# Renewable energy policy: risk hedging is taking center stage

By Nils May, Ingmar Jürgens and Karsten Neuhoff

The costs of renewable energy technologies have fallen sharply. Now the financing costs of new installations are playing an increasing role in the overall cost of Germany's energy transition. This has put the primary focus of support instruments for renewable energy on creating more affordable financing conditions for investments. This report compares the effects of various policy instruments on risk factors and on the costs of financing investment in the energy transition. Based on a survey evaluation and calculations, our analysis shows significant increases in the financing costs under green certificates and fixed premiums. These are passed on to end customers. For this reason, the further development of support instruments, as currently discussed within the context of the EU Renewable Energy Directive for the period 2020–2030, should avoid unnecessary risks for investors that could lead to higher financing costs.

With a projected volume of 50 billion euros annually in Europe until 2050,[1] investment in renewable energy is the cornerstone of the energy transition. Here the investment's capital costs are paramount, unlike for energy generation from fossil fuels, in which fuel cost plays the main role. As a consequence, the financing costs of investments are increasingly important for the overall energy costs. Low financing costs for investment in renewable energy are key to an affordable transformation of the energy system.

The design of the regulatory conditions and policy measures has a considerable impact on financing costs. Depending on this design, additional regulatory risks can raise financing costs or allow producers and customers to hedge against market risk, ultimately reducing both financing costs and the price of electricity. The risks are borne by the various players, again depending on the design. If project developers and operators[2] are not exposed to risks of plant performance, however, false incentives could be the consequence, leading to deficient quality or plant maintenance, which in turn would raise the overall cost. On both German and EU levels, one key issue in the future design of the regulatory framework is how the risks should be shared and which effects their distribution would entail for the overall cost. Adequate policy instruments could ease access to affordable financing.

The present report compares the effects of various policy instruments on risk factors and risk distribution as well as the effects of different scenarios on the costs of financing investment in the energy transition. The analysis focuses on institutional and contractual financing. The results are relevant when the support level is set by

1 Cambridge Economic Policy Associates (2016): Supporting investments into renewable electricity in context of deep market integration of RES-e after 2020: Study on EU-, regional- and national-level options. On behalf of the European Commission.

2 The term 'project developer' will be used indifferently for both in this study.

the regulator as well as when it results from auctions.[3] For the purpose of the analysis, we evaluated a survey of market participants about the role of support instruments and risks in Europe and conducted additional calculations regarding corporate finance. In our discussion we focus on long-term contracts in particular, which would have an important role in some policy design choices.

## Investment risks for renewable energy have shifted

Investment in renewable energy is subject to a range of risk factors—technology and project risks, funding risks, market price risks, and other regulatory risks—the relative importance of which has changed over time.

*Technology and project risks* are borne by the project developer, regardless of the general policy related conditions. For reasons of efficiency it should stay this way, above all for the established technologies of wind power and photovoltaics.

*Funding risks* affect project developers' potential uncertainty about revenues that go above and beyond the market value of electricity. This risk can result from price changes or adjustments to the general regulatory conditions. Appropriately designed funding instruments and policy processes can minimize or avert these risks, thus preventing additional risk premiums to further increase the cost of capital.

*Market risks* encompass uncertainty about the revenue generated by the sale of electricity. Electricity producers would prefer to hedge against low prices, and end customers in principle seek to hedge against high electricity prices. Both parties could thus benefit from signing long-term contracts to hedge against these risks. However, private households are not permitted to sign corresponding long-term contracts, and for most companies such contracts pose too large obligations. Support instruments can function as long-term contracts, reducing risks for both project developers and end customers.

Other *regulatory risks* can emerge from upcoming structural adjustments to the electricity market that drive the integration of renewable energy and promote sector coupling. Such adjustments can lead to changes in the general conditions, and in the case of deviation of power generation from production forecasts, to changes in prices and costs. Furthermore, differentiated temporal or spatial price profiles could result in risks that cannot be hedged for some of the support instruments.

3 The funding amount is settled via auctions for large solar installations since 2015 and for wind energy installations since 2017.

