Financing Power: Impacts of Energy Policies in Changing Regulatory Environments

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ABSTRACT

Power systems with increasing shares of wind and solar power generation have higher capital costs and lower operational costs than power systems based on fossil fuels. This increases the importance of the financing costs for total system cost. We quantify how renewable energy support policies can affect the financing costs by addressing regulatory risk and facilitating hedging. We use interview data on wind power financing costs from the EU and model how long-term contracts signed between project developers and energy suppliers impact financing costs. Regression analysis of investors' financing costs and an analytical model of off-takers financing costs reveal that between the support policies, the costs of renewable energy deployment differ by around 30 percent, but can be significantly lower or higher, depending on the financial situation of energy suppliers.

Keywords: Investments, Long-term contracts, Financing costs, Liberalization of power markets, Renewable energy policies

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1. INTRODUCTION

The rising share of capital-intensive assets increases the importance of financing costs for the total costs in power systems. In particular, this applies to renewable energies, as opposed to coal and gas power plants, because the costs of renewable energy deployment are, to a large extent, driven by the capital costs used to finance these assets. Bloomberg New Energy Finance (2017) project investments of $7.3 trillion into wind and solar power between 2017 and 2040, as well as an estimated further $5.3 trillion in order to achieve the goal of keeping the global temperature increase below two degrees.

The financing costs depend on the risks faced by investors, which hinge on the regulatory framework. On the one hand, regulation impacts the mere risk allocation; for example, regarding project performance, which is usually best left with investors to avoid adverse incentives. On the other hand, the regulatory framework can also induce risks, for instance, linked to uncertain policy developments, or it can eliminate risks, e.g. by facilitating contracts between parties with complementary exposure. The regulatory regime can have two main impacts on financing risks: regulatory risks and market risks.

First, regulatory risks arise due to uncertainty about the future revenues provided by support policies like feed-in tariffs, sliding premia, and green certificate schemes. The policy design may shift regulatory risk between parties, but where policy risk can be avoided altogether, policies

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can reduce, rather than shift, overall deployment costs. The deployment costs define how far investments into renewable energies are made and, for example, how high carbon prices need to be in order to facilitate the transition to renewable energies (Hirth and Steckel, 2016).

Second, market risks are introduced where support mechanisms do not comprise explicit off-take guarantees, i.e. guarantees that all generated electricity will be remunerated at a pre-determined price. Then, investors typically sign bilateral long-term contracts to secure these revenue streams. As Newbery (2016) argues, some forms of long-term contracts between generators and retailers are required to hedge against market risks and to provide investors with sufficient certainty about their future cash flows. Discussing investments into peak generators, Joskow (2006) analyzes how the lack of long-term contracts does not necessarily deter investments, but increases financing costs. Both producers and consumers are risk averse, preferring a stable price over an uncertain price. However, under liberalized power markets, individual and industrial customers do not sign contracts for durations exceeding a few years. This may reflect constraints on switching time-frames (or compensation payments), counterparty risks that are difficult to hedge, and asymmetric information about what would be a competitive price.

We quantify how much the regulatory and market risks under different renewable energy policies affect the overall deployment costs. To this end, we first analyze how far regulatory risks under feed-in tariffs, sliding premia, and tradable green certificates translate into higher financing costs for renewable energy investors. We test this with a unique dataset on wind power financing cost estimates for which investors, bankers, academics, and utilities provide estimates of the weighted average costs of capital in the EU. Second, we analyze the effects of market risks on long-term contracts when policies do not provide explicit or implicit off-take guarantees. We find structural reasons why the price renewable investors receive for long-term contracts is below the expected value, reflecting increased financing costs incurred by their counterparties when engaging in such contracts.

Overall, our results indicate that policy instruments can change the level of financing costs by about 4.8 percentage points overall, when comparing fixed feed-in tariffs with green certificate schemes, which is equivalent to a change in the costs of renewable energy deployment of about 29 percent. The change in costs is a result of, on the one hand, reducing regulatory risk and, on the other hand, eliminating market-related risks by facilitating implicit hedging between producers and consumers.

The remainder of this paper is structured as follows: After an overview over policies supporting renewable energy in section 2, we estimate policy impacts on investors' financing costs in section 3. We complement this with an analysis of the effects of long-term contracts on off-takers, i.e. the firms that commit to buy the electricity from project developers through long-term contracts. Section 4 analyzes how incomplete long-term contracts incur additional costs for off-takers. The paper ends with a conclusion.

2. INVESTMENTS INTO RENEWABLE ENERGY

Globally, three main policies that support renewable energy investments dominate: Fixed feed-in tariffs (FIT), sliding premia, and tradable green certificates (TGC).[1] In 2015, feed-in tariffs or sliding premia existed in 82 countries, whereas tradable green certificates were in place in 34

1. Alternative names for sliding premia are *Market Premium* and *Contracts for Difference*, with a major difference that under Contracts for Difference, the contractual obligation goes both ways, such that the premium can be negative, shielding consumers from high power prices. TGC are also called *Renewable Portfolio Standards* or *Green Quotas*.

countries and many US states (REN21, 2017).[2] Egli et al. (2018) demonstrate that it is support policies that enabled renewable energy investments at low financing costs.

Price-based support policies, e.g. feed-in tariffs and sliding premia, provide investors with a certain remuneration level. Under feed-in tariffs, the regulator takes the electricity output and guarantees a remuneration level such that operators face no uncertainty with respect to remuneration per kWh. Under sliding premia, investors sell their output to private off-takers and receive an additional sliding premium, where the sum of the two elements, on average, across all installations, equals the feed-in tariff remuneration. For any individual plant, there is some uncertainty with respect to the total remuneration due to deviations from average production patterns (May, 2017), while additional balancing costs or changes of price zones can induce risks (Tisdale et al., 2014), leading e.g. Couture and Gagnon (2010) to argue, based on theoretical arguments, that sliding premia entail risk premia as compared to feed-in tariffs. Yet, so far Klobasa et al. (2013) find no significant changes in investment conditions when analyzing descriptive statistics of the German experience after project developers were given the choice between continuing to receive a feed-in tariff or getting a sliding premium as of 2012. Kitzing (2014) goes as far as classifying feed-in tariffs and sliding premia as one, merely distinguishing higher risk fixed premia.

Tradable green certificates constitute quantity-based instruments where investors sell their electricity output to private counterparties and further receive green certificates proportional to their output. Retail companies are obliged to obtain such certificates, creating demand for them; thus establishing a revenue stream for renewable energy operators in addition to the sale of electricity.

