ASSESSING RENEWABLES POLICY IN THE EU

Co-funded by the Intelligent Energy Europe Programme of the European Union

KEY FINDINGS FROM THE DIACORE PROJECT

BACKGROUND

The foundations for 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 target for EU member states of 20% renewables by 2020, which was broken down into legally binding national targets. National policy instruments have since been created 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 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 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 this 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 2020 targets.
- Prepare key findings and recommendations to facilitate convergence in renewable 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

MARKET INTEGRATION OF RENEWABLES 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 to a minimum.

THEME 4

COORDINATING POLICIES WITH GLOBAL MARKET DEVELOPMENTS, namely technological advancement, observes the interplay between national policies and global trends. We focus on two renewable technologies: biomass and solar PV. Biomass is increasingly imported and used for energy, so coordination is required to ensure sustainable deployment. For solar PV, coordination mechanisms and information exchanges of technology developments are discussed, particularly in relation to timely tariff regressions.

THEME 5

KEEPING POLICY COSTS 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 for renewables.

KEY FINDINGS

COORDINATING EFFORTS TO REACH THE 2020 TARGETS

POLICY CONTEXT

It is widely acknowledged that when member states cooperate and coordinate policies this increases the likelihood of meeting the 2020 targets and reducing associated costs (see SWD(2013) 440 final, EU staff working document). Since the Renewable Energy Directive (RED) breaks down the overall 20% target into legally binding national targets based on transparent indicators, the degree of coordination regarding the effort-sharing is high. Less coordination was foreseen regarding the practical implementation of these targets, however, for instance regarding how renewables are supported and how non-economic barriers could be addressed (see COM(2015) 293 final). These aspects have been the focus of the DiaCore project.

SUBSTANTIAL PROGRESS IN THE COORDINATION OF SUPPORT SCHEMES

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.

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

[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 and tariffs. That means the premium could become negative in case of high electricity market prices.

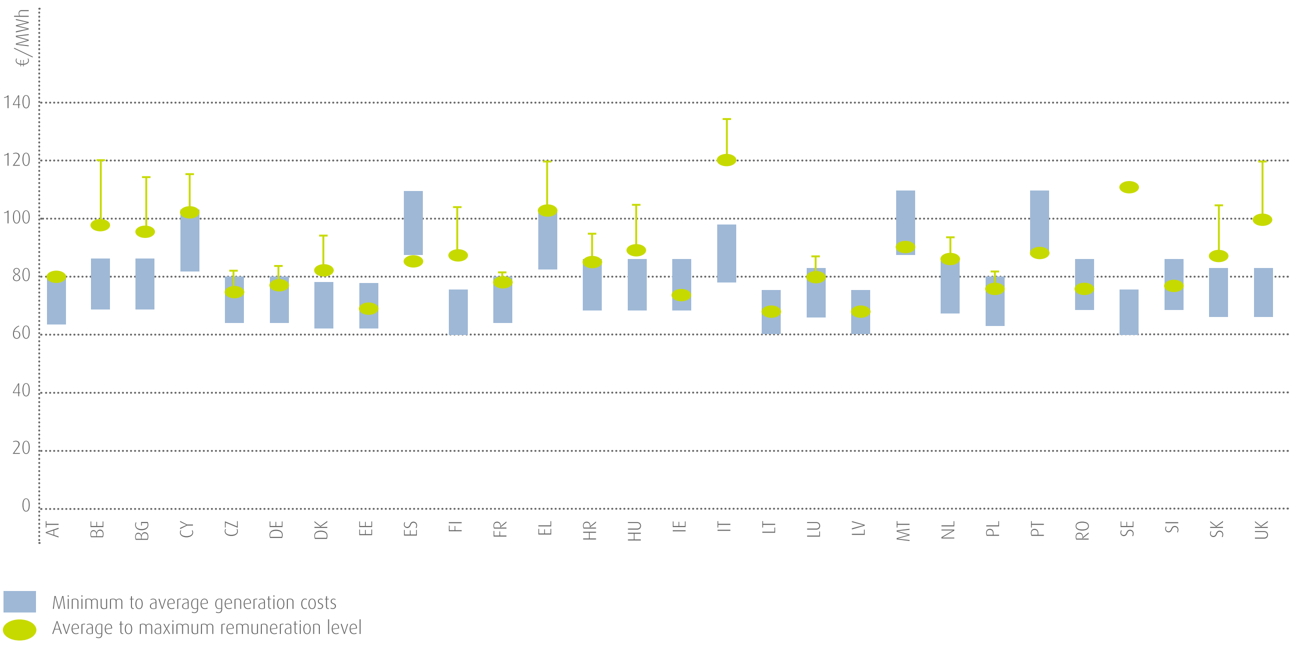
systems, while Poland and Sweden retained their technology-neutral quota. In general, there is a trend towards EU countries substituting quota obligations through alternative support schemes, such as feed-in premiums combined with competitive bidding procedures (Italy, Poland, and the UK).

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 are one cause for a fragmented market within Europe.** Creating an internal market implies overcoming this fragmentation, however, which in turn requires greater convergence on support scheme design.

Major differences also persist regarding remuneration levels. Figure 1 shows the range of remuneration levels and costs in small-scale decentralised heating systems, demonstrating a good correlation between costs and remuneration levels for most member states but pointing to a major mismatch for some countries. It also shows that additional coordination could be beneficial to reduce distortions between support schemes.

FIGURE 1:

Remuneration ranges (average to maximum remuneration) for decentralised biomass heating plants in the EU-28 in 2013 (average remuneration levels are indicative) compared to the long-term marginal generation costs (minimum to average costs)



Source: own formulation.

