment. Very high support levels exist in Belgium, Italy, Romania, and the UK. In Belgium and UK this is due to relatively high certificate prices within their quota schemes. It furthermore shows the important impact of the country specific risks and therefore different costs of capital on the profitability of wind onshore.

Figure 6 illustrates the combination of the expected profit from an investment in wind onshore power plants and the Policy Effectiveness Indicator for the year 2015. This figure is based on the uniform WACC of 6.5% in order to show the cumulated impact of risk premiums (therefore high WACC) and inappropriate compensation on the efficiency of support. Thereby the reason for negative values for the “potential profit range” can be either based on insufficient support levels or on actual WACC figures below the uniform value of 6.5%. Belgium, Denmark, Germany and Sweden clearly show the highest effectiveness levels. While the latter three combine this with moderate profit levels, profits are rather high in Belgium. The UK, Italy, and Romania cannot translate the high potential profit levels for wind power plants into high effectiveness.

[2] EurObserv’ER Wind Energy Barometers 2014 and 2015.
[3] http://diacore.eu/results/item/enhancing-res-investments-final-report/

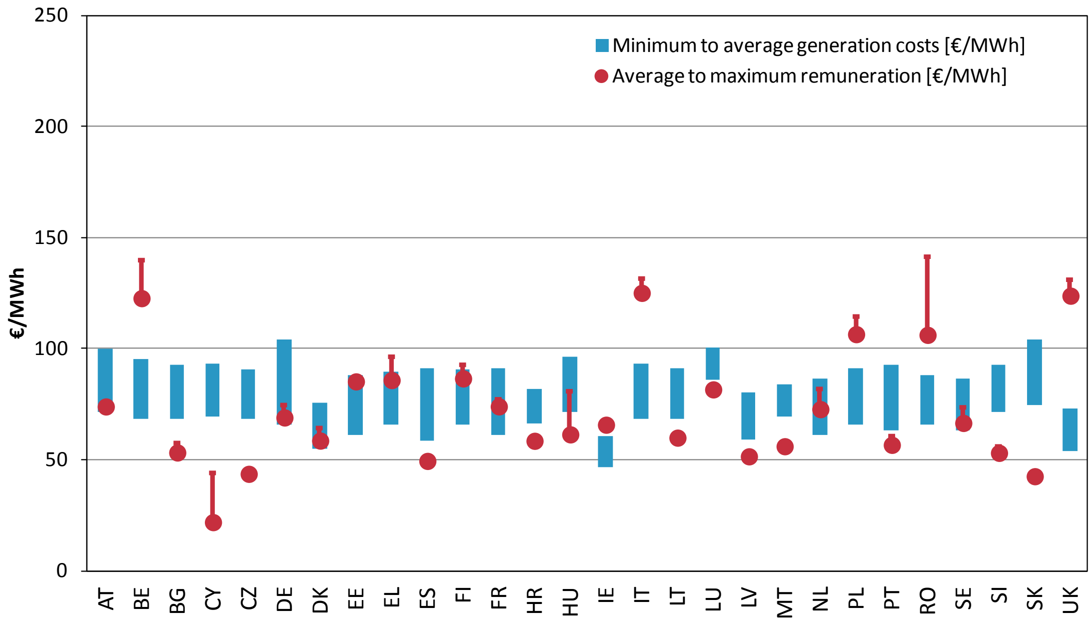


Figure 4: Remuneration ranges (average to maximum remuneration) for onshore wind in the EU-28 MS in 2015 (average tariffs are indicative) compared to the long-term marginal generation costs (minimum to average costs) – note that calculations shown in this figure are based on uniform costs of capital (WACC = 6.5% for all countries).

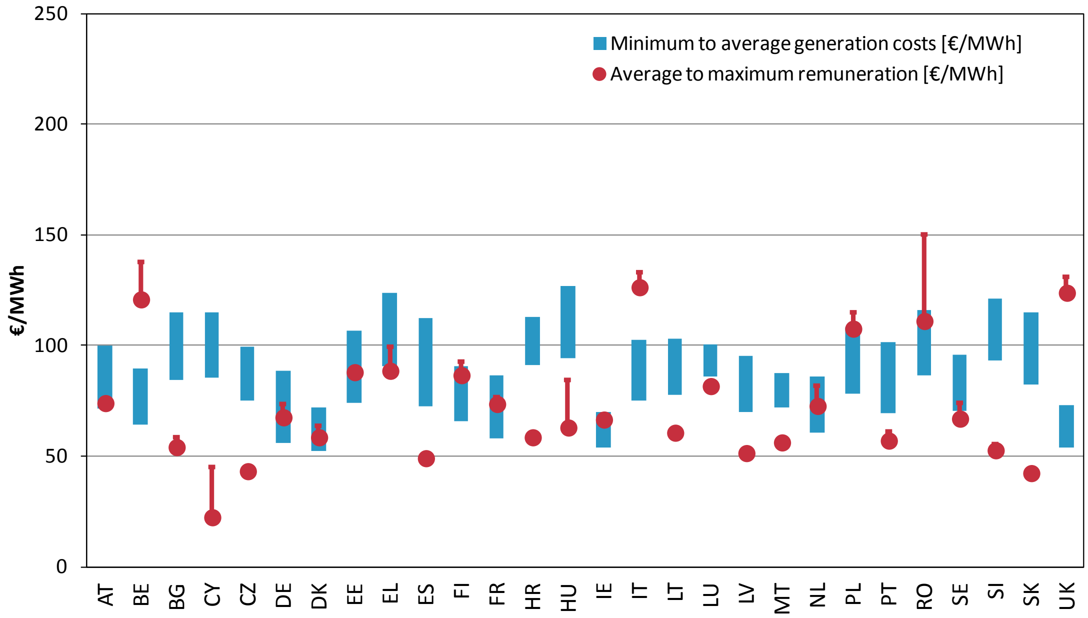


Figure 5: Remuneration ranges (average to maximum remuneration) for onshore wind in the EU-28 MS in 2015 (average tariffs are indicative) compared to the long-term marginal generation costs (minimum to average costs) – note that calculations shown in this figure are based on the actual country specific costs of capital (WACC figures) for 2015 (see Noothout et al. (2015)).

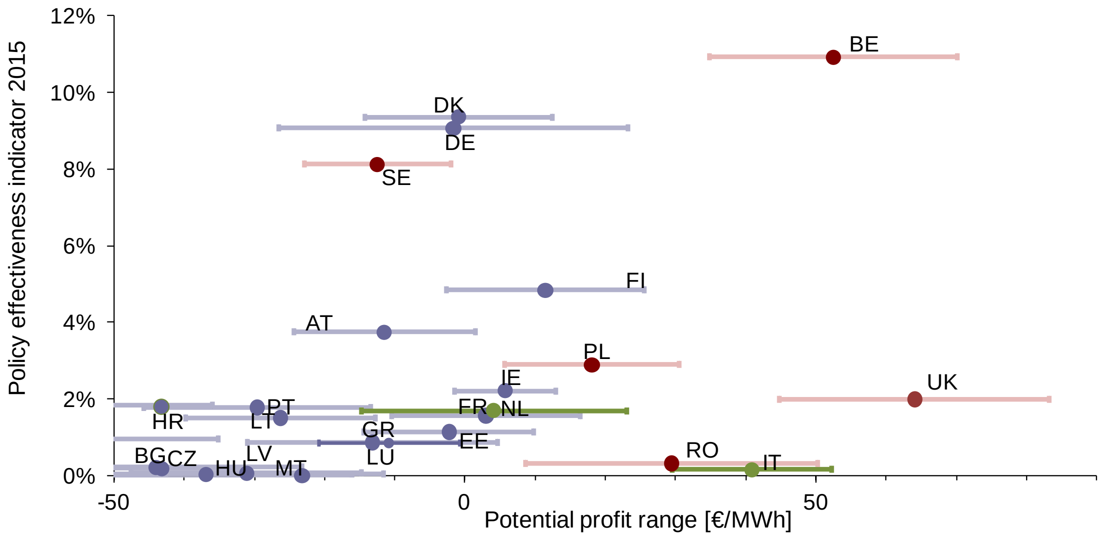


Figure 6: Potential profit ranges (average to maximum remuneration and minimum to average generation costs) available for investors in 2015 and Policy Effectiveness Indicator for onshore wind in 2015 – note that calculations shown in this figure are based on uniform costs of capital (WACC = 6.5% for all countries).

As a further example, Figure 7 and Figure 8 display the Deployment Status Indicator and the Policy Effectiveness Indicator for solar photovoltaic (PV). The deployment of PV in the EU has been very significant in the last 5 to 10 years (cf. Figure 7). However, while some markets show steady progress, others have slowed down or virtually stopped deployment in the last years, mostly as a result of reductions in policy support. The levels of PV production in 2015 as a fraction of potentials in 2030 remain low for many MS, revealing the enormous untapped mid-term potential of PV technology in Europe. Only Germany is considered to have reached the advanced deployment stage. Generally, high policy effectiveness could be observed for PV in the years from 2013 to 2015, especially in those countries with an intermediate deployment status (cf. Figure 8). This was due to rapid capacity increases as prices for PV installations dropped faster than support levels could follow. In response, MS with large PV markets like Germany and Italy severely reduced support levels in order to slow down growth, leading to relatively lower effectiveness indicator values in 2014 and 2015. In Spain and the Czech Republic, capacity additions already peaked in 2009 and 2011, respectively. Effectiveness there, as well as in several other countries such as Bulgaria, Greece, and Italy has since decreased due to subsidy cuts.

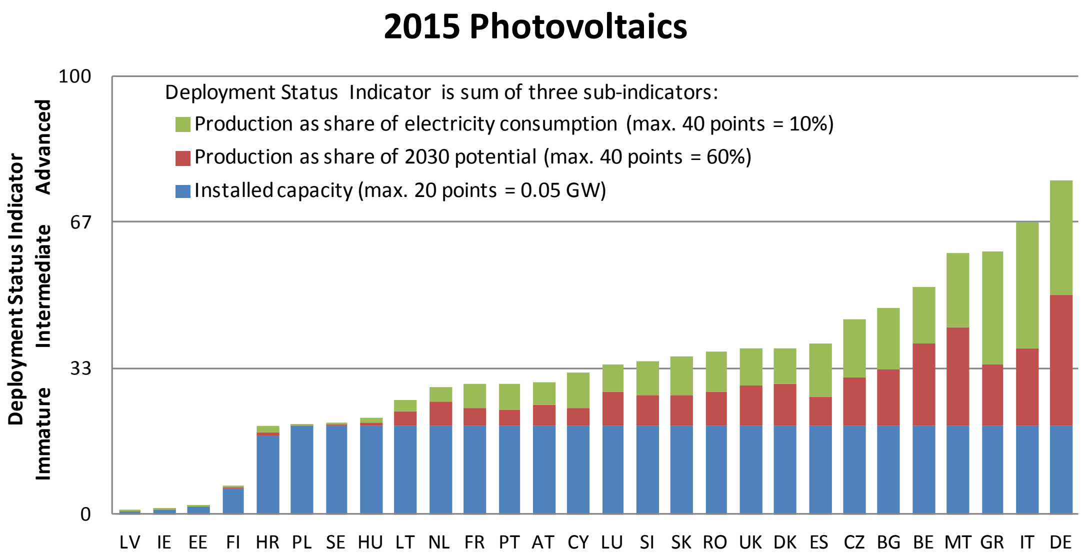


Figure 7: Deployment Status Indicator for Solar PV power plants in 2015

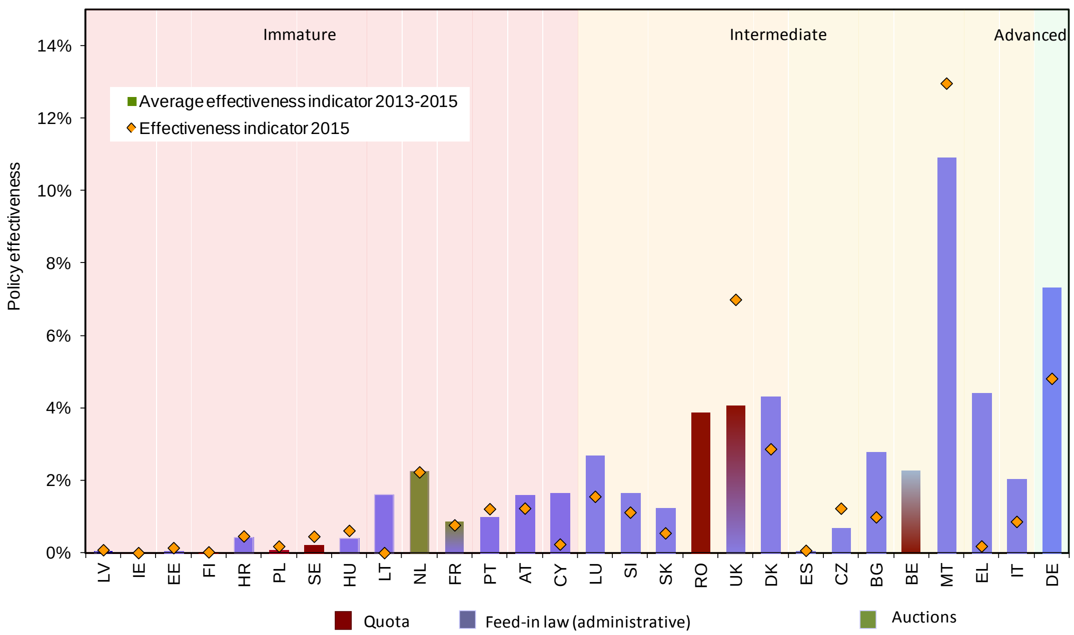
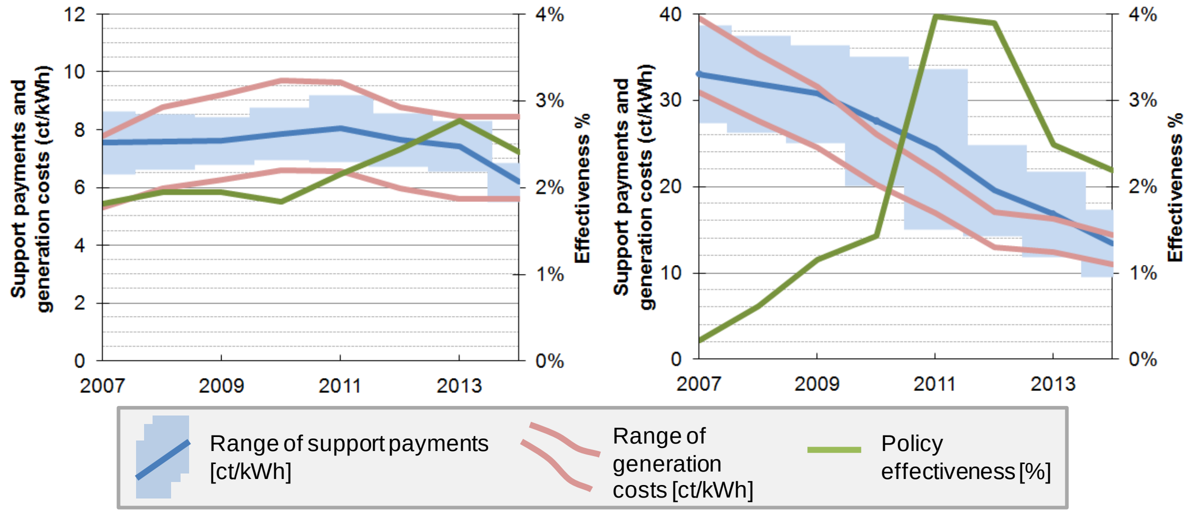


Figure 8: Policy Effectiveness Indicator for Solar PV power plants in the period 2013 – 2015

2.4.2 Development of support level performance over time

In order to be able to assess the evolutionary development of RES policy performance, the support payments, technology costs and the actual deployment of RET from 2007 to 2014 have been evaluated. Figure 9 exemplarily displays the results for solar PV and wind onshore.



(a) Onshore Wind (b) Solar PV

Figure 9: Annualised support payments, generation costs (left axis) in the EU28 compared to policy effectiveness (right axis)

In summary, the evaluation of EU RES policy reveals the following:

- For **solar PV**, the policy effectiveness increased steadily until it peaked in 2011 and has since then decreased again (see Figure 9, right side).
- The trend for the economic efficiency is less clear: Technology costs have decreased significantly since 2007 (-63%). However, the adjustment of support payments was not fully synchronised with this decrease between 2010 and 2012. This changed again after 2012 suggesting an improving economic efficiency in recent years.
- For **onshore wind power**, the policy effectiveness showed a continuous growth over the years with a slight decrease during the economic crisis in 2009/2010, which is contrary to the often stated view that the deployment of renewables was unaffected by the economic crisis. In 2014 it lightly dropped as compared to 2013 levels (see Figure 9, left side).
- Technology costs slightly increased between 2007 and 2009, primarily due to the fact that material costs were on the rise in that period (e.g. steel). Since 2010, decreasing technology costs can be observed.
- Overall, payment levels have been adjusted to follow the cost trend. However, falling wind power costs after 2010 have been reflected a bit slowly in some EU member

states. This suggests a period of decreasing efficiency which was, however, preceded by a period of low profit levels in 2008/2009 caused by increasing material prices. In 2014, however, support levels have been adjusted substantially. A national analysis shows that e.g. Italy realised strong cuts of support payments and achieved to reduce the previously high windfall profits available from the quota obligation with the introduction of an auction scheme.

Country focus: Evolution of solar PV support in Germany

The case of policy evolution in Germany is of particular interest, given the massive deployment of solar PV in the years 2011 and 2012. In this period, roughly 15 GW of solar panels were installed, which corresponds to 25% of the global new installations in these years. This raised heavy criticism, especially regarding the economic efficiency of the German support scheme. The development of the indicators is illustrated in Figure 10 and reveals the following key findings:

- From 2007 to 2011, an increasing trend for the effectiveness can be observed reaching a maximum of roughly 11% of the 2030 potential. On EU level, the effectiveness of solar PV support peaked at some 3.5% in 2012.
- Support payments were constantly adapted to reflect falling technology costs. A strong decline of solar panel prices resulted in a reduction of feed-in tariffs in 2010 and 2011. However, the level of support payments remained constant for one year in 2011.
- In December 2011, the peak of new installations was reached: 3 GW in one month. This can be understood as a pull-forward effect – investors anticipated the reduction of support payments for new installations in January 2012.
- Since 2012, tariffs are adjusted every month automatically (i.e. change does not have to be adopted by the Parliament). The absolute decrease of payments depends on whether deployment targets are met. Overachieving deployment targets leads to a stronger reduction of feed-in tariffs.
- The profit level was close to zero in 2013 and 2014. This indicates a high economic efficiency.

Overall, one of the key lessons to be learned from the development in Germany is that there is a need to constantly monitor technology costs and adapt support payments frequently to follow changes in costs rapidly. This is a solid measure to avoid overcompensation. Moreover, experience shows that automatic payment cuts based on transparent criteria are more effective than payment cuts that have to be adopted in a parliamentary process. The German example also shows that a stable and reliable support scheme ensures a high effectiveness. Conversely, high profit levels do not necessarily lead to a strong market growth, as examples of other EU MS show.

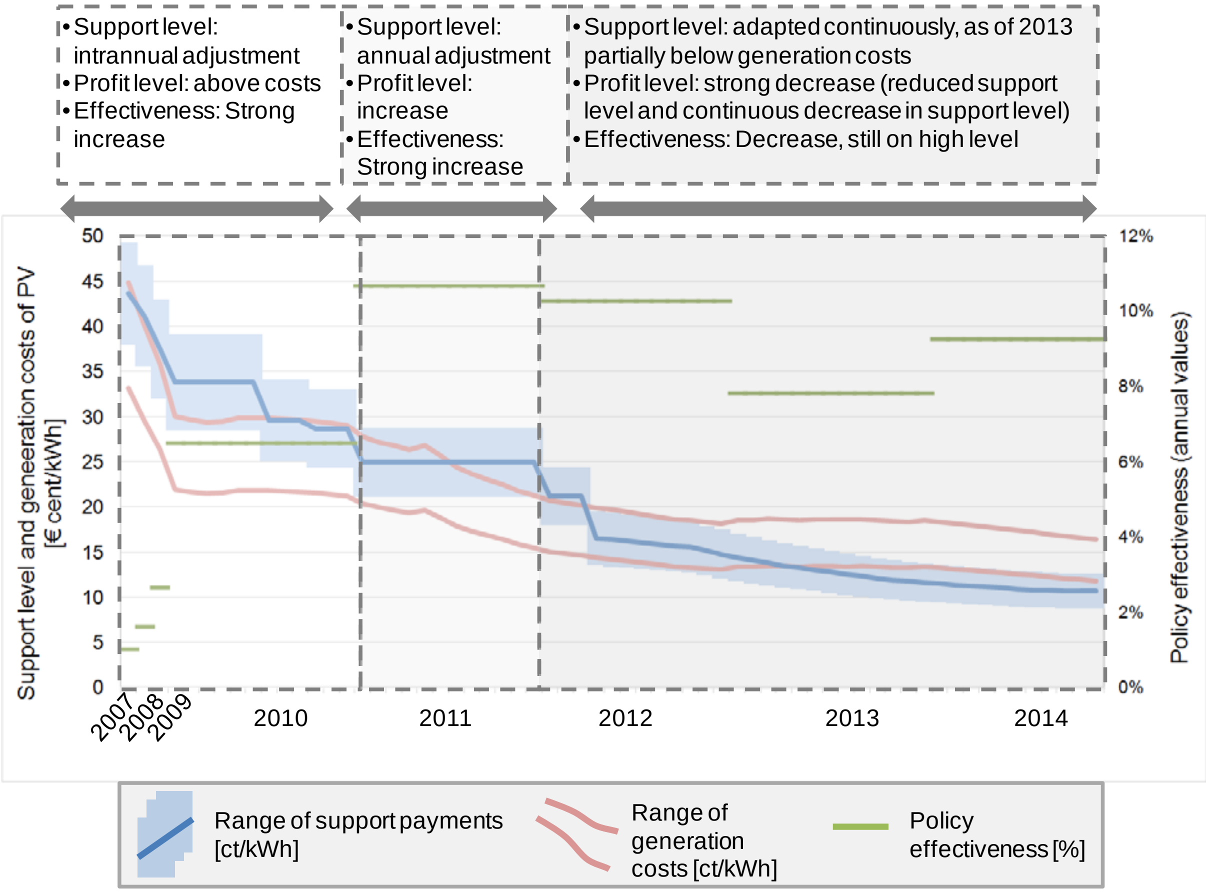


Figure 10: Evolution of support payments, generation costs and policy effectiveness for solar PV plants in Germany from 2007 to 2014

2.4.3 Electricity Market Preparedness

Figure 11 shows the openness of the power systems for RES in the EU Member States. As the utilized data sources did not provide data for all MS and sub-indicators, some values are missing - indicated by the dashed segments on top of the stacked bars.

According to the overall aggregated indicator, the electricity markets in Portugal, Spain and the United Kingdom seem to be best prepared for RES market integration with 45-50 out of 60 possible points. Only in *Sub-indicator A: Utilization of transmission capacity* Portugal and Spain rank poorly whereas the United Kingdom ranks poorly in *Sub-indicator F: Liquidity of intraday market*. Also Austria, Belgium, Denmark, Germany, Finland, France, Italy, Latvia, Luxembourg, the Netherlands and Sweden score comparably high between 30 and 44 points. The lack of data availability and their island status makes an assessment difficult for Cyprus and Malta whereas Bulgaria, Greece, Slovakia and Romania's markets currently seem to lack market preparedness for RES with less than 25 points.

The presented results intend to give a first overview of the preparedness of MS electricity markets for RES market integration: The six sub-indicators indicate the status of six aspects that are of high relevance to RES market integration. However, when looking in more detail at specific MSs, one might conclude that some of these aspects vary in their relevance due to local circumstances.

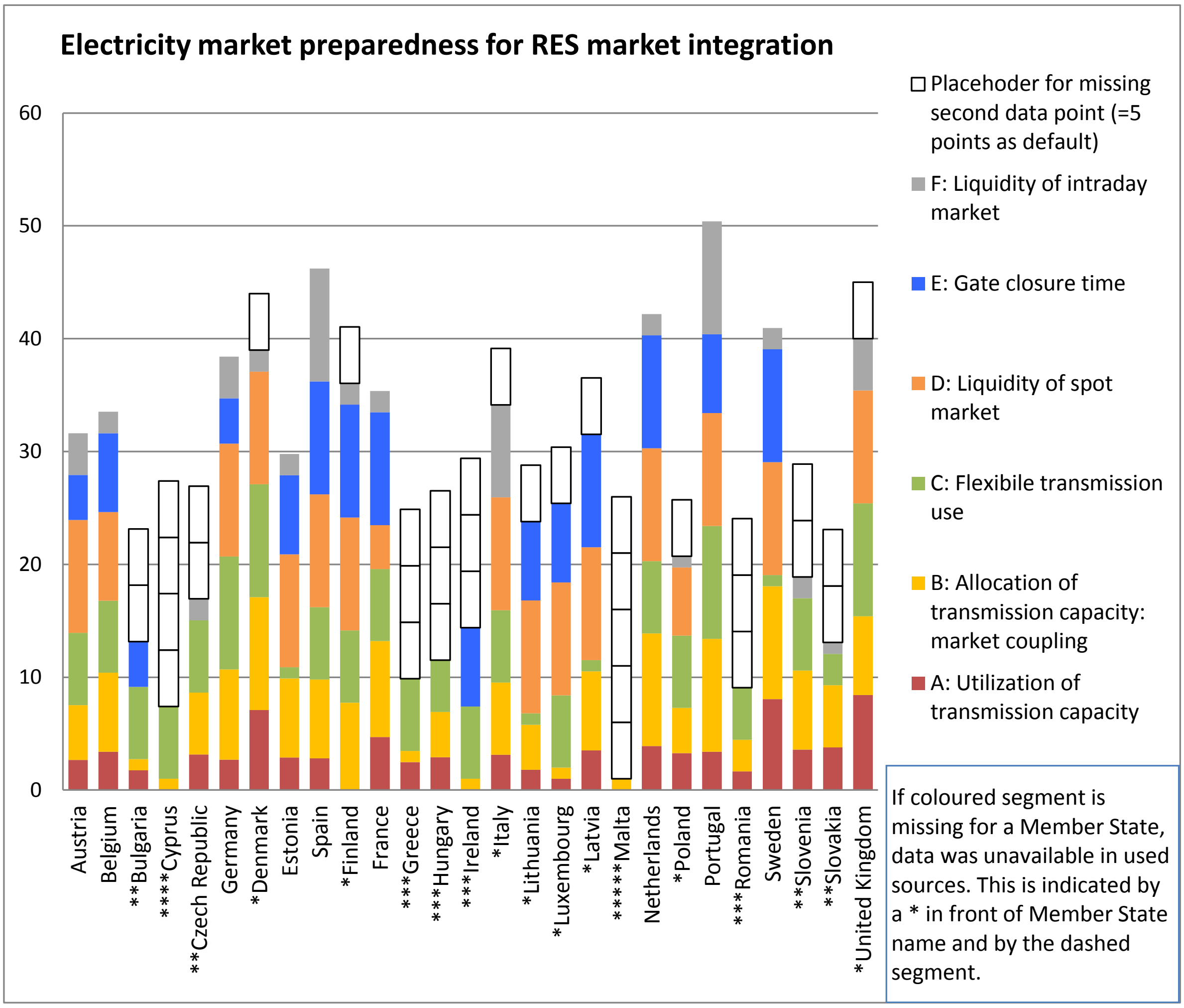


Figure 11: Electricity market preparedness for RES

2.4.4 Forward-looking RES-diffusion indicator

Apart from the provision of adequate economic support for RES, it is also crucial to create a level playing field for RET project developers by optimizing non-economic framework conditions. This involves a removal of, for example, administrative or regulatory barriers which limit the possibilities of exploiting the full RES potential. This aspect is particularly important since competitive tenders for RET support are becoming more prevalent in EU MS and in view of discussions about opening up national support schemes. Against this background, the distortion of competition should be minimized and policy makers should consider non-economic barriers and promote best practices and uniform standards in this field. The aspects identified as the most relevant determinants for RE-diffusion – as seen from the investor's perspective - are displayed in Table 1. Four main areas, namely the political and economic framework, the electricity market structure, grid regulation and grid infrastructure and administrative processes for RET projects were selected. Each of these areas comprises three to five sub-determinants which can be represented by quantitative or qualitative indicators and aggregated to an overall indicator score.

Table 1: Main determinants for RE diffusion from the investors' perspective

	Determinant / Indicator component	
A - Political & Economic Framework	A I	Existence & reliability of RE strategy & -support scheme
	A II	Relative remuneration level
	A III	Revenue risk
	A IV	Access to finance
B - Market structure & market regulation	B I	Fair & independent regulation of the electricity sector
	B II	Existence of functioning & non-discriminatory short term markets
	B III	Availability of reliable long-term contracts (PPA)
C - Grid regulation & grid infra-structure	C I	Cost of RE grid access
	C II	Lead time for RE grid access
	C III	Predictability & transparency of grid connection procedure
	C IV	Treatment of RE dispatch (curtailment)
	C V	Transparent & foreseeable grid development
D- Adminis-trative processes	D I	Cost of administrative procedure
	D II	Duration of administrative procedure
	D III	Complexity of administrative procedure
	D IV	Integration of RE in spatial & environmental planning

A questionnaire-based survey asking for the relative relevance of the identified determinants[4] covered more than 200 RE-experts across the EU. The results point out that a reliable political environment is the most important precondition for a continuous RES diffusion. Particularly important are the stability and reliability of the RES policy framework (median score for relevance of 9 out of 10), as this factor received even higher scores than the actual remuneration level (median score of 8) and the revenue risk (median score of 8). Also the duration and complexity of administrative and grid connection procedures are highly relevant aspects from the investors' perspective (median scores 6-8) as well as the integration of RES planning with spatial planning (median score 7). Grid related aspects received scores between 6 and 8, depending on the RES technology concerned.

[4] The assessment of the relative relevance was based on a scale between 0 (= not relevant for an investment decision at all) and 10 (=extremely relevant for an investment decision). The results for the basis for the weighting of the indicator components when aggregating the overall indicator score.

In-depth interviews with RE developers and investors in three EU MS (Germany, the UK and Spain) support these findings and highlight that policy stability and the diffusion of best practices, especially regarding administrative processes and spatial planning for renewables, are of major significance for RET developers. For instance, regional authorities responsible for project authorisation and spatial planning should be further supported through the provision of best practice guidelines or harmonised procedural standards at national level. In this context, stakeholders in Germany reported that non-harmonised regulations for spatial planning among the federal states (e.g. the 2015 distance regulation for wind parks in Bavaria) constitute a major barrier for wind energy development in Germany. Stricter time limits for permit approval were also mentioned as an appropriate measure to improve the predictability of planning procedures and to reduce risks and costs for developers. For example, project developers from the UK reported that approval procedures ('planning permit') for medium- and large-scale installations are lengthy, especially due to appeal processes. Stricter procedural timelines and greater support for local administrations (in terms of budget, staff and know-how) would significantly reduce the risks for renewable energy project developers.

Based on a comprehensive assessment of the RE framework factors (cf. Table 1) between 2012 and 2014 in three countries Germany, the UK and Spain, the composite diffusion indicator scores were calculated and utilized to derive short-term diffusion forecasts for the deployment of wind onshore and solar PV[5] until 2020. The exemplary results for the expected diffusion of wind energy in Germany are shown in Figure 12. The analysis covers three scenarios: A business as usual (BAU) scenario assuming a continuation of the present policy framework; a scenario assuming lower economic support but otherwise a stable regulatory framework; a scenario assuming a reduction of administrative costs. The following observations can be made from the results:

- Under BAU-assumptions large further growth until 2020 can be expected leading to 59% exploitation of the long term potential and an expected electricity generation of 104.6 TWh in 2020. Therefore, the German NREAP target for 2020 will be substantially overachieved.
- The assumption of lower profit levels, which are based on the difference of remuneration and costs as realized in 2013, leads to a substantially lower growth after 2014. Under this scenario, a penetration level of only 49% and a generation of about 80 TWh are reached.
- The change of the costs of the administrative process, assuming that the lower administrative costs as in 2012 can be achieved also after 2014, leads to a moderate increase of the growth of onshore wind deployment compared to the BAU assumptions. In this case, an electricity generation of 110.5 TWh is reached by 2020.

