D16 Report:

Towards triple-A policies: More renewable energy at lower cost

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RE-Shaping
Shaping an effective and efficient
European renewable energy market

The core objective of the RE-Shaping project is to assist Member State governments in preparing for the implementation of Directive 2009/28/EC and to guide a European policy for RES in the mid- to long term. The past and present success of policies for renewable energies will be evaluated and recommendations derived to improve future RES support schemes.

The core content of this collaborative research activity comprises:

- Developing a comprehensive policy background for RES support instruments.
- Providing the European Commission and Member States with scientifically based and statistically robust indicators to measure the success of currently implemented RES policies.
- Proposing innovative financing schemes for lower costs and better capital availability in RES financing.
- Initiation of National Policy Processes which attempt to stimulate debate and offer key stakeholders a meeting place to set and implement RES targets as well as options to improve the national policies fostering RES market penetration.
- Assessing options to coordinate or even gradually harmonize national RES policy approaches.

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Table of Contents

Abstract

Support policy cost for renewable electricity projects can be reduced by about 10% or €4billion/year in the EU and up to 50% for specific Member States/technologies while improving the investment climate for project developers and investors and thus enhancing the growth of renewable energy (RE) deployment considerably. This can be achieved if Member States consider the risk (perception) of project developers, investors and lenders more strongly and establish RE policies that deserve the attribute investment-grade or triple-A. This report presents the most important policy options to do so and quantifies their potential effect. It argues that policy makers should decide specifically per Member-State and technology which risks are better born by projects and which by the public and suggests indicators to base decisions on. It also presents the current status of RE financing in the EU.

Past research used in the European Commission evaluations of Member State support schemes revealed huge differences in Member State performance regarding policy effectiveness (realised growth) and efficiency (support paid compared to generation cost). High support, for example, did not always result in high growth. The results from this report can help explain these differences and give guidance on how to improve both effectiveness and efficiency of RE policies.

RE-Shaping

Summary

Towards triple-A policies: More renewable energy at lower cost

Credit ratings – with triple-A being the best achievable – are discussed controversially these days. As the concept of such ratings is now known to a broader audience, this report uses it as a – hopefully helpful - analogy in discussing the relation of risk and renewable energy policies.

A country receiving a triple-A rating is considered very creditworthy: Lenders will be eager to lend money to that country at comparably low interest rates because they have a high certainty that their loan will be paid back. Likewise many investors prefer such politically, legally and economically stable countries and will, due to the lower risk, accept moderate returns for their investment in these countries. A country paying attention to its creditworthiness will thus benefit from low cost for loans and increased attractiveness for foreign investments.

The same goes for the renewable energy (RE) sector. Before committing monies, investors and lenders make an assessment of the risks: The risks related to the technology involved, the risk in that country in general, and in particular the risks and features of the country's RE policy. The lower an RE project's risk profile, the more likely banks will be to lend to the project and the lower are investors' required returns on equity. An effective and cost-efficient RE policy is risk-conscious and does not introduce unnecessary policy-related risks. In analogy to credit ratings such a policy could be called a triple-A RE policy, and it would have comparable positive effects as a triple-A rating for creditworthiness: Low cost for loans and equity would reduce the cost of RE projects and the required financial support from governments or consumers, while more investments into RE projects can be attracted and more RE projects can be realised. A country establishing triple-A RE policies will experience more RE growth at lower specific generation cost. Lower generation cost can be translated almost 1:1 to lower required support policy cost for technologies that have a cost gap with conventional technologies which is currently covered by support policies. Without triple-A RE policies countries will pay a higher price to increase their RE share and/or may fail to reach their RE targets. Governments are thus recommended to consider risk carefully when designing RE policies.

Policy cost savings up to €4 billion per year in the EU and up to 50% in individual Member States

In order to reach the 2020 RE targets in all Member States set by the EU RE Directive, annual investments in the EU have to double comparing 2008/2009 to the decade 2011-20. Modelling for the European Commission shows that, through 'pro-active risk mitigation', €4bn annual support policy cost can be saved on average in the period until 2020 (€37bn instead of €41bn for all RES, about 10% of support cost) (Ecofys 2010).

Risk-conscious, triple-A or *investment-grade* policies (Hamilton 2009) are also essential to attract the increasing amounts of equity and loans needed. There is potential for institutional investors like pension funds to provide investments on a significant scale. However, most institutional investors are risk averse and prefer triple-A investments. Triple-A policies are imperative to enable small and medium enterprises independent of utilities, which do not have the creditworthiness and balance

sheet of large utilities and whose project financing is especially hit by the credit crisis, to continue to play their positive role in developing and innovating RE.

Some design details of triple-A policies have been analysed and the impact has been quantified in literature (Lüthi & Wüstenhagen 2010; Giebel 2011; de Jager & Rathmann 2008). This project compiled and analysed the key policy options needed towards triple-A RE policies based on literature, interviews with lenders, equity investors, project developers and project financing experts and the policy expertise within the RE-SHAPING project team: 20 policy options are described that each can reduce (levelized electricity production) cost by 2-20% or more. Implementing several options in parallel may reduce support policy cost by up to 50%[1] (including reduction of windfall profits) or enable growth to start in the first place in low-RE-growth Member States. The huge observed differences between Member States in financing cost affected by RE policies are in a comparable order of magnitude as the currently observed large spreads between government bonds in the EU. In best-practice countries many policy options are already implemented and remaining improvement potentials are smaller. In Member States with low growth and low support levels some options may need to be implemented to enable increased growth - a reduction of support levels in parallel is in that case only recommended if, overall, the investment attractiveness is still increased. The potential cost savings and growth effects of individual policy options are presented in table 1 and figure 1 below. Table 1 shows the potential reduction of average electricity production cost (*Levelized cost saving potential*) per policy option and its relevance to increase capacity growth by removing non-financial barriers or risks that often are *show-stoppers* (*Removing growth constraint* – right column).

Triple-A policies reduce cost of capital, investment cost, operational cost and increase revenues

The policy options presented in the table below positively affect cost of capital (debt/equity – here indicated as WACC+, see chapter 4.1 for details), investment cost (CAPEX), and operational cost (OPEX) and partly increase revenues from power sales (POWER) or support (SUPPORT). In order to fully grasp the effect of triple-A policies all these cost categories have to be considered and an approach considering only the effect on weighted average cost of capital is insufficient. This becomes clear in the explanation of policy option's effects in chapter 4.

[1] 50% corresponds to the order of magnitude of observed support levels exceeding generation cost (including default cost of capital) in some Member States for some technologies, as analyzed in [Held et al. 2010] and [Steinhilber et al. 2011].

Table 1 Triple-A policy options and their potential impact on cost reduction and growth

Legend

Symbol	Levelized cost saving potential:	Removing growth constraint:
■■■■	= up to 10% and more	= Strong effect
■■■	= up to 6%	= Medium effect
■■	= up to 4%	= Small effect
■	= up to 2%	

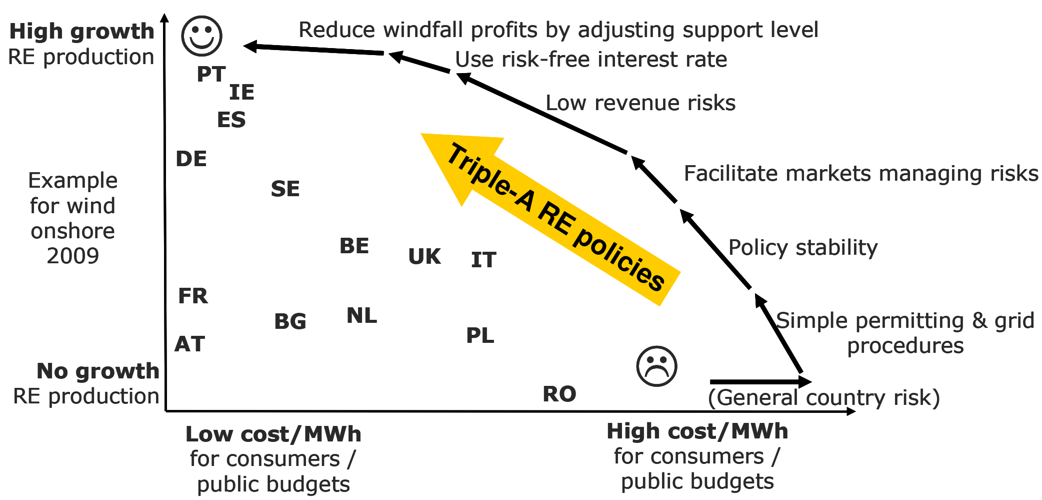
	Levelized cost saving potential: Cost			Reve-nue			Removing growth constraint
	WACC+	CAPEX	OPEX	POWER	SUPPORT	SUM	
INCREASING POLICY STABILITY							
1 No retro-active policy changes for existing projects	■■■■				□□□□	>20%	■■■■
2 No abrupt policy changes for upcoming projects		■■■■			□□□□	>10%	■■■■
3 Simple & transparent permitting & grid access procedures		■■■■				>10%	■■■■
4 No budget/capacity caps & continual access to support		■■■■				>10%	■■■■
APPLYING POLICY STABILIZERS							
5 Support financed off-budget via consumer surcharge	■	■				3%	
6 (Temporary) government participation	■■■					5%	
7 Loan guarantees	■■■					5%	■■
8 EU enforcement RE directive implementation & Member State support level coordination							
REDUCING REVENUE RISKS							
9 Quota: Long time-horizon & serious penalties	■■■■				□□	>10%	■■■
10 Quota: Price floor applied	■■				□□	7%	
11 Feed-in premium instead of quota system with TGC [1] incl. higher margins in quota system for technology suppliers and PPA counterparty)	■■	■■■■ [1]	■■		□□□□ [1]	>10%	
12 Feed-in tariff instead of feed-in premium [2] lower values in case of sliding feed-in premiums	■■ [2]	■	■	□□		8%*	
13 Priority in case of grid congestion, priority dispatch + Compensation for forced curtailment	■■ ■			□□ □	□□ □	10% +4%	■■■
14 Compensation for annual variability wind/solar	■					2%	
USING RISK-FREE INTEREST RATE							
15 Front-loading the support payment stream	■■■					6%	
16 Soft loan	■■■					6%	
FACILITATING RISK ASSESSMENT & INSURANCE							
17 Availability of standardized risk assessment tools and ratings	■■	■				4%	
18 Availability of insurances for risks that are so far not insurable	■					2%	■■■
MISCELLANEOUS							
19 TSO responsible for wind offshore grid connection	■	■				2%	

Source: Ecofys, own illustration

Results can explain observed differences in RE support effectiveness and efficiency

Past research used in the European Commission evaluations of Member State support schemes has shown that the amount of financial support a reference RE project (same technology, size and site quality) receives (and may require to be economically viable) differs hugely among EU Member States. These differences remain even if one corrects for issues like conventional electricity prices, grid connection cost and balancing cost. It also showed that high support does not always lead to high growth. These indicator-based results are summarized in the simplified figure below (see Steinhilber 2011 for details) and the results from this report can help explain these results: Differences between Member States in terms of RE production growth and cost to consumer per production may be explained by risk-related policy differences (mainly ‘Policy stability’ including permitting and grid procedures, ‘Low revenue risk’, ‘Using risk-free interest rate’ and ‘Facilitate markets managing risk’ shown as arrows in figure below and as categories in table above) and non-risk related policy differences summarized in the paragraph below (e.g. ‘Reducing windfall profits by adjusting support levels’). Obviously, part of the observed differences between Member States can also be explained by differences in the general country risk due to currency, legal stability and other non-RE-policy specific aspects (horizontal arrow).

Figure 1 Observed policy effectiveness and efficiency and potential Triple-A policy effect



Source: Ecofys, own illustration based on [Held et al. 2010]

Report focuses on risk-conscious RE policy improvements – More options exist to close the cost gap with conventional technologies

Some RE technologies at good locations are currently competitive with conventional technologies without support. For other RE technologies and less optimal locations currently a cost gap exists compared to conventional technologies. If RE technologies are to be applied this cost gap needs to be bridged by some kind of financial support mechanism introduced via RE policies. The support cost for these policies have to be covered by consumers, either directly via energy prices or via taxes in case support relies on government budgets. This report focuses on options to improve RE policies and particularly financial support mechanisms in such a way that the cost gap and related

support cost per energy output can be reduced while increasing the RE growth (Number 1 in list below). Keeping support cost low is important to maintain public acceptance for RE support.

Besides the policy improvements discussed in this report there are more ways to reduce the cost gap which should be part of the wider policy package (Number 2-6 in list below), but which are only briefly addressed in chapter 5 of this report for the sake of completeness:

1) Apply risk-conscious *triple-A* RE policies -> more investment certainty, less subsidy needed
2) Fully internalizing external cost and reducing (hidden) subsidies to conventional technologies (Policy failure in this respect is one justification for applying RE support schemes)
3) Reduce RE cost via R&D and mass deployment leading to technological learning
4) Adjust the financial support level to the RE generation cost in order to avoid windfall profits
5) Use of least-cost technologies and sites via flexible mechanisms in the RE Directive
6) Potential benefits of increased availability and liquidity of financial products and insurances in a further harmonized & larger market

The cost gap of RE compared to conventional technologies can be closed or massively reduced by including externalities and applying risk-conscious *triple-A* RE policies, making RE the economically most attractive options. Policies are needed to realise this.

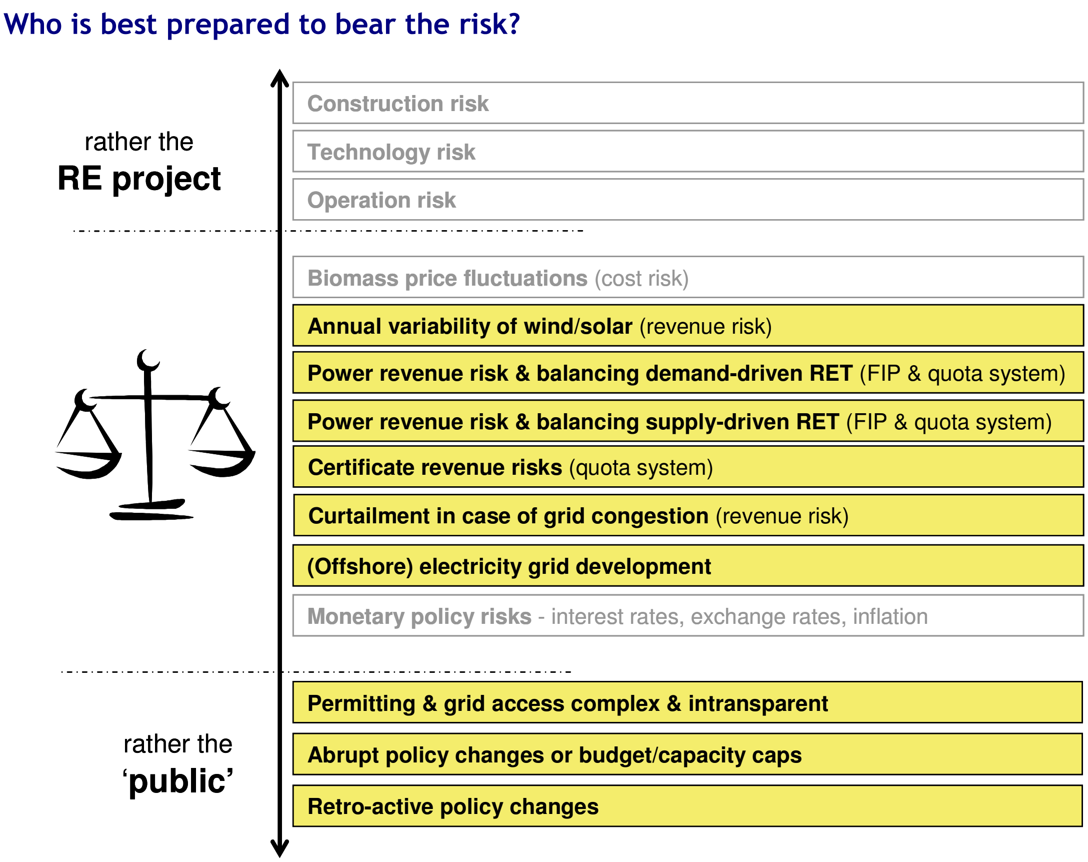
What is the macro-economically optimal allocation and treatment of risk?

Most of the triple-A policy options shown in table 1 above remove or reduce some kind of RE project (development) risk. This applies to the yellow-boxed risks in the figure below. Some risks can be reduced, in some cases the management of risks can be facilitated, and other risks cannot be reduced but merely be removed to other parties, e.g. away from the project to the public or a third party under government regulation. In the latter case the question arises which party is best prepared to bear the risk and can do so at macro-economically least cost. Answering this requires two steps:

1) Recognise that different parties have different options to mitigate risks at different cost and with different societal cost and benefits. Ideally risks have a positive effect (='productive risks'): Triggering developers, projects or the third party bearing the risk to adapt to the risk and deliver a better product. For some risks the positive effect of the risk, if born by developers and projects, is very low compared to the cost increase (='unproductive risks'), and the public or a regulated third party might be better prepared to bear the risk, leading to a better macro-economic result.
2) Recognise that one policy does not fit all: Macro-economically optimal allocation and treatment of risk will differ between countries and technologies based on
    a) Technology-specific risks and development status of that technology
    b) Country-specific deployment status of that technology
    c) Country-specific electricity market design and structure
    d) Envisaged project size and investor type

Chapter 3 discusses this in more detail and presents indicators that may be used for technology- and Member State-specific decision-making.

Figure 2 Risk allocation between RE project and 'public'



Source: Ecofys, own illustration

While the pros and cons of market revenue risk exposure are ambiguous (and therefore discussed in more detail in chapter 3), the picture tends to be clearer for the other risks shown: The policy and regulatory risks are generally risks that do not trigger any cost-optimized behaviour on the RE project side, but can be effectively reduced by governments at no or very low costs. The technology and project risk should not be fully burdened on the public, because they are generally better understood by the RE project (developers) than by the public sector.

How to read this report

This report is not necessarily to be read from A to Z. Chapters can be read rather independently of each other. The first three chapters give the context for the triple-A policy options presented in chapter 4, to which the experienced reader may also jump directly.

The **summary** above gives an introduction to the report and presents the key results and policy recommendations.

Chapter 1 introduces the basics of RE project development, financing and risk a reader unfamiliar to the subject might need for understanding the following core parts of the report.

Chapter 2 presents the current trends in RE financing in the EU regarding investment and financing volumes, financing structures and financial conditions applied.

Chapter 3 discusses which risks may give macro-economically positive incentives and which not, and whether rather the RE project or the public is better prepared to bear it.

Chapter 4 presents the key policy options that constitute triple-A policies and describes and quantifies their impact.

Chapter 5 gives an overview over all policy options to reduce the cost gap between RE and conventional technologies (not just the risk-related ones described in chapter 4) which should be part of the wider policy package.

A glossary is provided in **Annex 1.**

Annex 2 summarizes the effect of policy elements in a feed-in system on financing costs as analyzed by Giebel and Breitschopf 2011 based on conjoint analysis.

1 Basics of renewable energy project development, financing and risk

This chapter introduces the basics of RE project development, financing and risk. For readers unfamiliar to the subject this might be helpful for understanding the following core chapters of the report. Experienced readers could start directly with one of the following chapters.

1.1 Introduction

Increasing the share of renewable energy (RE) at the lowest possible cost are two of the key objectives of RE policies. The costs of RE depend on several factors such as the choice of technology, the quality of the site and infrastructure, fuel prices and financing costs. The policy framework affects to a large extent the energy market conditions under which RE power generators have to operate. Thus, RE policies and their specific design elements could contribute to shifting or minimizing typical RE-related risks and, hence, reduce financing costs.

Financing costs for RE investments are determined to greater or lesser extent by several financing variables. Wiser and Kahn (1996), Kahn (1995), Wiser and Pickle (1997) and later de Jager and Rathmann (2008) investigated in their papers the impact of financing terms on project cost and the role of policy design on financing investments in RE. The key financing variables they looked at and that significantly determine project cost are:

- Debt-Equity Ratio: refers to the mix of equity and debt that is used to finance a project and describes the capital structure.
- Return on Equity: represents an expected return on investment of equity investors.
- Loan Interest Rate: EURIBOR (In € countries) plus %-points to cover costs and risks of a loan.
- Debt Service Coverage Ratio (DSCR): the relation between available cash and total yearly debt service (annual income to annual debt service).
- Debt amortization: refers to the time period within which the loan (principal and interest) will be repaid.
- Debt/loan maturity: refers to the length of a loan, the time when the loan is due and is replaced with new borrowings.

Project cost increase in line with higher equity ratios, the expected return on equity and the submitted debt interest rate, while the impact of loan maturity is positive i.e. project cost decrease with increased loan repayment period. An increase in the minimum DSCR decreases the amount of debt in the optimal capital structure and hence leads to a rise in project cost.

A convenient measure for financing costs is the weighted average cost of capital (WACC) that is based on debt interest rate, return on equity and the debt-equity ratio (and corporate tax). Risks

affect financing costs directly through the cost of debt and equity and indirectly through the debt-equity ratio and the loan maturity and amortization scheme. .

Risk and RE policies do not only affect financing cost, they may also affect investment cost (including project development cost), operational cost and the revenues from power markets and support. When analyzing the policy options that constitute triple-A policies in chapter 5, all these cost categories will be considered.

1.2 RE investments and the rise of project finance

RE investments are financed by two sources: Either through debts in form of (unsecured) bonds and secured loans from a bank or through equity which is based on sales of equity-like shares in capital venture funds or stocks. Grants from sponsors (governments, NPO) are in this context considered as equity-like.

Regarding the financing type, investors and companies such as utilities finance their projects either “on balance sheet” or “off balance sheet”. The first refers to companies that raise money through their treasury departments either from internal resources (sale of stocks or shares) or from external resources in form of debt from public markets (bonds) or banks (loans). These financial transactions are reflected in the balance sheet of the corporation either as increase in liabilities (loans, bonds) or as increase (or change) in equity (shareholders). Utilities with a good rating and, hence, low borrowing costs prefer RE investments financed on balance sheet (UNEP 2009). Since loans are (low-risk) senior debts and mostly secured by collaterals, their borrowing costs are lower than the costs of equity where the expected returns on equity have to cover also potential risks.

