The Economics of Financing and Integrating Renewable Energies

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Prior Publications

Chapter 1: The Impact of Wind Power Support Schemes on Technology Choices

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  - May, Nils, Neuhoff, Karsten and Frieder Borggrefe. 2015. "Marktanreize für systemdienliche Auslegungen von Windkraftanlagen." *DIW Wochenbericht* 24.
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Chapter 2: Financing Power: Impacts of Energy Policies in Changing Regulatory Environments

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  - May, Nils, Jürgens, Ingmar and Karsten Neuhoff. 2017. "Renewable energy policy: risk hedging is taking center stage." *DIW Economic Bulletin* 39–40.

Chapter 3: Too good to be true? How time-inconsistent renewable energy policies can deter investments

- Co-author: Olga Chiappinelli (DIW Berlin)
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Abstract

This dissertation comprises three chapters on the economics of financing and integrating renewable energies and on designing associated support policies. The transition toward carbon-neutral economies requires large-scale investments into renewable energy. The integration of these intermittent renewable energies poses new challenges to power systems designed around dispatchable thermal power plants. As, for example, more and more wind power is generated in high wind, it is increasingly important to provide incentives that encourage project developers to choose alternative wind power technologies that supply power also under mediocre wind conditions. Another challenge are the investments' financing costs, as they, to a large extent, define overall investment costs and are affected by the design of support policies. The question arises which policies lead to higher financing costs. Further, in order to facilitate large investment volumes, it is crucial to design policies such that they constitute credible commitments on the basis of which investments can be made.

Chapter 1 analyzes the integration of wind power into energy systems with increasing shares of renewable energies. In energy systems with large shares of variable renewable energies, electricity generation is lower during unfavorable weather conditions. System-friendly wind turbines rectify this by producing a larger share of their electricity at low wind speeds. The chapter analyzes to what extent the benefits of system-friendly wind turbines out-weigh their additional costs and how to incentivize investments into them. A wind power investment model for Germany shows that system-friendly wind turbines indeed deliver benefits for the energy system that overcompensate for their cost premium. Sliding feed-in premia incentivize

their deployment only where investors bear significant price risks and possess sufficient foresight. Alternatively, a new production value-based benchmark triggers investors to install turbines that meet the requirements of power systems with increasing shares of variable renewable energies, without inducing additional investment risks.

Chapter 2 provides novel evidence that some support policies lead to higher financing and overall deployment costs than others. Power systems with increasing shares of wind and solar power generation have higher capital and lower operational costs than power systems based on fossil fuels. This increases the importance of the cost of financing for total system cost. We quantify how renewable policy design can influence the cost of financing by addressing regulatory risk and facilitating hedging. First, we use interview data on wind power financing costs from the EU and derive effects on project developers' financing costs. Second, we model how long-term contracts signed between project developers and energy suppliers impact financing costs in the context of green certificate schemes. The costs of renewable energies increase by about 30 percent in comparison to policies that provide implicit long-term contracts between project developers and electricity consumers.

Chapter 3 shows that time-inconsistency issues can arise for renewable energy investments, deterring investments, and how these issues can be addressed by policymakers. Investments into renewable energies are commonly enabled by support policies. Yet, governments can have incentives – and the ability – to deviate from previously-announced support once investments are made, which can deter investments. In the first step, we analyze a renewable energy regulation game and apply a model of time-inconsistency to renewable energy policies. Based on the model, we derive under what conditions governments have incentives to deviate from their commitments, analyzing the potentially mitigating effects of various policy designs and targets. In the second step, we provide a numerical example of our theoretical model and explain why Spain conducted retrospective changes in 2010-2013 whereas Germany stuck to its commitments. The model suggests that, on the one hand, the extra costs of renewable energies were considerably lower in Spain due to the higher wholesale electricity price, rendering compliance more attractive in Spain. However, on the other hand, this is outweighed by the dirtier German conventional power plant fleet and especially by the larger myopia of the Spanish regulator, caused by high discounting during the financial crisis of future benefits of sustained renewable energy deployment.

Zusammenfassung

Diese Dissertation umfasst drei Kapitel über die volkswirtschaftlichen Effekte der Finanzierung und Integration erneuerbarer Energien und das Design entsprechender Förderinstrumente. Die Umstellung hin zu einer CO_2-neutralen Wirtschaft bedingt groß angelegte Investitionen in erneuerbare Energien. Die Integration wetterabhängiger erneuerbarer Energien stellt neue Herausforderungen dar für Energiesysteme, die für regelbare thermische Kraftwerke ausgelegt wurden. Beispielsweise wird bei starkem Wind mehr und mehr Windenergie erzeugt. Deshalb ist es zunehmend wichtig, Anreize zu schaffen, die Projektentwickler dazu ermutigen, alternative Windkrafttechnologien zu wählen, welche Strom auch unter mittelmäßigen Windbedingungen liefern. Eine weitere Herausforderung sind die Finanzierungskosten der Investitionen, da sie die Gesamtinvestitionskosten weitgehend bestimmen und von der Gestaltung der Förderpolitik beeinflusst werden. Es stellt sich die Frage, welche Politikinstrumente mit höheren Finanzierungskosten einhergehen. Außerdem ist es, um große Investitionsvolumina zu ermöglichen, essentiell, Politikinstrumente so zu gestalten, dass sie glaubwürdige Zusagen darstellen, auf deren Grundlage Investitionen getätigt werden können.

Kapitel 1 analysiert die Integration von Windenergie in Energiesysteme mit steigenden Anteilen erneuerbarer Energien. In solchen Energiesystemen ist die Stromerzeugung bei ungünstigen Wetterbedingungen geringer. Systemfreundliche Windenergieanlagen korrigieren dies, indem sie einen größeren Anteil ihres Stroms bereits bei niedrigen Windgeschwindigkeiten produzieren. In diesem Beitrag wird analysiert, inwieweit die Vorteile systemfreundlicher Windenergieanlagen ihre zusätzlichen Kosten

übersteigen und wie man Anreize für Investitionen in solche Anlagen geben kann. Ein Windkraft-Investitionsmodell für Deutschland zeigt, dass systemfreundliche Windenergieanlagen tatsächlich Vorteile für das Energiesystem bieten, die ihre zusätzlichen Kosten überkompensieren. Gleitende Marktprämien bieten nur dann einen Anreiz für solche Anlagen, wenn Investoren ein erhebliches Preisrisiko tragen und ausreichend vorausschauend sind. Alternativ veranlasst ein neues Referenzwertmodell Investoren dazu, Anlagen zu installieren, die die Anforderungen von Energiesystemen mit steigenden Anteilen erneuerbarer Energien erfüllen, ohne dass Investoren dadurch zusätzliche Risiken entstehen.

Kapitel 2 liefert neue Belege dafür, dass einige Förderinstrumente zu höheren Finanzierungs- und Gesamtkosten der erneuerbaren Energien führen als andere. Energiesysteme mit steigenden Anteilen an Wind- und Solarenergie haben höhere Kapitalkosten und geringere Betriebskosten als Energiesysteme auf Basis fossiler Brennstoffe. Dies erhöht die Bedeutung der Finanzierungskosten für die Gesamtsystemkosten. Wir quantifizieren, wie Förderinstrumente die Finanzierungskosten beeinflussen können, indem sie regulatorische Risiken adressieren und Absicherungen ermöglichen. Zum einen verwenden wir Befragungsdaten zu den Finanzierungskosten für Windenergie aus der EU und ermitteln daraus die Auswirkungen von Förderinstrumenten auf die Finanzierungskosten der Projektentwickler. Zum anderen modellieren wir, wie langfristige Verträge zwischen Projektentwicklern und Energieversorgungsunternehmen die Finanzierungskosten bei grünen Zertifikatehandeln beeinflussen. Die Kosten für erneuerbare Energien steigen um etwa 30 Prozent im Vergleich zu Förderinstrumenten, welche implizite Langzeitverträge zwischen Projektentwicklern und Stromverbrauchern darstellen.

Kapitel 3 zeigt einerseits, dass Probleme zeitlicher Inkonsistenzen bei Investitionen in erneuerbare Energien auftreten können, wodurch Investitionen verhindert werden, und andererseits, wie diese Probleme von politischen Entscheidungsträgern angegangen werden können. Investitionen in erneuerbare Energien werden üblicherweise durch Förderinstrumente unterstützt. Regierungen können jedoch Anreize und die Möglichkeit haben, von zuvor angekündigten Vergütungszahlungen abzuweichen, sobald Investitionen getätigt wurden, was Investoren abschrecken kann. Im ersten Schritt analysieren wir ein Regulierungsspiel von Investitionen in erneuerbare Energien und wenden ein Modell der zeitlichen Inkonsistenz auf die Förderung erneuerbarer Energien an. Auf der Grundlage des Modells leiten wir ab, unter welchen Bedingungen Regierungen Anreize haben, von ihren Verpflichtungen abzuweichen, und analysieren die potenziell mildernden Auswirkungen verschiedener Förderinstrumente und von erneuerbare-Energien-Zielen. Im zweiten Schritt geben wir ein numerisches Beispiel für unser theoretisches Modell und erklären, warum Spanien 2010-2013 retrospektive Änderungen seiner Förderung durchführte, während Deutschland seinen Verpflichtungen nachkam. Die Modellergebnisse deuten darauf hin, dass die zusätzlichen Kosten für erneuerbare Energien in Spanien aufgrund des höheren Großhandelsstrompreises deutlich niedriger waren als in Deutschland, was eigentlich die Erfüllung der Verpflichtungen in Spanien attraktiver machte. Jedoch wird dies durch die schmutzigere deutsche konventionelle Kraftwerksflotte und insbesondere durch die Kurzsichtigkeit der spanischen Regulierer mehr als aufgewogen, welche in der Finanzkrise dem zukünftigen Nutzen erneuerbarer Energien durch hohe Diskontierung wenig Wert beimaßen.

General Introduction

Anthropogenic climate change increases the Earth's average global temperature and leads to the acidification of oceans (IPCC, 2014). Between 1880 and 2012, global average temperature has already increased by about 0.85 degrees Celsius. When the temperature increase surpasses tipping points, this results in self-reinforcing, irreversible climate-changing processes, possibly causing catastrophic damages (IPCC, 2014). As greenhouse gases accumulating in the atmosphere and the oceans are identified as the main culprit for climate change, the 2015 Paris Agreement sets the backdrop for large-scale mitigation actions, aiming to keep total warming well below two degrees (UNFCCC, 2015). By early 2018, 195 countries had signed the agreement and submitted nationally-determined contributions, laying out climate change mitigation and adaptation measures (UNFCCC, 2018).

Decreasing the emissions of the electricity sector through renewable energy deployment is a key means to implementing the national plans under the Paris Agreement. The energy supply sector represents around 35 percent of all man-made emissions, mostly stemming from electricity supply (IPCC, 2014). Therefore, renewable energy deployment is included in the national plans of 145 countries and 109 countries set themselves renewable energy targets (IRENA, 2017b). Global solar and wind power capacity has already grown from 94 Gigawatts (GW) in 2007 to around 467 GW in 2017 (IRENA, 2017a) and strong future growth is expected (IEA, 2017). For example, China is growing its renewable capacity by about 54 GW a year (IRENA, 2017a). The European Union set itself a target of 20 percent of energy to stem from renewable energies by 2020 and at least 27 percent by 2030 (European Union, 2009).

India plans to increase its renewable energy capacity to 175 GW by 2022, based on growth in solar power from 2016's 10 GW to 100 GW and in wind power from 2016's 29 GW to 60 GW (NREL et al., 2017, IRENA, 2017a).

Moreover, electricity from renewable energy is frequently envisioned to decarbonize sectors beyond the electricity sector, indicating strong future demand growth for electricity from, in particular, wind and solar power. Electric vehicles take on important roles in long-term decarbonization plans (IEA, 2017). Through heat pumps, wind and solar power can fuel part of the heating and cooling sector (see e.g. German Ministry for Economic Affairs and Energy (2017)). In light of these decarbonization plans, for example the upcoming German coalition government intends to significantly raise the country's 2030 renewable energies target explicitly in order to account for electricity demand growth from other sectors (CDU et al., 2018).

In order to facilitate the required large investment volumes, renewable energy investments are backed by support policies in almost all countries. As capital-intensive investments, they commonly require support policies to underpin future revenue streams. Such policies aim to decrease revenue risks and financing costs. Three types of policies dominate globally: feed-in tariffs, sliding feed-in premia and green certificate schemes. In 2015, 82 countries had feed-in tariffs or sliding feed-in premia. Green certificate schemes supported renewable energies in 34 countries. In addition, 35 countries auctioned the eligibility to support through tenders, which in principle can be combined with any of the support systems (REN21, 2017).

The support policy defines to a large extent how investors can finance their assets. Feed-in tariffs used to be, and in some regions still are, the most common support policy for renewable energy. Regulators (or regulated grid companies) take the electricity from investors,[1] who are paid a certain support level per electricity output. Thus, per unit of output, they generally do not face any revenue risks. With increasing shares of renewable energies, sliding feed-in premia have gained popularity to facilitate market integration. Investors sell their electricity themselves (or transfer the marketing

[1]This dissertation uses the terms investor, project developer and operator interchangeably, unless stated otherwise. The differences matter particularly when discussing the financing structure of projects, where project developers seek capital from investors.

rights to another firm), receiving the power price and introducing balancing risks, while they additionally receive a premium payment. Therefore, they face some uncertainty about their exact total remuneration level. The level of the premium varies with the technology-specific weighted power price, in most designs effectively shielding investors from a large degree of the revenue uncertainty. Among others, Germany, the Netherlands and the UK have shifted to feed-in premia (Eclareon, 2017).[2] Under quantity-based support policies, like green certificate schemes, implemented for example in Sweden and many US states, investors sell their electricity and receive green certificates proportional to their output. Retail electricity companies are obliged to obtain such certificates, thus creating demand for them and representing a revenue stream for renewable energy investors in addition to the sale of electricity.

With increasing shares of renewable energies, support policies increasingly need to account for the time and location of power generation. In power systems originally designed around inflexible thermal plants, electricity supply and electricity prices change with wind and solar conditions when introducing renewables. Whereas in windy periods, wind power supply is large and the production value is low, generation is scarce when there is no wind. Thus, with more renewable energy in the system, the average production value of renewable energy falls (Wiser et al., 2017, Fraunhofer IWES, 2013a, Fraunhofer ISE, 2014, Hirth, 2013). Rintamäki et al. (2017) show that in Germany, this effect is particularly pronounced for wind power, as the bulk of production takes place in hours of rather low demand. Regarding the locational dimension, Pechan (2017), Schmidt et al. (2013) and Grothe and Müsgens (2013) analyze how different policies affect the optimal locations for wind power investments.

System-friendly technologies can help to mitigate the decreasing value of wind power by having a larger share of their production in times of moderate wind (Fraunhofer IWES, 2013a). Hirth and Müller (2016) compare one system-friendly and one conventional wind turbine and demonstrate that, when installing system-friendly tur-

[2]Frequently, fixed feed-in premia are discussed where the premium is fixed, which exposes investors to all power price fluctuations, see for example (Kitzing, 2014) and (Pechan, 2017). However, due to the associated risks and, thus, higher financing costs, fixed feed-in premia are rarely used. This dissertation focuses on sliding feed-in premia and explicitly uses the term fixed premia when such premia are meant.

bines, the value of wind power remains significantly higher for high wind power penetration levels. However, they do not consider in how far individual investors can capture this additional value of system-friendly technologies and whether it is, hence, optimal for investors to choose such turbines. The overall output of system-friendly turbines tends to be lower, increasing their levelized cost of electricity (Molly, 2014), a measure of discounted lifetime costs per unit of output.

Chapter 1 asks how the requirements for renewable energy investments shift with increasing shares of renewable energies and how system-friendly wind power can contribute to the long-term integration of renewable energies. It analyzes investors' incentives to choose system-friendly technologies under different support policies. Further, it derives a socially-optimal level of system-friendliness and explores the design of a policy to align privately-optimal with socially-optimal technologies. How can incentives based on electricity prices be given to investors without inducing additional revenue risks and, thus, financing costs?

The chapter employs a simple analytical analysis, modeling the net present value of wind power technologies under different support policies, extending the analysis of Schmidt et al. (2013) to technology choices. Based on these theoretical arguments, the wind power technology maximizing value from a social perspective is derived. A numerical model of the net present value of projects for specific locations with a large number of wind power technologies allows the identification of marginal changes between technologies and goes beyond the literature's usual limited technology options. The model incorporates the wind power technologies and their respective electricity yield as functions of rotor blade length, hub height and capacity. Exposing project developers to different support policies allows for the identification of the impact of different support policies on investors' technology choices.

The role of support policies is changing due to the lower costs of renewables. The costs of solar power deployment in Germany, for example, have dropped by roughly 89 percent between 2007 and 2018 from €379 to €43 per MWh (megawatt hour) (IWR, 2018, Bundesnetzagentur, 2018a). Costs for onshore wind power have fallen by 40 percent from around €78 to €47 per MWh (IWR, 2018, Bundesnetzagentur, 2018b).[3] Diminishing additional funding is required beyond the electricity wholesale price. Rather than providing additional funding, support policies act as facilitators of low-cost financing, enabling investments at low capital costs.

As the share of renewable energies increases, the costs of renewable energies, defined largely by their financing costs, represent growing shares of the energy system's total costs. Based on a choice experiment, Lüthi and Wüstenhagen (2012) find that differences in the designs of support policies can directly translate into additional deployment costs. Analyzing the differences in financing costs, Haas et al. (2011) scrutinize descriptive statistics on installation numbers and support costs for a small number of European countries, finding that feed-in tariffs are more successful in both respects. Applying a mean-variance approach, Kitzing (2014) shows that the risks and financing costs under feed-in tariffs are lower than fixed feed-in premia. Couture and Gagnon (2010) argue that feed-in tariffs lead to lower financing costs than sliding feed-in premia as well. However, Klobasa et al. (2013) find no such effect after a change from tariff to premium in Germany. Butler and Neuhoff (2008) find that the German feed-in tariff has led to more investments at lower costs than the British green certificate scheme. Yet, Boomsma and Linnerud (2015) argue, based on a simulation of the green certificate scheme in Norway and Sweden, that the additional risks under green certificates are not economically significant. However, these policy comparisons are either based on observations from only a few countries or on theoretical or simulated arguments.

Chapter 2, jointly written with Karsten Neuhoff, analyzes the role of renewable energy support policies in facilitating low-cost financing. The chapter studies the differences in capital costs between support policies empirically, based on financing cost data from 23 EU countries. It further looks at how the absence of implicit long-term contracts between project developers and consumers under some policies influences contractual arrangements. It scrutinizes how private long-term contracts

[3] 2007's values are for large-scale installations to make them more comparable to 2018's auction results. Successful bids in the auctions have two years of time to implement their projects, whereas 2007's values refer to the actual date of implementation. 2007's value for wind power is based on discounting of 4 percent since the support varied over the installations' lifetimes.

between project developers and off-takers, currently debated as long-term alternatives to explicit support policies (BDEW, 2018), affect the financial situation of off-takers. How do private long-term contracts for renewable energies affect off-takers' own re-financing costs and, eventually, overall deployment costs of renewable energies?

The analysis in chapter 2 evaluates a survey conducted by Diacore (2015) for which investors, bankers, academics, and utility employees from 23 EU countries provided estimates of the financing costs of onshore wind power in their countries. The econometric estimation takes the nature of their replies into account, where some respondents do not provide point estimates, but rather answer that the financing costs are higher or lower than indicated thresholds. We account for this through various interpretations and an interval estimator that assumes the replies follow a normal distribution. As private long-term contracts are seen as a way to mitigate the additional risks under some policies, we then proceed to analyze the effects of such long-term contracts on off-takers financial position, applying a simple model of firms' re-financing costs and estimating the effects of changes in debt-equity ratios and credit ratings.

Several European countries, including Bulgaria, the Czech Republic, Italy, and, prominently, Spain – previously a front-runner in renewable energy deployment – implemented some kind of retrospective changes to their renewable energy support policies (Fouquet and Nysten, 2015), meaning they reduced their support payments for renewable energy investments earlier than initially promised.[4] Other countries stuck to their initial commitments. The incentives for regulators to conduct retrospective changes can be understood through models of time-inconsistency. These explain how regulators can have incentives to promise support payments to renewable energy investors, yet to deviate from these commitments once the investments are completed.

Models of time-inconsistency have previously been applied both in the wider

[4]This dissertation uses the term "retrospective changes" in line with the definition by Fouquet and Nysten (2015), i.e. changes to previously-made regulations that are valid as of the introduction of the changes. This stands in contrast to "retroactive changes" that are valid as of a past date and investors have to pay back previously-received support.

macroeconomics literature and to more specific climate policies. Kydland and Prescott (1977) introduced the concept, initially in the context of the interactions between inflation and unemployment. It has since been applied widely to general questions in climate policy, e.g. by Laffont and Tirole (1996) and Helm et al. (2004). Salant and Woroch (1992) explore how commitment equilibria can be sustained through trigger strategies in dynamic regulation games. Applying time-inconsistency to a general question of abatement, Jakob and Brunner (2014) demonstrate the nature and importance of target-setting by the regulator. Habermacher and Lehmann (2017) apply a model of time-inconsistency to renewable energy investments, yet focus on adjustments to the support for new installations, rather than the classic time-inconsistency issue where optimal regulation changes over time, even in the absence of new information. Hence, even though several countries have conducted policy changes to their renewable energy support potentially caused by time-inconsistency, the concept – and potential remedies – have not yet been applied to renewable energy policies and investments.

Chapter 3, jointly written with Olga Chiappinelli, extends a model of time-inconsistency by Chiappinelli and Neuhoff (2017) to renewable energy investments and regulation. The paper analyzes how time-inconsistency issues can arise for renewable energy policies and what regulators can do to address them. When does time-inconsistency occur and how can regulators use policy design to overcome it? What role can deployment targets play? Why did some countries, e.g. Spain in the 2010 to 2013 period, conduct retrospective cuts, indicating time-inconsistency issues, while other countries, like Germany, did not?

Analyzing a dynamic game setup, chapter 3 captures that support is commonly paid for output rather than capacity, which implies that past commitments last well into future periods, rendering investments potentially prone to time-inconsistency. We derive the incentives that regulators have to deviate from announced support. Through a numerical example of the respective situations in Spain and Germany around 2012, we test our model's applicability and derive the reasons why Spain conducted retrospective changes and why Germany lacked the incentives to do so.

Table 1: Overview over the dissertation's three chapters

Chapter	1	2	3
Title	The Impact of Wind Power Support Schemes on Technology Choices	Financing Power: Impacts of Energy Policies in Changing Regulatory Environments	Too Good to Be True? How Time-Inconsistent Renewable Energy Policies Can Deter Investments
Authors	Nils May	Nils May & Karsten Neuhoff	Nils May & Olga Chiappinelli
Metho-dology	a) Small analytical model of wind power investments; b) Numerical wind power investment model.	a) Econometric analysis of a survey of wind power financing costs in the EU; b) Analytical model of how private long-term contracts translate into higher re-financing costs of off-takers.	a) Regulatory game between regulator and renewable energy investors; b) Numerical example of the renewable energy policy settings in Spain and Germany in 2012.
Contri-butions to the litera-ture	1.) Identifies the incentives to invest into system-friendly technologies under different policies; 2.) Defines a way to measure system-optimal wind power technologies; 3.) Derives an optimal policy that aligns private and public optima.	1.) Finds empirical evidence that green certificates are associated with higher financing costs than feed-in tariffs and sliding feed-in premia; 2.) Explores implications of private long-term contracts; 3.) Shows that such contracts raise off-takers' re-financing costs, increasing overall costs.	1.) Derives when time-inconsistency issues can arise; 2.) Shows how support policies and deployment targets can alleviate these issues; 3.) Identifies the reasons why Spain around 2012 had incentives to retrospectively cut its support and Germany did not.
Own contri-bution	Single-authored paper	Nils May contributed to all parts; Karsten Neuhoff particularly to 3.1, 3.3, 3.4, and 3.6.	Nils May contributed to all parts; Olga Chiappinelli particularly to 4.1, 4.2, 4.3, and 4.5.

Chapter 1

The Impact of Wind Power Support Schemes on Technology Choices*

Abstract

In energy systems with large shares of variable renewable energies, electricity generation is lower during unfavorable weather conditions. System-friendly wind turbines (SFTs) rectify this by producing a larger share of their electricity at low wind speeds. This chapter analyzes to what extent the benefits of SFTs out-weigh their additional costs and how to incentivize investments into them. A wind power investment model for Germany shows that SFTs indeed deliver benefits for the energy system that over-compensate for their cost premium. Sliding feed-in premia incentivize their deployment only where investors bear significant price risks and possess sufficient foresight. Alternatively, a new production value-based benchmark approach triggers investors to install SFTs that meet the requirements of power systems with increasing shares of variable renewable energies.

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1.1 Introduction

Since 2000, global deployment of renewable energies, such as wind and solar power, has grown strongly. Germany has been at the forefront of this development, undergoing the *Energiewende*, which facilitates the country's transition to renewable energy. Renewables provided about 32.5 % of Germany's gross electricity consumption in 2015 (AG Energiebilanzen, 2015). The official national goal is a renewable share of at least 80 % by 2050. To achieve this, the German government targets an annual capacity increase on the order of 2.8-2.9 GW in onshore wind (Bundestag, 2016).

However, the volatile power generation of solar and wind power poses new challenges and costs to an energy system originally designed around thermal power plants. In times of little sunshine and low wind speeds, back-up capacity, storage and demand side response measures can be required in order to meet the – rather inelastic – demand for electricity.

Yet, there is also the option to directly address the volatile generation from renewables. For solar, alternative orientations facing east and west are discussed in this context, so that the power is supplied more smoothly throughout the day, see for example Fraunhofer ISE (2014). For wind power, the vast majority of electricity is currently produced in high wind, recently debated *system-friendly* turbines can serve this purpose. These have a larger share of their production in low and medium wind, i.e. when less wind power is in the system. *Ceteris paribus*, a lower supply of wind power means a lower supply of electricity, such that the price-setting power plant has higher marginal costs. Additionally, system-friendly turbines make better use of existing infrastructure, since their maximum output tends to be lower, meaning that there is less need to expand the grid and integration costs are lower. For the purpose of this study, only the increase in market prices is analyzed, as the avoided costs for grid expansion, integration, storage, back-up capacity, and demand side responses are hardly quantifiable. These benefits would persist even if all new installations shifted to system-friendly turbines. Could these benefits also be captured in this analysis, the *optimally*-deployed turbines would be more system-friendly than what is identified here.