[5] The detailed methodology for calculation of the indicator and the diffusion model is described in Boie et al. (2015).

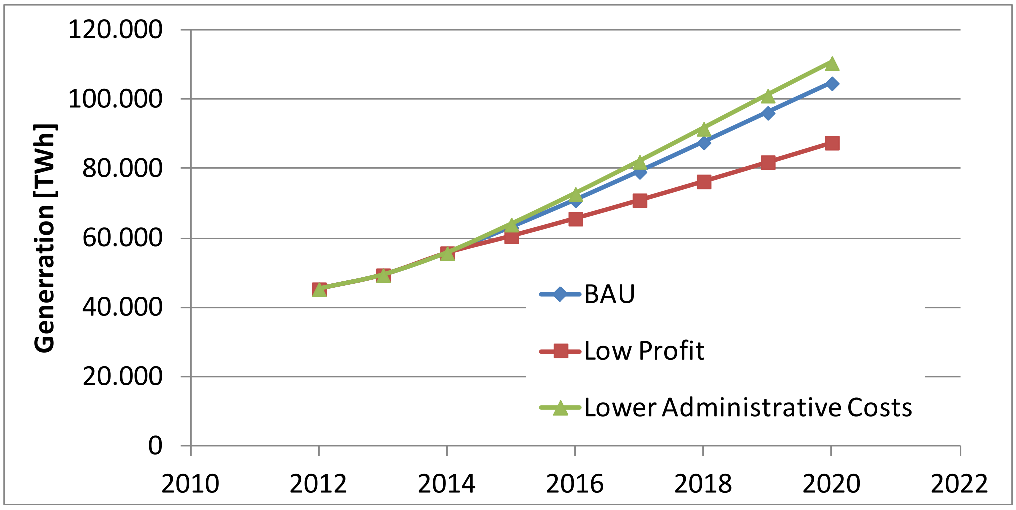


Figure 12: Short term diffusion outlook for wind onshore in Germany. Shown is the electricity generation for the three scenarios defined above.

Overall, the results show that the interplay of various economic and non-economic framework factors has a significant impact on the future growth of RES-E technologies and that a close monitoring of both is required to allow for optimization of RES policy strategies.

2.5 Recommendations

To achieve a stronger convergence towards best practice policies in the European context, two approaches are conceivable: i) support schemes and related regulations could be harmonised in a top-down manner, e.g. initiated by the European Commission, or ii) schemes could be coordinated in a bottom-up approach, without 'interference' from the EC. Currently, a mix of both approaches seems to be applied in Europe:

- top-down coordination in some policy areas, e.g. RES heating obligations in the building sector or state aid guidelines
- bottom-up coordination by member states, e.g. alignment of remuneration levels

In the past, a combination of coordination, cooperation and selective top-down harmonisation has been applied, and this approach is probably the most feasible one for the foreseeable future as well. This mixed approach can effectively lead to increased convergence of the most important aspects of effective and efficient support schemes, which allows for gradual and selective market integration (depending on the maturity of the relevant technology and market). Under this scenario, RES-E market conditions (comprising support scheme and other contextual conditions) would converge in the medium and long term rather than in the short term. As a result, the complete implementation of the internal market for RES-E would also have to be envisaged in the medium and long term as a gradual process. The continuation of a mix of top-down and bottom-up processes, also beyond 2020, would focus on harmonised minimum design criteria (top-down) and intensified coordination and cooperation between member states (bottom-up). This option would foster policy convergence and market integration, while respecting member states' different preferences, which should increase the political feasibility and public acceptance of such an approach.

This mixed approach will be crucial in the upcoming development of a post 2020 framework, which will explore options to encourage and incentivise regional coordination and cooperation. Thus, what are the main issues related to support scheme design that could be more strongly coordinated, without losing Europe's unique innovative capability?

- First, convergence will increase due to the new state aid guidelines in terms of phasing out FITs and implementing FIPs (see European Commission, 2014). There is a clear trend in Europe towards floating premium systems also called "contract for difference". These systems strike the right balance between market integration and mitigation of unproductive risks. Further coordination (and the resulting convergence) might be applied with regard to the calculation of premium payments (e.g. whether a yearly, monthly or daily electricity reference price is used).
- Second, the calculation of LCOEs is highly fragmented and could be coordinated further. This is somewhat politically sensitive as the cost-calculation is precisely the step used by national lobby groups to influence tariff setting. At the same time, a common methodology for LCOE calculation would improve information and accuracy of setting strike prices. This will also be needed, when auctions are used because of the necessity to fix maximum price limits in most cases and auction types.
- Third, as auctions will be increasingly implemented, an intensive exchange on possible auction designs and a structured evaluation of how different auction designs perform in different contexts seems highly advisable. This would likely lead to the identification of best practices in decisions on the use and design of auctions, which would be the basis for increased policy convergence within this specific aspect of support scheme design.
- Fourth, the diffusion of best practices regarding non-economic framework conditions, such as spatial planning or permitting procedures for RES, should receive more attention. This would facilitate the creation of a level playing field for RES developers across Europe.
- Fifth, revising and adjusting tariffs over time is handled differently throughout Europe and, admittedly, there seems to be no 'silver bullet' to strike a balance between adjustments to unforeseeable cost developments on the one hand and keeping investment risks in check on the other. In any case, adjustments should only apply to new plants and should be performed in a systematic and predictable manner.
- Sixth, quota obligations can be implemented as joint support schemes, but it is difficult to implement only selected joint elements. Problems with quota obligations as common support scheme occur in particular when banding factors are used for individual technologies. In this case, the quota fulfilment does not correspond to target fulfilment, which can render negotiations more difficult. Therefore, the difficulty to implement technology-banded common quota schemes and their recent substitution through other policies indicate that these are rather unsuitable for coordination.

- Seventh, with respect to burden-sharing, rules to determine industries that should be exempted from paying levies that are used to finance renewables could be coordinated and perhaps even harmonised among MS.

This coordination is not the same as full top-down harmonisation. However, if implemented more effectively, coordination would lead to increased policy convergence, thereby paving the way for a more effective implementation of the internal energy market, while strengthening a good balance between market compatibility and reduction of investment risks.

3 Integrating renewables into markets

3.1 Policy context

Policy-makers are currently following two main routes to accelerate the market integration of renewables: first, they are adapting support systems for renewables by gradually increasing the exposure of renewable generators to market prices and risks. A crucial task in this regard is to find the right balance between risk exposure and market integration, because additional risk implies higher financing costs.

The second option is to make the power system more flexible by defining market rules that reflect the nature of intermittent resources like wind and solar. This is expected to increase the market value of renewables, which in turn should reduce the level of public support required to trigger further renewable energy deployment. Ultimately, the level of required support premiums for renewable energy generators depends on the gap between their generation costs (incl. risk premiums) and potential revenues they can earn from markets. The importance of a counterbalance between risk premiums and potential additional revenues through more efficient marketing as a result of better incentive compatibility has already been discussed. However, the bigger part of this gap remains; Even if revenues would be considered to be perfectly deterministic and thus additional risk premiums merely disappear, market revenues would still not be sufficient in many cases to refinance new investments in renewable generation. If deployment of RES should not stop the remaining gap has to be filled by financial support to RES.

The crucial question here is how this gap, which is also an indicator for the competitiveness of a certain supported technology, could develop in the future. To answer this question one has to study both, the development of generation costs and market revenues over time; the results from such an analysis are one of the key outcomes of the DIA-CORE project. In this context, a historic assessment and continuous monitoring of selected effects of RES on electricity markets and the revenues they can potentially earn in these markets seems necessary. Also, quantifying the benefit of additional flexibility and the impact of other sensitivities on market revenues of RES constitutes an important task in order to develop estimations for future support requirements.

3.2 Objectives of the analysis

The topical focus of this section is on the assessment of the merit-order effect and market values of RES generation since both are relevant for a correct quantification of net support expenditures for RES in the electricity market. In particular, the analysis focuses on the assessment of these indicators for variable renewable energy sources, most prominently wind and solar PV. The installed capacity of variable renewable energy sources is being assumed to substantially increase to meet EU RES and climate targets. In case of high deployment shares the feedback effect on electricity markets is expected to reach a significant dimension and therefore indirectly influences the overall cost-benefit analysis.

3.3 Approach

In order to get insights about the size of potential risk premiums under a varying degree of risk exposure a survey among several stakeholders was conducted to assess how financing costs change under different support policy designs and varying degrees of risk exposure. The assessment of both the merit-order effect and market values are conducted from a historical and a future perspective. Based on historic data an econometric analysis has been performed for selected member states, which were already at the forefront of RES deployment in the past. This analysis was complemented by a comprehensive literature review in order to integrate and contrast also existing studies in this assessment. Second, a suitable framework for the modelling of potential future developments of both, the market value and the merit-order effect of and induced by RES is presented. The findings of this analysis shall finally serve as a basis to reassess the incentives established by a certain RES policy.

3.4 Results

3.4.1 How to balance risk exposure and market integration

Support systems can be designed with varying degrees of exposure to market prices. We are currently seeing a trend in which most EU member states are moving away from feed-in tariff systems, but are implementing feed-in premium systems instead. In this context, the UK's Contract-for-Difference is almost equivalent to Germany's sliding feed-in premium scheme. In both countries, a price is fixed *ex ante*, but is only guaranteed to the volumes announced one day before delivery. This means that renewable energy generators are directly responsible for day-ahead forecast errors, i.e. they have a balancing obligation.

Further market integration implies the imposition of more responsibilities on renewable energy generators. Transferring obligations from a central authority to generators is equivalent to a risk transfer and therefore leads to higher financing costs for renewable energy projects. In that case, a higher level of public support would be required to trigger the same amount of deployment, and overall policy costs would increase.

To determine the cost-effective level of risk transferred to generators, it is essential to weigh the resulting increase in policy costs against potential benefits. In the case of imposing balancing responsibility on generators, there is evidence that the benefits outweigh the costs, provided that liquid intraday markets exist, because forecast quality would increase (see Sensfuss et al. 2013). Therefore, the balancing risk is typically considered as a productive risk.

3.4.2 Financing costs under varying degrees of risk exposure

In the context of DiaCore, a survey among stakeholders was conducted to assess how financing costs change under different support policy designs and, thus, under a varying degree of risk exposure. It is important to note that the presented results rely on a small number of cases (n = 14) and are far from being representative for the whole EU. They should be considered as indicative results. However, the findings are in line with those of an earlier study on impacts of policy design on cost of capital of wind power projects (see Giebel and Breitschopf, 2011).

As a base case, a sliding feed-in premium scheme was assumed, where the remuneration level (strike price of Contract-for-Difference, CfD) is set administratively. Respondents indicated that the weighted average costs of capital (WACC) would increase by 80 to 140 basis points compared to the base case when additional risks are transferred to generators (see Figure 13).

More specifically, stakeholders were surveyed to indicate the impact of the following modifications to the base case:

- Case 1: CfD, but no support in times of negative market prices
- Case 2: fixed feed-in premium
- Case 3: CfD with tendering process for strike price

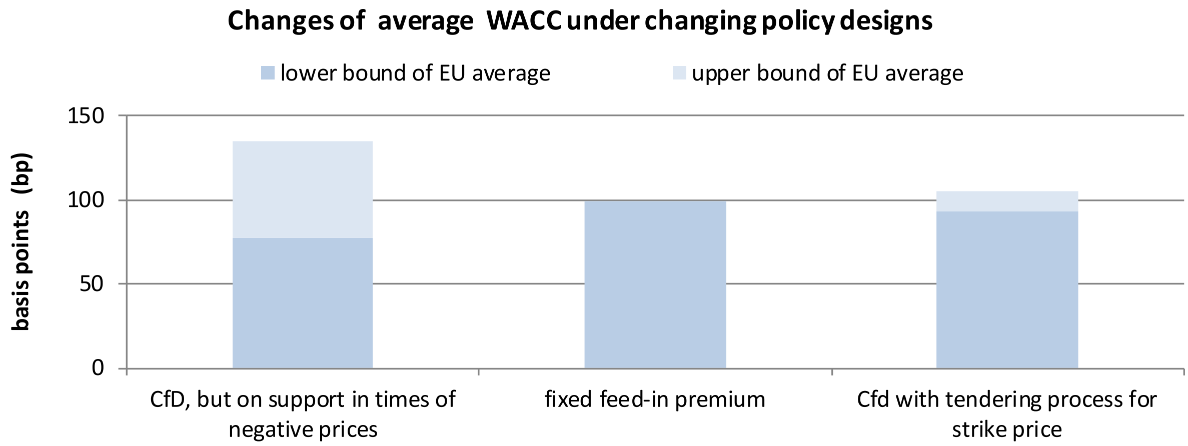


Figure 13: Indicative changes of the average EU WACC under different policy designs for onshore wind projects, June - Sept. 2015

Source: own formulation

The results of the survey show that moving away from the base policy case always leads to higher WACC – especially in case 1, where no support is granted in times of negative market prices. This is because the frequency of negative prices in the future is rather uncertain and difficult to forecast. As a result, revenue streams become more uncertain and financing costs increase. Furthermore, renewable generation, which is curtailed during negative prices, needs to be replaced by additional installations to ensure that renewable energy targets are met. Additional installations lead to higher policy costs, while benefits to the overall power system are considered ambiguous. On the one hand, some argue that the market price gives an undistorted dispatch signal, if no support is granted to renewables in times of negative market prices. On the other hand, the incentive to invest in flexible generation and demand is higher when negative prices occur. Furthermore, renewables are not the only plants that accept negative prices. It is also common for conventional plants that sell heat or provide balancing power, to accept them.

In the other two cases, the increase in financing costs is not as strong as in case 1 but is still significant, i.e. around 100 basis points.

In case 2, a fixed feed-in premium would be granted instead of a sliding premium. For generators, this means that in the event of falling power market prices they would be unable to recover their full costs. This risk is typically not considered to be a productive risk, because generators are exposed to the risk of falling fossil fuel and carbon allowance prices, to which they cannot react once a plant has been built. This is different for conventional plants, because there is inherent risk-hedging since falling fossil fuel prices also reduce production costs. Moreover, because there are policy targets for renewables, the investment decision should not depend on fossil fuel prices. Another disadvantage of a fixed premium is that overcompensation is a possible consequence of rising fossil fuel prices.

In case 3, a tender would be set up to determine the strike price of the CfD and penalties would be applied in the case of delayed completion. The expectation is that in a competitive bidding process, policy costs would be lower than when the strike price is set administratively. However, this also depends on the specific design of the auction mechanism. As with other aspects of support systems, design and supervision have a major impact on its efficiency and effectiveness.

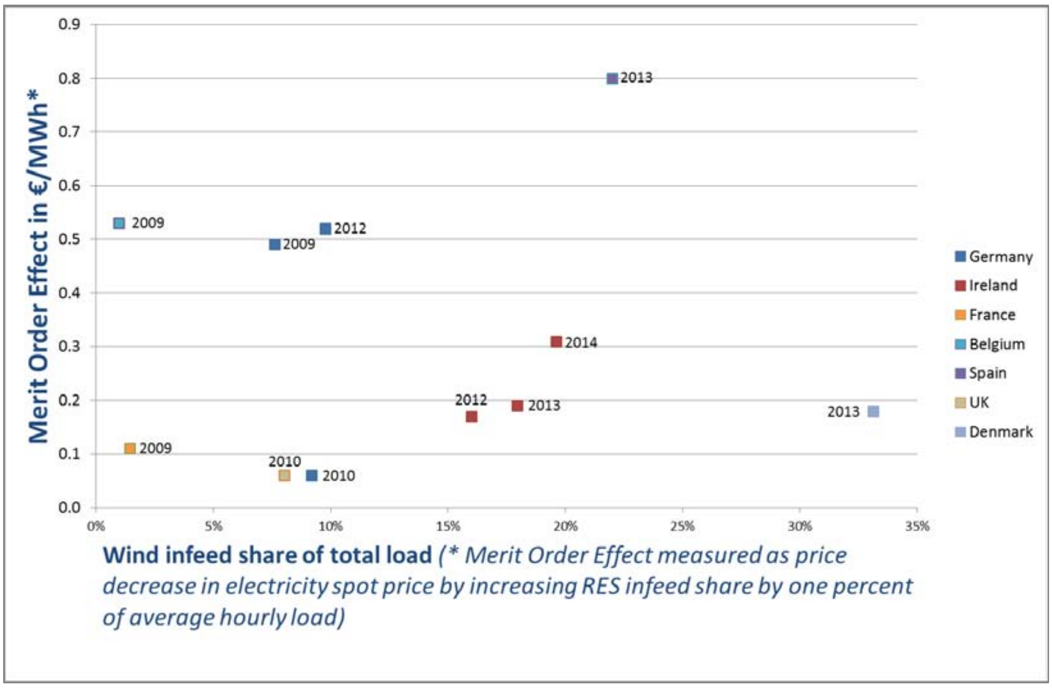
3.4.3 Benefits of RES-E in electricity wholesale markets

The focus of the DiaCore report D4.2[6] was to shed light on key effects of large-scale RES-E integration in electricity wholesale markets. First, it has been analyzed how price dynamics in wholesale markets induced by RES-E deployment have changed in the past and are expected to change based on a number of scenarios. These changes are summarized under the term *merit-order effect* of RES-E in the relevant literature (cf. Sensfuß et.al, 2008). Second, a closer look has been taken on potential earnings of RES-E stemming from electricity markets. Within this report the term *market value* of RES-E has been defined as the sum of revenues earned from RES-E plant operators through the marketing of generated electricity in spot markets. Both figures are closely related to each other. In the following the main results of the analysis as described in more detail within report D4.2 are summarized.

[6] Available at http://diacore.eu

3.4.4 The merit-order effect induced by RES-E

An **empirical analysis** has been conducted for all major European's electricity markets quantifying the historic merit-order effect induced by RES-E. This assessment has been complemented with the calculation of historic (wholesale) market values of wind onshore, wind offshore and large-scale solar PV in these markets. Finally, the results of this task have been related to corresponding findings in the relevant literature. Figure 14 illustrates the results of our econometric approach for selected European countries that already reached considerable RES-E shares. In this figure, price effects are related to the size of the respective country's electricity market: An increase in variable RES generation in the dimension of a one percent share of the average load of that country was used as a unit of reference for the price change. This approach is the most suitable for an overall comparison between Member States as they do differ in size (RES targets are also set in relative terms for this reason). Apart from a few outliers, there is a clear trend that a higher load share of variable RES leads to lower electricity prices, and can thus induce a merit-order effect. This trend is even more apparent in more recent years, whereas earlier years show more dispersion, possibly due to other unobserved effects that also influence electricity spot prices. The results show that feed-in of electricity from variable renewables (wind power and photovoltaics) has a negative impact on (day-ahead) electricity prices. The intensity of the drop however varies between member states. One additional percent of wind infeed leads to a drop of 0.53 €/MWh for e.g. Germany and 0.8 €/MWh for Spain. Scaling this up to a yearly measure would have meant 180.7 Million € or 197.7 Million € of additional costs of consumption without additional RES generation in the years 2012 and 2013. These findings are similar to those found in the literature.



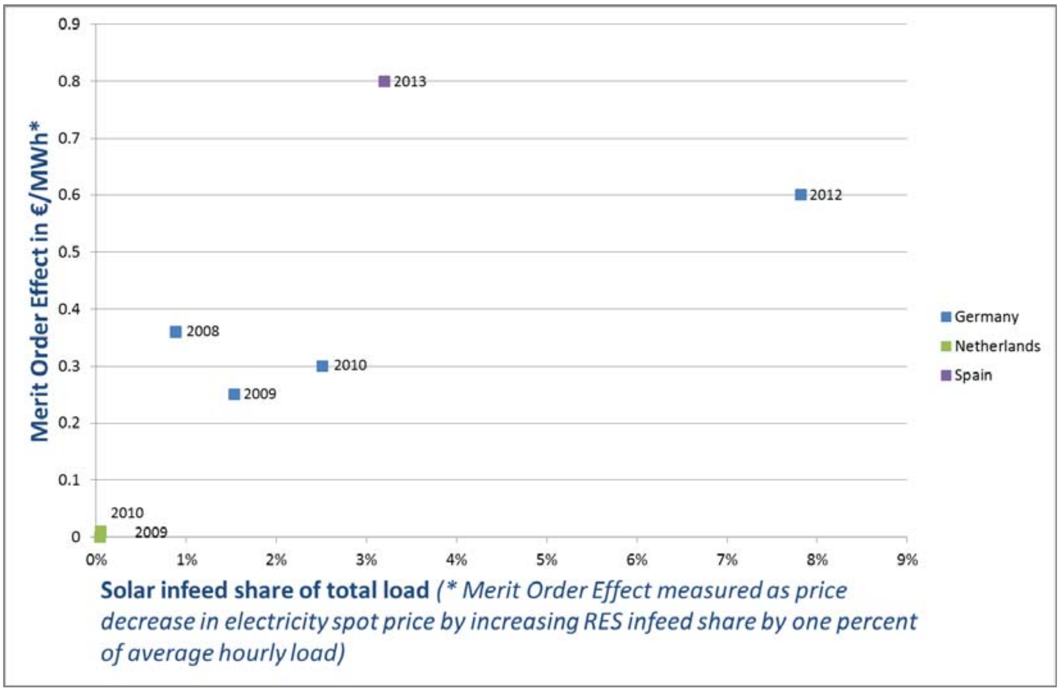


Figure 14: Historic merit-order effect induced by wind power and solar photovoltaics - Comparison of price changes induced by feed-in of variable RES (2008-2013)

The transition of Europe’s power systems towards more sustainability leads to trends in all important figures, therefore a **forward-looking perspective** has been taken as well. Based on a combination of three European-scale market- and investment models the expected future merit-order effect and market values of RES have been assessed under the assumption of different RES policy pathways and framework conditions. A description of important assumptions like fuel prices and demand forecasts are given in report D4.2.

Three distinct **Pathway scenarios** have been developed to reflect the evolvement of a certain mix of possible future developments in all dimensions that could most likely occur simultaneously. A business-as-usual scenario aims to reflect the most probable development (27% RES target achieved in 2030) in all of the before mentioned scenarios and will be used as reference scenario to be compared to all other scenarios. Besides that two alternative pathways (no dedicated RES support vs. a more ambitious RES target) comprised by a consistent set of variations in all dimensions are considered as well. Together, these three pathway scenarios allow us to derive a bandwidth of potential future market values of RES and the merit-order effect by explicitly considering substitutional and complementary effects, respectively.

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

Table 2 summarizes the considered scenarios for the assessment of market values and the merit-order effect. The scenarios in the table are grouped according to their type, e.g. either pathway or sensitivity scenario.

Table 2: Overview of modelled scenarios

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

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

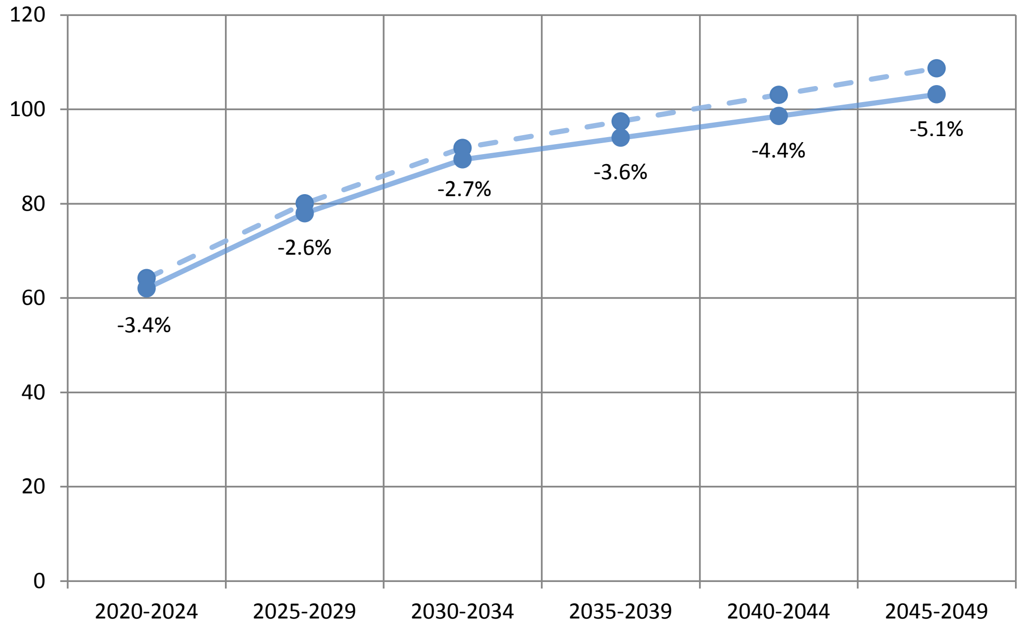


Figure 15: Average day-ahead electricity prices in the EU in the P-NoPolicy scenario (dashed line) and the P-Reference scenario (solid line).

Figure 15 shows the resulting day-ahead electricity price of both scenarios as an EU average. It can be seen that in each period of time the prices of the P-Reference scenario are below the ones in the P-NoPolicy scenario. This indicates that an additional amount of RES-E, ceteris paribus, decreases average electricity prices by 2 to 5 percent depending on the actual amount and type of additional RES-E and the corresponding in- and divestments in the conventional generation park. It has been assumed in the modelling that all conventional generators fully recover their total costs based on market revenues. However, it should be stressed that this analysis has been performed under the ceteris paribus condition. In reality, electricity markets are almost never in equilibrium and prices vary according to a large number of independent influences. This analysis has thus shown that given everything else remains constant, additional RES-E lowers average electricity prices.

The resulting prices do not equally drop within the EU. Price drops are more significant in Member States where relatively expensive generation technologies can be substituted and those adjacent states, whose markets are comparably well coupled to it. Figure 16 shows the spatial distribution of electricity prices across the EU in the year 2030. It has been assumed that that all Member States have implemented electricity markets and that all markets are implicitly coupled via current NTC values plus the extensions proposed in the TYNDP of ENTSO-E.

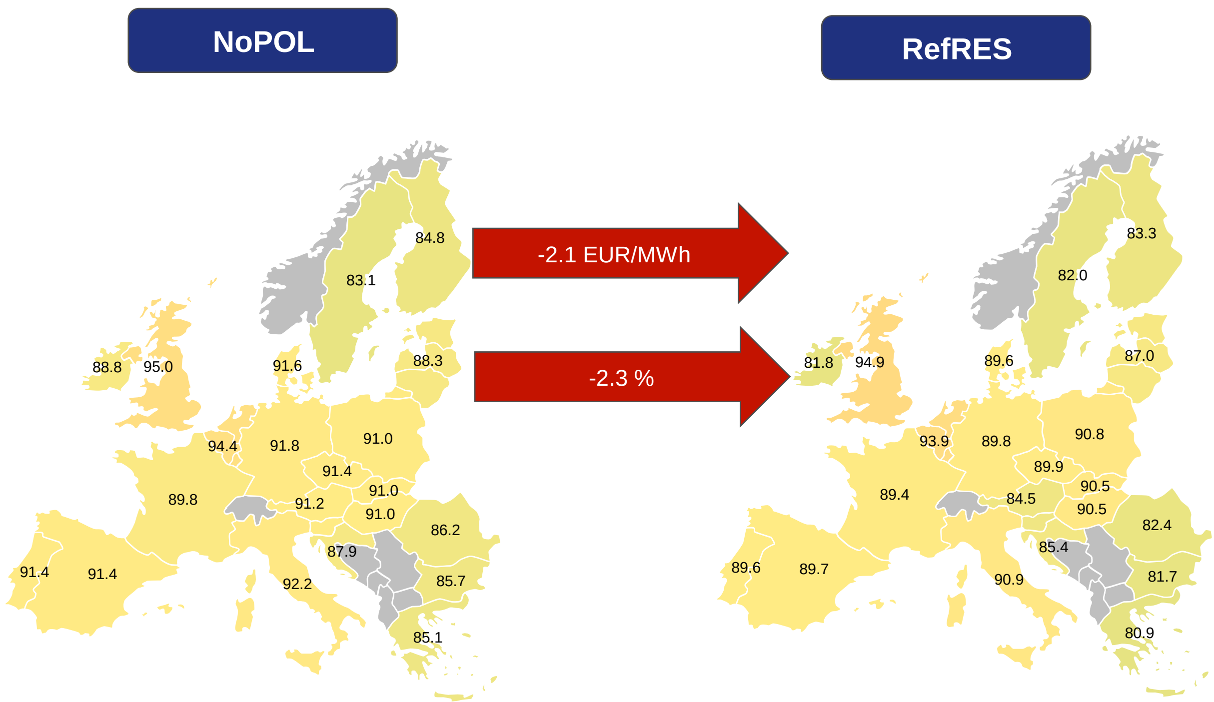


Figure 16: Average day-ahead electricity prices of the P-NoPolicy scenario (NoPOL) and the P-Reference scenarios (RefRES) across the EU in 2030.

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

3.4.5 Market values of variable RES-E

The ratio between potential market revenues of RE generators and baseload generators considerably drops with increasing penetration, especially for variable RES (vRES). This peculiarity can partly be explained through a special characteristic of variable RE generation, which is marketed (and thus valued) in energy-only electricity markets. The marginal value of the electricity generated based on vRES decreases with increasing market penetration, because higher priced generation is substituted by lower priced vRES. Therefore, market prices are low when (nearly zero priced) renewable electricity infeed is high and vice versa. This is a competitive disadvantage of variable (or non-dispatchable) electricity generation compared to dispatchable generation, which materialises in the form of relatively lower market revenues as compared to revenues of the same amount of constant electricity generation. In order to compare relative market revenue changes of certain technologies between different countries / price zones the yearly market revenues are divided by the corresponding yearly average (day-ahead) price level in their price zone. The resulting figure is called the **market value factor**.

The historic market value factors of wind onshore and solar PV in European countries are presented in Figure 17 based on actual hourly day-ahead prices and corresponding RES generation. The figure shows that in the past, the market value of PV was higher than that of wind. This is due to the effect that the sun usually shines at peak demand times, where in the past high demand used to trigger higher electricity prices and thus lead to a higher value for electricity generated by photovoltaic power plants. Furthermore, as the subset of analysed years presented is quite early with a comparably low installed capacity, a merit-order effect induced through photovoltaics is also not very likely due to its substantially small share. As will be seen in the model-based analysis, larger capacities and thus higher infeed can lead to a substantial drop in the market value of PV.