Overall, the significance of funding and its associated risks has declined due to the sharp cost decrease, in the costs of wind and solar power (Figure 1) driven by learning effects and innovation. In 2007, the typical tariff for photovoltaic power was 379 euros per megawatt hour (MWh).[4] The electricity price at that time covered approximately ten percent and government funding was responsible for the remaining 90 percent. Currently, the funding level is only 57 euros per MWh, approximately half of which is covered by the electricity price. The level for onshore wind power has also dropped sharply, from around 78 euros per MWh in 2007 to the current 43 euros per MWh.[5]

While funding stability was paramount in designing the general conditions for renewable energy in the past, the stability of revenue from the electricity sold in the market is the most important aspect today.

## Different funding instruments have different effects on investment risk

Looking at project developers only, traditionally the focus of policy, revenue stability plays a key role in evaluating funding instruments.

The conventional *feed-in tariff system* gives developers a fixed tariff for the electricity produced. They still bear the risk for their project's failure, but are not subject to any further tariff related risks. Wind power and photovoltaic systems had fixed feed-in tariffs until mid-2014 in Germany, and these still apply to smaller systems.

The *sliding market premium* for wind power plants and larger photovoltaic systems in Germany became optional in 2012 and mandatory as of mid-2014. In addition to revenues from selling electricity, plant operators receive a sliding premium. In general, they can count on a support level comparable to that of the fixed feed-in tariff, but their exact revenues can vary. Depending on the specific design, additional risks may be unavoidable. The goal was to provide operators with incentives for better forecasting of their (weather dependent) production and for selling their electricity at an optimized value in illiquid short-term markets.[6] But this also results in additional uncertainties from changes to intraday and balancing

4 Revenue resulting from the feed-in tariff awarded to solar installations at the time.

5 The figure of 43 euros per MWh equals the offers in calls for bids that have been accepted. They will not be realized until the near future and could benefit from anticipated further cost reductions. In the past, on the other hand, the production start date was the deciding factor.

6 As intraday auctions have gathered importance, markets have become liquid and the only incentives now called for are for reliable forecasts.

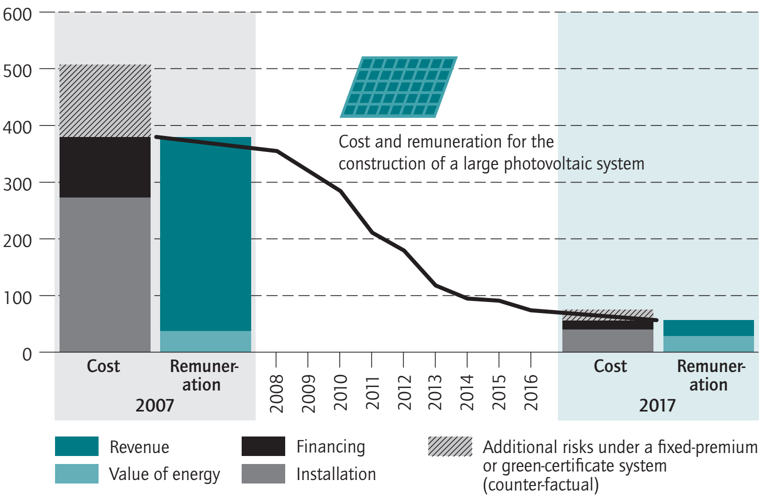
market design that influence prices at which adjustments to wind-output relative to initial forecast can be traded.[7]

Trading in *green certificates* and *fixed market premiums* are two additional policy instruments. Project developers sell their electricity at the current market value and receive a green certificate or premium for each megawatt hour they produce with wind or photovoltaics.[8] In this system, wind and solar power producers are exposed to uncertainty about the future price of electricity and the future value of the certificates. This leads to risk premiums for financing the installations.[9]

Figure 1

**Costs and funding of solar energy over time**

In euro per megawatt-hour




*Source: Authors' own depiction.*



The share of support in remuneration declines, risk hedging becomes more important.