Many authors raise concerns that, under real world conditions, green certificates induce additional investment risks. Butler and Neuhoff (2008) analyze the British green certificate scheme and the German feed-in tariff, finding that when correcting for the countries' different wind resources, the German system is more successful, in the sense that it triggered considerably more investments at lower cost to consumers. Similarly, Haas et al. (2011) scrutinize descriptive statistics on installation numbers and general remuneration costs for a small number of European countries, finding that feed-in tariffs are more successful in both respects. Further, Bürer and Wüstenhagen (2009) conduct a survey among investors and show, using a stated preferences approach, that they prefer feed-in tariffs over green certificates. A survey of British investors suggests that the expected risk premium of the green certificates compared to the newly-introduced sliding premium amounts to 0.8-1.7 percentage points (NERA, 2013). Similarly, Kitzing et al. (2017) show, using a real options approach, that policies have varying effects on capital costs, with green certificates leading to higher capital costs. Further, Kitzing and Weber (2015) and Klessmann et al. (2013) indicate that feed-in tariffs require lower support levels than policies that expose investors to more revenue risks. Nicolini and Tavoni (2017) evaluate data from five large EU countries and derive that feed-in tariffs lead to more deployment than green certificate schemes.

Polzin et al. (2019), in their review of the literature exploring renewable energy support policies, find that more effective policies are associated with lower volatility of returns and higher returns. Similarly, De Jager et al. (2008) identify that credible commitment of policy-makers towards sustained renewable energy deployment lowers costs, which May and Chiappinelli (2018) show is more difficult under green certificate schemes than under feed-in tariffs, while sliding premia fall in between.

Yet, some authors also argue in favor of the efficiency of quantity instruments. Applying a real options investment model, Boomsma and Linnerud (2015) argue that investment incentives do not differ strongly between green certificates and feed-in tariffs, meaning that additional risk premia

2. Since sliding premia dominate fixed premia globally, we discuss only *sliding* premia.

under green certificates are small. Many authors ignore the effects of additional revenue risks. For example, Petitet et al. (2016) analyze investments based on high carbon prices, but ignore the effects of uncertainty about future carbon prices. Similarly, Farrell et al. (2017) treat costs as exogenously given and, thus, equal across policies, not accounting for additional financing costs when revenue risks are larger.

However, studies on the impact of these policies on financing cost are based on theoretical assessments or on case studies for only very few countries. Analyzing a survey on wind power financing costs in 23 European countries, we contribute to the literature by providing empirical evidence on differences in financing costs between countries with different policies.

3. ESTIMATING INVESTORS' FINANCING COSTS

Renewable energy policies expose investors to varying degrees to revenue risks. We test the effects on financing costs with interview data on the financing costs of wind power projects from the EU. We estimate how much wind power policies can be associated with higher financing costs for wind power investors.

The WACC is potentially affected, on the one hand, by country-specific economic and political factors (e.g. stability of regulation, developed banking system, trust in juridical system) and, on the other hand, on renewable energy specific regulation, like the general support policy as well as individual regulations like retrospective changes to regulation and tendering procedures. We estimate the effect on the risk premium to control for general country-specific risk factors that are captured in the country-specific risk-free rate, such as political and economic factors affecting all investments in a country. Thus, the risk premium is the difference between the weighted average cost of capital (WACC) and a country's specific risk-free rate γ_c.

$$risk\ \ premium = WACC - \gamma_c \tag{1}$$

3.1 Data

For the analysis, we deploy interview data of financing cost estimates by project developers, bankers, and academics from 23 EU countries.[3] Table 1 provides descriptive statistics for the variables.

Financing costs are represented by the weighted average costs of capital, which reflect the costs of both equity and debt. Equity naturally has higher required returns than debt. The respective ratio between the two variables matters: higher shares of equity lead to higher weighted average cost of capital estimates. Details on the data and the interviews are in Diacore (2015). Interviewees were asked about their country's onshore wind power financing costs, which they provided in response to prior estimates of financing costs. Besides the share of debt and equity, along with the respective costs, which only some respondents provided, they gave overall financing costs estimates. However, 23 percent of interviewees did not provide specific point estimates, but rather ranges like 'more than X percent' or 'much less than Y percent', which we address through various interpretations and by assuming specific distributions of the underlying values.

We obtain the wind power risk premium by subtracting the risk-free rate from the weighted average cost of capital. This risk-free rate is commonly approximated by the yield on long-term

3. We lack data for Luxembourg, Malta, Portugal, and Slovenia. As explained in the following, we exclude Estonia due to its very particular FIT implementation.

Table 1: Descriptive statistics

Variable	N	Mean	Std.dev.	Min.	Max.
WACC	53	8.22	2.81	2.5	13.5
WACC approximated†	53	8.30	2.92	2.5	15
Avg gvt. bond yields 01/14	53	3.73	2.53	1.59	9.81
Risk premium approximated‡	53	4.57	1.43	0.73	7.25
Feed-in tariff	53	0.57	0.50	0	1
Sliding premium	53	0.23	0.42	0	1
TGC w. price floor	53	0.15	0.36	0	1
TGC w/o price floor	53	0.06	0.23	0	1
Tenders	53	0.08	0.27	0	1
Retroactive changes conducted	53	0.25	0.43	0	1
No policy in place	53	0.19	0.39	0	1
Consultant/Academic	53	0.32	0.47	0	1
Equity investor	53	0.34	0.48	0	1
Utility employee	53	0.17	0.38	0	1
Banker	53	0.17	0.38	0	1

Note: The policy dummies for feed-in tariff, sliding premium, TGC with price-floor, and TGC without price floor are mutually exclusive. The same holds for the interviewee types: consultant/academic, equity investor, utility employee, and banker. † For relative responses, “slightly higher” was treated as 0.5 percentage points higher, “higher” as 1.0 percentage point, and “much higher” as 1.5 percentage points. ‡ approximated WACC minus average government bond yields

government bonds, as it represents the varying country risks due to general political and financial contexts. At close to 10 percent, Greek bonds ranked the highest, followed by Cypriot and Portuguese bonds, based on Eurostat (2017). At the lower end, the bonds of Germany, Denmark, and Finland paid the lowest returns, at less than two percent.[4] Since the interviews were conducted in spring 2014, we approximate the country risk with the average yield in the six months before and after the beginning of 2014, i.e. 07/2013-06/2014.