WE NEED TO SUPPORT THE DIFFUSION OF BEST PRACTICES REGARDING NON-ECONOMIC FRAMEWORK CONDITIONS

It is crucial to create a level playing field for renewable energy project developers at national as well as EU level by optimising non-economic framework conditions in all member states, especially since competitive tenders for renewables support are becoming prevalent in EU member states and in view of discussions about opening up national support schemes. **Distortion of competition can be avoided if policy-makers consider non-economic barriers and also promote best practices and uniform standards in this field**.

The results of an EU-wide, comprehensive stakeholder survey complemented by in-depth interviews with RE developers and investors in three EU member states (Germany, the UK and Spain) emphasise that **a stable and reliable policy framework and the diffusion of best practices, especially regarding administrative processes and spatial planning for renewables, play a major role in this respect**.

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.

WHICH WAY FORWARD?

How can this convergence towards best practice be achieved? Two distinct approaches appear in the European context:
i) upport 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). 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 the increase the accuracy of setting strike prices.
- 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 schemes occur 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

are used to finance renewables could be coordinated and perhaps even harmonised among member states.

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 (or keeping in check) investment risks.

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INTEGRATING RENEWABLES INTO MARKETS

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. In this context, quantifying the benefit of additional flexibility constitutes an important task.

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.

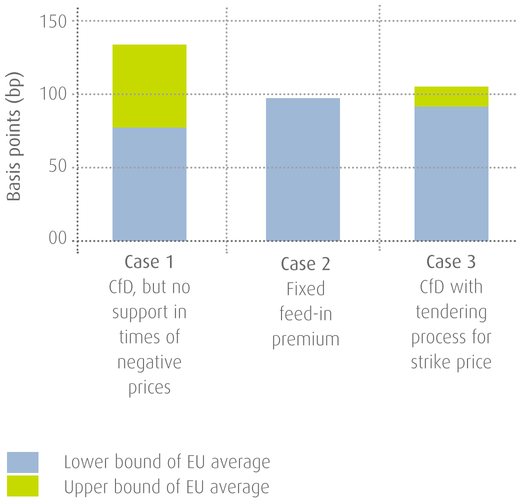
FINANCING COSTS UNDER VARYING DEGREES OF RISK EXPOSURE

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 2).

FIGURE 2:

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



Source: own formulation.

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

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 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.

A RACE BETWEEN GENERATION COSTS AND MARKET REVENUES

The level of required support for renewable energy generators ultimately depends on the gap between their generation costs (including risk premium) and the potential revenues they can earn from markets. Revenue streams are also subject to uncertainty. As discussed in the previous section, policy design determines the extent of uncertainty and thus the magnitude of the risk premium.

Yet, even if revenues were perfectly deterministic and risk premiums disappeared, market revenues would still not be sufficient in many cases to refinance new investments in renewable generation. The remaining gap has to be filled by financial support for RES, if we want to further increase the share of 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 of such an analysis are one of the key outcomes of the DiaCore project. The main finding is that under many assumed framework conditions new RES-E projects would still need financial support, even in 2030. This finding is true for many RES technologies and can be observed throughout the EU, in particular for the most promising RES technologies.

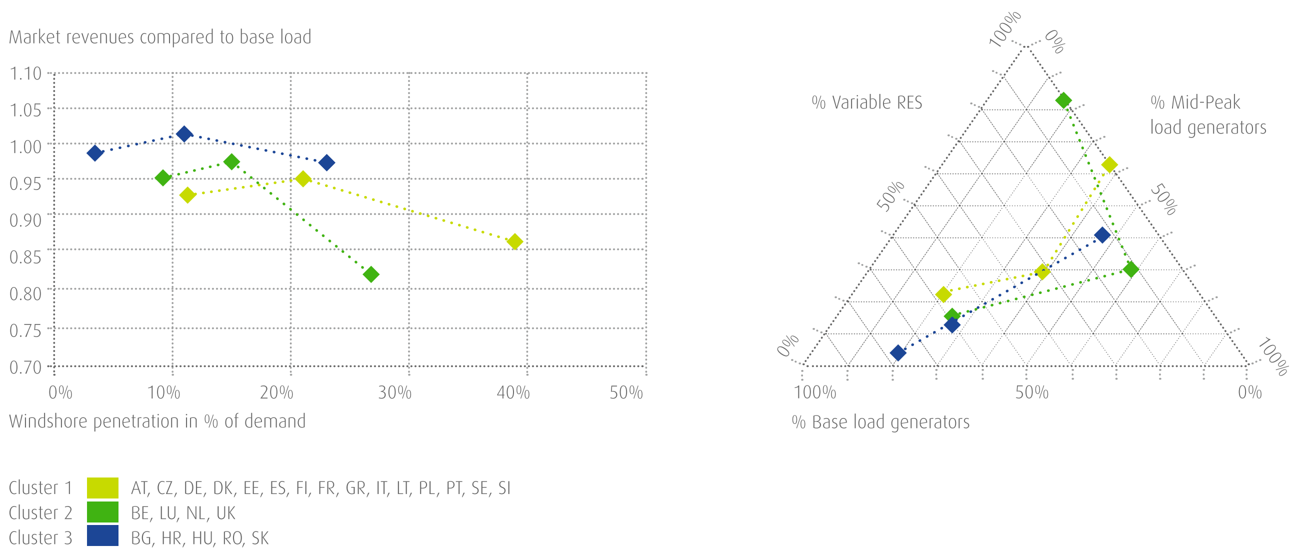
The ratio between potential market revenues of RES-E generators and the average market price drops considerably with the increasing penetration of renewables, especially for variable RES (vRES). This peculiarity can partly be explained by a special characteristic of variable RES generation, which is marketed (and thus valued) in energy-only electricity markets. The marginal value of its generated electricity decreases with increasing market penetration, because high-priced generation is substituted at higher infeed levels. Market prices are therefore 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 against dispatchable generation**, which materialises in the form of lower market revenues than revenues of the same amount of firmly generated electricity. **The magnitude of this effect decreases in more flexible power systems, however.**

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 3:

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.