Whether investors choose system-friendly turbines depends on the policy scheme. Originally, fixed *feed-in tariffs* (FIT) were the method of choice for increasing capacities of solar and wind power. Through the Renewable Energy Sources Act, a feed-in tariff was introduced in Germany in 2000. Under feed-in tariffs, investors receive a specific remuneration per produced MWh. Thus, the more electricity they produce, the higher the absolute amount of remuneration received.[1] As this remuneration is the only source of revenues, investors are indifferent to the actual wholesale electricity prices. Yet, the wholesale price reflects, to a certain degree, if supply is low and demand is high. In times of a relatively low power supply, prices will, *ceteris paribus*, be higher and vice versa prices be lower in relatively high supply. Summarized, fixed feed-in tariffs provide investors with a high degree of certainty, but little incentives to install system-friendly wind turbines.

The *sliding feed-in premium* (FIP) aims to bring the wind power supply closer to demand. Germany first introduced the feed-in premium on a voluntary basis in 2012, making it obligatory in August 2014, thus abolishing the fixed feed-in tariff except for very small installations. The FIP exposes operators to the wholesale electricity price and additionally provides them with a variable premium (Gawel and Purkus, 2013). The overall payment is based on how strongly a turbine's generation correlates with overall wind power production and whether deviations from it occur in hours of lower or higher electricity prices. Therefore, the covariance between a turbine's electricity generation with the overall German wind power feed-in plays an important role in determining investors' revenues (Schmidt et al., 2013).

This covariance with the overall German wind power feed-in is potentially influenced by the location. Grothe and Müsgens (2013) find that, under the FIP, locations in Germany gain or lose to different degrees, depending on their correlation with the overall German feed-in. Schmidt et al. (2013) analyze the covariance between the generation at Austrian sites with overall generation and find that under a feed-in pre-

[1]Due to the adjustments of the production volume-based benchmark approach, this does not exactly hold true in Germany. Higher generation can lead to a shorter extension of the higher feed-in tariff and can, hence, also partially lower remuneration; see appendix 3.7.

mium, the optimal allocation of turbines differs compared to the optimal allocation under a feed-in tariff.

Tisdale et al. (2014) analyze how feed-in premia influence the reliance on project finance for investors and find that the feed-in premium incurs additional risks to investors. The remuneration is potentially lower compared to feed-in tariffs. Therefore, investors' return on investment requirement is higher under feed-in premia than under feed-in tariffs. In order to have access to such cheap debt, investors are bound to conservative estimates of their future cash flows as these are usually the only source from which creditors are paid (Tisdale et al., 2014). Bürer and Wüstenhagen (2009) find that European investors especially prefer the secure revenue streams from feed-in tariffs over feed-in premia.

The prevailing policy regime also potentially affects the turbine technology deployed, yet the consequences of the shift toward the feed-in premium are not clear. Öko-Institut (2014) assume perfect foresight on the investors' side, yet find a minimal impact. However, they only enable investors to choose between two turbine models and no gradual changes are observable.

In 2015, installed turbines in Germany were more system-friendly compared to previous years (Deutsche WindGuard, 2015). This development can be driven by several reasons: A generally different investment environment, the (initially voluntary) introduction of a sliding feed-in premium in 2012, and the supply-side availability of more system-friendly turbines. Fraunhofer IWES (2013b) states that there is no clear evidence that turbine technologies in wind-rich regions have changed, but primarily became more specialized at low wind speeds at low-wind sites. In contrast, Fraunhofer IWES (2015) find that at sites with intermediate wind conditions, more system-friendly turbines have also gained in popularity. Among others, Deutsche WindGuard (2014), Molly (2011, 2012, 2014), Fraunhofer IWES (2013a,b), and Hirth and Müller (2016) argue that more system-friendly turbines would benefit the energy system as a whole.

One so-far neglected aspect is the question of how the *system-optimal* turbine should be defined. The aforementioned authors only generally state that more system-friendly turbines benefit the system. Only Molly (2012) defines an optimality criterion: The costs for a turbine that is combined with a storage, in order to perfectly smoothen the power generation over the year. However, this introduces excessive costs since the power production of any individual turbine does not necessarily need to be smooth. Alternatively, I define the system-optimal turbine to minimize the discounted difference between costs per MWh and the expected electricity value, i.e. price, per MWh.[2] This difference sets the subsidy level, so the required subsidy is minimized. This minimizes overall costs as the wind power output at times of higher value replaces costlier alternative electricity supply. The turbine that optimizes this criterion is considered *system-optimal*.

This study assesses the impact of different policy measures, such as the FIP, on investors' technology choices. By applying the optimality criterion, I scrutinize how close these technologies get to this system-optimum. Knowing about the effects on risk and locational choices, I analyze the effect of the FIP on investors' technology choices and the channels through which such effects can be induced. This is conducted by modeling investors' investment optimization problem. As in Schmidt et al. (2013) and Grothe and Müsgens (2013), investors are assumed to maximize the net present value of their investment, treating the prevailing policy as exogenously given. Yet, since investors depend on risk-averse project-finance, I assume they cannot integrate long-term expected power market changes into their investment decision, thus basing it on the current power price profile. Furthermore, unlike Grothe and Müsgens (2013), Schmidt et al. (2013), and Öko-Institut (2014), who take only one or two turbine types into account, I analyze investors who are free to choose from more than 140 turbine configurations. Importantly, I extend the analysis of Schmidt et al. (2013), who find that the covariance between turbines' production and the overall wind power supply affects the net present value. I allow this difference in covariances not only to occur between turbine locations, but also between turbine technologies.

Furthermore, I suggest and model a new alternative policy, the *production value-*

[2]As Joskow (2011) points out, it is not sufficient to merely compare the levelized cost of electricity and opt for the volatile technology that comes at the least costs per MWh because the production values can vary between technologies.

based benchmark approach. Based on a model of the future energy system, it *a priori* adjusts a turbine's remuneration level depending on its production's future market value. Thus, it replicates the cost-covering nature of the existing production *volume*-based benchmark approach (where remuneration is adjusted to the location, see appendix 3.7) and applies it to the turbine configuration and system-friendliness of turbines. Investors fully receive the average production value their turbines are forecast to obtain in the future. Hence, turbines that will provide a greater market value in the future are eligible for a higher remuneration level. This way, the system-optimal turbine is also most attractive to investors.[3]

The remainder of this chapter is structured as follows: In section 1.2, I present the investment model. Then, I give an overview of the calculations for the fee-in tariff, the feed-in premium, and the production value-based benchmark approach. I describe the data and wind turbine technologies in section 1.3. The results are discussed in section 1.4. Section 1.5 draws conclusions and identifies policy implications.

1.2 Methodology

Investors optimize their discounted future revenues and costs, taking the prevailing renewable support policy as exogenously given. I analyze one scenario per policy and investigate the differences between these. I outline the fixed feed-in tariff and the sliding feed-in premium in sections 1.2.2 and 1.2.3, indicating how they are implemented in the investment decision model. Finally, the production value-based benchmark approach is a policy explicitly granting remuneration depending on the turbine's future system-friendliness, as laid out in section 1.2.4.

[3] Öko-Institut (2014) suggest a different remuneration scheme where the remuneration depends on a turbine's production characteristics. This approach can support the development of system-friendly turbines. However, it does so explicitly, generally assuming their deployment is advantageous for the system.

1.2.1 Wind power investment

The investor maximizes their net present value (NPV) with respect to turbine technology i. Three technology characteristics are important determinants of output: hub height, generator nominal power and rotor blade length (cp. section 1.3.1). In its general form, turbine i's NPV N_i is defined as:

$$N_i = -\alpha_i + \sum_t \delta_t \omega_{i,t}(\pi_{policy_{i,t}} - \beta_t) \tag{1.1}$$

α_i represents the turbine's fixed costs. Its generated electricity at time t is $\omega_{i,t}$. It is discounted with the discount factor δ_t. The policy-specific remuneration per MWh is captured in $\pi_{policy_{i,t}}$. The variable operations and maintenance costs are β_t.[4]

1.2.2 Fixed feed-in tariff

Fixed feed-in tariffs compensate investors with a fixed payment per generated MWh. Even though the rate is fixed, in the German implementation, a turbine receives either the initial high payment F_{high} or a lower, subsequent payment F_{low}. The initial period lasts at least five years and can be extended to cover up to the entire lifetime. The exact time span depends on the location and technology chosen, cp. appendix 3.7. The payment $\pi_{F_{i,t}}$ is the payment per MWh for turbine i and is:

$$\pi_{F_{i,t}} = F_{i,t} \tag{1.2}$$

$$= \chi_{i,t} F_{high} + (1 - \chi_{i,t}) F_{low} \tag{1.3}$$

The payment is simply equal to the FIT $F_{i,t}$ because there is no other revenue source. The variable $\chi_{i,t}$ lies in the interval between 0 and 1. It reflects that at any time t, a turbine receives either the high initial FIT F_{high} or the lower subsequent FIT F_{low}.

[4]The operations and maintenance costs do not change the qualitative analysis in the following and are thus omitted from the theoretical analysis.

Following Schmidt et al. (2013) and treating $\omega_{i,t}$ as a random variable, it is possible to take the expectations of a combination of equations (1.1) and (1.2) to express the investor's expected NPV under the FIT N_F as in equation (1.4). The binary variable μ_i indicates which turbine an investor chooses.

$$E(N_F) = \sum_i \mu_i \left(-\alpha_i + \sum_t \delta_t \Big(E(\omega_{i,t}) E(\pi_{F_{i,t}}) + Cov(\omega_{i,t}, \pi_{F_{i,t}}) \Big) \right) \tag{1.4}$$

This equation simply states that the NPV is influenced by the expected production amount, the expected remuneration and the covariance between the two. With uniform remuneration levels across turbines, the covariance between production and remuneration is equal across turbines. Consequently, investors will choose – from among turbines with equal costs – the turbine with the largest expected energy yield.

Figure 1-1 depicts that with low shares of wind power, the turbine with the lowest levelized cost of electricity minimizes support and overall costs and is, thus, optimal. Parallel to the increase in nominal power shown on the x-axis, the rotor blade length and the hub height decrease, so that more system-friendly turbines appear on the left of the figure. The value curve runs horizontally. This is the case because without significant shares of wind power, the electricity price is independent of wind strengths and is, therefore, equal across turbines.

Equal remuneration across turbines means a FIT. Consequently, the cost-minimizing turbine (i.e. the turbine that has the lowest levelized cost of electricity) is optimal for investors, in the example a turbine with a nominal power of 3 MW (Megawatt).

1.2.3 Sliding feed-in premium

The remuneration for a generated MWh by wind power is (Bundestag, 2014):

$$\pi_{M_{i,t}} = p(\gamma_{-i,t}) + P_{i,t} \tag{1.5}$$

$\pi_{M_{i,t}}$ represents the payment for one MWh of generated electricity by turbine i

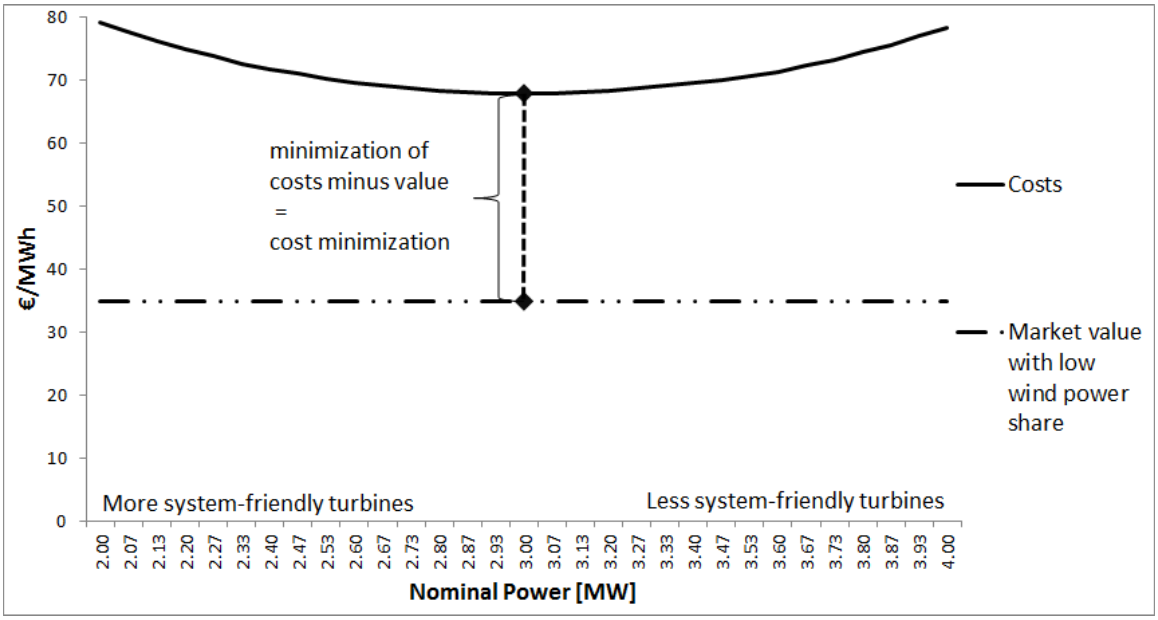

Figure 1-1: Illustrative visualization of turbine chosen under cost-minimizing FIT. The value/costs refer to levelized lifetime value/costs per MWh.

at time t. $p(\gamma_{-i,t})$ is the electricity price as a function of the wind power production $\gamma_{-i,t}$ of all other turbines $-i$, assuming that an individual investor's decision to install turbine i has no effect on the electricity price. However, the cumulative output $\gamma_{-i,t}$ of all German wind turbines depresses electricity prices via the merit-order effect.

The feed-in premium $P_{i,t}$ is defined as

$$P_{i,t} = F_{i,t} - \psi_t \bar{p}_t \tag{1.6}$$

The feed-in premium is comparable to the support level under fixed feed-in tariffs minus the average German day-ahead market price $\bar{p}_t$ times ψ_t, a month-specific wind-value adjustment factor. In any month, if German wind power was sold at 90 % of the average market price, ψ_t would be equal to 0.9. Sliding feed-in premia have been implemented with different arrangements: While the UK's Contracts for Differences have hourly adjustment factors and thus very little price risk for investors, annual adjustments as in the Netherlands are also conceivable, where investors' price exposure is considerably higher. Appendix 1.6.2 indicates the implications of such annual adjustments.

Under this support scheme, it is theoretically possible for turbines to earn more compared to the FIT. Turbines that produce at times of scarcity are rewarded. Production at times of surplus is penalized. An intended consequence is that turbines stop operating in times in which their overall payment per MWh is negative. This is the case when the electricity price is negative and its absolute value is larger than the feed-in premium. This can similarly be achieved under the FIT through the provision of respective wind spill regulations. In all scenarios, turbines are assumed to operate only when the payment per MWh is positive.

For the FIP, the NPV of every turbine technology i is

$$NPV_{M_i} = -\alpha_i + \sum_t \delta_t \omega_{i,t} \pi_{M_{i,t}} \tag{1.7}$$

Taking expectations of and transforming equation (1.7) and combining the result with equations (1.5) and equation (1.6) yields

$$E(N_{M_i}) = -\alpha_i + \sum_t \delta_t \Bigg(E(\omega_{i,t}) E(p(\gamma_{-i,t}) + P_{i,t}) + Cov(\omega_{i,t}, p(\gamma_{-i,t}) + P_{i,t}) \Bigg) \tag{1.8}$$

Regardless of the absolute merit-order effect, the resulting price as function of the merit order effect can be expressed as $p(\gamma_{-i,t}) = p^*_t - f(p^*_t, \gamma_{-i,t})$, where p^*_t is the reference price without any wind power supply and f is the merit order effect as function of the initial price level p^*_t and the overall wind power supply $\gamma_{-i,t}$. Next, the equation can be rewritten as[5]

$$\begin{aligned} E(N_{M_i}) = -\alpha_i + \sum_t \delta_t \Bigg(& E(\omega_{i,t}) E(p^*_t - f(p^*_t, \gamma_{-i,t}) + P_{i,t}) \\ & - Cov(\omega_{i,t}, f(p^*_t, \gamma_{-i,t}) - P_{i,t}) \Bigg) \end{aligned} \tag{1.9}$$

[5] For simplicity, assuming that $Cov(\omega_{i,t}, p^*_t) = 0$. In the numerical model, the price is an exogenous variable, such that this assumption is dropped.

Again, the NPV depends on the expected production amount and the expected remuneration level. Moreover, the expected price $p_t^* - f(p_t^*, \gamma_{-i,t})$ is introduced. Most importantly, the equation shows that the expected NPV of a turbine technology i decreases the larger the covariance between on the one hand the turbine's generation $\omega_{i,t}$ and on the other hand the overall German wind power supply $\gamma_{-i,t}$ and the negative feed-in premium $-P_{i,t}$. Notably, a turbine's NPV decreases, the larger the covariance between its own production and the overall German wind power feed-in. Stated positively, the subtraction of $Cov(\omega_{i,t}, f(p_t^*, \gamma_{-i,t}))$ implies that a turbine technology is more attractive to investors, the lower the covariance of its electricity generation with German wind power supply. An investor can potentially lower this "penalty for a high positive covariance" by opting for a system-friendly wind turbine, i.e. a turbine technology under which a larger share of production occurs in times of generally low wind power feed-in.

1.2.4 Production value-based benchmark approach

The production value-based benchmark approach incentivizes the deployment of turbines that in the future provide the greatest value to the system, measured as the levelized difference between costs and market value of the production. This difference sets the required subsidy level in energy system where renewables are unable to entirely re-finance themselves through the electricity market.[6] Minimization of this difference thus defines the *system-optimal* turbine.

In systems with increasing shares of wind power, more system-friendly turbines become optimal from the system's perspective. Wind turbines have a stronger impact on electricity prices, such that more system-friendly turbines produce at higher average market values in systems with high shares of wind power. The difference between costs and market value is minimized with a more-system friendly turbine, as depicted in figure 1-2. This turbine comes at a higher cost than the cost-minimizing[7]

[6]Ideally, the policy-maker knows the costs of companies and sets the remuneration level accordingly. The important question how to find this remuneration level is beyond the scope of this chapter. In the German context, tenders have been introduced in 2017 (Bundestag, 2016).

[7]The turbine with the lowest levelized cost of electricity.

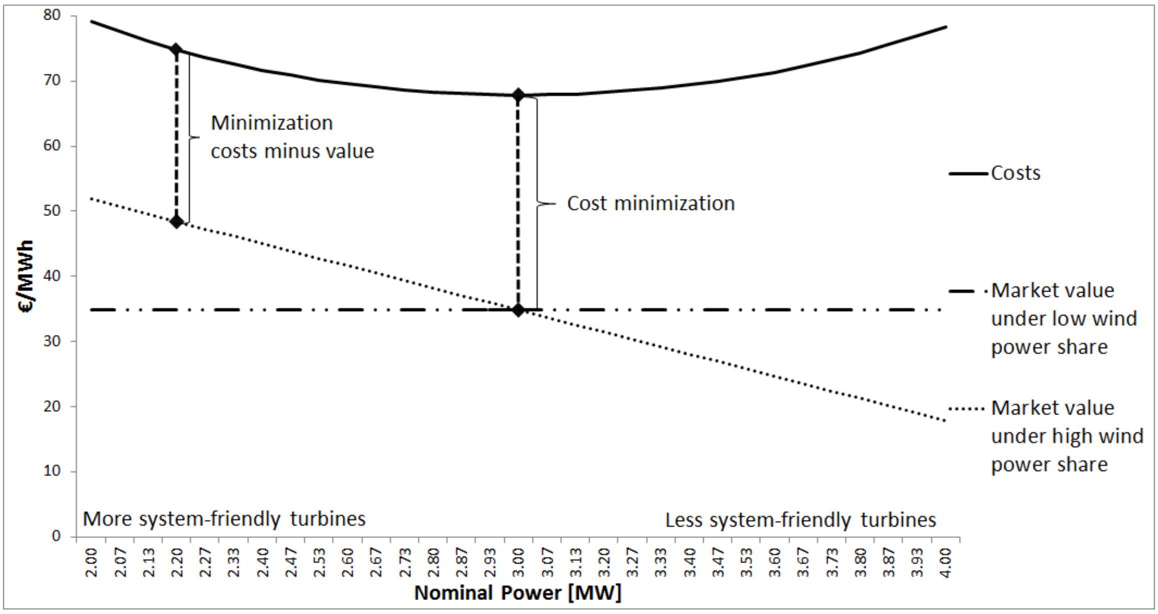

Figure 1-2: Illustrative visualization of turbine costs and values. The value/costs refer to levelized lifetime value/costs per MWh.

one, but overcompensates for these additional costs through the increased value of its production. The higher the share of wind power in the system, the steeper the drop in market value for less system-friendly turbines. While the nominal power increases, the rotor blade length and the hub height decrease, rendering turbines on the right of the figure again less system-friendly. If this difference in production values is not accounted for, the turbines will not be system-friendly enough as compared to the system-optimum, leading to an increased required subsidy level.

Since the considered level of wind power penetration matters, the system-optimum depends on the chosen time horizon and the discount factor. Lower social discount factors lead to stronger valuations of the future. Depending on these parameters, the system-optimal turbine will be more or less system-friendly, i.e. lies further right or left in figure 1-2. In the following, I abstract from the discussion of which period to consider and what discount factor to apply. I simplify by assuming that the energy system of 2030 is what solely defines the system optimal turbine. Sensitivities in the appendix 1.6.3 indicate that also with alternative definitions, the results hold.[8]

[8]Arguably, the question as to which time span to consider at what discount factor leaves ample space for research. The presented mechanism works as a proxy for an in-depth treatment of this

In order to overcome the overvaluation of current power price profiles characterized by low shares of wind power, renumeration can be directly based on future market values, taking into account renewable energy deployment targets. This can be implemented analogous to the existing production *volume*-based benchmark approach where remuneration is adjusted comparing production *volumes* for every location with a *benchmark location.* Analogously, remuneration can be adjusted comparing production *values* for every turbine type with a *benchmark turbine.* In consequence, independent of investors' foresight of power price profile changes, they are incentivized to build wind turbines that are system-optimal for energy systems with increasing shares of wind power.

This installation-specific remuneration level is implemented based on a fixed feed-in tariff and could alternatively be based on an hourly-sliding feed-in premium. Remuneration is adjusted based on an installation's production characteristics: Those that provide a higher value to the system, measured as the average electricity price they obtain in the future, receive a higher remuneration level than other installations. This means that the remuneration level under the FIT, F_{high}/F_{low} is individualized to F_{high_i}/F_{low_i}. This comparison is conducted with respect to a benchmark turbine λ. For this turbine, its future average electricity value $\bar{p}_{2030_\lambda}$ is calculated. Introducing this benchmark turbine erases the relevance of the general price level of the considered future period and only deviations from the average level influence the remuneration.[9] The power price forecasts are provided by a power market model for 2030 by the German Aerospace Center, see section 1.3.2.

To calculate the turbine-specific remuneration levels, the difference between the turbines' future production value and the benchmark turbine's future production

issue. New technologies could challenge some, but not all, of the advantages of system-friendly turbines. Under the production value-based benchmark approach, the regulator carries this risk, in order to prevent investors from having to pay excessive risk premia or underinvest in system-friendly turbines.

[9] In practice, the benchmark turbine λ could be any turbine. In the analysis, for every location it is the turbine that investors choose there under the normal FIT. This allows for comparing the remuneration directly, as only the differences in remuneration levels between turbine types matter to the analysis, not the absolute level. Using a different benchmark turbine would only change the absolute remuneration level, but not the differences in remuneration levels.

value is added to the baseline remuneration level. Combining future electricity prices, wind speed data at the analyzed sites, and any turbine's power curve, it is possible to calculate the expected average price a turbine will obtain in 2030, $\bar{p}_{2030_i}$. The average production value in 2030 of the benchmark turbine λ is $\bar{p}_{2030_\lambda}$. The difference between the two is added to the default remuneration level, as shown in equation (1.10).

$$F_{high/low_i} = F_{high/low} + (\bar{p}_{2030_i} - \bar{p}_{2030_\lambda}) \tag{1.10}$$

The advantage of this approach over explicit extra-remuneration for certain more system-friendly turbines is that $\bar{p}_{2030_i}$ only depends on value to the system, but is turbine-technology independent. It is based on *production* characteristics rather than *technological* characteristics. Remuneration can be computed in advance, such that no additional investment risks are incurred for investors and investors are not required to possess perfect foresight. A limitation is that, in advance, the investor requires a wind speed time-series from the baseline year at the analyzed location(s) which is reliable enough to calculate $\bar{p}_{2030_i}$. If no reliable enough wind speed information was available, an alternative option could be the use of average wind speeds at nearby measuring points. Moreover, the regulator needs to provide a forecast for the future power price profile. While such projections are inherently uncertain, e.g. linked to fuel and carbon price assumptions, not the absolute level, but only deviations from average prices are utilized.[10] The most relevant uncertainties link to shares of renewables, grid and storage development and, thus, are largely determined by public policy choices. As such, the commitment of a regulator to a specific future perspective, for example with the power price profile forecast, is the basis for coordinating private actor choices. Assuming that future electricity prices differ between hours with high and low amounts of wind power seems reasonable to expect and is in line with the findings of Hirth and Müller (2016) and Ueckerdt et al. (2013).

[10]Leaving the regulator with the risk that future price variability is much lower than expected, i.e. the case for system-friendly turbines is lower than anticipated.

1.3 Data

Turbine technologies, their production characteristics and how these have been implemented are shown in section 1.3.1. Past day-ahead electricity prices and modeled market prices in future energy systems are explained in section 1.3.2. Measured wind speeds and their extrapolation to actual hub heights are described in section 1.3.3. The numerical application is detailed in section 1.3.4.