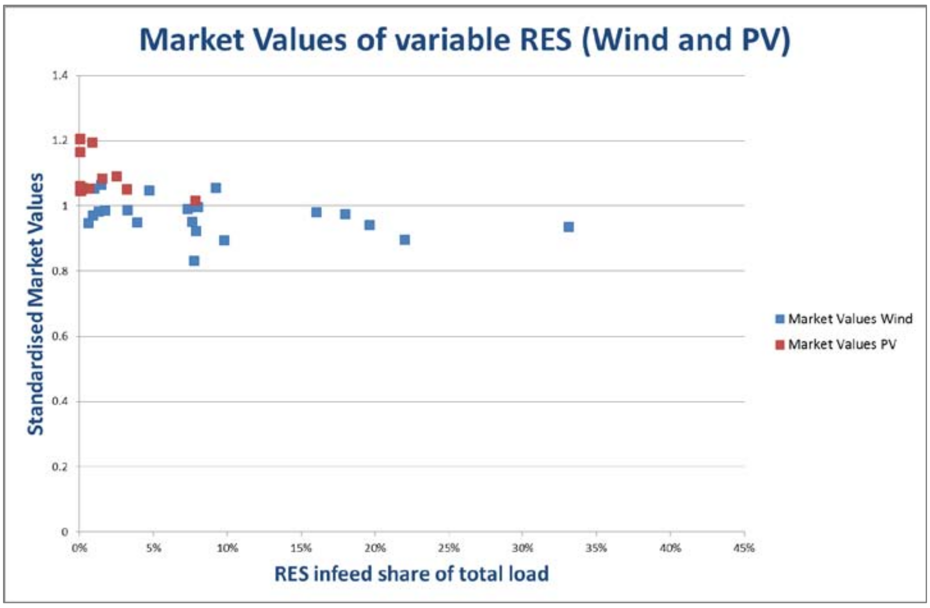


Figure 17: Historic market value factors of wind onshore and photovoltaics

To study the size of this effect in a forward-looking perspective the three scenarios P-NoPolicy, P-Reference and P-HighRES have been contrasted with each other (cf. Table 2). The NoPolicy scenario and the Reference scenario only differ in their RES-share, whereas the HighRES scenario also assumes a considerable amount of additional energy efficiency measures. The absolute levels are not much higher than in the Reference scenario. In the following the relative market value factor will be shown for these scenarios and different time frames. Figure 18 shows boxplots that each contains the market value factors of all EU member states in the respective scenario. In the year 2020 the absolute amount of RES between the different scenarios does not significantly differ. However, they differ in their RES-E generation mix and the location of RES investments.

The first three boxplots in Figure 18 illustrate the aforementioned effect. Even the absolute amount of RES-E is the same across the EU, investment at locations with higher market values or the total mix of variable renewables (in this case additional PV) can change the value of the generation profile in a way that relative revenues increase. In the period of 2030 and 2050 the decreasing effect of market value factors becomes apparent. Not only the median values decrease from nearly 100% down to around 80% with higher RES-E penetration, but also both minimum and maximum value factors drop in the lower range.

The same holds for wind offshore. It can be seen in Figure 19 that market value factors of wind offshore can even be above the revenues of a baseload generator at low penetration levels. With higher penetration also the relative market values drop, however less step than they do for wind onshore. The strongest decline in relative market revenues can be observed for the case of PV (cf. Figure 20).

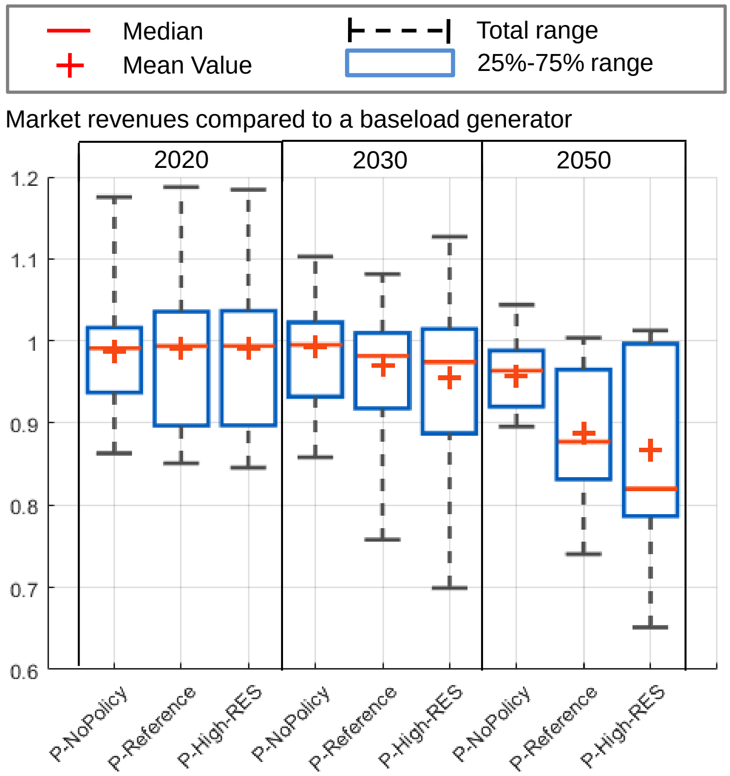


Figure 18: Market value factor of wind onshore within the EU for different RES scenarios.

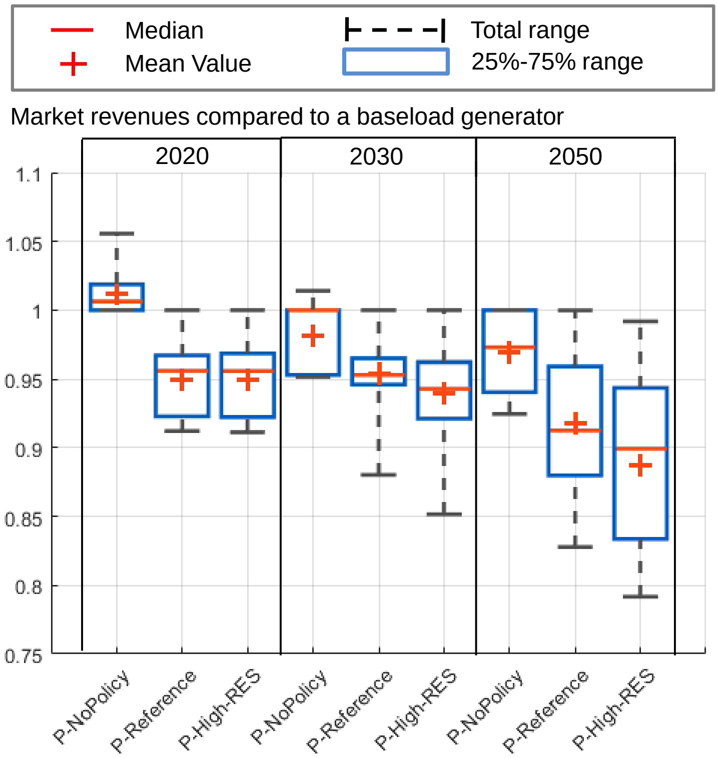


Figure 19: Market value factor of wind offshore within the EU for different RES scenarios.

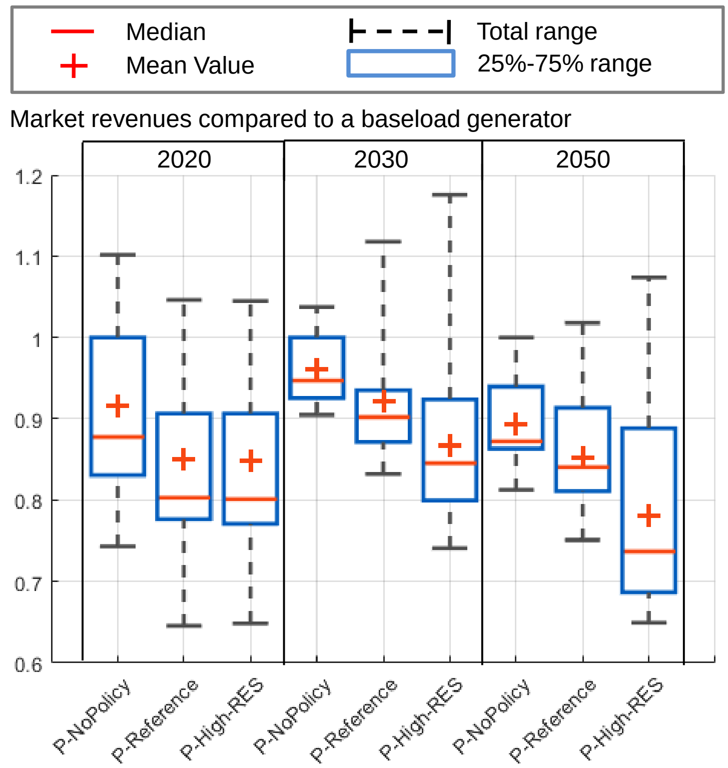


Figure 20: Market value factor of PV within the EU for different RES scenarios.

3.4.6 Sensitivity of market values caused by external factors

In general, electricity prices are strongly influenced by economical and technical framework conditions. As a consequence, also revenues of RES-E are impacted by these conditions. Basically, there are two opposing sets of conditions that influence the level of market value factors of vRES. The first set of conditions is adding variability to the market. This is e.g. the case if additional vRES are installed, which has been discussed in the previous section, but it can be any other addition of inflexibility as well. Under such conditions the market value factors of vRES decrease. The other set of conditions add flexibility to markets. These are, e.g. well-known measures as additional storages, demand-side management, energy sector-coupling, making conventional generation units more flexible, or expanding transmission grids. By adding flexibility to the market the market values of vRES increase. In order to assess the magnitude of such influences several sensitivity scenarios have been evaluated with regard to their impact on market values of wind onshore, wind offshore and solar PV. The results of this evaluation can be seen in the Figure 21 to Figure 26. We compare each of the sensitivity scenarios to the reference scenario (P-Reference) in order to assess the impact of framework conditions on market values (cf. Table 2).

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

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

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

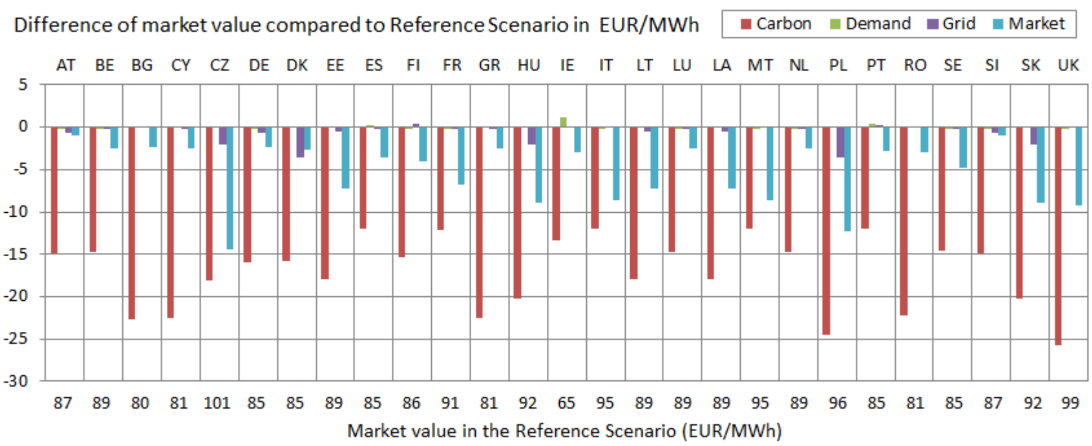


Figure 21: Change in market values of wind onshore as compared to the Reference Scenario in 2030

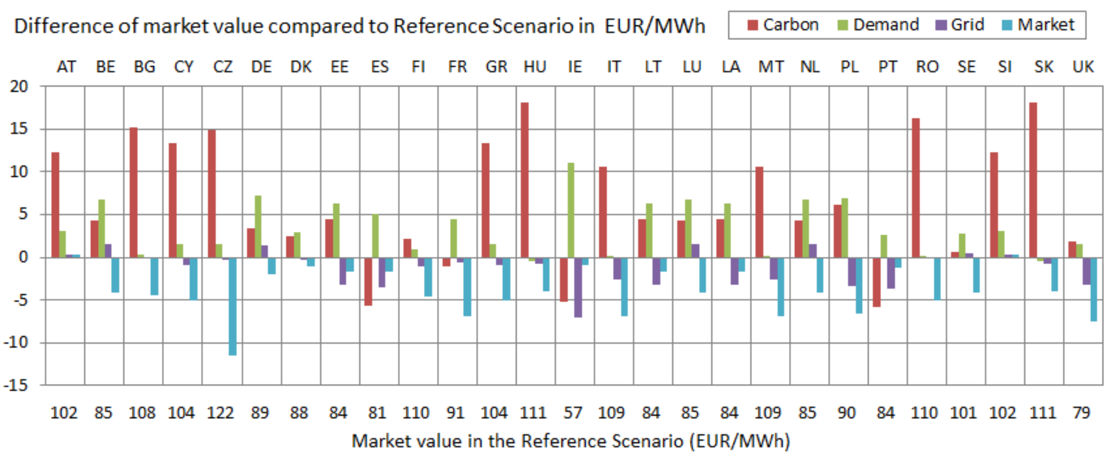


Figure 22: Change in market values of wind onshore as compared to the Reference Scenario in 2050

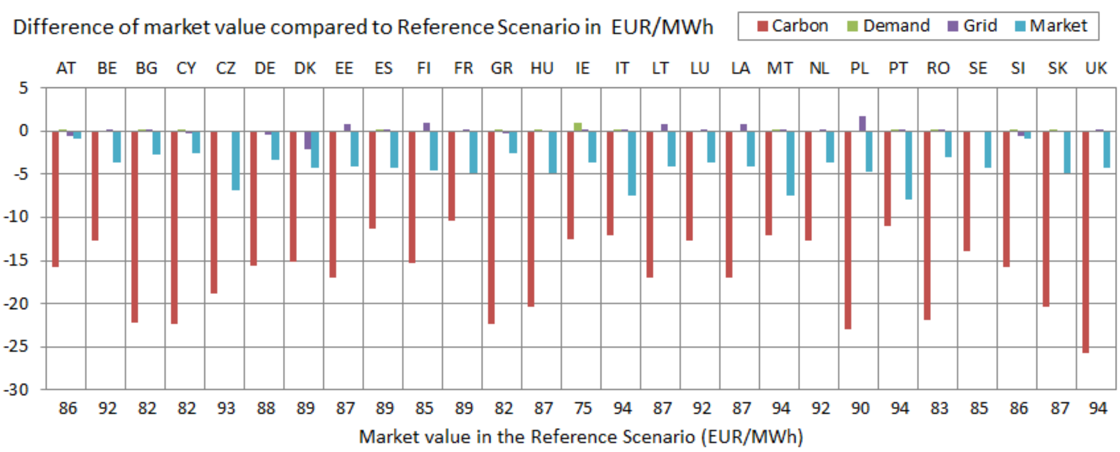


Figure 23: Change in market values of wind offshore as compared to the Reference Scenario in 2030

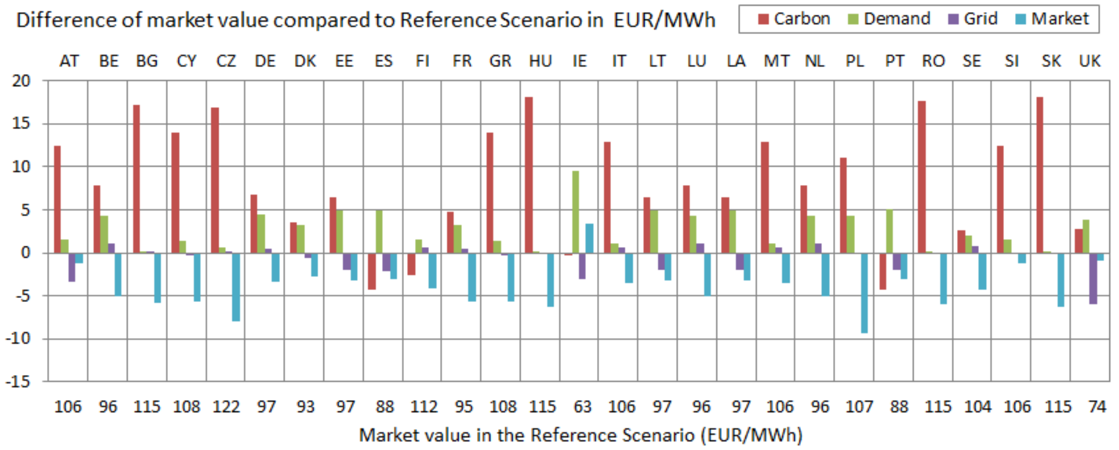


Figure 24: Change in market values of wind offshore as compared to the Reference Scenario in 2050

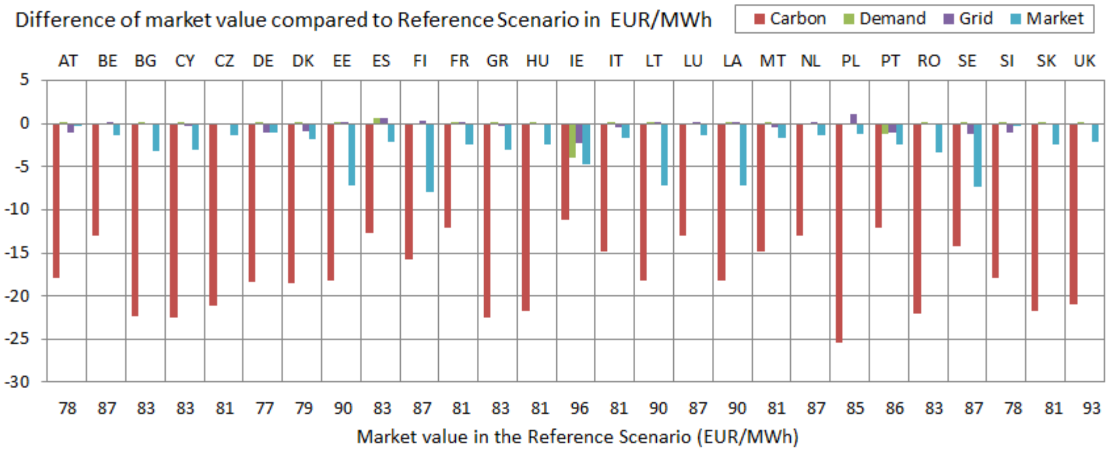


Figure 25: Change in market values of solar PV as compared to the Reference Scenario in 2030

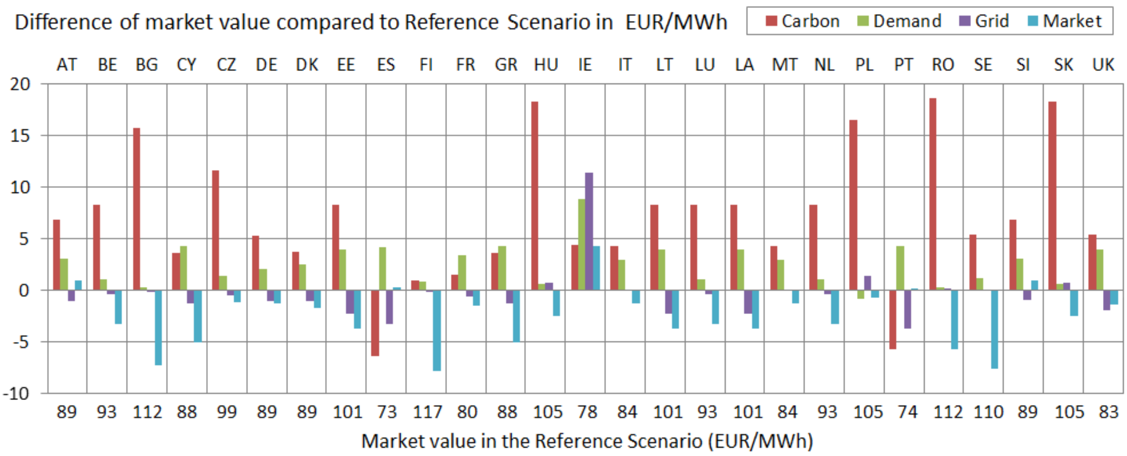


Figure 26: Change in market values of solar PV as compared to the Reference Scenario in 2050

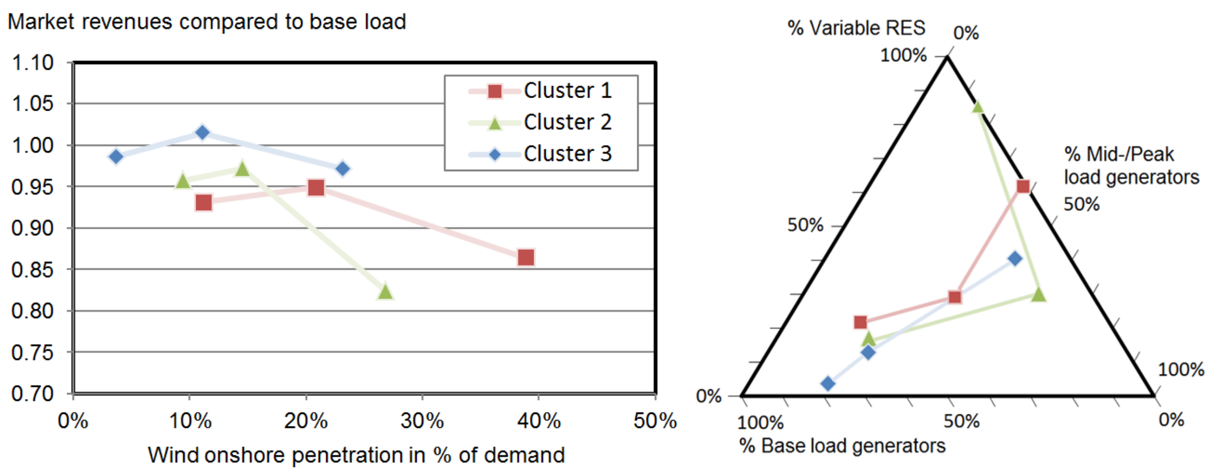
This market design suppresses price peaks in scarcity events and thus lowers average electricity prices in electricity wholesale markets. In this case generators receive besides the revenues from electricity wholesale markets additional revenues from capacity markets. These markets value firm capacity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

3.4.7 More flexible power systems increase the market value of variable renewable electricity

Flexible power systems are able to accommodate a certain amount of variable renewable generation at lower cost. The flexibility of a power system is defined by its flexibility of supply, the flexibility of its demand and the ability to transmit power without congestion. The flexibility of supply is determined by the share of generators with relatively short start-up/shut-down times and thus low costs and very low must-run output. These attributes are typically met by mid-merit and peak-load generators and less often by base load generators. Furthermore, more flexible generation profiles shift load factors into a range where mid-merit and peak-load generators can be operated more economically than base load generators. A flexible demand additionally eases the integration of variable renewable generation by shifting (additional) demand into hours with lower prices that indicate a high infeed of renewables at times of low demand. Finally, when geographically distinct supply areas (e.g. countries) are better connected via sufficient transmission capacity the aggregated generation profile of variable renewables can flatten out and more dispatchable generators and consumers are enabled to fully utilise their flexibility.

Figure 27 provides an illustration of this effect for wind onshore based on selected modelling results from DiaCore. Both graphs contain aggregated values for three country clusters for the years 2020, 2030 and 2050 (one curve). The countries are clustered according to their level of market price, expressed as a yearly average wholesale price. If the price difference between two countries is lower than €1.5/MWh, they fall within the same cluster. The generation mix of each (integrated) country cluster develops differently over time (right graph). The left graph plots potential revenues that wind onshore can earn on average compared to a base load generator.

The general trend that can be observed is that with increasing penetration of wind onshore its relative market value decreases. This can be observed for all variable renewable generators with low marginal generation costs. For that reason, the total amount of variable RES on the generation mix is decisive for the value of wind onshore, as it is for all other variable RES. The interesting point to note is that in general relative market revenues remain stable, or even increase temporarily if power systems become more flexible. The decisive element here is the relation between the speed of phasing in vRES versus the speed of enhancing flexibility phasing out base load generation, because flexibility should be interpreted relative to the share of vRES in the mix. Cluster 3 has the highest market value because the aggregated vRES generation profile of the cluster is fairly flat, or even correlates slightly with its demand. In this system the market revenues of wind onshore remain relatively stable, which can partly be explained by the fact that additional vRES replace base load generation and mid-/peak load generation remains rather stable. In clusters 2 and 3 we even see a strong shift from base to mid- and peak-load generation in the period between 2020 and 2030. This causes relative market revenues to rise temporarily. In the later period up to 2030 in these clusters the proportion of vRES in the generation mix increases disproportionally, which leads to falling market values. The effect in cluster 2 is more distinct as the overall share of vRES in the mix is notably higher than in cluster 1. The same effects can be seen when power systems become more flexible through more interconnection, or when there is a stronger participation of consumers in balancing supply and demand. The general finding remains: an ambitious phase-in of vRES requires an appropriate accompanying backup/demand system transition towards more flexibility in order to efficiently integrate variable renewables.



Cluster 1: AT, CZ, DE, DK, EE, ES, FI, FR, GR, IT, LT, PL, PT, SE, SI

Figure 27: Development of market revenues of wind onshore (relative to revenues of a base load generator) throughout the EU (left graph) and corresponding generation mix of the cluster (right graph) in 2020, 2030 and 2050

Source: own formulation

3.5 Recommendations

Further market integration implies the imposition of more responsibilities on renewable energy generators. To determine the cost-effective level of risk transferred to generators, it is essential to weigh the resulting increase in policy costs against potential benefits. In case that the benefits outweigh the costs the risk is considered as a productive risk. To identify productive risks more practical experiences with actual market integration models need to be gathered.

With regard to market revenues of RES-E generators it has been shown that revenues – and thus support costs – considerably depend on electricity market design and the available flexibility within the underlying power system. Moreover, revenues change over years as a result of varying meteorological conditions. Consequently, it is necessary to consider interlinkages of electricity market design, regulation and grid development plans within RES policy and to keep track of average market revenues of RES via constant monitoring of market values to assess potential support costs of RES-E.

4 Financing renewables and risk allocation

4.1 Policy context

In order to meet the 2020 EU targets on renewable energy, considerable investments are required from all Member States. For the EU, the total annual investments is estimated at €60-70 billion per year[7]. From previous years, we know that this is possible, yet annual investments show a declining trend. In 2011, European[8] investments in renewable power and fuels added up to almost €115 billion, but then decreased to €86 billion in 2012 and €48 billion in 2013 (REN21, 2015).

In several countries, the policy support has been decreased to a minimum or totally abolished, sometimes even retrospectively. As policy support is a very important condition for the business case of renewable energy, (sudden) policy changes impact the risk perception of investors. If investors see a high risk, they will ask a higher return for their investment, driving up the costs for renewable energy.

Policy support is not the only factor that has an impact on renewable energy investments. Permitting procedures, public perception, grid access etc. can influence investment decisions of financiers and be perceived as a risk. Understanding the risks and estimating their impact on renewable energy investments is therefore important to decrease the costs of renewable energy projects and enhance investments.

4.2 Objectives of the analysis

This analysis takes a closer look at the **role of risk** influencing RES investments and focuses on identifying barriers and solutions to **enhance investments** in the RES sector:

- It assesses the relevance and severity of risks in EU Member States, focusing on **policy-related risks**.
- It provides insights in the most important renewable energy investments risks per Member States (**country risk profiles** for each Member State).
- Furthermore, it offers policy options for mitigating investment risks by preparing a **policy toolbox** providing input and guidance to develop country specific measures for mitigating investment risks.

Against this background, this analysis aims at responding to the following questions:

- What risks influence RES-E investment decisions?
- What is their impact?
- How do they differ among EU Member States?
- What are effective policy options to mitigate these risks, thereby reducing the costs of capital and increasing capital availability?

[7] Financing Renewable energy in the European Energy market, Ecofys, Ernst & Young, Fraunhofer ISI, TU Vienna, 2010.
[8] Including non-EU countries and Russia.

4.3 Approach

Our approach consisted of two parts:

1. identifying renewable energy investment risks
2. formulating policy measures to mitigate RES investments risks (see Figure 28).

In Part 1, insights were gained in the cost of capital for investments in renewable energy sources (RES). In order to estimate the Weighted Average Cost of Capital (WACC)[9], a theoretical model was constructed. In this model, an **estimation of the cost of equity** was made for **onshore wind projects** in each EU Member State based on the fluctuation of RES industries' share values compared to average fluctuations in market share values. Secondly, the WACC was estimated for each Member State based on the modelled result of the cost of equity, information on the cost of debt as well as the debt-to-equity ratio for onshore wind projects.

After estimating the financing parameters, we gathered information on risks influencing the RES investments. These risks influence the cost of equity and cost of debt for RES and, thus, the WACC of RES investments. Based on reports, previous studies, and databases, an overview was created presenting the **most important risks** for each EU Member State.

The outcomes of the theoretical model were evaluated and tested during interviews with over 80 financial experts from 26 Member States[10]. Based on these interviews, both the financial parameters and the ranking of the risks were adapted and used to draft **country risk profiles** for each EU Member State.

In Part 2, the focus was to assess the impact of policy design changes on the cost of capital and to formulate policy measures to mitigate RES investments risks. First, **a survey was conducted focusing specifically on the role of policy design**. The respondents were asked to indicate how the interest rate, equity share, and the expected return to equity would change if policy design elements were changed. The results show how the WACC changes when switching from one policy design to another.

Finally, an assessment was made on how policy measures can influence the risks impacting onshore wind energy investments. In general, there are four risk control strategies: avoid, mitigate, transfer/share, and accept. For this study, mitigate and transfer/share are most relevant. During the interviews with financial experts, information was gathered on how policies could mitigate investments risks. The results were used to prepare the **policy toolbox**.

The table below provides an overview of the project:

[9] Nominal post-tax, at financial closure.
[10] For Luxembourg and Malta no interviews could be conducted.

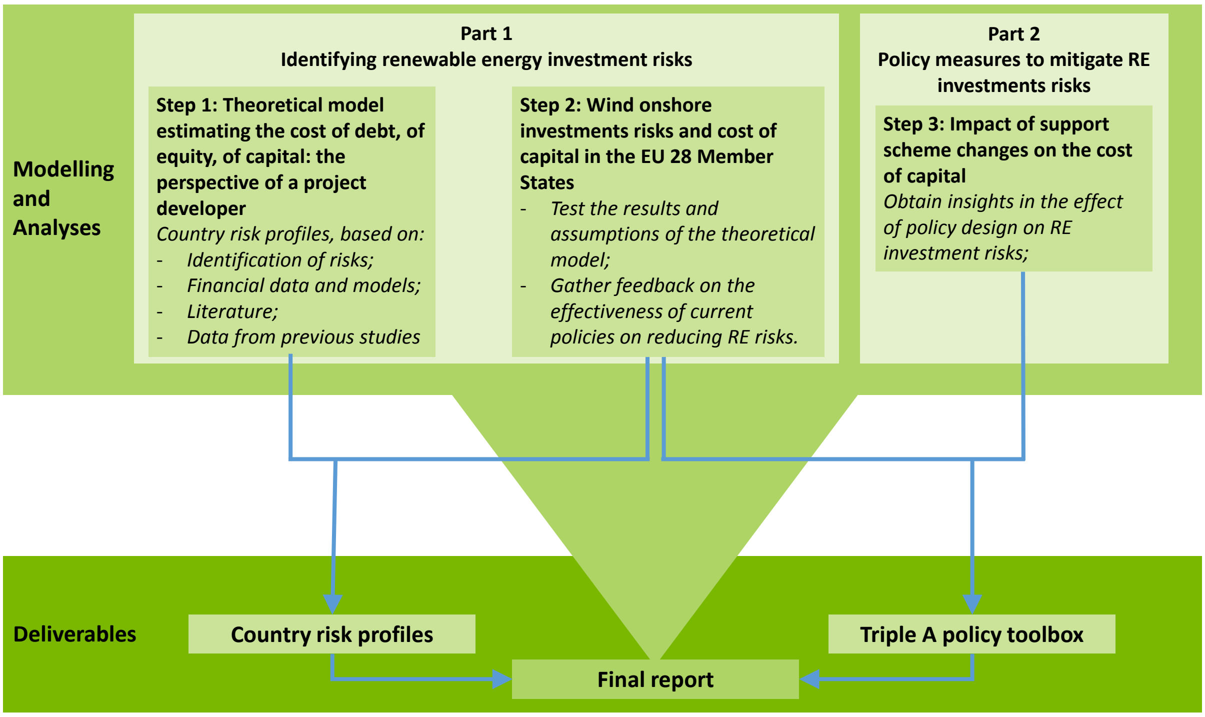


Figure 28: Methodological Approach

Within the two parts, three steps have been defined. These steps are described below.