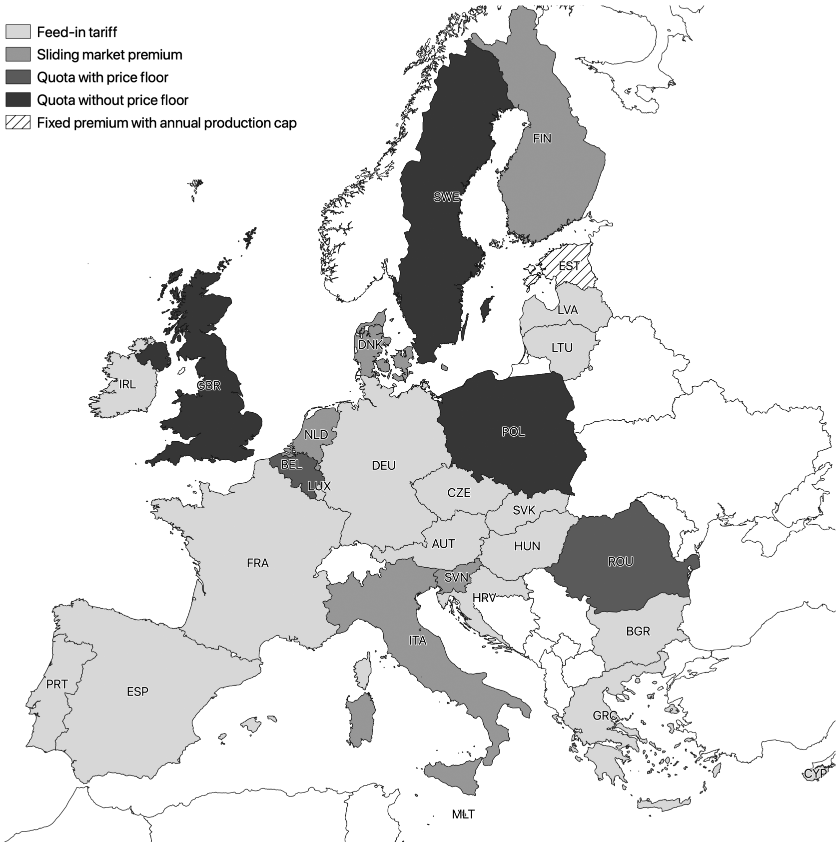
Based on Eclareon (2017) and González and Arántegui (2015), we identify whether feed-in tariffs, sliding premia, or green certificate schemes prevailed in early 2014 in the EU countries (see figure 1). When support varied with project size, we classify the country using the policy for larger installations, as project developers are more likely to be involved in larger settings.

Several countries had specific policy implementations that distinguish their schemes from those of other countries (Dijkgraaf et al., 2018). In Germany, investors could choose between a feed-in tariff and a sliding premium in early 2014. Diverging from Klobasa et al. (2013), we evaluate this as a feed-in tariff, since investors were always able to choose the safe feed-in tariff (until the sliding premium became obligatory in August 2014, i.e. after the interviews were conducted). Estonia defines an annual limit of remunerated generation. Once this limit is reached, no further remuneration is paid, as occurred in 2015, when about 13 percent of production did not receive any support (Estonian Windpower Association, 2015). This mechanism introduces significant revenue risks for operators and seems to be not comparable to the usual policies, such that we drop the Estonian observations (which indeed show very high risk premia). The Belgian regions and Romania run green certificate schemes. However, price minima provide absolute safety against lower returns, similar to feed-in tariffs. Thus, we count their policies as feed-in tariffs. For sensitivity analyses, we drop this assumption and include them as a separate class of policy scheme. Only Denmark em-

4. We also tested using official Eurostat data on firm lending rates. Yet, we deemed the data unreliable, as in 2013 and 2014, lending rates for Spanish, Italian, and Greek firms seemed unrealistically low, i.e. lower than, for example, the lending rate of British firms. Additionally, the resulting risk premium for renewable projects was partially negative, additionally casting doubts on this dataset’s reliability.

ployed a fixed premium. However, its payouts partially resemble sliding premia, as total remuneration is capped, similar to a strike price under sliding premia. Explicitly treating Denmark as having a fixed premium does not influence the results in the following, such that we generally include it in the group of countries with sliding premia. The Czech Republic, Spain, and Latvia had implicitly abandoned any remuneration for new projects, if not explicitly. Only Italy used tenders for large-scale wind power projects at that time.

Figure 1: Onshore wind power policies in the EU in spring 2014. Source: Eclareon (2017) and González and Arántegui (2015)



Furthermore, in the interview data, we have information on whether respondents think that retrospective cuts were conducted in their countries. Moreover, we know the type of interviewee, with roughly a third comprising consultants/academics, a third equity investors, about a sixth of utility employees, and another sixth bankers.

3.2 Estimation strategy

We aim to estimate the effect of wind power policies on the wind power risk premium, i.e. the weighted average cost of capital minus the risk-free rate, estimated as shown in equation (2). Importantly, our key explanatory variable, whose effect we aim to assess, is the policy scheme. Its coefficients are β_1 for sliding premia and β_2 for green certificate schemes, as compared to the baseline of a fixed feed-in tariff.

$$risk\ premium_i = \alpha + \beta_1 PREMIUM + \beta_2 TGC + X\delta + u_i \qquad (2)$$

For each interview-observation *i*, we control for additional factors through explanatory variables contained in *X*. Our additional co-variates are dummies for the implicit stop of renewable energy support (*No policy*), retrospective changes, tenders, and the type of respondent. Retrospective changes play a particularly important role. Some countries have implicitly, if not explicitly, abandoned any support for renewable energies, for instance through the abolition of remuneration payments or network operators stopped grid connections for new wind power plants due to network stability concerns. Where governments have retrospectively changed remuneration, the underlying risks for new installations may have also shifted, resulting in additional renewable energy risk premia. Through such changes, some governments aim to reduce their own or their constituents' financial obligations to existing projects. Therefore, we also include information about whether such changes have occurred. An additional dimension are tenders. These are potentially implemented on top of the regular policy regime, such that market actors have to participate in tenders in order to be entitled to receive the normal remuneration. The type of respondent—project developer, banker or academic—might also influence the results if these groups have systematically different perceptions of financing parameters.

This simple specification can be estimated using ordinary least squares (OLS). One obvious necessity for this estimator is that the dependent variable consists of individual values, e.g. a risk premium of 5.3 percent. However, in several interviews (23 percent), respondents did not provide point estimates for the financing costs, but ranges with an open upper or lower limit, e.g. "The weighted average cost of capital is less than 5.3 percent." Consequently, in order to run an ordinary least square regression, we have to approximate the exact value they mean. Initially, when interviewees responded that the financing costs were "slightly lower" (higher) than some percentage value, we assume that the correct value is .5 percentage points lower (higher) than the respective value. When they replied it was "lower" (higher), we interpret this as a 1 percentage point difference, and when they replied "much lower" (higher), we interpret this as a 1.5 percentage point difference.

Further, omitted variables might bias our results. We conduct a formal analysis of how large such an unknown variable would have to be to render our estimates invalid. The analysis shows that such an omitted variable would need to be more relevant than even our most relevant explanatory variable, which appears highly unlikely. Further details can be found in the Supplementary Material.

3.3 Results

The results of our main specification show that feed-in tariffs and sliding premia are associated with the same risk premium for investors, whereas green certificate schemes are associated with significantly higher costs. The differences between feed-in tariffs and sliding premia are insignificant (see column (1) of table 2). Under the sliding premium, the revenue risk remains as low as under the feed-in tariff, most likely because investors receive the sliding market premium on top of the electricity prices, with a specific, almost certain, strike price. It appears that markets evaluate the risks as low as under feed-in tariffs or that they trust that the regulator would bail-out any stranded assets that might appear due to e.g. the introduction of new price zones. We present an additional regression with all "safe policies" as baseline, feed-in tariff and sliding premium, shown in column (2). In both estimations (1) and (2), the significance of the explanatory variables remains the same.