1.3.1 Wind turbine technology

Investors choose certain turbine technologies which decide the turbines' system-friendliness. Based on two of the three technology parameters, the power curve describes how much electricity a turbine produces under different wind conditions. Based on this modeling, I allow investors to choose from a wide range of turbines, unlike most models in the literature where investors can only choose from one or a few turbine types.

Technology parameters

Three main technology parameters define a turbine's production pattern and its system-friendliness: the hub height, the rotor blade length and the nominal power. First, a higher turbine induces higher costs for materials, but as wind strengths increase in greater heights, a turbine encounters higher wind speeds. Thus, it is able to generate electricity at more times and more regularly. The more obstacles there are on the ground, the more the wind strength increases with additional height. This is one reason why we observe that wind turbines in southern Germany tend to be higher than turbines at the northern coasts, which are exposed to the open sea. Second, the rotor blade length defines how much energy a turbine can harvest from the wind at any given wind strength. With a longer rotor blade and a larger rotor swept area, the turbine is exposed to more wind energy. Third, a lower nominal power of the generator implies that the maximum conversion level is already obtained at a lower wind speed.

The ratio of nominal power to rotor swept area is the *specific power*, measured in Wm^{-2}. In the case of a very low specific power (large rotor blades and a generator with a low nominal power), a turbine is almost always able to capture enough wind energy to operate its generator at full nominal power. Such a turbine would have a very high capacity factor and high number of full load hours. Accordingly, turbines with a lower specific power are considered more *system-friendly* (Molly, 2011).

In contrast, a turbine with a high specific power (short rotor blades and generator with a large nominal power) can rarely reap enough energy from the wind to run its generator at full capacity. With every small change in wind speeds, the amount of generated electricity changes, as the generator is operating below its maximum (Molly, 2011).

Power curve scaling

Power curves describe how efficiently turbines convert kinetic energy from the wind into electricity. They are defined by turbines' rotor blade lengths and their nominal powers. The third technology parameter hub height is not reflected in the power curve as it merely influences which wind speed a turbine is exposed to, but not how well this energy is converted. Based on Narbel et al. (2014), the general formula for the potentially generated electricity P_{pot} is:

$$P_{pot} = \frac{1}{2}\varphi_{air}\pi C_p(v)r^2v^3 \tag{1.11}$$

φ_{air} is the air density (assumed to be $1.225\,\mathrm{kg/m^3}$, a standard value for Germany (Deutsches Institut für Bautechnik, 2012)). $C_p(v)$ is the mechanical efficiency and depends on the wind speed. According to Betz' law, it cannot possibly exceed about 59 percent (Narbel et al., 2014). In modern turbines, factors of up 45-52 % percent can be observed, e.g. in Enercon (2012). Lastly, the wind speed v enters the formula in cubic form, demonstrating the importance of favorable wind conditions for wind power generation.

Once the nominal power P_{nom} is reached, the actual produced amount of electricity, P_W, ceases to increase and stays at this maximum until reaching its cut-out speed at around $25\,\mathrm{ms}^{-1}$, as in Enercon (2012). Close to reaching its nominal power, however, a turbine's mechanical efficiency decreases, resulting in a characteristic dent in the power curve.[11] In addition, turbines also possess cut-in speeds below which they cannot start running. I assume these to lie uniformly at $3\,\mathrm{ms}^{-1}$, as depicted in Enercon (2012), where turbines have very low efficiencies below this level. Just above this threshold their efficiency is not high yet, approximated by a low mechanical efficiency until a wind speed of $4\,\mathrm{ms}^{-1}$ is reached. Summarized, equation (1.12) shows these calculations of the generated electricity over different wind speeds, P_W.

$$P_W = \begin{cases} 0 & \text{if } v \leq 3ms^{-1}, \\ 0.9 * P_{pot} & \text{if } v > 3ms^{-1} \text{ and } v \leq 4ms^{-1}, \\ P_{pot} & \text{if } v > 4ms^{-1} \text{ and } P_{pot} \leq 0.85 * P_{nom}, \\ \dfrac{P_{pot} - 0.85 * P_{nom}}{2} + 0.85 * P_{nom} & \text{if } 1.15 * P_{nom} \geq P_{pot} \geq 0.85 * P_{nom}, \\ P_{nom} & \text{if } P_{pot} > 1.15 * P_{nom}. \end{cases} \tag{1.12}$$

Hence, the power curves are based on the underlying technology parameters. This way, the model is flexible to accommodate for investment decisions not only between a few real-world turbines and their respective power curves, but enables the choice from 147 different turbines.

Two extreme turbine configurations are depicted in figure 1-3. Both have the same price, as explained in section 1.3.1. The less system-friendly one's nominal power is 4 MW and the diameter of its rotor blades is rather low at 90 m. The second, more system-friendly technology configuration has a much smaller nominal power at 2 MW and the diameter of its rotor blades is considerably higher at 122.5 m. Both configurations possess the same hub height of 80 m. Further, the frequency of wind speeds at a roughly typical German location is displayed, namely the frequency

[11] Here, I used a decrease in efficiency starting at 85 % of the rated output, approximated from Enercon (2012). The results are robust to sensitivity analyses with respect to the exact specification.

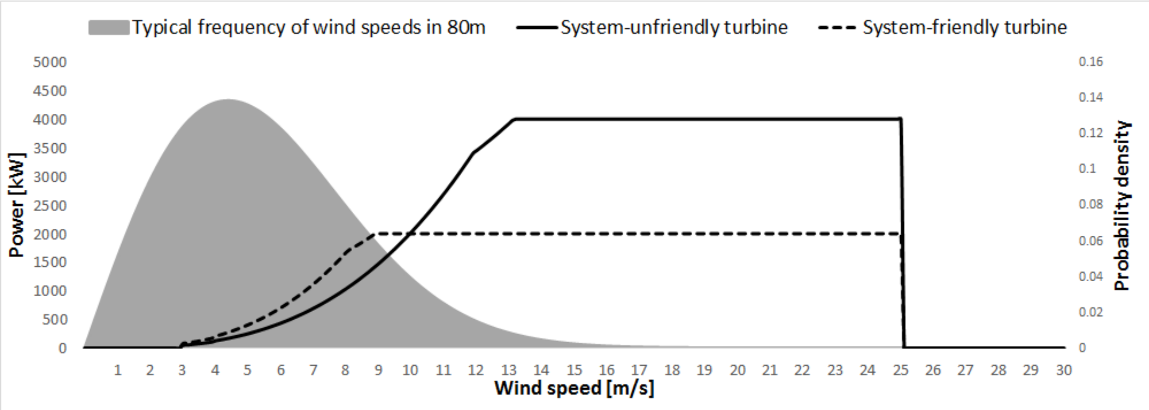

Figure 1-3: Power curves of two exemplary technology configurations

of wind speeds at the benchmark location as defined in the German law, cp. appendix 3.7. From this we see that at most times, the system-friendly turbine actually generates more electricity. Here, it does so in 72 % of the time, whereas the system-unfriendly configuration only produces more 8 % of the time. Moreover, as most German project sites actually have worse wind conditions than this wind distribution (Deutsche WindGuard, 2014), this comparison would be even more favorable for the system-friendly configuration there.

It is easy to see that the less system-friendly turbine can produce more electricity at fairly strong winds and that the alternative turbine is more efficient at medium-strong winds. Figure 1-4 depicts the modeled power output of the two extreme turbine configurations for two exemplary days at the same location in January 2015: Whereas the system-unfriendly turbine generates much more power in some of the hours, the system-friendly configuration runs considerably more constantly also in hours of low wind speeds.

Technology trade-off

Investors face a trade-off between the three technology parameters hub height, rotor blade length and nominal power. An increment in each of these categories leads to an increase in investment costs. In the model, the investor can opt for a range of combinations covering very system-friendly and system-unfriendly turbines. Based

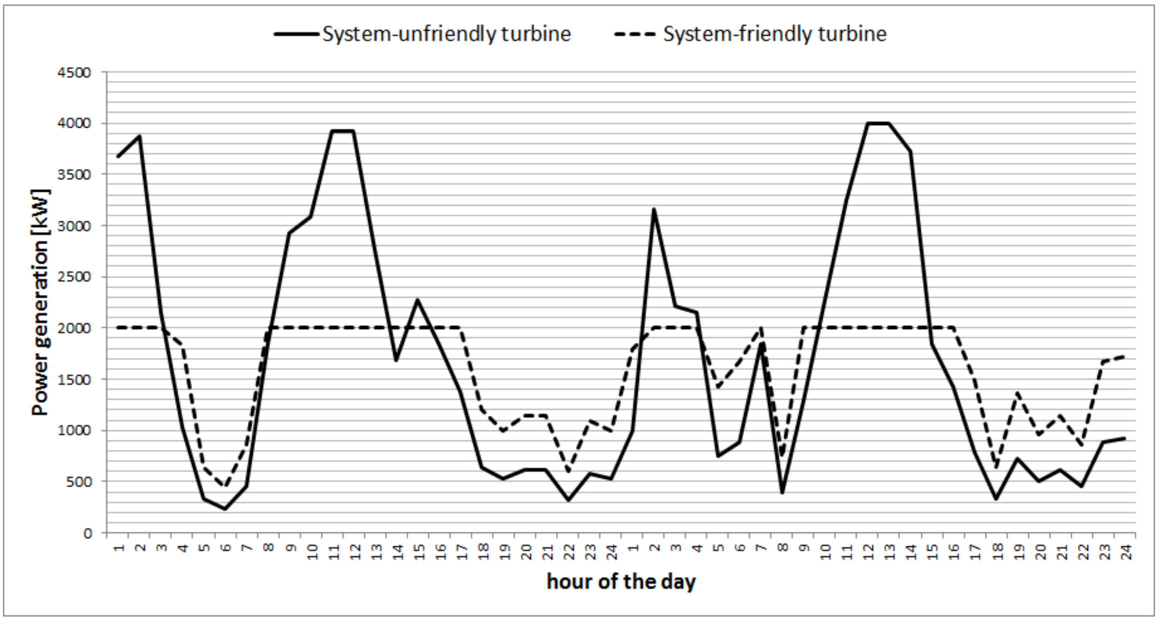

Figure 1-4: Comparison of power production on January 13th and 14th 2015

on the three technology parameters, the turbine's power curve is then calculated, as described in the previous section.

Investment costs α_i are held constant for this purpose, so that an investor has to optimize the relative costs and benefits of the three parameters and cannot simply opt for a configuration where all three are very large. Rough cost estimates from Deutsche WindGuard (2013) give €1150 per kW (kilowatt) in nominal power and €410 per m^2 in rotor swept area. Averaging cost estimates for different hub heights between 80 and 140 m from Hau (2014) yield approximate costs of €12 500 per meter hub height increase. The analyzed specific powers, i.e. the ratio between nominal power and rotor-swept area, lie between 167 and 629 Wm^{-2}, covering all new onshore installations in 2014 (NREL, 2015). The generator's nominal power is between 2 and 4 MW, covering 91.5 % of all sizes installed in 2014. The rotor blade length is between 45 and 61.7 m, covering about 74 % of new turbines, and finally the hub height lies between 80 and 140 m, covering 76 % of new onshore installations (Deutsche WindGuard, 2015). As it turns out, the privately optimal investment decision in almost all cases lies on one trajectory between on the one hand a very high nominal power (4 MW), short rotor blades (45 m) and a low hub height (80 m) and on the

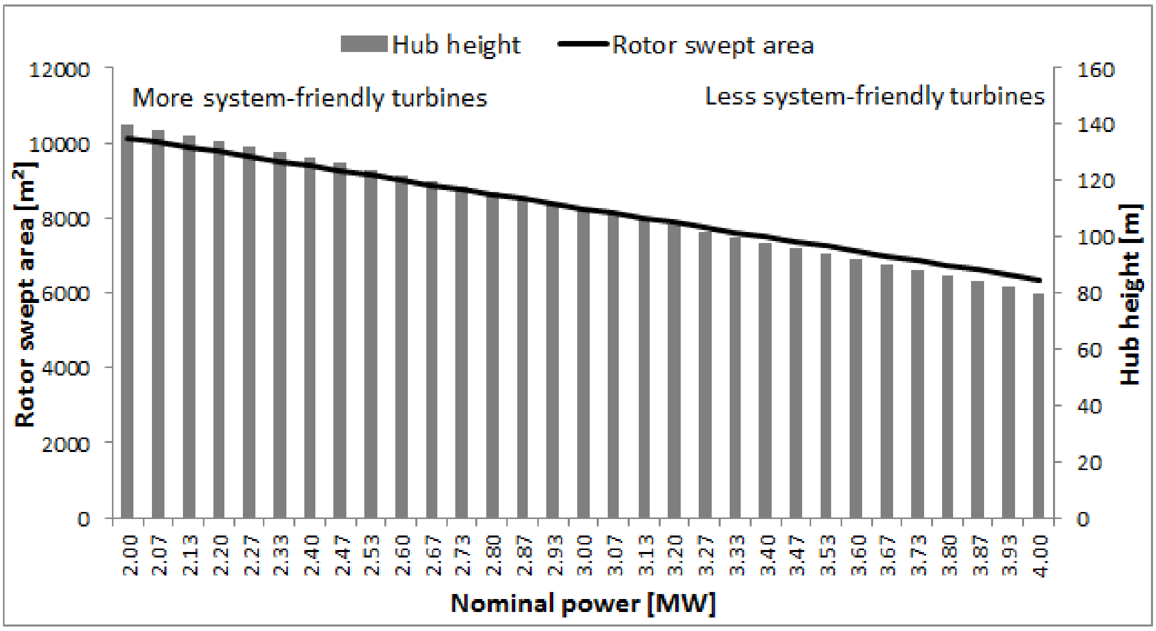

Figure 1-5: The turbines' technology configurations

other hand a fairly small generator (2 m), rather long rotor blades (56.8 m) and rather high hub height (140 m). Figure 1-5 visualizes this trajectory. Following Deutsche WindGuard (2013), quasi-fixed annual costs and variable operations and maintenance costs amount to 24.1 €/MWh for the first ten operational years and 26.8 €/MWh afterwards.

1.3.2 Prices

The day-ahead prices for 2013 and 2015 are obtained from European Energy Exchange (2016). 2013's average price stood at €37.8 per MWh, with a standard deviation of €16.5 per MWh. There were 64 hours with negative prices and an average negative price of -€14.17. In 2015, the number of hours had increased to 126, but at an average value closer to zero at -€9.00. The mean value decreased to €31.6 per MWh, with a decreased standard deviation of €12.7 per MWh, i.e. a flatter power price profile. The model is implemented with a discount factor of $\delta = 0.95$. As turbines are eligible for some kind of remuneration for 20 years, the lifetime T is assumed to be 20.

The underlying model REMix estimates electricity prices in 2030 and was developed by Deutsches Zentrum für Luft-und Raumfahrt (2014) in order to evaluate the long-term developments of power plants, the power grid, demand side management, energy storage as well as combined heat and power. The model covers Western and Northern Europe, as well as parts of Eastern Europe and North Africa. It assumes a minimum share of renewable energies of 50 percent of the total electricity generation by 2030. Wind power investments are endogenous and take place at the sites with the best wind resources first, using system-unfriendly turbines.[12] The modeled years are based on the wind speed patterns of 2006. The electricity prices indicate the value of power generation in future energy systems with higher shares of renewables. The price variation increases, possibly due to the further-increasing share of fluctuating renewable energies.

In the baseline scenario, national and international grid investments are assumed to occur as envisioned by the European Ten-Year Network Development Plans (ENTSO-E, 2012) and in Germany according to the national network development plans (50Hertz et al., 2013). All these grid connections become operational as planned and on time. The results have been tested for robustness with a scenario with additional, endogenous, optimized grid investments, shown in appendix 1.6.2. As expected, price variation and, thus, the case for system-friendly turbine designs decreases, but only slightly so. Appendix 1.6.3 gives some details on the resulting power price profile. Deutsches Zentrum für Luft-und Raumfahrt (2014) provides a detailed explanation of the model.

1.3.3 Wind speed data

As input to the model, I use historic wind speed information provided by Deutscher Wetterdienst (2016). As a site with very favorable wind conditions, Heligoland is analyzed, an island in the North Sea. As a site with medium wind resource, Boltenhagen in the North-East is used. For sensitivity analyses, sites with generally unfavorable conditions (Hanover) and several other locations are scrutinized, see appendix 1.6.2.

[12]If the model included more system-friendly turbines, the covariance between the general wind output and any new system-friendly turbines would lie higher. Still, new system-friendly turbines would produce at higher value and be beneficial as they shift production away from very windy hours and produce more predictably.

Results are robust across locations, unless stated otherwise.

For the primary analysis, I employ data for 2013. As sensitivity analysis, data from 2015 has also been used, with robust results. In order to compute inputs into the future energy systems which are based on the wind patterns of 2006, 2006 wind speed data is also used. When measurements for individual hours were missing, the arithmetic mean of the two adjacent existing measurements was taken.

The data on wind speeds was measured at different heights than the turbines' hub heights. This requires height scaling. As commonly done, I assume a logarithmic vertical height profile, described in Hau (2014). Knowing a wind speed at height $h2$, the speed at height $h1$ can be calculated by:

$$v_{h1} = v_{h2} * \frac{\ln \frac{h1}{z_0}}{\ln \frac{h2}{z_0}} \tag{1.13}$$

z_0 stands for the roughness length at the ground, i.e. if there are many obstacles like trees or buildings. It varies between locations. Urban places tend to have more obstacles and, thus, the roughness length is higher, e.g. about 0.5 for Hanover. Rural places have lower values, e.g. Boltenhagen (German Baltic coast) rather has a value of 0.1 (Silva et al., 2000). Even if these values based on broader categorizations were not exactly correct, it would not spoil this analysis, as the focus of this study is not where turbines are allocated in the first place, but how the utilized technologies differ under different policy regimes.

1.3.4 Numerical application

I concentrate on the investment decision for a single turbine. The optimization problem is implemented in GAMS. Naturally, investments can occur in locations with very favorable wind conditions, so the analysis focuses on one such location. Moreover, the German support scheme incentivizes installations also at sites with only fair wind resources, thus such a site is also analyzed. Deployment at sites with very poor wind conditions is not incentivized and therefore not relevant.

The volatility of the applied time series of power prices matters for two cases:

First, under the sliding feed-in premium, investors consider some power price profile for their optimization. Second, in order to derive an *optimal* decision from a regulator's perspective, the considered power price profile of the regulator also matters.[13]

In the numerical application, investors and the regulator differ in their applied time horizons: Whereas investors stress current flat power price profiles, the regulator also considers the implications of systems with a high share of variable renewable energies. As commonly assumed, investors have higher discount rates than the regulator. Moreover, and extraordinarily for renewable energy projects, the vast majority of projects relies on (risk-averse) project finance (Steffen, 2018). This implies that in order to gain access to cheap capital, they are unable to incorporate long-term drastic changes in the power market. Consequently, investors apply a power price profile which resembles the current, rather flat profile with few price spikes.

The regulator uses a lower discount rate. Importantly, when the regulator is committed to a future with a high(er) share of renewable energies, the regulator is able to incorporate the future implications of such a future power system: Less base load power production, more volatile generation, and, thus, a more variable power price profile with more price spikes.

The exact time horizons are parametric choices. Sensitivity analyses with respect to these choices can be found in appendix 1.6.2. In the base case, investors only consider a current flat power price profile, implemented for every year of the optimization once on the basis of the electricity prices of 2013 and once based on the prices of 2030. In sensitivities, the power price profiles of 2015 were applied, as well as a combination of 2013's prices for the first ten years of turbine lifetime and 2030's prices for the subsequent ten years.

The regulator considers only the future volatile power price profile of 2030, on the basis of which the *optimal* turbine is derived. In a sensitivity, the regulator assumes the profile of 2013 to prevail in the first ten years of turbine lifetime and 2030's volatile profile afterwards. With a low social discount rate of 2 %, this implies a weight of

[13] In both cases only the volatility of the power price profile matters, not the absolute price level, as such differences are canceled out by design under either remuneration scheme.

55 % on 2013's profile and 45 % on 2030's.

The production value-based benchmark approach functions independently of the specific parameterization. The degree to which a regulator wants to commit to and consider exclusively such a future power system in the end is a political question beyond the scope of this chapter.

1.4 Results

In every scenario, the investors take the policy regime as exogenously given and optimize their net present value. I discuss the findings for one location with mediocre wind resources, Boltenhagen, and one location with very favorable wind resources, Heligoland.

Figure 1-6 provides an overview over the results for the site with mediocre wind conditions. It depicts the remuneration amounts under the different policies and the levelized cost of electricity. The system-optimum is shown as the turbine chosen when accounting for future production values, minimizing the difference between costs and market value. The system optimal turbine's nominal power is 2.4 MW. In comparison, the fixed feed-in tariff leads to a relatively system-unfriendly configuration of 2.7 MW.[14]

The feed-in premium leads to only very limited incentives for a more system-friendly design when investors' foresight is limited; the slope is barely distinguishable from the feed-in tariff's. With better foresight and with higher price exposure, the investments come closer to what is socially-optimal. The results are detailed in the following.

[14]Due to the default production volume-based benchmark approach, the FIT already distinguishes between the turbine designs to a limited extent, with the result that the remuneration line has a slight downward slope.

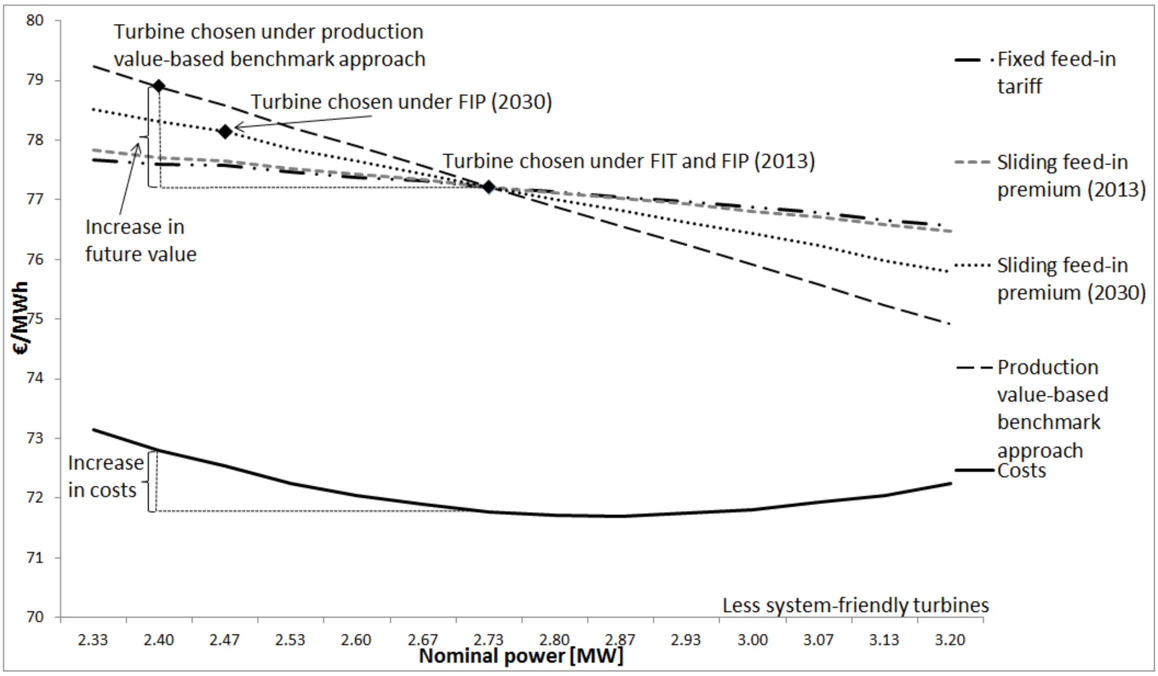

Figure 1-6: Remuneration and levelized cost of electricity for Boltenhagen. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

1.4.1 Fixed feed-in tariff

Under the fixed feed-in tariff, investors opt for a turbine which is not very system-friendly, as shown in figure 1-6. This is in line with the empirical data we can observe in Germany: rather large generator capacities compared to the rotor blade lengths. Such technology combinations yield, under the fixed FIT, the largest returns for investors. The chosen turbine in this baseline scenario has a nominal power of 2.7 MW and a rotor swept area of 8756 m^2, based on a rotor blade length of 52.8 m. The hub height lies at 118 m.

On more wind-rich Heligoland, the privately-optimal turbine under the FIT is naturally more specialized in the generation at high wind speeds. It is considerably less system-friendly than the privately-optimal one in Boltenhagen: It has a higher nominal power, shorter rotor blades and lower hub height. The nominal power lies 32 % higher at 3.6 MW, visualized in figure 1-7.

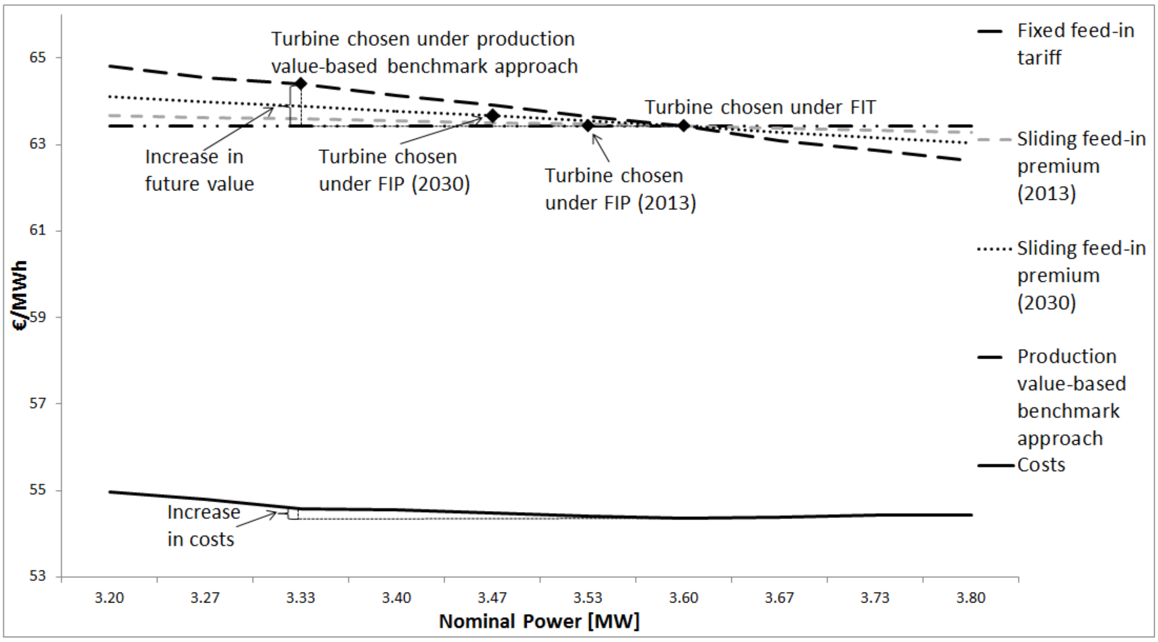

Figure 1-7: Remuneration and levelized cost of electricity for Heligoland. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

As expected, the model demonstrates that more system-friendly turbines lead to higher capacity factors. The turbines' number of full load hours increases and they produce a larger share of their production in times of weak and medium wind speeds.