Figure 3 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, 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**.

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FINANCING RENEWABLES AND RISK ALLOCATION

POLICY CONTEXT

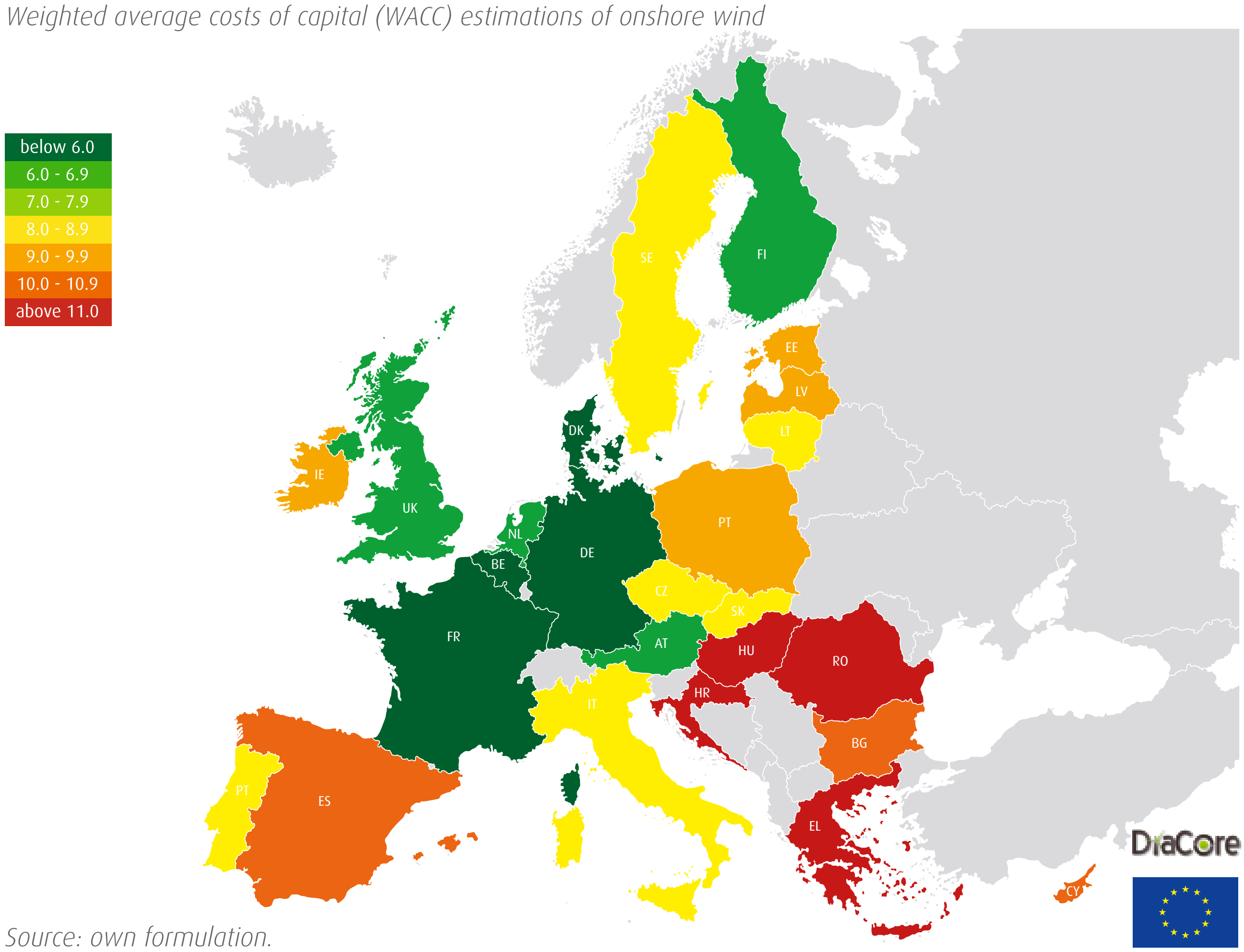
Unlike investment in conventional electricity generation, investments in RES such as wind and solar power require large upfront investment before the system becomes operational, but low working/operating capital. From an investor's perspective this means that the overall investment risks increase. To compensate, they will require a higher rate of return for their investments, leading to increased capital costs for investments.

It has been estimated that meeting the policy target of 20% renewables by 2020 will require total annual investments of €60-70 billion, which will have to come from investors, bankers and equity providers.

To lower the cost of capital, renewables policies are designed to create more certainty in project revenues and expenditures. If policies fail to address these uncertainties, the increased cost of capital might cause a decrease in the number of RES projects, as only highly profitable projects will be organised.

FIGURE 4:

Weighted average costs of capital (WACC) estimations of onshore wind



Source: own formulation.

This makes the cost of capital a decisive factor for RES investments and, subsequently, for meeting the EU target and reducing the cost to electricity consumers.

EU MEMBER STATES EXPOSED TO VARYING DEGREES OF INVESTMENT RISK

Within the DiaCore project we provide an estimation of the cost of capital for onshore wind energy projects across the EU. According to our findings, **the Weighted Average Cost of Capital (WACC) varied significantly in 2014 across EU member states – between 3.5% in Germany and 12% in Greece and Croatia for onshore wind projects** (see Figure 4).