Most importantly, tradable green certificates are associated with an increase in the risk premium by on average 1.2-1.3 percentage points, or 27-33 percent in the logarithmic specification. This indicates that investors keep some of the power price risk. This is also possibly the case when they sign long-term contracts with off-takers, as these off-takers might go bankrupt or ask for renegotiations of contracts when spot market prices fall (Finon, 2011). For any individual investor, lending conditions additionally depend on their own creditworthiness, leading to lower or higher individual risk premia.

Where regulators have implicitly, if not officially, stopped implementing the policy scheme for new installations, financing costs are also increased. The results indicate they are increased by 2.3 percentage points. One reason for this could be the additional uncertainty with respect to administrative processes and the significant revenue uncertainty. Similarly, in the logarithmic specifications, the coefficients are statistically significant at the one percent level, implying an increase in financing costs by almost 50 percent.

Table 2: OLS estimation results

Dep. var: risk premium	(1) Level	(2) Level	(3) Log	(4) Log
Sliding premium	–0.290		–0.176	
	(0.501)		(0.187)	
Tradable green certificates	1.209**	1.306**	0.269**	0.328***
	(0.417)	(0.389)	(0.095)	(0.087)
No policy	2.274***	2.341***	0.453***	0.494***
	(0.438)	(0.421)	(0.097)	(0.087)
Retrosp. changes	–0.139	–0.082	–0.048	–0.013
	(0.366)	(0.361)	(0.088)	(0.083)
Tenders	1.030	0.887	0.304	0.217
	(0.608)	(0.575)	(0.156)	(0.130)
Equity investor	–0.266	–0.293	–0.048	–0.065
	(0.323)	(0.320)	(0.080)	(0.074)
Utility employee	–0.336	–0.316	–0.093	–0.080
	(0.539)	(0.528)	(0.126)	(0.118)
Banker	–0.708	–0.729	–0.263	–0.275
	(0.507)	(0.535)	(0.192)	(0.212)
N	53	53	53	53
R^2	0.50	0.49	0.40	0.37

Robust standard errors in parentheses.
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.
Fixed feed-in tariff and the Belgian and Romanian TGC systems with significant price floors are the baseline policy. In columns 2 and 4, also the sliding premium is in the base-line. Academic/Consultants are the baseline respondent group.

Somewhat surprisingly, retrospective changes do not have a statistically significant effect on financing costs. One explanation is that the respondents evaluated their country's situation *as if* these changes had not taken place. Additionally, countries that conducted retrospective changes usually also changed their support policies, frequently by implicitly abandoning support payments, which—as identified above—increases financing costs by around 2.3 percentage points and might also capture the effects of retrospective changes, which we cannot disentangle where both are the case.

Furthermore, tenders do not decrease or increase revenue risks if they are implemented on top of the main policies. This means tenders set the price level, but once investors have won them, regular feed-in tariffs/premia apply, i.e. no new revenue risks are induced for investors at that stage. Where financing needs to be secured before the tenders, uncertainty about the tender outcome can still induce risks at such an early stage. The responses from the different types of investors do not differ from one another. Compared to the baseline academic/consultant, none of the interviewee categories (equity investors, utility employees, or bankers) gave systematically different replies.

Our results indicate that secure designs of sliding premia facilitate such policies without inducing significant additional revenue risks and, thus, without additional financing costs, at least in the short term. However, with potentially increasing balancing costs and changes in power market design, investors might perceive the revenues under sliding premia as more uncertain, which would lead to increases in financing costs.

These results rest on several assumptions. We assume that by controlling for countries' general financing environments, we can control for national factors that influence project financing costs for wind power projects or that such variations occur randomly across countries. Moreover, we rely on the respondents' knowledge of the financing costs in their country. If this knowledge varies with the prevailing policy scheme, the results are biased.

3.4 Robustness checks

We conduct robustness checks with respect to our assessment of financing costs of observations, where respondents only stated that the financing costs lie higher or lower than some indicated threshold but did not provide a specific point estimate. We can derive the unknown estimates conditional on the known ones, assuming a specific functional form for the distribution of the risk premium estimates. We have a vector of lower boundaries (in case of statements where the upper boundary is open) and a vector of upper boundaries (in case of statements where the lower boundary is open). We assume that the lower (upper) boundaries follow normal distributions and that the unknown values also adhere to these distributions. Consequently, a maximum likelihood estimator is unbiased: the interval regression estimator, which is a generalized censored regression estimator. The unbiasedness of this estimator hinges on two assumptions: First, the lower (upper) estimates need to follow normal distributions. Second, the unknown values must follow the same normal distribution. We can test only the first of these assumptions. Visual and numerical checks of this assumption state that normality of the known estimates cannot be rejected for a specification in levels. As it is rejected in the logarithmic specification, we prefer the level specification over the logarithmic one. Details on the normality assumptions are provided in the Supplementary Material.

The results from the interval regression are very similar to the OLS estimates, indicating that neither estimator induces significant biases, therefore confirming the validity of our initial approach. Table 3 provides an overview of the results for the interval regressions. As argued before, the level specification in columns 1 and 2 are preferred over the logarithmic estimations in columns 3 and 4. The first estimation indicates that the differences between feed-in tariff and sliding premium are again insignificant.

Under the interval regression, tradable green certificates are also associated with a 1.2 percentage points higher risk premium at a one percent significance level. This is, on average, equivalent to an increase of the risk premium by almost a third and, thus, also significant economically. Turning toward the other explanatory variables, their sign and statistical significance are similar to those of the OLS regressions. Where policies are implicitly abolished, financing costs strongly increase.

The interval regression estimator relies on additional assumptions on asymptotic characteristics of the data. Specifically, it assumes that the unknown weighted average cost of capital estimates are distributed according to the normal distributions derived from the known estimates. Yet, particularly in the case of the unknown ones, one could argue that they are likely to be outliers as compared to those that are known.

Additional robustness checks test how sensitive the OLS specification is to the necessary interpretation of replies, as the unbiasedness of OLS relies on the correct interpretation of these

Table 3: Interval regression estimation results

Dep. var: risk premium	(1) Level	(2) Level	(3) Log	(4) Log
Sliding premium	–0.030		–0.130	
	(0.535)		(0.228)	
Tradable green certificates	1.213**	1.222**	0.292**	0.333**
	(0.417)	(0.414)	(0.094)	(0.108)
No policy	2.477***	2.484***	0.528***	0.557***
	(0.458)	(0.451)	(0.105)	(0.110)
Retrosp. changes	–0.212	–0.207	–0.047	–0.023
	(0.354)	(0.354)	(0.092)	(0.092)
Tenders	0.867	0.851	0.270	0.203
	(0.604)	(0.534)	(0.177)	(0.125)
Equity investor	–0.320	–0.323	–0.057	–0.069
	(0.304)	(0.311)	(0.080)	(0.078)
Utility employee	–0.369	–0.366	–0.122	–0.107
	(0.522)	(0.516)	(0.129)	(0.119)
Banker	–0.592	–0.592	–0.229	–0.230
	(0.496)	(0.500)	(0.198)	(0.208)
N	53	53	53	53
Maximum Likelihood R^2	0.46	0.46	0.36	0.35

Robust standard errors in parentheses.
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.
Fixed feed-in tariff and the Belgian and Romanian TGC systems with significant price floors are the baseline policy. In columns 2 and 4, also the premium is in the base-line. Academic/Consultants are the baseline respondent group.

replies. The relevance of this limitation can be identified by comparing the results with different codings. We estimate the regression with different absolute interval interpretations and with relative interpretations, i.e. "slightly lower" (higher) implying five percent lower (higher) weighted average cost of capital, ten percent when it was "lower" (higher), and 20 percent when it was "much lower" (higher). These sensitivity estimates are presented in the Supplementary Material. They support the results of the main analysis, implying that the actual coding-specification has some effect on the magnitude of the point estimates, but does not strongly affect statistical significance and indicating that no significant bias is introduced by the necessary response interpretations under the OLS specification.