1.4.2 Sliding feed-in premium

Investors with limited foresight ("FIP 2013") only slightly alter their investment decisions under feed-in premia. In figures 1-6 and 1-7, we can see that while the investment decision does not change at all in Boltenhagen, there is a slight adjustment in turbine configuration in wind-rich Heligoland. However, this adjustment remains well less system-friendly than what is identified as system-optimal. Where investors possess greater foresight ("FIP 2030"), they opt for more system-friendly designs in both Boltenhagen and Heligoland, as they consider a more volatile price profile. In Boltenhagen, the chosen turbine has a nominal power of slightly less than 2.5 MW, its blades are 1.5 m longer than the ones under the FIT, and its tower stands 8 m

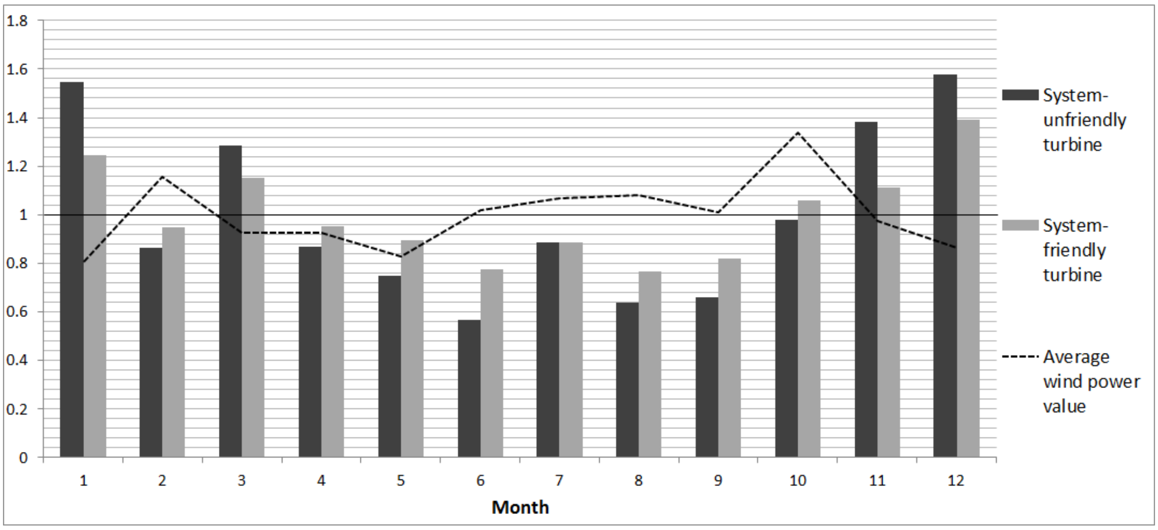

Figure 1-8: Production of two turbine configurations and the average wind power value in 2015, relative to monthly averages.

taller at 126 m.

The policy design causes the incentive for more system-friendly deployment to be weaker than optimal. The theoretical analysis of section 1.2.3 holds at the hourly, daily and weekly level, but not on a monthly, annual or life-time level. The remuneration level is defined such that the average remuneration level is the same for every month, even though price levels vary between months. Hence, investors do not receive higher remuneration when turbines produce in months with higher production values. Incentives under the feed-in premium are hence not even aligned with the system-optimum when both the investor and the regulator take into account the exact same power price profile, as shown in appendix 1.6.2. Figure 1-8 indicates the effect of this in 2015: Both turbines produce – relatively speaking – a lot of energy in the windy winter months. The system-unfriendly turbine exclusively generates more electricity than the system-friendly turbine in months where the price is below average. The system-friendly turbine has a larger share of its production in months with relatively low wind speeds, where prices are relatively high. Due to the policy design, this difference in production values is not captured in the investors' optimization, independent of the investor's foresight.

This changes with annually-adjusted feed-in premia, where the average remu-

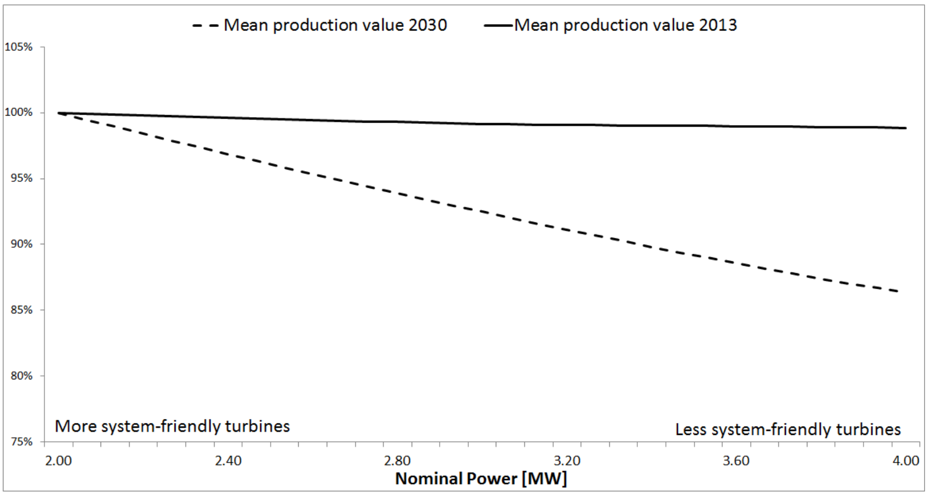

Figure 1-9: Average production values in Boltenhagen, each data series normed to 100 % for the most system-friendly configuration

neration is based on the annual average wind power production value; thus investors are fully exposed to sub-annual price fluctuations. Then, if investors have no limited foresight, investment incentives are aligned with the system-optimum, as appendix 1.6.2 shows, with investors choosing significantly more system-friendly turbines. Naturally, investors take larger price risks under this design, inducing higher financing risk premia.

The results suggest that under current flat power price profiles investors can barely deviate systematically from the overall German wind generation remuneration level through their turbine technology choice, even though it is theoretically conceivable. Under flat power price profiles, $Cov(\omega_{i,t}, f(p^*_t, \gamma_{-i,t}))$ does not differ strongly at the sub-monthly level for different turbine technologies. Thus, the electricity prices $p(\gamma_{-i,t})$ for different turbines lie too close together to impact revenues strongly enough to incentivize more system-friendly turbines when investors cannot incorporate long-term power system changes into their optimization.

Figure 1-9 shows that the additional value of system-friendly turbines materializes stronger in the future. Under the flat profile of 2013, system-friendly turbines' production is barely priced higher than other turbines'. Between the most extreme configurations, the difference is a mere 1.1 % of prices, or 0.6 % of total remuneration. Thus, the sliding feed-in premium's slopes in figures 1-6 and 1-7 remain relatively flat. Yet, under a future, more volatile price profile, system-friendly turbines produce at considerably higher values than system-unfriendly ones, explaining the stronger incentives for system-friendly turbines when investors possess greater foresight. In the example for Boltenhagen the average value difference amounts to 14 % of prices.

These results hold under a variety of assumptions regarding the investors' foresight and their ability to incorporate long-term changes in the price profile into their optimization. Appendix 1.6.2 lays out a number of sensitivities. Investors utilize a different base year for their optimization, foresee long-term changes in the price profile, or entirely optimize based on a long-term future price profile. Results vary slightly, but they share that without inducing additional revenue risks, the private optimum is not aligned with the system optimum, as higher generation in higher-priced months is not converted into incentives for investors, even if investors possessed perfect foresight. Moreover, it remains questionable in how far investors are able to apply long-term developments in their investment decisions.

1.4.3 Production value-based benchmark approach

The production value-based benchmark approach conveys strong incentives to investors to alter their investment decisions. As shown in Figures 1-6 and 1-7, the remuneration is more strongly differentiated between turbines. By design, investors will always choose the system-optimal turbine configurations.

For Boltenhagen, compared to the baseline, the optimally chosen turbine's nominal power is reduced by 333 kW, whereas the rotor swept area increases by 630 m^2, the rotor blade length rises by 1.9 m, and the hub height goes up by 10 m. The specific power is reduced by 18 %. This results in an increase in full load hours by 11 % or equivalently an increase in capacity factor by 5 percentage points. More importantly, the share of the production shifts to times of lower wind speeds with *ceteris paribus* higher electricity values, in particular in systems with high shares of intermittent renewable energies. For lower wind speeds ($<5\,m^{-1}$) (occurring about 30 percent of the time in Boltenhagen), the (generally low) number of full load hours increases by

26 percent. For medium wind speeds ($\geq 5\,\mathrm{m}^{-1}$ and $<10\,\mathrm{m}^{-1}$, about 50 percent of the time), the number of full load hours increases by 19 percent and for strong winds ($\geq 10\,\mathrm{m}^{-1}$, about 20 percent of the time) it remains equal.

On wind-rich Heligoland, remuneration under feed-in tariff and sliding feed-in premium are almost constant across turbines and the value-based benchmark approach establishes some differentiation between turbines. The resulting turbine has a nominal power of 3.3 MW. Its rotor blades are 1.7 m longer and the hub height is increased by 8 m compared to the baseline, resulting in the specific power, the ratio of nominal power to rotor-swept area, lieing 14 % lower at 422 Wm^{-2}. The number of full load hours increases by 12 % and production is shifted into hours with higher value.

1.5 Conclusion

The power generation profile of wind turbines differs greatly from conventional thermal plants'. Prices in times of strong winds diminish, whereas electricity prices in low wind relatively increase. In line with previous literature, I argue that turbines with a higher share of their production in low and medium wind, i.e. system-friendly wind turbines, provide higher values to the energy system. This is, on the one hand, quantifiable in the higher average value of their production and, on the other hand, not quantifiable in terms of their more constant and predictable production. In detail, these are turbines with a lower nominal power, longer rotor blades, and higher towers.

I evaluate the effectiveness of different policies to encourage the deployment of system-friendly turbines. Since other benefits are hardly quantifiable, I use the increased average production value as main criterion. For this purpose, I define the *system-optimal* turbine to minimize production costs minus expected future market value.

The introduction of the sliding feed-in premium sought to change investors' investment decisions by incentivizing the alignment of wind energy supply and its demand. I demonstrate through which mechanism investors' behavior can be influenced, namely through the covariance between a turbine's power generation and the overall national wind power generation. However, under monthly-adjusted feed-in premia, investors do not benefit from production in months with higher prices, since the monthly remuneration level is independent of the monthly price level. Based on a wind power investment model and assuming that investors are constrained by imperfect foresight and are bound to conservative power price profile developments due to their financing structure, I show that this sliding feed-in premium does not strongly align wind power supply and demand. Both with better foresight and with higher price risk exposure, investment decisions come closer to the social optimum. However, larger risk exposure also possibly raises financing costs.

The production value-based benchmark approach takes future energy systems' prices into account and incentivizes system-friendly deployment for investors. Based on the fixed feed-in tariff or hourly-sliding feed-in premia, an adjustment to the remuneration level – depending on the average electricity value at which a turbine is expected to produce in the future – is implemented. Through this variation, investors strongly adjust their investment behavior, since they can fully integrate the additional future value of system-friendly turbines into their projected cash flows. Investments are aligned with system-optimality. An additional requirement is that regulators need to project power price profiles that are based on the hourly wind patterns of a pre-defined year (or set of years), which needs to be made available to investors. The regulator then takes over the power price profile risk, i.e. that a more or less volatile profile develops. If a different price profile emerges, more or less system-friendly turbines might be optimal. An important difference to feed-in premia with high price exposure is that under those, investors carry the price risk, possibly inducing higher financing cost risk premia. Hence, in contrast to investments incentives under feed-in premia, the production value-based benchmark approach is a way to prevent these additional risk-induced costs, but to still set incentives for system-friendly deployment.

This analysis can be expanded by exploring if adjustments are necessary with respect to the construction of wind parks. Losses in the wind energy content through shading might differ across wind turbine types and thus justify further adjustments. Furthermore it needs to be assessed how robust the results for wind turbine choices are to changes in system parameters, to the question of whether it suffices to select one historic reference year of wind output or whether multiple years are required, the question how constrained investors are in their foresight and whether to use a 2030 projection of power price profiles or a combination of several years.

1.6 Appendix

1.6.1 Production volume-based benchmark approach

The production volume-based benchmark approach aims to diversify the installation locations of German wind turbines. Across a broad range of sites, it provides cost-covering remuneration. Because local diversification has been, and still is, desired, the production volume-based benchmark approach has been part of the fixed feed-in tariff and prevails under the feed-in premium of 2014 (Bundestag, 2014).[15] Without it, investors would – even more than observed – only prefer those sites with the most favorable wind conditions, largely in the north at the German coast. The production volume-based benchmark approach increases the attractiveness of sites with poorer wind conditions.

The approach sets a turbine's average remuneration level by defining for how long a turbine is eligible to the higher initial feed-in payment. Thus, it sets $\chi_{i,t}$ in equations (1.2) and (1.5). Figure 1-10 illustrates what the average remuneration level is for investments in one turbine type at different locations.[16] It is evident that investments in a wind-rich location, such as Heligoland, require a lower feed-in tariff than investments in areas with low wind strengths, such as Frankfurt (Main).

The approach works by comparing any turbine's actual production with its theoretical production at a *benchmark location* (Bundestag, 2014). The wind profile at the latter location follows a Weibull distribution with a shape parameter of $\alpha = 2$ (which makes it a Rayleigh distribution), with an average wind speed of $5.5\,\mathrm{ms}^{-1}$ at a height of 30 m. Vertical extrapolation functions through a logarithmic height profile. Its roughness length z_0 is 0.1. In accordance with legislation, every wind turbine type is theoretically installed at this benchmark location and the annual *benchmark*

[15] The definition of the volume-based benchmark approach has since changed (Bundestag, 2016), but the key mechanisms and incentives continue to function as before.

[16] The cost curve is of an illustrative nature, scaled to equal the remuneration for a turbine that reaches 80 percent of the electricity yield at the benchmark location, as explained in the following. For the illustration, the costs per MWh are assumed to depend solely on the amount of energy produced at a site.

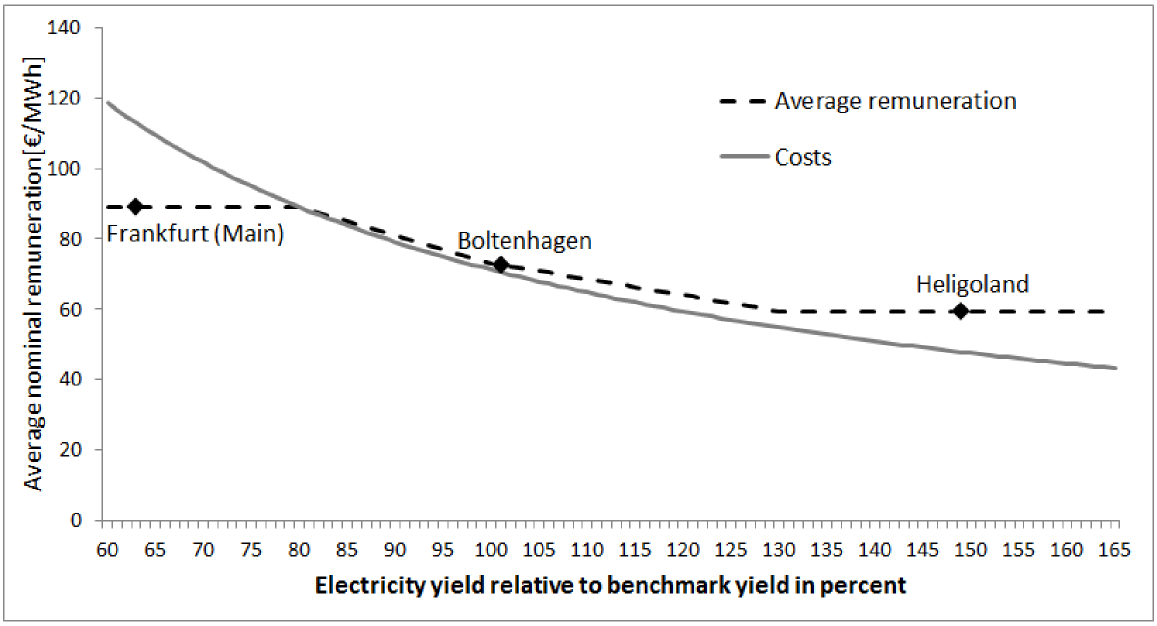

Figure 1-10: Average remuneration at different locations

yield is calculated. The actual electricity yield where a wind turbine is installed, $\omega_{i,t}$, is then set in relation to this *benchmark yield*, which gives the *benchmark ratio* ζ_i. The lower this benchmark ratio is, the longer a wind investor receives the higher feed-in payment. Consequently, turbines at poorer sites receive higher average remunerations.

$$l_i = \begin{cases} 60 & \text{if } \zeta_i \geq 130\%, \\ 60 + \dfrac{130 - \zeta_i}{0.36} & \text{if } 130\% \geq \zeta_i \geq 100\%, \\ 60 + \dfrac{130 - \zeta_i}{0.36} + \dfrac{100 - \zeta_i}{0.48} & \text{if } 100\% \geq \zeta_i \geq 80\%, \\ 240 & \text{if } \zeta_i \leq 80. \end{cases} \tag{1.14}$$

The exact remuneration depends on the *benchmark ratio* and has changed over time. Since an adjustment in August 2014, the calculation of the length extension l_i, measured in months after installation, adheres to equation (1.14). The calculated length extension l_i directly translates into whether in a year $\chi_{i,t}$ is equal to zero, one, or a value in between. For example, a value of 60 implies that χ_i, t is equal to one for the initial five years and zero ever after.

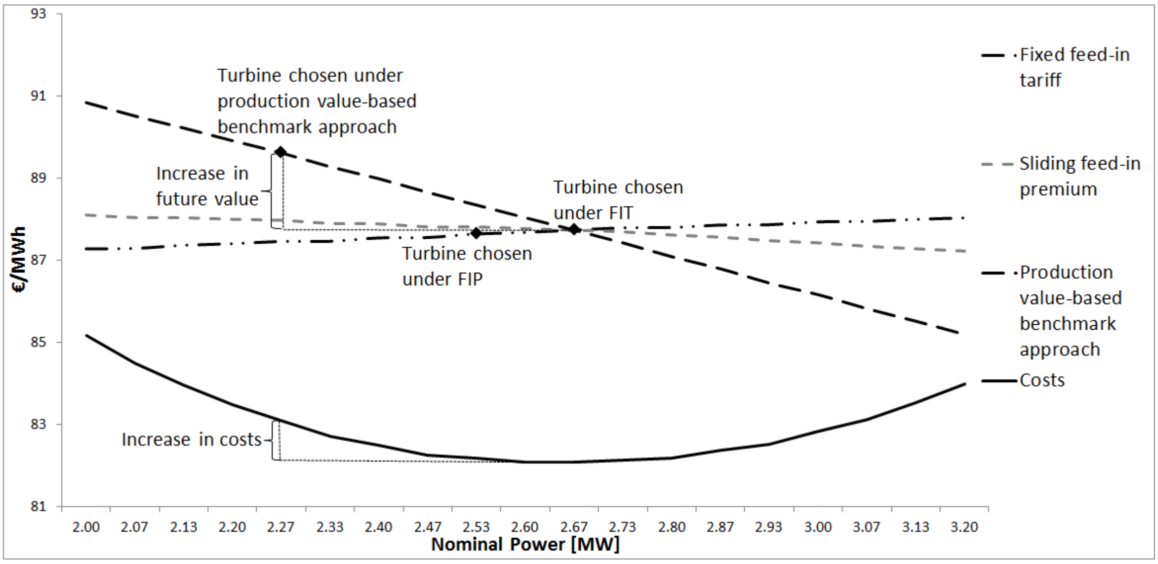

Figure 1-11: Remuneration and levelized cost of electricity for Hanover. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

1.6.2 Sensitivities

In the following, the results of model runs for different locations and different optimization parameters are given. In general, these sensitivities support the findings of the main analysis, unless stated there explicitly.

Locations

The results show similar patterns across locations. In wind-poor Hanover in central northern Germany, the privately-optimal turbine under the FIP is slightly more system-friendly than under the FIT, as figure 1-11 depicts. Under the FIP, the nominal power is 2.6 MW, whereas it is 2.7 MW under the FIT. The system-optimal turbine is encouraged under the production value-based benchmark approach. It has a lower nominal power of 2.3 MW. Its tower is 130 m and hence 10 m higher than under the FIT. At 55.0 m, its rotor blades are 1.9 longer. Consequently, its power production is more constant as its capacity factor is 11 % higher and production is shifted into hours with higher value.

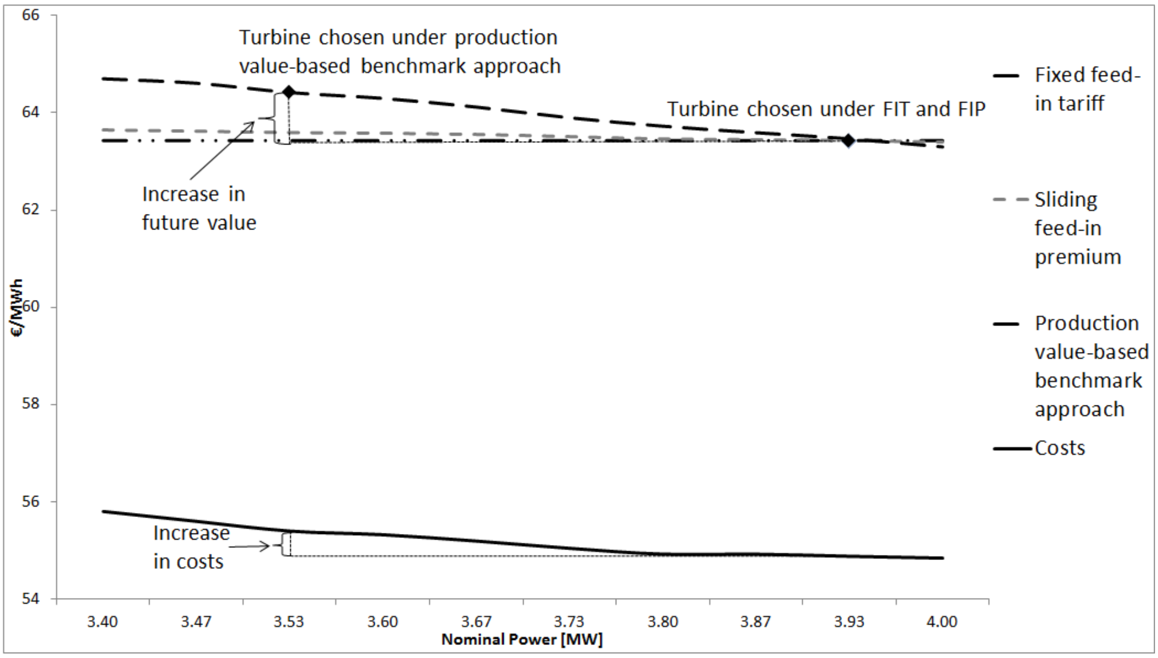

Figure 1-12: Remuneration and levelized cost of electricity for Feldberg. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

Feldberg is a wind-rich location in the south of Germany. Both the FIT and the FIP lead to a 3.9 MW turbine, as figure 1-12 visualizes. The production value-based benchmark approach incentivizes a considerably more system-friendly turbine at 3.5 MW, with an increment in rotor blade length by 2.5 m to 48.0 m and of hub height by 13 m to 94 m. Consequently, the capacity factor rises by 20.2 %, equivalent to an increase in full load hours by 442 h.

The results in figure 1-13 for Kahler Asten, a location in Germany's west, show a comparable pattern. Incentives under FIT and FIP are fairly similar. Under the FIT, investors opt for a turbine with 2.7 MW, whereas under the FIP they opt for a 2.6 MW turbine. Conversely, the remuneration is strongly differentiated according to system-friendliness under the production value-based benchmark approach. Thus, a 2.3 MW turbine is optimal, increasing hub height by 14 m to 132 m and rotor blade length by 2.6 m to 55.4 m. This results in an increase in capacity factor by 16.0 % or 570 full load hours.