Off balance sheet finance refers to project finance where equity investors buy shares of a project that is typically constructed as a special purpose company with limited liability. Debt investors (loans from banks or bonds from private capital) lend money based on the project’s cash flow and the project assets and are not based on the creditworthiness of the company, developing agent or investor. Lenders, especially banks, bear a smaller risk than equity providers whose capital is subordinated to loans and not secured by collaterals.

In the 1930s in the US, the concept of project finance came up in context with commercial oil exploitation and lack of financial resources (Pollio 1998). Banks developed a production loan relying solely on the project’s anticipated cash flow. The loan was secured by the cash generating potential of the project’s resources and by title to the reserves in case of default. Although the petroleum and natural resource industries have been leading in project finance, a large number of project financing takes place among projects in the area of power and other private infrastructure projects (Pollio 1998). The total value of the global project financing volume hit a record (321 billion USD) in 2008 and decreased only by 9 percentage points in 2009 (Dealogic 2010). In 2009, the energy sector attracted more project finance than any other sector and the debt share of total project financing volume was 81% while equity funding ranged around 19% (Megginson 2010).

A definition of project finance is given in Megginson (2010): “the creation of a legally independent project company financed with equity from one or more sponsoring firms and non recourse debt for the purpose of investing in a capital asset.” Yescombe (2002) describes it as a type of structured finance with the following general characteristics: Project finance is leant to a new, separate entity, which is legally and economically self-contained. Debt usually comprises 70-90% of the financ-

ing volume, which is comparatively higher than other types of financing. The remainder of the financing comes from equity investors with no or limited guarantees. Future project cash flow, the project lifetime, and the entity's contracts, licenses, and ownership are the main considerations in these types of loans. Project finance places more importance on legal agreements, which reduce the risk of project's costs and income. Key agreements usually include those that address the main income streams. Further descriptions emphasis project finance as a risk management instrument reducing a potential negative impact on the balance sheet (Pollio 1998).

A project structured under project finance is normally registered as an independent entity, known as a Special Purpose Vehicle or Company or Entity (SPV or SPC or SPE). The equity investors can choose to invest via shares in the project developing company or directly via shares in the SPC. Institutional investors such as pension funds have tended to invest in project developers, but now increasingly invest in SPC directly. The lenders provide loans directly to the SPC.

The main difference between project and corporate finance is the focus on the project's expected return (cash flow) versus the focus on the creditworthiness of the corporation. However, the evaluation of a project's soundness implies comprehensive documentation and screening of agreements and contracts, evaluation management, engineers, technologies applied requiring a high level of time input and due diligence for project financing rendering financing costs expensive (LBBW 2009, REFOCUS 2001, Pollio 1998, Megginson 2010, renewable energy focus 2008, Wiser et al. 1998).

Although corporate loans usually display better loan terms, require simpler procedures and result in quicker approvals than project finance, in many cases project finance is preferred for a number of reasons. The high debt/equity ratio common in project finance can allow a company to gain a greater return on a smaller investment and afford greater tax benefits. The debt is kept off from a company's balance sheet and corporate credit line. Project financing may be used for longer financing terms or to take advantage of the buyer's credit rating. A company's credit rating is not affected by negative project outcomes. The project may simply be too large for one company, and project finance allows multiple partners to invest in the project. And finally, it enables small partners to hold a more equal share since the required equity volume is rather low.

The main characteristics, strengths and disadvantages of project finance are depicted in the table below.

Table 1-1 Main characteristics and strengths of project finance

	Project financing	Corporate financing
Characteristics		
Debtor	• SPC, not sponsors, • Open for non utility generators, increasingly used by utility generators	• Sponsors (owner of SPC), • Mainly utility generators
Lender	mainly large banks	banks, public market (e.g. bonds)
Sponsors	>= 1 (risk sharing)	= 1
Basis for loan repayment	cash-flow	• creditworthiness • corporate balance sheet and profit
Loan securities	• charge over revenues and assets (stocks, resources, etc), • charge of sponsors share	

	in SPC, • assignment of leases, insurances, purchasing agreements, contracts, • step in rights to appoint contractors	
Effect on balance sheet	none	• debt-equity ratio, • costs/loss in case of default
Project failure	• limited to sponsor's share, • limited to collaterals	unlimited for (parent) corporation
Documents	• general contractor, • sub contractor, • agreements for all income streams (power purchase agreements, subsidies, tax credit, green certificates) • supply agreements	annual report of corporation (balance sheet, cash flow, P&L)

	Project financing	**Corporate financing**
Strengths and disadvantages		
Loan size	large	Small
Maximizing financial (debt) leverage	yes	no
Shifting/sharing or transfer of risks	yes	no
Impact of management effort on likelihood of favorable outcome	positive	low impact
Transaction cost due to documentation, due diligence (e.g. strong purchase commitments), handling time	high	low
Number of simultaneously pursued projects	>= 1	= 1
Financing terms: Debt cost: • fee (for work prior to financial closure) • spread for risks Debt-equity ratio	 high yes yes (100-200bp) high	 low no no low
Compensation of low domestic financial development	yes	no

Source: own composition based upon diverse sources (LBBW 2009, REFOCUS 2001, Pollio 1998, Megginson 2010, renewable energy focus 2008, Wiser et al. 1998)

A special type of loan in project financing is the "non-recourse loan" where the loan is secured by collaterals (real property, equipment, machinery, etc.) but for which the SPC or the equity holders

are not personally liable. In case of credit default, the lender's recovery is limited to the collateral. The lender has to bear the difference between the collateral value and the outstanding loan obligation. Thus, non-recourse debt is typically limited (50% to 60% loan-to-value ratios). In contrast, in case the shareholders of the SPC are liable for the loan - or the difference between the collateral value and the loan obligations - it is referred to as recourse loan.

The share of balance sheet financing in RE investments is decreasing over the last years (as can be seen in Figure 2-5 in chapter 2). It can be assumed that the importance of project finance in the EU will increase, given the amount of future investments needed in RE and the credit rating of utilities starting to be affected negatively by unbundling (separation from grids), increased security standards and concerns regarding nuclear power and increasing share of RE in portfolios.

1.3 Project development stages and associated risks

The main question in this subchapter is: What are the key risks associated with RE projects that affect (financing) costs negatively? To approach that question, we look first at the risks occurring over the life time of a project and, second, at the type of risks.

Risks are commonly categorized according to the stage in the project where they are most prominent. Therefore, some studies consider only a subset of project stages. Analyses from the project developer's perspective concentrate mainly on the initial stages: prefeasibility, feasibility and development (van Zuijlen, 2010). Risk assessments such as Beidleman (1990), UNEP (2006), de Jager (2008) focus on four categories: development, construction, operation, and sometimes decommissioning. Here, we rely on project stages according to IFC (1998) REFOCUS (2005/7/8), REFOCUS (2001/9) and LBBW (2009). They focus on three stages that are characterized by different risks, loan exposure and capital needs (IFC 1998):

- Planning period: the project developer has to secure the technical, institutional, administrative and financial feasibility and assess potential project risks. The risk exposure for investors and lenders is still low but increasing in line with the planning progress and drawing of capital. This phase might take a few months till several years depending on the RE technologies, administrative procedures and project size. Important risks are related to obtaining permit of construction and grid access.
- Construction period: the project developer draws down the majority of the loan or investments to finance construction activities, equipment purchase, and other pre-operating costs. This phase might last several years, depending on the RE technology and project size, bottlenecks in schedules and budget, equipment supply and technical (construction) performance.
- Operation period: at the start-up of the project the risk and loan exposure is the highest since technology is tested, inputs ordered, final payments and initial working capital requirements are due. During full operation risk exposure might decline in line with the repayment of loans, the production (functioning of technology) and the sales of outputs. Main risks are input and output uncertainties, price fluctuations, technology, operation and maintenance problems.

Prior to investing, screening and assessment of the project risks (due diligence) takes place. Normally, due diligence is undertaken during the planning phase. For this, information on prices, costs, markets, contracts, arrangements to secure project success etc. is gathered. Besides the typical project risks, lenders and equity investors also screen the project developers' characteristics (structure, reputation, experience), the main technology suppliers' proficiency as well as the industry characteristics (Dinica 2006). When the financial closure is due or pending, all potential risks are screened, shifted to or shared with other market participants and the remaining risks are directly translated into capital costs. Hence, risk costs will be included in project costs. The risk screening and assessment process itself can be considered as a risk mitigation measure whose costs incur at the first project phase and augment total financing costs (REFOCUS 2001/9). To illustrate the extent of due diligence, the activities and required information for financial closure (and risk assessment) during the planning period are listed from the perspective of a financial institution in the table below.

Table 1-2 Evaluation activities prior to financial closure of a project

Financial plan: review of the financial plan, type and share of equity, liability, security arrangements and financing conditions
Long term cash-flow: checking of indicated revenues and expenditures, comparison with figures from contracts and other sources
Cost benefit analysis: checking of calculation and figures
Screening of technologies and engineering input: study on technical feasibility
Market analysis for output: analysis of past and future market development, market structures, expected prices, potential purchasers, required supply and purchase contracts, potential impacts of policies on market demand
Policy: evaluation of past, present and future promotion schemes, evaluation of implementation of policies and reliability and long term policy setting regarding the investment
Contracts for input supply, services and purchase agreements: checking of contracts regarding legal correctness and enforcement potential, screening of creditworthiness and proficiency of technology suppliers and buyers, checking of cost/prices and quality of inputs, equipments, services
Legal requirements (fulfillment) for construction: clarification of administrative requirements, rights, regulations and the feasibility of fulfillment
Project structure: checking of the project set up, management, project structure, the institutional feasibility, legal correctness and the creditworthiness, reputation, experience of actors involved in the project, time table
Human capital: verification of competences and experience of management and staff (CV)
Evaluation of the institutional set up, the regulations as well as the characteristics of the industry

Source: IFC 1998, LBBW 2009, own supplements

Regarding the type of risks, several classifications and distinction can be found in literature. Typical risk from the perspective of a debt or equity provider are country and financial risks, policy and regulatory risks, technical and project specific risks as well as market risk (UNEP et al. 2009). The first type of risk is a rather broad term and covers i) economic risks such as inflation, local regulation, ii) financial risks such as interest rates, refinancing, iii) currency risks, iiii) security risks. Policy and regulatory risks include risks such as political stability and durability, maturity of the legal system, transparency of business, changes of RE support policies, regulatory risks like permits, authorizations and licences. Technical and project specific risks refer to construction risks, technological, environmental, operation and management risks. Finally, market risks are topics covered by market specialists focusing on prices, new competitors and sales aspects.

Enzenberger et al (2003) classifies project risks into three main categories: technical risks commercial risks and other risks such as country, regulatory, social acceptance risks and force majeure. While technical risks comprise all uncertainties with respect to the physical assets like construction, technology and reserve risks, commercial risks refer to all business activities related to the project. These include supply risks, operation risks, demand risks and financial risks. These all have an impact on the availability or costs of capital. Martinot (2000) identifies from a bank's perspective new technologies, new contractual mechanisms and institutional development and technology acceptance as non-traditional project risks of RES project. Further, with respect to the nature of the input sources supply uncertainties due to intermittent sources (wind, solar radiation) or quality standards for biomass represent also a typical risk. Especially, the regulation of prices, demand or production in RES electricity generation leads to a large dependence on policies and turns up as policy change risk.

Our approach to identify diverse risk types in RES project is based on the identification of the key drivers that affect the key parameter of a RE investment, namely the cash-flow over the project's life time. Strongly related to the cash-flow is the expected profitability of a project. Hence, lenders and investors in project financing view risks with respect to threats to the project's cash-flow. To identify the special risks of RES projects we extend the classification of Enzensberger et al (2003) and try to determine key factors that have a significant impact on the cash flow of an RE investment, or better, on the revenue and expenditure flows of an RE investment. Since these are future revenues and expenditures whose actual occurrence is unsure, they reflect expectations.

The **expected revenue** flow depends on the power price, market sales and performance of power generation:

- Output price: power prices depend primarily on the supply of and demand for power. Uncertainties on prices occur due to unforeseen changes or shocks in demand and supply. However, the extent and probability of change depends on the availability of substitutes, the existence of purchase contracts, policies with respect to regulation, taxes, subsidies and tariffs (feed-in tariffs) as well as on expectations on future development. Overall, the uncertainty of generation plant operators with respect to market prices is called price risk.
- Quantity of sales: the amount of power a generation plant sells at the market depends primarily on supply of and demand for power. However, purchase agreements or diverse support systems i.e., quota system with tradable green certificates, RE generation limits, priority feed in for RE, etc. reduce more or less the uncertainty about the sales quantity. The uncertainty regarding the quantity of power sales is referred to as demand risk.

- Output performance: the actual quantity of power generated depends first of all on the availability of intermittent sources, fuels and other inputs, the natural environment and the technology performance. The availability includes quality aspects, quantity aspects as well as timing. Although forecasts, empirical values and technological experiences exist, the probability of occurrence of an envisaged future power output is smaller than one. This uncertainty on output performance is called performance risk.

The **expected expenditure** flow – the counterpart/complement factor of the expected revenues - depends on costs (prices) and availability of inputs, on contractual and financing aspects and includes:

- Input cost: capital costs and expenditures for operation (depending on input prices) accrue during the planning, construction and operation periods. To avoid unforeseen cost increases due to price rises (unforeseen expenditures) supply or service contracts are applied to reduce price risks of services and other inputs. Policies that require certain quality standards might at first glance increase costs due to higher input prices but in the long run keep cost low due to good technical performance. The unexpected changes in costs due to price changes are called price (cost) risk.
- Input availability: the replacement of inputs that are not available in time, in required quantity or quality cause additional costs. Major factors contribute to unexpected changes: during the planning and construction phase the performance of the project planning and engineering body, during the operation phase the performance of suppliers and service providers as well as the force majeure. Therefore, highly experienced key players or staff, corresponding management structures, high reliability and quality of technology are required to keep input bottlenecks low. Technological / quality requirements specified in policies might ensure on the one hand a good performance but on the other hand it could be the reason for delays in supply of inputs and increasing expenditures. The availability of inputs affecting overall performance of the RE investments is referred to as performance risk.
- Contracting aspects: although subcontracting of technology providers and suppliers as well as purchasing agreements represent instruments to reduce or shift market, price and performance risks, they pose a further risk, namely the contractual risk. It could cause an increase in expenditures in case of breach of contract or in case of intensive contracting and enforcement of transactions.
- Financing terms: in case of variable or short-term or foreign exchange rate contracts and undue security/collateral requirements financing cost could increase expenditures unexpectedly. However, the financing arrangements are risk mitigation measures from the perspective of a lender and just pose a financing risk for the equity investor.

For an efficient and effective policy promotion, policy measures are necessary that avoid an increase in uncertainty about future cash-flows and which shift or mitigate price and demand risks. However, the introduction of RE policies to promote the RE deployment at low costs conceals, in turn, further threads or uncertainties in terms of uncertainty about stability, consistency and reliability of political regimes. Consistent regulations not prohibiting authorizations, permits or licences to operate as well as clarity over development or changes of regulations are crucial, too. Therefore, we have to analyze what the impact of policies on RE investment is, namely which risks (market,

price and performance) are reduced or avoided by RE policies and which (new) policy risks are induced or enforced by RE policies.

1.4 Types of cost caused by risk

Although risk exposure starts with the beginning of a project, then accrue up to the operational start and ends with the decommissioning of the installation, costs related to risks incur already at the very beginning of the project. This is because risks are evaluated and mitigation measures such as risk sharing are ensured before the financial closure. Therefore, risk related costs encompass three types of costs:

1. increase in financing costs (weighted average capital cost (WACC)) measured as the difference between the capital cost of a risk-free and a risky project[2] (risk margin,), plus
2. risk assessment (ASS) costs of debt and equity investors or project developer that accrue in the first project phase (e.g. due diligence) and hence either augment investment costs or expenditures (as fee or margin), plus
3. risk shifting/mitigation costs (MIT) arising from fees for insurances, transactions cost of agreements or subcontracts, which accrue over the project's lifetime. They are aimed at reducing risks by sharing or shifting them to other players in the field that either have better knowledge, influence, risk pooling or incentives for good performance.

Note that ASS will in most cases be one order of magnitude lower than WACC or MIT. Risk cost and hence financing cost increase when price, demand, performance, contractual or financing risks increase.

An investment is mainly assessed by balancing the expected revenues and expenditures. The minimum acceptable expected return sets the limit for the economic market potential of renewable electricity. The actual value of the expected return depends on the project's risks that enter as probability of default the project's expected return. In addition, the expected return depends also on the (expected) expenditures for risk sharing and mitigation.

[2] The riskiness of a project or rather the risk margin includes not only price, demand and performance risks but also country specific risks that are reflected in the credit default swap rates, in financing and contractual (legal, enforcement) aspects as well.

2 Status and trends of RE financing in the EU

This chapter presents the current trends in RE financing in the EU regarding investment and financing volumes, financing structures and financial conditions applied. This may be a useful background for the report's core topic - risk-conscious RE policies and their effect on support policy cost - discussed in chapter 3 and 4.

2.1 Global RE investments

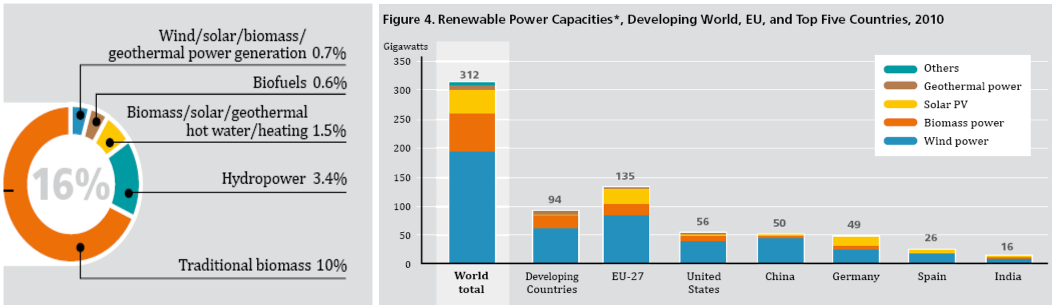
RE is undergoing a period of significant growth, which is likely to continue. Concerns of both energy security and global warming have fuelled interest in how to accelerate this growth. As of early 201, at least 118 countries had RE targets in place (Al Jaber et al. 2011) including all 27 EU countries. Many countries have decided on targets for power generation, typically a share between 5-30%, and significantly higher in countries with an historically high share of hydropower. Further targets are shares regarding total primary or final energy supply or installed capacities of certain technologies. The EU-27 has committed to provide 20% of final energy consumption by RE in 2020 (EU Directive 2009/28/EC). This represents a doubling of the RE generation from 2008 (Eurostat 2010). Japan, Australia, South Korea have targets aiming for 2020 or beyond.

Besides targets, many countries– at least 96 countries – have policies that promote RE power generation. The most common support instrument is the feed-in system that is in force in about 61 countries and 26 states/provinces. The policy has induced innovation and increased investments in RE (Al Jaber et al. 2011).

In 2004, of all new power generation capacity added to the grid worldwide only 10% was from RE. In 2009, that portion had increased to 36% (McCrone et al. 2011). In total over 312 GW of RE power generation capacities (without large scale hydro power) are globally installed. Wind power contributes about 200 GW to total capacity while the share of biomass and small scale hydro power ranges between 60 and 70 GW, respectively. China has the largest share in wind power (45 GW in 2010) the US are second (40 GW in 2010). Germany holds the largest share in solar power capacity (44%) in 2010, followed by Spain (10%). Together, China, US, Germany, Spain and India make up around 65% of the current renewable electricity capacity in the world.

In 2009 about 16% of global final energy consumption was supplied by RE (Al Jaber et al. 2011) whereas the traditional use of biomass contributed by far the most to the RE share in final energy consumption followed by hydropower – without traditional biomass use the global RE share were around 6%.

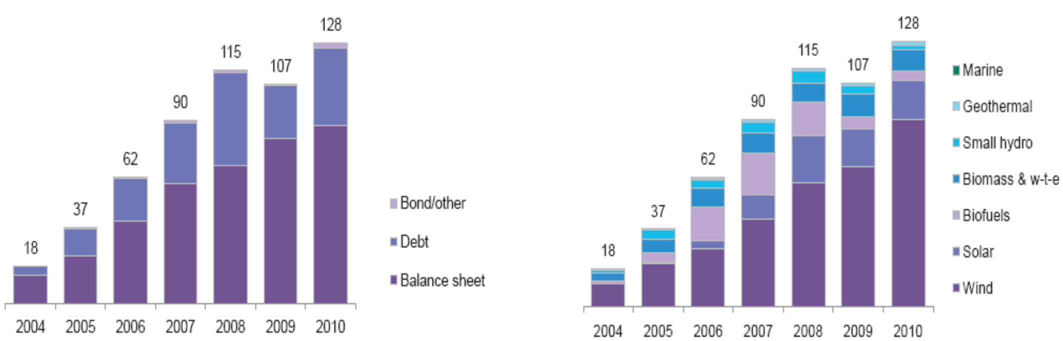
Figure 2-1 RE share of global final energy consumption and RE power capacities: Developing world, EU and top six countries



Source: Al Jaber et al. 2011

During 2004 to 2010, in total $557 billion was invested in asset financing for new utility scale RE projects (excluding small distributed projects like roof-top PV, which can constitute the bulk of investments as e.g. in Germany). In 2010 the asset financing comprises $128 billion (McCrone et al. 2011). The distribution between the different technologies or RE sources is shown in Figure 2-2.