When looking specifically at the cost of equity, which is the equity providers' remuneration for providing capital (opportunity costs and risks), significant differences are also observed in the EU. **The cost of equity for onshore wind projects in 2014 ranged between 6% (Germany) and more than 15% in Estonia, Greece, Latvia, Lithuania, Romania and Slovenia**. Besides the country risks, the cost of equity is often influenced by existing regulations and policies. In countries where renewable energy is not yet mainstream or subject to unexpected, sudden or even retrospective regulatory changes, the cost of equity is higher.

Moreover, the **cost of debt** (which is the remuneration for debt providers, i.e. banks, for making capital available) **varied between 1.8% in Germany and 12.6% in Greece in 2014**. According to investors, the main factors influencing the cost of debt are the general country risk, the specific renewable investment risks and demand for capital.

Overall, these results shed light on a growing gap among EU member states, where varying costs of capital can lead to significant cost differences in the development of similar renewable energy projects in member states.

The risk perception of investors can be influenced by several factors, such as policy design, sudden policy changes, permitting procedures, grid access etc. Within the project, specific risk categories were identified that impact wind onshore projects throughout their duration. **Across all EU member states, and among all the risk**

categories identified, the risk of policy design is perceived as the most pressing risk. This includes, among others, the choice of support scheme (feed-in tariff, feed-in premium, quota etc.); the level of support payment; guaranteed tariffs; compensation for demand; compensation in case of curtailment; price fluctuations, and how they will develop over the coming years.

Policies play a role in mitigating investment risks, leading to additional cost savings. Within this project, the magnitude of these savings has been estimated. The results are summarised under Theme 5, in the section on "improving financing conditions through optimised RES policy design".

The policy toolbox is available online at:
http://DiaCore.eu/component/content/article?id=17

METHODOLOGY

To gain insight into the cost of capital for renewables investments and to estimate the Weighted Average Cost of Capital (WACC) (Nominal post-tax, at financial closure), a theoretical model was constructed. In this model, an estimation of the cost of equity was made for onshore wind projects in each member state, based on the fluctuation of renewables industries' share values compared to average fluctuations in share values. Second, based on the modelled result of the cost of equity, the cost of debt, and the debt to equity ratio for onshore wind projects, the WACC was estimated for each member state.

To determine which risk categories are influencing the financing parameters, information on renewables investment risks was gathered on member state level. Based on reports, previous studies and databases an overview was created of the most significant risks for each member state.

The outcomes of the theoretical model were evaluated and tested during interviews with over 80 financial experts from 26 member states (No interviews could be conducted for Luxembourg and Malta). Based on these interviews, both the financing parameters and the ranking of the risks were adapted and used to draft risk profiles for each EU country.

We also analysed 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 the most relevant. During the interviews with financial experts, information was gathered on how policies could mitigate investment risks. Additionally, a questionnaire was made available to focus on the role of policy design: how can a change of support scheme influence financial parameters? The results were used to prepare a policy toolbox to support policy-makers in the member states in mitigating risks and lowering the cost of capital for onshore wind projects.

COORDINATING EU RENEWABLES POLICY WITH GLOBAL MARKET DEVELOPMENTS

POLICY CONTEXT

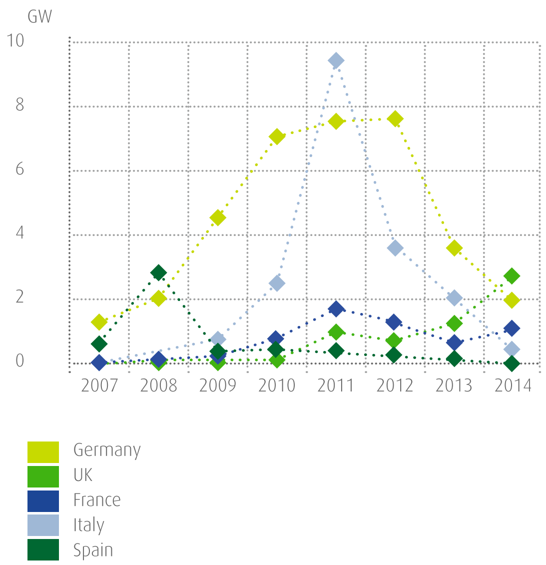
Technology and fuel demand created by EU renewables policies has global implications. As such, EU policies should be coordinated with global developments, such as technology cost reductions. This is shown for photovoltaic solar power (PV) and biomass policies.

COORDINATION MECHANISMS FOR CONCERTED PV DEVELOPMENT

In the past, EU member states pursued national PV policies. As Figure 5 shows, at times they experienced higher-than-expected installations due to the dynamics of the global PV market as well as generous provisions at the start of projects. **When acting individually, member states were slow to react to rapidly declining PV costs**. Feed-in tariffs (and increasingly feed-in premiums) are a widespread policy instrument in the EU to support PV generation. Yet, especially for large-scale installations, they pose the challenge of setting remuneration levels (strike prices) that are appropriately aligned with technological cost reductions.

FIGURE 5:

Annual PV deployment for largest EU markets



Source: own formulation.

NATIONAL PV POLICIES FREQUENTLY LEAD TO OUTLIERS WITH HIGHER-THAN-EXPECTED INSTALLATION VOLUMES

While Directive 2009/28/EC provides various cooperation mechanisms between EU member states (namely statistical transfers, joint projects and joint support schemes), the Directive states that "cooperation can also take the form of [...] exchanges of information and [...] other voluntary coordination between all types of support schemes".