4. LONG-TERM CONTRACTS

Long-term contracts play a key role for renewable energy investments under green certificate schemes and fixed premia. Where policy design does not comprise implicit long-term contract, we observe that market participants seek to sign bilateral long-term contracts as the basis for project financing of renewable energy projects. The counterparty to the project developer, which we refer to as the off-taker in the following, may incur risks in signing such contracts: the price to which the power is acquired via long-term contract may exceed the price at which the off-taker can sell it in future years to customers. Such risks imply that the off-taker only offers prices below the expected value of the energy from the renewable project to compensate for its additional costs. This means that the project needs to obtain additional support to break even, which directly translates into additional deployment costs. Section 4.3 shows descriptive statistics on large EU utilities as example of common off-takers of long-term contracts. Hence, their parameter values—debt-equity ratio and credit rating—give an idea of how to parameterize the theoretical approach developed in section 4.2 of measuring the impact of such contracts on the off-takers' financing costs.

While we focus the subsequent discussion on investments through project finance, the most common financing arrangement e.g. in Germany (Steffen, 2018), the analysis and results holds similarly for vertically-integrated companies, as Finon (2008) describes how long-term contracts between generators and retailers are substitutes with vertical integration to establish the required long-term cash flow security. Aïd et al. (2011) argue that whether vertical integration or long-term contracts prevails depends on the degree of power price uncertainty.

4.1 Implications of long-term contracts for private off-takers

Project investors seek long-term certainty about their revenue streams; commonly securing them for between ten and twenty years into the future, in order to facilitate a high share of debt relative to equity and, thus, low capital costs for the investment.[5] Such long-term contracts can, on the one hand, include the sale of electricity, called direct power purchase agreement (PPA), when there is a direct physical transmission of electricity to the off-taker, or called sleeved PPA, when the electricity is sold between the party, but the transmission runs through the general transmission grid (HSH Nordbank, 2018). On the other hand, PPAs can be purely financial, called synthetic PPA or privately-backed Contracts for Difference (CfDs), which provide both contract parties with revenue/cost certainty, but they still sell/buy their electricity supply/demand at a power exchange (HSH Nordbank, 2018).[6] With long-term contracts and the according low variability of project revenues, lenders' revenue requirements lie lower, i.e. the project's financing costs (Markowitz, 1952; Roques et al., 2008). This is particularly important since long-term financial hedging is not available for electricity, unlike for ordinary commodities. It is not storable economically on a long-term at large scale and it is heterogeneous: its value varies with place and time of generation (Finon, 2011; Roques et al., 2008).

We quantify the additional risks for the long-term contract's off-taker. This risk is primarily that the off-taker has contracted the power at long-term prices that turn out to be above spot market prices. However, the off-taker, usually electricity retail companies, cannot sign equivalent long-term contracts with private households for regulatory reasons and such contracts pose too large obligations for most companies, such that off-takers cannot sign corresponding long-term contracts with final customers. Therefore, the off-taker carries the price risk and, in a situation with low spot prices, incurs losses.[7]

This explains why, according to Baringa (2013) and Standard & Poor's (2017), rating agencies consider long-term contracts as imputed debt in their credit rating by adding the value of the long-term contract to the liabilities of a company. Accordingly, an additional long-term contract is treated equivalently to additional debt, hence increasing the debt-equity ratio. The higher debt-equity ratio reduces the credit rating, resulting in higher default spreads, i.e. risk premia on interest

5. Market actors hedge output on the short-term via exchange-traded products and with different associated strategies and risks, see, for example, Richstein et al. (2019) and Boroumand et al. (2015).

6. Alternatives to long-term electricity contracts exist, for example hedging via gas forwards that are based on a strong correlation between gas and electricity prices, which exist in some markets, and entails uncertainties about how these will develop in the future (Aydin et al., 2017). While portfolios of renewable energy assets across locations and renewable energy technologies can balance out project-specific profile factors relating to the timing of generation, they cannot address the general risk of low electricity prices (Wind Europe, 2017).

7. The off-taker also incurs the risk that the project fails to produce at times when the contract price is below the spot price level.

that need to be paid above the risk-free rates, for all debt raised and higher return requirements for equity.[8]

Consequently, the off-taker will only sign long-term contracts at a discount to the expected power price, which, in competitive markets, reflects the increased financing costs. Project developers will require compensating payments through other channels, e.g. by bidding higher required remuneration levels under fixed premia requiring higher green certificate prices.

We approximate the cost incurred by an off-taker in signing a long-term contract. A firm's total capital cost *C* and comprises both the cost for debt *d* and equity *e* at the respective return requirements r_{debt} and r_{equity}.

$$c(d,e) = r_{debt}d + r_{equity}e \tag{3}$$

The return requirements depend on the rating grade $g(d,e)$, which is, in turn, a function of the debt-equity ratio. Thus, the total capital costs are

$$c(d,e) = r_{debt}(g(d,e))d + r_{equity}(g(d,e))e \tag{4}$$

Private off-takers' balance sheets change for rating purposes when they sign long-term contracts. The additional long-term liabilities are added to the companies' debt stock, worsening their debt-equity ratio and rating grade. For simplicity, we analyze only the changes in the costs of debt, rendering our estimates a lower bound of the costs of an increase in debt, as equity can be expected to become more expensive as well. The derivate is:

$$\frac{\partial c(d,e)}{\partial d} = \frac{\partial r_{debt}(g(d,e))}{\partial g}\frac{\partial g(d,e)}{\partial d}d + r_{debt}(g(d,e)) \tag{5}$$

The term $\frac{\partial r_{debt}(g(d,e))}{\partial g}\frac{\partial g(d,e)}{\partial d}d$ represents the increase in costs caused by the increase in interest rate, as this higher interest rate is, in the long run, applied to the total stock of debt *d*. The term $r_{debt}(g(d,e))$ represents the costs of an additional unit of debt and simply equals the interest rate. As described in Standard & Poor's (2017), the long-term contract is evaluated as imputed debt, i.e. equivalent to an increase in liabilities, hence, impacting the debt-equity ratio. Debt is not formally increased, so we omit the term $r_{debt}(g(d,e))$ in the following.