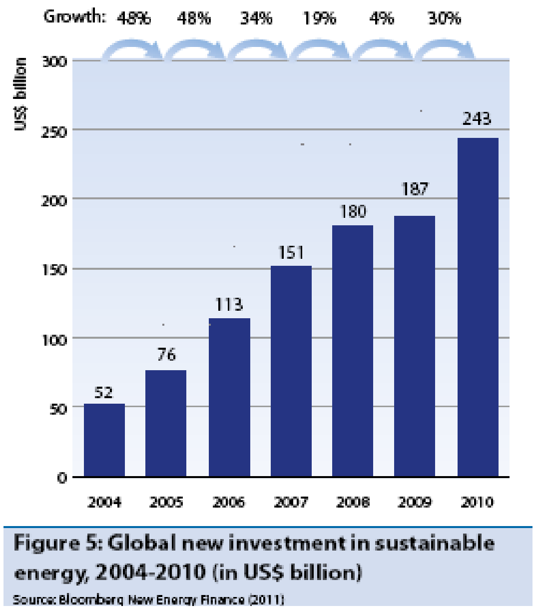
Figure 2-2 Estimated global asset financing by types RE source and financial instruments



Source: McCrone et al. 2011

Overall investments in RE (not only in assets but including investments in companies) achieved $187 billion in 2009 and over $243 billion in 2010 (McCrone et al. 2011, see Figure 2-3. To reach the targets set increasing investment will be a significant challenge in the coming decades. The IEA estimates over $10 trillion of additional investment would be needed for keeping GHG emission levels below 450 ppm, compared to the business as usual scenario (IEA 2009). To meet EU targets, it is necessary to roughly double the annual capital invested in power from €35 billion in 2008 to €60-70 billion on average during the decade 2011-20 (Ecofys 2010) or according to another source from €30 billion in 2010 to €65 billion in 2025 (ECF Roadmap, 2050).

Figure 2-3 Global investment in sustainable energy, in billion USD



Source: McCrone et al. 2011

The RE investment volume seems extremely large, but it fades in comparison to the global investment capital available. The bond market alone is worth $80-90 trillion worldwide, of which $23 trillion is invested in the EU alone (Asset Allocation Advisor 2009). Pension funds hold $16 trillion USD in assets worldwide, but currently only 1.1% of those in EU pension plans are invested in infrastructure projects (Inderst and Müller 2009). Since 2007, the EU, World Bank and IFC have issued billions of dollars worth of 'green bonds'. In recent years, successful bond offerings have taken place for individual RE companies and projects, such as Vestas and Evelop's Burgervlotburg project respectively. Ernst &Young estimate that global private investment in infrastructure could exceed $1 trillion annually (2008).

2.2 Current investment dynamics in the EU

To analyze the current RE investment situation in the EU, the investments in RE projects are estimated via two approaches:

- RE investments are based on a data set on financial activities (BNEF 2010) in the field of RE. The data set provides information on the number and volume of transactions in the corresponding year.
- RE investments rely on the estimation of the monetary value of the installed RE capacities in the EU based upon average capital costs per capacity (Held 2010) and capacities installed (EUROSTAT 2010). These investments reflect the capacities of the installations completed in the corresponding year.

Both approaches - the investment based on financial transactions and on capacity installations - are depicted in the following paragraphs.

Investments in RE based on financial transactions

The data base of BNEF applied in the first approach reflects asset financing related to the generation of electricity, heat or fuel from RE sources.[3] The estimation includes RE investments within the EU, differentiated into RE sectors, countries and types of transactions such as acquisitions, refinancing or financing of RE projects by debts and equity. The financial transactions are marked with the status “announced” or “completed”. This status refers to the transaction status and not to the project development status. A completed or announced financing could coincidence with different project development phases e.g. project planning or construction, while refinancing or acquisitions can also take place during the operation phase. The analysis of the data refers to the number of transactions and the transaction volume. The transaction volume – if disclosed - either comprises total capital (equity and debt) invested, debt or equity only. Not disclosed values on transaction volumes have been supplemented.[4] Since the transaction volume only reflects partial investments – in several cases just equity or debt – total investments in RE tend to be underestimated. Furthermore, small individual investments, grants or investment subsidies provided by states, governmental organizations or NGOs are not listed in the data set. However, this approach reveals current investment trends and activities, and allows a differentiation of investments with respect to financing instruments.

The results of the first approach show that asset financing of RE projects in the EU has significantly increased in number and transaction volume during the last decade. The number of planned, announced or completed transactions in RE projects encompassing biomass, solar energy, wind power, small hydropower, tidal power and geothermal plants reached with around 750 activities in 2008 the top and decreased slightly in 2009. Data on activities in 2010 are still incomplete and hence not fully usable. However, first publications of BNEF 2011 reveal even a further increase in RE invest-

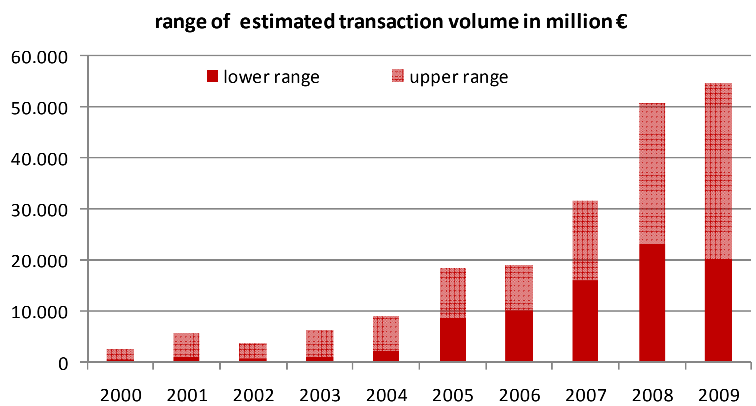
3 Based on the output of the database of Bloomberg New Energy Finance, reflecting financial transactions.

4 Where deal values are not disclosed, an estimated value based on an average values per technology and per country is assigned.

ments in 2010. Regarding the type of transaction, financing of new RE installations dominates by number and volume and strongly determines the growth in RE financing activities.

For further analysis the completed transactions - and not announced or planned transactions - are of interest. The development pattern of completed transactions is similar to the pattern of total RE asset financing. In numbers and financed volume investments peak in 2008 and 2009, respectively. The total volume of investments in RE projects in 2009 is estimated between 20 and 53 billion €. The large uncertainty is due to the fact that for many projects in the database the total transaction volume is not disclosed (see Figure 2-4). The upper range refers to the assumption that the average transaction volume of all disclosed transactions is used for the non-disclosed ones. The lower range displays the financing volume if non-disclosed transactions are set to zero. In the last years, the investment in RE has been dominated by wind and solar power. Most of the transactions take place in Spain, United Kingdom, Germany, France and Italy (2008 and 2009), where mainly PV and wind power projects are developed.

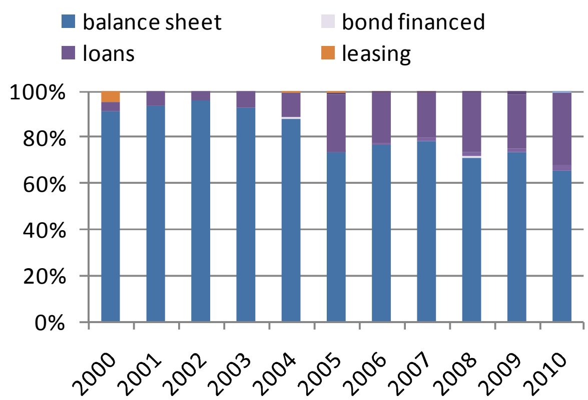
Figure 2-4: Financing of new RE projects in the EU from 2000 - 2010, estimated volume of transactions in million €



Source: Data based on BNEF 2010, adjusted for incomplete data; exception 2010: representing a share of actual transactions; own calculations

Regarding the type of finance, balance sheet financing[5] is still dominating the financial activities but with decreasing importance. In turn, loans – construction loans, syndicated bank loans – gain in importance. The growth of loans and public capital in RE financing signals an increasingly maturing market and decreasing risks, both also probably influenced by the increasing use of RE policy support mechanisms with guaranteed off-take prices.

Figure 2-5: Shares of financing instruments, based on number of transactions (new installations), EU 2000 – 2010, in %



Source: Data based on BNEF 2010, adjusted for incomplete data; exception 2010: representing a share of actual transactions; own calculations

2.2.1 Investments based on RE installations

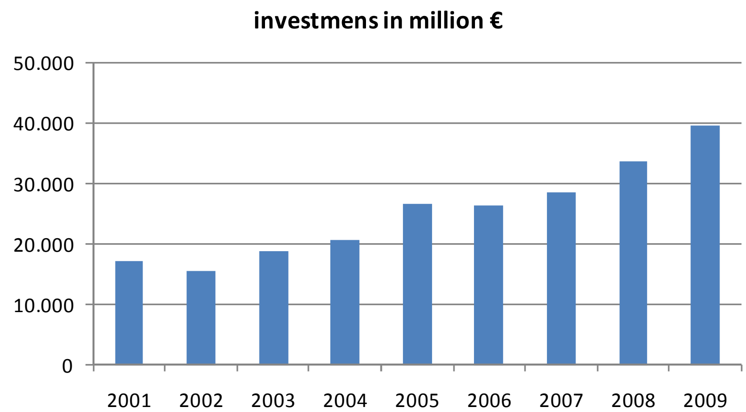
A second approach, based on installations in RE power generation plants, has been pursued. The investments are estimated based on the growth of installed RE generation capacities weighted with the average investment per capacity. The data on capacity installations relies on current statistical data from EUROSTAT. Therefore, the values[6] for 2009 are projected values based on the development of the previous years. The data for the average capital costs per installed capacity are from Held 2010. The investments enter the statistical database in the year the generation plant starts operation.

The results depicted in Figure 2-6 show a steadily increasing investment in RE projects reaching around 40 billion € in 2009. Regarding RE installations with respect to RE technology and country, PV and wind power have dominated the RE projects in recent years, and Spain, Germany, Italy, United Kingdom and France are also the leading countries in RE investments. Compared to the first approach, this method reveals an investment volume that is significantly lower than the estimated investment volume based on financial transactions. Furthermore, it allows no conclusions on the financial instruments used to finance RE investments but it shows the capital funds needed.

5 Asset financing with equity and debt

6 for biomass, hydro and solarthermal power, while data on installations in wind power and PV are available for 2009.

Figure 2-6: Investments of new RE projects in the EU from 2001 – 2009, in million €

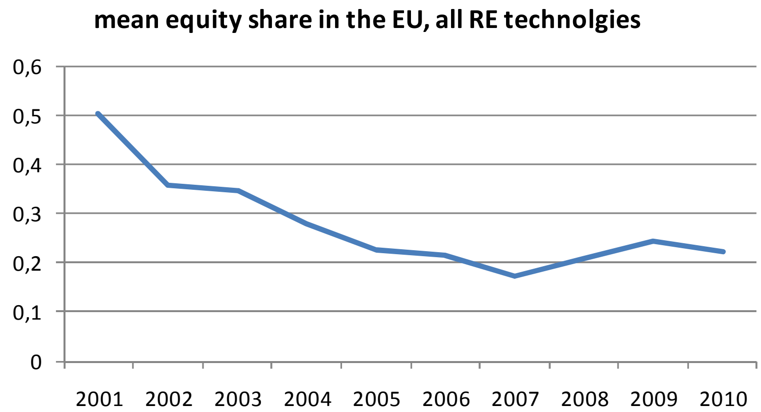


Conclusions

The estimated investments based on financial transactions show a similar level as those based on capacity of around 40 billion € in 2009, whereas the estimate based on completed transactions is subject to substantial uncertainty. In both approaches most investments were carried out in wind power and PV and take predominant place in the same five countries but with a slightly different order. One of the main reasons for the differences in investment volume is likely to be the time gap between financial transactions and installed capacity. The first takes place during planning, development and construction of the generation plant while the latter occurs with the completed installation or operation of the plant. Further, financial transactions include all RE projects (power and fuel, possibly heat) while installed capacities include only plants for electric power generation but no fuel refineries. Additionally data on financial transactions are most likely rather incomplete for the earlier years of the last decade. And finally, in 2000, markets for RE investments were less mature than in 2010, therefore probably less financing deals were closed in the market.

The decreasing equity share in RE investments (see Figure 2-7) shows changes in financing pattern that could be explained by technology and market development, resulting in a reduction of risks. Furthermore, from the viewpoint of investors and lenders the strong political commitment for RE deployment might also contribute to a reduction and/or shift of risks.

Figure 2-7: Average equity-debt ratio of RE investments in the EU from 2001 – 2010



Source: data based on BNEF 2010, based on a limited set of data, adjusted for incomplete data. 100% share of debt or equity is ignored.

Overall, in the EU financial transactions – and hence investments - in RE projects have strongly increased over the last years and range between 55 and 62 bn € (60 and 70 billion US$ in 2008 and 2009, respectively). The estimated investments exceed those indicated by REN21 for Europe, Middle East and Africa (42 billion US$ in 2009). Capital expenditures needed to achieve the EU deployment objectives are estimated at 70 billion € per year (Ecofys et al. 2011), which is still quite above the current actual investments; but they tend to get closer. Furthermore, capacity-based installation has been relatively high at the beginning of the decade but grew in a slower pace than financial transactions. The dominance of capacity-based investment in 2000-2006 can be explained by rather immature markets for RE investments in line with a strong political commitment. While at the beginning of the decade balance sheet financing (with equity) has strongly dominated the financial instruments, in recent years debts or loans are growing in number revealing an increasing confidence of lenders and other investors in the RE business/market.

2.3 Applied financing structures and conditions

To depict the potential impact of policy measures on financing parameters and, hence, on financing cost, the financing structures and conditions in selected EU countries are investigated in detail. For this, key players in financing RE investments have been interviewed with respect to financial conditions and risks, their expectations regarding RE policies and financing issues as well as with respect to potential bottlenecks for RE investments. In total more than 20 interviews were conducted covering banks, project developers, investors and utilities active in 15 countries (NL, IT, UK, HU, FR, BE, IE, ES, SK, BG, PL, DK, RO, AT, DE, Turkey) involved in wind off and onshore, PV and biomass projects.

Since the financial crisis affected the conditions in RE financing significantly and a comparison between financing conditions before and after the crisis were not feasible, the focus of the discussion were first on the impact of the financial crisis on RE financing. In a second step differences between the countries and technologies were discussed.

Impact of the financial crisis on RE financing

Financial conditions have undergone significant changes over the past years mainly due to the financial crisis. Before the crisis, the equity share of investors ranged between 10 to 20% and sometimes even 100% debt financing was possible, after the crises the equity share rose above 20-30% and private equity fundraising capabilities have decreased. Furthermore, interest premiums over EURIBOR increased by 150 – 500 basis points (or 1.5-5.0%) and recourse loans became strongly preferred instead of non-recourse loans. The main capital shortage occurs during the construction period of a project i.e. to overcome “construction + 6 months” period, when there is limited capital available at higher rates.

Table 2-1 Financial conditions for RE before and after the crisis

	Before crisis	After crisis
Equity participation	10-20+% equity	30+% equity
Interest premiums over EURIBOR	Old EU: 100-150 bp New EU: 100-200 bp	Old EU: 250-300 bp New EU: 400-700 bp
Construction risk	Manageable	Significant
Exchange rate risk	Considered as limited	Significant non EURO countries
Order of loan withdrawal	Proportional with Equity	Equity first followed by loan
Recourse	Non-recourse SPV based project financing	Recourse to Stakeholders
Loan period	In line with takeover period (no major change)	
Residual financing	Some bullets or balloons at term end	No bullets or balloons
DSCR (depends on project & country, e.g.)	1.15	1.30

CEE countries have experienced the largest increase in spreads over EURIBOR. This observation is also backed by the high spreads of the Credit Default Swap (CDS), which is one of the best indicators of the market's current perception of sovereign risk by countries. The most severe situations are being experienced in the CE European markets having 1) CDS (credit default swaps) rates over 300 bp over Western European countries, 2) exchange rate risks from non EURO currencies and 3) the largest pressure on disposable incomes such that political decision makers became more reluctant to finance support in a stable manner via a levy on consumers. In those countries, nonrecourse loans for special purpose companies were stopped almost completely by a large number of banks and RE financing has only taken place on the basis of corporate financing while project stakeholders are required to back the loan and are often forced to raise money with more favourable conditions in their Western European home countries. The lack of credibility - required for recourse based financing - often leads to an exclusion of small and medium enterprises from project sponsoring.

Further, due to negative experiences in the past banks are often reluctant to syndicate loans in CEE countries. The strategy of local banks is limited to “originate & hold”, meaning to use own funds and be present on the local market but be unable to raise external funds through international syndication.

Table 2-2 Five year bond Sovereign Credit-Default Swaps (as of December 2010)

	bp		bp
Greece	1019,5	Poland	197,7
Ireland	602,9	Czech Republic	149,1
Portugal	496,6	Slovakia	139,4
Romania	406,0	Slovenia	135,2
Latvia	382,0	Belgium	129,5
Hungary	380,0	France	107,0
Spain	348,4	Austria	100,3
Bulgaria	331,0	United Kingdom	86,8
Lithuania	299,0	Netherlands	62,1
Italy	237,9	Germany	57,0

Source: Datastream, Natixis 12/2010

Note: Spreads are expressed in terms of basis points, where 100 bp is the equivalent of 1% chance that the issuing government will default.

Subsequently, the low availability of capital, the higher capital costs and the strict financing requirements (e.g. equity share, recourse loans, exchange risk hedging) in addition to the CDS spreads resulted in – if loans and equity are available at all - very high financing cost for RE investment projects, especially in CEE countries. Further consequences were:

- Due to high cost of local debt capital, project developers with international background often choose to use international corporate loans available at head quarter level (in Western Europe), rather than relying on expensive project financing offered by local banks;
- Exchange rate risk in non EURO countries became a major issue, leading to a stop of EURO and CHF based financing which in turn were replaced by more costly financing in local currencies
- Residual loan repayment at term end is often not being offered as banks were forced by State Financial Authorisation to make provisions for loss against all bullet proportion of loans
- Biomass or biogas based RE projects have higher interest rates than fossil based power plant projects (coal or natural gas), mainly due to fuel uncertainty (homogeneousness, logistics, continued availability) and technological issues.
- Seasonality issues associated with different wind patterns throughout the year have to be gapped by use of semi-annual repayment schedules (rather than quarterly) or higher debt service reserves;
- Projects accumulate in the pipeline waiting to be given a green light for construction.

Financing conditions by country and technology

The current financing terms for RE investments can best be described by the financing variables in the table below providing general rough ranges. Usually financiers distinguish between projects where technology maturity is high and/or the supply uncertainties low and projects with low technology maturity and/or high uncertainties in supply. Thus, they differentiate between projects with high and low performance risks, i.e. between wind onshore and rooftop PV projects and in wind offshore and biomass projects respectively. The division of the financing variables according to

countries might reflect financing and country risks (CDS) as well as impact of policy measures via price and demand risks on financing costs.

Table 2-3 Financing variables by country

Financial parameters for less risky RE projects, i.e. <u>wind on land and rooftop PV</u>, status <u>2010</u>

Member State:	AT	BE	BG	FR	DE	HU	IT	NL	PL	RO	SK	ES	GB
RE policy system	FIT	Quota	FIT	FIT	FIT	FIT	Quota	FIP	Quota	Quota	FIT	FIT	Quota
Equity participation	20+%	20+%	30+%	20+%	20%	30+%	20-25%	20%	30+%	30+%	30+%	20+%	20+%
Loan period (# years less than support period)	2 - 5	3 - 7		2 - 5	2	2 - 5	2 - 5	2	3			5 - 10	2 - 5
Interest premium over EURIBOR (bps)	250-300	250-350	400-700	250-300	150-250	400-700	300-400	200-300	350-500	400-700	400-700	350-500	175-250
Debt service coverage ratio DSCR	1,2	1,2	1,3	1,2	1,2	1,3	1,2	1.2	1,3	1,3	1,3	1,2	1,2
Debt service reserve account DBSRA (# months)	6	6	6	6	6	6	6	6	6	6	6	6	6

Financial parameters for complex and risky RE projects, i.e. <u>offshore wind and biomass,</u> status <u>2010</u>

Member State:	AT	BE	BG	FR	DE	HU	IT	NL	PL	RO	SK	ES	GB
RE policy system	FIT	Quota	FIT	FIT	FIT	FIT	Quota	FIP	Quota	Quota	FIT	FIT	Quota
Equity participation	30+%	30+%	40+%	30+%	25%	40+%	30+%	30+%	40+%	40+%	40+%	30+%	30+%
Loan period (# years less than support period)	2 - 5	3 - 7		2 - 5	2	2 - 5	2 - 5	2 - 5				5 - 10	2 - 5
Interest premium over EURIBOR (bps)	250-300	250-350	400-700	250-300	150-250	400-700	300-400	200-300	350-500	400-700	400-700	350-500	175-250
Debt service coverage ratio DSCR	1,2	1,2	1,3	1,2	1,2	1,3	1,2	1,2	1,3	1,3	1,3	1,2	1,2
Debt service reserve account DBSRA (# months)	6	6	6	6	6	6	6	6	6	6	6	6	6

Source: own composition based on interviews

The figures in the table above suggest that besides the RE-specific policy framework also the country risk strongly influences the financing variables and hence financing conditions for RE investments. All CEE countries require a higher equity share and premium over EURIBOR than countries with a low country risk such as UK, France, Belgium, NL and Germany. From the interviews held, it appears that differences in equity share or premium between countries with a quota or feed-in system are moderate. However, the more detailed results in chapter 5 show the strong influence of the RE-specific policy framework on overall RE production cost: Often risk and cost do not materialize in weighted average cost of capital (WACC) composed of the parameters in the table above, but rather in financing fees, increased investment or operation cost or decreased power or support revenues.

It is being observed that in new EU countries higher per unit project costs exist than in EU10. One of the reasons for this development is that in new EU countries permitting problems cause project developers to incur large project development costs without final assurance on the conditions to receive the permit.

3% to 11% of the total project budget is usually spent on project development before financial closure. This share differs depending on the project type and size, since the absolute budget for project planning (financial closure) does not increase linearly with project size.

RE technology-specific interview observations

Offshore wind is generally regarded as a special profession in RE, with special requirements and risks attached. A very crucial issue for financing is the secured access (connection) to the grid. For example, in France projects have to be commissioned within 3 years after receiving all permits, whereas in Italy the support level is only set and known when the grid connection is realized. Since wind offshore project requires high capital investments and high proficiency in technology-know-how, only experienced and large partners in low-risk countries engage in these projects.