There are several options to coordinate support for renewable energies across EU member states. One extreme is harmonised tariff adjustment mechanisms with equal remuneration levels across countries. However, such **harmonised tariffs do not seem to be a feasible option because of different national market conditions and information asymmetries**. Alternatively, governments can exchange information to coordinate support schemes, for instance to improve their tariff adjustment procedures. Such procedures are already often the norm, but are usually based on historical national data. **Countries could exchange different information more frequently and more detailed data, for instance about deployment, installation costs or prices, tariff levels, financing agreements, policy changes, tax frameworks, or administrative barriers**. Furthermore, joint projects and auctions are possible. This way, countries can finance projects together, or increase competition by allowing projects to take place in a larger geographical area.

GOVERNMENTS CAN EXCHANGE INFORMATION TO COORDINATE SUPPORT SCHEMES

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. Otherwise, such technology cost reductions could lead to undesired deployment peaks and windfall profits. Coordinated schemes have to take into account the global nature of PV module prices, where common European demand can have price-effects. As European demand as a whole has price-effects, the demand could be coordinated mutually. Simulation results show that if national adjustment procedures are coordinated this way, national and European deployment targets could be reached more easily. Yet this only holds as long as countries have similar response rates between deployment and profit margins. Empirically, this has not necessarily been the case (see Grau and Neuhoff 2015). With heterogeneous markets, national adjustment procedures should be based on national historical information. Thus, information on national deployment behaviour dictates remuneration-level adjustments. This finding is of particular interest because dependence on international information in many ways mimics 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.

Simulation results show that separate schemes remain more effective than coordinated mechanisms with regard to reaching national target corridors in the long term. However, there are two issues where coordinated support schemes might have specific positive effects in the event 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 the case of specific module or installation price shocks from an aggregate corridor perspective.

Coordination could also take the form of information exchange between countries in the process of calibrating national remuneration adjustment schemes. Such coordination might support countries with less of a track record in a specific technology to set appropriate tariff levels. In particular, information from countries that are rather similar in terms of economic environment and solar resource is relevant in this instance. Moreover, coordinated remuneration schemes may help to reduce incentives for strategic gaming. This can happen in small countries if incumbent companies or large projects withhold installations in order to increase prices.

Coordinating and harmonising general legislation has additional benefits, especially for smaller countries. Harmonised regulation is easier to evaluate and therefore more attractive for international investors. Countries with such policies can thus attract more investment from abroad.

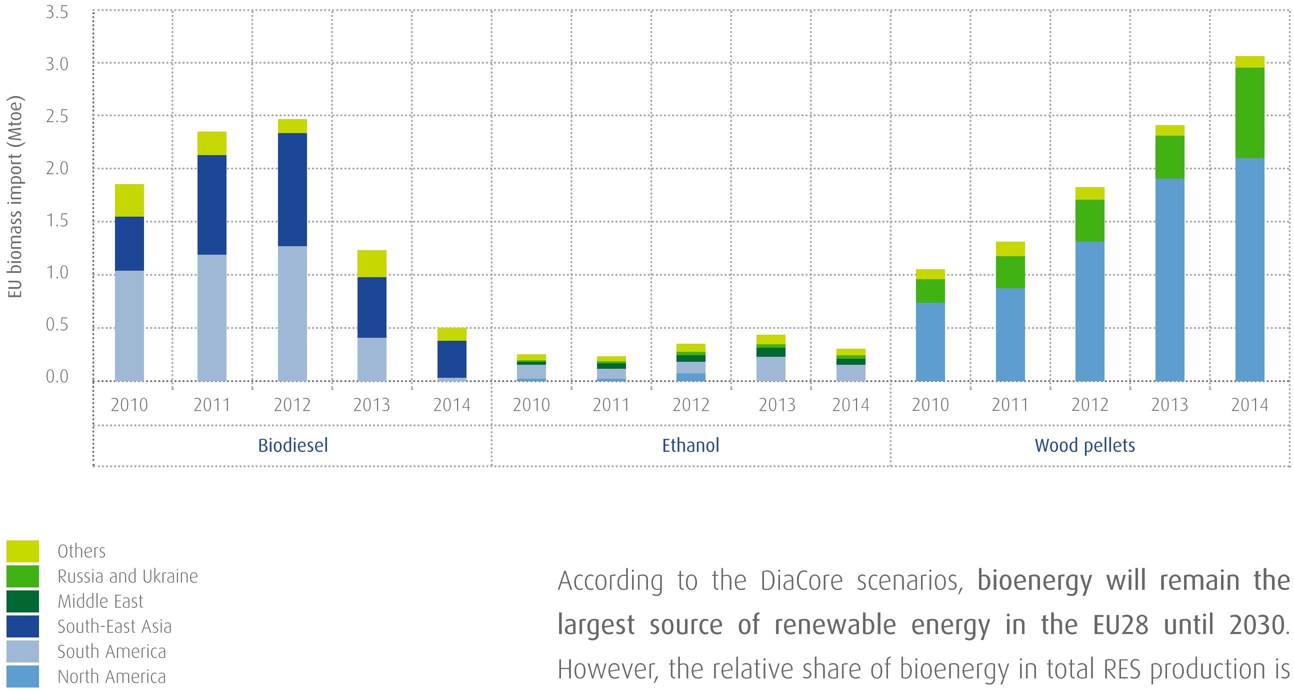
INTERPLAY OF EU BIOMASS POLICY WITH GLOBAL TRENDS

Today, biomass makes up 61% of renewable energy consumption in the EU28, with 89% of renewable heat and 18% of renewable electricity. It is therefore the largest source of renewable energy in the EU28. Gross inland consumption of renewable energy from biomass (incl. biowaste) more than doubled from 61 Mtoe in 2000 to 129 Mtoe in 2014. Before 2000, international trade in biomass for energy purposes was still very small. However, regional restrictions in economic supply of biomass sources have been increasingly overtaken by large-scale inter-regional trading of liquid and solid biofuels. In 2013, net imports of biomass were 4.9 Mtoe, 3.8% of gross inland consumption of biomass. Note that in the same year, the EU imported 903 Mtoe of solid fossil fuels, natural gas, petroleum and products, representing 73% of gross inland consumption of fossil fuels and making the EU the world largest importer of fossil fuels (see AEBIOM 2015). Compared to fossil fuels, renewable energy supply in the EU is thus still highly self-sufficient. Nevertheless, strategic and international coordination is required to ensure a sustainable and efficient deployment of biomass for bioenergy in the future.