We analyze how the interest rate responds to an incremental change in credit rating using data provided by Damodaran (2017) for all traded US companies.[9] Analyzing the link between default spreads and ratings reveals that the default spread function is non-linear in rating: The worse the rating, the stronger the impact of a one step change in the credit rating on the default spread (see figure 2).[10]

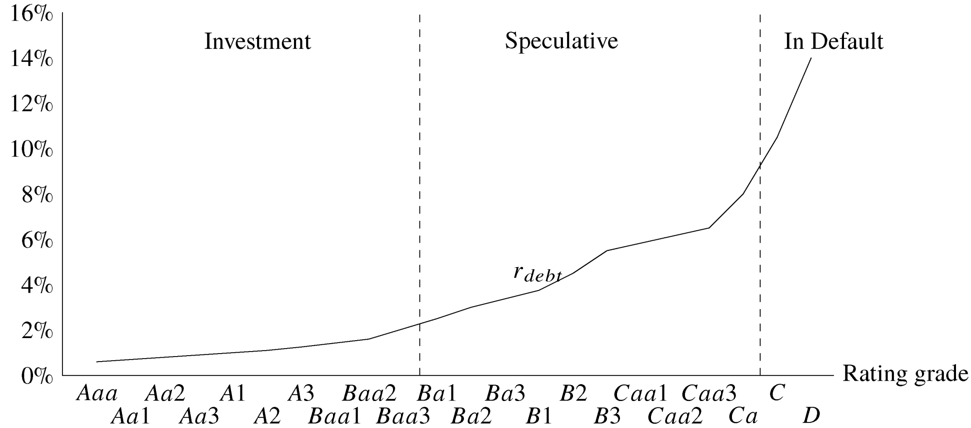
Moreover, the credit rating itself is approximately a linear function of debt. The data by Damodaran (2017) on the relationship between another key financial metric, the interest coverage ratio, and the credit rating indicates that the rating is roughly linear in interest coverage ratio (and approximately correspondingly in debt-equity ratio). This implies that the distances between the otherwise ordinal rating grades *g* are approximately equidistant.

8. If rating agencies treat only part of the contract value as liabilities, this reduces the estimated costs. Yet, according to Standard & Poor's (2017), even for companies not subject to retail competition and with regulated cost recovery, half of the contract value is counted, indicating even higher numbers for companies in retail competition.

9. We refer to the rating categories in Moody's nomenclature.

10. For comparison, the Supplementary Material shows the estimation and results for a linear functional form, that, however, has a lower R-squared (82 percent in the linear against 93 percent in the quadratic case).

Figure 2: Default spread as function of corporate credit rating, based on Damodaran (2017)



4.2 Estimation of off-takers' costs

We estimate off-takers' costs of signing long-term contracts by parameterizing equation (5). To this end, we derive the default spread based on the credit rating and we parameterize function $r_{debt}(g(d,e))$. As argued before, the spread increases approximately exponentially, as confirmed by Moody's (2005) and Elton et al. (2001). A respective non-linear function for the default spread r_{debt} as function of credit grade ($g(d,e)$) is:[11]

$$r_{debt}(g(d,e)) = m + \lambda g(d,e)^2 \tag{6}$$

where m is a constant and λ the coefficient on the squared credit grade g. The slope of the function is:

$$\frac{\partial r_{debt}(g(d,e))}{\partial g(d,e)} = 2\lambda g(d,e) \tag{7}$$

To get an idea of the magnitude of these effects, we estimate exemplary parameter values based on financial data by Damodaran (2017), as detailed in the Supplementary Material. The coefficient λ is statistically significant and is equal to 0.00023, while the constant m is insignificant. This describes how the default spread reacts to a change in credit grade. For example, a downgrade by one rating from Ba2 to Ba3 results in an increase in default spread from 2.8 to 3.3 percent.

The rating grade $g(d,e)$ is a function of the debt-equity ratio. The function differs between industries, such that we prefer deriving parameter values from a sample of European utilities. The credit grade function can be expressed as:

$$g(d,e) = b + \varepsilon \frac{d}{e} \tag{8}$$

where b is a constant and ε the effect of a one unit increase in the debt-equity ratio on the credit grade. The function's derivative with respect to d is:

$$\frac{\partial g(d,e)}{\partial d} = \frac{\varepsilon}{e} \tag{9}$$

11. We estimate a function for the default spread, even though we previously discuss the interest rate. Yet, we are only interested in changes in the default spread, i.e. the slope. The risk-free rate would be contained in the constant and, thus, is not relevant for our subsequent analysis.

For the parameterization, we use aggregated annual data on average debt-equity ratios and credit ratings of twelve large European utility companies over 11 years, as detailed in the Supplementary Material. The slope ε is estimated as 2.88 and the constant n is insignificant. Hence, an increase in debt-equity ratio by one is associated with a downgrade of almost three rating grades.

Combined, we can calculate the off-taker's cost of signing a long-term contract and holding it as liability on the balance sheet for a year by inserting the estimated parameters into equation (5).

$$\frac{\partial c(d,e)}{\partial d} = 2\lambda(b + \varepsilon\frac{d}{e})\frac{\varepsilon}{e}d \qquad (10)$$

Based on European utilities' average debt-equity ratio in 2015 of 1.85, we calculate these annual costs as 1.84 percent of contract value. In order to obtain the present value of the imputed debt over the contract lifetime, we need to calculate the present value equivalent to levelizing the cost of electricity according to equation (11). The remaining outstanding liabilities decrease every year, as captured in the numerator. For an exemplary lifetime of T of 20 years, the off-taker possesses liabilities for 20 more years in the first year, in the second year for another 19 years, and so forth.

$$c_{present} = \frac{\sum_{t=1}^{T}\zeta^{t-1}c_{annual}(T-t-1)}{\sum_{t=1}^{T}\zeta^{t-1}} \qquad (11)$$

Applying a discount factor ζ of exemplary 0.96 percent, the levelized average costs $c_{present}$ are 21.8 percent of the contract value. The costs are depicted in figure 3 across a range of debt-equity ratios of the off-taking company.

These costs lie lower for off-takers in more favorable financial positions: The average debt-equity ratio of the 12 European utilities in 2005 was 1.15. Inserting this ratio and the parameter values yields a credit rating between A1 and A2 and, thus, extra costs of only 9.9 percent.