Biomass projects appear to be less popular among debt investors due to their complexity. Some banks refrain from biomass plant projects, due to uncertainty in feedstock supply (only short term contracts available), sustainability issues and frequent technical problems in the operational phase. Additionally, the financial crises as well as the increase in raw material prices have had an impact on some financial parameters: equity share rose from 20% to currently about 40%.

Overall, financial institutions are very selective and require highly experienced and renowned partners in biomass projects. Important mitigating measures to reduce risk in biomass projects are 1) long-term biomass feedstock supply contracts (5 yr contracts are possible in the market) and 2) multi-feed plants, i.e. diversification of biomass input and thus of risks.

Because of the low net efficiency, biomass power generation plants without option to sell heat (CHP), will not be able to compete on the wholesale electricity market and, hence, run into problems when the mandatory takeover period expires.

3 Macro-economically optimal allocation and treatment of risk

This chapter argues, that cost of RE production can be minimized by applying a differentiated approach to risk treatment and allocation: In some cases a risk can best be born by the RE project, in others by the public. This will depend on the type of risk, the technology, the electricity market, and the project size and investor type. While the pros and cons of market revenue risk exposure are ambiguous, the picture tends to be clearer for the other risks discussed: The policy and regulatory risks are generally risks that do not trigger any cost-optimized behavior on the RE project side, but can be effectively reduced by governments at no or very low costs. The technology and project risk should not be fully burdened on the public, because they are generally better understood by the RE project (developers) than by the public sector.

Most risks a RE project has to deal with increase cost, as discussed in chapter 1.4. Ideally risks also have a positive effect: Triggering developers and projects to adapt to the risk and deliver a better product. However, often the positive effect is zero or very low compared to the cost increase. Sometimes another party or the public might be better prepared to cover a risk and can do so at lower societal cost. This leads to the question:

What is the macro-economically optimal allocation and treatment of risk?

Defining this requires the following four steps:

1. **Recognise that risks can be productive or unproductive**
2. **Recognise that different parties can bear the risk**
3. **Recognise that one policy does not fit all: Optimal allocation and treatment of risk will differ between countries and technologies** based on
    e) Technology-specific risks and development status of technology
    f) Country-specific deployment status of that technology
    g) Country-specific electricity market design and structure
    h) Project size and investor group
4. **Act: Reduce risk where possible, then allocate the risk and create regulatory framework in such way that macro-economically optimal treatment is ensured**

Below these steps are explained and afterwards applied to concrete examples.

An important issue in the RES-E policy discussion – especially regarding support policies and risk – is electricity market integration: It is often stated as an objective that in the long term RES-E technologies should be integrated completely into the power market, meaning it should be exposed to the same market signals and risks as conventional technologies. In the support policy discussion one key discussion in this respect is the question whether RES-E projects are made responsible for selling their power and for balancing (like in quota or feed-in premium systems) or not (like in feed-in

tariff systems): Exposure to (hourly) fluctuating electricity prices is a risk, but also an important market signal for balancing demand and supply. Related examples will be used below during explanation of the four steps.

1. **Recognise that risks can be productive or unproductive**

   We define productive/unproductive risk as follows:

   - **Productive risk** = RE project is triggered to apply risk mitigation action, which is macro-economically beneficial
   - **Unproductive risk** = No macro-economically beneficial risk mitigation action exists or RE project is triggered to apply risk mitigation action that is macro-economically not beneficial.

   Whether a risk is productive or unproductive depends to a large extent on the party bearing the risk and the country- and technology-specific circumstances described below. This will be illustrated during the discussion of examples.[7]

2. **Recognise that different parties can bear the risk**

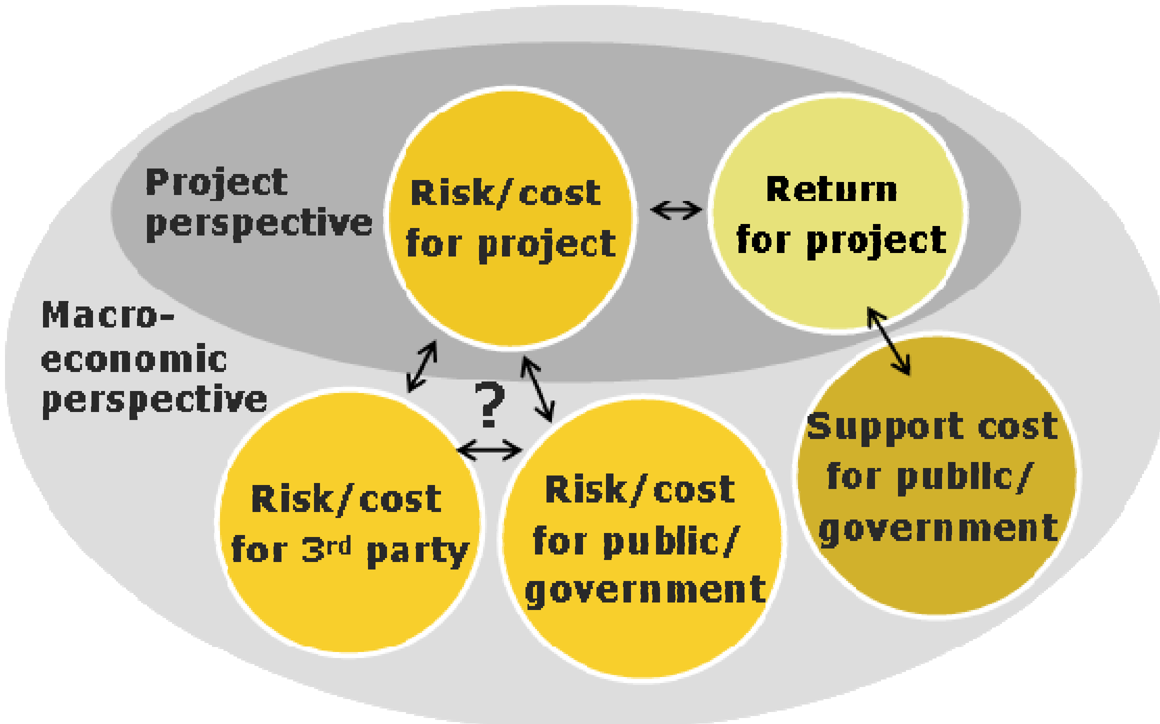
   Parties that can bear risks can be divided into the following:

   - **Project company** or a company contracted and paid by the project company, including insurance companies
   - **Other private party** obliged by the public to bear the risk, like e.g. grid operators or incumbent utilities for forecasting, wholesale trade & balancing
   - **The public** or a body related to it

[7] In this context also another useful risk classification could be applied:

- Risks that can be avoided (performance risks due to administrative processes, legal uncertainty, etc.).
- Risks that can be mitigated (from the perspective of all parties, not only from one): performance risks based on lack of or incomplete information
- Risks that can not be avoided but must be shared: price risk, demand risk, performance risk (technology, resources)

Figure 8 Risk sharing



3. **Recognise that one policy does not fit all: Optimal allocation and treatment of risk will differ between countries and technologies based on:**

   a) **Technology-specific risks and development status of technology**

   Some risks of RE projects exist independent of the applied technology; many risks however are specific to a technology, like e.g. wind resource to wind projects. The amount of risks (perceived) usually decreases when technologies become more mature and globally applied. This may justify a technology-specific (risk approach) in RE policies. In biomass technologies often biomass supply risks are more relevant than conversion technology risks.

   Illustration: Differentiating market integration according to technology

   All RES-E technologies can be split into two groups: Production of *supply-driven* (or fluctuating) technologies depends on fluctuating natural sources and can only be forecasted and curtailed, but production cannot be guaranteed and steered independently of the natural source. *Demand-driven* (or flexible) technologies can exactly forecast and steer their production and should therefore be used to balance fluctuations in the residual load remaining between supply-driven technologies and electricity demand. The distinction between supply- and demand-driven technologies is obviously of huge importance for the market integration discussion: A demand-driven technology exposed to the revenue risk from hourly changing electricity prices can respond e.g. by increasing production in hours with high prices and decreasing production in hours with low prices. A supply-driven technology cannot respond in such a way; it can only aim for a good production (wind/sun) forecast in order to minimize the need for expensive balancing power for deviations of production from forecast.

Policy implication: Exposing demand-driven technologies to hourly electricity price fluctuation makes sense as it triggers considerable macro-economically positive reactions, whereas for supply-driven technologies this is less obvious as the options to react are very limited. E.g. wind turbines can be controlled downwards and also upwards when some power reservation is left. Such a power reservation increases specific production cost which has to be weighed against the value of the balancing services provided.

Figure 9 Supply- and demand-driven RES-E technologies

Supply-driven RES-E technologies	**Demand-driven RES-E technologies**
Produce when nature prefers • Wind • Photovoltaics • CSP without heat storage • Run-off-the-river hydro • Biomass in heat-lead CHP • Tide & wave	*Should balance fluctuating RES-E* • Hydro with reservoir • Biomass in power only • Biomass in power-lead CHP • Deep geothermal (limited sense due to low marginal cost) • CSP with heat storage

b) Country-specific deployment status of that technology

A technology may be broadly applied in one country while little experience with that technology exists in another country: Local project developers, energy companies, banks and administrations will have little or no experience with the respective technology and production will be still low, leading to different kinds of risks and risk perception compared to a very developed market. An immature market can therefore cope with less risk than an advanced market.

Illustration: Differentiating market integration according to country-specific technology deployment status

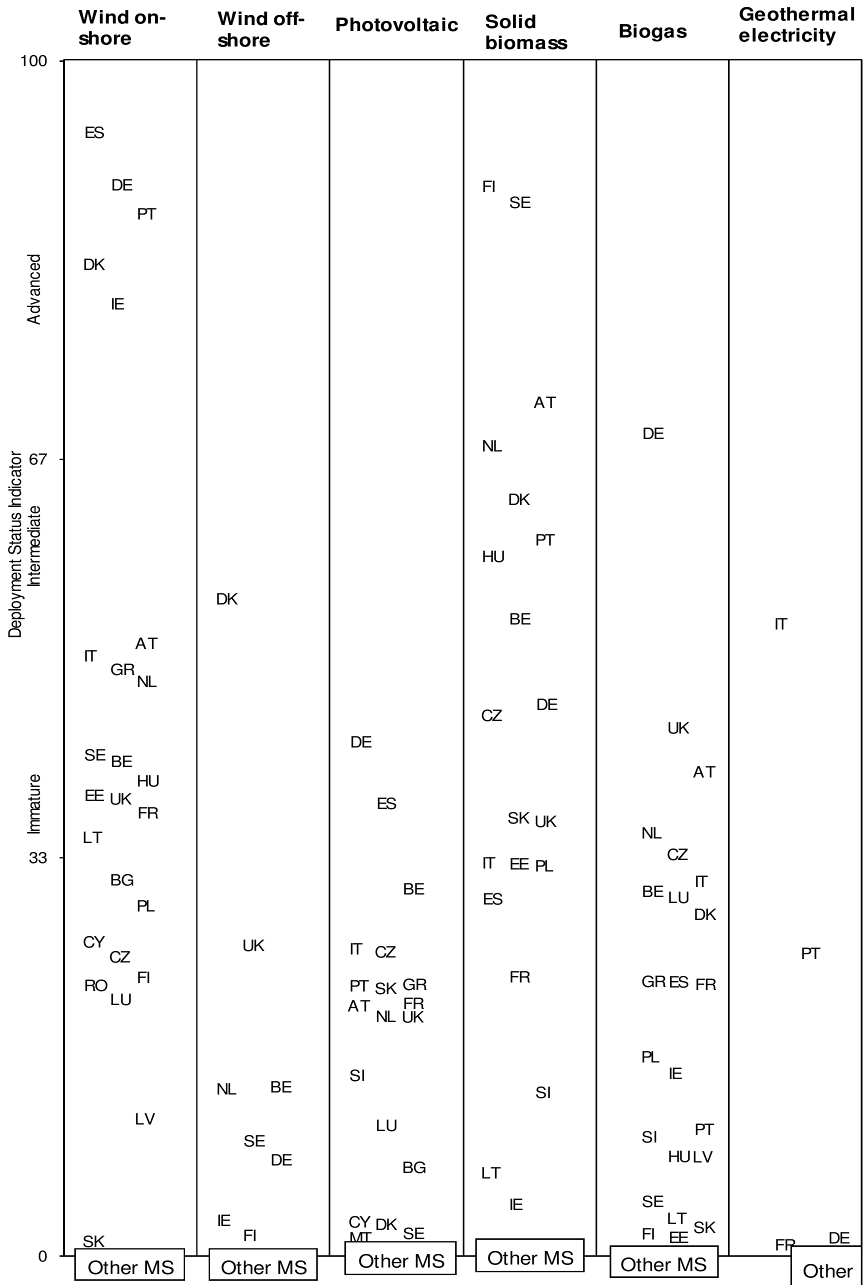
Within the RE-SHAPING project, the RET (Renewable Energy Technology) Deployment Status Indicator has been developed. It aims to quantify how advanced the market for a specific RET is in a specific Member State: the higher the value, the higher the maturity of that specific technology market in that country. The indicator is applicable to the 15 key RET in 27 EU Member States based on existing statistical data. It consists of three sub-indicators: 1) Share of production in the respective energy sector consumption - 2) share of production in the mid-term potential – 3) whether installed capacity has reached a minimum threshold. See D5/6 report on www.reshaping-res-policy.eu for more detail. In the figure below the deployment status for the key RES-E technologies is shown.

In this figure the Member State abbreviations indicate the level of Deployment Status (immature – intermediate – advanced). Member States with very low potential or deployment

status indicators close to zero are not shown in the figure, but indicated by the placeholder "other MS".

The figure shows that only few Member States have reached an advanced Deployment Status for some RES-E technologies: the wind onshore markets in Spain, Germany, Portugal, Denmark and Ireland score advanced; the same is true for solid biomass in Finland, Sweden, Austria and the Netherlands (even though this is a heterogeneous RET category, as explained above). For these RET, the spread of results is very broad, with further countries scoring intermediate and others immature. For the other technologies (wind offshore, PV, biogas and geothermal), a clear majority of countries is characterized by an immature Deployment Status. Still, there are top runner markets for each technology: Denmark for wind offshore, Germany for PV, Germany and UK for biogas, and Italy for geothermal electricity, all of them with intermediate deployment status.

Figure 10 Deployment Status Indicator for key electricity technologies 2009/10



Note:
Not shown is hydro (Deployment Status in most MS advanced), solarthermal electricity and tide & wave (in 2009 Deployment Status in all MS still close to zero).
Solid biomass is a very heterogenous category as it comprises different technologies (pure biomass plants and co-firing) and both domestic and imported biomass. This limits comparability between countries.

c) Country-specific electricity market design and structure

Many RE project risks are related to the electricity market in the respective country. The electricity market is needed to sell power to and buy balancing power (not in Feed-in tariff

systems). The electricity market design and structure therefore determine the related costs, revenue risks and margins taken by buyers of power and green certificates. The utilities active on that market might also be buyers of full RE projects or competitors in project development and for investors and bank loans. The large incumbent players might have the largest lobbying power and interest regarding (renewable) energy policy.

Illustration: Differentiating market integration according to electricity market design and structure

Within the RE-SHAPING project, the *Electricity Market Preparedness Indicator* has been developed. It aims to quantify how well the market design (sub-indicators A to D) and market structure (sub-indicator E) are suited to market integration of (supply-driven) renewable electricity. In the figure below the deployment *Electricity Market Preparedness Indicator* is shown. As it is based on existing statistical data only, it currently omits important aspects regarding balancing markets, intraday trading and cross-border markets for which data are not easily available. See D5/6 report on www.reshaping-res-policy.eu for more detail.

According to the overall indicator, the electricity markets seem to be best prepared for RES-E market integration in the Nordic countries Denmark, Finland and Sweden, in Spain, the Netherlands and probably the UK (data missing) with scores between 70 and 85 points. Note that of these countries three apply a Feed-in premium and three a quota system as primary support instrument: This is not the reason for their high score, rather the other way round one can argue that a high score is a precondition for successfully applying these support instruments that demand higher market integration from RES-E projects; this is not to say that all of these Member States actually are very effective in increasing RES deployment – the picture in that respect is very diverse as described in the sections before. E.g. the very liquid power exchange in the Nordic countries (NordPool) strongly facilitates market integration, as e.g. PPAs are not needed in all cases for projects to be bankable – reducing cost for PPA counterparty margin and upside (see chapter 4.2 policy option 12 for details).

Also Ireland, Poland, Romania, Germany and probably Slovenia (data missing) score comparably high between 60 and 70 points. Italy and Portugal score 50 to 60 points, barely belonging to the better half of Member States.

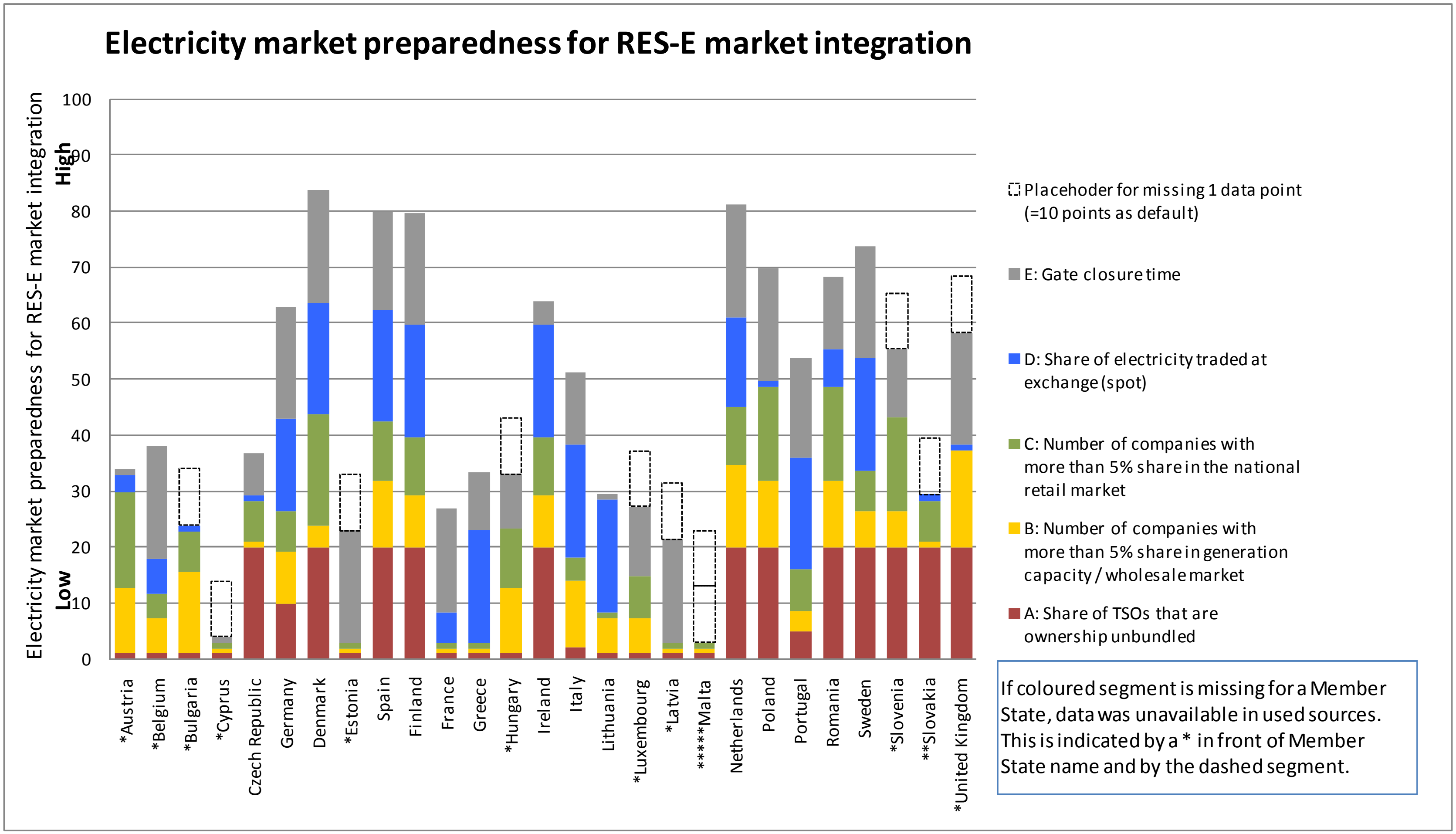


Figure 11 Electricity market preparedness for RES-E market integration 2010

d) Project size and investor group

As opposed to many other markets renewable electricity production is characterized by a huge variety of project sizes and investor types. Sizes may vary from one kW photovoltaic to one GW offshore wind – **a factor of one million in terms of installed capacity and about one million in terms of investment**. Even within technologies size variety can be huge: Next to domestic rooftop photovoltaic with few kW also ground-mounted photovoltaic parks up to 100 MW exist. Next to single wind turbines of 2MW onshore wind farms of several hundred MW are installed. Next to biogas or biomass plants of 100 kW, 100 MW or more biomass is co-fired in a single coal power plant.

The variation among types of investors is comparably large:

- Incumbent utilities investing especially in offshore wind, large onshore wind or large biomass projects
- New independent power producers often investing in a bit smaller projects, sometimes developing new markets and/or innovative technologies not (yet) addressed by incumbent utilities
- Consumers investing alone in domestic photovoltaic rooftop systems or domestic ('micro') combined heat and power production based on biomass or biogas
- Consumers investing cooperatively in local wind, local heat grids based on CHP, larger photovoltaic projects
- Farmers investing (alone or cooperatively) in small to medium wind onshore and electricity generation based on biogas (anaerobic digestion) or woody biomass on their own land
- Cities/villages investing in all kinds of local RE production
- Wastewater treatment facilities investing in sewage gas production

Why do countries address the full spectrum of investors and project sizes?