Figure 6 shows the development of biodiesel, ethanol and wood pellet imports to the EU. Trade in biodiesel became significant after 2005 and was almost solely driven by the 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 imports to the EU in 2012. In 2013, effective anti-dumping measures against Indonesian and Argentinean biodiesel were taken, which reduced imports to the EU substantially. Similar measures were taken against ethanol imports from the US in 2014, which could previously be circumvented via indirect import to the EU via Norway. Wood pellet imports have increased due to growth in both the industrial and heating markets. Large-scale conversion of coal fired power plants in the UK, for example, increased wood pellet consumption to 3.5 Mt (1.4 Mtoe) in 2013, whereas in Italy wood pellet demand for residential heating increased to 3.3 Mt (1.3 Mtoe) in 2013.

FIGURE 6:

Annual EU imports of liquid biofuels (biodiesel, ethanol) and solid biomass (wood pellets),



Source: DiaCore report D5.3, Hoefnagels et al. (2015) and Keller (2016). "The Global Biofuel Trade - Outlook on 2016 biodiesel and bioethanol markets", presented at the 13th International Conference on Biofuels, Berlin, January 19, Ratzeburg, Germany.

According to the DiaCore scenarios, **bioenergy will remain the largest source of renewable energy in the EU28 until 2030**. However, the relative share of bioenergy in total RES production is projected to decline moderately from about 60% today to 51- 55% in 2030 as a result of growth in other renewable energy sources (mainly wind and PV). In terms of final energy, heat will remain bioenergy's largest contribution, providing over two-thirds of total final bioenergy supply by 2030 and well over one-third of total renewable energy generation in all scenarios. **Most biomass will still be produced from domestic sources, but the role of biomass trade and especially extra-EU trade is growing in importance** (see Hoefnagels et al. 2015). The total share of extra-EU solid biomass will increase up to 7% in 2020 and up to 13% in 2030.

Currently, extra-EU imports of wood pellets are mainly used for industrial purposes, including large- scale electricity generation and Combined Heat and Power (CHP), whereas pellet heating is mainly supplied from domestic resources or imported from neighbouring 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, and natural gas) and may become the main driver for increased trade of solid biomass. Furthermore, up to 15% of extra-EU solid biomass import is projected to be used for advanced biofuel production by 2030.

To ensure the sustainable use of biomass, both from domestic and imported sources, binding sustainability criteria have been set in the RED (Renewable Energy Directive) for liquid biofuels. These criteria do not apply to solid and liquid biofuels used for electricity, heating and cooling, however. Mandatory and voluntary sustainability criteria have therefore been implemented in different national support schemes in countries that import solid biomass for large-scale industrial uses, such as Belgium, Denmark, the Netherlands and the UK. But with increasing extra-EU imports of solid biofuels and the projected convergence of industrial and residential wood pellet markets, **the need for harmonised sustainability criteria and support schemes is growing, preferably at the EU level**.

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KEEPING POLICY COSTS FOR RENEWABLES AT AN ACCEPTABLE LEVEL

POLICY CONTEXT

The global financial crisis has shaken national economies across the EU, and tight state budgets still influence policy-making in various fields, including energy policy and the regulatory framework for renewables.

The spotlight has thus fallen on the financial support offered to renewable energies, commonly known as policy costs, which are being carefully observed and debated. It is essential to keep the costs of these policy interventions at acceptable levels, from a societal point of view. This will ensure 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 an ill.

This section aims to provide the quantitative underpinning for the abovementioned recommendations in the various themes, including the creation of a level playing field for all types of generators, financing conditions, renewables policy-making and the design of related support instruments.

GENERAL APPROACH

This analysis builds on modelling works undertaken by the use of TU Wien's Green-X model (see box, below). More precisely, the outcomes of a quantitative policy analysis of various scenarios[2] on future renewables deployment within the EU are used to indicate the impact of our suggested measures on related policy costs.

Short summary of the Green-X model

Green-X is an energy system model that offers a detailed representation of renewables potentials and related technologies in Europe and neighbouring countries. It aims to identify the consequences of renewables policy choices in a real-world energy policy context. The model simulates technology-specific renewables deployment by country on a yearly basis, in the time span up to 2050,[3] taking into account the impact of dedicated support schemes and 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 in-depth analysis of future RES deployment and corresponding costs, expenditures and benefits arising from the preconditioned policy choices at country, sector and technology level.

For specific purposes, such as 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 Green-X model.

THE QUANTITATIVE IMPACT OF SUGGESTED MEASURES

➔ 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 barriers mitigated — *Strengthened national (RES) policies (in accordance with 2020 and 2030 RES targets), non-economic RES barriers mitigated*

SNP barriers prevail — *Strengthened national (RES) policies (in accordance with 2020 and 2030 RES targets), non-economic RES barriers prevail*

In this subsection we show and describe the quantitative impact of various changes in renewables policy design and in related framework conditions, specifically concerning non-economic barriers that hinder the uptake of renewables. These changes are indicated by two scenarios (see Figure 7 and Figure 8) that will be compared to a business-as-usual (BAU) scenario.[4]

- 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 renewables ES 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 cross-border 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, in addition to the strengthened national policies, non-economic barriers are mitigated, which will facilitate the deployment of renewables.