4.3.1 Step 1 – Theoretical model estimating the cost of debt, equity, of capital: the perspective of a project developer

As a first step, a theoretical model was constructed to estimate the influence of risks on renewable energy investments for individual Member States. This model helps providing insights in the scale of the investment risks per Member State (MS) and which risks are perceived as most relevant.

4.3.1.1 Risks categories

From an investor's point of view, the main goal of investing is to maximise the return. In general, investors strive to minimise risks, but are willing to accept risks if these are compensated with a higher return rate.

Risks associated with RES development are widely described in literature: Ecofys (2008), Justice (2009), Waissbein, et al. (2013), Ragwitz, et al. (2007), IEA-RETD (2010). These studies identify and categorise possible sources of risk that can influence future results and thus investor's decisions about whether or not to invest in RES projects. Based on these studies, nine risk categories have been identified, namely: country risk, social acceptance risk, administrative risk, financing risk, technical & management risk, grid access risk, policy design risk, market design & regulatory risk and sudden policy change risk. These nine categories describe a large array of risks, covering the development process of RES projects, as presented in Figure 29.

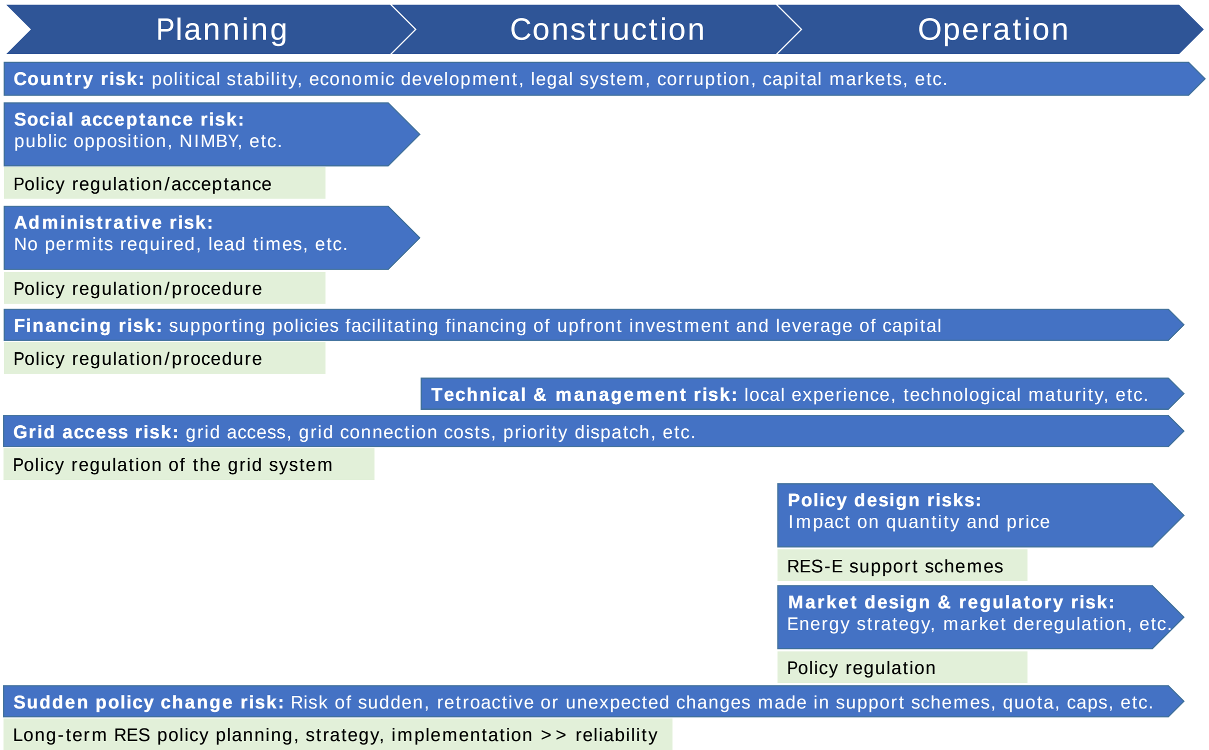


Figure 29: Risks related to RES projects

The figure above shows the development of a RES project distinguishing three phases[11]: project planning, construction and operation (Enzensberger, Fichtner, & Rentz, 2003). At every phase, the project is influenced by different risks (Breitschopf & Pudlik, 2013). Social and administrative risks occur in the planning phase, technical & management risks in the construction and operation phases, and finally, grid access, policy and market design & regulatory risks during operation. Financing risks as well as grid access and sudden policy change risks influence the project in all phases.

4.3.1.2 Influence of risks on investment decisions

Investors, depending on their risk preferences, will choose to invest in riskier or safer projects. As explained above, investors estimate these risks by setting discount rates. The height of these discount rates is important in the investment decision. With a high discount rate, only projects with a high IRR will be eligible for investments. This increases the costs for attracting capital, and thus the costs for renewable energy projects. If the discount rate is set too high, chances are that the IRR of renewable energy projects will not meet the discount rate, meaning that there will be no investments at all and renewable energy development will come to a standstill.

[11] Decommissioning is not included here, as (discounted) costs and risks during this phase are typically negligible for RES.

To create more insights in the size of investment risks, a theoretical model was constructed to estimate the cost of equity for investing in renewable energy projects in each EU-28 Member State. To make the assessment more specific, the model focused on the development of **onshore wind projects**. In order to provide insight in what risk categories are most pressing, a break down into the nine risk categories has been provided (see Figure 29). The results of the theoretical model were tested during interviews with financial experts (step 2).

To estimate the scale of the risks, the cost of equity (CoE) of onshore wind projects has been quantified per Member State. For this, existing financial models were used together with data from literature and financial information. To break down investments risks in nine categories, insights per Member State were obtained on the importance of each category. For this, a database on RES barriers was used.

4.3.2 Step 2 – Wind onshore investments risks and cost of capital in the EU-28 Member States

In this step the modelling results were validated through interviews with experts from all Member States. Over 80 equity providers, project developers and bankers were approached. The goals of the interviews were as follows:

- Check whether the identified risk categories were covering all risks;
- Evaluate the risk profiles;
- Evaluate the estimated cost of equity and ranking of investments risks;
- Evaluate the effectiveness of policy on reducing investments risks and how this could be improved;
- Check model assumptions (e.g. assumptions used to calculate the cost of equity).

Based on the networks of the project team, a database of financial experts across the EU-28 was composed. Member States for which no or too few contacts were available, additional contacts were found through renewable energy associations, banks, project developers, utilities, etc.

After conducting the interviews, country profiles were created, reflecting both the view of the interviewed experts and the model results[12].

4.3.3 Step 3 – Impact of support scheme changes on the cost of capital

The role and influence of policy on decreasing investment risks is analysed in more detail. To gain insights in the role of policy, an online questionnaire was created in which respondents were asked how financial parameters will change under different policy schemes. The reference case is a typical onshore wind project supported by a Feed-In Premium (FIP) policy scheme. By changing the policy scheme to non-sliding FIP, fixed

[12] The country profiles are available at: http://diacore.eu/?option=com_content&view=article&id=11

FIP, tender with policy, and Feed-In Tariff, insights are obtained in the influence of policy schemes on cost of capital (i.e. cost of debt, cost of equity, Weighted Average Cost of Capital (WACC)).

4.4 Results

Our results focused on the EU-wide perspective, presenting an overview of the differences between Member States seeking to answer the following questions:

- Which risks to wind onshore projects have which impact on RES investments?
- How high is the cost of capital in the 28 EU MS for wind onshore projects?
- How do changes in policy design affect costs of capital?
- How can policies support to mitigate risks?

4.4.1 Risk perception

The following graph provides an overview on how market actors in 24 out of 28 EU Member States rank the risks categories identified for onshore wind energy projects.

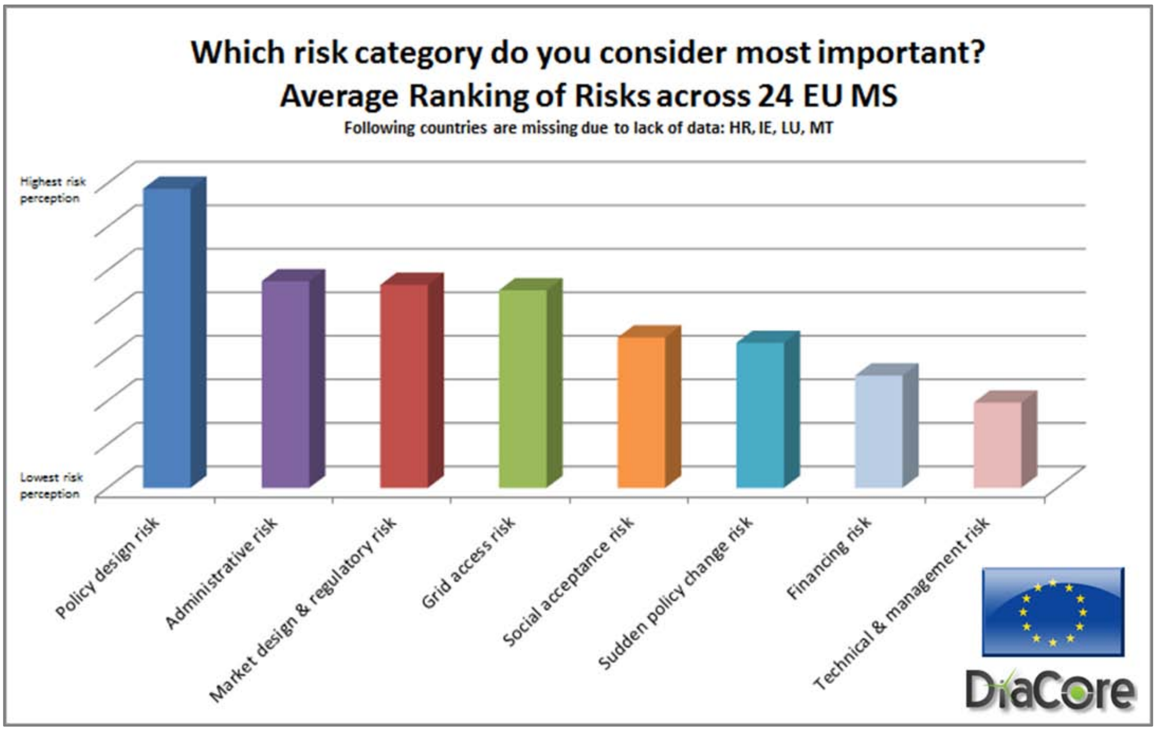


Figure 30: Average ranking of risks across 24 EU MS13

[13] The highest ranked risk per Member State was awarded 8 points, while the lowest ranked risk received 1 point. In countries where not all 8 risk categories were reported, the 8 points were evenly distributed between the present risk categories (e.g. in case only 5 risks were reported, the highest risk received 8 points, the second 6.4, the third 4.8, the fourth 3.2 and the lowest risk 1.6 points). Subsequently, we calculated for each

Figure 30 shows that, on average, policy design risks were perceived as the most pressing risk to onshore wind energy projects across the EU. We can derive from this very high ranking that **the design of the support scheme is still one, if not the key, prerequisite for stable investment conditions**. Several experts referred to the policy design as being "the rules of the game". For this reason, changes made in the policy design will have a high impact on investors, as it will change these "rules" and therefore bring uncertainty to investors. For instance, upcoming policy scheme changes[14] can lead to some unrest as projects developers are trying to find out what are the advantages and disadvantages of the new policy scheme, how it will affect their projects and, most importantly, if there is a reason to advance or postpone their projects.

A group of risks concerning **administrative issues, market design and grid access,** follow at a relatively equal level. Interviews revealed that in most countries there are issues with obtaining grid access for renewable energy. With increasing shares of intermittent renewable energy sources and lack of clarity on responsibilities for connecting, enforcing and bearing the costs, it can be expected that this will become a more serious problem in the coming decades.

The third group of risks contains the **social acceptance, sudden policy change and financing risks**. These risks are all considered very critical in some of the Member States while they are not relevant in others. Technical & management risk is at the end of the ranking, despite the fact that resource risk is considered as a pressing issue. This challenge, however, is regarded in most markets as part of the policy design.

Figure 31 provides an overview of the risks which were perceived as the most important risks in each Member State. **Policy design is ranked as most important risk in 10 out of the 28 Member States, followed by administrative risks (7 Member States) and market design & regulatory risks (3 Member States)**.

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of the three regional groups as well as the entire EU-28 the average value per risk category.

[14] The changes discussed under policy design risk are changes that have been announced upfront. Changes that are being imposed suddenly are categorised under sudden policy changes.

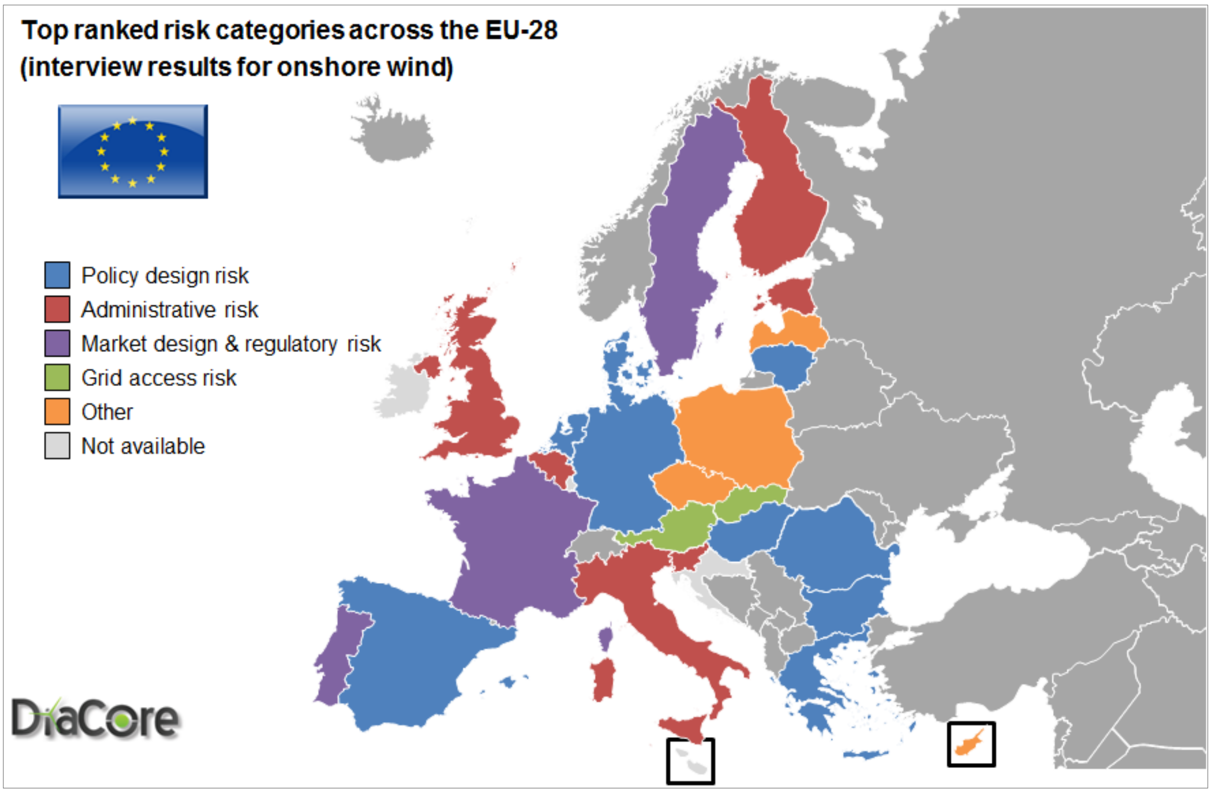

Figure 31: Top ranked risk categories across the EU-28 (interview results for onshore wind)

4.4.2 The Weighted Average Cost of Capital (WACC) in the EU-28

An important parameter indicating the investment climate in a country is the Weighted Average Cost of Capital (WACC). During the interviews, country experts were asked to comment on the modelled outputs of the financial parameters. Their input was used to update the WACC-figures. The result is presented in the map presented in Figure 32.

The first result is a **significant gap between EU Member States: Germany has the lowest WACC in the EU-28, with a value of 3.5-4.5% for onshore wind energy projects**. From an investor's perspective Germany thus provides a low risk environment for onshore wind energy investments, which enables investments with relatively low capital costs. **The other extreme in the EU are Croatia and Greece, where circumstances are less favourable,** showing WACC-values that can be more three times as high as in Germany. In between, there is a large number of Member States with WACC-values twice and three times as high as Germany. This difference can be explained by the fact that, in all factors of the WACC calculation, the German case is the most favourable: with a lower risk premium and both costs of debt as well as equity being much lower. Moreover, the relatively low-risk environment in Germany allows for a higher share of (lower) debts in the WACC, thereby further reducing the value. According to interviewees, another important reason is the fierce competition between banks that significantly reduces the cost of debt.

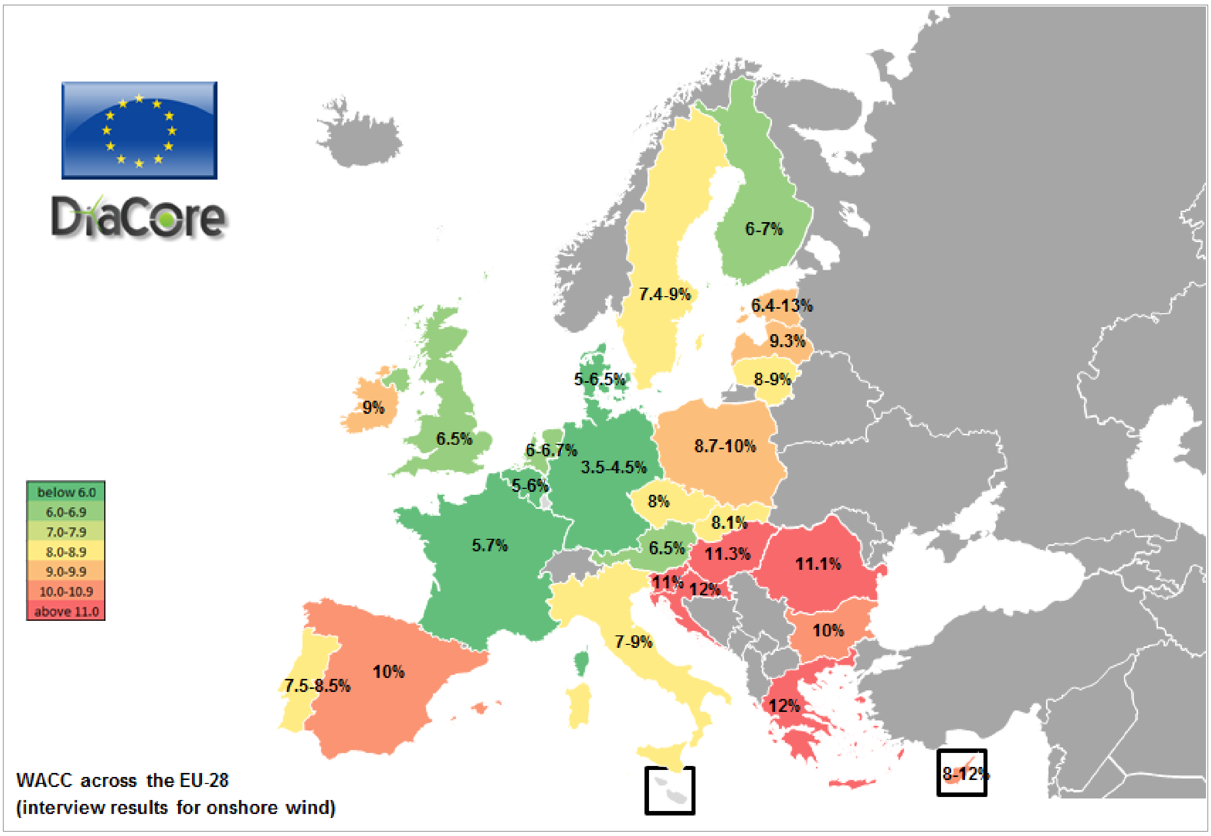

Figure 32: WACC estimations onshore wind – approximation based on interviews

The effects of such high WACC-values are remarkable, especially when taking into account the fact that capital expenditure is the main cost factor for wind energy projects. High capital costs directly result in higher cost of electricity for wind energy project developers, who require higher tariffs to have a viable business case.

As a consequence, in Member States with higher risks the same installed capacities will lead to higher costs when compared to a market that carries lower risks and thus lower capital costs. The comparison also qualifies the relevance of natural conditions for the economic assessment. Markets with relatively mediocre wind conditions (such as Germany) can be financially much more interesting than markets with very good wind energy conditions (such as Spain or Portugal). This shows that natural resources are only one factor among others in the investment decision. Other factors that have an impact on the WACC – such as the policy design risks or country risk – must also be taken into account. Last but not least, the figures show that the energy transition in many EU Member States was also possible because of very low and favourable costs for capital.

Other interesting observations can be drawn from the examination of the WACC, but also the single factors of the WACC, i.e. the values for cost of debt, cost of equity and the ratio between debt and equity in the single Member States.

4.4.3 Debt / equity ratio across the EU-28

Figure 33 shows the ratio of cost and debt for onshore wind projects across the EU-28. The figures are based on our model, and have been modified in accordance with the results of the interviews with project developers and investors. The comparison confirms the conclusions drawn from the WACC examination: **the conditions for financing onshore wind projects differ significantly from country to country. In 2014, when the market actors were interviewed, the markets in Germany and Denmark allowed for a debt ratio that reached or even surpassed 80%**. This allowed developers in these markets to benefit from lower cost of debts, as they were able to use a very high leverage.

Investors in South-East European Member States had to provide up to 50% of their investment budget through equity financing. This drove up the costs for financing onshore wind energy plants and often made financing of projects impossible. A debt ratio below 70% (ranging from 50%-65%) was found in almost a third of all EU markets, which illustrates the perceived risks for onshore wind investments in many EU Member States.

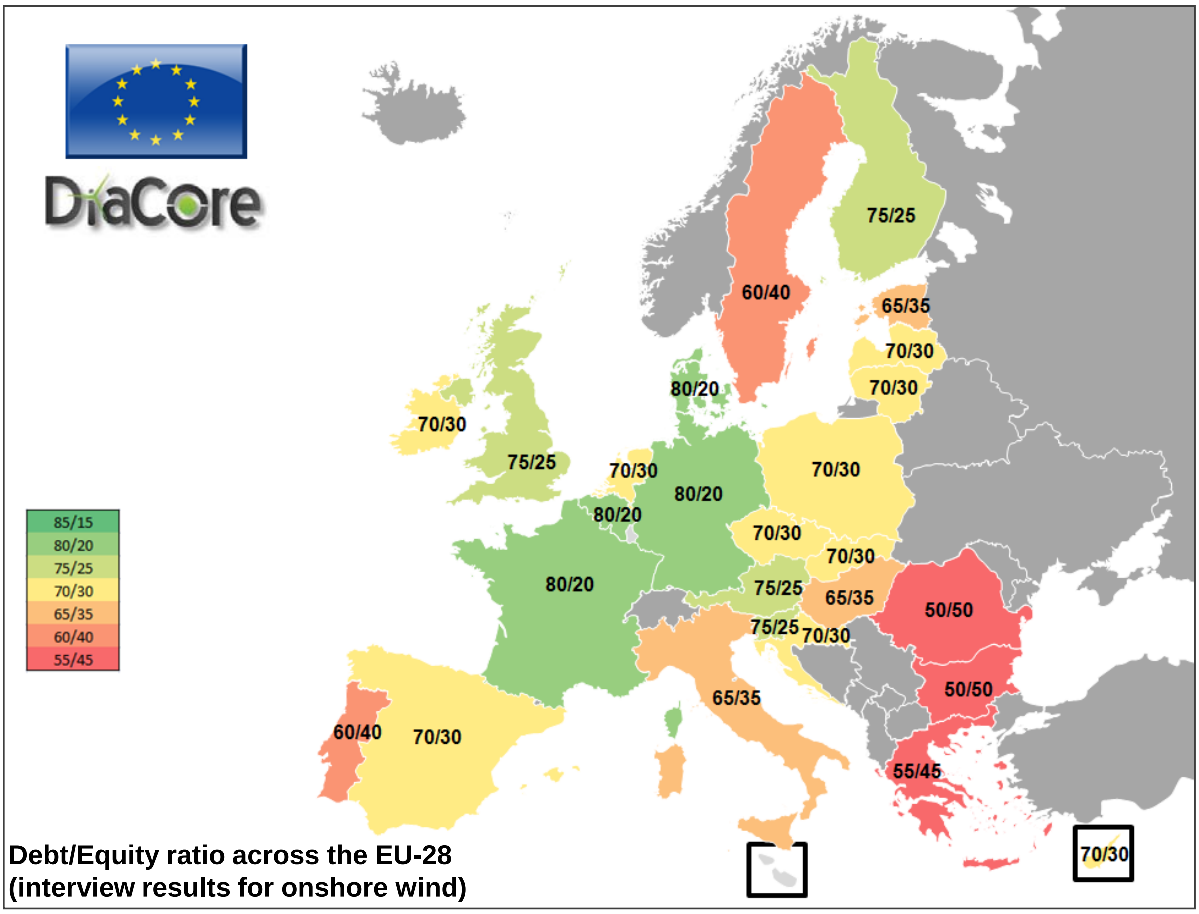

Figure 33: Debt / Equity ratios across the EU-28 (estimation for onshore wind)

4.4.4 Cost of debt in the EU-28

Figure 34 presents the results for the cost of debt across the EU-28. Again, **Germany shows the lowest results with values for cost of debt ranging between 1.8% and 3.2% with a falling tendency in 2015**. According to German experts, another reason for the very low values is the above-mentioned **competition between German banks**: many banks have come to consider wind energy projects as secure investments and underbid each other. As a result, **German project developers face much lower costs of debt than developers in countries with less competition.**

The cost of debt is currently featuring a falling tendency caused by post-crisis measures, resulting in declining EIB loans and EURIBOR. What was surprising – and quite alarming – was that, **in some countries, the values for the cost of debt were found to be substantially higher than in the model results. Among these countries are Romania, Bulgaria, Italy and Spain**.

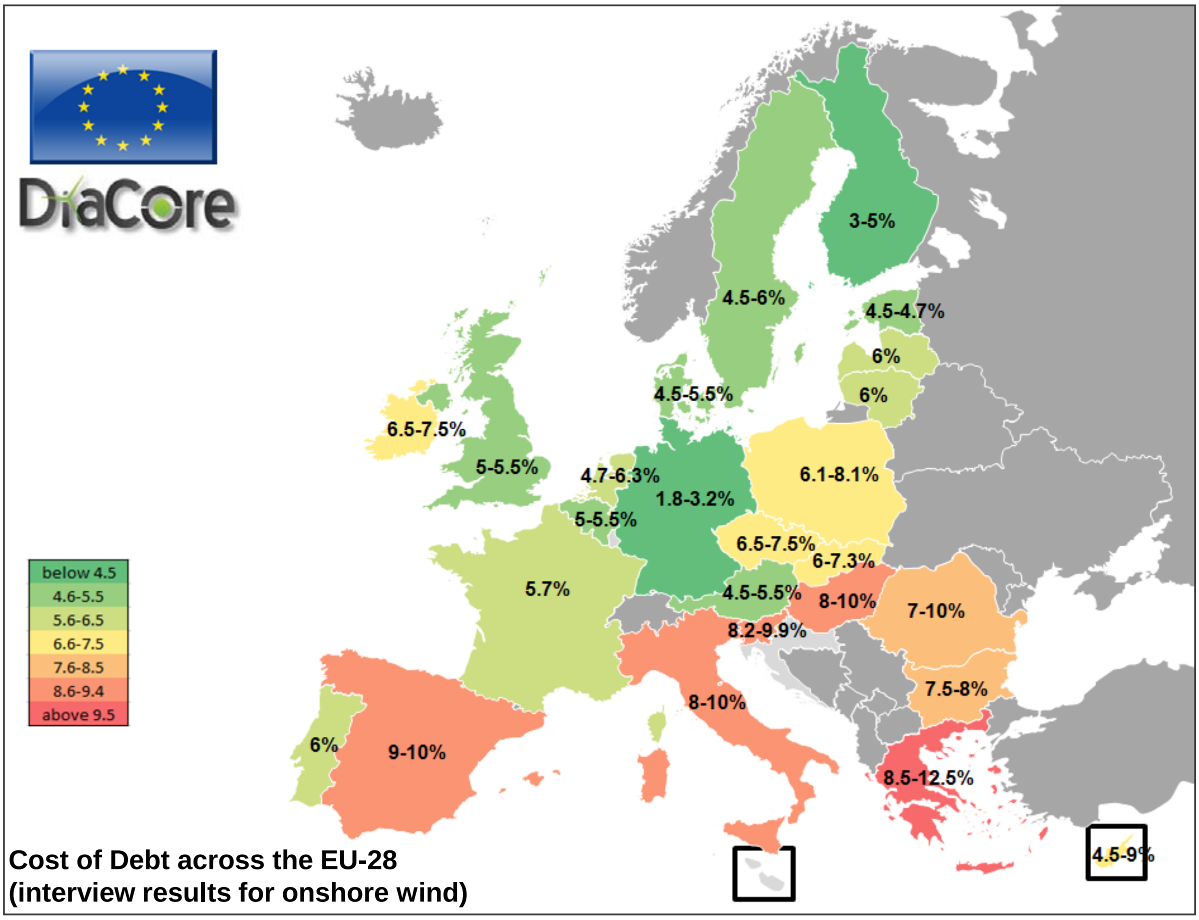

Figure 34: Cost of debt across the EU-28

It is difficult to assess whether the increase of rates is due to specific renewable energy policies (e.g. the level of support per kWh), due to the general economic situation or due to a lack of competition between national banks. In any case, it sheds a light on a growing gap within Europe between Northern European countries that benefit from lower costs of debt and Southern European countries that do not.

4.4.5 Cost of equity in the EU-28

The interview results for the cost of equity are presented in Figure 35. According to interviewees, the values of cost of equity have changed over the last years as a result of the collapsing renewable energy boom. During the boom, the cost of debt was much higher because the interest in business opportunities, as well as the interest in higher profit margins, had initiated speculations in grid capacities. This example illustrates that sustainable support scheme tariffs or quotas do not necessarily require high tariffs. Quite the contrary, in some cases, very attractive tariffs can cause instabilities for the overall policy design. The interplay between profitable and stable business conditions should be kept in mind when assessing or defining the policy design.