Many countries aim to engage the full spectrum of investors and project sizes to increase the share of RE. Countries base this decision for example on one or more of the following reasons:

- In order to achieve long term RE targets, the full potential needs to be exploited, including several technologies and large as well as small projects. Realizing very large projects may require capital and experience of large companies, realizing small projects may require engaging local actors like consumers and farmers.
- Against economies-of-scale assumptions, small projects may be able to produce against lower support cost due to lower cost of capital, grid cost savings, unpaid work, etc.
- Governments may pursue other policy objectives (than increasing RE production against lowest possible cost), like
    - industry policy;

- development opportunities for farmers and rural areas;
- increasing political acceptance and/or 'democratization' of energy supply via community-owned projects or small-scale household level projects;
- improving market structure in oligopolistic markets by tailoring RE policies to allow new independent power producers to gain market share from incumbent market players.

How does addressing the full spectrum affect risk and policies?

Below some reasons are given why RE policies may need to be tailored to project size and/or investor type:

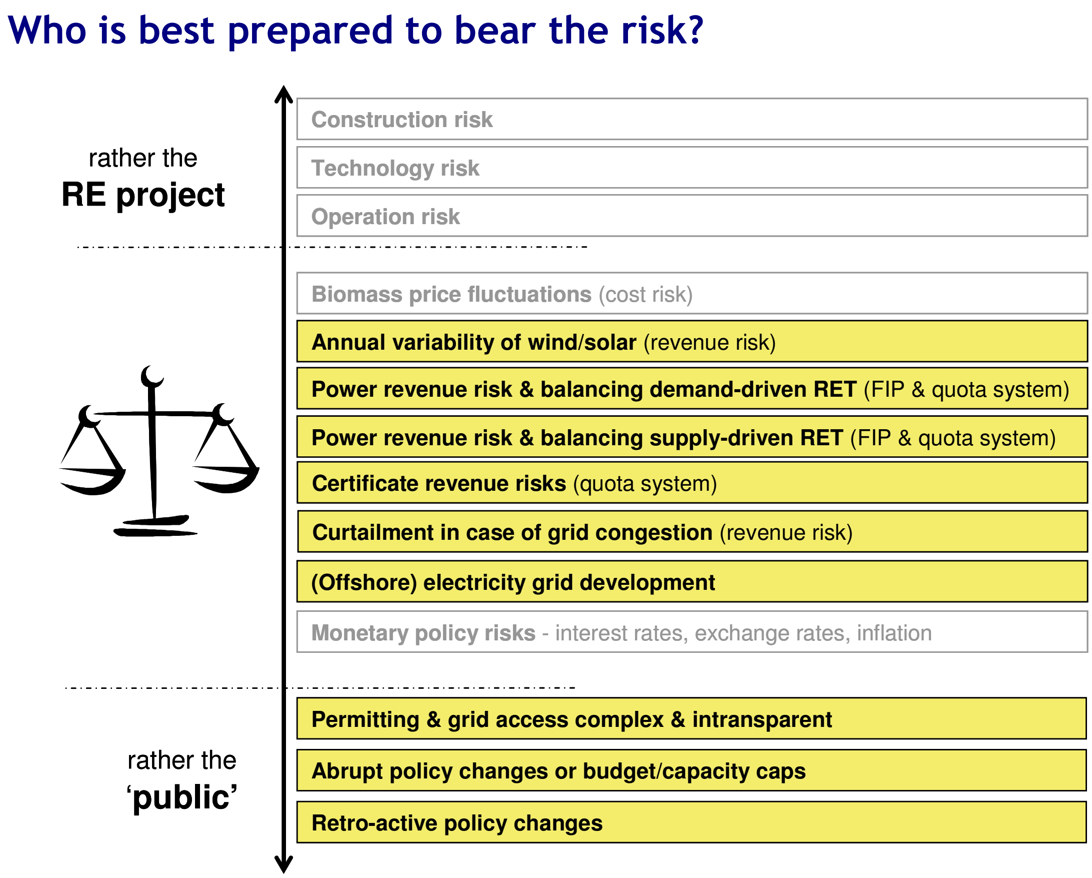
- Transaction cost due to e.g. permit applications, identifying and closing power purchase agreements, forecasting and balancing supply-driven power production, are for small-scale projects often much higher per energy production.
- Utilities with large and diversified own generation portfolio have more options to hedge risks than smaller independent power producers, farmers and consumers. RE policies need
- Smaller independent power producers usually rely on non-recourse project finance whereas utilities can resort to recourse financing and there high creditworthiness.

4. **Act: Reduce unproductive risk where possible, allocate risk and create regulatory framework in such way that macro-economically optimal treatment is ensured**
    1. Reduce risk that can be avoided, e.g. when unnecessarily caused by policy or regulations.
    2. Allocate the risk to the party that is best suited to bear the risk (= can do so at macro-economically least cost).
    3. Enable RE project to conduct macro-economically beneficial risk mitigation actions by removing barriers or changing design details in the policy framework.

EXAMPLES for risks and policy options analyzed according to above structure:

The figure below illustrates how risks could be divided between RE projects and the 'public' or third parties obliged by the 'public'.

Figure 12 Risk allocation between RE project and 'public'



At the upper end of the figure above risks are shown that can probably best be born by the RE project: Risks around engineering, procurement, construction and the quality of technology and operation. These risks are assumed to be *productive*, because the RE project has a strong influence to minimize negative effects from this risk by choosing good technology providers etc.

At the lower end of the figure risks are shown that can probably best be born or reduced by the public: Inappropriate design and stability of administrative processes, grid regulation and support schemes can impose massive risk to RE projects. But RE projects have no risk mitigation options for these risks that would lead to macro-economically better result compared to risk reduction by the public. Whether a RE projects will suffer from these risks is pure chance, leaving the risk to RE projects therefore creates *unproductive* risk. In detail this refers to the following risks:

- Retro-active policy changes
- Unforeseen policy changes for upcoming projects
- Absence of priority dispatch or curtailment compensation
- Permitting procedures and budget/capacity caps in the support scheme leading to a low success rate of project development, especially if decisions on permits or support are only made at a late project development stage when the value at risk (money invested in project development) is high.

Caps and (retro-active, frequent or not well in advance announced) policy changes are a result of insufficient policy foresight: A government closely observing and anticipating market developments, sticking to its political targets and commitments, and carefully designing RE policies would barely need them. To such a government bearing these risk, i.e. not exposing RE projects to these risks, does not create much additional cost. However, to governments establishing inappropriate policies cost of covering these risks may be high: If e.g. feed-in tariffs for photovoltaic are set too high, cost for maintaining the tariff for all projects flooding the market will be high; a proper policy however would e.g. include an automatic adjustment of feed-in tariffs according to market growth at regular intervals, which would prevent unnecessary cost.

In the middle of the figure risks are shown for which macro-economically optimal allocation and treatment will differ between countries and technologies depending on (as discussed earlier):

1. Technology-specific risks and technology maturity
2. Country-specific technology deployment status
3. Country-specific electricity market design and structure
4. Project size and investor group
5. Influenced by dominating macro-economic paradigms

This refers e.g. to the risks surrounding market integration: Balancing risk, revenue risks from power sales and revenue risks from fluctuating certificate prices. Below the example of electricity market integration and the application of the criteria is discussed in more detail.

Policy options to reduce the risks shown in yellow boxes in the figure above are described in chapter 5.

Example electricity market integration

The table below summarizes the criteria discussed before that can be used to decide on the macro-economically optimal level of electricity market integration of RE projects. It is assumed, that the macro-economic benefits of RES-E market integration depend on the following aspects:

- Demand-driven technologies have a much higher ability to respond to the (risks from) hourly changing electricity market prices than supply-driven technologies.
- In large projects the transaction cost due to increased market integration are less relevant than in small projects.
- The more of a RET is deployed in a country and the more experienced and professional the involved actors are, the better they can cope with risks associated with increased market integration. This aspect is represented by the *Deployment Status Indicator*.
- The better the market design and market structure of an electricity market is suited to (fluctuating) RES-E and the more potential obstacles for RES-E projects are reduced, the lower the risk and related cost for RES-E market integration. This aspect is represented by the *Electricity Market Preparedness indicator*.
- The two aspects before are especially relevant for RES-E producers operating independent of incumbents, because they rely on either fair PPAs (Power Purchase Agreements) from in-

cumbents or market conditions that allow direct selling through a power exchange or new intermediaries. Projects operating independently from incumbents also rely more often on project-finance and thus depend more heavily on risk assessments of banks which will depend partly on the deployment status of a RET in the respective country and on the global technological maturity a RET has achieved. If overall risks are perceived too high, projects will not get loan financing.

Table 4 Decision criteria for macro-economically optimal level of market integration

	Depending on criteria in left column, **macro-economically optimal level of electricity market integration is rather**		
Criterion	**Low (Feed-in tariff)**	**High (feed-in premium / Quota)**	**Criterion affects**
Technology is …	*Supply-driven*	*Demand-driven*	Ability to respond to risk/market price
Envisaged project size is …	*Small*	*Large*	Transaction cost
Country-specific technology market deployment status is …	*Immature*	*Advanced*	Overall risk may be prohibitively high
Country-specific electricity market preparedness is …	*Low*	*High*	Ability/conditions for acting on electricity market
Technology is …	*Immature*	*Mature*	Overall risk may be prohibitively high
Envisaged investor type is …	*Consumers, Farmers, Independent power producers*	*Incumbent utilities*	Creditworthiness, Hedging options

If a low level of electricity market integration (Feed-in tariff) is chosen, the risk of (hourly) fluctuating electricity prices is allocated to the party responsible for purchasing power from RE producers against feed-in tariffs and selling this power to the market. That party will recover its cost in some way via government budget or electricity consumers and thus the risk is socialized. Cost savings may occur from the fact that the party obliged to purchase and balance can conduct the market integration at lower cost due to e.g. its large own generation portfolio, production fluctuations being leveled out over the various RE plants in a large geographical area and better production forecasts, lower transaction cost due to integrating all RE at once.

Concerning market integration one advantage of supply-driven RE producers as compared to a central party may be the access to local production and wind speed data, which are valuable for fore-

casting production. An alternative to full market integration or a forecast obligation for individual suppliers would be an obligation to disclose all wind measurement and production data in real time and making all data publicly available. Companies offering forecast services would then compete based on the criterion whose model produces the best forecast, instead of the criterion who has ensured best data access. All have all data, which should result in better and cheaper forecasts.

4 Policy options constituting triple-A policies and their cost-saving effect

This chapter presents 20 key policy options essential or at least beneficial towards triple-A RE policies. Their effect on various cost categories and overall production cost is described and quantified. In 4.1 the approach to select, quantify and present the policy options is explained. In 4.2 an overview table and the details are given for each of the 20 policy options individually.

4.1 Selection, quantification & presentation of policy options

Selection: Interviewees agree with options selected based on literature & expertise

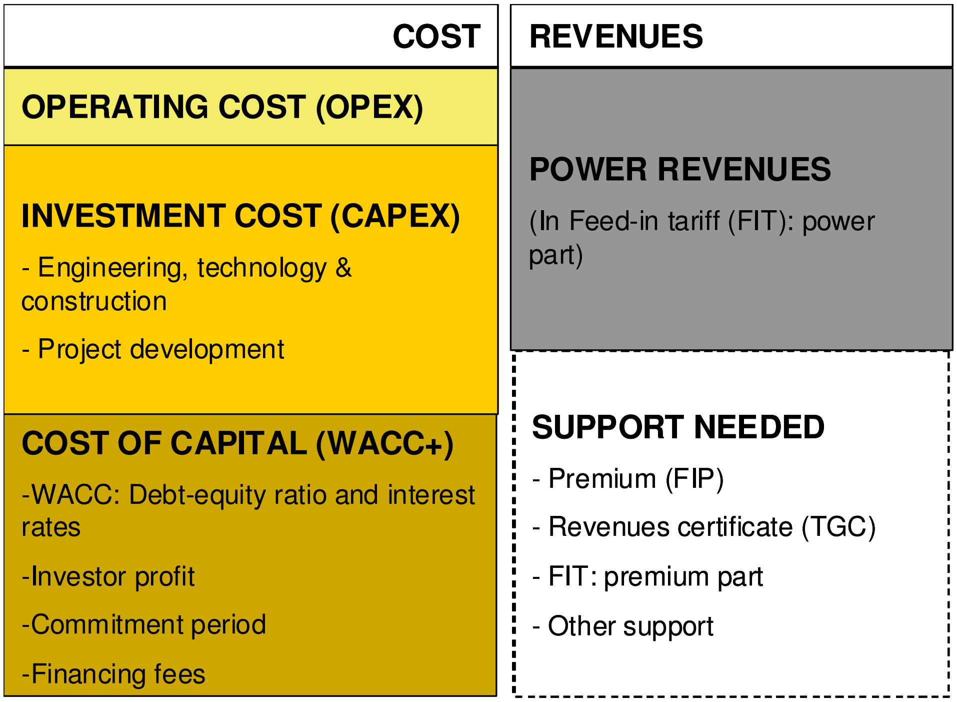
This chapter compiles and analyzes 20 key policy options essential or at least beneficial towards triple-A RE policies. The list of policy options is not exhaustive but aims to include the most relevant policy options which are available to reduce risk-related cost; it does not include necessary complementary non-risk-related policy options like adjusting support levels to generation cost to avoid windfall profits or reducing (hidden) subsidies for conventional generation to reduce the cost gap with RE – such complementary policy options are briefly described in chapter 5.

Some design details of triple-A policies have earlier been analysed and the impact has been quantified in literature (Lüthi & Wüstenhagen 2010a, 2010b; Giebel 2011; de Jager & Rathmann 2008), the former three based on conjoint analysis. The policy options identified in these projects and the quantification of their impact was used as a starting point in this project. The list of options was adapted based on the expertise available within the RE-Shaping consortium. In this project 25 interviewees were selected that are directly involved in financing RE projects in various countries, be it as lender (bank), equity investor, project developer or financing expert. Focus was on interviewees that have RE project activities in various countries, to be able to compare the perception and effect of policy in various countries on financing and cost. This allows describing the effect of details of a policy framework, instead of only comparing the overall effect of a country's policy framework. The interviewees agreed to a very large extent that the policy options selected represent the most relevant ones, only minor adjustments needed to be conducted.

Cost categories: Policies affect all cost and revenue categories, not only cost of capital

The figure below shows the cost and revenue categories affected by policies, as defined for this project. Interviewees were asked to specify per policy option whether and how the different cost categories are affected.

Figure 13 Cost categories affected by policies



The RES generation costs from the RET project/ investor's perspective consist of the following elements:

- The investment costs (**CAPEX** – capital expenditures), i.e. the cost for technology, land, construction and project development (costs for permits, grid connection contracts, consultancy, structuring finance etc.);
- The cost of capital (**WACC+**), consisting predominantly of the weighted average cost of capital (WACC) determined by the interest rate for debt and equity needed to cover the investment cost and the debt-equity ratio. In this report we also subsume investor profit under cost of capital (included in equity interest rate). Additionally included are fees paid for acquiring and structuring the required capital, and cost of capital occurring (sometimes long) before project construction or operation commences (e.g. if projects have to commit to penalties in case of not building the project/not using an offshore grid connection). The cost of capital can represent 20 to >50% of levelized cost of electricity in an average wind/pv project.
- The operating expenditures (**OPEX**), i.e. fuel and maintenance costs and cost for service contracts, guarantees and insurances, once the RES plant is operational. In wind onshore or PV projects this cost category is small compared to the other cost categories, in wind offshore OPEX becomes more relevant, and especially in case of biomass projects this becomes a major cost category due to the feedstock required.

The cost of capital is in literature sometimes subsumed under CAPEX. We explicitly differentiate investment costs and cost of capital, since both cost categories are influenced by different policy options. Often only the effect on WACC is considered, neglecting e.g. the effect of policies on project development cost (=investment cost).

With these variables, one can calculate the levelized generation cost, which represents the present value of the total cost of building and operating a plant over its financial life, converted to equal annual payments and amortised over the expected annual generation. The calculation of levelized generation cost allows the comparison between different energy technologies, as well as the determination of the financial gap between RES generation costs and **revenues from the power market**, that has to be covered by **support** to make projects economically viable (see right part of figure above).

Note that there is an interrelation between the cost of capital (especially WACC) and the risks that banks/investors assume around the other cost categories on the cost and revenue side: E.g. increased uncertainty around the level of power market revenues will drive up WACC, e.g. through increased interest rates and/or banks lending a lower share of the capital needed and thus more equity at higher interest rates being needed. Triple-A policies therefore have to address all cost categories.

Quantification

Based on the interviews and the literature mentioned the effect of policy options on the cost categories and on the overall levelized cost (i.e. average production cost) is quantified for an average wind onshore or PV project (both have no fuel cost as compared to biomass projects). The literature used mainly mentions effects on WACC and on overall levelized production cost or on overall revenues required. The interviewees were asked to describe the effect a policy option has on the various cost categories and to quantify this effect, either in terms of % change of a cost category (e.g. CAPEX), change of WACC in base points (100 base points = 1%) or % change of levelized production cost.

Based on the ECOFYS cash flow model answers given in terms of % change of a cost category or change of WACC in base points can be converted into % change of levelized production cost and vice versa. The following relations are used, which roughly fit most average wind onshore and PV projects:

2% reduction of levelized production cost	corresponds to / can be realized via	• WACC reduced by 50 base points, i.e. e.g. from 7.5% to 7.0%, or comparable changes in commitment period or financing fees **or** • CAPEX reduced by 2.5% **or** • OPEX reduced by 8%.

Lower levelized production cost translate to lower required support policy cost for technologies that have a cost gap with conventional technologies which is currently covered by support policies (compare figure 14 above): €1/MWh lower production cost will mean roughly €1/MWh less support needed – the exact ratio depends on how strongly support levels deviate from production cost. In case of relative figures (percentage cost reduction) a certain levelized production cost reduction

corresponds to a higher relative support policy cost reduction because the absolute amount of support policy cost is usually smaller than the absolute amount of levelized production cost.

Presentation

The figure below is used to present the quantitative results of the effect of policy options on levelized production cost. For each cost category a square indicates whether a relevant effect is observed. The size of the square indicates how strongly the policy option effects levelized production cost via this specific cost category (see legend below figure). E.g. the square showing the effect on WACC+ in the example below indicates that this policy option can reduce WACC+ in the order of up to 6% of levelized production cost. Sometimes below the square a range is given representing the values that may occur depending on technology, project size, country, literature source and interviewee: The lower value represents the minimum confirmed by most interviewees or literature sources and the upper value the maximum given by interviewees or literature. The sum given is the median of the range of answers given by interviewees.

Some policy options have instead of / additionally to the cost saving potential a positive impact on the amount of projects that can be realized – they remove a development constraint (barrier/bottleneck). Strong negative effects on growth – indicated by the large square symbol – can be observed in case of e.g. retro-active or abrupt policy changes, complex and lengthy permitting and grid connection or budget/capacity caps in the support system; in Member States where such conditions apply many project developers and investors will not consider to become active even if the level of financial support is high.

Figure 14 Quantification of effect and calculation of levelized cost saving potential

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■	■	▪			■	■
2-6%	3-4%	1-2%			9%	
(a)	(b)	(c)	(d)	(e)	(f)	(g)

Legend	Levelized cost saving potential:	Removing growth constraint:
■	= up to 10% and more	= Strong effect
■	= up to 6%	= Medium effect
▪	= up to 4%	= Small effect
▪	= up to 2%	

4.2 Description of policy options and their quantitative effect

The table below gives an overview of the 20 policy options presented in this chapter and their quantitative effect. Qualitatively the effects are explained afterwards individually per policy option.

The policy options are roughly sorted according to the following categories:

Policy stability is widely agreed to be the single most important element of Triple-A policies. It is a precondition for a good performance of the support policy in terms of reducing support cost and enhancing growth. Besides the elements of policy stability presented below, an important factor is the general political commitment of government and administration towards RE, the RE targets, stability, reliability and predictability.

While the importance of policy stability is widely agreed upon, often the question – even by policy makers – arises how to achieve policy stability. Four policy options are presented that can contribute to stabilizing the whole policy framework. The benefit of the ***Policy stabilizers*** is therefore mainly the cost savings and reduced deployment constraints described for the four *Policy stability* options described above. Both categories are strongly interrelated.

Besides *Policy Stability*, the policy options summarized under the header ***Revenue Risks*** have the largest influence on risk, risk premiums, support cost and growth. The policy options can reduce or remove the following risks:

- Certificate revenue risks in quota systems
- Power revenue and balancing risk
- Curtailment risk
- Annual variability risk

Further policy options are characterized by ***Using risk-free interest rates*** or ***Facilitating risk assessment & insurance*** and are analyzed and described in less detail.

Figure 15 Overview of triple-A policy options

Legend Levelized cost saving potential:
- ⬛ = up to 10% and more
- ■ = up to 6%
- ▪ = up to 4%
- · = up to 2%

Removing growth constraint:
- = Strong effect
- = Medium effect
- = Small effect

	Levelized cost saving potential: Cost – WACC+	Cost – CAPEX	Cost – OPEX	Revenue – POWER	Revenue – SUPPORT	SUM	Removing growth constraint
INCREASING POLICY STABILITY							
1 No retro-active policy changes for existing projects	⬛				⬜	>20%	⬛
2 No abrupt policy changes for upcoming projects		⬛			⬜	>10%	⬛
3 Simple & transparent permitting & grid access procedures		⬛				>10%	⬛
4 No budget/capacity caps & continual access to support		⬛				>10%	⬛
APPLYING POLICY STABILIZERS							
5 Support financed off-budget via consumer surcharge	·	·				3%	
6 (Temporary) government participation	■					5%	
7 Loan guarantees	■					5%	▪
8 EU enforcement RE directive implementation & Member State support level coordination							
REDUCING REVENUE RISKS							
9 Quota: Long time-horizon & serious penalties	⬛				▫	>10%	■
10 Quota: Price floor applied	▪				▫	7%	
11 Feed-in premium instead of quota system with TGC [1] incl. higher margins in quota system for technology suppliers and PPA counterparty)	▪	⬛ 1	▪		⬜ 1	>10%	
12 Feed-in tariff instead of feed-in premium [2] lower values in case of sliding feed-in premiums	▪ 2	·	·	▫		8%*	
13 Priority in case of grid congestion, priority dispatch + Compensation for forced curtailment	▪ ·			▫ ·	▫ ·	10% +4%	■
14 Compensation for annual variability wind/solar	·					2%	
USING RISK-FREE INTEREST RATE							
15 Front-loading the support payment stream	■					6%	
16 Soft loan	■					6%	
FACILITATING RISK ASSESSMENT & INSURANCE							
17 Availability of standardized risk assessment tools and ratings	▪	·				4%	
18 Availability of insurances for risks that are so far not insurable	·					2%	■
MISCELLANEOUS							
19 TSO responsible for wind offshore grid connection	·	·				2%	

Introduction POLICY STABILITY

Policy stability is widely agreed to be the single most important element of Triple-A policies. It is a precondition for a good performance of the support policy in terms of reducing support cost and enhancing growth. Besides the elements of policy stability presented below, an important factor is the general political commitment of government and administration towards RE, the RE targets, stability, reliability and predictability. Policy stability is a perception more than a fact, e.g. the four policy options presented below can not always exactly be monitored in practice. Once lost, the perception of stability is difficult and long to recover. When instability is perceived even high revenue is not able to overcome the risk and constitutes a severe growth constraint.