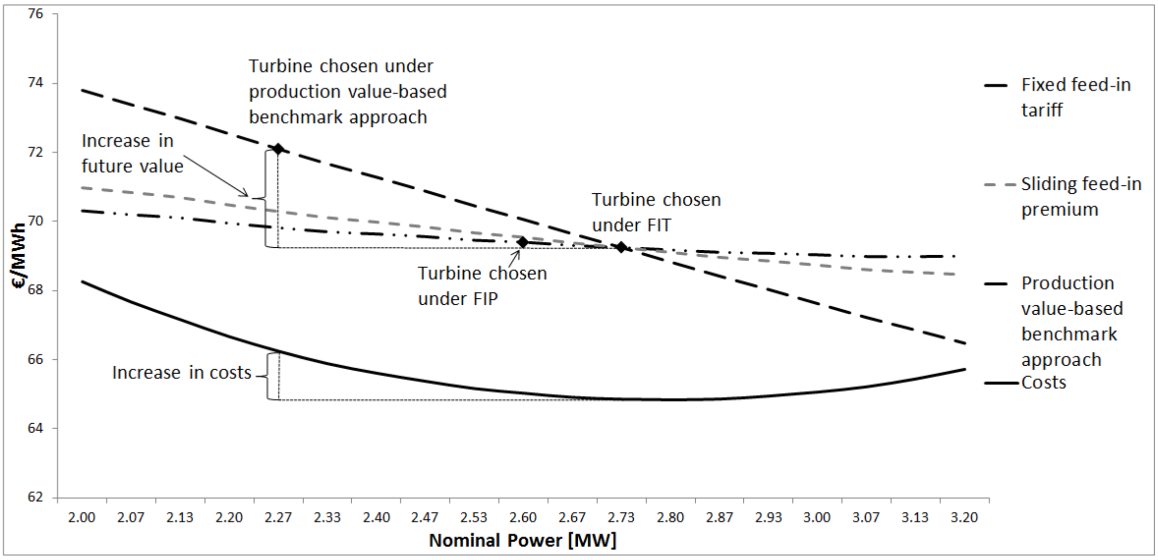

Figure 1-13: Remuneration and levelized cost of electricity for Kahler Asten. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

Investor optimization

Investors can utilize different power price profiles for their optimization, which matter particularly under the feed-in premium scheme. Yet, due to the policy design, only the price profile, i.e. its volatility and correlation with high wind speeds, matters, but not the absolute price level. The baseline scenario is based on the 2013 prices. Figure 1-14 shows sensitivities for different assumptions with respect to their optimization, at the example of Boltenhagen. As alternative, the prices and wind speeds of 2015 are applied. Moreover, investors could possess a greater ability to incorporate expected long-term developments in the power market, for instance if they do not rely on project finance. In one scenario, investors assume 2013's flat power price profile to be representative for the first ten years of the investment. In the second half of the turbine's lifetime, a volatile price profile based on 2030 is applied. Furthermore, a pure FIP-based optimization based on the prices of 2030 is conducted. These results can be compared to the social optimum, which is derived from 2030's prices.

The results indicate that more forward-looking optimization can lead to more system-friendly turbines, but does not reach the system-optimum. Optimization

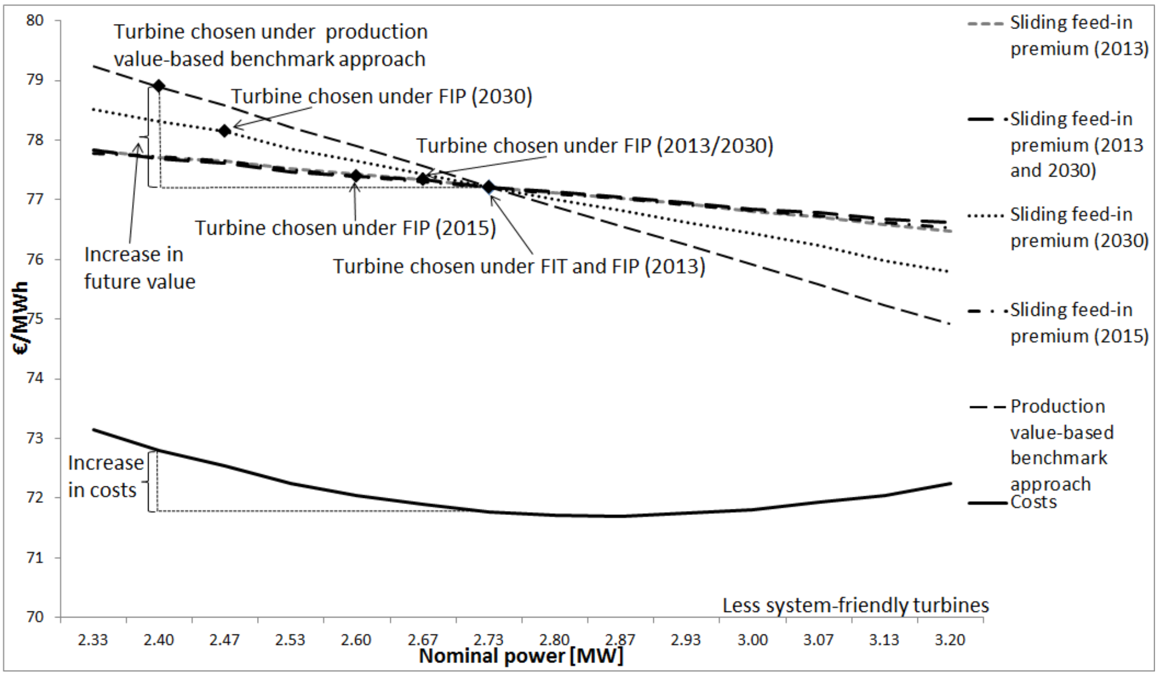

Figure 1-14: Remuneration and levelized cost of electricity for Boltenhagen. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

based on 2015's price profile leads to a somewhat more system-friendly configuration in Boltenhagen. However, this effect stems not only from the different volatility of the price profile, but also from the different weather in 2015. While in Hanover, the effect is similar, in Feldberg, Kahler Asten and Heligoland, optimization based on 2015 only leads to insignificant changes.

The private optimum does not reach the system-optimum in any of the scenarios, even when investors apply the very same price profiles as the regulator. This is the case because investors will not see all additional value of more system-friendly turbines in their optimization, even if they do possess perfect foresight. Production in months with higher production values is not rewarded, as discussed in section 1.4.2. Consequently, even with optimization based exclusively on 2030's price profile, the system-optimum is not attained.

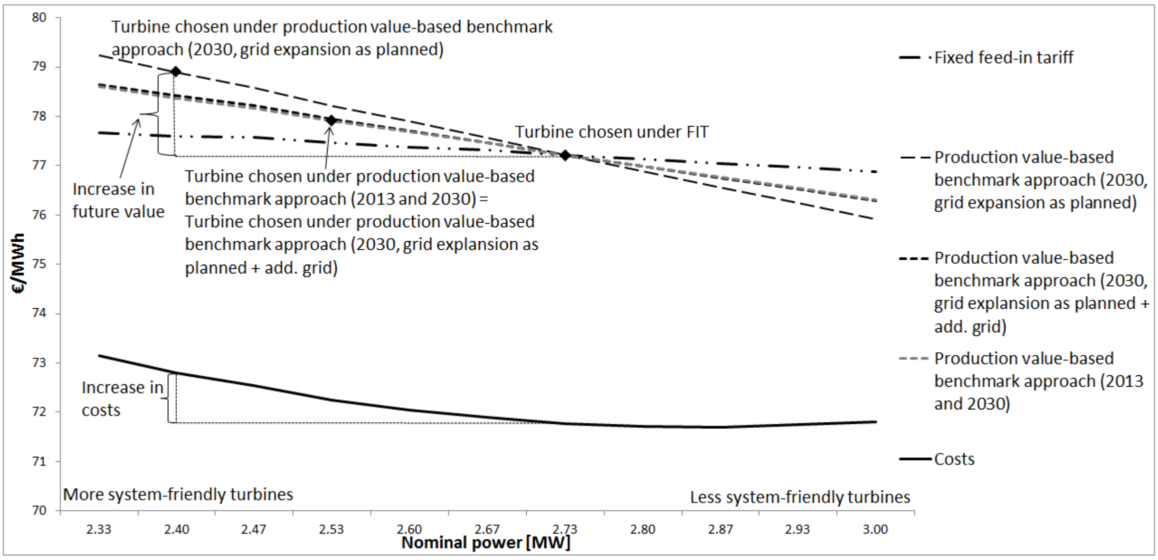

Figure 1-15: Remuneration and levelized cost of electricity for Boltenhagen. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

Regulator optimization

The regulator's choice of which time period to consider influences the definition of the socially-optimal turbine and thus of the privately-optimal turbine under the production value-based benchmark approach. Again, only the volatility and the correlation with wind patterns impact the optimal choices. Figure 1-15 depicts the remuneration under the production value-based benchmark approach for different choices of the regulator, again at the example of Boltenhagen. The scenario "Production value-based benchmark approach (2030, grid expansion as planned)" is the base scenario in the main analysis. As previously, the optimal turbine's nominal power is 2.4 MW, its hub height 128 m and its rotor blade length 54.7 m.

Additional grid expansions ("Production value-based benchmark approach (2030, grid expansion as planned + add. grid)") beyond what is planned could lead to a similar effect as the deployment of more system-friendly turbines: as the resulting power price profile is less volatile, the optimal turbine is also less system-friendly. Its nominal power lies 133 kW higher, its hub height is 4 m lower and its rotor blades are 0.7 m shorter.

When the regulator chooses to apply a combination of current flat (2013) and future (2030) power price profiles ("Production value-based benchmark approach (2013 and 2030)", the optimal turbine is the same one as in the case with further additional grid expansion. The remuneration varies slightly under the two different remuneration schemes, but is barely distinguishable, leading to the same chosen turbine. Importantly, even when both the regulator and the investor (under the FIP) apply a combination of 2013 and 2030 prices, the socially- and privately-optimal turbines differ.

Design of the feed-in premium

Sliding feed-in premia can have alternative remuneration designs, exposing investors to the electricity price to varying degrees and impacting risks and investment incentives differently. Beyond the so-far discussed monthly arrangements, deviations from the national wind power feed-in can also be calculated e.g. on an hourly or yearly basis, which changes the premium of equation (1.6). Hourly adjustments as under the UK's Contracts for Differences allow for no deviations from the strike price and, thus, – besides potential balancing costs and related risks – have very similar implications as fixed feed-in tariffs.

Annual adjustments expose the investor to the electricity price and erase only the *annual* average wind power value variability. Investors are more exposed to the price than under monthly approaches. They face higher price risks, possibly inducing higher financing costs. At the same time, stronger incentives for investments into system-friendly turbines can be expected.

Figure 1-16 shows the results for feed-in premium schemes with annually-sliding premia. They naturally depend on the year applied for the investor's optimization. Based on 2013, the optimal turbine is equal to the one under a fixed feed-in tariff. With prices of 2015, incentives for system-friendly turbines are stronger: The privately-optimal turbine's nominal power lies 5 % lower at 2.6 MW, has longer rotor blades and a higher tower.

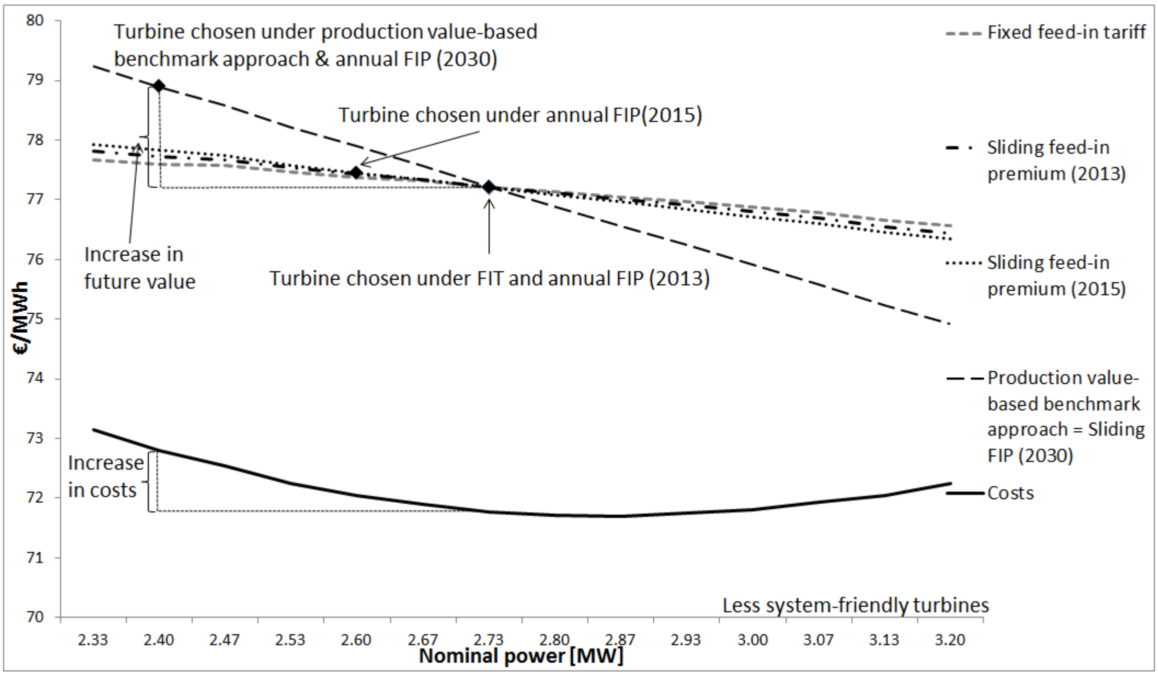

Figure 1-16: Remuneration and levelized cost of electricity for Boltenhagen. For comparability, the level of the FIP is set to equal the fixed FIT for the turbine that is chosen under the fixed FIT. The remuneration/costs refer to levelized lifetime remuneration/costs per MWh for the investor.

Annual premia based on 2030 yield the same strong incentives for system-friendly turbines as the regulator's optimization: The system-optimal turbine is chosen. From a modeling perspective, the two approaches are very similar. The main differences are that under annually-sliding feed-in premia, investors take over a larger part of the price risk and require foresight with respect to future price patterns. Where future price patterns are uncertain, investors potentially have to pay higher financing costs. When future price patterns are uncertain under the production value-based benchmark approach, no additional financing costs are induced, but the regulator risks to incentivize configurations that are either too system-friendly or not system-friendly enough.

1.6.3 REMix model

The REMix model is used to model future power price profiles for the year 2030. It is a dynamic bottom-up energy system model that focuses on the operational optimization of electricity and heat-generating technologies in conjunction with temporal and spatial load-balancing options.

For Germany, the average price and its volatility increase compared to 2013 and 2015. The mean price is €66 per MWh, with an increased standard deviation of €27 per MWh. In the sensitivity with further grid expansion, many additional grid connections are assumed to operate in 2030. Germany possesses additional 28 GW of capacity to its neighboring countries and an additional 8 GW of internal connections. The resulting power price profile is flatter, leading to a decreased standard deviation of €21 per MWh.

The model does not directly allow for negative prices, but near-zero prices occur frequently. In 492 hours, prices are below €5 in the base scenario, almost four times as frequently as in 2013. These prices are obtained by taking the average of prices from the six geographical regions into which Germany is divided in the model. Prices are equal across regions unless there is congestion between them. These prices are weighed by the areas' supply and demand and the average of the supply-weighed and the demand-weighed prices is taken.

Table 1.1 indicates the installed capacities across generation technologies in Germany in 2030. While nuclear energy has been phased out, wind and solar power have been scaled up. Hard coal is assumed to cost €59 per MWh, lignite €69 per MWh and gas €43 per MWh. The CO_2 price is €45 per ton. Further details are given in Deutsches Zentrum für Luft-und Raumfahrt (2014).

Technology	Installed capacity (GW)
Nuclear	0
Coal	21.4
Gas and oil	38.9
PV	87
Wind onshore	64.4
Wind offshore	29.2
Hydro	4.9
Biomass	10.9
Geothermal	1
Pump storage and other storage	6.5
Total	264.2

Table 1.1: Installed capacities in 2030 (Deutsches Zentrum für Luft-und Raumfahrt, 2014)

Chapter 2

Financing Power: Impacts of Energy Policies in Changing Regulatory Environments*

Abstract

Power systems with increasing shares of wind and solar power generation have higher capital and lower operational costs than power systems based on fossil fuels. This increases the importance of the cost of financing for total system cost. We quantify how renewable energy support policies can influence 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 in the context of green certificate schemes. We find that between the support policies, the costs of renewable energy deployment differ by around 30 percent.

*This chapter is based on joint work with Karsten Neuhoff. We thank Robert Brückmann, Olga Chiappinelli, Ingmar Jürgens, Nolan Ritter, Marie Therese von Schickfus, Bjarne Steffen, Oliver Tietjen, and Vera Zipperer for their helpful comments and suggestions. We also benefited from comments by participants at the 11th Conference on The Economics of Energy and Climate Change at the Toulouse School of Economics, the 23rd EAERE conference, the 12th AURÖ workshop, the 5th International Symposium on Environment and Energy Finance Issues, the 39th conference of the International Association for Energy Economics, a seminar at UCL London, a seminar at the University of St. Gallen, and internal seminars at DIW Berlin.

2.1 Introduction

The rising share of capital-intensive assets increases the importance of financing costs for the total costs in power systems. This applies particularly 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 (2016) project investments of \$7.3 trillion into wind and solar power between 2017 and 2040 and a estimate a 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, feed-in premia, and green certificate schemes. The policy design may shift regulatory risk between parties, but where policy risk can be avoided altogether, policies can reduce, rather than shift, overall deployment costs.

Second, market risks are introduced where support mechanisms do not comprise explicit off-take guarantees. Investors then 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 feed-in 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 design 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 chapter is structured as follows: After an overview over policies supporting renewable energy in section 2.2, we estimate policy impacts on investors' financing costs in section 2.3. Section 2.4 analyzes how incomplete long-term contracts incur additional costs for off-takers. The chapter ends with a conclusion.

2.2 Investments into renewable energy

Three main policies that support renewable energy investments dominate globally: Fixed feed-in tariffs (FIT), sliding feed-in premia (FIP) and tradable green certificates (TGC).[1] In 2015, feed-in tariffs or feed-in premia existed in 82 countries, whereas tradable green certificates were in place in 34 countries and many US states (REN21, 2017).[2]

Price-based support policies, e.g. feed-in tariffs and feed-in 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 feed-in 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 feed-in 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 a shift in 2012 from a feed-in tariff to a sliding premium, and Kitzing (2014) goes as far as classifying feed-in tariffs and sliding feed-in premia as one, merely distinguishing higher risk fixed feed-in 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 cer-

[1] Alternative names for FIPs are *Market Premium* and *Contracts for Differences*, while the main difference is that under Contracts for Differences, 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*.

[2] Since sliding feed-in premia dominate fixed feed-in premia globally, we discuss only *sliding* feed-in premia.

tificates, 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 has been 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 have been more successful in both respects. In line, Bürer and Wüstenhagen (2009) conduct a survey among investors and show, using a stated preferences approach, that these 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 feed-in premium amounts to 0.8-1.7 percentage points (NERA, 2013).

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 under green certificates are small. Schmalensee (2012) argues that social costs under feed-in tariffs are higher due to the unknown installation quantities.

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.

2.3 Estimating investors' financing costs

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

The risk premium is the difference between the weighted average cost of capital (WACC) and a country's specific risk-free rate γ_c.

$$risk\ premium = WACC - \gamma_c \tag{2.1}$$

2.3.1 Data

For the analysis, we deploy interview data of financing cost estimates by project developers, bankers, and academics from 23 EU countries.[3] Table 2.1 provides descriptive statistics for the variables.

The 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).

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 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 ones, based on Eurostat (2017a). At the lower end, the bonds of Germany, Denmark, and Finland paid the lowest returns with less than two percent.[4] Since the interviews were conducted in

[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.

[4] We also tested using official Eurostat data on firm lending rates. Yet, we deemed the data unre-

Table 2.1: 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 feed-in 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 feed-in 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

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 feed-in premia, or green certificate schemes prevailed in early 2014 in the EU countries (see figure 2-1). 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 particular policy implementations that distinguish their

liable, 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.

schemes from those of other countries. In Germany, investors could choose between a feed-in tariff and a feed-in 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. 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 not comparable to the usual policies, such that we drop the Estonian observations (which show indeed 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 employed a fixed feed-in 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 feed-in premium does not influence the results in the following, such that we generally simply include it in the group of countries with sliding feed-in 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.

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

2.3.2 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 (2.16). Importantly, our key explanatory variable, whose effect we aim to

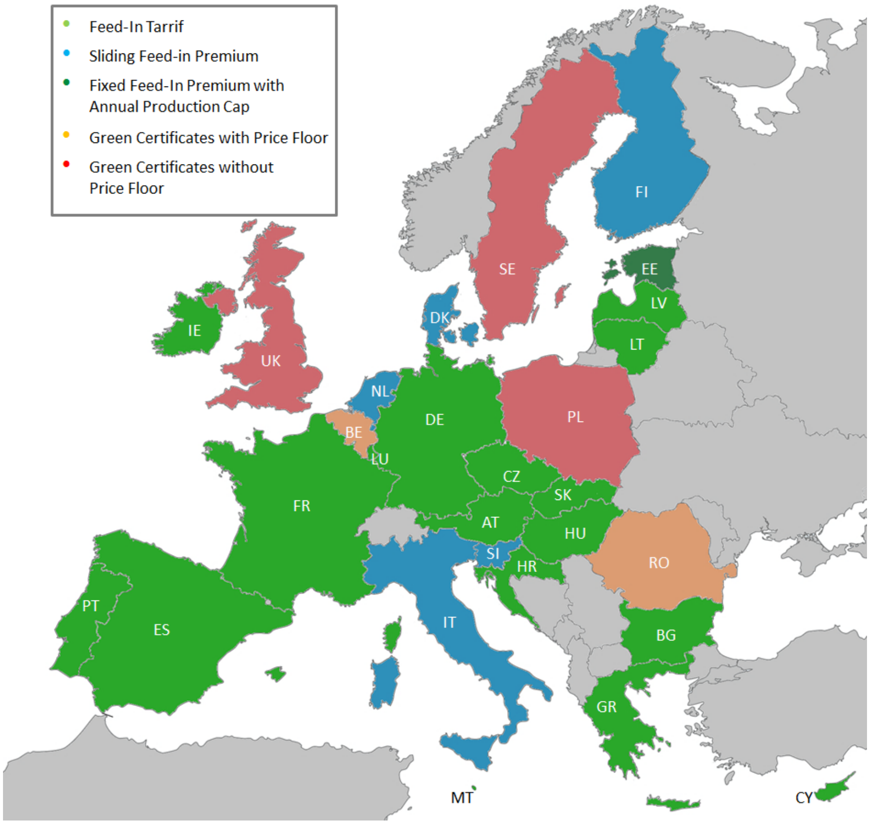

Figure 2-1: Onshore wind power policies in the EU in spring 2014. Source: Eclareon (2017) and González and Arántegui (2015)

assess, is the policy scheme. Its coefficients are β_1 for sliding feed-in premia and β_2 for green certificate schemes, as compared to the baseline of a fixed feed-in tariff.

$$risk\ premium_i = \alpha + \beta_1 FIP + \beta_2 TGC + X\delta + u_i \tag{2.2}$$

For each interview-observation i, we control for additional factors through explanatory variables contained in X. Our additional co-variates include dummies for the implicit stop of renewable energy support, 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). However, 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. In a first step, we assume the decrease (increase) to be .5 percentage points when the actual number was "slightly lower" (higher), 1 percentage point when it was "lower" (higher), and 1.5 percentage points when it was "much lower" (higher).

2.3.3 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 feed-in premia are insignificant (see column (1) of table 2.2). Under the feed-in 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 particular, 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 feed-in premium, shown in column (2). In both estimations (1) and (2), significance of the explanatory variables remains the same.

Most importantly, tradable green certificates are associated with an increase in the risk premium by 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).

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.

Somewhat surprisingly, retrospective changes have no statistically significant effect on the 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 and bankers) gave systematically different replies.

Table 2.2: OLS estimation results

	(1)	(2)	(3)	(4)
	Level	Level	Log	Log
Dep. var: risk premium				
Sliding feed-in 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

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 feed-in premium is in the baseline. Academic/Consultants are the baseline respondent group.

Our results indicate that secure designs of sliding feed-in premia facilitates 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 the power market design, investors might perceive the revenues under feed-in 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.

2.3.4 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 have to 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 given in Appendix 2.7.1.

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 2.3 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 feed-in premium are again insignificant.

Also under the interval regression, tradable green certificates are 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 have been abolished implicitly, financing costs strongly increase.

Table 2.3: Interval regression estimation results

	(1) Level	(2) Level	(3) Log	(4) Log
Dep. var: risk premium				
Sliding feed-in 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

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 feed-in premium is in the baseline. Academic/Consultants are the baseline respondent group.

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, especially 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 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 Appendix 3.7. 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.

2.4 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 basis for project financing of renewable energy projects. The counterparty to the project developer, which we will in the following refer to as off-taker, 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, in turn, implies that the project needs to obtain additional support to break even, which directly translates into additional deployment 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.

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

Project investors seek long-term certainty about their revenue streams; commonly securing them 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. 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-taker 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.[5]

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

[5]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.

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 for all debt raised and higher return requirements for equity.[6]

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, or 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}.

$$c(d,e) = r_{debt}d + r_{equity}e \tag{2.3}$$

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

$$c(d,e) = r_{debt}(g(d,e))d + r_{equity}(g(d,e))e \tag{2.4}$$

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:

[6] 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.

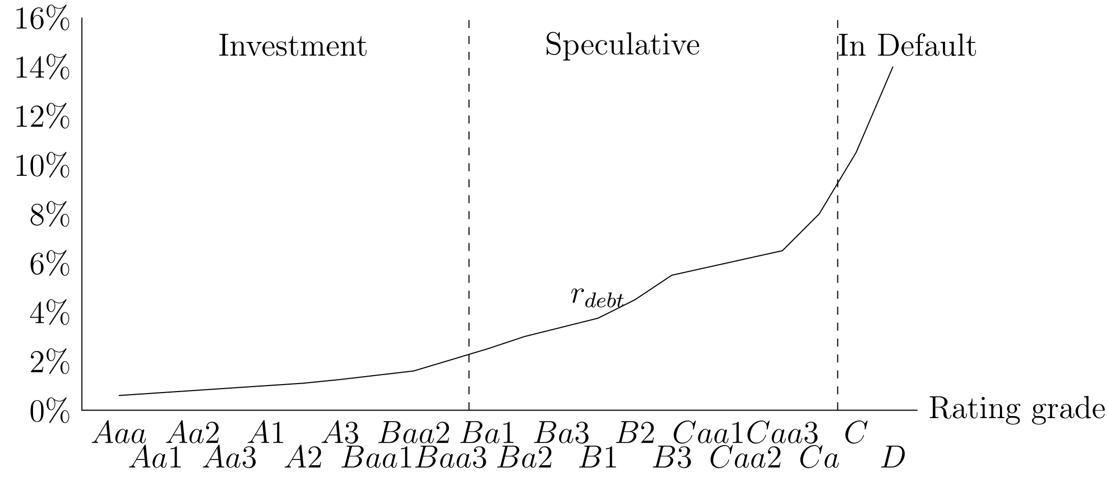

Figure 2-2: Default spread as function of corporate credit rating, based on Damodaran (2017)

$$\frac{\partial c(d,e)}{\partial d} = \frac{\partial r_{debt}(g(d,e))}{\partial g} \frac{\partial g(d,e)}{\partial d} d + r_{debt}(g(d,e)) \tag{2.5}$$

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.[7] 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 2-2).[8]

Moreover, the credit rating itself is approximately a linear function of debt. The

[7]We refer to the rating categories in Moody's nomenclature.