4.3 Financial position of private off-takers

To shed some light on the importance of the effects identified in the previous section and displayed for a large range of potential debt-equity ratios in figure 3, we analyze the financial position of common off-takers in more detail. Utility companies are commonly the sole market actors

Figure 3: Extra re-financing costs for private off-takers as share of contract value

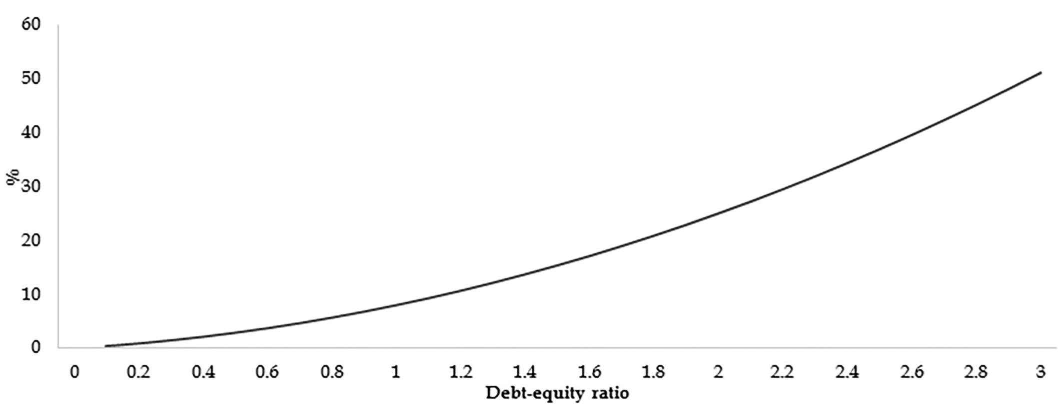


Figure 4: Average debt-equity ratio of twelve large EU utilities. Source: Own calculations based on Datastream International (2016) and Vattenfall (2015)

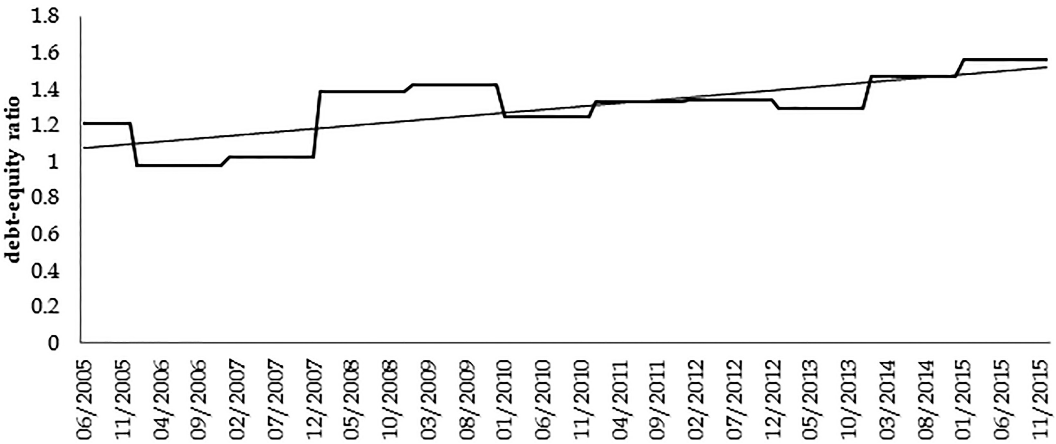
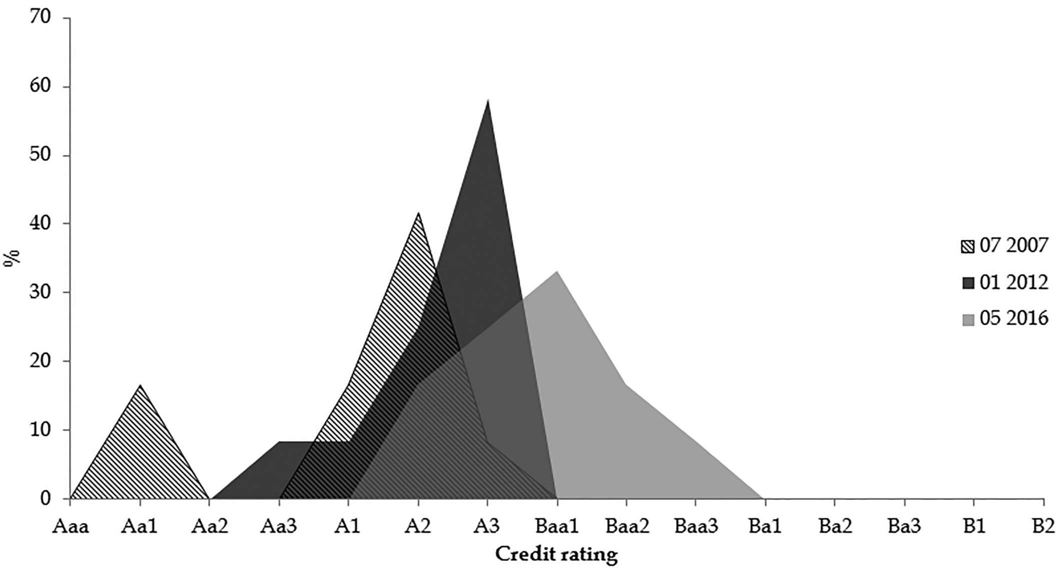


Figure 5: Credit ratings of large EU utilities. Source: Based on Moody's (2017)



that hold relatively stable long-term customer bases, which essentially function as price hedges (Finon, 2011).[12] Moreover, utilities have traditionally possessed relatively strong financial positions and large portfolios, enabling them to commit to long-term contracts (Baringa, 2013), as well as experience with electricity markets that may decrease their renewable energy risk premia compared to institutional investors (Salm, 2018). Consequently, green certificate schemes generally depend on utilities with large sticky customer bases and strong financial positions. However, the subsequent analysis extends to other kinds of companies as well.

12. Sometimes, companies other than utilities aim to obtain renewable electricity directly from investors. In particular, in the US, large (IT) companies have acted as off-takers to long-term contracts (Bloomberg New Energy Finance, 2017).

Liberalized electricity markets mean new competition on the retail and wholesale markets (Tulloch et al., 2017),[13] while the rise of renewable energies challenged incumbents' business models due to its differing risk-return profiles (Helms et al., 2015). This resulted in reduced valuations of conventional power stations, reducing the equity value of companies. Figure 4 visualizes the development of utilities' debt-equity ratios. The average debt-equity ratio of Europe's ten largest utilities, by electricity sales according to RWE (2015), plus the UK's Centrica and SSE, increased strongly between 2005 and 2015: Whereas the average debt-equity ratio stood at 116 percent in June 2005, it was 184 percent in December 2015, an average annual increase of 6.5 percentage points. A multitude of factors may underlie this: generally falling costs of debt, write-downs on thermal power assets, and the increased competition due to market liberalization.

As a result, utilities' credit ratings have worsened. As figure 5 indicates, credit ratings have declined across the board in the 2010s. On average, bond ratings have fallen more than 2.5 rating categories, e.g. from Aa1 to Aa2 or from A3 to Baa1.