Policy stability

1 No retro-active policy changes for existing projects

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■				□	■	■
>10%				0-10%	>20%	
(a)				(e)		(g)

Retro-active policy changes are defined as policy changes that are announced and negatively affect projects for which financial close has already been reached and that are already under construction or operation. For example recently in Spain and the Czech Republic support levels for photovoltaic projects under operation have been reduced, although their support systems usually guarantee that the support level will be maintained for a certain amount of years. As investments have already been made, projects and their investors have to accept significant losses and/or undergo legal procedures in order to sue the regulator.

(a) Reduced investment certainty leading to higher (policy) risk premiums

Future investors will consider investment certainty to be lower and require higher risk premiums in a country where retro-active policy changes are considered possible (e.g. due to past experience). This may increase cost of capital considerably (WACC). The effect is comparable to the higher country risk premiums that have to be paid in countries with low legal stability, high corruption or the like.

(e) In quota systems higher margin for certificate counterparty

In quota systems the risk of retro-active policy changes may cause additional policy cost: In order to be bankable, projects have to sell the green certificates in advance to a creditworthy counterparty. That counterparty will take a higher margin in order to compensate for the risk of unexpectedly low future certificate prices due to retro-active policy changes.

(g) Project developers/investors will avoid the country

If a country implements retro-active policy changes it can take a long period afterwards to restore investor confidence. In this period risk-averse project developers and investors may completely avoid that country.

Policy recommendation:

Avoid retro-active policy changes. In case retro-active policy changes are considered in order to reduce policy cost: The policy cost savings that may be achievable in the short term may by far be outweighed by the increasing policy cost (risk premiums) in the long term.

- See policy recommendations to policy option 2 below.
- For appropriate policy responses to control policy cost see recommendations to policy option 4 *No budget or capacity caps & continual access to support*.
- Apply 'policy stabilizers' (policy options 5 to 8).

2 No abrupt policy changes for upcoming projects

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
	■			□	■	■
	2-10%			0-10%	>10%	
	(b)			(e)	(f)	(g)

Abrupt policy changes are defined as unexpected policy changes that affect projects still under development, before reaching financial close and starting construction. This is a key difference to *retro-active policy changes* affecting projects for which financial close has already been reached and that are already under construction or operation. Due to this difference *abrupt policy changes* affect investment cost instead of the cost of capital affected by *retro-active policy changes*:

(b) Increased project development cost

Abrupt policy changes may have three different effects:

Some projects under development can still be realized after adapting to the changed policy, but this adaptation and delay will increase their project development cost.

Some projects cannot be realized under the changed policy situation. This leads to sunk cost for project developers. Project developers will aim to recover these sunk costs in other, successful projects, again driving up project development cost of successful projects.

However, in support systems where support levels allow only moderate overall project returns, the room for recovering sunk cost in successful projects is limited. Often financiers will not accept development fees higher than a technology- & project-size-specific percentage in investment cost (e.g. 5%). If that is not sufficient to recover sunk cost, project development in that country will be considered an unattractive business and less new project development will be started, leading to a drying up project pipeline and less future growth opportunities for that country.

(e) In quota systems higher margin for certificate counterparty

(Same mechanism as under policy option 1)

In quota systems the risk of retro-active policy changes may cause additional policy cost: In order to be bankable, projects have to sell the green certificates in advance to a creditworthy counterparty. That counterparty will take a higher margin in order to compensate for the risk of unexpectedly low future certificate prices due to retro-active policy changes.

(f) According to [Lüthi 2010a] a country with one to three significant unexpected policy changes during the last five years would need to offer 10-30% higher revenues to attract investors/project developers. Increase in levelized cost occurs only if support level allows for higher project development cost (see (b) above), otherwise:

(g) Project developers/investors will avoid the country

If project development cost and sunk cost are too high to be recovered. See (b) above.

Policy recommendation:

Policy changes are inevitable because of policy learning or to adapt the policy to a changing context or evolving technologies. Key policy recommendations to reduce the impact of inevitable policy changes and avoid perception of policy instability:

- Avoid abrupt policy changes.
- Give enough but not too long notice for policy changes.
- Put in place transitional arrangements with grandfathering for existing projects & transparent transition milestones between old and new system for future projects.
- Engage with stakeholders in policy making process.

For appropriate policy responses to control policy cost see recommendations to policy option *No budget or capacity caps & continual access to support*.

Policy stability

3 Simple & transparent permitting & grid access procedures

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
	■				■	■
	2 - >10%				>10%	
	(b)				(f)	(g)

It is well known that complex, long and intransparent permitting & grid access procedures are a key barrier to RE deployment and drive up cost, in a comparable way as described for policy option 2 *No abrupt policy changes for upcoming projects*. This is especially important for technologies with NIMBY syndrome (e.g wind and large biomass).

(b) Increased project development cost

(comparable mechanism as under policy option 2)

Long, complex or intransparent (hard to forecast) permitting and grid access procedures may lead to three different effects:

Some projects can be realized, but laborious procedures and delays increase their project development cost.

Some projects cannot be realized as permits or grid access can not be achieved. This leads to sunk cost for project developers. Project developers will aim to recover these sunk costs in other, successful projects, again driving up the minimum required revenues for (project development of) successful projects.

However, in support systems where support levels allow only moderate overall project returns, the room for recovering sunk cost in successful projects is limited. Often financiers will not accept development fees higher than a technology- & project-size-specific percentage in investment cost (e.g. 5%). If that is not sufficient to recover sunk cost, project development in that country will be considered an unattractive business and less new project development will be started, leading to a drying up project pipeline and less future growth opportunities for that country.

(f) According to Lüthi 2010 a country would need to offer 10% higher revenues to PV projects for each half year of prolonged administrative procedures in order to still attract investors/project developers. This adds up to 40% in case of two additional years of procedures. Results for wind onshore are comparable. Increase in levelised cost occurs only if support level allows for higher project development cost (see (b) above), otherwise:

(g) Project developers/investors will avoid the country

In case of too long and complex procedures even high revenues will not be sufficient to overcome the risk and to recover project development cost and sunk cost. See (b) above.

These results are illustrated by an example from two Italian regions - Sicily and Puglia: In both regions the same feed-in tariff applies. Although Sicily has better solar resources, Puglia has more PV projects as procedures are shorter - investors accept lower profits if procedures are shorter/more transparent. This example also illustrates why EU wide harmonized support would not automatically lead to projects being allocated at best sites.

Policy recommendation:

Besides the well-known general recommendation to streamline and shorten processes: The negative impact of sunk cost due to defaulting project development can be minimized if requirements to project (i.e. financial/labour effort = investment at stake) do not increase faster than the success chance of projects. This is explained in more detail in the recommendation for policy option 4 *No budget or capacity caps & continual access to support*.

Policy stability

4 No budget or capacity caps & continual access to support

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
	■				■	■
	2-10%				>10%	
	(b)				(f)	(g)

Some Member States apply caps in order to limit growth or policy cost to be covered from government budget or consumers. Often caps are technology-specific and specify a maximum budget or capacity to be built or committed in a given period. In some systems projects receive support on a first-come first-serve basis. In other systems projects have to apply before a fixed date and are chosen randomly in case of demand being higher than the cap – a “gamble” from the project developer’s perspective. Caps lead to stop-and-go in the market. Effects are comparable to those of policy option 2 *No abrupt policy changes for upcoming projects*:

(b) Increased project development cost

(comparable mechanism as under policy option 2)

The existence of caps and application processes for support may have three different negative effects:

Some projects do not gain support during their first application, but gain support one or several years later and can still be realized. The delay and repeated application for support will increase project development cost.

Some projects cannot be realized because they never gain support or project developers give up applying. This leads to sunk cost for project developers. Project developers will aim to recover these sunk costs in other, successful projects, driving up project development cost of successful projects.

However, in support systems where support levels allow only moderate overall project returns, the room for recovering sunk cost in successful projects is limited. Often financiers will not accept development fees higher than a technology- & project-size-specific percentage in investment cost (e.g. 5%). If that is not sufficient to recover sunk cost, project development in that country will be considered an unattractive business and less new project development will be started, leading to a drying up project pipeline and less future growth opportunities for that country.

(f) According to Lüthi 2010 a country would need to offer 10-30% higher revenues in case a cap is applied in order to still attract investors/project developers. Increase in levelised cost occurs only if support level allows for higher project development cost (see (b) above), otherwise:

(g) Project developers/investors will avoid the country

If project development cost and sunk cost are too high to be recovered. See (b) above.

Policy recommendations:

Budget or capacity caps should be avoided. Projects should continuously be able to apply for support. However, especially for more expensive technologies like photovoltaics, cost reductions and growth increases can be huge, as recently observed in various Member States, potentially heavily affecting policy cost. Possible policy responses are summarized below.

Governments should **monitor market development and cost price development in all supported technologies very closely**. That allows reacting timely to faster than desired growth or faster than envisaged production cost reductions. Member States should learn from each other when determining support levels and growth trajectories and could even coordinate these, compare *Option 8) Member State coordination of support levels*. Compare also *Option 6) Temporary government participations,* as these may also be helpful to gain insight in market and cost price development.

A precondition to avoid caps may be off-budget financing of support, compare *Option 5) Support financed off-budget via consumer surcharge*.

The appropriate reaction is a reduction of support levels for new projects in one or several smaller steps, announced as long beforehand as possible. However, even support level reductions announced at short notice are by most market parties considered to be preferable above caps. From a financier perspective support level reductions that closely follow the production cost reductions may be considered positive as they reduce the risk of future retro-active changes.

Preferable above abrupt support level changes are growth corridors with automatic adjustment of support levels. These increase investment stability as development of support levels is better foreseeable for project developers and may be more effective in limiting support policy cost if the political/bureaucratic process is considered to be too slow for the required quick policy response. A growth corridor or growth path is the amount of renewable capacity a country would like to see installed in a given year (e.g. 800-1,200 MW, or 1,000 MW) or part of a year (e.g. 200-300 MW per three months). In case growth is in line with that growth corridor, the normal tariff degression would apply (e.g. minus 10% per year). In case growth is stronger than envisaged, the tariff degression is increased (e.g. minus 1% per 10% overshoot). In case of less growth than envisaged, tariff degression is decreased. In order to be effective in limiting the increase of support policy cost, automatic adjustments may have to be frequent and/or rigorous. The higher the frequency of adjustments (e.g. once in three months instead of once a year) and the higher the increase of tariff degression in case of overshoot, the higher the control on support cost, but the lower the investment stability.

If caps are still to be applied: Two step support application process

The negative impact of caps can be reduced – not completely avoided - if requirements to project (i.e. financial/labour effort = investment at stake) do not increase faster than the success chance of projects. This can e.g. be achieved by a two step support application process (compare UK Renewable Energy Association, *REA response to Electricity Market Reform consultation*, p. 11/12, March 2011, www.r-e-a.net):

1) A project can reserve capacity under the cap and the support level at a first gate, e.g. as soon as a site is secured, certain permits are in place and a quotation for grid connection is in place.

2) The project then has a certain period to negotiate engineering, procurement and construction contracts, financing, and possible power or certificate purchase contracts. If these are in place and financial close is in place within the given period, support as reserved in step 1 is guaranteed as long as the project is commissioned within a given period and progress can be shown at regular intervals during that period. If not, the reservation is cancelled and the capacity is available for other projects. The project can re-apply for support, but now new support levels and caps may apply.

Such a system may limit risk for project developers and also provide government with more detailed and early information about the development of the project pipeline needed to adapt support policy optimally. Disadvantage may be high administrative effort. This process can still not prohibit that capacity/budget is reserved for projects that never materialize.

Introduction POLICY STABILIZERS

While the importance of policy stability is widely agreed upon, often the question – even by policy makers – arises how to achieve policy stability. Below four policy options are presented that can contribute to stabilizing the whole policy framework. The benefit of the *POLICY STABILIZERS* is therefore mainly the cost savings and reduced deployment constraints described for the four *POLICY STABILITY* options described above.

Policy options 6 and 7 have in common that the government shares in the risk of projects, via temporary participation or loan guarantees. A government would be more careful when changing policies, as envisaged (budgetary) benefits from policy changes may be eaten up by losses from projects that are negatively affected by the policy change and where government has own money at stake.

Policy Stabilizer

5 Support financed off-budget via consumer surcharge

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪	▪				■	
2%	0-2%				3%	
(a)	(b)				(f)	

Historical experience shows that support instruments relying on the government budget are more prone to abrupt or frequent policy changes than those instruments that do not rely on the budget. This is due to the fact that the budget is (annually) subject to heavy political discussions especially in times of constrained budgets or when new governments are looking for options to cut expenditures in order to be able to finance changed political priorities. Off-budget financing can reduce risks of abrupt or retro-active policy changes, but does not prevent them completely.

Especially feed-in systems are already in many Member States financed off-budget via consumer surcharges. Investment grant and fiscal incentive schemes still usually rely on budgets with negative effects for stability. Quota systems usually do not rely on the budget.

(a) Reduced risk of retro-active policy changes due to government budget constraints.

(b) Reduced risk of abrupt policy changes affects development of upcoming projects.

(f) If in a Member State off-budget financing is the key to more stable policies, its effect on cost savings will be much higher, like the figures for the four *POLICY STABILITY* options showed. However, the exact contribution of off-budget financing to policy stability is hard to quantify generally, the figure therefore represents a best guess by interviewees.

Policy recommendation:

Finance support off-budget via consumer surcharges. Ideally the level of the surcharge automatically follows the amount of support needed, without need for political decision making or even without government institutions being involved like e.g. in Germany. In case regular government intervention is needed to determine the surcharge level this can again cause constraints and stop-and-go policies. Using such flexible off-budget financing is usually a precondition enabling policy option *4 No budget/capacity caps & continual access to support,* because it is impossible to exactly forecast growth and required budget for a given year. The latter is, however, not necessary as long as the average of growth and support needed over several years is in line with the longer term targets and envisaged growth trajectories – as long as overspending in one year is compensated in other years consumers are not negatively affected in the long term. Consumer surcharge is not fully without risk: The risk of opposition from public because of higher electricity prices exists.

Policy Stabilizer

6 (Temporary) government participation

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■					■	
4-6%					5%	
(a)				(e)	(f)	

Government participations have in many Member States for decennia been used in the oil and gas exploration, development and production. In the RE sector e.g. the UK Crown Estate participates with 50% in joint ventures for project development of offshore wind energy. Similar roles have been / could be played by institutions like Nordsøfonden (Danish North Sea Fund) in Denmark or Energie Beheer Nederland in the Netherlands.

Government participation can be limited to development, construction and commissioning plus e.g. two years of operation. When a project is operational with a proven track record, it can possibly be refinanced at better loan terms (e.g. higher leverage with lower equity participation and lower interest costs), and such the government participation can be repaid and used for other new projects on a revolving fund basis. This way the effect on the government budget can be minimized. Alternatively the government can initially give investment grants which are converted to equity (government participation) or debt after successful commissioning of a project.

(a) Increased trust by investors and banks

Government participation increases trust by investors and banks that a project can become commercially successful, reducing the cost of capital. On the one hand it can be expected that the government will support the project during permitting and construction, and will not change policy negatively affecting the project. On the other hand hesitating investors/banks may see government participation as a quality label for the project which convinces them to also step in - as an interviewee put it: “Crucial is not the amount of government (equity) money but the trust that it builds with other investors”.

(e) Allows better adjustment of support levels to actual cost

Through participations in projects government can gain in-depth insight into the cost structure of RE projects. This knowledge may be used when determining support levels - besides the usual market surveys and input from lobbying parties. This allows support levels to be set better in line with actual cost and envisaged growth, avoiding undesired high or low growth or high support cost.

(f) [Taskforce NL] expects a WACC reduction of 1.4% for offshore wind projects (-3.5% required return on equity & -0.5% debt interest).

Policy Stabilizer

7 Loan guarantees

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■					■	■
4-6%					5%	
(a)					(f)	

Loan guarantees are frequently used by many Member States' export credit agencies and international institutions like the World Bank group (IFC). In a loan guarantee, the government underwrites all or part of the debt for a project or provides guarantees for the case a project defaults. Whenever projects cannot repay their loan and 'default', the loan guarantee applies and the government/the loan guarantee scheme pay the guarantee or take over a commercially not viable project. That way lenders (banks) have significantly lower risk in case of default or underperformance of the project. Projects may have to pay a fee for such guarantees, like they would have for other types of (commercially) available insurances.

(a) Reduced risk for lenders

The reduced risk for lenders leads to a lower WACC. The exact parameter change leading to the reduced WACC depends on the project; options include better debt-equity shares, lower interest rate, or longer debt terms.

Some projects only become bankable through a loan guarantee. For both investors and lenders a loan guarantee increases the trust that policies will not be changed negatively affecting the project.

(f) The overall cost saving is determined by the reduced cost of capital on the one hand, and the income from or cost of the loan guarantee scheme on the other hand. The income from or cost for the loan guarantee scheme depends on the percentage of projects defaulting, the average cost for defaulting projects, and the premiums that projects pay for a loan guarantee.

Policy Stabilizer

8 EU enforcement RE directive implementation & Member State support level coordination

Below two options are described that may have impact on national policies and would only indirectly affect RE projects. Their effect can therefore hardly be quantified but most interviewees supported them and stressed their relevance. The benefit of these *POLICY STABILIZERS* is therefore mainly the cost savings and reduced growth constraints described for the four *POLICY STABILITY* options described before.

Strict enforcement of RE Directive implementation by EC

The European Commission ensures that the RE Directive provisions (like priority grid connection) are implemented and sufficient policies to achieve targets are in place. If necessary the EC promptly enforces the implementation by Member States via legal procedures. Additionally the EC could issue guidelines on minimum design standards and/or best practice design.

Support-level coordination

As described in *Option 4) No budget or capacity caps* some Member States determine support levels that are inappropriately high from the start, due to outdated information on production cost or effective industry lobby. Often this leads to unexpected policy changes when Member States later want to abruptly limit support cost. This may have negative repercussions for other Member States: Retro-active policy changes reducing sector-wide investor confidence; disproportionally high support in one country spoiling efforts to bring support cost down in other Member States. This could justify a voluntary or binding process for support-level coordination, either bottom-up by some Member States or top-down by the European Commission.

Such a process could have the following **objectives/benefits:**

- Helping Member States to learn from each other how to determine (technology-specific) support levels in such a way that they suit their (technology-specific) deployment target.
- Assuring that support levels give sufficient investment incentive, but not allowing excessive profits and thus avoiding national boom and bust cycles for certain technologies (e.g. PV). This leads to lower policy cost and makes target achievement more likely.
- Counterbalancing national industry lobbies in the national support level setting process (e.g. the PV lobby successfully delayed support level reduction in several Member States). Leads to lower policy cost.
- Increasing perceived policy stability by industry due to a more rational support level setting process and less examples of stop-and-go around Europe. Leads to increased credibility of NREAP growth trajectories which will stimulate sufficient investments into the supply chain, thus avoiding future bottlenecks and competition among Member States leading to scarcity prices. -> lower risk premiums for supply chain investments -> lower investment cost for RE technology -> lower policy cost
- Leaving Member States freedom in

- selecting preferred technologies and capacities -> process would aim to suit support level to Member State-specific technology-specific deployment targets
- support system choice -> process can be applied to all support systems (FIT, FIP (both fixed and sliding) and quota systems (in case banding factors and/or minimum prices apply)).

Such a **process** could be started informally among a group of interested Member States or be coordinated by the EC right from the start. A first step could be a more or less standardized process how to inform other Member States about envisaged support level or other policy changes, e.g.:

- announce upcoming support level review/change as soon as government starts considerations
- specify elements/rationale in support level determination/change a specified time before the envisaged implementation date
- use a standardized reporting format for this purpose

Do Member States have to participate in this process? Do Member States have to stick/react to feedback from other Member States or the EC? - **Various degrees of freedom (from completely voluntary until binding) can be imagined:**

- Member States only inform each other / the EC on envisaged changes
- Member States 'peer review' each other with (non-)binding feedback
- The EC gives guidance/opinion or just provides information regarding the elements below and puts information of Member States on transparency platform

Elements for potential coordination or information provision include:

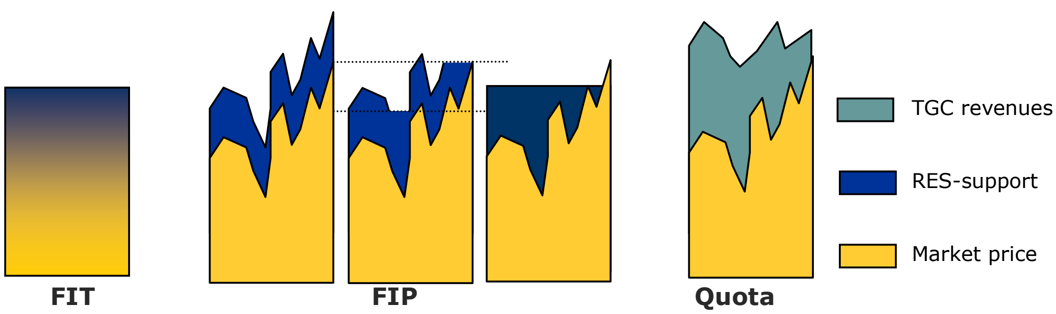
- formulae for calculation of levelized cost of electricity
- the level for specific investments per technology (frequently updated)
- regionally specific capacity factors
- biomass prices
- reasonable (country specific) interest rates, duration of support, grid connection cost
- in FIP and quota: calculation of value of RES electricity, costs for balancing

Introduction REVENUE RISKS

Besides *Policy Stability*, the policy options summarized under the header *Revenue Risks* have the largest influence on risk, risk premiums, support cost and growth. The policy options can reduce or remove the following risks:

- Certificate revenue risks in quota systems
- Power revenue and balancing risk
- Curtailment risk
- Annual variability risk

While the importance of aiming for *Policy Stability* is widely acknowledged, some of the policy options presented below are more controversially discussed – compare the discussion *Macro-economically optimal allocation and treatment of risk* in chapter 4. Listing all these options is not to be seen as a judgment that all these options should be implemented. As discussed in chapter 4, it depends on the specific Member State and its energy market, technology, envisaged investor group and project size which policy options are ideally applied.



fixed premium - cap & floor - sliding/Contract for difference

The figure above illustrates the different degrees of revenue fluctuation in the different support instruments. On the y-axis the overall revenues are shown during the support period (x-axis).