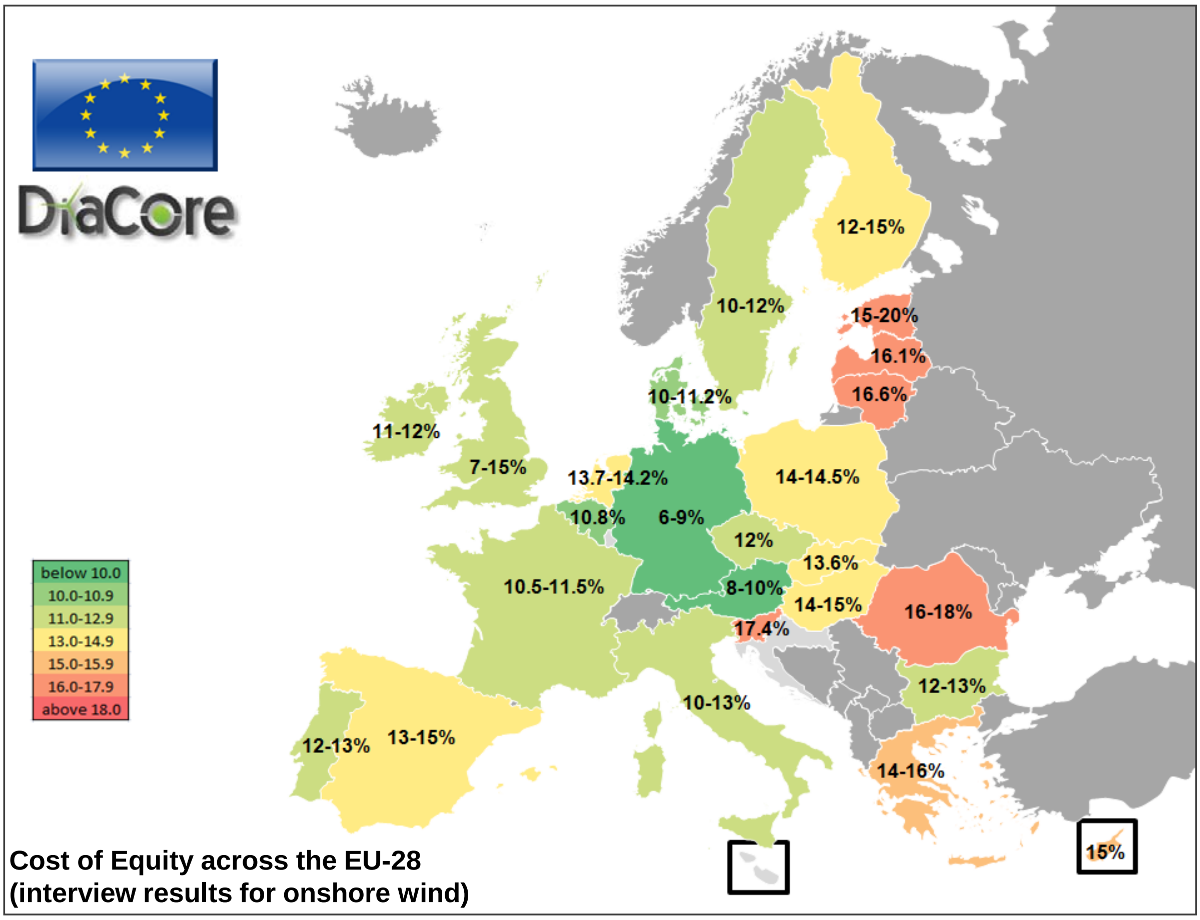

Figure 35: Cost of equity across the EU-28

4.4.6 Impact of policy designs on WACC

As the selected policy designs address different levels of uncertainties in revenues and expenditures, investors' risks differ and, hence, the financing parameters do too. The survey results display different changes of interest rate, return on equity and equity shares by type of region and policy design. However, the presented results rely on a small number of cases (n = 14) and are far from being representative for the whole EU. They should be considered as indicative results. The results for the EU will be shown as an average across all respondents, i.e. each respondent gets the same weight (lower bound) and as an average of countries, in which each country has the same weight (upper bound). The latter reduces the influence of the number of respondents per country while single answers per country receive a relatively high weight.

Given these financing parameters, the WACC is calculated based on the average financing parameters under a sliding FIP and a FIT. The first ranges roughly between 5%-6% for the EU average, while the WACC under a FIT scheme is between 4.4%-5% (Figure 36). The WACC level between central and Southern EU countries differs strongly under both policy schemes. For sliding FIP, the WACC is about 90 basis points (bp) (1% = 100bp) higher in South EU countries compared to Central EU countries, for FIT the difference is about 140 bp.

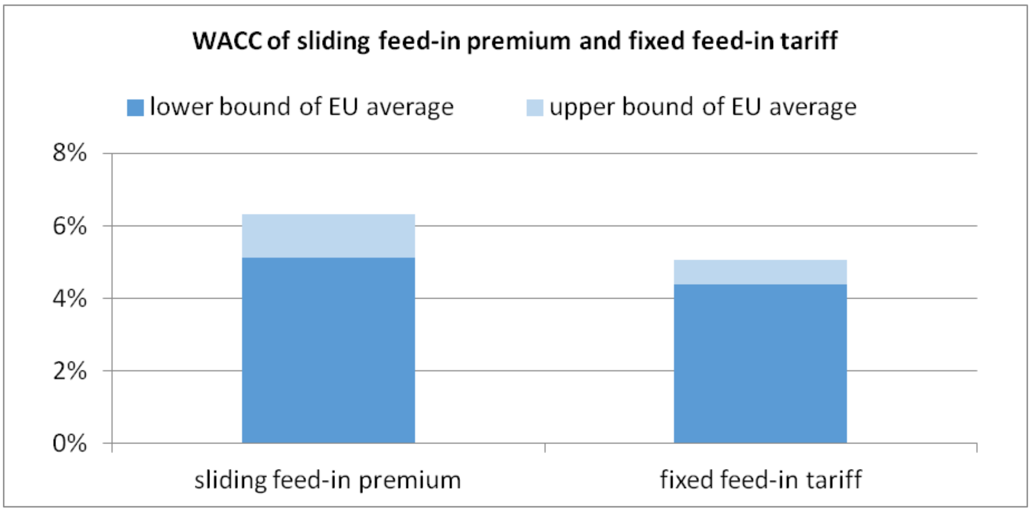

Figure 36: Indicative values of the WACC in the EU (average) under a sliding feed-in premium and feed-in tariff policy for wind on-shore projects, June - Sept. 2015

The changes in policy designs could lead to WACCs ranging between 4.5%-5% p.a. for the low risk policy FIT (Figure 36) and between 5%-7% p.a. for larger risk exposure in sliding FIP with tender or fixed FIP. While in Central EU countries the *sliding FIP with tender* is regarded as the policy with the highest risk – measured in terms of WACC –, in Southern EU countries the *fixed FIP* policy is considered as more risky.

The switch from a sliding feed-in premium to a sliding FIP with tender or fixed FIP, significantly increases the EU average of the WACC by about 100 bp (Figure 37). The results of a change to a *sliding FIP without premium payments under negative market prices* show a relative large range. Differentiating between regions, the increase in cost of capital due to a shift from sliding to fixed FIP is perceived as much higher by central European countries (120-160 bp) than by Southern European countries (90 bp). This might be explained by the difference in knowledge background and experiences with FIT, fixed and sliding FIP in these countries and highlight the relevance of perception.

Furthermore, the probability of negative prices increases with increasing shares of intermittent renewable energy. In regions or markets in which intermittent renewable energy has already a significant share, this policy scheme might not be favoured.

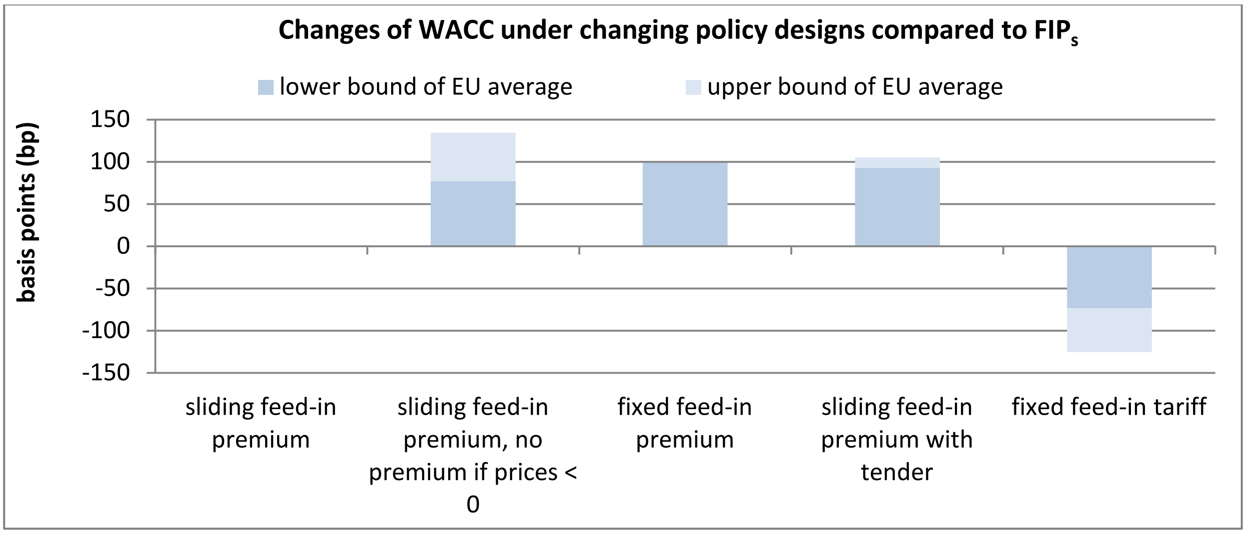

Figure 37: Indicative changes of the average EU WACC under different policy designs for wind on-shore projects, June - Sept. 2015

The conclusion is therefore that the significant differences in WACC between the Member States are mainly due to country specific risks and less due to specific RE policy designs. The differences in WACC between countries is about 1000 bp while the changes in policy design have an impact of about 100 bp on the WACC.

Comparing these results to other studies, e.g. Giebel & Breitschopf (2011), similar changes in WACC are reported when shifting from a fixed feed-in tariff to a fixed feed-in premium or sliding feed-in premium. Although this impact assessment of policies on cost of capital has a more indicative character, it seems to provide some interesting insights and supports other findings and statements (Wiser & Pickle, 1998; Giebel & Breitschopf, 2011).

4.4.7 Policies measures to mitigate renewable energy investments risks

For each of the nine risk categories, measures to mitigate these risks have been formulated, based on the input from interviewees, project developers and policy-makers. The resulting measures provide a starting point and useful guidance[15]. In order to be effectively implemented, the measures should be tailored to the specific needs of Member States' national regulatory framework. For mitigating **country risks**, it is most important to make **RES deployment a part of a (long-term) economic and industrial policy framework** by improving competitiveness of RES options and the availability, accessibility and quality of resources.

For **social acceptance risk** it is most important to **focus on the stakeholder process** and provide the opposition a platform for sharing their concerns. Several approaches and strategies are mentioned, ranging from new democratic models (in which citizens are pro-actively asked for their input) to co-development by government.

Administrative risks focus mostly on permitting procedures and relate quite strongly to the **structure and quality of the public administrative system**. With a stronger integration of RES in the built environment, interaction of policies and spatial planning requires clear guidelines, one-stop shops and education of civil servants.

Financing risks are mostly related to the perception of the banks and equity providers on the market-, financial-, economic- and/or policy circumstances and how these might change. This might lead to high cost of capital, which can then jeopardize the project. **Risk sharing and/or a strong(er) involvement of governments** can mitigate these risks by functioning as a safety net.

Technical & management risks refer to the availability of knowledge and experience to successfully develop, construct, operate and decommission a particular RES project. Mitigation of these risks relate to **development of knowledge, skills and experience**.

For **grid access risks**, the focus is on ensuring timely grid connection for new projects. Any uncertainty on this procedure will result in higher uncertainty in project returns, and, hence, higher cost of capital. Mitigating these risks will therefore focus on **creating clarity on grid procedures and processes** with regard to grid extension (plans), grid access, and on liabilities and compensation in case of delayed or interrupted access or curtailment.

Policy design risks relate mostly to support schemes and other government interventions to support the implementation of RES. Depending on the support scheme, risks are transferred between the market and project developers. In order to reduce the cost of capital, mitigating measures typically address the **level of the expected return and/or the standard deviation in the expected return**. Important in this discussion

[15] The Policy toolbox is available online: http://diacore.eu/?option=com_content&view=article&id=17

is the balance between support to stimulate RES development, implementation and overspending (windfall profits).

Market design & regulatory risks describe uncertainties regarding government energy strategy and power/energy market liberalization. Implementing **fair and independent regulation** ensures non-discriminatory access for RES-producers to the market.

Sudden policy change risks refer to drastic and sudden changes in a country's RES strategy and/or support scheme. The result of these changes is a significant decrease or even a complete standstill of the development of RES. Causes for sudden policy changes are, for instance, the cost-effectiveness of government budgets spent on the implementation of RES. A good balance needs to be found between stimulating RES with the right policy design while ensuring cost-effectiveness in order to **avoid windfall profits of high government or societal expenditures**.

The Green-X Model was used to estimate the effect of policy measures on the cost of capital. These calculations show that if all countries would have the same renewable energy policy risk profile as the best in class, the EU Member States could reduce the policy costs for wind onshore by more than 15%[16]. A reduced country risk could lead to greater savings.

4.5 Recommendations

The objective of this report was to take a closer look at the **role of risk** in renewable energy investments, to identify barriers and provide solutions in the form of **policy measures** to **enhance investments** in the RES sector. Our research led to the following key results:

Across all EU Member States, the risk related to the policy design is perceived as one of the most pressing.

RES investments are influenced and impacted by several risks categories. Apart from the country risk, the policy design risk is ranked as one of the most severe risks. An important part of the policy design is the support scheme to increase the cost-price competitiveness between renewable energy and fossil alternatives. In ten Member States, policy design is ranked as the most important risk. Other risks frequently mentioned in the top-3 risk categories are administrative risks (including permit procedures), market design & regulatory risks (including energy strategies and market deregulation), and grid access risks. In Member States where national governments introduced retroactive measures to support schemes (e.g. Czech Republic, Bulgaria, Slovenia, Spain), the risk of sudden policy change was ranked very high, too.

[16] These results are based on a hypothetical case, as they look at isolated RE risks profile changes. This indicative calculation aims to provide a first estimate of cost savings potential.

In developing onshore wind markets, administrative risks are particular relevant. **Administrative risks, grid access risk and technical & management risks are perceived most relevant in emerging markets, while policy design risks are ranked relatively low in comparison to nascent and mature markets.**

There are significant differences in capital costs among EU Member States.

The **cost of capital** for onshore wind projects varies between Member States. The WACC **(Weighted average Cost of Capital)** is an important input parameter in project evaluations. As RES technologies such as onshore wind require high upfront investments costs, the WACC significantly influences the business case of such projects. According to the interviewed experts, the 2014 WACC for onshore wind projects varies massively, for example between 3.5% in Germany and 12% in Greece and Croatia. In most North-Western Member States, WACC figures will be 7% or lower, providing a good financial basis for onshore wind. Eastern and Southern Member States show higher WACC figures. There the WACC ranges between 10-12%, resulting in increased expenses for tax payers and energy consumers.

The parameters of the WACC, namely cost of equity, and cost of debt show similar results. The **cost of equity** for onshore wind projects in 2014 ranges between 6% (Germany) and 15% or more (Estonia, Greece, Latvia, Lithuania, Romania and Slovenia). Western Member States generally show lower values (typically between 6-15%), while higher figures are observed in Eastern countries (16% and more). An increased level of support can lead to lowering the risk perception of equity providers and subsequently to lower cost of equity and WACC. The **cost of debt** varies between 1.8% in Germany and 12.6% in Greece. **Germany shows the lowest results with values for cost of debt ranging between 1.8% and 3.2%**. A reason for the very low values could be the competition between banks: many banks have come to consider wind energy projects as secure investments and underbid each other. The cost of debt currently features a falling tendency caused by post-crisis measures, resulting in declining EIB loans and EURIBOR.

In some countries, the values for the cost of debt were found to be substantially higher than in the model results (e.g. Romania, Bulgaria, Italy and Spain). It is difficult to assess, for each individual example, whether the increase of rates is due to specific renewable energy policies or due to the general economic situation or to a lack of competition between national banks. In any case, it sheds a light on a growing gap within Europe between Northern European countries that benefit from lower costs of debt and Southern European countries that do not. Across Europe, the lower values of cost of debt values are found in Northern Member States (up to 6%), while the Southern countries show values of 7% and up. According to investors, the main factors for the cost of debt value are the general country risk, the specific renewable investment risks and also the competition between debtors.

The debt/equity ratio varies considerably between Member States, caused by both country specific aspects and the financial crisis.

In 2014[17], the markets in Germany and Denmark allowed a debt share reaching, or even surpassing, 80%. This enabled developers in these markets to benefit from lower cost of debts, as they were able to use a very high leverage. Investors in South-Eastern Europe had to provide up to 50% of their investment budget through equity financing. This drove up the costs for financing onshore wind energy plants and often made financing of projects impossible. A debt share below 70% (ranging from 50%-65%) was found in almost a third of all EU markets, which illustrates the perceived risks for onshore wind investments in many EU Member States.

Germany has the lowest weighted average cost of capital in the EU-28, with a value of 3.5-4.5% for onshore wind energy plants. **The other extremes in the EU are Croatia and Greece where circumstances are less favourable,** showing WACC-values that are up to three times as high as in Germany. Nevertheless, policy design has an impact on WACC as well.

RE Policies ensuring certain revenues shift risks from generators to society: Lower risks for investors due to increased certainty in revenues implies a shift of risks from investors/operators to those actors paying the premium or tariff, in most cases the final electricity consumers. This is because guaranteed feed in or fixed remuneration sets off the market mechanisms, and forecasting and marketing is shifted from generators to transmission grid operators, which transfer their costs to consumers (in case of burden sharing through electricity consumers). And, at the system level, the levelized costs of electricity generation decrease due to falling costs of capital.

The sliding FIP with a tender is the preferred option. Compared to a sliding FIP without a tender, the FIP with a tender seems to ensure a lower but sufficient level of revenues (assuming an efficient and effective[18] tender process) while compared to a fixed FIP, it limits risk exposure by providing a certain remuneration, leading to lower policy costs for the public due to “efficient” premiums.

Although policy designs have an influence on the WACC, **the large differences between the WACCs of Member States are mainly due to country specific risks and less due to specific RE policy designs**. The differences in WACC between countries is about 1000 bp while the changes in policy design have an impact of about 100 bp on the WACC.

Efficiently allocating risks and hence costs between generators and society is a challenge. In summary, an increasing market integration of RES generation implies more responsibility for RES generators. This is equivalent to shifting risks from the public (e.g. consumer) to generators. This increase in risk entails higher return on equity and

[17] When the market actors were interviewed.
[18] Under an effective bidding process price (premium) = marginal costs.

equity shares, hence higher financing costs. As a consequence, appropriate remuneration levels are required to achieve the RES targets and compensate for higher risks and trigger RES deployment. This leads to increased policy costs, which are offset by decreasing costs for market integration (decreasing cost of balancing). Therefore, careful monitoring of the balance of policy costs – reduction due to risk shifts (balancing) versus increase of policy costs due to high remuneration levels – is needed.

Policies have a role to play in mitigating investment risks, leading to additional savings. Governments potentially have a big role in mitigating risks, for instance by providing clarity on grid procedures and processes, implementing long-term stable policy schemes, improving structure and quality of the public administrative system and providing financial risk-sharing. As Member States show great variety in regulatory frameworks supporting renewable energy, in the maturity of the market, the availability of capital, and the involvement of governments, each of the measures should be tailored to fit the needs of individual Member State and mitigate risks efficiently and effectively. Policy designs stimulating RES, while keeping a good balance on cost-effectiveness, are important to **avoid windfall profits of high government or societal expenditures**. We drafted a policy toolbox providing a starting point for mitigating investment risks and lowering the cost of capital for RES investments.

Calculations based on the Green X Model show that if all countries would have the same renewable energy policy risk profile as the best in class, EU Member States could reduce the policy costs for wind onshore by more than 15%. A reduced country risk could lead to greater savings.

5 Coordinating EU renewables policy with market developments

Technology and fuel demand created by EU renewables policies has global implications. As such, EU policies should be coordinated with global developments, such as technology cost reductions. This is shown for photovoltaic solar power (PV) and biomass policies.

5.1 Coordination mechanisms for concerted PV development

5.1.1 Policy context

The increasing scale and dynamics of the global market for renewable energy technologies has often resulted in unexpected high deployment volumes in EU Member States. These unexpected demand peaks were particularly strong for solar photovoltaics (PV) technologies because of their dynamic cost reductions and short project durations, and often occurred in countries using feed-in tariff remuneration mechanisms. Figure 38 shows historic PV deployment levels in Germany, UK, France, Italy, and Spain. These countries represent the largest PV markets in Europe and together account for 82% of the European market at the end of 2014. They have used different types of feed-in tariff mechanisms to remunerate PV power generation.

In Germany, annual PV deployment volumes reached around 7.5 GW in both 2011 and 2012, despite numerous previous adjustments to the feed-in tariff mechanism. While Spain experienced strong deployment in 2008, Italy had a strong deployment peak in 2011. In this period, Germany was the largest PV market in the world, and the UK has been the largest PV market in Europe in 2014 (REN21, 2015).

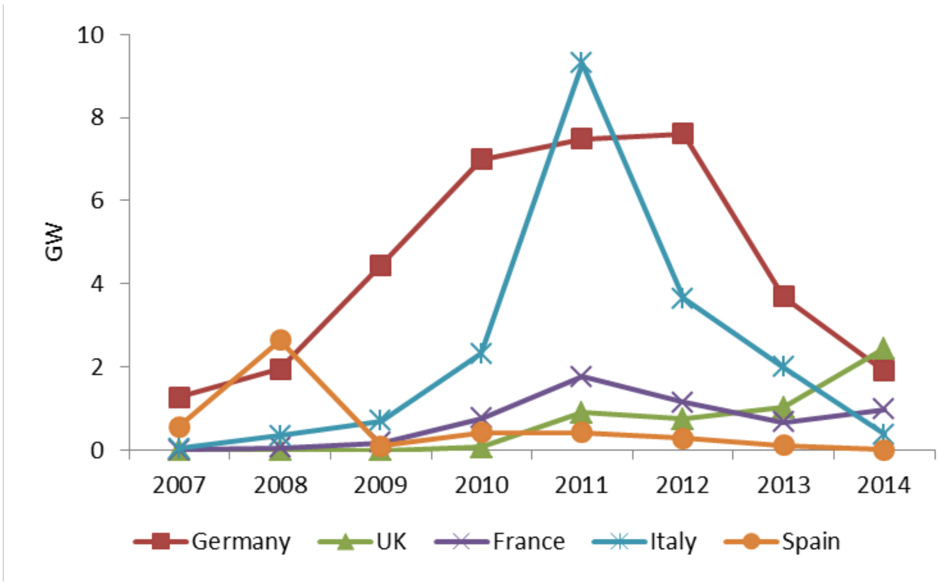

Figure 38: Annual PV deployment for largest EU markets (Data source: IRENA, 2015)

Renewable electricity in Europe has mainly been remunerated through feed-in tariffs, as they provide low investment risks in comparison to quota systems (Held et al., 2014). However, feed-in tariff schemes – just like contracts for differences - pose the challenge of setting remuneration levels which are appropriately aligned with technological cost developments. If tariff setting across EU Member States will be increasingly coordinated, then an increasing share of global demand will be covered by tariffs or quantities set in coordinated mechanisms. In this case it might no longer be suitable to consider the developments of global markets as exogenous.

EU countries are currently individually responsible for the selection, design and implementation of support schemes for renewable energy. However, the EU renewable energy directive provides different cooperation mechanisms between Member States, namely statistical transfers, joint projects and joint support schemes. Klessmann et al. (2014) provide an overview of Member States' progress in implementing these cooperation mechanisms. While policy makers must coordinate their decisions when cooperating on joint projects and joint support schemes, they need to agree on a common policy type in case of joint support schemes (Kitzing et al., 2012). Moreover, the Directive states that "cooperation can also take the form of […] exchanges of information and […] other voluntary coordination between all types of support schemes" (EU Directive, 2009).

There are numerous options to coordinate remuneration schemes across Member States. For instance, remuneration levels or tariff adjustment mechanisms can be fully harmonised across the EU, adapted to regional conditions or national requirements. While EU-wide harmonisation of remuneration rules for renewable electricity generation might realise cost saving potentials from clustering installations in beneficial areas (PV in the south, wind turbines in coastal areas), there are additional costs associated with grid extension and long-distance transmission, and different national and local benefits of renewable electricity generation (Lehmann et al., 2012). Moreover, completely harmonised schemes like harmonised tariff levels are difficult to implement, because of large differences in market conditions (resource conditions, differences in installation prices, etc.), and because of information asymmetries across countries.

Governments can also exchange information to coordinate remuneration schemes, for instance to improve their tariff setting procedures or to calibrate their tariff adjustment mechanisms. National governments normally do not possess comprehensive information about recent international deployment volumes, transparent costs of module production, equipment and installations work, or changes in foreign market or policy frameworks. To coordinate support schemes, countries could exchange information about the following data: deployment, installation costs or prices (installation labour, customer acquisition and system design, permitting, interconnection, inspection), tariff levels, impact of tariffs on installation prices, weather conditions, financing agreements, policy changes, tax frameworks, or administrative barriers. Such information can be exchanged on different timescales, for instance on a monthly or weekly basis, considering necessary time lags to gather the relevant information.

5.1.2 Objectives of the analysis

EU Member States apply different methodologies to revise and adjust feed-in tariff levels to technological learning effects: (i) periodic revision and adjustment, (ii) periodical degression, and (iii) tariff adjustment dependent on recently installed capacity (Held et al., 2014). We focus on capacity dependent tariff adjustments for new installations, as this methodology is able to quickly and automatically align tariff levels so as to reach specific deployment corridors. Capacity based tariff adjustments are especially promising for technologies with fast cost reductions and short project development durations, like PV. In this mechanism, the remuneration level for new installations is adjusted regularly by a flexible value which depends on installed capacities in a certain historic period, while existing plants usually receive a constant tariff for a guaranteed period of remuneration.

We aim to analyse the impact of coordinating tariffs for renewable electricity. In particular, we study those impacts while allowing for interactions between harmonized demand and module price levels. Thus, we are able to capture the main drivers that are relevant for the coordination of support schemes between Member States.

5.1.3 Approach

We develop a model for the impact of coordinating renewable energy tariffs and calibrate it based on the experience with PV. We base our model on data for Germany, which is the largest PV market in Europe, and the UK, which has been the largest PV market in Europe in 2014. Details are available in Grau and Neuhoff (2015). PV technologies are characterised by high upfront investment cost, no fuel cost, and limited maintenance cost. The prices for installed PV systems cover their costs and margins. The price of a PV system can be separated into the module price and the installation price.

Figure 39 visualizes PV system prices in 2013 in Germany, the UK, France and Italy. Across the classes, prices differ between the different markets. However, these cost differences do not primarily stem from differing module prices. PV modules tend to be global commodities (IEA, 2014), which can be purchased at similar prices in mature PV markets (Seel et al., 2014). Figure 40 shows prices for crystalline PV modules from Germany and China on the European spot market. While German modules were 35% more expensive than Chinese modules at the beginning of 2012, prices strongly converged over the last years and reached a minor 2% price difference in July 2015. By that time prices amounted to around 570 €/kW.

Thus, the large PV system price discrepancies between countries for similar system types depicted in Figure 40 result primarily from differences in national installation prices. The installation price covers the inverter and the balance of system (BOS; including planning, permitting, mounting, grid connection). For current ground-mounted PV systems with 1 MW size in Germany, the module has a 55% share of the investment cost (Fh ISE, 2015). Operation and maintenance (O&M) cost for PV are relatively small in comparison to investment cost, annual O&M accounts for around 1% of investment (IEA, 2014).

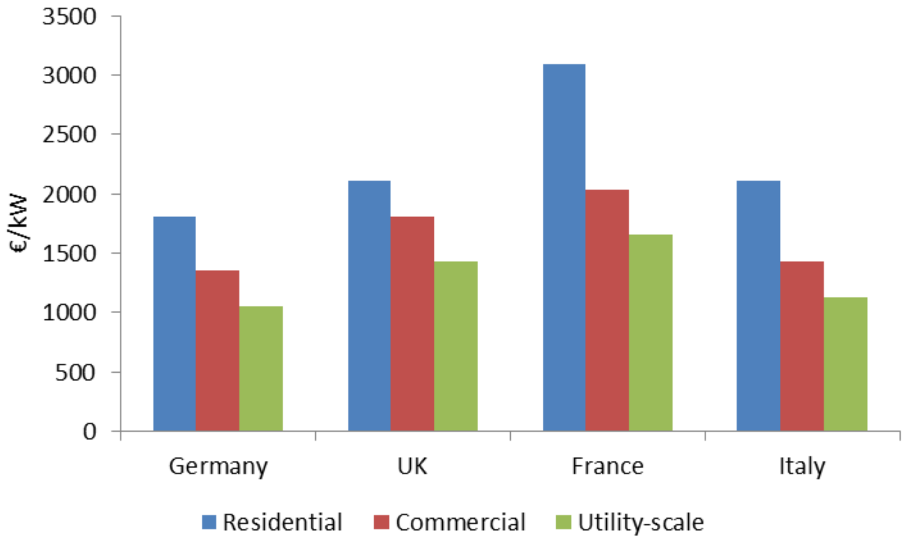

Figure 39: PV system prices in 2013 in selected EU countries (Data source: IEA, 2014. Currency exchange rate from oanda.com)

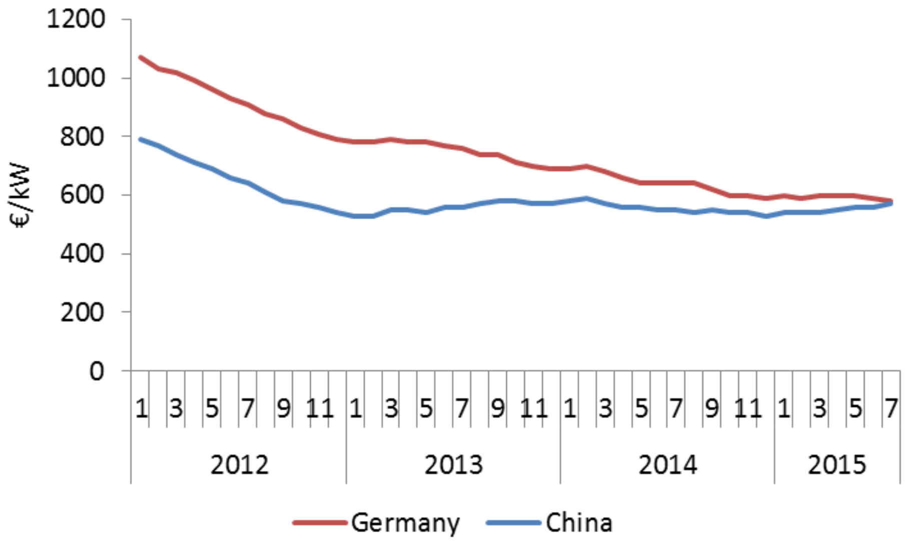

Figure 40: Prices for crystalline PV modules from Germany and China between 2012 and July 2015 (Data source: PvXchange, 2015) 19

19 Wholesale average net prices on the European spot market, without value added tax.

Figure 41 and Figure 42 show weekly PV deployment of systems up to 50 kW and corresponding profit margins for investors in Germany and the UK. Specific shares of these margins are needed to cover project development costs and risks during project lifetime. Profit levels are calculated as net present value, taking into account the present value of the feed-in tariff and the system price of the project. For PV capacity utilisation, we use 1100 full load hours per year for Germany and 1000 full load hours per year for the UK (Philipps et al., 2014). Feed-in tariffs are paid for 20 years, and we assume a 3% annual interest rate. We use weekly system prices for PV installations up to 50 kW in Germany and the UK.