## Empirical analysis: major differences in financing costs throughout Europe

Due to the lack of data on financing costs in countries with different support systems, until now the precise effects of individual policy instruments on financing costs have primarily been examined in individual case studies. With the help of a 2014 survey on the costs of financing wind power in the EU, we were able to examine the effects in more detail.[10] Bankers, project developers, academics, and utility employees in 23 EU member states participated in the survey on financing costs for onshore wind power.[11] This resulted in a picture of the financing costs in Europe (Map).

In general, projects in southern and eastern Europe have higher financing costs than those in western and northern Europe. But financing costs also vary between countries with similar macroeconomic conditions. For example, wind power in Sweden report weighted average cost of capital (WACC) for equity and debt of 7.4 to 9.0 percent, significantly more than the costs in Germany (3.5 to 4.5 percent), although the risk-free interest rates of both countries were rather similar in 2014.[12] To prevent country-specific factors above and beyond the general regulatory conditions from distorting the picture, we considered in the subsequent analysis only the risk premium—the amount by which the financing costs for wind power exceed the relevant national risk-free interest rates.

In 2014 fixed feed-in tariffs were still in effect for wind power in most EU member states. Italy, the Netherlands, and Finland had sliding market premiums, and Denmark had a fixed premium that exhibited some elements of a sliding premium. The United Kingdom, Sweden, Poland, Belgium, and Romania all used a system for trading green certificates.[13]

## Green certificates lead to higher costs

A regression analysis for 2014 resulted in a premium of 1.1 to 1.7 percentage points on the financing costs of renewable energy investments with green certificates. Conversations with project developers revealed that they

**7** See Toby Couture and Yves Gagnon, "An analysis of feed-in tariff remuneration models: Implications for renewable energy investment," *Energy Policy* 38 (2) (2010): 955–965.

**8** In the case of green certificates, energy suppliers must document a fixed proportion of green certificates for each megawatt hour of electricity provided to end customers. This obligates them to generate an adequate number of green certificates with their own renewable energy plants or procure them in the market.

**9** See Mary Jean Bürer and Rolf Wüstenhagen, "Which renewable energy policy is a venture capitalist's best friend? Empirical evidence from a survey of international cleantech investors," *Energy Policy* 37 (12) (2009): 4997–5006 and Lucy Butler and Karsten Neuhoff, "Comparison of feed-in tariff, quota and auction mechanisms to support wind power development," *Renewable Energy* 33 (8) (2008): 1854–1867.

**10** For a detailed evaluation see Nils May and Karsten Neuhoff, "Financing Power–The Impact of Support Policies under Changing Regulatory Environments," *DIW Discussion Paper* Nr. 1684 (2017).

**11** See Paul Noothout, David de Jager, Lucie Tesnière, Sascha van Rooijen, Nikolaos Karypidis (all Ecofys), Robert Brückmann, Filip Jirouš (both eclareon), Barbara Breitschopf (Fraunhofer ISI), Dimitrios Angelopoulos, Haris Doukas (beide EPU-NTUA), Inga Konstantinavičiūtė (LEI) und Gustav Resch (TU Wien) (2016): "DIA-CORE: The impact of risks in renewable energy investments and the role of smart policies," (PDF, Fraunhofer ISI, Karlsruhe, 2016) (available online, accessed September 11, 2017. This also applies to all other online sources in this study, if not stated otherwise).

**12** For ten-year government bonds, at that time the interest rate in Sweden was 2.1 percent and 1.5 percent in Germany.

**13** However, the systems in Belgium and Romania had a special feature: project developers were guaranteed substantial minimum prices. The price risks there were quite limited.

sign long-term purchase agreements at fixed prices with large energy suppliers for both electricity and green certificates. The fact that the financing costs are still subject to risk premiums indicates either incomplete contractual coverage or the persistence of residual risks. For example, energy suppliers and project developers could negotiate agreement adjustments if the price of green certificates plunges in order to avoid bankruptcy for the former and safeguard at least part of the value for the latter.[14]

## Feed-in tariff and sliding market premium still on same level

With regard to financing costs, our analysis showed no statistically significant difference between fixed feed-in tariffs and sliding market premiums. The market considers the additional risks of a sliding premium to be low.

In the medium to long term, however, these prevailing systems could differ with regard to financing costs.