[8]For comparison, appendix 2.7.3 shows the estimation and results for a linear functional form, which, however, has a lower R-squared (82 percent in the linear against 93 percent in the quadratic case).

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.

2.4.2 Estimation of off-takers' costs

We estimate off-takers' costs of signing long-term contracts by parameterizing equation (2.5). 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:[9]

$$r_{debt}(g(d,e)) = m + \lambda g(d,e)^2 \tag{2.6}$$

with slope

$$\frac{\partial r_{debt}(g(d,e))}{\partial g(d,e)} = 2\lambda g(d,e) \tag{2.7}$$

We estimate equation (2.14) with the aggregated data by Damodaran (2017). Specifically, we regress the default spread on the according squared rating, using a simple OLS estimator. Following the discussion in section 2.4, we assume equidistant rating grades and codify them as numerical values n, with the best rating AAA as 1, the second best rating *AA1* as 2, and so forth. The term u_g represents the error term.

$$r_{debt_g} = m + \lambda n_g^2 + u_g \tag{2.8}$$

[9] We estimate a function for the default spread, even though we discussed the interest rate previously. 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.

Table 2.4: Interest rate as quadratic function of traded US companies' credit ratings, based on aggregate data by Damodaran (2017)

Estimation results	
	(1)
Dep. var.: r_{debt}	
g^2	0.000231***
	(0.0000175)
m	-0.000481
	(0.00434)
N	15
Robust standard errors in parentheses	
* p<0.10, ** p<0.05, *** p<0.010	

The coefficient λ is statistically significant and is equal to 0.00023, while the constant is insignificant, as table 2.4 shows. The equation 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:

$$g(d, e) = n + \epsilon \frac{d}{e} \tag{2.9}$$

where n 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:

$$\frac{\partial g(d, e)}{\partial d} = \frac{\epsilon}{e} \tag{2.10}$$

We regress the credit rating on the debt-equity ratio, applying an OLS estimator. We use aggregated annual data on average debt-equity ratios and credit ratings of twelve large European utility companies over 11 years. The term u_t represents the error term.

$$n_{g_t} = b + \epsilon(\frac{d}{e})_t + u_t \tag{2.11}$$

Table 2.5: Credit grade as function of debt-equity ratio based on aggregated annual averages of large EU utilities

Estimation results	
	(1)
Dep. var.: g	
debt-equity ratio	2.876032***
	(0.5518585)
m	2.183433
	(0.7326723)
N	11
Robust standard errors in parentheses	
* p<0.10, ** p<0.05, *** p<0.010	

The slope ϵ is estimated as 2.88 and the constant b is 2.18, as shown in table 2.5. 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 (2.5).

$$\frac{\partial c(d,e)}{\partial d} = 2\lambda(b + \epsilon\frac{d}{e})\frac{\epsilon}{e}d \tag{2.12}$$

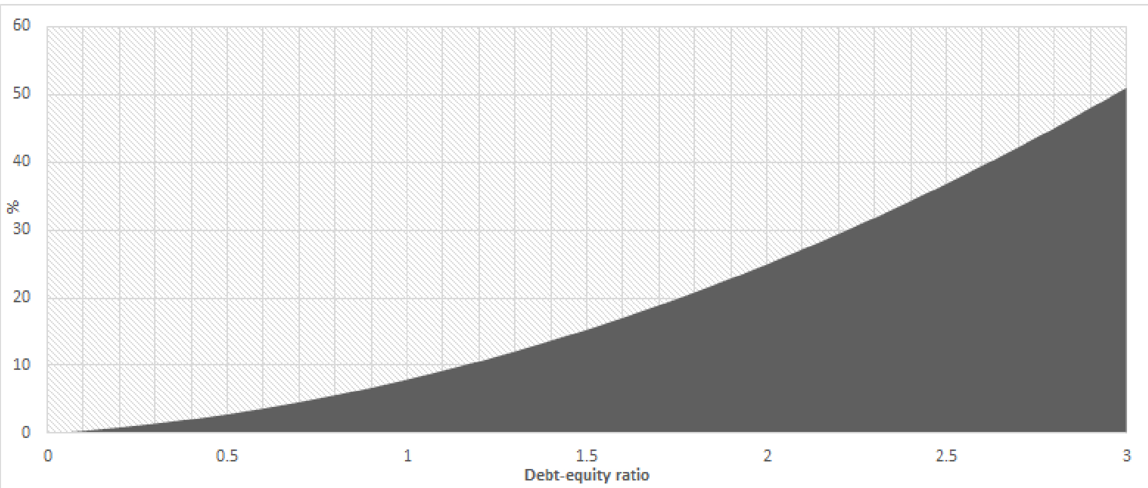

Figure 2-3: Extra re-financing costs for private off-takers as share of contract value

Based on European utilities' average debt-equity ratio of 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 (2.13). 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.

$$c_{present} = \frac{\sum_{t=1}^{T} \zeta^{t-1} c_{annual}(T-t-1)}{\sum_{t=1}^{T} \zeta^{t-1}} \tag{2.13}$$

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 2-3 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.

2.4.3 Financial position of private off-takers

In the absence of long-term financial hedges, utilities are commonly the sole market actors that hold relatively stable long-term customer bases, which essentially function as price hedges (Finon, 2011).[10] Moreover, utilities have traditionally possessed relatively strong financial positions and large portfolios, enabling them to commit to long-term contracts (Baringa, 2013), and experience with electricity markets possibly decreases 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.

[10]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, 2016).

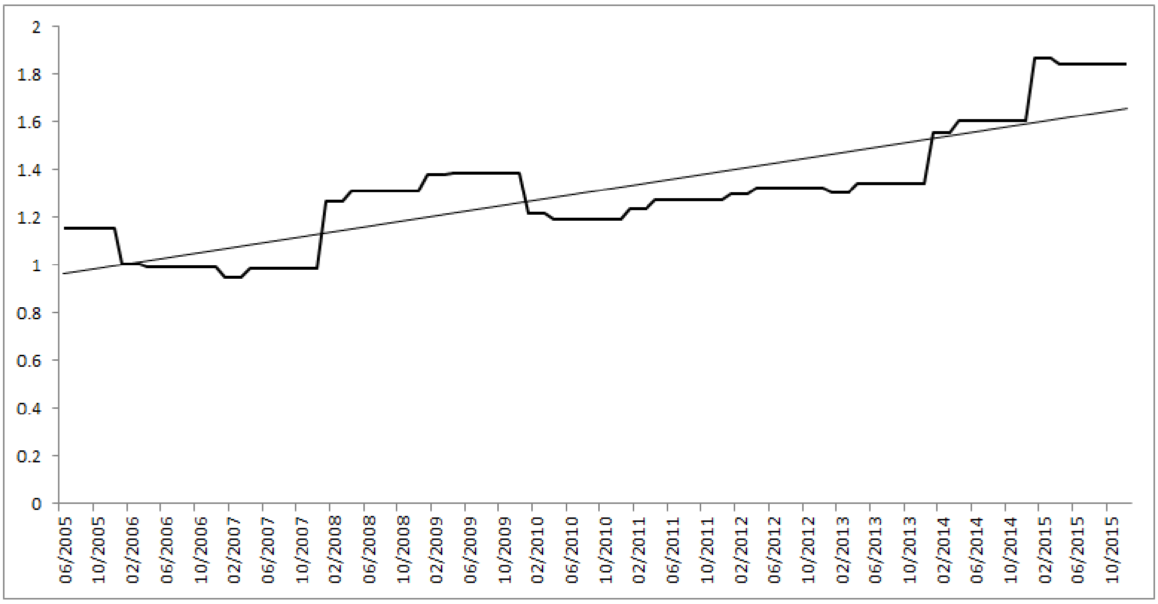

Figure 2-4: Average debt-equity ratio of twelve large EU utilities. Source: Own calculations based on Datastream International (2016) and Vattenfall (2015)

Liberalized electricity markets mean new competition on the retail and wholesale markets (Tulloch et al., 2017), while the rise of renewable energies challenged incumbents' business models due to different risk-return profiles (Helms et al., 2015). This resulted in reduced valuations of conventional power stations, reducing the equity value of companies. Figure 2-4 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, has 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 2-5 indicates, the credit ratings have declined across the board over recent years. On average, bond ratings have fallen more than 2.5 rating categories, e.g. from Aa1 to Aa2 or from A3 to Baa1.

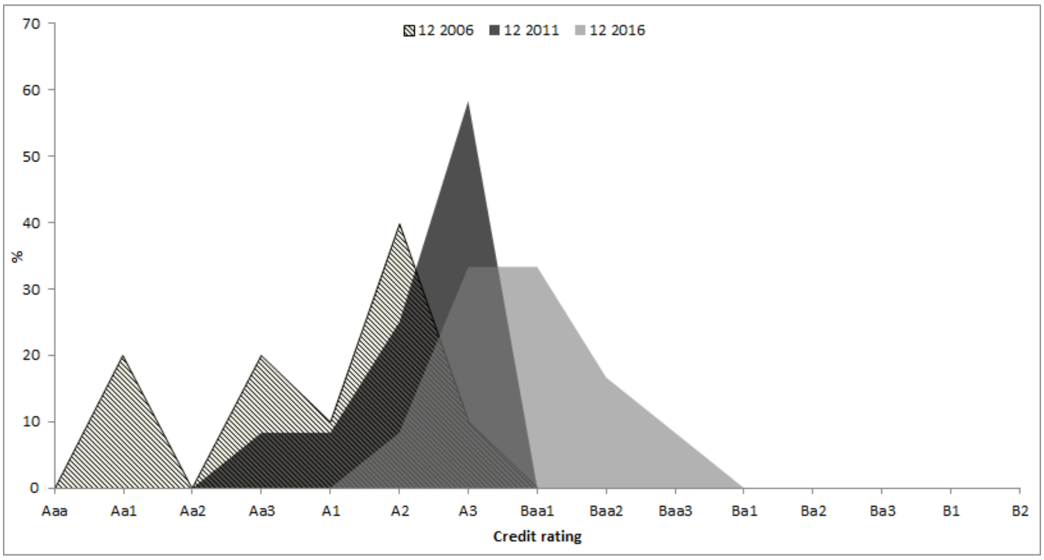

Figure 2-5: Credit ratings of large EU utilities. Source: Based on Moody's (2017)

2.5 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,[11] the average technology-weighed power price of 2016 pays for about half of the costs, with the other half required as additional support. Under green certificates, the overall costs increase to about €65 per MWh, increasing the required support (overall remuneration minus power price) by roughly 75 percent.

This 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 2.3.3. This translates into an increase to €53 per MWh, as shown in figure 2-6. 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 2.4. This translate

[11]We apply rather low cost estimates of €1080 per kW 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.

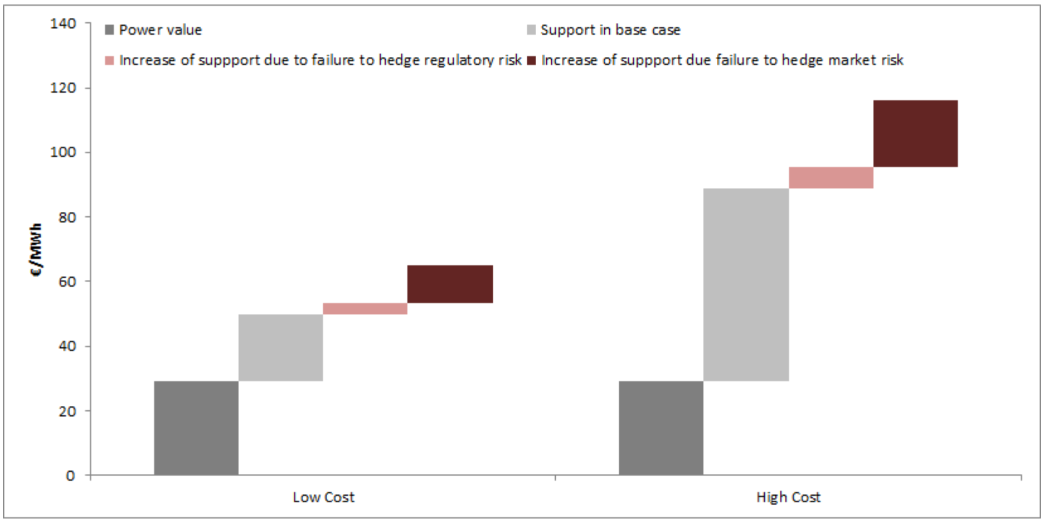

Figure 2-6: Additional costs under green certificates

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.

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.[12] This divides into additional costs of €per MWh for the new regulatory risks and additional costs of €20 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. Then, 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

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

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.

2.6 Conclusion

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 investors' financing costs.

First, based on a survey on wind power financing cost estimates from 23 EU countries, we find that sliding feed-in premia do not increase financing costs in comparison with fixed feed-in tariffs. With evolving power market designs, however, investors are exposed to additional risks under feed-in 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 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.

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 — resulting in around 20 percent additional costs of renewable energy deployment.

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, increasing 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.

Combining the effects of risk for project investors and risk for counterparties signing long-term off-take contracts may also explain a paradox of previous assessments. Studies like Ragwitz et al. (2012) and Butler and Neuhoff (2008) show that significantly higher support levels are required where policy design involves green certificate systems, but no equivalent discrepancy in financing cost has been 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.

2.7 Appendix

2.7.1 Normality of weighted average cost of capital estimates

We test the normality of the estimates of the weighted average cost of capital, provided by the interviewees. A rough initial visual check of this assumption can be made by plotting the existing responses against normal distributions and evaluating if the data appears to adhere to the distribution. Figure 2-7 shows the risk premium in levels, figure 2-8 shows it in logarithms. The level specification appears like a better match, as the data is less skewed towards a very narrow interval and has fewer outliers.

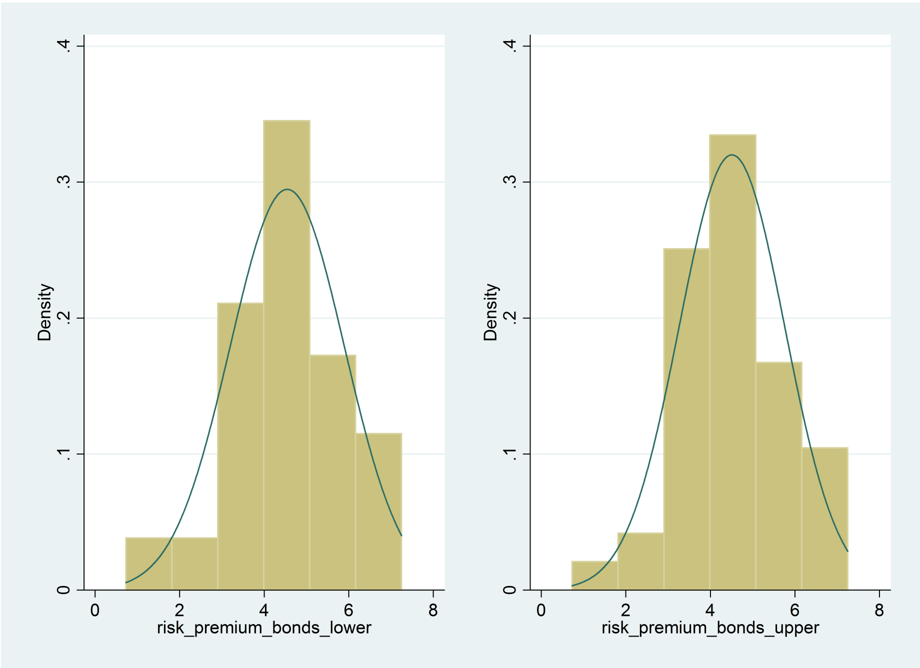

Figure 2-7: Normality assumption for lower and upper estimates of risk premium in levels

Numerically, we check normality through a Shapiro-Wilk test. It tests the null hypothesis that certain data is normally-distributed (Shapiro and Wilk, 1965). The test of the lower bound yields a W-value of 0.954, with a resulting p-value of 0.0578. Hence, the null hypothesis of the data following a normal distribution cannot be discarded at a five percent significance level, yet is rejected at a ten percent significance level. The respective test of the upper bound yields a W-value of 0.963 and a p-value of 0.161. Thus, we cannot reject the null hypothesis of a normal distribution for the upper bound at any reasonable significance level. Summarizing, some doubts remain with respect to the normality of the lower risk premium boundary, whereas the upper boundary appears normally distributed.

The same tests for the logarithm of the risk premium clearly reject the null hypotheses of normality: The lower boundary's W-value is 0.719, with a p-value of 0.000. The upper boundary's W-value is 0.776, with a resulting p-value of 0.000. Hence, we prefer the levels-estimation over the log-specification, as the latter will be biased.

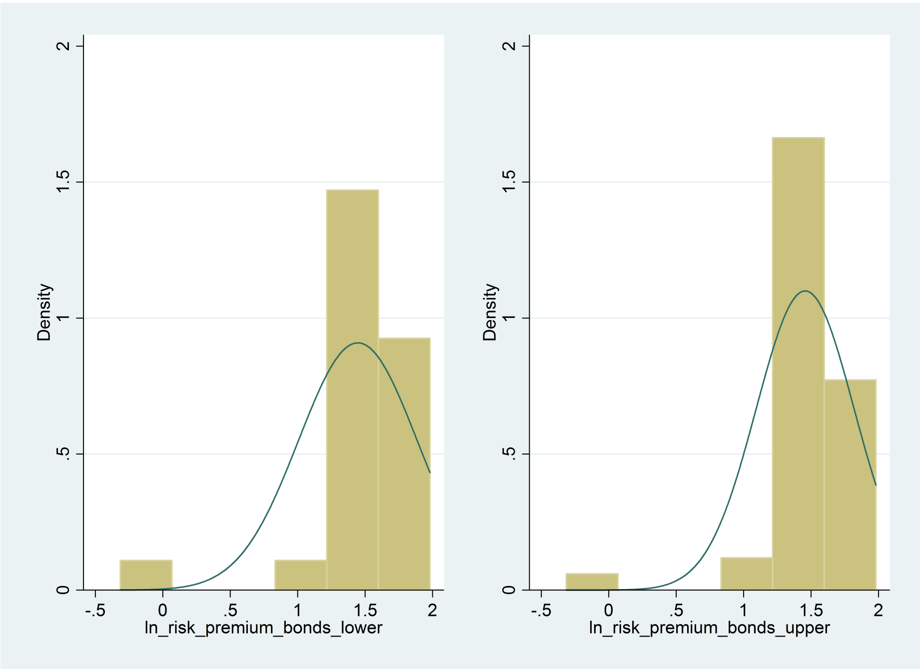

Figure 2-8: Normality assumption for lower and upper estimates of risk premium in logarithms

2.7.2 Sensitivity analyses regarding the coding of responses

Table 2.6: OLS estimation results w. alternative coding

	(1)	(2)	(3)	(4)
	Level	Level	Log	Log
Dep. var: risk premium				
Sliding feed-in premium	-0.467		-0.241	
	(0.599)		(0.225)	
Tradable green certificates	1.585**	1.741**	0.372**	0.453***
	(0.533)	(0.507)	(0.125)	(0.119)
No policy	2.622***	2.729***	0.568***	0.623***
	(0.591)	(0.572)	(0.146)	(0.140)
Retrosp. changes	0.033	0.125	-0.027	0.021
	(0.559)	(0.569)	(0.147)	(0.148)
Tenders	1.214	0.984	0.415*	0.296
	(0.677)	(0.634)	(0.187)	(0.149)
Equity investor	-0.377	-0.421	-0.095	-0.118
	(0.473)	(0.467)	(0.128)	(0.125)
Utility employee	-0.552	-0.519	-0.144	-0.128
	(0.613)	(0.605)	(0.159)	(0.156)
Banker	-0.567	-0.601	-0.159	-0.176
	(0.534)	(0.556)	(0.194)	(0.212)
N	53	53	53	53

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 feed-in premium is in the baseline. Academic/Consultants are the baseline respondent group.

The interview replies are interpreted in some cases where the replies do not yield a point estimate, but provide ranges above or below a certain threshold. Consequently, for OLS regressions, we must make assumptions about what interviewees possibly meant. In the baseline scenario, we count "slightly higher" as 0.5 percentage points higher, "higher" as 1.0 percentage point, and "much higher" as 1.5 percentage points. In the first sensitivity, we change these interpretations to 1, 2, and 3 percentage points, respectively. Table 2.6 shows the results. Statistical significance levels are the same as previously. The only relevant difference is that the effect of green certificates is even more pronounced: They are associated with an increase of financing costs of

1.6-1.7 percentage points.

Another interpretation of the responses is in relative terms: "slightly higher" implies a five percent higher value, "higher" ten percent, and "much higher" 20 percent. Table 2.7 shows the results. Statistical significance levels are the same as before. However, tradable green certificates are only significant at the five percent significance level. Their coefficient is also slightly smaller and lies at 1.1-1.2 in the levels-specification, implying an increase in financing costs by 1.1-1.2 percentage points.

Table 2.7: OLS estimation results w. alternative coding II

	(1) Level	(2) Level	(3) Log	(4) Log
Dep. var: risk premium				
Sliding feed-in premium	-0.380		-0.231	
	(0.516)		(0.203)	
Tradable green certificates	1.122*	1.249**	0.242*	0.319**
	(0.434)	(0.402)	(0.100)	(0.092)
No policy	2.052***	2.140***	0.406***	0.460***
	(0.495)	(0.472)	(0.109)	(0.098)
Retrosp. changes	-0.072	0.003	-0.056	-0.010
	(0.453)	(0.455)	(0.105)	(0.102)
Tenders	1.012	0.824	0.320	0.206
	(0.628)	(0.606)	(0.168)	(0.137)
Equity investor	-0.106	-0.141	-0.004	-0.025
	(0.376)	(0.369)	(0.088)	(0.081)
Utility employee	-0.267	-0.241	-0.079	-0.063
	(0.547)	(0.534)	(0.131)	(0.119)
Banker	-0.764	-0.791	-0.317	-0.333
	(0.544)	(0.580)	(0.214)	(0.241)
N	53	53	53	53

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 feed-in premium is in the baseline. Academic/Consultants are the baseline respondent group.

Table 2.8: Interest rate as linear function of traded US companies' credit ratings, based on aggregate data by Damodaran (2017)

Estimation results	
	(1)
Dep. var.: r_{debt}	
g	0.0052989***
	(0.0009123)
m	-0.02087331**
	(0.0096336)
N	15
Robust standard errors in parentheses	
* p<0.10, ** p<0.05, *** p<0.010	

2.7.3 Functional form of the interest rate function

Assuming a linear functional form for the interest rate function r_{debt_g}, we formulate the following function:

$$r_{debt}(g(d,e)) = m + \lambda g(d,e) \tag{2.14}$$

with slope

$$\frac{\partial r_{debt}(g(d,e))}{\partial g(d,e)} = \lambda \tag{2.15}$$

Equivalent to the previous estimation, we estimate:

$$r_{debt_g} = m + \lambda n_g + u_g \tag{2.16}$$

In this case, the constant is -.0208 and the slope is 0.0052, as depicted in 2.8.

The additional costs for long-term contracts under green certificates differ accordingly, as depicted in figure 2-9. Using the exemplary cost parameters laid out in section 2.5, an installation based on the average debt-equity ratio of the large EU utilities of 1.85 sees additional costs of about 33.4%, i.e. considerably more than in the quadratic case. With worse debt-equity ratios, the costs under the quadratic functional form increase more sharply.

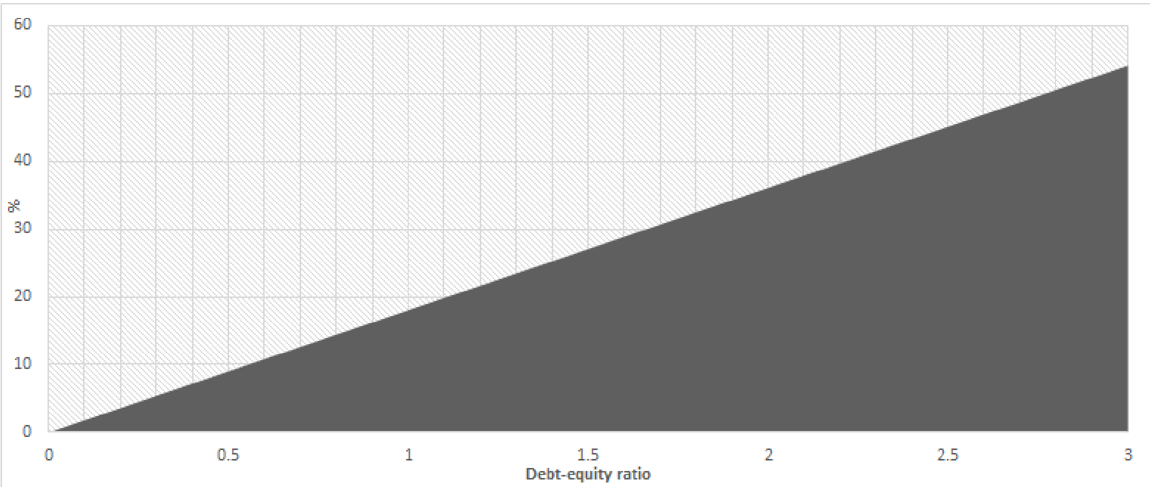

Figure 2-9: Extra re-financing costs for private off-takers as share of contract value with linear interest rate

Chapter 3

Too Good to Be True? How Time-Inconsistent Renewable Energy Policies Can Deter Investments*

Abstract

The transition towards low-carbon economies requires massive investments into renewable energies, which are commonly supported through regulatory frameworks. Yet, governments can have incentives – and the ability – to deviate from previously-announced support once those investments have been made, which can deter investments. We analyze a renewable energy regulation game, apply a model of time-inconsistency to renewable energy policy and derive under what conditions governments have incentives to deviate from their commitments. We analyze the effects of various support policies and deployment targets and explain why Spain conducted retrospective changes in the period 2010-2013 whereas Germany stuck to its commitments.