Feed-in systems with a fixed tariff (FIT) offer the highest level of revenue stability, followed by premium systems that cover the difference between the spot market price and the guaranteed price (sliding FIP / contract for difference). Lower levels of revenue stability are provided by fixed premiums and especially by quota systems where both power market and support revenues can fluctuate.

Revenue stability very much depends on the detailed support policy design. Influencing factors are e.g. the support duration and inflation adjustments in feed-in systems or in quota systems the time horizon of the obligation, the penalty system, technology splits or banking of certificates.

Revenue risks > reducing certificate revenue risk

9 Quota: Long time-horizon & serious penalties

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■				▪	■	▪
10%				4%	>10%	
(a)				(e)		

Obligation levels need to be set well in advance and the quota obligation should be guaranteed to be in place for a sufficiently long time period in the future in order to guarantee future demand for RES. For the same reason penalties should be set well in advance, significantly above green certificate prices, and enforcement of the quota obligation should be guaranteed.

These issues are widely accepted to be preconditions for properly functioning quota systems. In best-practice systems they are already applied, therefore this policy option is presented separately from the following one (Policy option 10 *Price floor*) which is only used in some quota systems. Compared to a quota system where these issues are not yet applied, the following effects and related cost savings likely occur.

(a) **Reduced risk of lower certificate prices/revenues**

If the issues above are applied, future demand for certificates will be stable and foreseeable. This reduces the risk of decreasing future certificate prices due to low future demand and therefore the risk of lower than expected revenues. WACC will be lower.

(e) **Lower risk premium/margin for counterparty buying certificates**

In order to be bankable, projects need to ensure a stable revenue stream for certificates via a contract with a creditworthy counterparty, usually an energy supply company obliged under the quota obligation. For the same reason as described above (a), this counterparty will include a lower risk premium when negotiating certificate prices if uncertainty about future development of certificate prices is reduced.

Revenue risks > reducing certificate revenue risk

10 Quota: Price floor applied

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■				■	■	
4%				2-4%	7%	
(a)				(e)		

Policy option 9 *Long time-horizon and serious penalties* described above is a first step to stabilize certificate prices. Revenue risks can be further reduced by one of the following measures that ensure a certain minimum price / price floor for certificates:

- A minimum (fall-back) price exists e.g. in Belgium, where investors can chose to sell their certificates for that price to the TSO.
- In the UK system so called *Headroom* is implemented, meaning that the quota level will be increased in case production comes close to the quota. Therefore the *buy-out price* (penalty) actually becomes the minimum price for certificates (because certificate supply will never suffice to meet demand and revenues from the penalty will be distributed over those parties that submit certificates).
- Government could also use market makers to ensure a certain certificate price.

In all cases the quota system characteristics come closer to a feed-in premium system as a large share of the revenues from certificate sales become comparably certain to those from a feed-in premium. The part of revenues that depends on certificate prices above the price floor remains risky.

(a) **Reduced risk of decreasing future certificate prices**

WACC will be lower.

(e) **Lower risk premium/margin for counterparty buying certificates**

In order to be bankable, projects need to ensure a stable revenue stream for certificates via a contract with a creditworthy counterparty, usually an energy supply company obliged under the quota obligation. This counterparty will include a lower risk premium when negotiating certificate prices if uncertainty about future development of certificate prices is reduced.

Revenue risks > removing certificate revenue risk

11 Feed-in premium instead of quota system with tradable certificates

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■	■ + ■	■		■ + ■	■	
4%	4 + 6%	4%		4 + 6%	>10%	
(a)	(b1) (b2)	(c)		(e1) (e2)	(f)	

The certificate revenue risk can be reduced to a large extent if policy options *9 Long time horizon and serious penalties* and *10 Price floor* are applied. In order to fully remove certificate revenue risks a quota scheme can be replaced by a feed-in premium or a feed-in tariff. This policy option 11 compares a best-practice quota system (with long time horizon and serious penalties but without price floor) with a fixed feed-in premium. The next policy option (12) assesses the additional effect of removing power revenue and balancing risk if a feed-in tariff instead of a feed-in premium is applied and the effect of a premium that is corrected for wholesale electricity prices ('sliding' or 'contract for difference').

While a price floor (option 10) guarantees that a large share of the revenues from certificate sales become comparably certain to those from a feed-in premium, the part of revenues that depends on certificate prices above the price floor remains risky in a quota system. Taking away the full revenue risk leads to comparable but a bit stronger effects as option 10:

(a) No risk of decreasing future certificate prices

WACC will be lower and financing fees may be lower due to simpler revenue structure.

(e1) No risk premium/margin for counterparty buying certificates

In order to be bankable, projects in a quota system need to ensure a stable revenue stream for certificates via a contract with a creditworthy counterparty, usually an energy supply company obliged under the quota obligation. This is not needed in a feed-in premium system.

In a quota system – compared to a feed-in premium – banks and investors will either increase cost of capital in order to compensate for higher risks as described above. Or they may aim to compensate the higher risk from certificate revenues via requiring projects to only contract established companies / technology providers and use especially complete performance guarantees or warranties and the like. In the latter case the cost of capital would not be higher than in a feed-in premium, but investment cost and operating cost would increase:

(b1) Lower investment cost in feed-in premium

In quota system banks may require only contracting established companies/ technology providers in order to minimize overall project risk.

Due to the more complex revenue structure in a quota system higher cost for structuring contracts and consultancy assessments of future certificate prices occur.

(c) Lower operational cost in feed-in premium

In quota system banks may require especially complete and long performance guarantees, service contracts, warranties and the like in order to minimize overall project risk.

Two further effects can be observed:

(b2) Higher prices/margins for technology and project development in quota systems

Currently in most quota countries prices for technology and project development are higher than in most non-quota countries, and thus are margins for supplying companies. It can not be judged whether this causes the comparatively high certificate prices or whether it is due to high certificate prices and potential project profits that internationally active technology suppliers and project developers adapt their prices.

(e2) Counterparty taking higher margin and both project & counterparty taking upside at consumer cost in quota system

If potential project profits are high due to high certificate prices, the certificate counterparty in a quota system will also require a higher margin.

Besides, the upside (chance of unexpectedly high future certificate prices) is shared between the project and the counterparty at consumer cost while such an upside does not necessarily exist in feed-in premium systems (depending whether the premium is fixed or sliding with power prices).

(f) Altogether, a feed-in premium will reduce levelised cost by at least 10% compared to a quota system without price floor, which is more than a price floor can achieve. Most likely, taking into account all effects above and the currently observed differences in potential profit rates among Member States, the cost saving potential is considerably higher.

Revenue risks > removing power revenue and balancing risk

12 Feed-in tariff instead of feed-in premium

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■	▪	▪	■		■	
2-4%	1-2%	1-2%	2-4%		8%	
(a)	(b)	(c)	(d)	(e)	(f)	

In both quota and feed-in premium systems the RE project is responsible for selling its produced power to the market. Under a feed-in tariff a fixed price is paid to the RE project encompassing both the value of the physical power and the premium.

(a) Reduced power revenue and balancing risk

WACC will be lower due to less risk and financing fees may be lower due to simpler revenue structure (only one guaranteed revenue stream).

The power revenue risk can also be reduced within feed-in premium systems, e.g. if premiums refer to the average annual electricity market price ('sliding premium', 'contract for difference' as applied/introduce in e.g. Spain, Denmark, Netherlands, Germany, UK) – in that case the levelized cost saving potential of a feed-in tariff is substantially lower than 8%, or in other words, a sliding premium is from a risk perspective between a feed-in tariff and a fixed premium, according to some respondents almost comparable to a feed-in tariff. Risk in a FIP system is also reduced almost completely in case projects can choose – e.g. monthly – whether the FIP or a parallel FIT system should apply to their project.

(b) Lower investment cost

Due to the more simple revenue structure cost for structuring contracts may be lower and no consultancy assessments of future power and balancing prices need to be paid.

The requirements of banks to minimize risk via contracting (more expensive) established companies/ technology providers may be lower than in a feed-in premium due to the lower revenue risk.

(c) Lower operational cost

No transaction cost for selling power, forecasting & balancing occur under a feed-in tariff. The actual cost for forecasting & balancing are shifted to a 3rd party obliged by government, and therefore these cost savings are not included in above table. Discussion is ongoing whether rather projects or 3rd parties are better prepared to forecast and balance at minimum cost - compare discussion in chapter 4.

The requirements of banks to minimize risk via especially complete performance guarantees, warranties and the like may be lower than in a feed-in premium due to the lower revenue risk.

(d) No margin and upside for PPA counterparty

Under a quota or feed-in premium system the counterparty for the power purchase agreement (PPA) will charge a certain amount for forecasting and balancing – these cost savings are not included in above table as they still occur at a 3rd party. On top of these cost however, the PPA counterparty requires a margin and wants to share in the upside (chance of unexpectedly high future power market prices). This upside does only exist in fixed premium systems – it does not exist if the premium is sliding with power prices. In markets with very liquid power exchanges (only NordPool so far) PPAs are not needed in all cases for projects to be bankable – in that case a feed-in premium does not cause additional cost for PPA counterparty margin/upside.

(f) The levelised cost savings of a feed-in tariff compared to a fixed feed-in premium are expected to be about 8%. Some literature sources quantified this effect in the past, usually with a focus on the effect on WACC, and it is not clear in how far the other effects shown above which do not materialize in WACC are included:

- [Giebel] assessed via conjoint analysis that WACC in a feed-in premium for wind onshore in Germany would be 2% higher (4% higher return on equity & 1% higher debt interest). This would translate to 8% higher levelized cost based on our assumptions.
- [Pöyri] expects for the UK market that WACC in a feed-in premium would be 1% higher compared to a feed-in tariff. This would translate to 4% higher levelised cost based on our assumptions.

Revenue risks > curtailment risk

13 Priority in case of grid congestion, priority dispatch + compensation for forced curtailment

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■ + ▪			■ + ▪	■ + ▪	■	■
4% + 2%			4% + 2%	0-4% + 0-2%	10%+ 4%	
(a1) (a2)			(d1) (d2)	(e1) (e2	(f)	(g)

Curtailment means that a RE plant is forced to temporarily reduce or stop its production and represents a major revenue risk. This may happen in two situations:

- In case of grid congestion a reduction of production is required to maintain grid stability. In many situations this should be improved through grid extensions, but in the longer term future in case of very high RE shares some curtailment may be needed to avoid extremely high grid investments.
- In case priority dispatch applies to RE production, low power demand during times of high RE and baseload production can lead to negative power prices paid by baseload producers in order to avoid costly production reduction for few hours only. In some Member States regulators consider curtailment in order to avoid the macro-economically questionable effect of negative power prices (however, it is also argued negative prices are a price signal to invest in more flexible conventional production capacities and in demand-side management and storage).

According to the RE Directive RE plants should receive priority in case of grid congestion and within the dispatch. Proper implementation of this priority can reduce the curtailment revenue risk considerably (effects a1, d1, e1) and is considered a pre-condition for investment.

The curtailment revenue risk can be completely eliminated if, on top of this priority treatment, RE producers are financially compensated for lost revenues in case of curtailment, occurring due to grid congestion or (extremely) negative power prices (add effect a2, d2, e2). Such a compensation can also be organized outside of the support system e.g. via the grid congestion management system. A downside of curtailment compensation from a macro-economic perspective is the removal of locational signals stimulating RE projects to choose sites best suited from a grid and market integration perspective.

(a) Reduced risk of lost power & support revenues in case of grid priority and priority dispatch (a1). In case curtailment compensation applies no risk exists (a1+a2).

(d) Reduced power revenue losses in case of grid priority and priority dispatch (d1). In case curtailment compensation applies no risk exists (d1+d2).

(e) Reduced support revenue losses in case of grid priority and priority dispatch (e1). In case curtailment compensation applies no risk exists (e1+e2).

(f) Priority in case of grid congestion and priority dispatch reduces levelized cost by about 10%. Additional curtailment compensation is expected to reduce levelized cost by another 4% ([Giebel] expects a WACC reduction by 0.9% for wind onshore projects). The importance of grid priority in wind onshore projects across the EU is also stressed by Lüthi 2010.

Revenue risks > annual variability risk

14 Compensation for annual variability wind & solar

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪					▪	
2%					2%	
(a)					(f)	

An important part of the revenue risks in wind or solar projects is caused by the annual resource variability: Full load hours of a wind project during a full year for example can deviate by more than 10% from the long-term average. Banks require debts to be repaid also during one or more exceptionally bad wind or solar years. This can be guaranteed via three means:

- Insuring/hedging the risk via wind derivatives. However, since the credit crisis liquidity in wind derivatives appears to be lower and they are therefore less used in projects.
- The support level is annually adjusted to the wind/solar yield: Higher per MWh support level in years with low yield and lower per MWh support level in years with high yield. Such a system has not yet been implemented and details would need to be worked out. Currently some Member States already adjust support levels to average site-specific wind yield, and all base their support level somehow on the national wind conditions (even in quota systems via banding); if the long-term average national wind conditions would change due to climatic changes, support levels would most likely also be adjusted by governments – justifying also annual adjustments? Compare chapter 4 for the discussion whether annual variability risk is better covered by projects or by the public.
- In case neither of the two options above is available, usually the equity share or the loan repayment reserve account is increased and the debt share is decreased, which increases the cost of capital.

A compensation in the support system for the annual variability of wind or solar resources would therefore lead to a

(a) Reduced/no risk of defaulting project due to one or more exceptionally bad wind/solar years. This leads to a lower WACC due to a more favourable debt-equity share.

(f) [Giebel] assessed via conjoint analysis that WACC under such a compensation mechanism would be 0.6% lower. This would translate to 2% higher levelised cost.

Using risk-free interest rate

15 Front-loading the support payment stream

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪ + ■					▪ + ■	
2 + 4%					2% + 4%	
(a1) (a2)					(f)	

Instead of having a constant support level for the complete support duration, it can be considered to increase support for the first years of a project while decreasing support in the last years. The total sum of financial support stays constant or can be reduced in line with the reduced cost of capital.

Front-loading is for example applied in the German support for wind energy, where for most projects feed-in tariffs are reduced in later years. The wind offshore industry in Germany now suggested having even stronger front-loading than so far: 8 years high tariff, followed by 12 years low tariff.

Front-loading is also possible in quota systems with banding: More certificates per MWh in first years, less certificates per MWH in last years.

A comparable effect can be achieved via tax law allowing accelerated or flexible depreciation.

An extreme case of front-loading is cash grants paid at the project start (investment subsidies). The reason most support currently is paid for production during a plant's lifetime is that the aim is to stimulate maximum production over a plant's lifetime, while in the past a too strong focus on grants has sometimes lead to incentivizing capacity which is afterwards not optimally maintained and operated or plant design with generator capacity being too high compared to other parts of a plant. Therefore a balance has to be found between ensuring optimum production over the plant's lifetime and reducing its production cost via front-loading, which may include certain amounts of cash grants.

(a1) Less risk due to earlier repayment of loan and equity

Front-loading will reduce WACC slightly because negative events occurring in later years of a plant's lifetime have less impact on a project's financial result. Often manufacturer's performance guarantees and full service agreements are in place only during the first years of a plant's lifetime and front-loading leads to a smaller share of revenues being paid during the unsecured latter years. The effect of cash-grants is even stronger than the effect of front-loading production support.

The exact effect also depends on fiscal consideration of the companies involved.

(a2) Less interest to be paid

The project has to pay interest over a shorter period and/or for less loan/equity. The support on the other hand has to be paid earlier. This constitutes a macro-economic cost saving only, if for the support (paid by consumers or government budget) a lower / risk-free discount rate can be assumed.

Using risk-free interest rate

16 Soft loan

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪ + ■					▪ + ■	
2 + 4%					2% + 4%	
(a1) (a2)						

Interest rates and repayment periods of loans have a major impact on the overall cost of RES projects. Especially new technologies, smaller projects or project developers without a proven track record often experience difficulties in obtaining commercial loans at reasonable conditions. Governments can increase commercial viability of projects significantly by offering low interest loans or loan guarantees. Governments can offer low interest loans for specific technologies directly through state-owned banks or through subsidies to commercial banks. These loans can be characterized by lower interest rates (typically 1-2%) and/or longer repayment periods. Low interest loans have been applied successfully in for example Spain and Germany.

(a1) Soft loan conditions set a market standard which influences other financing parameters

Soft loans may indirectly affect other key financial parameters used by investors and other lenders, such as a longer economic lifetime, longer loan tenure and a shorter tail (time span between debt being fully repaid and end of economic lifetime). The alignment of the debt period in the German low-interest government loan (KfW bank) with the period of the feed-in tariff scheme, both contribute to a longer loan tenure and significantly lower cost of capital.

Soft loans may help developing an immature loan market for (innovative) technologies, triggering more commercial banks to engage in RE financing, which leads to improved loan availability.

Some financiers see soft loans reducing the equity share.

(a2) Less interest to be paid

The project has to pay less interest. This constitutes a macro-economic cost saving only, if for the soft loan (subsidy) (paid by consumers or government budget) a lower / risk-free discount rate can be assumed.

Availability of soft loan is considered a medium benefit for wind onshore in [Lüthi 2010b]

Market facilitation & transformation

17 Availability of standardized risk assessment tools and ratings

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
■	▪				■	
2-4%	0-2%				4%	
(a)	(b)				(f)	

The financial sector could be triggered to develop more standardized risk assessment tools and ratings for RE technologies, in order to offer an independent opinion of a project's ability to deliver the expected returns and thus increase a developer's ability to attract investment. The possibility to rate some projects as “investment grade” projects (i.e. above a specific rating level) would attract investment and enable access to capital at reduced costs. Such rating would include a review of the full range of risks, i.e. country, site-specific, construction, technological, environmental, operation and management risks. This rating could be performed by a dedicated EU rating agency or possibly by traditional rating agencies. If the option of an EU agency were to be pursued, it should provide direct advice to financial bodies in charge of issuing loans, loan guarantees, letters of credit, and insurance support, and/or by taking direct equity stakes. The idea of a standardized risk assessment tool is also raised in Altran 2011. Establishing standardized instruments might be very complex as they must be sector-/technology- and Member State-specific; frequent amendments might be needed due to fast evolution of technologies; and it might be difficult to convince stakeholders using new instead of their (internally) established ones. Wind offshore might be the technology where this option is most promising.

Next to using these tools and ratings for individual projects, banks could use them for their risk models, based on which they are assessed under BASEL regulations for solvency. Banks could more precisely estimate their Risk-adjusted-Rate of Return (RAROC, calculation rules defined in BASEL) and thereby decrease the amount of reserves they have to keep with the Central Banks. Also Re-assessment of risks in projects under operation may be useful as it can help to reduce RAROC equity reserve banks have to keep. **RAROC rules and better data availability for assessing RAROC may be a central lever to increase debt availability for RES globally!**

Especially **government action to make empirical data internationally available would help substantially to facilitate both risk assessments and *increased availability of insurances*** (policy option 18 below). In projects receiving government support, support could be made conditional to the (anonymized) disclosure of data to a dedicated international risk database for the RE industry. This could include all data relevant for further development of insurances, risk assessments and the technology and project development in general: E.g. on project risks, problems occurring in practice, performance and wind/solar resource in practice compared to expectations beforehand, geothermal drilling success rates, etc. Companies will usually prefer to keep these data confidential as access to the data may be a competitive advantage. However, from a (global) macro-economic perspective sharing the data may be preferable as it may increase learning rates and cost reductions and thus reduce future support cost. From a national government perspective for some kind of data

a trade-off may exist between driving down (support) cost and maintaining competitive advantages of national RE industry, but most likely for some kind of data this trade-off may be less critical and clear economic advantages from disclosure could be realized.

(a) **Increases investor/lender confidence**

A standardized and independent assessment/rating of a project's ability to deliver the expected returns increases investor/lender confidence and can thus reduce WACC. However, a very dominant factor in bank/investor decision making is the counterparty trust and experiences made. This partly subjective factor will not be fully replaced by objective standardized assessments.

(b) **Reduced cost for risk assessment / structuring finance**

This may especially be beneficial for smaller projects to reduce relatively higher transaction cost.

18 Availability of insurances for risks that are so far not insurable

Levelized cost saving potential						Removing growth constraint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪	▪				▪	■
0-2%	0-2%				2%	
(a)	(b)				(f)	

The development of private insurances for risks not yet considered to be commercially insurable could be encouraged by public organizations. This applies especially to novel technologies without a long-term track record, e.g. for wind offshore not all warranties desired are commercially available or the sums covered are too low. Public organizations could help/finance gathering sufficient statistical or track record data (see policy option 17 above for more details).