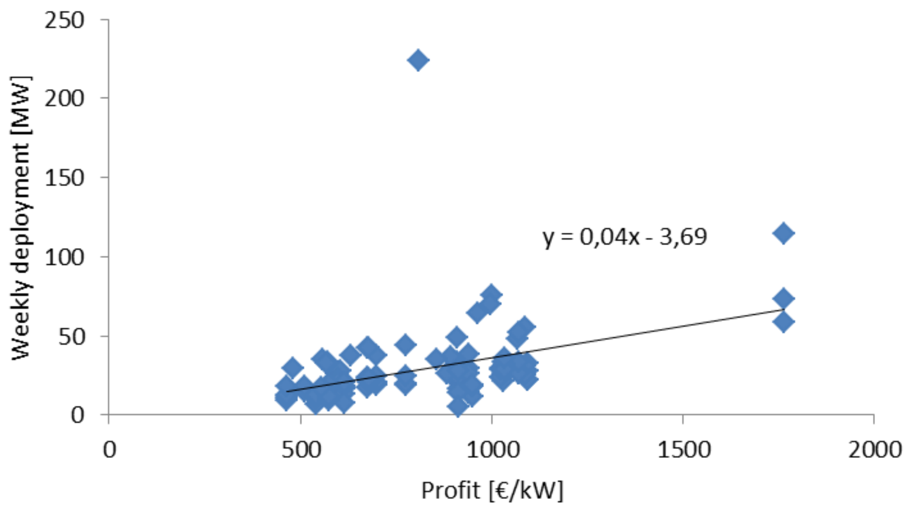

Figure 41: Weekly PV installations and profit levels for systems up to 50 kW in Germany between March 2012 and March 2014

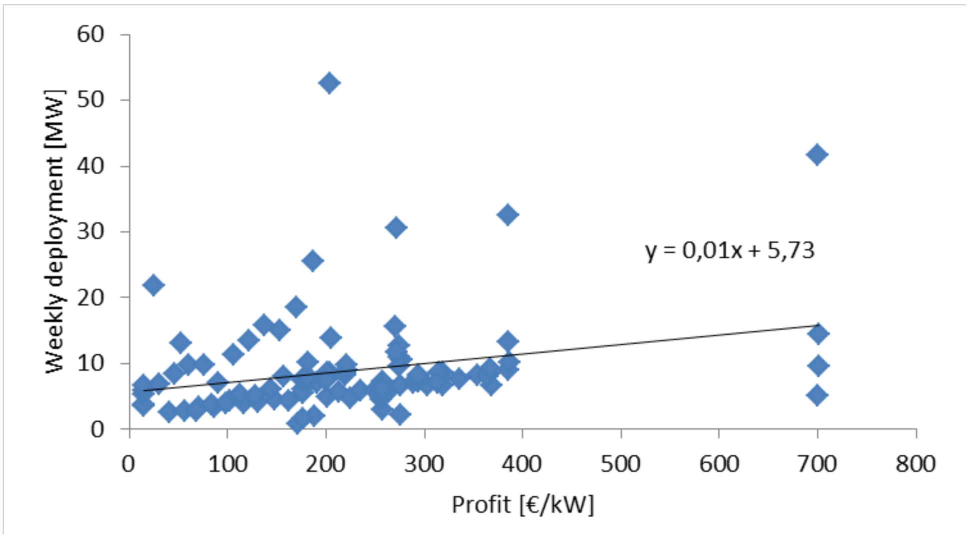

Figure 42: Weekly PV installations and profit levels for systems up to 50 kW in the UK between March 2012 and March 2014

From this, we can derive important conclusions: German investors appear more responsive to changes in the profit margin (i.e. the slope of the fitted regression line is steeper).

5.1.4 Results

Figure 43 shows simulated aggregated PV deployment in both Germany and the UK for separate and coordinated tariff adjustment schemes. While the separate tariff adjustment mechanism takes into account only national deployment of the previous quarter, the coordinated scheme incorporates both German and UK historic deployment. Both tariff mechanisms are able to keep aggregate deployment within the aggregate target corridor. While the coordinated scheme results in slightly increasing aggregate deployment, separate tariff mechanisms result in slightly decreasing aggregate deployment.

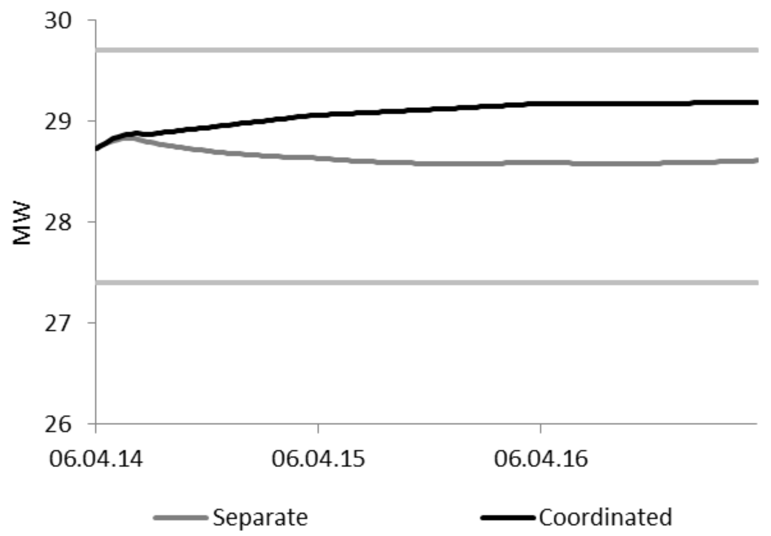

Figure 43: Simulated weekly aggregated deployment of PV systems up to 50 kW for separate and coordinated tariff adjustment mechanisms in Germany and the UK

At the beginning of the simulation period, the model calculates that German deployment starts above the target corridor while UK deployment starts below, as Figure 44 signals. We observe that separate national tariff adjustment schemes guide national deployment relatively quickly back to the respective national target corridor. In contrast, with the coordinated tariff mechanism applying the same adjustment factor to German and UK tariffs, resulting national deployment only gradually converges towards the national corridor (Figure 44). With coordinated schemes, deployment in the UK stays below its target corridor, whereas it remains above the target corridor in Germany. This happens since overall deployment is in line with the overall target and therefore price levels are not explicitly adjusted. For PV systems up to 50 kW in Germany and the UK, around two thirds of the total system prices are determined by elements other than globally traded PV module prices; therefore the adjustment to country specific deviations is more important than the adjustment to the global (PV module) price trend.

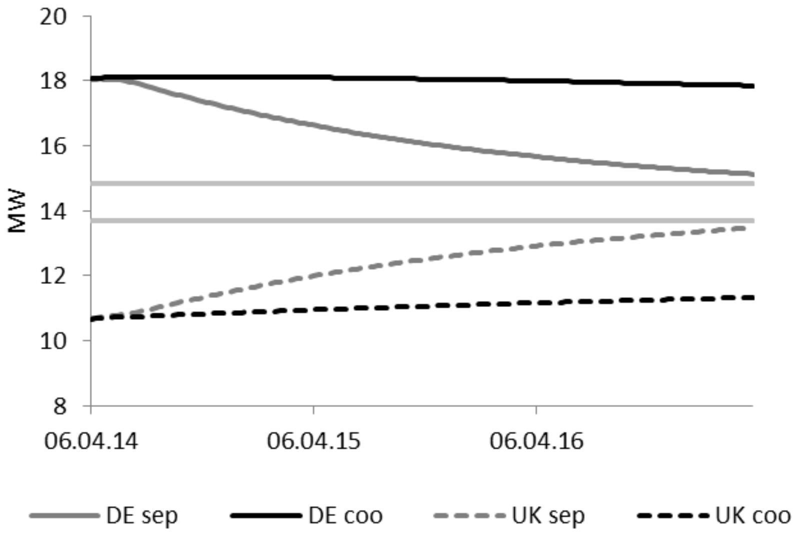

Figure 44: Simulated weekly national deployment of systems up to 50 kW for separate and coordinated tariff adjustment mechanisms in Germany and the UK in the reference scenario

Figure 45 shows specific examples to illustrate that these generic statements may not apply in specific instances. The figure depicts simulated weekly aggregated installations of systems up to 50 kW in both countries for separate and coordinated tariff mechanisms in the 'Low slope' (slow response to profit margin changes) and 'High slope' (quick response to changes in the profit margin) scenarios. If aggregate deployment at the beginning of the simulation period starts below target levels, coordinated tariff mechanisms are more effective in terms of reaching the aggregate corridor again – in this case all countries require the same direction of adjustment and the joint adjustment ensures a stronger response also in Germany to correct for the large deviation caused from the UK. However, if aggregate deployment starts above corridor, separate tariff mechanisms may again more effective.

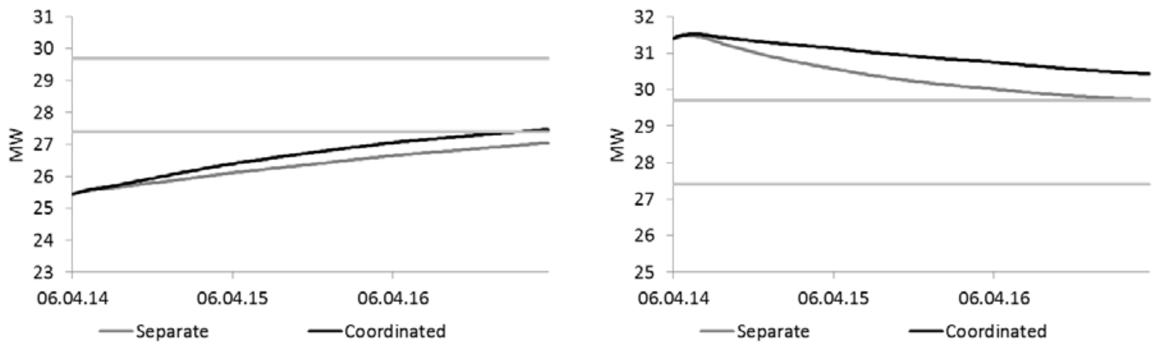

Figure 45: Simulated aggregated installations for separate and coordinated tariff mechanisms in the 'Low slope' scenario (left) and the 'High slope' scenario (right)

These model results illustrate several implications. If countries have different asymmetric response rates between deployment and profit margins, separate tariff adjustment mechanisms are more effective for national corridor achievement than coordinated schemes. However, it is possible to identify specific scenarios in which coordinated tariff adjustment can be more effective concerning aggregate corridor achievement.

5.1.5 Recommendations

Our model results show that separate schemes are more effective than coordinated mechanisms in reaching national deployment target corridors if countries have different asymmetric response rates between deployment and profit margins. However, in the case of aggregate shocks, for specific supply functions and installation price scenarios a coordinated scheme with identical tariff adjustment factors may be more effective in terms of reaching aggregate deployment target corridors. This inferior performance of the coordinated tariff adjustment is in particular of interest because it mimics in many ways internationally integrated market premium or tradable certificate systems (e.g. harmonisation of premium or certificate trade). This suggests that harmonised premiums and tradable certificate systems do not lead to efficient outcomes under heterogeneous market conditions.

However, there are two issues where coordinated support schemes might have specific positive effects in case of market shocks. First, in the short term, coordination can be more effective concerning national corridor achievement for specific temporary deployment shocks with opposed effects in neighbouring countries. Second, coordinated schemes can be slightly more effective in case of specific module or installation price shocks from an aggregate corridor perspective. Overall, effective coordinated schemes should enable specific ad hoc tariff adjustments in case of extreme or permanent market shocks.

Coordination could also take the form of information exchange between countries in the process of calibrating national remuneration adjustment schemes, for instance to improve their national tariff adjustment procedures. Such procedures are already often the norm, but are usually based on historical national data. Such coordination might especially support countries with less of a track record in a specific technology to set appropriate tariff levels. Countries could exchange information more frequently and in more detail, for instance about deployment, installation costs or prices, tariff levels, financing agreements, policy changes, tax frameworks, or administrative barriers. For solar PV in particular, a frequent exchange (weekly or monthly) of technology cost data is crucial. This allows for a better and swifter adjustment of support levels in response to cost shocks. Otherwise, such technology cost reductions could lead to undesired deployment peaks. It could also result in windfall profits in particular for countries with large incumbents. In times of fast cost reductions, such incumbents could utilize their market power and try to withhold new capacity installations in order to keep remuneration levels high and hence make windfall profits. With international data exchange on installation volumes and prices, the regulator could detect such behaviour more easily.

Additionally, harmonisation of administrative procedures facilitates a simpler assessment of investment opportunities across countries. Especially smaller countries can benefit if their remuneration system is easily accessible to outside financing parties and investors. Otherwise, specific national administrative requirements can imply barriers for investors to obtain financing access.

Furthermore, joint projects and auctions are possible. This way, projects can be financed against a joint remuneration mechanism that may reduce regulatory risk and thus financing cost. Countries could thus also increase competition by allowing projects to take place in larger geographical areas.

5.2 Interplay of EU biomass policy with global trends

5.2.1 Policy context

Development of international biomass trade

Gross inland consumption of renewable energy from biomass and renewable wastes in the EU28 more than doubled from 61 Mtoe in 2000 to 129 Mtoe in 2014. As a result of this development and regional restrictions in economic supply of biomass sources, international trade in biomass for energy purposes has grown exponentially in the same period. In 2014, net imports of liquid and solid biofuels to the EU were 5.45 Mtoe[20] of which 5% ethanol, 9% biodiesel, 48% wood pellets and 37% other wood fuels (Figure 46). By comparison, net imports of solid fossil fuels, natural gas, petroleum and products made up 73% (909 Mtoe) of gross inland consumption of fossil fuels (1230 Mtoe) making the EU the world largest importer of fossil fuels (AEBIOM 2015).

Trade of biodiesel started to become significant after 2005 and was almost solely driven by EU blending targets for biofuels. Soybean oil from Argentina (South America) and palm oil from Indonesia and Malaysia (Southeast Asia) accounted for over 90% of biodiesel import to the EU in 2012. In 2013, effective anti-dumping measures against Indonesian and Argentinean biodiesel were taken reducing imports to the EU substantially. Similar measures were taken to ethanol imports from the US in 2014 that could previously be circumvented via indirect import to the EU via Norway.

Wood pellets have become the largest imported biomass commodity. Other wood fuels include mainly wood chips and firewood that are imported from other European countries, Russia and Ukraine firewood, but also small amounts of palm kernel shells from South East Asia.

[20] Calculated based on Keller (2016) for liquid biofuels and AEBIOM (2015) for solid wood fuels. According to EUROSTAT, net imports of biomass to the EU28 are slightly lower (4.92 Mtoe in 2014). Differences occur because of the difficulties (and/or lack of) traceability and reporting of biomass trade flows.

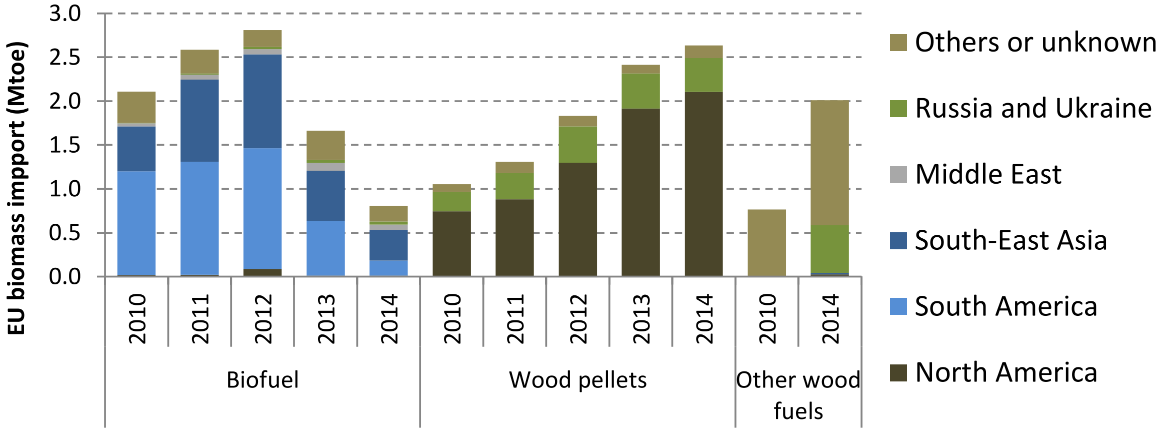

Figure 46: Annual EU imports of liquid biofuels (biodiesel, ethanol), wood pellets and other wood fuels (AEBIOM 2015; Keller 2016; Lamers et al. 2012)

Pellets cover the majority of imports from third countries to the EU and have overtaken imports of liquid biofuels already in 2013. The market for industrial uses (electricity and CHP) is highly sensitive to developments in support policies. In the Netherlands for example, industrial pellet consumption decreased from over 0.41 Mtoe (1.0 Mt) in 2013 to 0.08 Mtoe (0.2 Mt) by 2014 as a result of the expiration of the support subsidy scheme (MEP) for co-firing whereas in Belgium, two power plants stopped production in 2014 (Rodenhuize and Les Awirs) as a result of a regulatory dispute and economic reasons (AEBIOM 2015). Total industrial pellet consumption did not fall dramatically as a result of the strong growth in consumption in the UK. The UK consumed 1.9 Mtoe (4.7 Mt) in 2014 equivalent to 28 of gross inland consumption of biomass (Figure 47). Pellets are consumed in just two power plants in the UK: Drax Power and Eon's power plant at Ironbridge. Ironbridge was closed by the end of 2015.

Between 2008 and 2015, heating pellet demand doubled in the EU28 with 6 member states making up almost 80% of the market in 2014. These include Italy (1.2 Mtoe, 2.9 Mt), Germany (0.8 Mtoe, 2.0 Mt), Sweden (0.6 Mtoe, 1.4 Mt, Austria (0.3 Mtoe, 0.8 Mt), France (0.4 Mtoe, 0.9 Mt), Denmark (0.3 Mtoe, 0.7 Mt). Other EU member states consumed 0.9 Mtoe (2.1 Mt) in 2014 (AEBIOM 2015). Although pellet heating is supported in some EU member states, for example via investment subsidies for pellet boilers and VAT tax reductions on wood pellets, pellet heating is considered a self-sustaining commercial activity driven by high prices of alternative fuels (Hawkins Wright 2014).

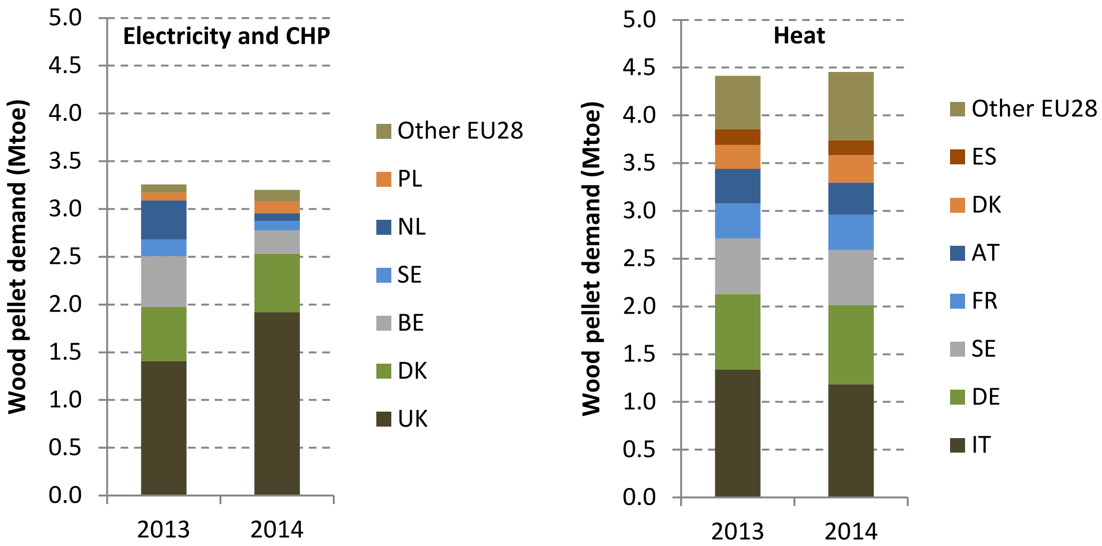

Figure 47: Wood pellet consumption for electricity and CHP (left) and heat (right) in 2013 and 2014 in the EU28 (AEBIOM 2015)

Sustainability criteria

To ensure the sustainable use of biomass, both from domestic and imported sources, binding sustainability criteria have been set in the RED for liquid biofuels. However, these criteria do not apply to solid and liquid biofuels used for electricity, heating and cooling. The greenhouse gas (GHG) saving criteria set for liquid biofuels[21] in the RED can in most cases easily be met by solid biomass. In general, GHG savings for heat and electricity are well above 60% and could exceed 70% if efficient conversion systems are used such as CHP plants or co-firing in modern coal fired power plants (Giuntoli et al. 2015; Sikkema et al. 2010). The impact of other sustainability criteria on the extra-EU supply potential including temporal imbalances in carbon and the resulting carbon debt as well as required sustainable forest management (SFM) principles are difficult to quantify (Galik and Abt 2015).

The largest importing countries of industrial pellets including Belgium, Denmark, the Netherlands and the UK have developed voluntary agreements with industrial stakeholders or mandatory criteria in legislation at the national level to safeguard sustainable production and consumption of solid biomass. These national schemes differ on some key aspects including the inclusion of Sustainable Forest Management criteria and voluntary schemes (FSC, PEFC, SFI, ATFS and CSA), carbon accounting, measures to prevent feedstock competition (Mai-Moulin and Junginger 2016).

[21] These minimum GHG saving requirements are 35% today and increasing to 50% in 2017 and 60% for new installations in 2018.

5.2.2 Objectives of the analysis

Biomass provides 61% of renewable energy consumption today and is therefore the largest source of renewable energy in the EU28. As a result of growth in other renewable energy sources, the relative share of biomass is expected decrease in the future. In absolute terms however, bioenergy will still grow substantially and although bioenergy supply in the EU28 is still highly self-sufficient compared to fossil fuels, international trade of biomass has grown exponentially in the last decade. Strategic and international coordination is therefore required to ensure a sustainable and efficient deployment of biomass for bioenergy in the future. To this purpose, insight is required in the prospective supply and demand markets of biomass, intra- and extra-EU trade as well as current and future feedstock requirements by different end-users.

The future development of biomass demand and its impact on international trade is inherently uncertain. Co-firing at existing coal power plants and full conversion of units to biomass, leads to rapid growth of solid biomass consumption, but remains fully dependent on policy support. When support expires (Netherlands) or is not granted anymore (Belgium), it leads to a sharp drop in demand. Exchange rates, fossil fuel prices and mild winters are the key factors that influence international trade of wood pellets for heat markets. Many of these uncertainties are beyond the scope of modelling framework used in DiaCore, but could have a substantial impact on the developments in demand and trade volumes of especially industrial uses of wood pellets (electricity, CHP). To this purpose, European scenario projections made with Green-X are compared with a recent market outlook at the national level, based on market announcements and relevant reports (such as AEBIOM).

5.2.3 Results

Scenario outcomes

This section compares the DiaCore **Baseline** scenario, in which a continuation of current RES support to 2020 is assumed followed by a phase out of RES support beyond 2020, to a scenario that assumes that the target of at least 27% renewable energy share in gross final energy consumption by 2030 will be met. In this scenario, current RES policies is assumed to be replaced with a more harmonized policy concept of EU-wide quotas (**QUO**) to achieve the target beyond 2020. The impact on bioenergy deployment and trade of other scenarios (Extra-EU biomass supply, RES policies) are assessed in DiaCore report D5.3 (Hoefnagels et al. 2015).

In the Baseline scenario, the share of renewable energy in the EU28 will increase moderately to 18% in 2020, and 21% in 2030 thus not meeting its targets. In the **QUO-27** scenario, 27% renewable energy will be feasible. Bioenergy will increase in absolute terms, even in the baseline scenario. As a result of strong increases in wind and solar energy, the share of bioenergy in total RES production is projected to decline moderately from 61% today to between 51% and 55% in 2030. Nevertheless, bioenergy will remain the largest source of renewable energy to 2030. In terms of final energy, heat will remain the largest contribution of bioenergy, providing over two-thirds of total final bioenergy supply by 2030 and well over one-third of total renewable energy generation in all scenarios.

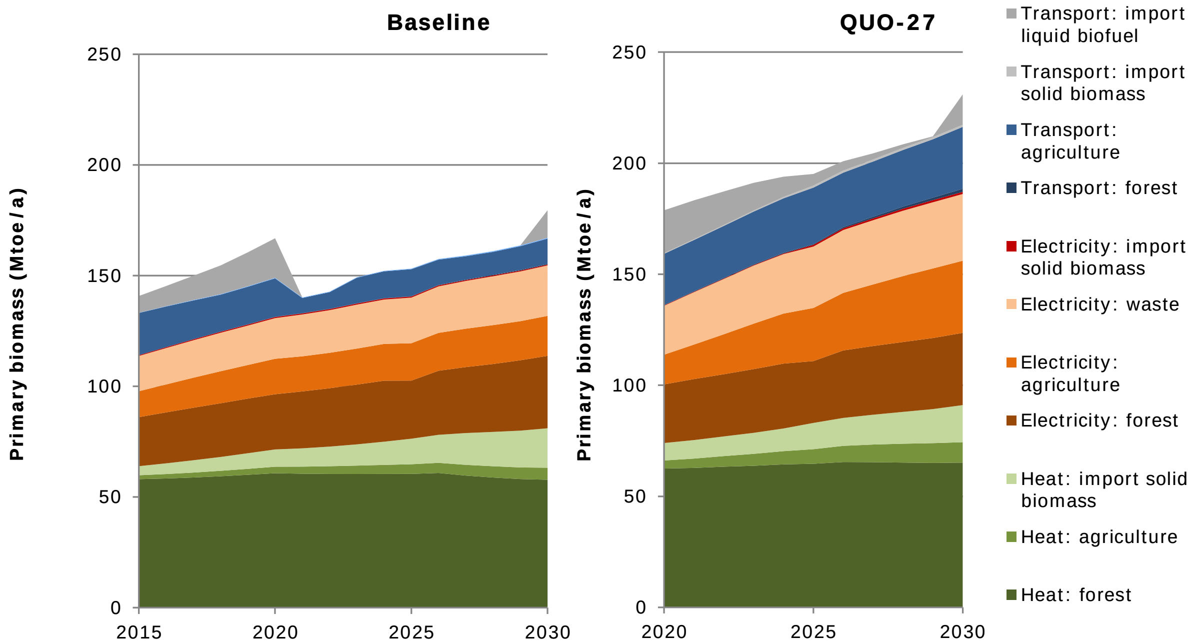

Figure 48: Primary biomass consumption for heat electricity and transport in the Baseline and QUO-27 scenario between 2015 and 2030 in the EU28

According to the Baseline scenario projections, primary biomass demand will grow moderately with 28% between 2015 and 2030 compared to 58% in the QUO-27 scenario (Figure 48). Imports of liquid biofuels are projected to decline beyond 2020 as a result of phasing out support for biofuels. The role of biomass trade and especially extra-EU trade is becoming increasingly important, but the major share of biomass will still be supplied from domestic sources. The total share of extra-EU liquid biofuel and solid biomass biomass increases up to 13% by 2020 and up to 18% by 2030.

Currently, extra-EU imports of wood pellets are mainly used for industrial purposes including large scale electricity generation and CHP whereas pellet heating is mainly supplied from domestic resources or imported from neighboring countries. However, heat markets for Extra-EU imports of solid biomass might grow as a result of competitive price levels compared to fossil heating fuels (LPG, heating oil, natural gas) and may become the main driver for increased trade of solid biomass. This also explains why extra-EU imports of solid biomass are less sensitive to the assumed policy support scenarios. In both the Baseline and QUO-27 scenario, Extra-EU imports of solid biomass increase up to 18.6 Mtoe (44 Mt) limited by the supply potential of extra-EU sources of solid biomass (Figure 49). Note that when higher potentials are assumed, the difference between the baseline and policy scenarios becomes larger.

Similar to extra-EU trade of solid biomass, trade of solid biomass within the EU is projected to increase. Intra-EU trade projections do however show to be more sensitive to the policy scenario conditions assumed. In the Baseline scenario, Intra-EU trade of solid biomass increases to 5.7 Mtoe (14) by 2030 compared to 12.3 Mtoe (29 Mt) in the QUO-27 scenario.

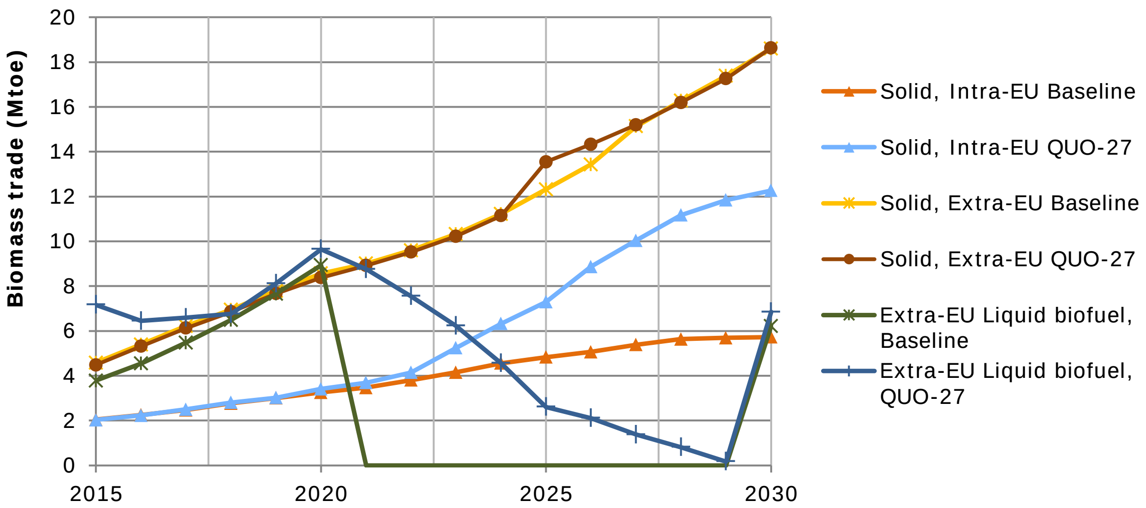

Figure 49: Intra-EU and Extra-EU biomass trade in the scenarios to 2030.

Market outlook

Under current market expectations, industrial wood pellet consumption for electricity and CHP plants might increase to over 8.7 Mtoe (21 Mt) before 2020 in key importing countries in the EU (Belgium, Denmark, the Netherlands and the UK) compared to 2.9 Mtoe (7.0 Mt) in 2014. In the Netherlands, wood pellet consumption for co-firing is still expected to ramp up again under support of the SDE+ schemes in which it is capped at final supply of 25 PJ (3.0 – 3.5 Mt wood pellets). In Belgium, there are several plans for the conversion of existing or building of new plants with a total expected demand of 3.0 Mt by 2020. Denmark aims to end coal use by 2030. Consumption in Denmark might increase to 3.5 Mt to be used in CHP plants converted from coal to biomass and district heating plants (AEBIOM 2015). In the UK, Drax may convert its third boiler to biomass. Furthermore, the Lynemouth station (420 MW) has been recently sold to EP UK aiming to convert to biomass and consume 1.5 Mt wood pellets. Also the 299 MW biomass CHP plant Teesside is currently under construction. The plant is expected to consume 2.4 Mt wood pellets[22]. If Drax converts its third boiler to biomass, it will consume 7-7.5 MT wood pellets. Total wood pellet consumption in the UK might therefore increase to over 11 Mt (4.7 Mtoe).

Although pellets for residential heating are still mainly sourced from regional supply, in recent years, increasing amounts of wood pellets for heat markets are imported. Pellet

[22] http://www.power-technology.com/projects/tees-renewable-plant-teesside/

heating in the EU28 is projected to increase to 6.9 Mtoe (17 Mt) by 2024 (Hawkins Wright 2014) with Italy and Germany expected to remain largest. However, also substantial growth in France is expected. Growth in heat is a relatively autonomous development according to Hawkins Wright (2014), but depends also on the development of amongst others fossil fuel prices such as heating oil. Others consider that support will be needed to develop these markets (Thomson and Liddell 2015).

Based on development in industrial and residential pellet markets in Europe, the demand in Europe is expected to increase to 37 Mt in 2024 (17 Mt heat, 20 – 21 Mt industrial) (Walker 2014). If we extrapolate the trend to 2030 assuming linear growth between 2020 and 2030, total wood pellet demand will grow to 42 Mt by 2030.

5.2.4 Recommendations

Lack of harmonization between national schemes could cause trade barriers and may hamper further development of international biomass markets. The need for harmonized sustainability criteria and support schemes is therefore growing, preferably at the EU level. Secondly, according to the DiaCore scenario projections, increasing extra-EU imports of solid biomass will be used for heat markets towards 2030. This might create a convergence between industrial and residential wood pellet markets. The interplay between domestic and international biomass supply and between different markets are important to be addressed in developing sustainable and international biomass supply.