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3.1 Introduction

In 2016, global investments into renewables-based power capacity outpaced investments into coal and gas power plants, amounting to €297 billion (IEA, 2017). Investment needs remain high over the next decades, supporting countries' transitions to not just low-carbon electricity but also other energy sectors. The vast majority of renewable energy projects are facilitated through supportive regulatory frameworks and policies. These policies offset the usually not-internalized negative externalities of thermal power plants and support the learning of technologies (Edenhofer et al., 2013).

Governments support renewable energy investments by promising investors certain policy frameworks and remuneration levels. Time-inconsistency can arise as regulators follow a multi-objective agenda: They pursue long-term decarbonization trajectories, yet these may conflict with short term distributional concerns regarding the costs of energy (Chiappinelli and Neuhoff, 2017). Moreover, in addition to the desire to do so, regulators can have the ability to deviate from previously-announced support levels since renewable energy investments are irreversible and operate at very low marginal costs: Regulators interested in renewable energy announce support levels to be paid via levies on electricity, based on which investors respond by investing into new capacity. However, regulators then possibly deviate, not paying out the promised support, benefiting from both the now-existing renewable energy capacity and the low costs of electricity. Firms anticipate this opportunistic behavior and do not invest in the first place. However, when the game is repeated, there is scope for compliance depending on policies and technology parameters.

The monetary policy literature first applied time-inconsistency concepts to inflation and economic growth. In their ground-breaking article, Kydland and Prescott (1977) analyze unemployment and inflation and lay out the problem that rational agents optimizing at different points in time adjust their behavior simply due to the different timing, leading to sub-optimal outcomes when agents are rational. Barro and Gordon (1983) underpin the argument that rules for government behavior can have favorable outcomes rather than the discretion to adjust policies when optimal.

Subsequently, the concept has been used to analyze broader climate policies. Helm et al. (2003) demonstrate that emission pricing faces similar problems since agents foresee that incentives for emission reductions that are optimal *ex-ante* become suboptimal *ex-post*, thus diminishing their credibility in the first place. This is extended for different cases, e.g. where governments and firms are uncertain about future governments' preferences, inducing arguments for research grants (Ulph and Ulph, 2013). Brunner et al. (2012) discuss solutions to the commitment problem with a focus on delegation to an independent climate agency, long-term planning via targets and securitization through legal rights. In this context, they mention feed-in tariffs for renewable energies as favorable example and dismiss the retrospective changes that Spain had just initiated as "unlikely to affect investors' property" (p.16), which has since turned out to be incorrect. Remuneration levels were cut by around 25 percent on average (Comisión Nacional de los Mercados y la Competencia, 2014, 2015).

Renewable energy policy has some common features with general environmental regulation: Demand for renewable energy is driven and affected by government regulations. Due to their high initial capital intensity and low marginal costs, investments into wind and solar power are potentially exposed to time-inconsistency issues as once investments are made, operators will usually operate the assets independent of remuneration. Consequently, governments might face incentives to deviate because existing installations will run in any case.

We contribute to the literature by scrutinizing time-inconsistency problems of renewable energy policies in detail. Building on the analysis of time-inconsistency of environmental regulation by Chiappinelli and Neuhoff (2017), we show that renewable energy policies can be affected by time-inconsistency and consider different policy regimes and how they affect regulatory compliance. As renewable energy support is usually not paid out as capacity support, but rather over the projects' lifetimes as payments for output, we model the interaction between firms and the government as a dynamic game where the effects of past periods' support commitments and investments last into the present.

We analyze commitment devices in the field of renewable energy. While Borghesi (2011) argues that renewable energy targets, like the European 2020 renewable energy targets can incentivize commitment, we show that targets only do so under certain conditions. Habermacher and Lehmann (2017) analyze more generally how uncertainty about environmental benefits leads to changing optimal support levels over time, but do not focus on the classical commitment problem where the optimal regulatory support differs over time even in the absence of new information.

Our analysis can explain why some countries deviate from their announced renewable energy support policies while others do not. For example, Spain, then a global frontrunner in renewable energies, cut its renewable energy support over the 2010 to 2013 period, while Germany, another frontrunner, did not.

The chapter is structured as follows: Section 3.2 describes the dynamic regulatory game. Section 3.3 characterizes optimal regulatory and firm behavior. We discuss the effects of various renewable energy policies and targets in section 3.4. Next, in section 3.5, we proceed to apply the model to the situations facing Spain and Germany around 2012 to derive reasons for their differing behavior. The chapter ends with a conclusion.

3.2 Setup of the regulation game

Regulatory support for renewable energies can be modeled as a game where the regulator announces and sets support levels, while firms form expectations about the anticipated support levels and choose to invest or not. A dynamic regulatory game is a useful model of renewable energies support policies for the following reasons: First, investments into renewable energies are capital intensive up-front, which implies that expectations about lifetime earnings formed at the investment stage define capital costs and, thus, the required support level (see, among others, Couture et al., 2010, Haas et al., 2011, May, 2017). Due to the dependence of investments on support policies, investors emphasize the importance of stable regulation without unexpected changes (Lüthi and Wüstenhagen, 2012). Only a small fraction of the costs is incurred after the investment stage, such that installations will operate (almost) independent of actual revenues. This matters because, secondly, renewable support is typically paid out throughout the lifetime of the assets as support per output to incentivize efficient project planning and management. Consequently, over the lifetime of the assets, there is ample time for regulators to behave strategically and to deviate of their initial support commitments because the assets will continue generating power regardless.

The government acts as Nash leader, such that it announces a renewable energy regime and support level that a representative firm, as Nash follower, can observe and take into account for its investment decision. The firms invest into renewable energy depending on the remuneration they expect.

The game modifies the more general setup introduced by Chiappinelli and Neuhoff (2017) to take into account dynamic aspects of the interaction between the government and the firms, depicting the renewable energy setting in more detail. Figure 3-1 visualizes the general setup. First, the government announces its support for renewable energy. The remuneration is financed as a levy on the electricity price, to be paid by all electricity consumers, thus decreasing the demand for electricity, as is implemented in most European countries (Eclareon, 2017). Second, the firms choose to invest into renewable energy capacity, generating renewable energy. Third, the government observes the firms' investment decisions and sets the actual remuneration level. This mirrors that regulators can, if the policy design allows them to, alter the support level after project completion, effectively changing the remuneration over the entire lifetime of the project.

To reflect that renewable energy support is almost universally paid out per unit of output, rather than installed capacity, the model is dynamic and actions directly affect future periods. Support promised in period t lasts into the next period $t+1$ and investments undertaken in t still reduce emissions in $t+1$, after which they are assumed to cease operating.

We adopt a linear direct demand function Q_t where electricity prices increase with

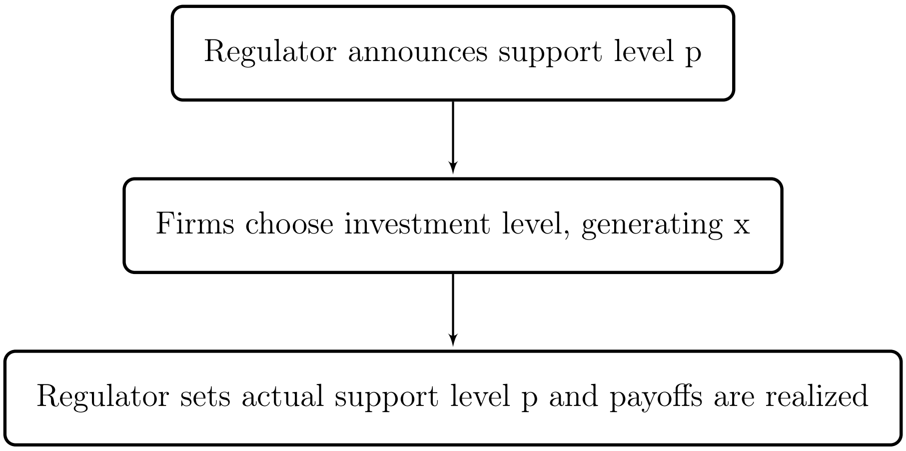

Figure 3-1: Timing of the period game, which is repeated indefinitely

renewable energy support: Without support, demand is equal to a and decreases by b for every Euro of support per megawatt-hour (MWh). Support for renewable energies p is promised for two periods,[1] such that both the past period's promised support p_{t-1} and the present support p_t influence demand in the present.

$$Q_t = a - bp_{t-1} - bp_t \tag{3.1}$$

In every period, the government optimizes welfare W_t by setting the renewable energy levy p_t. The regulator represents the interests of electricity customers and, thus, cares about consumer surplus, comparable to the model setup in Salant and Woroch (1992), but also cares about environmental pollution, as in Chiappinelli and Neuhoff (2017). As shown in equation (3.2), per-period welfare depends on the consumer surplus from the consumption of electricity (first term) and the environmental damage caused by the production of non-renewable electricity (second term).[2] Damage depends on emissions from covering the demand and are reduced by generation from renewable energies. These renewable energies are the sum of generation across

[1] While this can easily be increased to longer support horizons, it does not alter the nature of the results; such that we stick to two periods for notional simplicity.

[2] We are interpreting the alternative to investments into renewable energy as running existing thermal plants, e.g. coal and gas power plants. The avoided costs of running these, the so-called merit-order effects (Ketterer, 2014), implicitly dampen the costs for renewable energy support. In the numerical application in section 3.5, we subtract these costs from the renewables' support costs.

all firms j, $\sum_{j=1}^{J} x_{j_t}$ and $\sum_{j=1}^{J} x_{j_{t-1}}$,[3] again reflecting that previous investments impact later periods. The sum is multiplied with a pollution parameter e, indicating how polluting the non-renewable power supply is.[4]

$$W_t = \int_{p_t}^{p'_t} Q(z)dz - e(Q_t - \sum_{j=1}^{J} x_{j_t} - \sum_{j=1}^{J} x_{j_{t-1}}) \tag{3.2}$$

The maximum total support, at which electricity demand drops to zero, is given by $\frac{a}{b}$. Consequently, the maximum level for p_t is $p'_t = \frac{a}{b} - p_{t-1}$.

In the long-run, welfare is the sum of future welfare, discounted by the discount factor $\delta \in [0, 1]$.

$$W = \sum_{s=t}^{\infty} \delta^{s-t} \Big[\int_{p_s}^{p'_s} Q(z)dz - e(Q_s - \sum_{j=1}^{J} x_{j_s} - \sum_{j=1}^{J} x_{j_{s-1}}) \Big] \tag{3.3}$$

The firms are identical competitive price-takers, representing the investment behavior of renewable energy investors and covering all demand. Every individual firm's renewable generation x_{i_t} is very small compared to the sum of all firms' generation $\sum_{j=1}^{J} x_{j_t}$. For simplicity, the convex cost function $c(x_{i_t})$ is assumed to be quadratic in investments, depending on some factor $\alpha > 0$, as shown in equation (3.4). Costs occur up-front and increase with deployment because project developers might only have capacities to implement a limited number of projects at a time and because suitable sites are scarce. Marginal operational costs are zero.

$$c(x_{i_t}) = \frac{\alpha}{2} x_{i_t}^2 \tag{3.4}$$

Each firm's short-run profits π_{i_t} are influenced by the firm's present and past renewable energy investments x_{i_t} and $x_{i_{t-1}}$ and the support per unit of output. The overall support payments divided by the overall new generation from renewables, $\frac{p_t Q_t}{\sum_{j=1}^{J} x_{j_t}}$,

[3]Precisely, x stands for renewable energy generation, so when discussing "investments", we refer to "the investments necessary to generate x".

[4]Not all non-renewable electricity is equal. With increasing renewable energy shares, thermal power plants with higher marginal costs, e.g. gas power plants in most of Europe, might be replaced first, while other plants are replaced later. We abstract from this differentiation and assume one single pollution parameter.

represent the support per unit of output. Stated differently, the ratio $\frac{x_{i_t}}{\sum_{j=1}^{J} x_{j_t}} p_t Q_t$ indicates how much of the overall support for renewable energies for new generation in period t, $p_t Q_t$, is generated by firm i.[5]

$$\pi_{i_t} = \frac{x_{i_t}}{\sum_{j=1}^{J} x_{j_t}} p_t Q_t + \frac{x_{i_t - 1}}{\sum_{j=1}^{J} x_{j_{t-1}}} p_{t-1} Q_t - c_t \tag{3.5}$$

In the long-run, firms' profits are the sum of all future profits, discounted by the discount factor δ.

$$\pi_i = \sum_{s=t}^{\infty} \delta^{s-t} \left[\frac{x_{i_s}}{\sum_{j=1}^{J} x_{j_s}} p_s Q_s + \frac{x_{i_s - 1}}{\sum_{j=1}^{J} x_{j_{s-1}}} p_{s-1} Q_s - c_{i_s} \right] \tag{3.6}$$

3.3 Regulatory optima

The government maximizes welfare by setting the support level, while the firms maximize profits by choosing investment levels. In the commitment benchmark, the government has to set exactly the level it has previously announced, whereas in the absence of commitment, it has the ability to deviate. In the absence of renewable energy investments, electricity demand is covered by conventional technologies, leading to proportional environmental damage.[6]

3.3.1 Commitment benchmark

When the government can commit to a particular support level p_t, it can take the firms' reaction function $\sum_{j=1}^{J} x_{j_t}(p_t)$ into account for its optimization of welfare W. Accordingly, we solve the game by backward induction, starting with the firms' reaction function. When optimizing, any firm's production is very small compared to

[5]To ensure that levy payments by electricity consumers and pay-offs for renewable energy output match exactly, independent of demand fluctuations, balancing accounts facilitate this inter-temporal exchange, cp. for example the German "renewable energy accounts" (Bundestag, 2016). For simplicity and as the management of these balancing accounts is not our focus, we abstract from them and assume that levy payments and payouts match exactly in every period.

[6]We assume that in the absence of any renewable investments, the government will always set a support level of zero, i.e. curbing demand is not an end in itself. Appendix 3.7.1 spells out this condition.

overall production such that it takes the sum of production as constant. This implies that any one firm's action does not alter the support per output, whereas all firms' collective investments may well change the support per output.

Deriving any firm's profit function yields that its marginal costs, αx_{i_t}, must in the optimum equal its marginal revenues, $\frac{p_t(Q_t+\delta Q_{t+1})}{\sum_{j=1}^{J} x_{j_t}}$, which are composed of the revenues in in the investment period and in the discounted subsequent period. The optimal investments are thus:

$$x_{i_t}^* = \frac{p_t(Q_t + \delta Q_{t+1})}{\alpha \sum_{j=1}^{J} x_{j_t}} \tag{3.7}$$

Therefore, the sum of renewable energy generation from new investments is:

$$\sum_{j=1}^{J} x_{j_t}^* = \frac{p_t(Q_t + \delta Q_{t+1})}{\alpha} \tag{3.8}$$

Consequently, the regulator takes the firms' investment decisions into account when setting the optimal support level p_s which maximizes welfare:

$$W = \sum_{s=t}^{\infty} \delta^{s-t} \left[\int_{p_s}^{p_s'} Q(z)dz - e(Q_s - \frac{p_s(Q_s + \delta Q_{s+1})}{\alpha} - \frac{p_{s-1}(Q_{s-1} + \delta Q_s)}{\alpha}) \right] \tag{3.9}$$

In the optimum, the regulator sets the support level in every period such that on the margin, the additional costs of an increase in the levy in terms of reduced consumer surplus equal the environmental benefits of the increase of the levy. The regulator is able do this under commitment as it knows the firms' reaction functions and possesses perfect foresight. Consequently, in this simple setup without new information during the game, the regulator will optimally set the same levy in every period, $p_{t-1} = p_t = p_{t+1}$. Any deviation would decrease welfare. When increasing the levy from this optimal levy, the costs of a higher levy would not be worth the resulting environmental benefits. When decreasing the levy, welfare would be lower due to the forsaken environmental benefits.[7] Imposing the steady state yields:

[7]In our setup, a potentially optimal alternative to the steady state exists: Consumer surplus is

$$p^* = \frac{a\alpha - bec - ae - ae\delta}{b(2c + 2c\delta - 3e - 8e\delta - 4e\delta^2)}(1+\delta) \tag{3.10}$$

Overall, investments are:

$$\sum_{j=1}^{J} x_j^* = \frac{p^*a - 2bp^*}{\alpha}(1+\delta) \tag{3.11}$$

Every firm invests:

$$x_i^* = \frac{p^*a - 2bp^*}{\alpha \sum_{j=1}^{J}}(1+\delta) \tag{3.12}$$

3.3.2 Dynamic optimization: no commitment case

Without commitment, the regulator deviates from the announced support level if that is optimal. Whether or not it is optimal depends on the strategies the players are following: Under open loop strategies, they only consider the current period's pay-offs, while under trigger strategies, past actions impact future actions. We explore how far the commitment outcome can be attained under these strategies and what factors attainment relies on.

Open loop strategies

When the government cannot commit, it can observe the firms' investment decisions and choose to set the remuneration level to the level that optimizes welfare, independent of its initial announcement. The government optimizes, taking the renewable energy output as exogenously given.

decreased by the sum of the levy of the current and the previous period. Thus, the levy does not actually have to be equal in every individual period in order to set the marginal costs of an increase of the levy equal to the marginal benefits of an increase of the levy; it suffices that the total per-period payments are the same. The regulator could constantly switch between a high levy in one period and a low levy in the next period, such that the total per-period levy payments are the same in all periods. However, this decreases welfare due to the convexity of costs in combination with linear demand and linear environmental damages. Besides, this seems unrealistic, as real-options theory indicates that potential investors would delay their investments until levies are high, see e.g. Ritzenhofen and Spinler (2016).

$$\frac{\partial W}{\partial p_t} = \sum_{s=t}^{\infty} \delta^{s-t} \left[\frac{\partial}{\partial p_t} \int_{p_s}^{p'_s} Q(z)dz - e\frac{\partial Q_s}{\partial p_t} \right] \tag{3.13}$$

Any positive remuneration level curbs demand, which reduces consumer surplus. The only benefits are the avoided emissions due to the lower demand. However, we assumed that the regulator will not set a levy only in order to curb demand, see appendix 3.7.1. Thus, the government sets the support level to zero. The firms anticipate this and optimally choose not to invest – a classical expropriation argument (see e.g. Williamson (1975)).

Grim trigger strategies

With trigger strategies, players are able to observe the others' past behavior and react. A grim trigger means that once the payers deviate, they are punished forever. In our setup, only the regulator can deviate owing to the timing of output-based support payments. The firms can punish by not making further investments after the regulator has deviated from its previously-announced support. In order to sustain a subgame perfect Nash equilibrium, a deviation may not be profitable for the regulator at any time. For a detailed formal definition of such trigger strategies, see Chiappinelli and Neuhoff (2017).

The regulator evaluates the overall benefits of deviating against the threat of no new investments in the future. To this end, the government compares the welfare of compliance W^c to the welfare if it deviates W^d.

$$W^c \geq W^d \tag{3.14}$$

$$\sum_{s=t}^{\infty} \delta^{s-t} W(p_s = p^*, x_{i_s} = x_i^*) \geq \sum_{s=t}^{\infty} \delta^{s-t} W(p_s = 0, x_{i_{s=t}} = x_i^*, x_{i_{s \neq t}} = 0) \tag{3.15}$$

Transforming yields as compliance condition:

$$\sum_{s=t}^{\infty} \delta^{s-t} 2bep^* + \sum_{s=t+1}^{\infty} \delta^{s-t} \frac{2e}{\alpha}(1+\delta)p^*Q \geq \sum_{s=t}^{\infty} \delta^{s-t}(ap^* - bp^{*^2}) \tag{3.16}$$

The left hand side of equation (3.16) represents the total discounted environmental benefits that occur under compliance. Demand is reduced when the support level is positive, which occurs in every period with some environmental benefits captured by $2bep^*$. In contrast, only future investments are decision-relevant because the investments in period t have been made regardless. Thus, the environmental benefits from renewable energies $\frac{2e}{\alpha}(1+\delta)p^*Q$ only accrue from period $t+1$ onward. Naturally, past investments' environmental benefits also do not play a role.

The right hand side shows the benefits of deviating: consumer surplus is increased since no more support is paid. Importantly, this already begins in period t, even though new investments have potentially still been triggered in period t, to which the regulator is not paying the promised support. Equivalently, the regulator also does not pay any longer for generation from investments made in period $t-1$, which are also still eligible to support in period t.

3.4 The role of policies and targets

We analyze the effects that different support policies and explicit renewable energy deployment targets have on compliance, costs, and renewable energy investments.

3.4.1 Time-inconsistency under different policy regimes

Policy regimes can support commitment equilibrium outcomes even though no governmental action is able to rule out deviations altogether. Yet, some policy frameworks allow for easier changes to announced support than others. An example that is easily integrated into the model are prohibitively high costs in case of "full" deviations: Beyond some threshold, e.g. a deviation on more than a certain share $(1-\gamma)$ with

$\gamma \in [0,1]$ of commitments, firms in other sectors will also fear deviations by the regulator, which outweighs the gains from full deviations. Depending on the policy regime, this threshold can differ. The fear of contamination of other sectors' investments might be larger when the initial promise of the government is stronger, as the necessary political and legal barriers are harder to overcome. If the government is willing to get over large barriers to deviate from its renewable energy commitments, it might appear more likely to do so in other sectors as well. In contrast, when support levels are not clearly defined, deviations are harder to detect and understand, and deviations might be less likely to spread to other sectors.

The model is easily extended to incorporate limited deviations. Since the pay-offs under compliance remain unaltered, the optimal support level p^* and the optimal investment level x_i^* remain the same. However, the left hand side of the compliance inequality (3.16) – the environmental benefits of compliance – decrease. Whereas the second term on the left hand side of equation (3.17), the environmental benefits of new investments, does not change, the environmental benefits from a decrease in demand actually decrease with limited deviations compared to full deviations, as shown in equation (3.17). The simple reason is that in the first two periods after the deviation, the levy for commitments made until the time of deviation remains at γp^* rather than falling to zero. As of the second period after deviation, the levy is zero once again and the benefits accrue just as with full deviations. Appendix 3.7.2 details the calculations.

Similarly, the benefits of deviating in terms of reduced levy payments decrease compared to full deviations. As of the second period after a deviation, the pay-offs are the same as under full deviations. After deviating, some levy γp^* remains, rendering deviations less attractive.

In total, compliance becomes more attractive when deviations are limited than when regulators can fully deviate. Demand is depressed after the deviation, leading to some environmental benefits on its own, but larger negative impacts on consumer surplus (which holds independently of the levy p and the remaining share γ by our assumption of negative impacts on welfare in the absence of investments; see appendix

3.7.1). The value of the left hand side decreases less than the value of the right hand side between equations (3.16) and (3.17).

$$
\begin{aligned}
&eb\gamma p^*(2+\delta) + \sum_{s=t+2}^{\infty} \delta^{s-t} 2bep^* + \sum_{s=t+1}^{\infty} \delta^{s-t} \frac{2e}{\alpha}(1+\delta)p^*Q \geq \\
&\gamma(1+\delta)ap^* - \gamma^2(1+\frac{\delta}{2}b){p^*}^2 + \sum_{s=t+2}^{\infty} \delta^{s-t}(ap^* - b{p^*}^2)
\end{aligned}
\tag{3.17}
$$

We differentiate between three policy frameworks: Those where deviations are difficult for governments to implement as they must also change the constitution, frameworks where a – simpler – change of law suffices, and, lastly, such frameworks where only some rules need to be adjusted in order to deviate.

First, there are policy frameworks where the renewable energy policy itself stresses that it represents a remuneration stream that will not and cannot be altered over time and where, additionally, the constitution provides investment security through strong grandfathering rules. In order to change the constitution, which explicitly protects existing assets from legal changes, usually a qualified majority is required in parliament, posing a high threshold for retrospective changes of the renewable energy policy (Jakob and Brunner, 2014). This can be the case both for feed-in tariffs and feed-in premia. However, under feed-in premia, balancing costs remain with the investors, rendering the rules around balancing cost assignment prone to time-inconsistency issues (Neuhoff et al., 2016). Thus, with constitutional rights and respective policies, no full deviations are possible and γ in equation (3.17) is increased, rendering compliance more attractive.

Second, policy frameworks provide investors with an investment environment where regulators legally guarantee some support, but this support is not backed by constitutional grandfathering rights. Regulators can explicitly guarantee a specific remuneration level or a sense can prevail that overall profitability of projects is guaranteed, but not specific support levels. Without constitutional grandfathering rights and specified support levels, γ in equation (3.17) is lower than under the first set of policies.

Based on such arguments, Spanish investors who had invested before 2010 lost their case against the Spanish government that had retrospectively cut their support payments. The Spanish supreme court judges argued that the investors were entitled to profitability of their investments, but not necessarily the exact level they had initially been promised. In particular, they stated that the adjustments were in line with "legitimate expectations" (El País, 2014). This has since been explicitly codified in the Spanish remuneration scheme and investors are guaranteed a certain markup over the returns of governmental long-term bonds (Spanish Ministry of Industry and Energy and Tourism, 2014). As early as between 2004 and 2007, the policy regime explicitly adjusted support levels based on the wholesale electricity price (Spanish Ministry of Economic Affairs, 2004), indicating a more subtle promise of support stability in comparison to explicit long-term stability of specific support levels.