To deal with the growing share of renewable electricity, both national initiatives and part of the EU Winter Package[15] will develop the electricity market in the coming years. Changes in price zones, the spatial distribution of new systems, grid expansion, the further development of intraday and balancing markets, and changes to the supply and demand for flexibility options are all potential sources of uncertainty for project developers not hedged by the sliding market premium in its current design.

In exchange for the insurance project developers receive against low market prices, they could also be required to insure consumers against high market prices. Their overall remuneration level would thus stay constant—even at times of high market prices. At such times, a sliding premium would be negative (also sometimes referred to as contract for difference) or a fixed feed-in tariff would be below the electricity spot price. This would create a symmetric relationship between producers and final consumers—providing for all parties a valuable hedge against price volatility.

## Hedging of market risks leads to additional costs

In the case of green certificate trading, fixed premiums, or in the absence of support instruments, long-term contracts between project developers and energy suppliers are important for project financing because they ensure reliable revenue streams from electricity sales.

This is why it is essential to examine the conditions under which these types of long-term contracts can be signed. Are the contractual prices equal to the prices anticipated over the term of the agreement? Or will project developers have to sell their electricity at a discount in order to sign longer-term contracts?

In most EU member states, only a few major energy suppliers have had the financial strength to sign long-term contracts for electricity. That may have resulted in market power and with it, the opportunity to negotiate lower contract prices. Under perfect competition, a second effect we have quantified here is also significant.

The greatest risk for energy suppliers that enter into long-term contracts with project developers is that the actual price of electricity or green certificates is lower than the contractual price. If this comes to pass, energy suppliers will have to pay the higher contractual price for electricity—even if they can only pass the lower spot price on to their final customers (see Figure 2).

In order to estimate the risks that would result for energy suppliers, we examined the effect of these agreements on refinancing costs.

A long-term purchase agreement is a long-term liability. Higher liabilities lead to less favorable financial ratios, which in turn cause lower credit ratings. As a result, energy suppliers must bear higher costs for their own refinancing.

In the past decade, the market capitalization of energy suppliers has declined, and their debt-equity ratio has increased (Figure 3). As a result, additional long-term liabilities are particularly relevant.

To estimate the additional costs caused by long-term contracts, we first analyze how increasing liabilities reduce the credit ratings based on the debt-equity ratios and credit ratings for the twelve largest European utilities.

In a second step, data regarding the relationship between credit rating and risk premiums is analyzed. Due to greater availability, we used the data of publicly traded US companies. It is evaluated how a worsened credit rating affects the risk premium.

Based on this analysis we find that a 20-year contract, for example, would result in additional financing costs equal to 21.8 percent of the contract value. For energy suppliers with larger shares of debt and thus lower credit ratings, the increase of financing cost is even higher.