A similar financial risk mitigation instrument that would involve both public and private actors is a private-public "efficacy insurance" that covers RES technologies regarded as too risky for conventional insurances (suggested by BNEF and CEG 2010 based on industry consultation). Commercial insurers with appropriate levels of technical expertise could assess and support selected technologies with such insurance and receive support in turn for a portion of their risk in the form of publicly guaranteed or funded reinsurance pools. Project developers would pay a premium and transfer the performance risk of the new technology elements to the insurance pool.

(a) Lower risk premiums, due to risk being covered by insurance.

(b) Reduced cost in structuring finance due to lower risk.

19 TSO responsible for wind offshore grid connection

Levelized cost saving potential						Removing growth con-straint
Cost			Revenues		SUM	
WACC+	CAPEX	OPEX	POWER	SUPPORT		
▪	▪				▪	
1%	1%				2%	
(a)	(b)				(f)	

Wind offshore grid connections can be constructed under and paid for by either the project or the TSO, both variants are applied in EU Member States. Grid connection contributes a very substantial part to the overall cost of an offshore project, depending on the distance to shore.

(a) TSO may get cheaper loans and can depreciate over longer period

Due to their low-risk and government-backed activities TSO may on average be able to get cheaper loans than offshore wind projects. Furthermore TSOs can more easily (be enabled) to depreciate grid connections over the cable lifetime (e.g. 40a) instead of the wind farm lifetime (e.g. 20a) which may reduce annual depreciation substantially.

(b) TSO can build grid connection at lower investment cost

Investment cost for an offshore wind project can be reduced by up to one third, however, cost for TSO increase in almost the same order of magnitude. Still TSOs likely can build grid connections at lower cost as it is their core business and planning and purchase of (larger amounts of) cables may be more efficient. Substantial cost savings may derive from a more efficient offshore grid design if coordinated by the TSO for several projects instead of each project designing its grid connection individually.

5 Other essential policy options reducing the cost gap of RE

Besides the policy options discussed in chapter 4 there are more ways to reduce the cost gap which should be part of the wider policy package (Number 1-5 in list below). They are briefly described in this chapter for the sake of completeness. Under number 6 risk-related RE policy options not discussed in this report are mentioned.

1) *Fully internalizing external cost and reducing (hidden) subsidies to conventional technologies*
2) *Reduce RE cost via R&D and mass deployment leading to technological learning*
3) *Adjust the financial support level to the RE generation cost in order to avoid windfall profits*
4) *Use of least-cost technologies and sites via flexible mechanisms in the RE Directive*
5) *Potential benefits of increased availability and liquidity of financial products and insurances in a further harmonized & larger market*
6) *Risk-related RE policy options not discussed in chapter 4*

1. Fully internalizing external cost and reducing (hidden) subsidies to conventional technologies

Conventional technologies do not yet fully pay for the cost caused by their impact on climate change, resource depletion and other environmental impacts (external cost). For example CO2-prices in the EU Emission Trading System are by most experts considered to be both below the external cost and the price level needed to trigger the investments in low carbon technologies needed to reach the EU's long-term targets. Also other forms of (hidden) subsidies prevent the energy market prices from reflecting economic truth.

2. Reduce RE cost via R&D and mass deployment leading to technological learning

Investments in research and development reduce the technology cost of RE. They complement and enhance the technology cost reductions achieved through mass deployment and the related technological learning. Current public and private spending on RE R&D are by most experts considered to be too low.

3. Adjust the financial support level to the RE generation cost in order to avoid windfall profits

Huge production cost differences exist between technologies, but also depending on site quality (high or rather average wind/solar conditions) or fuel source (biowaste, landfill gas, woody biomass, energy crops, etc). Applying uniform support to all technologies and/or sites will lead to massive windfall profits for cheaper technologies, fuel sources and good sites, while currently still more expensive technologies, fuel sources and average sites needed to achieve long-term targets will not

be developed. Windfall profits are obviously no problem to investors and banks, but they unnecessarily drive up support cost for consumers or government budgets. Therefore almost all Member States now differentiate their support levels and policy according to technologies and many also to site and fuel source. For the most common RES-E production support instruments, this alignment is organized in different ways, all requiring good monitoring and knowledge of the RE market:

- The feed-in tariff level should directly reflect the assumed generation costs (levelised over the duration of the feed-in tariff payment), but allow for a producer rent that is high enough to attract investors with moderate risk appetite and return expectations. A regular review of tariffs is useful to evaluate the accuracy of the cost estimates. A yearly digression of tariffs for new installations (like in Germany) may be used to reflect technological learning in a simplified way and to stimulate further cost reductions.
- For feed-in premiums, the same logic applies, but the reference parameter for determining the support level is the difference between generation cost and electricity market revenue. Since electricity market prices are volatile, over- or under-support should be avoided by cap and floor prices (like in Spain) or other provisions (e.g. the determination of the premium based on the average yearly electricity price like in the Netherlands)[8].
- In quota systems with tradable green certificates, the maximum certificate price can be controlled by the price of the penalty for non-compliance, at the risk of lower RE production than envisaged by the quota. In addition, floor prices have proven to be beneficial for limiting the certificate price risk (e.g. in Belgium). Technology banding is the central tool to adapt certificate revenues to technology-specific generation cost.

The importance of technology specification for cost-effective RES support has also been demonstrated in quantitative terms (Held et al. 2010). One should be aware, however, that there is no “one size fits all” solution: Policy differentiation should also reflect that RET are at different development stages, have different characteristics, different project sizes and type of investors involved (e.g. utility-scale offshore wind, domestic photovoltaics, agricultural biogas, community-owned onshore wind), which results in different return on investment expectations.

According to Resch et al. 2009, the yearly average support expenditures would increase by at least € 10 billion per year, if uniform, technology-neutral support was applied for all Europe.

If support levels are below generation cost, usually no growth can be observed.

4. Use of least-cost technologies and sites via flexible mechanisms in the RE Directive

Another strategy for increasing the cost-effectiveness and reducing the consumer costs of RET support in the member states is the optimisation of the supported RET portfolio. Generally speaking, cost savings can be accomplished in two ways:

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[8] Both systems have a flaw preventing optimal functioning: In the Spanish system cap and floor values are applied hourly, which prevents any meaningful positive demand-response by RE projects. Cap and floor values should rather be applied to annual averages. In the Dutch system the premium is not further increased in case the average yearly electricity prices falls below a pre-defined minimum. This is in order to increase public budget certainty, but imposes a major revenue risk on projects.

- European cooperation for optimised resource exploitation
- Focusing the RET support on less expensive technologies as long as dynamic efficiency is ensured

The pros and cons of these closely related options have been discussed controversially on European level for many years, particularly in the context of risks and benefits of European harmonisation.

European cooperation for optimized resource exploitation

The EU RES directive brakes down the EU 2020 RES target in national RES targets for the member states. The allocation of differentiated national targets is based on a flat rate approach (same additional share for each country) adjusted to the member state's GDP. This target allocation approach does not correlate with the member states' natural RES potentials, which vary substantially. In consequence, also the expected policy and investment costs for reaching the national targets domestically differ between member states. In order to account for these differences, the RES directive introduces flexible cooperation mechanisms which allow those member states with low or expensive RES potential, to partially fulfil their RES target in other countries with higher RES potential or lower generation costs. According to the Green-X scenarios developed in [Ecofys 2010], intensified cooperation between member states until 2020 could lead to cost savings in consumer expenditures of approx. € 2.3-2.8 billion per year compared to purely national target achievement. Nevertheless, only few member states have revealed any plans to use the cooperation mechanisms so far (NREAPs 2011). While it is still possible that they will start using the cooperation mechanisms in the coming years, there are also some structural reasons for the reluctant use of the cooperation mechanisms: In their RET deployment and cooperation strategy, member state governments may also consider indirect costs and benefits of RET deployment that are not included in the direct support cost assessment, e.g. domestic benefits like job creation and other local added value, or domestic costs like grid reinforcement, impact on landscape etc. Also, the acceptance of consumers to pay for RET support tends to be higher in case RET are installed domestically, rather than in foreign countries.

In a nutshell, increased cooperation between member states does hold the potential for increasing cost-effectiveness of RES target achievement, but policy makers need to pay attention to avoiding high producer rents for low-cost technologies and sites that may offset the benefits of cooperation. Furthermore, indirect costs and benefits and public acceptance need to be considered in the assessment, and may be considered more important by Member States compared to potential efficiency gains.

Focusing the RET support on less expensive technologies

A closely related option for reducing the consumer costs of RES target achievement is focusing the policy support on low-cost technologies, rather than on more costly technology options. According to the Green-X scenarios in [Ecofys 2010], the deployment of less innovative technologies for the RES 2020 target could lead to consumer cost savings of approx. € 3.4-3.7 billion per year until 2020, but they add that the resulting RET portfolio may not be balanced from a long-term perspective.

Again, the focus on less-costly technologies is not a straight-forward approach, as other considerations may influence the choice of technology, e.g. the mix of supply-driven and flexible RETs, as well as indirect costs and benefits of the RET deployment, including industrial policy considerations

to support innovative, more expensive RET in order to gain a front-runner advantage and create lead markets. Furthermore, supporting solely low-cost RETs may prevent the timely development of innovative, more expensive technologies needed for future climate and RET target achievement, and timely upscaling of their supply chain in order to avoid future supply chain constraints and scarcity rents increasing support cost in the long-term (dynamic efficiency). In some Member States it seems possible to optimise the supported RET mix, even without neglecting innovative technologies. This applies to cases where innovative technologies like PV or wind offshore are developed at a faster pace than low-cost alternatives like wind onshore or renewable heat options (see policy effectiveness indicators in Held et al. 2010 for details). While the support of low-cost technologies has been discussed extensively for the electricity sector, governments usually pay little attention to the heating sector, which provides lower cost RET options in terms of final energy than the electricity sector. Since the RES 2020 target is measured in final energy, increasing the RES-H share in the overall RES target achievement would also lead to cost-savings. On the other hand, there are relevant barriers that hamper such approach, e.g. the scarcity of biomass potentials and the slow retrofit of heating systems in buildings.

One can conclude that focusing support on less expensive RET holds significant cost savings potential in few Member States, but the appropriate technology mix will also depend on other important factors. In the majority of Member States support of innovative technologies is currently probably too low to ensure dynamic efficiency, which may lead to unnecessarily high support cost in the future. Furthermore, the policy design feature for selecting the technology mix should avoid introducing additional risks (compare discussion of budget/capacity caps in chapter 4).

5. Potential benefits of increased availability and liquidity of financial products and insurances in a further harmonized & larger market

Presently the European Member States are fairly heterogeneous regarding their support policies, revenue risks, country risks, the development stage of their RE industry, the access to capital, geographical conditions for RE and RE project sizes. The EU and especially the CEE countries might benefit if some elements of RE policies would be standardized and/or guaranteed EU-wide. Especially relevant in this context may be:

- Ensuring minimum RE policy design standards in all EU Member States. This may include absence of retro-active policy changes, proper implementation of priority dispatch or curtailment compensation.
- EU guarantees that support from all MS policy schemes will actually be paid, even in case of policy defaults or restructuring of government debt.

Note that these measures would not require a full harmonization of RE policy as currently opposed by many Member States and could go alongside with the current system of flexible mechanisms for import and export.

These measures would enable benefits through:

- Reduced cost of capital through abolishment of key revenue and country risks. Revenue risks depending on the chosen support policy instrument (Feed-in tariff, premium, quota) would remain. Also the exchange rate risks are left, especially for the remaining non-EURO coun-

tries (Great Britain, Sweden, Denmark, Poland, Czech Republic, Hungary, Romania, and Bulgaria).

- Greater direct access to European and global capital markets, especially with (state-owned) investment funds considering single EU Member States to small. The capital markets could also raise capital at EU level (not locally) focusing more on the EU RE industry aspects of a project rather than the country risks. This has been similar in the utility sectors, where financing is often raised at the ultimate parent level. Potential RE investments not appearing on the radar screen of international investors so far, may attract international investors and strategic partners EU wide.
- Allowing RE investment portfolios becoming more easily exchangeable commodities with the opportunity to be entered and exited on a liquid market bases by investment funds and creating the framework for the development of a bond market (ideal for accessing EU pension funds) more RE projects than currently could be financed and implemented.

6. Risk-related RE policy options not discussed in chapter 4

Below, further policy options which can be relevant to reduce risk are listed, which for various reasons were not presented in chapter 4.

- **Legal security**: According to [Lüthi] legal security (incl. absence of corruption) is the most important policy option as long as minimum standards are not reached.
- **Measures to improve availability and conditions of PPAs and/or TGC offtake contracts** (in FIP and quota systems). E.g. governments can oblige obliged parties to offer long-term contracts (as applied in California). This can reduce price risks for both producers and obliged parties. Obliged parties might not always be interested in signing long-term contracts, especially if certificate prices are expected to decrease. For electricity only or for both electricity and TGC combined.
- **Remove or share part of the price risk in tenders.** Incorporating corrections for inflation, currency exchange rates and market prices of key commodities (e.g. steel, biomass) between tender closure and realization of the project helps to transfer financial risk from the project developer to the tendering body.
- **No large capital commitments long in advance.** Such commitments drive up overall financing cost and may be required e.g. in permitting or grid connection procedures, e.g. grid connection deposits or turbine purchase contracts for wind offshore grid connections.
- **Inflation adjustments in support instruments** might positively affect the equity ratio of a project. An inflation component mainly addresses risk from the perspective of equity providers. The impact of inflation is not very substantial. Moreover, inflation levels are currently quite low. From a debt investor's perspective an inflation factor in RES subsidies is not a very important issue as long as their portfolio of projects is balanced.

Annex 1: Glossary

Contingent grant: Contingent grants are grant repaid in part or in full when the project has reached the operation and revenue-generating stages.

Corporate Finance: Debt provided by banks to companies that have a proven track record, using 'on-balance sheet' assets as collateral. Most mature companies have access to corporate finance, but have limited total debt loads and therefore must rationalize each additional loan with other capital needs.

Equity: RE equity investors take an ownership stake in a project, or company.

Export Credits, Insurance, and other Risk Management Instruments are used to transfer specific risks away from the project sponsors and lenders to insurers and other parties better able to underwrite or manage the risk exposure.

Grant: Bestowed by a public organization (called the grantor) for specified purposes to an eligible recipient (called the grantee).

Mezzanine Finance groups together a variety of structures positioned in the financing package somewhere between the high risk / high upside equity position and the lower risk / fixed returns debt position.

Mezzanine fund: Debt that incorporates equity-based options, such as warrants, with a lower-priority debt. Mezzanine debt is actually closer to equity than debt, in that the debt is usually only of importance in the event of bankruptcy.

Quasi Equity: A category of debt taken on by a company that has some characteristics of equity, such as having flexible repayment options or being unsecured. Examples of quasi-equity include mezzanine debt.

Private Equity: Private equity is money invested in companies that are not publicly traded on a stock exchange.

Private Finance from personal savings or bank loans secured by private assets. This type of finance is concerned mainly with smaller companies and projects.

Project Finance, debt provided by banks to distinct, single-purpose companies, whose energy sales are guaranteed by power purchase agreements (PPA). Often known as off-balance sheet or non-recourse finance, since the financiers rely mostly on the certainty of project cash flows to pay back the loan, not the creditworthiness of the project sponsors.

Risk Capital, equity investment that comes from venture capitalists, private equity funds or strategic investors (e.g. equipment manufacturers). Besides the developers own equity and private finance, risk capital is generally the only financing option for new businesses.

Soft Loans: loans that offer flexible or lenient terms for repayment, usually at lower than market interest rates. Soft loans provided customarily by government agencies and not by financial institutions. Also called concessional funding.

Senior debt: Debt that has priority for repayment in case of liquidation.

Third-Party Finance, where an independent party finances many individual energy systems. This can include hire-purchase, fee-for-service and leasing schemes, as well as various types of consumer finance.

Venture capital: Venture Capital is an equity investment focused on ‘early stage’ or ‘growth stage’ technology companies.

Annex 2: Giebel & Breitschopf 2011 – Conjoint analysis policy design affecting revenue risks

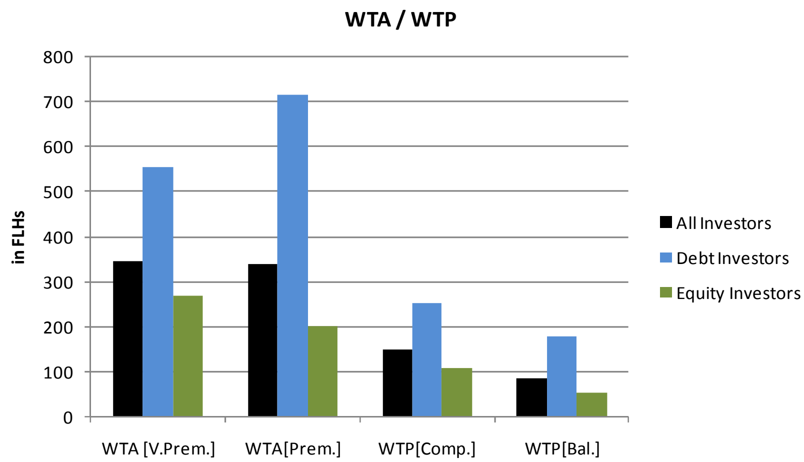
To assess the impact of policy elements in a feed-in system on financing costs Giebel and Breitschopf (2011) conducted an analysis that relies on the stated preference approach. Their analysis focuses on risks for wind onshore investors in Germany. Four remuneration elements have been considered in the investigation. Each element reflects a certain kind and level of risk for investors. The four elements are:

- Premium Model: The RE producer receives a constant premium over the hourly spot market price of electricity. The premium is adjusted annually to add up on average to €95 per MWh. But the remuneration fluctuates in contrast to a fixed remuneration scheme, where the tariff is independent from market prices of electricity. Hence, this option displays a certain price risk for investors.
- Variable Premium with Cap&Floor: Caps and floors are introduced to guarantee the RE producer a minimum price of €75 per MWh and setting a cap at €115. Only if the spot price lies above that, the RE producer receives more than the cap. With this option the price risk is limited, but not zero as with a fixed tariff.
- Shut-Down Compensation: In case of a potential breakdown of the transmission grid, wind turbines are shut down to prevent damages. No energy is produced during this time. If RE operators are compensated for their unproduced power, they receive an equivalent amount of money as if power were produced. Without the compensation they suffer a loss. Since 2009 RE operators are compensated in Germany. This element reduces performance risks (grid capacity problems).
- Quantity Balancing: Wind yield is not stable. 2009 only 86% of the long term average was reached. This fluctuation can be addressed by paying more at the end of the year when wind yield was below the average and paying less when wind yield was above the average. With quantity balancing element, remuneration increases by 11% when wind yields reached only 90% of the 10-year average wind yields. Under this option the risks of intermittent sources is limited, hence, again the performance risk is mitigated.

Since in Germany the grid operators are obliged to feed in any generated RE power, the demand risk for RE power is zero in Germany.

The influence of the policy elements are investigated using a conjoint analysis - stated preference method. Hypothetical investment options are designed based on the described elements and on one further investment characteristic “full load hours (FLH)” that indicates for how many hours per annum the wind power plant has generated electricity. The respondents are faced with two investment options and asked to indicate which investment option they prefer by indicating the preference on a Likert scale. In September and October 2010 wind onshore investors from Germany were contacted and asked to participate. In the end 26 respondents filled out the questionnaire. Applying a linear additive preference model the investors’ willingness to accept [WTA] unfavorable feed-in elements or their willingness to pay [WTP] for favorable elements has been estimated. The following figure shows the results.

Figure 0-1 Willingness to accept policy elements increasing price risks in comparison to a feed-in tariff and willingness to pay for policy elements compensating for performance risks.



Source: Giebel and Breitschopf (2011)

First, the data of all interviewees (black bars) are analyzed without distinguishing between the type of interviewees. The analysis shows that under a variable premium with cap and floor the RE project has to offer on average 346 full load hours more than under a fixed remuneration model - ceteris paribus - in order to attract investors the same way. The willingness to accept the premium model versus a feed-in tariff is similarly high (338 FLHs). A shut-down compensation protects the investor against unexpected revenue defaults resulting from enforced shut-downs of a wind turbine in case of potential grid instability. On average investors agree to waive 148 FLHs in order to receive this kind of security. The last element incorporated into the conjoint analysis is connected to uncertainty about wind yield. It is addressed through quantity balancing. Investors have on average a willingness-to-pay for this kind of risk mitigation about 86 full load hours; in relation to the other values a small amount. The dataset is also split up into debt investors and equity investors. Considerable differences are detected. Debt investors seem to be very keen on the fixed remuneration, while equity investors oddly favor the premium model over the variable premium model.

The findings of the survey suggest that amending the fixed feed-in tariff towards premium models requires considerably higher return in form of FLH. Using a cash-flow model and calculating the internal rate of return (IIR) based on the basic level of FLH, the marginal rate of substitution of FLH and the respective financing variables, the WACC can be estimated under the assumption of a given equity debt ratio (25%:75%). The results suggest, that the financing cost in average increases by 185 bp or 215 bp in case of a switch from a fixed feed-in tariff to a premium with cap and floor or a premium, respectively. The financing cost decreases in case of a compensation for grid problems or intermittent sources by 90 bp and 60 bp, respectively. A distinction between the types of investors shows that debt investors are rather risk averse and their WTA must be compensated by higher capital cost while the WTP for risk mitigation is higher, meaning they would reduce capital cost (e.g. interest rate) more than an equity investor who would give up between 31-66 bp of his IRR (table below).

Table 0-1 Financing cost (WACC) in dependence of policy elements

Variable	Δ IRR		Δ WACC
	Debt Investor	Equity Investor	
V.Prem.	3.12%	1.56%	1.85%
Prem.	3.96%	1.17%	2.15%
Comp.	-1.57%	-0.66%	-0.90%
Bal.	-1.10%	-0.31%	-0.60%

Source: Giebel and Breitschopf (2011)

In summary, this study shows to what extent an increased price risk resulting from a change of policy element has to be compensated by changes in FLH. A translation of the changes in FLH reflects into IRR provides a rough measure of change in capital cost by might not necessarily reflect the actual increase since in practice other - so far unknown - measures than an increase in FLH might compensate for this rise in risks.

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