[2] Note that the specific scenarios used are introduced into the individual exercises to illustrate the impacts of proposed measures.

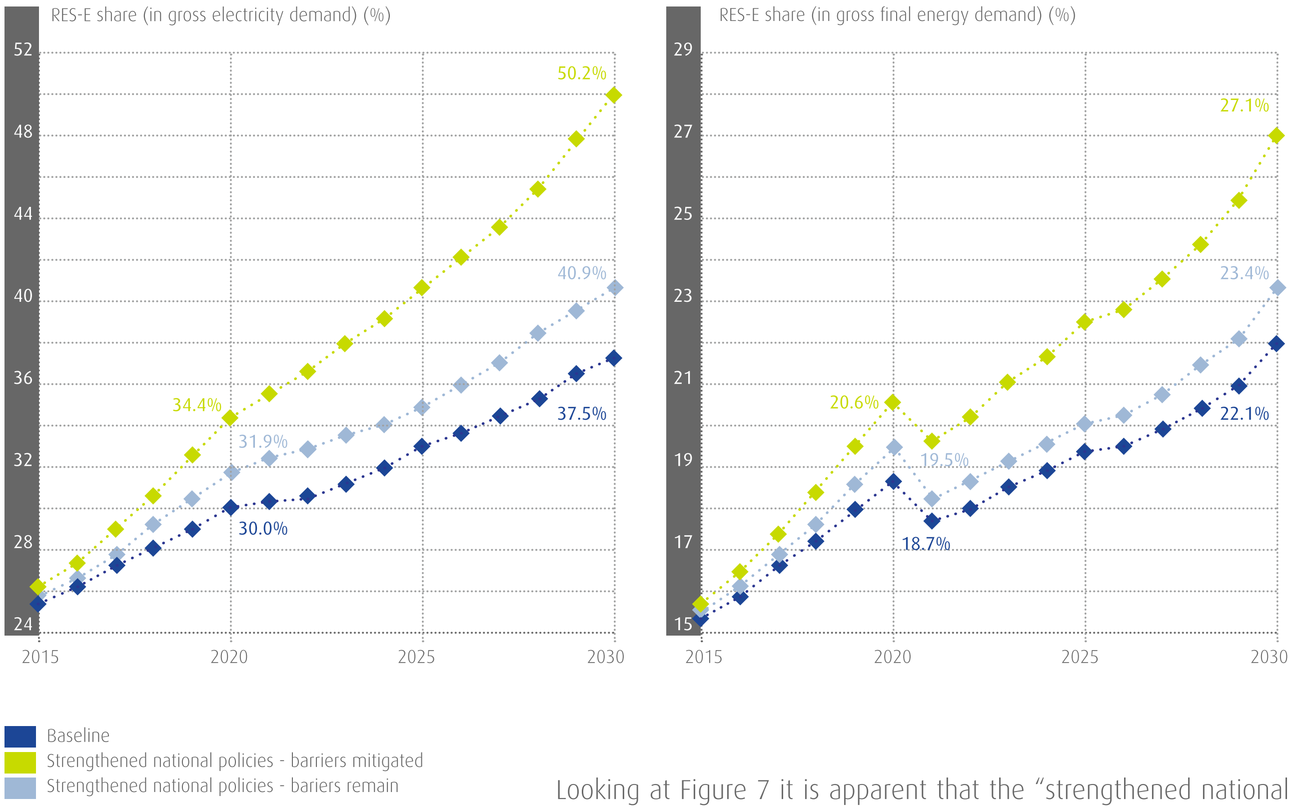
[3] For this exercise model calculations are limited to the period up to 2030.

[4] The business-as-usual (BAU) scenario reflects the currently implemented RES policy framework for the period up to 2020, and a phase-out of support post 2020. More precisely, in the case of biofuels an immediate phase-out of support is assumed to take place directly by 2021, whereas for RES electricity and RES in heating and cooling, first a significant reduction of support levels is assumed (by 2021), followed by a gradual phase-out in follow up years. Moreover, in that scenario non-economic barriers that limit the uptake of RES technologies in various countries are assumed to prevail.

Common to all assessed cases is the assumption that dedicated support for biofuels in transport will be phased out post 2020, including a removal of blending obligations, for example. This has a strong negative impact on biofuel deployment in the years after 2020 in particular, and also overall RES share is affected significantly (cf. Figure 7 (right)). This explains the decline in Figure 7 (right), where the overall RES share drops by about 1 percentage point from 2020 to 2021 in all assessed scenarios.

FIGURE 7:

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)