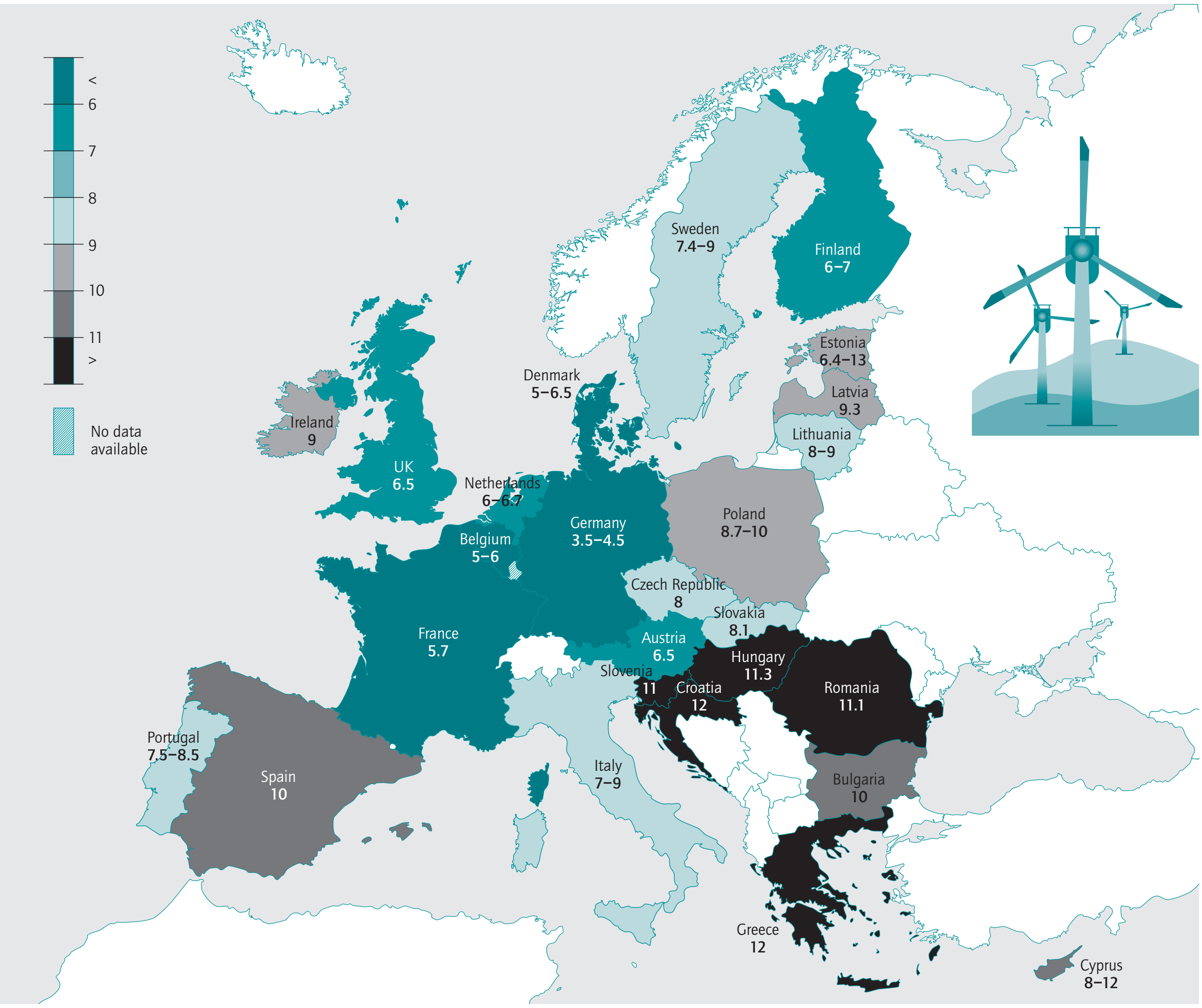
**14** Dominique Finon, "Investment risk allocation in decentralised electricity markets. The need of long-term contracts and vertical integration," *OPEC Energy Review* 32 (2008): 150–183.

**15** European Commission, "European Semester 2017: Winter Package explained," (Web page, European Commission, Brussels, 2017) (available online).

Map

**Financing costs of onshore wind energy across the EU**

Weighted average cost of capital (in percent)




*Source: Paul Noothout, David de Jager, Lucie Tesnière, Sascha van Rooijen, Nikolaos Karypidis (all Ecofys), Robert Brückmann, Filip Jirouš (both eclareon), Barbara Breitschopf (Fraunhofer ISI), Dimitrios Angelopoulos, Haris Doukas (beide EPU-NTUA), Inga Konstantinavičiūtė (LEI) und Gustav Resch (TU Vienna) DIACORE (2016): Final Report. (2016): The impact of risks in renewable investments and the role of smart policies.*