5. ILLUSTRATIVE ADDITIONAL COSTS UNDER GREEN CERTIFICATE SCHEMES

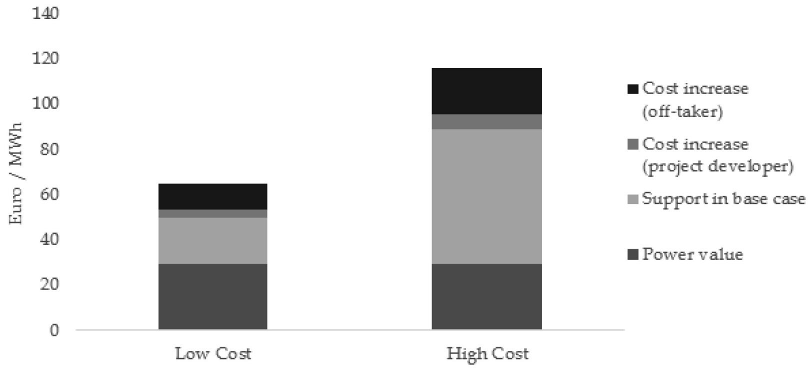
Due to regulatory and market risks, green certificates especially increase the costs of renewable energy deployment. For an exemplary wind power project with levelized costs of electricity of €50 per MWh under a feed-in tariff,[14] the average technology-weighted power price of 2016 pays for about half of the costs, with the other half required as additional support. Under green certificates and using the parameter values from the small sample of large EU utility companies, the overall costs increase to about €65 per MWh, increasing the required support (overall remuneration minus power price) by roughly 75 percent. The total increase by around 29 percent is in line with the values identified by ?, who provide an exemplary increase by 28 percent when power price risks are borne by investors, by Enertrag (2019), who estimate 25 percent overall, and by Energy Brainpool (2019), who identify an overall increase by 34 percent.

The increase stems from both additional regulatory risks, inducing higher financing costs for investors, and market risks, inducing costs for off-takers of long-term contracts. Firstly, incomplete hedging of regulatory risks increase investors' financing costs by about 1.2 percentage points, as identified in section 3.3. We do not distinguish between channels—off-takers could directly pass-through costs to final consumers or take-off electricity only at significant discounts from project developers, who then need to increase revenues from other channels—as the effect on overall costs for final consumers is the same. This translates into an increase from €50 per MWh to €53 per MWh, as shown in figure 6. Secondly, the failure to hedge market risks induce higher costs for off-takers of long-term contracts, amounting to about 21.8 percent of the contract value, as described in section 4. This translate into a cost increase to €65 per MWh, equivalent to an increase in investors' financing costs by another 3.6 percentage points. In total, this cost increase is equivalent to an increase in investors' financing costs by 4.8 percentage points.Not all costs are necessarily additive, as survey results could already include some discounts of contract values due to off-takers induced costs even

13. The degree of competition varies between regions and levels, such that some markets continue to have regulated monopolists; for example, regarding electricity distribution, that, however, also face some degree of yardstick competition (Dimitropoulos and Yatchew, 2017).

14. We apply rather low cost estimates of €1080 per kW as investment costs and €50 per kW annually as operation and maintenance costs combined with a high capacity factor of 33 percent, based on Deutsche WindGuard (2013), and exemplary 4 percent financing costs.

Figure 6: Exemplary costs for low and high cost onshore wind power under different policies



though the surveys did not address discounts in contract values. However, as these induced costs are larger than the effect on project developers' financing costs, this does not seem to be the case for most of the effect.

With higher initial project costs, the additional costs increase proportionally. Initial costs of €89 per MWh under a feed-in tariff rise to €116 per MWh under green certificates.[15] This divides into additional costs of €6.5 per MWh for the new regulatory risks and additional costs of €21 per MWh for the new market risks.

In general, the same extra costs for long-term contracts are introduced when all policy support is abolished and investments are conducted based on a significant carbon price. This price would have to be high enough that the expectation of the resulting power price is sufficient to support investments into renewable energies. Investors would still hedge their resulting price risks and liabilities, implying similar cost increases.

Under fixed premia, the cost increase applies only to a part of the overall costs of renewable energies. Investors sell their electricity and receive additional, fixed premia, so they only need to sign long-term contracts for the power value, as the premium is guaranteed by the regulator. If, as in the previous example, the power price makes up about half of the total remuneration, then the extra costs of 21.8 percent only applies to this half. Thus, the additional costs for the off-takers increase the overall costs by around eleven percent.

6. DISCUSSION

Power systems with increasing shares of wind and solar generation have high capital and low operational costs. This increases the importance of the cost of financing for total system cost. We estimate how different risk factors affect, on the one hand, renewable energy investors' financing costs, and, on the other hand, the costs of off-takers of long-term contracts.

First, based on a survey on wind power financing cost estimates from 23 EU countries, we find that sliding premia do not increase financing costs in comparison with fixed feed-in tariffs. However, with evolving power market designs, investors are exposed to additional risks under sliding premia, e.g. in relation to balancing costs, such that risk premia might increase in the future.

Tradable green certificates can be associated with increases in the wind power risk premium by about 1.2 percentage points. Capital providers require higher risk premia because of the

15. This scenario grounds on the same cost assumption as previously, but higher investment costs of €1500 per kW and a reduced capacity factor of 23 percent.

higher revenue variability. These results hold under ordinary least square specifications as well as with interval regressions, which take into account the specific nature of responses, with several replies in relative terms. However, small sample sizes mean that there is plenty of room for future research that collects and uses larger datasets, allowing for more detailed analyses.

Second, we model the implicit long-term hedge that renewable support mechanisms can offer to market participants. In principle, both renewable project developers and final consumers would like to hedge against price uncertainty. In practice, market design rules and counterparty risks inhibit such long-term contracts between project developers and final consumers. In the absence of such long-term contracts, project developers commonly sign long-term contracts with electricity retail companies in order to secure revenue streams for financing purposes. Yet, signing such long-term contracts constitutes imputed debt on the balance sheets of the retail companies. We estimate by how much such contracts increase retail companies' re-financing costs. Ultimately, these costs are passed on to consumers. The magnitude of additional costs depends on the financial position of the long-term contracts' off-takers. Parameterizing these costs based on 2015 financial data of a small sample of the largest EU utility companies, these extra costs amount to around 22 percent additional costs for renewable energy deployment. However, this is a lower bound, as we would also usually expect equity to become more expensive, which we are not disregarding in the current setting, assuming constant costs of equity.

The combined increases in financing costs for the investor and for the private off-takers of long-term contracts render renewable energy deployment about 30 percent more expensive under green certificate schemes compared to feed-in tariffs when using the exemplary EU utility data. This increases the costs of an illustrative wind power plant from €50 per MWh to €65 per MWh. With increasing shares of renewable energies and higher contracted volumes, this cost premium increases. The small sample size in the estimation of project developers' financing cost premia, however, means that the specific value of the cost premium is uncertain, which would ideally be resolved with more systematic collection of the financing conditions underlying renewable energy projects.

Combining the effects of risk for project investors and risk for counterparties signing long-term off-take contracts may also explain the somewhat opposing findings of previous assessments. Studies like Ragwitz et al. (2012) and Butler and Neuhoff (2008) show that significantly higher support levels are required when policy design involves green certificate systems, but no equivalent discrepancy in financing cost is identified in surveys of investors. Ample space for future research remains with respect to changes in financing costs over time. When sales represent a larger share of revenues, then the extra costs of policies with a higher power price exposure might induce higher extra costs. Information on renewable energy financing cost over time would allow for identification of such effects. Future research could also investigate the role of additional dimensions of renewable energy support like preferential public loans and priority dispatch on investors' financing costs.

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