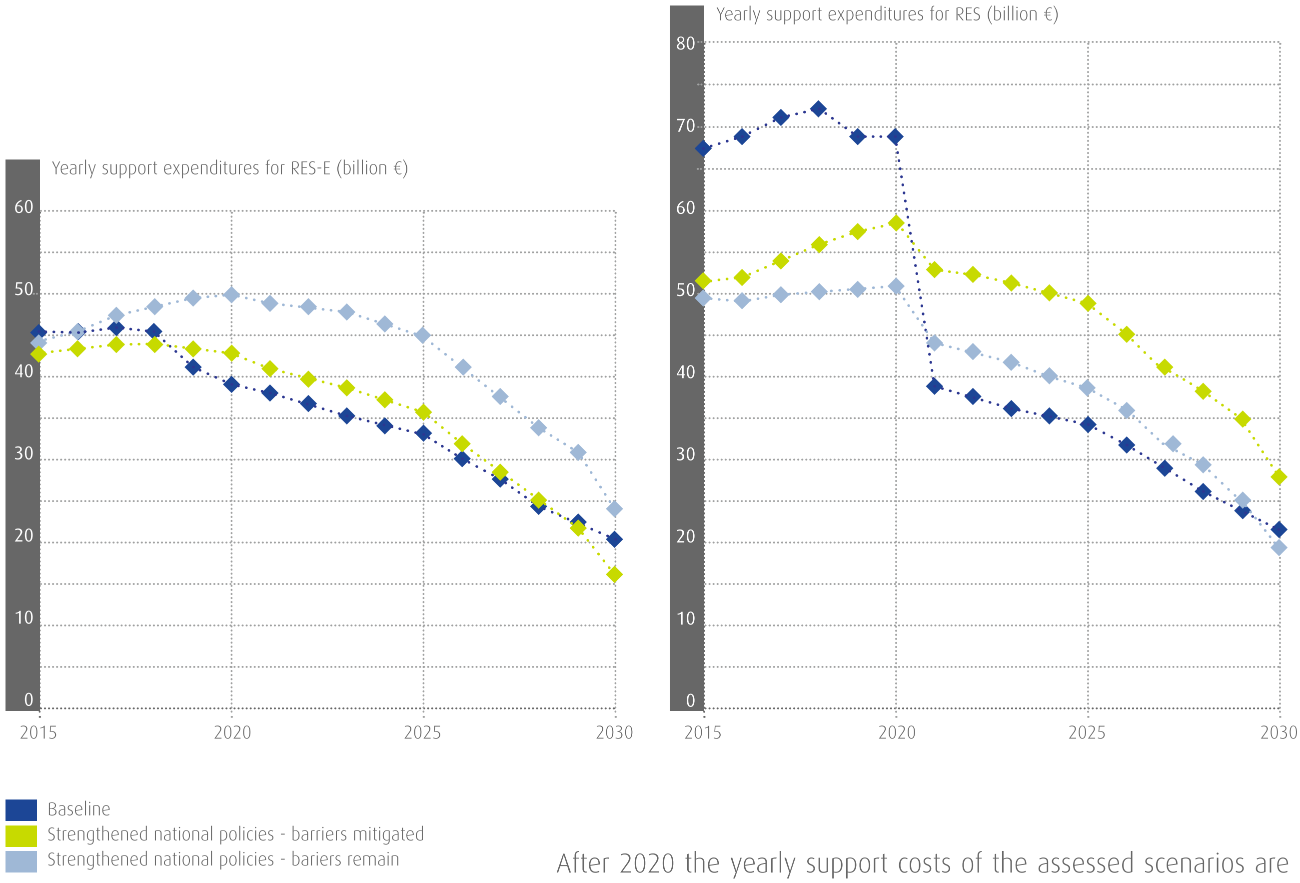
Source: own formulation.

Looking at Figure 7 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 8 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**.

FIGURE 8:

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)



Source: own formulation.

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.

→ 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. Theme 3, "Financing renewables"). The assessment of the impact of improving financing conditions builds on four different scenarios, 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 1. 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.

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, EU member states could reduce the policy costs for wind onshore by more than 15%**.

TABLE 1:

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%			8.3%	5.9%		
	(Unit)			Change to WACC real	%*			Change to WACC real	%*
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 expeditures 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)*

Source: Green-X modelling.

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KEY FINDINGS

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 coordination between member states respectively.

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 uniformed standards across the EU. Furthermore, stricter time limits for permit approval should be agreed.

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.

Capital costs 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, 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 liable 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 great variety in regulatory frameworks supporting renewables, market** maturity, availability of capital, government involvement, each of the measures should be tailored to fit the needs of an individual member state and 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.

It is clear that renewables are becoming mainstream. Market integration is therefore essential to their economic efficiency. 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.

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.

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 is less feasible, governments could instead exchange information more frequently regarding deployment, installation costs and tariff levels. Moreover, with 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 also crucial for solid biomass used for electricity, heating and cooling.

BRIEF OVERVIEW OF DIACORE

PARTNERS

Fraunhofer Institute for Systems and Innovations Research ISI
www.isi.fraunhofer.de

Technische Universität Wien, Energy Economics Group (EEG)
www.eeg.tuwien.ac.at

Ecofys Netherlands bv
www.ecofys.com

eclareon GmbH
www.eclareon.com

National Technical University of Athens (NTUA)
www.epu.ntua.gr

CEPS
www.ceps.eu

Lithuanian Energy Institute (LEI)
www.lei.lt

DIW Berlin
www.diw.de

Universiteit Utrecht
www.uu.nl

Axpo Austria GmbH
www.axpo.com

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PROJECT COORDINATOR

Mario Ragwitz (Fraunhofer ISI)

PROJECT TEAM

Anne Held, Barbara Breitschopf, Inga Boie, Simone Steinhilber (Fraunhofer ISI)

Gustav Resch, Marijke Welisch, Christoph Zehetner, André Ortner, Sebastian Busch, Lukas Liebmann, Gerhard Totschnig (EEG)

Paul Noothout, David de Jager, Lucie Tesnière, Sascha van Rooijen, Nikolaos Karypidis, Luis Janeiro, Malte Gephart, Fabian Wigand (Ecofys)

Robert Brückmann, Filip Jirous (eclareon)

John Psarras, Haris Doukas, Dimitrios Angelopoulos (NTUA)

Fabio Genoese, Arno Behrens, Anna Dimitrova, Monica Alessi, Eleanor Drabik (CEPS)

Inga Konstantinaviciute, Viktorija Bobinaite, Vaclovas Miskinis, Dalius Tarvydas (LEI)

Thilo Grau, Karsten Neuhoff, Nils May (DIW)

Ric Hoefnagels, Martin Junginger (UU)

Roman Stütz, Sylvia Steinbäcker (Axpo)

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