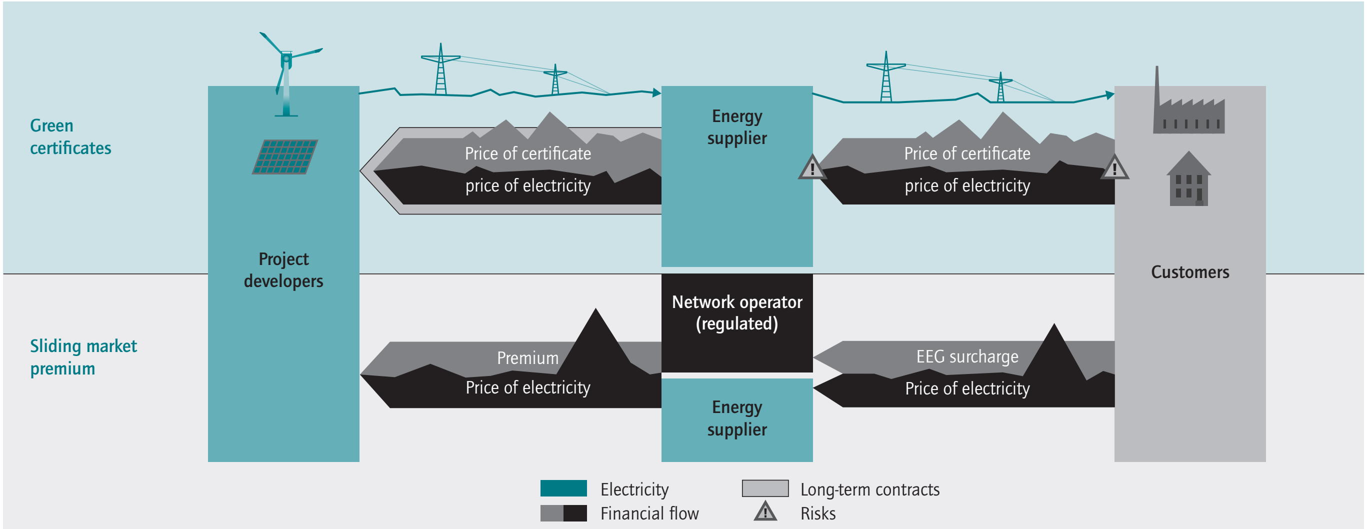
Financing costs vary greatly within Europe.

These additional costs mean that energy suppliers are only willing to enter into long-term contracts with project developers at correspondingly lower contract prices. At the same time, they sell electricity to end customers at prices based on short-term market prices. On average, these prices are higher than the costs of the long-term contracts, enabling energy suppliers to earn extra revenue with which they can cover their higher (re)financing costs.[16]

**16** Such "premiums" compensating positive and negative price deviations are also referred to as contract for difference.

Figure 2

**Project developers, energy suppliers and end customers and how they interact n a green certificate and in a sliding premium system**




*Source: Authors' own depiction.*



Under green certificates and fixed premiums, price risks remain with energy suppliers and final customers.

For project developers, the lower contractual prices in long-term contracts lead to lower revenues. To balance out the situation and continue to render realizing projects attractive, the prices of green certificates, fixed premiums or the $CO_2$ price reflected in wholesale power prices must rise. These additional funding costs are passed on to final customers.

## Three key factors affect additional costs

Additional costs are reduced when a portion of the contract value is not considered a liability for energy suppliers. For example, the rating agency Standard & Poor's allows for counting only a share of the contract value as liability if support instruments cover at least part of the contract value.[17]

On the other hand, the additional costs would rise if the effects on the equity capital side were also included. Just like higher debt levels, liabilities arising from long-term contracts lead to higher risks for equity investors (shareholders). As compensation, they expect higher returns. In order to generate higher returns from long-term contracts, the contract prices again must decline.

Calculating additional costs also greatly depends on how risk premiums increase with higher debt-equity leverage-ratios and with decreasing credit ratings. In line with the literature, we assumed a non-linear relationship. Additional costs rise more sharply if the volume of long-term contracts increases when renewable electricity has a growing proportion of overall electricity production. In an alternative calculation with a linear relationship, higher financing costs are calculated for moderate debt-equity ratios, but financing costs then increase less for firms with higher debt-equity ratios or larger volumes of long-term contracts that would result from increasing shares of renewable energies.

Considering all these factors, the calculations presented here are a conservative estimate of the additional costs.

## Electricity customers bear the additional costs

The sum of the additional costs for both project developers and energy suppliers described here ends up on end-customer bills.