6 Keeping policy costs for renewables at an acceptable level – results of the model-based RES policy assessment

6.1 Policy context

Renewables have progressed substantially in Europe throughout last years despite non-inspiring economic and political developments. The global financial crisis has shaken national economies across the EU, and tight state budgets influence policy making in various fields, including energy policy and specifically the regulatory framework for renewables.

Thus, light has been shed on the financial support offered to renewable energies, and support expenditures for renewables, commonly named as policy costs, are carefully observed and frequently heavily debated. Thus, it appears essential to keep the costs of these policy interventions at acceptable levels from a societal point of view. This will assure that public acceptance of Europe's proactive movement towards a sustainable and climate benign energy system is maintained, and that renewables are seen as a cure and not as a problem.

6.2 Objectives of the analysis

This section is dedicated to provide the quantitative underpinning of previously discussed recommendations in the various fields, including the forming of a level playing field in energy supply, financing conditions and also more directly concerning RES policy making and the design of related support instruments.

Moreover, we aim for a brief quantitative analysis on meeting the 2030 27% RES target, serving as input for the ongoing policy debate on renewables including the legislative frame being provided at EU level for the period post 2020. Thus, we highlight key results of a comprehensive model-based RES policy assessment with focus on the upcoming decade, indicating possible RES developments in the years up to 2030. We will also shed light on accompanying costs and expenditures, including capital costs, support expenditures and additional generation costs, as well as corresponding benefits, with focus on avoided fossil fuels and CO_2 emissions.

6.3 Approach

This analysis builds on modelling works undertaken by the use of TU Wien's Green-X model (cf. Box 1). More precisely, the outcomes of a quantitative policy analysis of various scenarios[23] on future RES deployment within the EU are used to indicate the impact of our suggested measures on related policy costs.

Box 1: Brief characterization of the Green-X model

Green-X is an energy system model that offers a detailed representation of RES potentials and related technologies in Europe and in neighbouring countries. It aims at indicating consequences of RES policy choices in a real-world energy policy context. The model simulates technology-specific RES deployment by country on a yearly basis, in the time span up to 2050[24], taking into account the impact of dedicated support schemes as well as economic and non-economic framework conditions (e.g. regulatory and societal constraints). Moreover, the model allows for an appropriate representation of financing conditions and of the related impact on investor's risk. This, in turn, allows conducting in-depth analyses of future RES deployment and corresponding costs, expenditures and benefits arising from the preconditioned policy choices on country, sector and technology level.

For specific purposes, e.g. within a detailed assessment of the merit order effect and related market values of the produced electricity for variable and dispatchable renewables, Green-X was complemented by its power-system companion – i.e. the HiREPS model – to shed further light on the interplay between supply, demand and storage in the electricity sector thanks to a higher intertemporal resolution than in the RES investment model Green-X.

Key parameter

In order to ensure maximum consistency with existing EU scenarios and projections the key input parameters of the scenarios presented in this report are derived from PRIMES modelling and from the Green-X database with respect to the potentials and cost of RES technologies. Table 3 shows which parameters are based on PRIMES, on the Green-X database and which have been defined for this study. The PRIMES scenarios used for this assessment are the latest publicly available *reference scenario* (European Commission, 2013b) and a climate mitigation scenario building on an enhanced use of energy efficiency and renewables named "GHG40EERES30" as presented in the European Commission's Impact assessment (SWD(2014) 15) related to its Communication on "A policy framework for climate and energy in the period from 2020 to 2030" (COM(2014) 15 final).

Although a target of 27% for energy efficiency has already been fixed for 2030, we show ranges with regard to the actual achievement of energy efficiency to cover both, a higher

[23] Please note that the specific scenarios used are introduced in the individual exercises for illustrating the impacts of proposed measures.
[24] For this exercise model calculations are however limited to the period up to 2030.

or substantially lower level of ambition in terms of energy efficiency policy: Under reference conditions an improvement in energy efficiency of 21% compared to the 2007 baseline of the PRIMES model is projected for 2030, whereas in the “GHG40EERES30” case, assuming a medium ambition level for energy efficiency, an increase to 30% is assumed.

Table 3: Main input sources for scenario parameters

Based on PRIMES	Based on Green-X database	Defined for this assessment
Primary energy prices	Renewable energy technology cost (investment, fuel, O&M)	Renewable energy policy framework
Conventional supply portfolio and conversion efficiencies	Renewable energy potentials	Reference electricity prices
CO_2 intensity of sectors	Biomass trade specification	
Energy demand by sector	Technology diffusion / Non-economic barriers	
	Learning rates	
	Market values for variable renewables	

6.4 Results

6.4.1 The quantitative impact of suggested measures

Below we aim for indicating the impact of suggested measures as derived in various fields in previous parts of this report. This comprises improvements in RES policy design and in corresponding framework conditions affecting renewables, the forming of a level playing field in energy supply as well as financing conditions.

Improving support scheme design and removing non-economic barriers

Overview on RES policy scenarios used in this exercise:

BAU	Business-as-usual scenario of RES policy schemes, non-economic RES barriers prevail	SNP-27 – barriers mitigated	Strengthened national (RES) policies (in accordance with 2020 and 2030 RES targets), non-economic RES barriers mitigated
SNP-27 – barriers prevail	Strengthened national (RES) policies (in accordance with 2020 and 2030 RES targets), non-economic RES barriers prevail		

In this subsection the quantitative impact of **various changes in RES policy design and in related framework conditions, specifically concerning non-economic barriers** that hinder the uptake of RES, will be shown and described. Those changes are indicated by two scenarios (see Figure 50 and Figure 51) that will be compared to a business-as-usual (BAU) scenario[25].

- Strengthened national policies – barriers remain: In this scenario (that relates to a target of 27% RES by 2030), a continuation of the current policy framework with national RES targets (for 2030 and beyond) is assumed. Each country uses national support schemes in the electricity sector to meet its own target, but contrary to the BAU scenario it is complemented by RES cooperation if necessary. Support levels are generally based on technology specific generation costs per country.
- Strengthened national policies – barriers mitigated: In this scenario it is assumed that, additionally to the strengthened national policies, non-economic barriers are mitigated, which will facilitate the RES deployment.

Common to all assessed cases is the assumption that dedicated support for biofuels in transport will be phased-out post 2020, including for example a removal of blending obligations. This has a strong negative impact on biofuel deployment in the years after 2020 in particular, and also overall RES deployment is affected significantly (cf. Figure 50 (right)).[26]

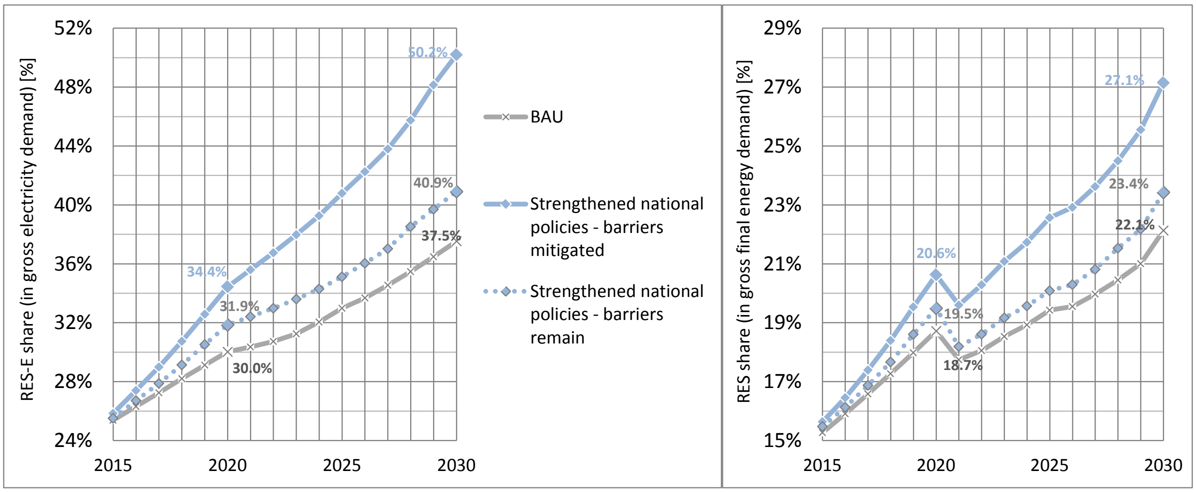

Figure 50: RES-E (left) and RES (right) deployment (expressed as share in gross electricity demand (left) / gross final energy demand (right)) in the period 2011 to 2020 in the EU-27 according to the BAU case and the case of "strengthened national policies" (incl. a sensitivity variant of prevailing barriers)

[25] The business-as-usual (BAU) scenario reflects the currently implemented RES policy framework in the period up to 2020, and a gradual (or immediate in the case of biofuels) phase-out of RES support post 2020. Moreover, in that scenario non-economic barriers that limit the uptake of RES technologies in various countries are assumed to prevail.
[26] A steep decline in the overall RES share by about 1 percentage point is applicable in Figure 50 (right) from 2020 to 2021 in all assessed scenarios.

Looking at Figure 50 it is apparent that the “strengthened national policy-barriers remain” case, where the same framework conditions concerning non-economic RES barriers as in the BAU scenario are implemented, leads to a significant increase of the RES-share in the electricity sector (from 37.5% to 40.9% in 2030), as well as in the overall energy sector (from 22.1% to 23.4% in 2030) when compared to the BAU scenario. Retaining the same policy design, supplemented by a mitigation of non-economic deficits, would lead to an even more pronounced increase in the 2030 RES-E share to over 50% of gross electricity demand (compared to 37.5% in the BAU scenario). The corresponding figure for RES in total is 27.1% of gross final energy demand (instead of 22.1% in the baseline scenario).

The changes in the policy design and framework conditions (with impact on non-economic RES barriers) have a severe effect on the corresponding policy costs as well. Looking at the right side of Figure 51 it can be seen that the yearly support expenditures for RES until 2020 are up to 30% below the baseline scenario, even though the achieved RES share is higher. This indicates the cost reductions that can be achieved by an optimised policy design and improved framework conditions. After 2020 the yearly support costs of the assessed scenarios are generally higher than in the BAU scenario which is caused, on the one hand, by the strongly increased RES deployment compared to BAU, and, on the other hand, by the assumed (gradual) phase-out of RES support post 2020 under BAU conditions. Compared to BAU this leads to an increase of support expenditures in absolute terms, whereas specific support costs (measured in € per MWh RES generation) are expected to decline.

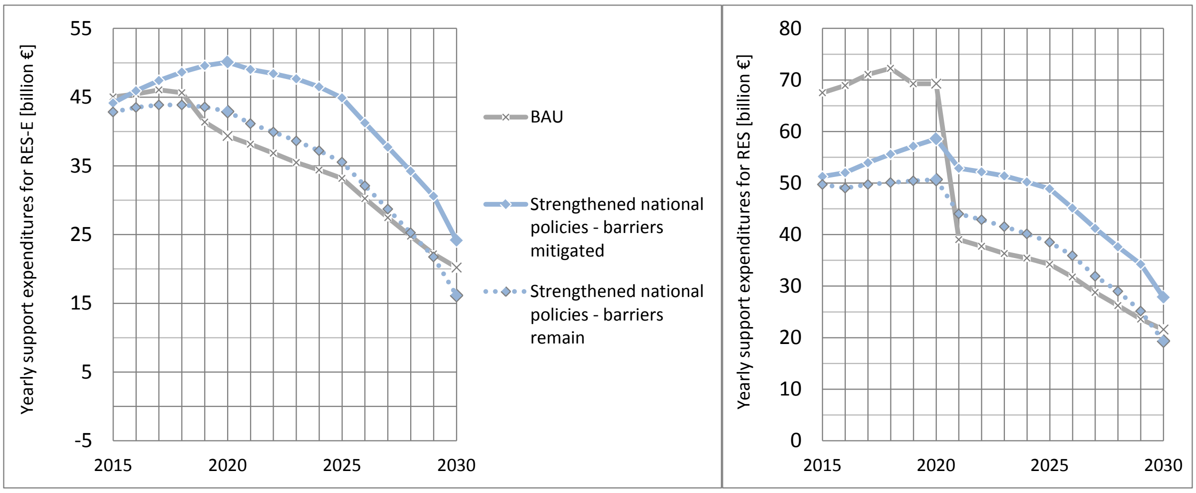

Figure 51: Yearly support expenditures for RES-E (left) and for RES (right) in the period 2011 to 2020 in the EU-27 according to the BAU case and the case of “strengthened national policies” (incl. a sensitivity variant of prevailing barriers)

Improving financing conditions through optimised RES policy design

This subsection aims to provide the quantitative underpinning of previously discussed findings and recommendations on improving financing conditions across the EU (cf. section 4). The assessment of the impact of improving financing conditions builds on four different scenarios that are defined as follows:

- Two distinct renewables policy pathways are used, i.e. a **BAU scenario** that reflects the currently implemented renewables policy framework and where non-economic barriers that limit the uptake of renewables technologies in various countries are assumed to prevail, and, alternatively, an ideal policy world of **strengthened national renewables policies (SNP)**, assuming a strengthening of policy instruments in accordance with binding 2020 and 2030 renewables targets, together with a rapid mitigation of non-economic barriers.
- Both overall RES policy pathways are combined with the two WACC scenarios – i.e. **real** and **ideal WACC** conditions are thoroughly assessed and discussed in the remainder of this report. In the case of ideal WACC it was assumed that all member states have the same, best-in-class cost of equity (i.e. Germany). The cost of debt was kept at the country-specific level. This approach leads to a significant reduction of the WACC from 8.3% to 5.9% on the EU28 average. Concerning the transition period, in the ideal WACC case the assumption is made that gradual improvements in financing conditions materialise in the years up to 2020, forming a level playing field for wind onshore investments across the EU in the period after 2020.

Key results of the model-based assessment of the impacts of improving financing conditions are summarised in Table 4. More precisely, this table provides an overview of results concerning deployment and policy costs – i.e. RES-related support expenditures – in the period up to 2020 and beyond (up to 2030). Impacts are shown for wind onshore, being in the spotlight for the risk evaluation performed.

Table 4: Key results on the impacts of improving financing conditions for wind onshore across the EU

Impacts of improvements in risk performance (WACC) at EU level (EU28)	Scenario:	Business-As-Usual (BAU)				Strengthened National Policies (SNP)			
		WACC real	WACC ideal			WACC real	WACC ideal		
	EU28 (average)	8.3%	5.9%	Change to WACC real		8.3%	5.9%	Change to WACC real	
	[Unit]				%*				%*
Impact on wind onshore									
Electricity generation from wind onshore									
2020	TWh	319.0	324.9	5.9	1.9%	353.7	362.6	8.9	2.5%
2030	TWh	560.1	576.6	16.5	2.9%	674.5	680.7	6.2	0.9%
Support expenditures for wind onshore, yearly average									
2016 to 2020	billion €	8.8	8.6	-0.2	-2.1%	8.7	8.4	-0.4	-4.2%
2016 to 2030	billion €	7.8	7.5	-0.2	-3.1%	8.4	7.1	-1.3	-15.6%

Note: * ... deviation to default (WACC real), expressed in percentage terms (compared to default)

Under BAU conditions the switch from a real to an ideal WACC case shows strong impact on wind onshore deployment: the amount of electricity generated from wind onshore increases by slightly less than 2% until 2020, and by about 3% until 2030 while the corresponding support costs decrease by up to 3.1%.

The scenarios of strengthened national policies (SNP) show a different picture. The reduction of yearly support expenditures would be around 4.2% for the period until 2020, and 15.6% for the forthcoming decade.

Summing up, calculations based on the Green X model show that if all countries had the same renewable energy policy risk profile as the best in class, the EU Member States could reduce the policy costs for wind onshore by more than 15%.

6.4.2 Outlook: RES developments in the EU up to 2030

This section illustrates the outcomes of the **model-based assessment of future RES policy developments up to 2030** within the European Union and its Member States. Compared to the previous subsection where a focus is laid on national policy approaches the scenario and policy scope is broadened, including approaches that aim for forming a level playing field across the EU through further alignment and harmonisation.

Overview on RES policy scenarios used in this exercise:

BAU	Business-as-usual scenario of RES policy schemes, non-economic RES barriers prevail	SNP-27	Strengthened national (RES) policies (in accordance with 2020 and 2030 RES targets)
QUO-27 (with biofuel support)	Harmonised (RES) support post 2020 (EU-wide quotas with certificate trading for RES-E), in accordance with 2030 RES target, with dedicated support for biofuels post 2020	QUO-27	Harmonised (RES) support post 2020 (EU-wide quotas with certificate trading for RES-E), in accordance with 2030 RES target
QUO-27 (with biofuel support) – strong EE	Harmonised (RES) support post 2020 (EU-wide quotas with certificate trading for RES-E), in accordance with 2030 RES target, with dedicated support for biofuels post 2020, with strong energy efficiency measures	QUO-27 – strong EE	Harmonised (RES) support post 2020 (EU-wide quotas with certificate trading for RES-E), in accordance with 2030 RES target, with strong energy efficiency measures
QUO-30 – strong EE	Harmonised (RES) support post 2020 (EU-wide quotas with certificate trading for RES-E), aiming for a higher RES share than prescribed by the 2030 RES target, with strong energy efficiency measures		

The scenarios analysed combine two different characteristics: different ambition levels for RES deployment in 2030 in particular and different support policies for renewables from 2020 onwards. With respect to the underlying policy concepts the following assumptions are taken for the assessed alternative policy paths:

- As described for one of the previous exercises, in the Strengthened National Policies (SNP) scenario (that relates to a target of 27% RES by 2030), a continuation of the current policy framework with national RES targets (for 2030 and beyond) is assumed. Each country uses national (in most cases technology-specific) support schemes in the electricity sector to meet its own target, complemented by RES cooperation between Member States (and with the EU's neighbours) in the case of insufficient or comparatively expensive domestic renewable sources. In the SNP scenario support levels are generally based on technology specific generation costs per country.
- In the scenarios referring to the use of a quota system (i.e. QUO-27 and QUO-30), an EU-wide harmonised support scheme is assumed for the electricity sector that does not differentiate between different technologies. In this case the marginal technology to meet the EU RES-target sets the price for the overall portfolio of RES technologies in the electricity sector. The policy costs occurring in the quota system can be calculated as the certificate price multiplied by the RES generation under the quota system. These costs are then distributed in a harmonised way across the EU so that each type of consumer pays the same (virtual) surcharge per unit of electricity consumed.
- As a further sensitivity variant for the 2030 RES target we assessed the impact of having dedicated support for biofuels also in the period post 2020 (whereas under default conditions no financial support for biofuels in transport is prescribed).
- Additionally, we also shed light on the impact of complementary energy efficiency measures: Although a target of 27% for energy efficiency has already been fixed for 2030, we show ranges with regard to the actual achievement of energy efficiency to cover both, a higher or substantially lower level of ambition in terms of energy efficiency policy: Under reference conditions an improvement in energy efficiency of 21% compared to the 2007 baseline of the PRIMES model is projected for 2030, whereas in the "GHG40EERES30" case, assuming a medium ambition level for energy efficiency, an increase to 30% is assumed.

Please note that all alternative RES policy pathways (SNP and all QUO cases) build on a strengthening of national policies already in the period before 2020, serving to meet the given 2020 RES targets and where a gradual mitigation of currently prevailing non-economic RES barriers is presumed.

We start with a discussion of RES deployment whereas results concerning the capital, O&M, and fuel expenditures of RES, additional generation costs and support expenditures as well as savings related to fossil fuel (imports) are discussed subsequently.

Key results on RES deployment

We start with an analysis of RES deployment according to Green-X RES policy cases conducted on the basis of corresponding PRIMES scenarios that have been developed for and are discussed in the Impact Assessment accompanying the Communication from the European Commission “A policy framework for climate and energy in the period from 2020 to 2030” (COM(2014) 15 final). More precisely, Figure 52 below shows the development of the RES share in gross final energy demand throughout the period 2015 to 2030 in the EU 28 according to the assessed Green-X cases. As reference or 2030 also the shares in the PRIMES scenarios are indicated. Noticeably, an alignment to PRIMES results could be achieved at the aggregated level (total RES deployment, EU28) for the policy track aiming for a RES share of 30% (QUO-30) by 2030. This finding is also confirmed by a subsequent more detailed analysis that involves sector-specific results also indicates that comparatively similar trends are observable by 2030 for the EU 28 at sector level.

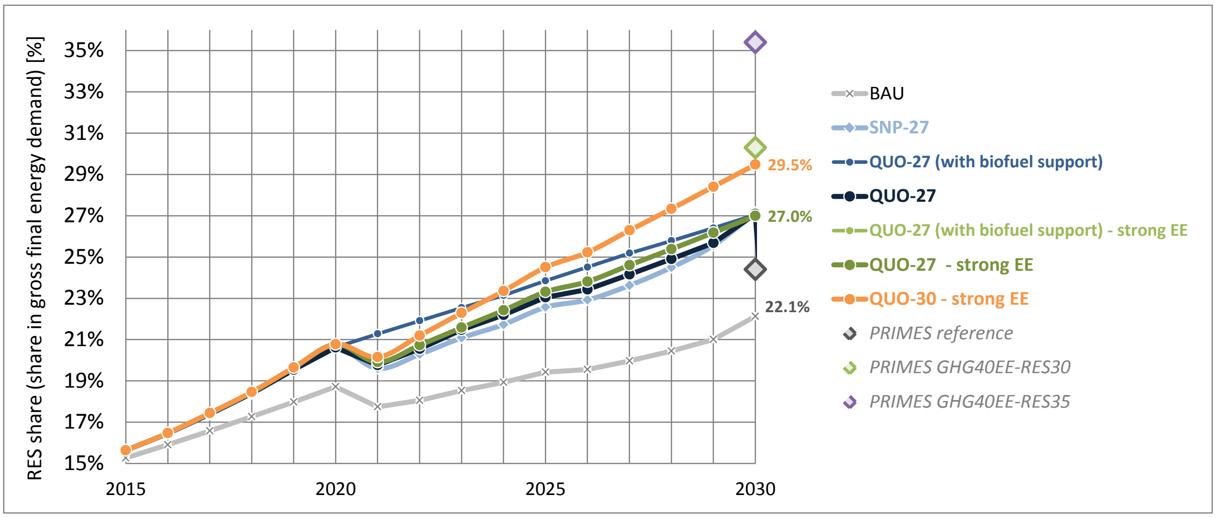

Figure 52: Comparison of the resulting RES deployment in relative terms (i.e. as share in gross final energy demand) over time in the EU 28 for all assessed cases (incl. PRIMES scenarios)

Figure 53 takes a closer look at the sector-specific RES deployment at EU-28 level. While sector-specific RES shares differ only to a small extent among the assessed cases, (strong) differences are observable regarding the overall deployment of new RES installations: 27% RES by 2030 in comparison to the baseline (BAU scenario) means a 41% increase in the deployment of new RES installations post 2020 – if similar developments are prescribed concerning overall energy demand developments in forthcoming years. If proactive energy efficiency policies and measures are however taken as assumed in the PRIMES efficiency scenario, leading to demand decline by 30% instead of 21% as assumed in the reference case, a substantially higher RES share can be achieved by 2030 with less new RES installation: an increase by 37% in the deployment of new RES installations compared to BAU would then lead to a 2030 RES share of 29.5% (cf. QUO-30).

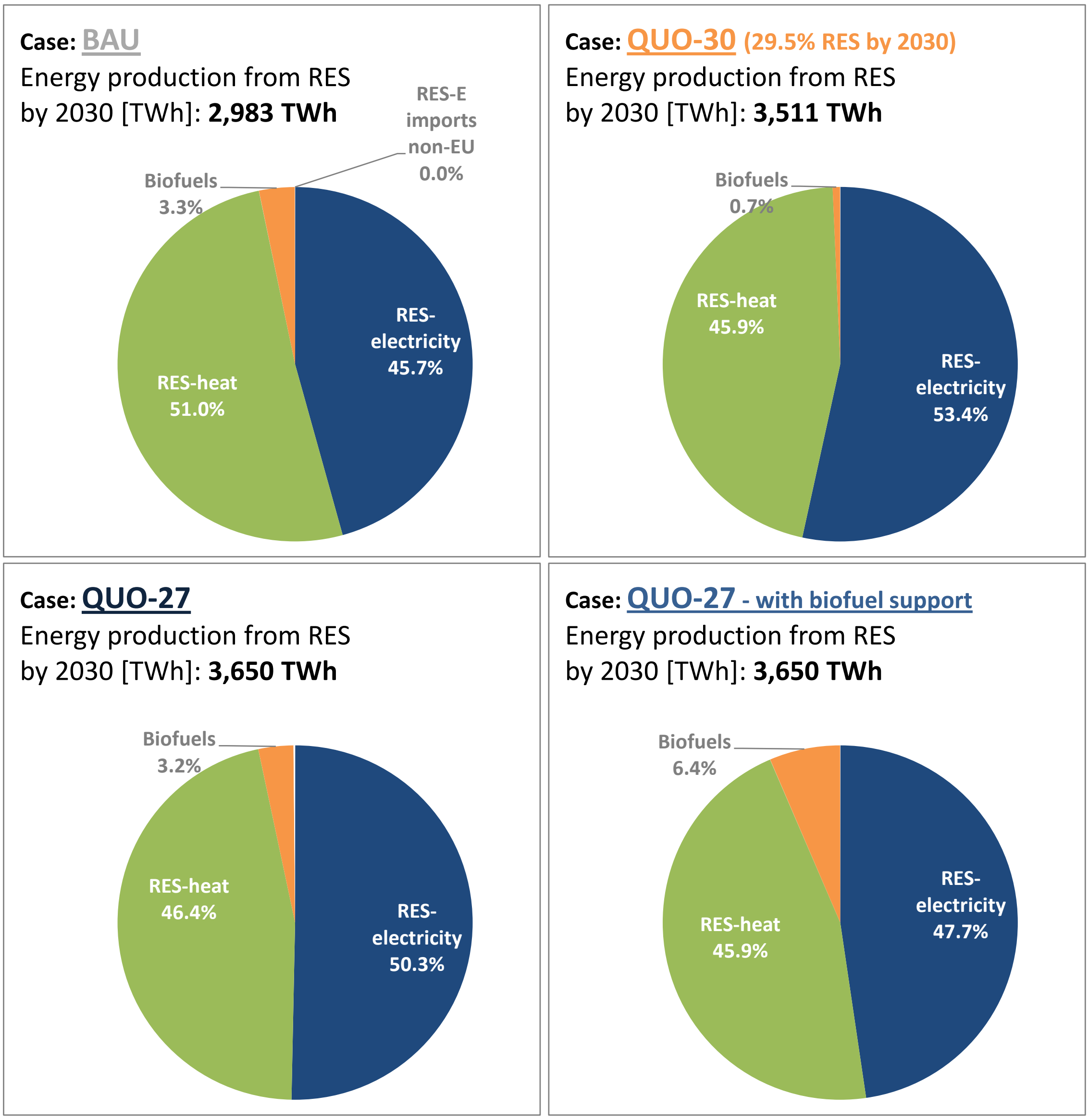

Figure 53: Sector-specific RES deployment at EU 28 level by 2030 for selected cases

Details on RES in the electricity sector

Next, a brief overview of the results gained for RES in the electricity sector is given, showing key indicators on RES deployment over time and at technology level (see Figure 54 and Figure 55).

More precisely, Figure 54 illustrates the feasible RES-E deployment for all assessed policy cases over time (top) as well as by 2030 (bottom), indicating the penetration of new RES-E installations within the observed time frame. It becomes evident that, without or with low dedicated support, RES-E deployment would increase modestly after 2020, reaching for example a share of 37.5% RES-E by 2030 in the baseline case. This indicates that the ETS alone complemented by only moderate dedicated RES incentives do not provide sufficient stimuli for RES-E deployment to maintain a level of ambition consistent with the development until 2020. In contrast to the baseline case, the expected RES deployment in the electricity sector increases more substantially in all other policy variants by 2030, ranging from 42.9% (QUO-27 with biofuels) to around 52.6% (QUO-30).

If total RES deployment is considered, a 21% RES share in gross final energy demand would be achieved under baseline conditions by 2030, while the targeted RES deployment volumes are reached in all other policy paths (i.e. 27% under SNP-27 and QUO-27 (with and without biofuel support), and 30% in the QUO-30, respectively).

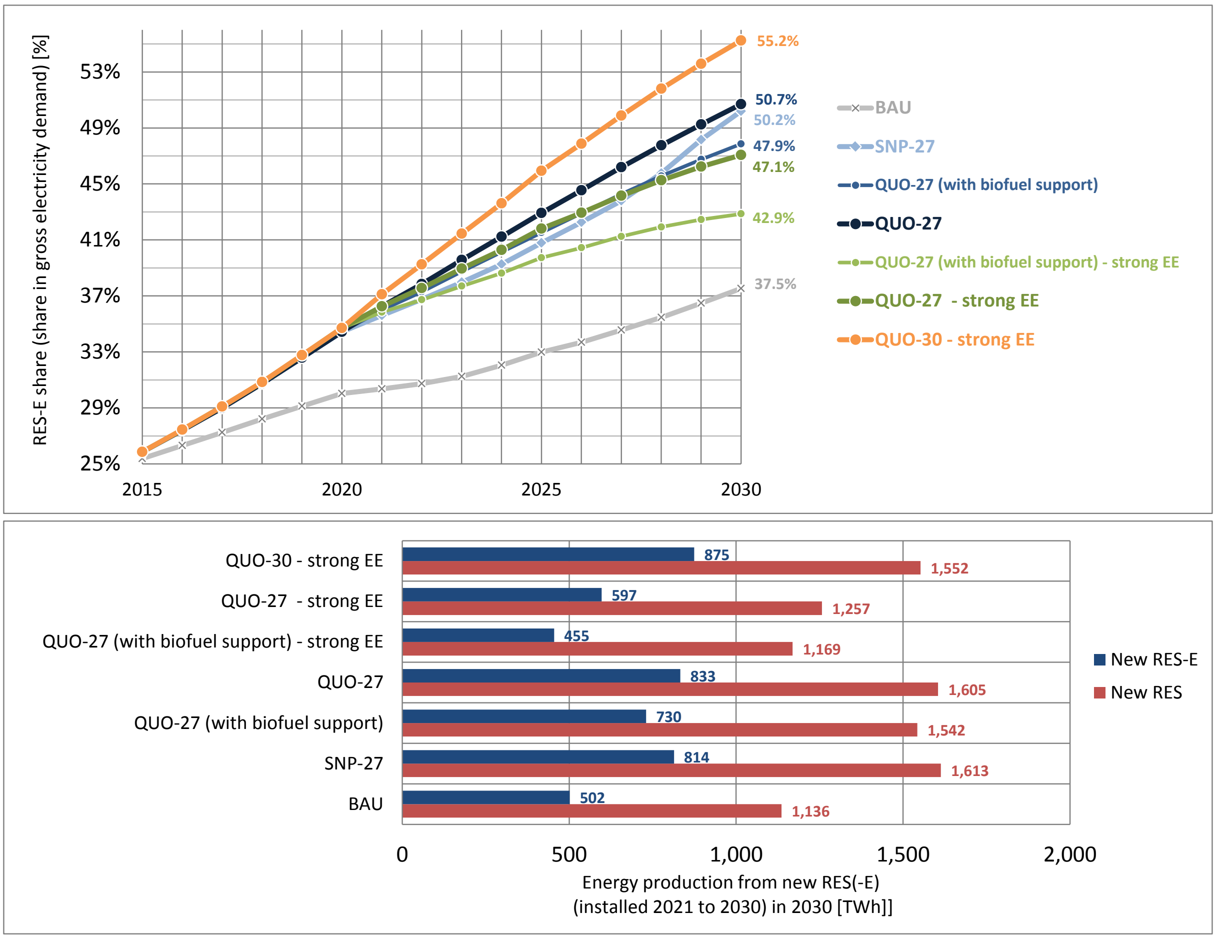

Figure 54: Comparison of the resulting deployment over time (top) and by 2030 for new RES-E and RES installations only (from 2021 to 2030) (bottom) in the EU 28 for all assessed cases.