As an example, if a wind power installation were built under sliding premiums or fixed feed-in system at an expected revenue of 50 euros per MWh, the additional

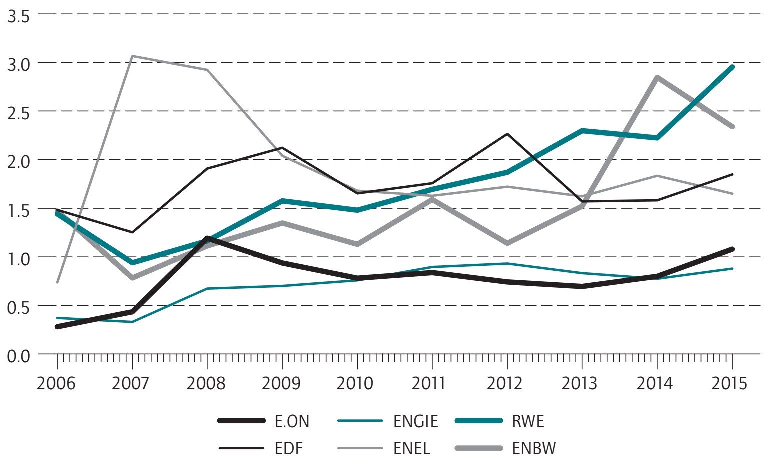
**17** Standard & Poor's, "Key Credit Factors For The Regulated Utilities Industry" (2017).

financing costs for project developers would increase the required revenue to 53 euros per MWh with higher regulatory risk. This required revenue would further increase to 65 euros per MWh if support mechanisms do not facilitate hedging and instead energy suppliers (or other parties) signing long-term contracts incur additional financing costs. The risk premiums on long-term contracts have the same effect on overall costs as a 3.6 percentage point premium on project developers' financing costs. Overall, we can assume a financing cost increase of around five percentage points.

Examining the risk premium in long-term contracts can also explain a paradox revealed by earlier studies. They identified only moderate additional costs at the magnitude of one to two percent on the financing costs;[18] while other studies that compared the difference between revenue and costs in countries with different support instruments observe overall revenues higher by ten to 40 euros per MWh for green certificates.[19]

Figure 3

**Debt-to-equity ratio of some German and European energy suppliers**




*Source: Authors' own calculation based on Datastream (2017).*



The debt level of German energy suppliers has increased substantially.

## Conclusion: Risk hedging to become main focus of funding instruments

Expansion of renewable energy capacity is required to meet climate and energy policy targets. Even though the costs of renewable energy technologies have declined, political support instruments are still required. Their primary task is no longer coverage of incremental costs, but, increasingly, facilitating hedging of price risks. This is important for limiting costs of financing and thus overall costs of an energy transition.

Wind power and photovoltaics operators are increasingly drawing their revenue from selling the electricity they produce as opposed to additional funding. Until now, their revenues were hedged by fixed tariffs or sliding market premiums. This facilitated affordable financing. If the support mechanisms were changed to green certificates or market premiums, or even eliminated in expectation of higher carbon prices, then this would result in revenue uncertainty that cannot be hedge in the power market, This risk would increase financing costs which would be passed on to end customers. The calculations in the present report indicate an increase in the overall costs of renewable energies in the magnitude of 30 percent.

For this reason, avoiding unnecessary regulatory risks and facilitating hedging should be a key criterion in any further development of renewable support mechanisms. One aspect that may be of particular relevance is the further development of the European electricity market for the integration of increasing shares of renewable energy, electrical mobility, and flexible demand. More differentiated regional power prices and new rules for short-term markets are under discussion. Further developments of the sliding market premium should address potential uncertainties resulting for investors from such changes in order to avoid increased financing costs.

Renewable support mechanisms can facilitate a mutual insurance of project developers against low and end customers against high power prices. This requires that project developers using a renewable support mechanism to hedge against low power price, would also have to contribute to the mechanism at times of high power prices, for example accepting to pay at such times a (negative) sliding premium. This creates a symmetrical relationship between the contractual parties and ensures that all benefit from risk hedging.

**18** Nera Economic Consulting, "Changes in Hurdle Rates for Low-Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime" (2013), on behalf on the UK Department of Energy and Climate Change (available online).

**19** RE-Shaping, "Shaping an effective and efficient European renewable energy market", *D23 Final Report* (2012) (available online).

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