Complementary to the above, Figure 55 provides a technology breakdown of RES-E deployment at EU 28 level by 2030. The figure shows the amount of electricity generation by 2030 that stems from new installations in the assessed period 2021 to 2030, for each of the analysed policy pathways.. It is apparent that onhore wind energy, followed by biomass and in certain scenarios also photovoltaics and offshore wind energy dominate the picture. Even in the baseline case, significant numbers of new installations can be expected, in particular for onshore wind energy. Differences are observable between all the other cases and are a consequence of the targeted RES volumes (27% or 30% RES by 2030) or of the policy approach assumed to reach that target. An ambitious RES target (30% RES by 2030) generally requires a larger contribution of the various available RES-E options. Technology-neutral incentives as assumed under the policy variant with harmonised uniform RES-E support (QUO-27 and QUO-30) however fail to provide the necessary incentive to encourage more expensive and less mature RES-E options on a timely basis, what is particularly true for the QUO-27 case. Consequently, the deployment of CSP, tidal stream or wave power, but also to a certain extent offshore wind, may be delayed or even abandoned. The gap in deployment would be compensated by an increased penetration of low to moderate cost RES-E options, in particular onshore wind and biomass used for co-firing or in large-scale plants.

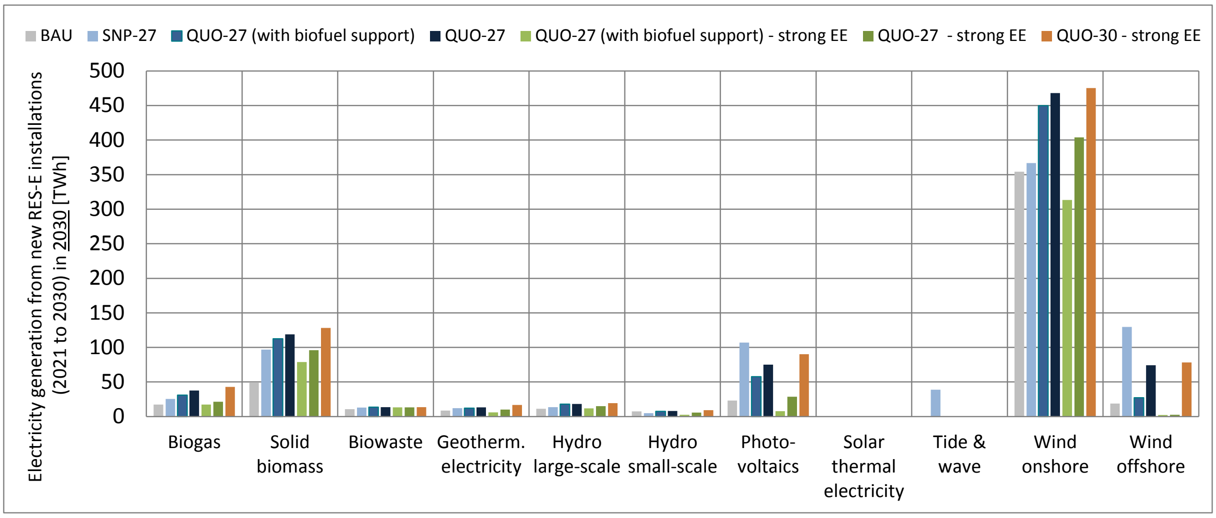

Figure 55: Technology-specific breakdown of RES-E generation from new installations by 2030 (incl. new installations from 2021 to 2030) at EU 28 level for all assessed cases.

RES deployment by 2030 at country level

Figure 56 offers a comparison of the resulting country-specific RES deployment by 2030 according to selected scenarios: a baseline (BAU) case and two alternative policy pathways that refer to an EU-wide target of 27% RES by 2030 (i.e. QUO-27 and SNP-27) are included in the illustration.

Moreover, the graph also indicates possible country-specific (voluntary) 2030 RES targets, prescribed as 2030 RES benchmarks, following the approach used in Directive 2009/28/EC for defining 2020 RES targets. Thus, as such this approach considers the Member State's economic strength in terms of GDP as well as efforts made in the past. On the other hand, the approach ignores other aspects such as the potential availability of renewable resources and related costs.

It can be seen that under baseline conditions an EU target of 27% RES by 2030 appears out of reach for the majority of Member States. A comparison of the results related to alternative policy cases indicates partly significant differences in country-specific RES deployment; compare e.g. RES deployment in the UK or in Portugal according to the distinct case of having a more national or European policy orientation. In the case of the UK this nicely illustrates the low level of ambition of a 27% RES target: for doing so, offshore wind as largely available in northern parts of Europe is hardly required and would consequently deploy only to a limited extent if a "least cost" approach defines the way forward at EU level.

When looking at the baseline scenario, i.e. where countries follow a pathway with their current policy settings, the majority of the member states will not be able to reach a EU 27% or a more ambitioned national goal for RES deployment. As can be seen in Figure 56, this concerns countries such as the Netherlands or the UK whereas countries as Sweden or Austria already have policies in place that would lead them to (over-)fulfil the targets given that the policies are kept unchanged.

Looking into the countries where the indicative national 27% RES goal would be reached, different cases can be identified: For some countries, it does not matter much for their actual achievement whether they adapt a national goal or an overall 27% EU RES goal. This is the case for e.g. the Czech Republic or Belgium.

Comparing the RES deployment in other countries gives very different results when assuming potential own national goals for 2030 and when assuming no national policy strategy but only an overall EU 27% goal. These differences are especially evident in the UK, Portugal or Croatia. In concrete terms, a 27% EU goal would induce only limited investment in costlier technologies as e.g. offshore wind in the UK. In Portugal on the other hand, an overall 27% RES EU goal would induce a substantial expansion in relatively cheap onshore wind parks, whereas a national goal would come along with lower investments. The same can be seen for Croatia, which would also deploy more onshore wind under a harmonized 27 % RES goal.

This highlights the low level of ambition that a 27% RES target represents: countries would focus on the "least cost" approach; further development of costlier technologies would not be needed since these would be deployed only to a very limited extent.

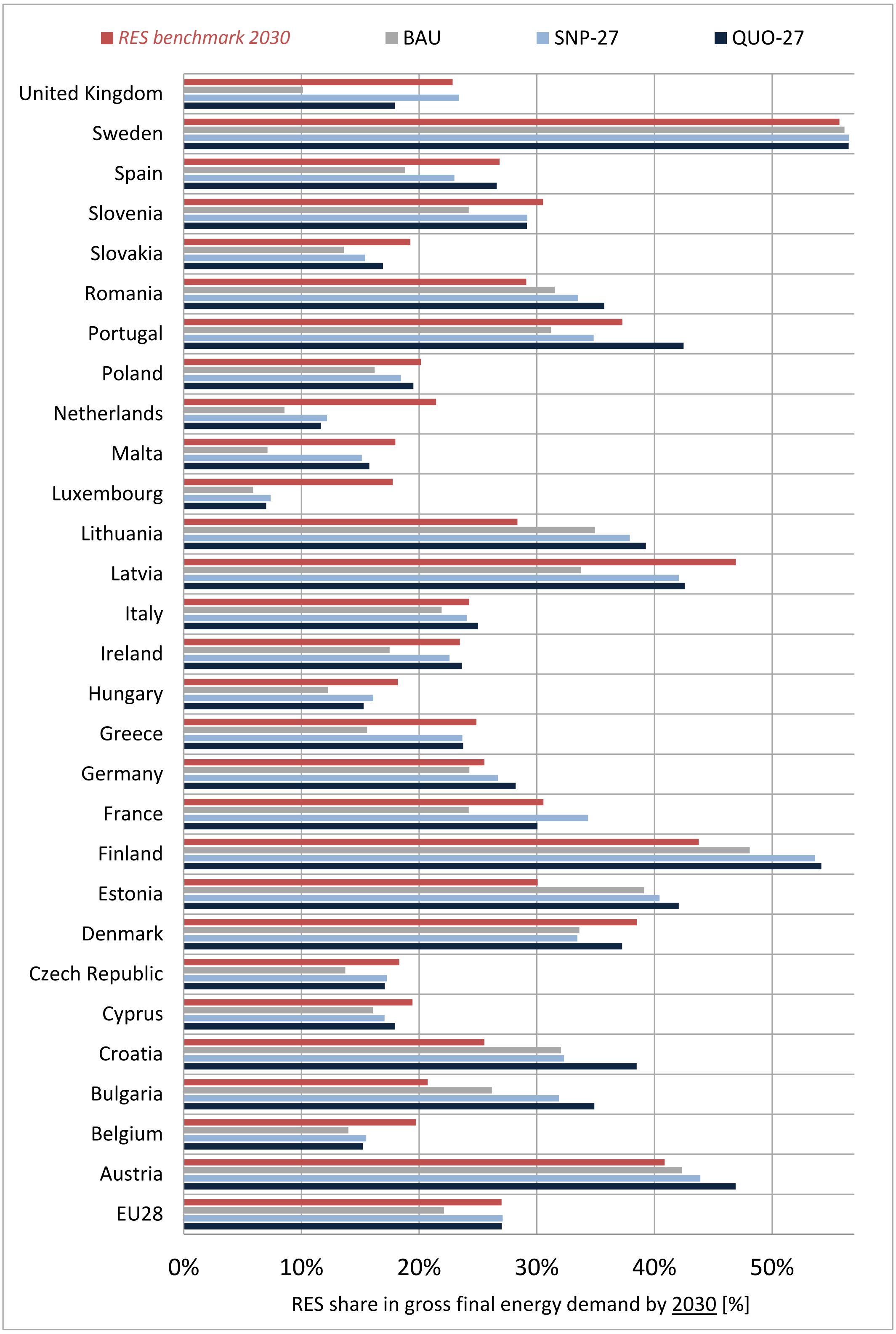

Figure 56: Comparison of the resulting country-specific RES deployment by 2030 according to selected scenarios (baseline and alternative policy pathways related to 27% RES by 2030)

Direct impacts of future RES deployment: Costs, expenditures and benefits

The outcomes of Green-X modelling related to capital, O&M, and fuel expenditures of RES as well as to additional generation costs, support expenditures and savings related to fossil fuel (imports) are presented in this section. The results are complemented by a qualitative discussion based on key indicators.

Indicators of costs, expenditures and benefits of RES

Figure 57 summarises the assessed costs, expenditures and benefits arising from future RES deployment in the focal period 2021 to 2030. More precisely, these graphs show the *additional*[27] investment needs, O&M and (biomass) fuel expenditures and the resulting costs – i.e. additional generation cost, and support expenditures for the selected cases (all on average per year throughout the assessed period). Moreover, they indicate the accompanying benefits in terms of supply security (avoided fossil fuels expressed in monetary terms – with impact on a country's trade balance) and climate protection (avoided CO_2 emissions –expressed in monetary terms as avoided expenses for emission allowances).

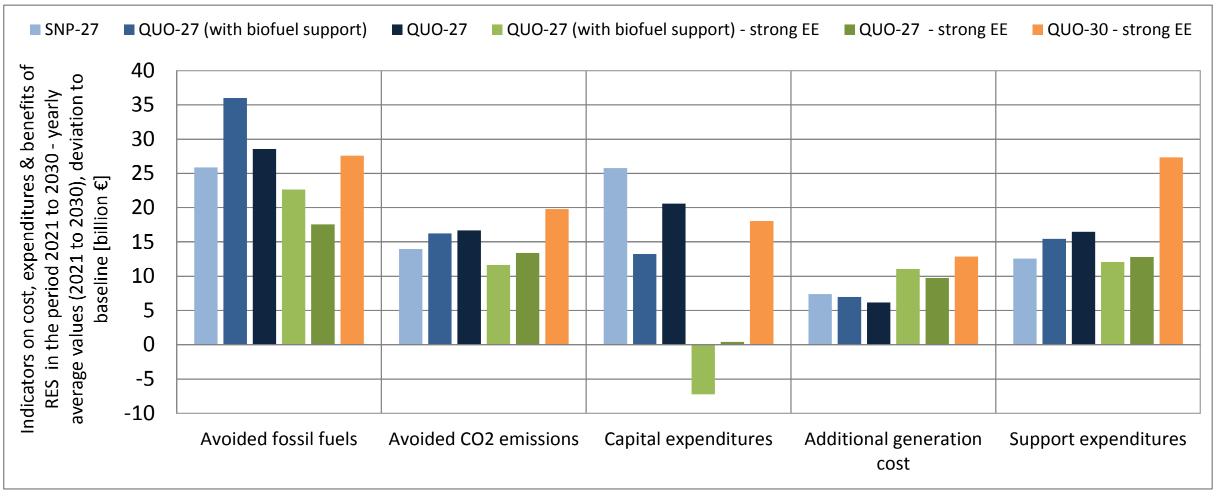

Figure 57: Indicators on yearly average cost, expenditures and benefits of RES at EU 28 level for all assessed cases, monetary expressed in absolute terms (billion €) per decade (2021 to 2030)

Some key observations can be made from Figure 57:

- Not so surprisingly scenarios that reach a 27% target lead to overall costs in a comparable order of magnitude. Also it can be observed that a 27% Quota generally leads to lower capital expenditures / additional generation costs

[27] *Additional* here means the difference to the baseline for all policy cases and indicators, indicating the additional costs or benefits accompanying the anticipated RES policy intervention.

compared to the case of national policies, however these savings hardly can be passed on to consumers due to the marginal technology determining the price for all technologies.

- Moving from a 27% to a 30% target comes at a cost, in this case average yearly support expenditures would almost double to a level of 27 billion Euros in order to “achieve” the last three percentage points of RES deployment.
- These extra costs however are also mirrored by increasing benefits. In all scenarios average yearly capital expenditures are surpassed by the monetary value of avoided fossil fuels. In other words: Fuels cost savings of conventional plants alone are sufficient to finance the capital costs of new RES installations.
- Furthermore when interpreting the numbers it has to be kept in mind that all scenarios assume a reference case with respect to energy demand development. Thus efficiency improvements could make a 30% target much more easily achievable.

Indicators of support expenditures for RES installations

Figure 58 complements the above depictions of RES deployment and overall economic impacts, indicating the resulting support expenditures for RES in relation to the RES deployment in more detail. More precisely, Figure 58 compares overall RES deployment by 2030 with the corresponding support expenditures (on average per year for the period 2021 to 2030) for the selected policy pathways by depicting the RES share in gross final energy demand. We can identify an almost linear relationship between an increase in RES-related support expenditures and an increase in RES deployment. Moreover Figure 58 reveals that a continuation of Business-as-Usual policies would lead to a share of about 22% in 2030.

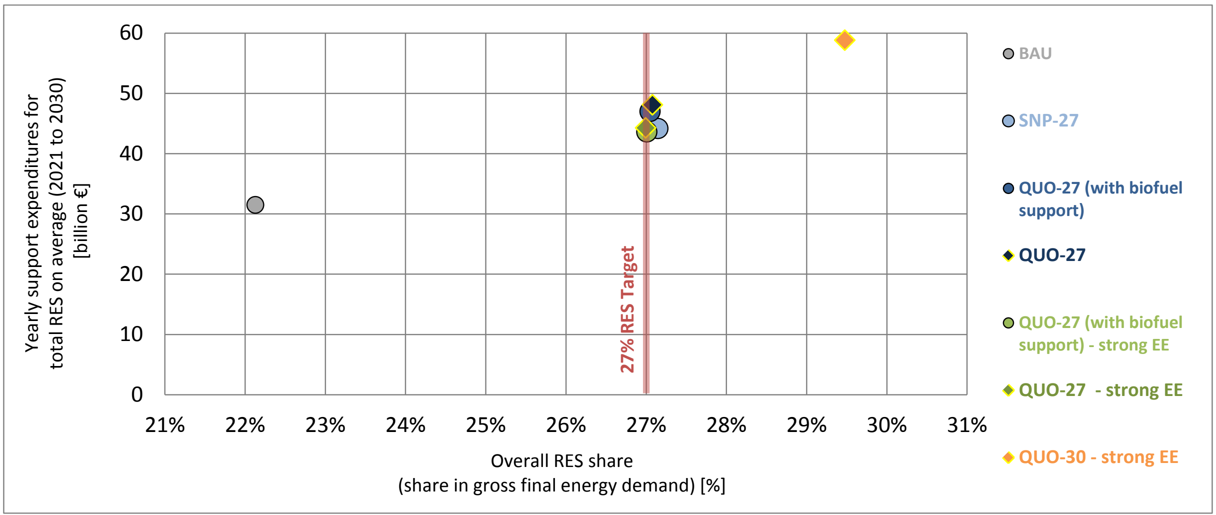

Figure 58: Comparison of the resulting 2030 RES deployment and the corresponding (yearly average) support expenditures for new RES (installed 2021 to 2030) in the EU 28 for all assessed cases.

Next, a closer look is taken at the **financial impact of RES support in the electricity sector**. The support expenditures for RES-E or policy costs from a consumer perspective are analysed in more detail. In this context, (top) provides a comparison of the dynamic evolution of the required support expenditures in the period 2011 to 2030 for all RES-E (i.e. existing and new installations in the focal period). Note that these figures represent an average premium at EU 28 level, while significant differences may occur at the country-level, even in the case of harmonised support settings. Complementary to that, Figure 59 (bottom) shows yearly average support expenditures for new RES and RES-E installations in the period of 2021 to 2030.

When inspecting Figure 59 the yearly support expenditures it has to be kept in mind that absolute cost values are displayed in contrast to Figure 57 where differential costs (compared to the baseline) are displayed. From the lower part of Figure 59 it can be seen that new RES-E installations are responsible for the bulk of newly arising support expenditures.

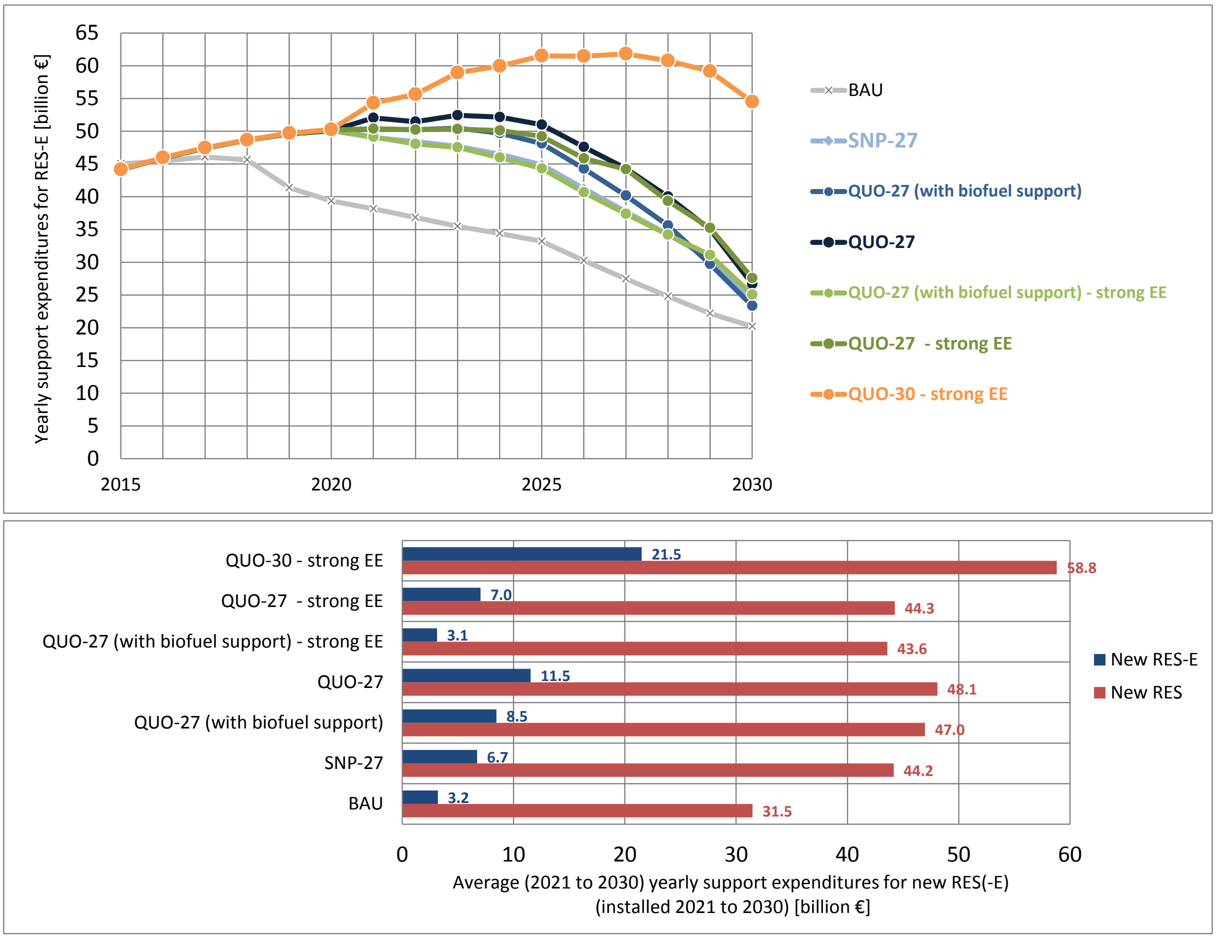

Figure 59: Comparison of the resulting yearly support expenditures over time (top) and on average (2021 to 2030) (bottom) for new RES-E and RES installations only (from 2021 to 2030) in the EU 28 for all assessed cases.

Figure 60 (left) shows the dynamic development of the necessary financial support per MWh of RES-E generation for new installations (on average) up to 2030 and, complementary to that, Figure 60 (right) expresses average values (for the forthcoming decade 2021 to 2030) per technology. The amount represents the average additional premium on top of the power price (normalised to a period of 15 years) for a new RES-E installation in a given year from an investor's viewpoint; whilst, from a consumer perspective, it indicates the additional expenditure per $MWh_{RES\text{-}E}$ required for a new RES-E plant compared with a conventional option (characterised by the power price).

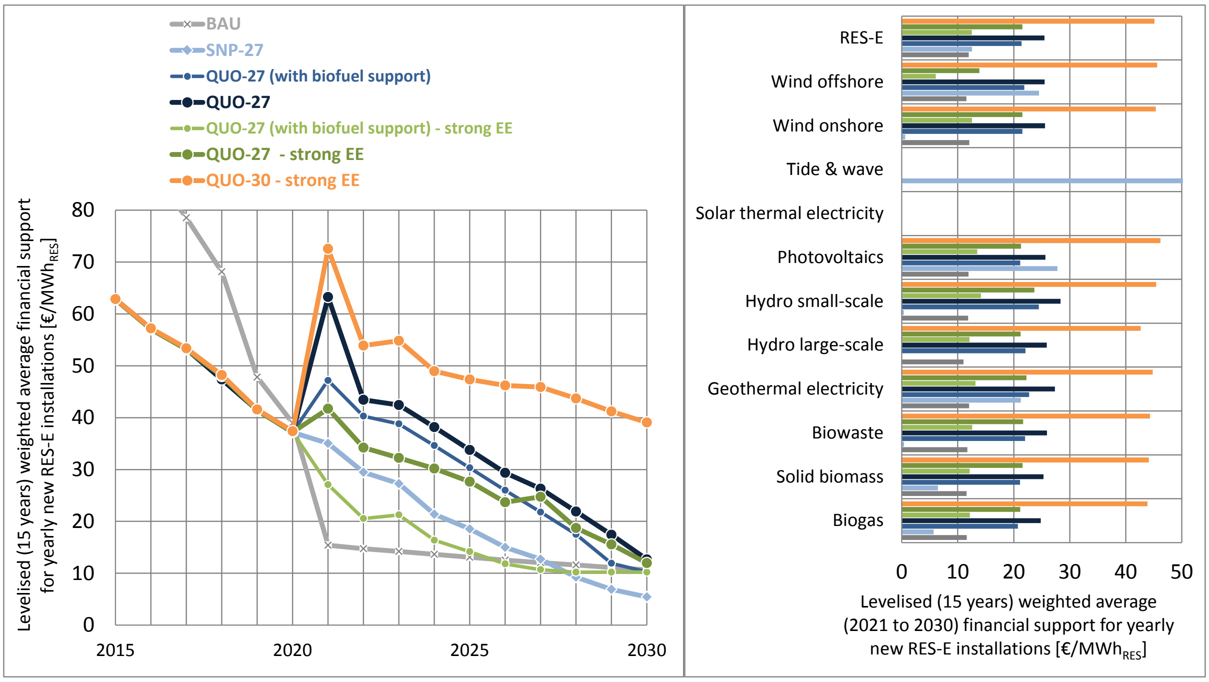

Figure 60: Comparison of financial support (premium to power price) for new RES-E installations at EU 28 level over time (2015 to 2030) (left) and on average (2021 to 2030) by technology (right)

In general, a decline of the required financial support per $MWh_{RES\text{-}E}$ is apparent, but differences between the policy variants can be observed. Generally, the average support is higher under a technology-neutral scheme compared to policy approaches that offer incentives tailored to the specific needs. The decrease of financial support appears most pronounced under baseline conditions: Under this scenario a phase-out of currently strong deployment incentives for RES-E is assumed in the period post 2020. This causes a sharp decline of the financial support for *yearly new* constructed RES-E installations while cumulative support expenditures decline moderately.

6.5 Recommendations

The impact of suggested measures

Improvements in RES policy design, complemented by a removal of non-economic barriers that hinder the uptake of RES can bring down policy costs significantly. This has been demonstrated by our related assessment of impressively.

A further key element for keeping RES-related policy costs at acceptable levels is financing. Our calculations based on the Green X model have shown that if all countries had the same renewable energy policy risk profile as the best in class, the EU Member States could reduce the policy costs for wind onshore by more than 15%.

Prospects for RES post 2020

The binding EU-wide RES target of achieving at least 27% as RES share in gross final energy demand as adopted recently by the Council has to be seen as an important first step in defining the framework for RES post 2020. Other steps, like a clear concept for and agreement on the effort sharing across Member States have to follow.

The agreed target of 27% RES appears feasible to achieve without strong efforts to be taken at EU and at country level. Even in the absence of additional energy efficiency measures alternative policy scenarios related to 27% RES by 2030 lead to moderate increases in system costs and support expenditures at EU-28 level compared to baseline conditions (where a phase-out of RES support beyond 2020 is presumed). A clear and guiding framework and a removal of currently prevailing non-economic barriers is however a key necessity to keep the cost burden low and to balance cost nicely with accompanying benefits.

More than 27% RES by 2030 appears feasible but requires additional efforts to be taken. The increase in renewables would regardless come along with increased benefits related to Europe’s trade balance due to a (significantly) decreased demand for fossil fuels and related imports from abroad.

7 Policy recommendations

Effective and economically efficient policy interventions are key to ensure that our targets for renewables are achieved. Effective policies are able to trigger investments in the targeted amount of renewables, while economically efficient policies ensure that this target is met at low cost.

Coordinated national interventions are more beneficial than a fragmented approach because the latter hinders cross-border cooperation. While there has been substantial convergence of national policies in recent years, numerous support schemes still differ from acknowledged best practices. This limits their effectiveness and efficiency and provides a sub-optimal balance between market compatibility and investment security. In general, to achieve convergence towards best practices, both top-down and bottom-up approaches can be taken, through the European Commission and by coordination among the member states, respectively.

Exchange on best practices on auction design will become more relevant in the next years. This will include the right balance between physical and financial prequalification criteria, the definition of auction schedules and the determination of reasonable penalty levels. In this respect, also guidance on LCOE calculation might be beneficial which is, for example, needed for the determination of ceiling prices in auctions and for plants and technologies where auctioning does not apply. In the heating sector building obligations in new buildings should be extended to existing buildings, which is not yet the case in most member states. These are examples of policy areas where stronger coordination could lead to substantial benefits. In some other fields the flexibility of member states regarding policy design seems more beneficial and should thus be preserved. This includes the question, whether support schemes should be technology-neutral or technology-specific. The answer to this question strongly depends on the technology portfolio of the individual member states and on the question whether different technologies have different system integration costs, which are exogenous to the support scheme.

Creating equal opportunities for all renewable energy developers in terms of non-economic framework conditions will also increase the efficiency of public interventions. To achieve this, regional authorities responsible for project authorisation and spatial planning could be supported through provisions of best practice guidelines or uniform standards across the EU. Furthermore, stricter time limits for permit approval should be agreed as risks associated to the project development process will be reflected in the expectations regarding the remuneration level.

Given the **cost structure of renewables**, with their high upfront and relatively low operational costs, the **cost of capital is a decisive factor for investment decisions** and therefore also for policy, because it determines the level of support that is needed to trigger deployment. Generally, the cost of capital is influenced by the perceived level of investment risk.

Weighted average cost of capital vary significantly across EU member states, e.g. from 3.5-4.5% in Germany to 12% in Greece in the case of onshore wind, as revealed in a survey based on over 80 interviews. The main cost drivers are policy design risk, regulatory intervention risk, grid access and the general country risk. **Governments can play an important role in mitigating risks, for instance by implementing long-term stable policy schemes that are less susceptible to regulatory interventions.** Likewise, improving the structure and quality of the public administrative system and providing financial risk-sharing can also help to reduce these risks. As member states show a great variety in regulatory frameworks supporting renewables, market maturity, availability of capital and government involvement each of the measures should be tailored to fit the needs of the individual member state and to mitigate risks efficiently and effectively. If policy-makers managed to lower the level of investment risk to the current best-in-class level, yearly support expenditures could be reduced significantly, i.e. by some 4.2% this decade, and by 15.6% in the next decade for the case of onshore wind. As a first important step to mitigate financing costs in the EU it will be crucial to implement a continuous monitoring of costs of capital in the EU member states. This will facilitate a better understanding of the main drivers of investment risk. Unproductive risks linked to RES policies should be avoided in any case. In particular the level of remuneration should be fixed in the moment of the investment decision, which is, for example, the case for auction-based contracts for difference CfDs. The next step could be to equalise cost of capital in EU member states through a risk sharing facility.

It is clear that renewables are becoming mainstream. Market integration is therefore essential to the economic efficiency of their deployment. Further market integration implies that renewable energy generators assume more responsibility when it comes to selling their electricity production. This is equivalent to a risk transfer and thus leads to higher financing costs for renewable energy projects. **To determine the cost-effective level of risk transferred to generators, it is essential to weigh the resulting increase in policy costs against potential benefits.** For example, it has been shown that CfDs contribute to market integration of renewable energies and serve as a risk hedging instrument at the same time. Best practice design criteria for CfDs, e.g. regarding periods for calculation of reference prices, should be promoted in order to facilitate fast institutional learning among EU member states.

At the same time, market integration of renewables can also be facilitated by more flexible power markets and systems that reflect the intermittent nature of renewables such as wind and solar. For instance, **there is empirical evidence that their market value is higher in power systems with more flexible generation assets and a stronger participation of consumers in balancing supply and demand.** Still, even for highly flexible power systems, **we expect that new renewables projects will need dedicated financial support in 2030.** This finding holds true for most technologies and can be observed throughout the EU. In order to increase market values of RES it is important to enable a quick phase-out of conventional must-run capacities, to pool flexibility reserves among EU member states and to promote the coupling between the electricity, heating and transport sectors.

Finally, an important task is to coordinate EU renewable policy with global market developments. Support levels should be aligned with technology cost reductions in order to avoid windfall profits. Yet this can be challenging in the case of unforeseen cost reductions, as experienced with solar in the past decade. **Rather than coordinating automatic tariff adjustment mechanisms between member states, which appears less feasible, governments could instead exchange information more frequently regarding deployment, installation costs and tariff levels.** Moreover, with the EU demand for biomass being increasingly met by imports, both from intra-EU and extra-EU sources, harmonised sustainability criteria are needed. Next to liquid biofuels in transport, this is crucial also for solid biomass used for electricity, heating and cooling.

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