Third, policy regimes like tradable green certificates promise remuneration streams that can be adjusted over time without retrospective legal changes. Under green certificate schemes, the number of certificates in the system defines the value of these certificates and, thus, the remuneration levels that renewable energies receive. Regulators can devalue certificates by flooding the market, e.g. by providing new certificates to foster new technologies. Alternatively, the regulator can decrease the demand for certificates by lowering (or not increasing) the number of certificates that power suppliers need to obtain, as was the case in Poland between 2010 and 2012 (Skarżyński, 2016) and in Romania in 2017 (Business Review, 2016). In any of these cases, the anticipated remuneration level is lowered during the lifetime of projects without the need for explicit retrospective legal changes. Therefore, γ in equation (3.17) is even lower compared to the other discussed policies.

These three policy frameworks hold implications for the overall costs of renewable energy deployment. When firms have imperfect foresight, the investment costs α increase when retrospective changes are easier to implement. In turn, this renders retrospective changes more likely, which increases the investment costs even further, creating a vicious cycle. This implies that *ceteris paribus* policies leaving more space for regulators to deviate lead to higher costs of deployment.[8]

3.4.2 Targets as commitment devices

National targets monitored or enforced by a supranational entity or the public can impact governmental behavior and can act as commitment devices. They do not directly affect the possibility of deviations, but they increase the costs at stake when considering deviations. Targets from a supranational level cannot usually be changed through changes of law at the national level. As Jakob and Brunner (2014) outline, such costs can be in terms of reputation, described by Barro and Gordon (1983), or financially.

The commitment benchmark changes. The firms' profit functions are not touched in the first stage and the reaction functions remain the same as before. Welfare under commitment is altered, incorporating the potential fine from deviation if the target expansion $\bar{x}$ is not reached. The fine f is multiplied with the deviation from the investment trajectory target, $\bar{x}$.

$$W_t = \int_{p_t}^{p_t'} Q(z)dz - e(Q_t - \sum_{j=1}^{J} x_{j_t}(p) - \sum_{j=1}^{J} x_{j_{t-1}}(p)) - f[\bar{x} - \sum_{j=1}^{J} x_{j_t}(p) - \sum_{j=1}^{J} x_{j_{t-1}}(p)] \tag{3.18}$$

with $f = 0$ if $\sum_{j=1}^{J} x_{j_t}(p) + \sum_{j=1}^{J} x_{j_{t-1}}(p) \geq \bar{x}$. As long as the renewable energy target is not reached, the fine f works similarly to the increased environmental benefits of renewable energies, with the only exception that reducing demand does not inherently decrease potential fines.[9] Solving for the optimal levy in the steady state yields as optimal levy:

$$p^*_{target} = \frac{a\alpha - bec - a(e+f)(1+\delta)}{b[2c(1+\delta) - (e+f)(3+8\delta+4\delta^2)]}(1+\delta) \tag{3.19}$$

[8] Citizen ownership is another means to alleviate time-inconsistency issues. When the regulator represents the interests of electricity consumers and those consumers also constitute electricity producers, the regulator also weighs producer surplus, reducing time-inconsistency issues.

[9] When targets are set relative to demand, then the additional effect occurs that reducing demand lowers the renewable energy target, which is not captured by our model.

Therefore, the levy under commitment is larger if the renewable energy target is not already reached without target. Similarly, based on the same reaction function as before, the investment level under commitment increases. If the renewable target is not yet reached without target, but the optimal levy and investment levels with target yield an expansion beyond the renewable target, then the corner solution $\sum_{j=1}^{J} x_{j_t}(p) + \sum_{j=1}^{J} x_{j_{t-1}}(p) = \bar{x}$ maximizes welfare.

As a result, potential costs of not-achievement are added to the left hand side of equation (3.16) if the expansion target $\bar{x}$ is not reached. Inequality (3.20) provides the compliance condition. The second term on the left hand side, the environmental benefits of renewable energy investments, is increased by the potential benefits of avoided fines.

$$\sum_{s=t}^{\infty} \delta^{s-t} 2be + \sum_{s=t+1}^{\infty} \delta^{s-t} \frac{2(e+f)}{\alpha}(1+\delta)Q \geq \sum_{s=t}^{\infty} \delta^{s-t}(ap^{*}_{target} - bp^{*^2}_{target}) \quad (3.20)$$

Therefore, with target, compliance becomes more likely than without targets due to the increased benefits of renewable energies if the target is high enough. With a low target that is over-achieved in any case, the target does not increase the levy, the investment level, or the attractiveness of compliance.

The European Union's renewable energy deployment targets for 2020 are potentially relevant for national decision-making. In 2009, the European Union introduced the Renewable Directive. It included binding targets for the share of energy stemming from renewable energies both at the European level and at the individual country level. It specifies the share out of total energy use, incorporating the transport, heating, cooling and the electricity sectors.

The European targets are binding at the national level. These are based on each country's initial share of renewable energy in 2005 and their wealth, requiring stronger actions from wealthier member states. In 2005, Malta was the country with the lowest share of renewable energy, 0.2 percent, which it has to increase to ten percent by 2020, whereas the country with the second-lowest share, the UK at 1.4

percent, must increase its share to 15 percent. On the other hand, Sweden with the highest initial share of 40.6 percent, has to increase it to 49 percent and Latvia with the second-highest share of 32.3 percent needs to reach 40 percent. Between 2009 and 2020, there are additional non-binding targets, indicating whether countries are on track to reaching their 2020 targets.

These national targets influence the regulatory incentives for compliance as they might be fined by the European Commission. Alternatively, countries missing their targets can directly pay other EU countries that over-achieve their targets for statistical transfers of renewable energies, of which the first deals were closed in 2017, technically transferring renewable energy production from Lithuania and Estonia to Luxembourg (European Commission, 2017a,b). Equivalently, this implies a direct financial cost for countries that do not achieve their targets through their own renewable energy generation.

The 2020 targets only function as commitment devices when countries do not possess sufficient alternatives. The sustainability of biomass matters less in some countries (Ratarova et al., 2012). Using biomass seems to have been cheaper than wind and solar power in many Eastern European countries. Consequently, on the one hand, the European targets made biomass investments more attractive. On the other hand, they did not render compliance more likely for wind and solar power in these countries, as they can reach their targets more or less regardless of wind and solar power deployment.

Figure 3-2 shows the growth in renewable energy generation since the baseline year of 2005 in Bulgaria.[10] Starting at an initial share of 9.4 percent of renewable energies, it stood at 18.2 percent in 2015, an increase of 8.8 percentage points. The share of biomass has grown significantly and together with a small uptake in hydro power generation almost suffices to fulfill the Bulgarian 2020 target of 16 percent (an increase of 6.6 percentage points since 2005).[11] Thus, targets do not function as

[10] Assuming that the growth in renewable energies for heating and cooling came from biomass.

[11] Still, some wind and solar power have been installed. However, as no sustained growth in their capacities is required to reach the 2020 target, compliance is not attractive to the Bulgarian government. In 2013, it retrospectively introduced a 20 percent revenue tax for wind and solar

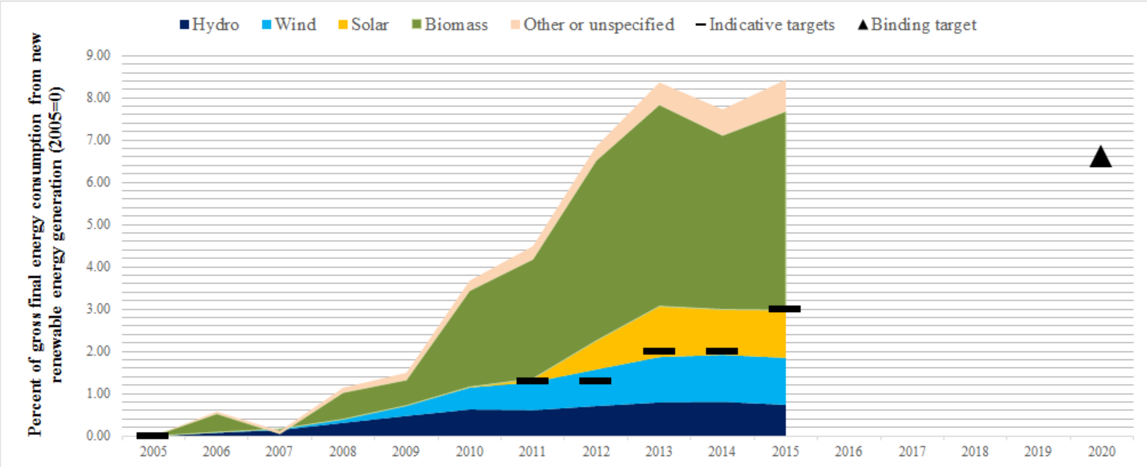

Figure 3-2: New generation from renewable energies since 2005 in Bulgaria, based on Eurostat (2017b)

commitment devices when alternative, preferred technologies exist or if targets are reached ahead of time.

In most Western European countries, electricity from wind and solar power are the main viable renewable energy technologies to reach the 2020 targets.[12] Figure 3-3 depicts the increase in renewable energy in Germany since 2005.[13] Even though biomass and other renewable energies, particularly energy from municipal waste, also play a role, new wind and solar power is considerably more prominent than it is in Bulgaria.

Figure 3-4 shows the growth in generation from renewable energies in Spain since 2005. Starting at 8.4 percent in 2005, the country initially strongly increased its renewable energy share. However, after retrospective cuts between 2010 and 2013 and the passing of a moratorium for new installations, the renewable energy share stagnated, such that the 20 percent target for 2020 is more difficult to achieve.

power, yet not for biomass installations (Fouquet and Nysten, 2015). In parallel, it announced a moratorium for all new wind and solar power installations. The national constitutional court has since ruled that the retrospective revenue tax was unconstitutional (Fouquet and Nysten, 2015).

[12]Finland and Sweden represent interesting exceptions as they have strongly increased their shares of biomass fuels in the transport sector.

[13]Approximating the generation and installation data from BSW-Solar (2016), we assume that two-thirds of the solar thermal production of 2015 was installed after 2005, in roughly equal annual amounts. The remainder of renewable energy growth in the heating and cooling sector is assumed to come from biomass.

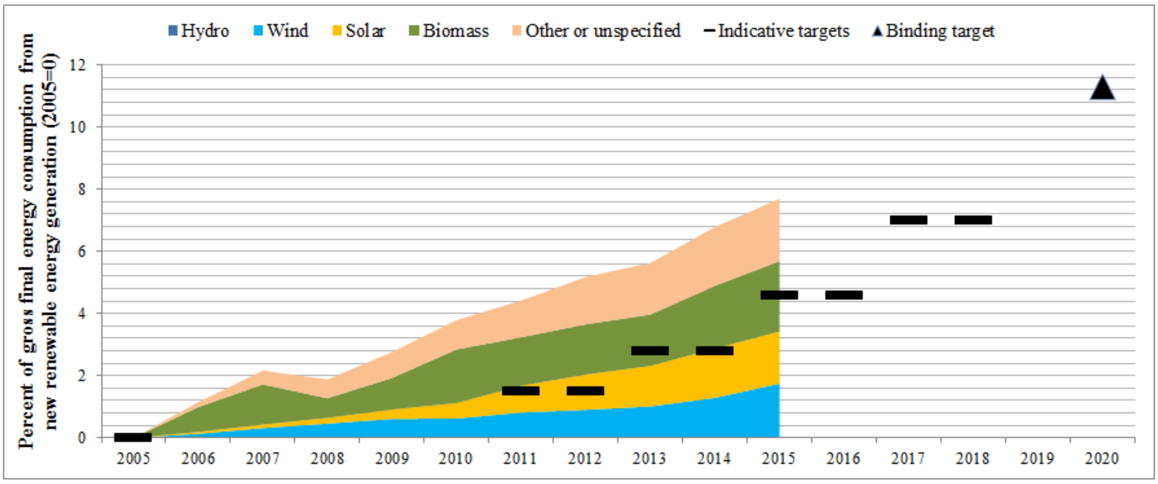

Figure 3-3: New generation from renewable energies since 2005 in Germany, based on Eurostat (2017b)

Countries that can only reach their targets through long-term favorable investment environments for specific technologies are more likely to stay committed to these technologies. If they have viable alternative technologies or reach their targets ahead of time, the potential fines f in equation (3.4.2) diminish. Thus, commitments are more credible in countries that are endowed with the potential for few alternative technologies and that lag behind enforceable, supranational targets.

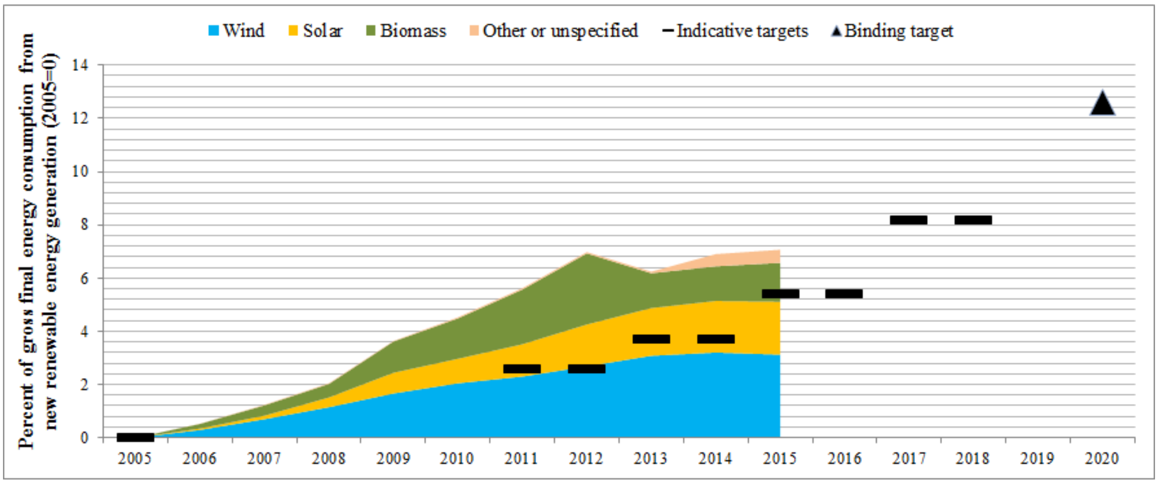

Figure 3-4: New generation from renewable energies since 2005 in Spain, based on Eurostat (2017b)

3.5 Why did Spain deviate when Germany did not?

We evaluate the time-inconsistency model for 2012 by numerically modeling the examples of Spain and Germany as these countries were frontrunners in renewable energy, but only Spain deviated. Germany in 2012 was the global number three in terms of installed wind power capacity and number one for solar, Spain was number four for wind power and number five for solar power (IRENA, 2017a). With its renewable energy payments at about €34 per MWh in 2012 (Comisión Nacional de Energia, 2012), Spain conducted retrospective changes between 2010 and 2013. Germany did not, even though it had also experienced unprecedented growth in PV installations, increasing the levy three-fold from €11.3 per MWh in 2009 to €36.9 per MWh in 2012 (and subsequently to €52.7 per MWh in 2013) (Bundesnetzagentur, 2017). Why did and could Spain take these measures, whereas Germany did not?

As this analysis focuses on time-inconsistency, all past investments into renewable energies are taken for granted and not accounted for in terms of environmental benefits because they accrue in any case. This is also where potential time-inconsistency arises from: As the investments before 2012 have already been made, only their disadvantages, namely their costs, persist and matter for the decision-maker.

3.5.1 Parameters in 2012

In 2012, Spain had 22.8 GW of wind power and 6.6 GW of solar capacity, highlighting a focus on (then cheaper) wind power. Germany had 31.3 GW of wind power capacity, owing to rather constant growth in wind power capacities, and rather erratic growth in PV between 2009 and 2012, when 22 GW of the PV total of 32.8 GW were installed (IRENA, 2017a).

The policy framework sets the backdrop against which investors invest and specifies how easily retrospective changes can be conducted. After some policy changes in the 2000s, Spain had a feed-in tariff for wind power, photovoltaics and concentrated solar power. Between 2004 and 2007, installations were not granted specific remuneration levels, but multiples of the power price. This policy, based on a more general sense of profitability as laid out in section 3.4.1, allowed some deviations. Spain cut about 25 percent of its renewable energy payments from a total of €9.1 billion to €6.6 billion (Comisión Nacional de los Mercados y la Competencia, 2014, 2015). Since then, there have been conflicting court rulings. As detailed in section 3.4.1, the Spanish Supreme Court decided that Spanish investors were not eligible for compensation. International investors have been deploying the Energy Charter Treaty, which also led to different outcomes: On the one hand, one firm successfully argued that its revenues fell by two-thirds and it was awarded compensation from the Spanish government. On the other hand, a similar case of another firm that had invested somewhat later was dropped on the grounds that "no reasonable investor could have the expectation that this framework would not be modified in the future and would remain unchanged" (Stibbe, 2017). Therefore, we assume that the Spanish regulators were able to cut around twenty percent of support payments, setting $\gamma = 0.8$ in equation (3.17), slightly less than the actual 25 percent, which, at least in some cases, seems to have infringed on investors' legal rights.

Germany had a feed-in tariff that allowed firms the option to shift to a feed-in premium. As described in section 3.4.1, the focus of the legislation and the constitutional grandfathering rights was on providing stable support. This enables only small deviations. In order to compare factors other than the policy regime differences between Spain and Germany, we set $\gamma = 0.8$ for Germany as well, noting that this is an upper bound of the attractiveness of deviating.

The regulator compares the current and future benefits and costs of compliance and deviation based on equation (3.17). The payouts are calculated for all future periods until 2050, summing up the discounted welfare of the individual years.

Costs of renewable energy

We need to know how renewable energy generation x, costs c, power demand Q, and the renewable energy support p develop in the future under compliance. We use a detailed model created by Öko-Institut (2017) that provides estimates for the German renewable energy levy, which uses installation trajectories, power demand, and costs as inputs. In order to calculate the levy under compliance for Spain, we calculate how large the levy would have been without deviation and add approximated extra costs of new renewables installed after 2012 under compliance. Details of the calculations can be found in appendix 3.7.3.

Discount factor

The discount factor δ determines the relative weight of current and future periods and affects time-(in)consistent behavior to a large extent. Spain was at the height of the financial crisis in 2012. The government passed austerity measures in many sectors of the economy. Whereas the government previously filled the utility companies' tariff deficit, it was severely constrained to do so. We use the average Spanish ten-year governmental bond rate, a standard indicator of the regulatory discount rate of 2012, which was 5.9 percent (Eurostat, 2017a). In Germany, this rate was considerably lower at 1.5 percent (Eurostat, 2017a).

Demand

In line with the model setup, we assume that demand Q is linear. We need to assume values for a and b. For both countries, we assume a demand slope of $b = 30$ MWh^2/€. This is based on long-run inelastic demand elasticities of .16 in Germany and .3 in Spain, obtained from Madlener et al. (2011). For example, for Germany in 2012, this yields that a levy of €36 per MWh and at an exemplary household electricity price without levy of €230 per MWh reduces demand by about 2.5 percent. Based on this, we can calculate the increase in demand after a deviation, i.e. with a lowered levy. We use the same demand slope for Spain as for Germany because Spanish demand is lower, but the demand elasticity is almost twice as high. For Spain, this implies that the Spanish levy of €34 per MWh decreases demand without levy by about 4.3 percent. Moreover, based on realized demand volumes and the demand elasticities, we derive a, the demand without any levy. For Germany, this demand in 2017 was about 361 TWh,[14] whereas it stood at 239 TWh in Spain. Details on the calculations can be found in appendix 3.7.4.

We treat the costs of renewable energies as levy in Spain as well, even though this is only partially correct: Utility companies bore the costs, but were only partially reimbursed through customers' electricity bills. They were stuck with a considerable chunk of the costs. This accumulated in a tariff deficit, which accumulated to €30 billion (Linden et al., 2014). These costs were eventually securitized and offered on the financial market. Ultimately, these costs are borne by electricity consumers (Reuters, 2010), such that the link between costs of new investments and levy is less direct than in Germany, but nevertheless exists.

Environmental benefits

The environmental benefits e from renewable energies (and to a much smaller extent from the reduction in demand) are the main factor driving and justifying renewable energy support. For both countries, we apply a shadow carbon price of €50 per ton of CO_2. This by far exceeds the observed emission prices of the European emission trading scheme, for which many authors argue that they insufficiently reflect the true costs of pollution, e.g. Grubb (2012) and Edenhofer et al. (2017).

The carbon price is then multiplied with the carbon intensity for each country. In Spain, the average carbon intensity in 2013 stood at 303 grams of carbon dioxide equivalents per MWh (Moro and Lonza, 2017), yielding $e = 15.15$ €/MWh, which we apply for every period after 2012. In Germany, the intensity was 567 grams per ton (Moro and Lonza, 2017), implying that the environmental benefits of reduced conventional generation of $e = 28.35$ €/MWh exceed Spain's.

Investment volumes after 2012

In Spain, we observe a stand-still following the deviation and the simultaneously-introduced moratorium. Thus, we do not know what installation volume a regulator

[14] In addition, there are around 150 TWh of industry demand and self-consumption of electricity that are mostly exempted from the renewable levy.

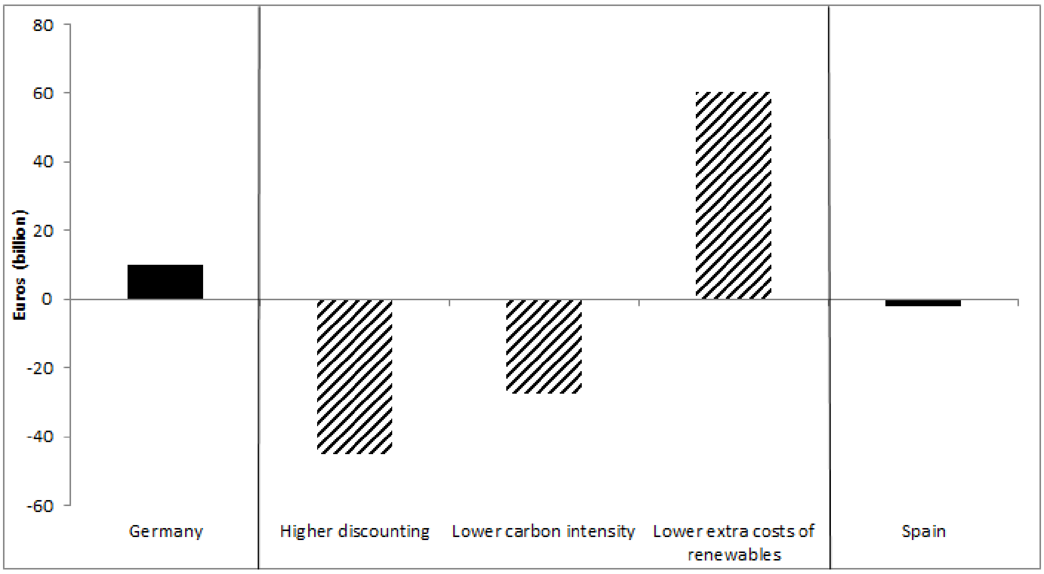

Figure 3-5: Drivers of the Spanish deviation. Positive values indicate that compliance is (rendered) more attractive, negative values that deviating is (rendered) more attractive.

would have assumed. We choose 1500 MW for wind power, 750 MW for photovoltaics, and no new concentrated solar power. For Germany, we use the realized installation volumes for 2013-2016, even though those, particularly the PV boom between 2010 and 2012, certainly were not exactly expected.

Targets

As detailed in section 3.4.2, Spain and Germany were on a rather similar track toward reaching their 2020 obligations in 2012. Spain's renewable energy share was 14.3 percent in 2012, well on its way toward its target of 20 percent by 2020 (Eurostat, 2018). Germany's share in 2012 was 12.1 percent, similarly far on its path to reaching 18 percent by 2020 (Eurostat, 2018).

3.5.2 Results

In Spain, deviation was more attractive than compliance by about €2 billion, whereas in Germany compliance was more attractive by about €10 billion. Figure 3-5 visualizes the effects of the main drivers: Spain's higher discounting of future periods,

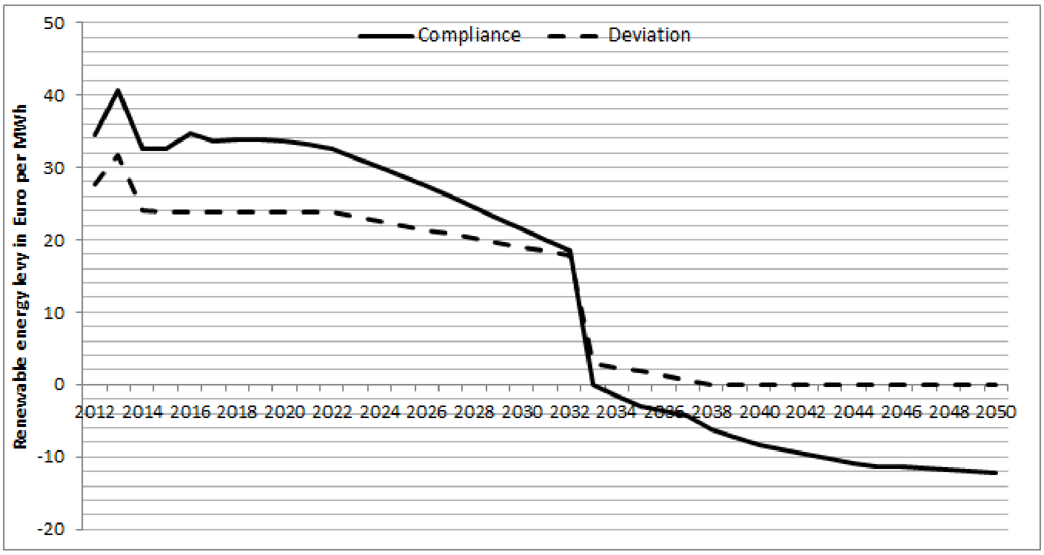

Figure 3-6: Spanish renewable energy levy, where compliance includes benefits of the merit-order effect of renewable energies installed after 2012

Germany's relatively dirty fleet of conventional power plants, and Spain's higher electricity prices implying lower extra costs for renewable energies.

The higher Spanish discount factor is able to explain a significant part of the difference between Germany and Spain. Had Germany conducted the same discounting as Spain, deviating would have been more attractive also there. The higher discount rate would have made deviating €45 billion more promising. The high Spanish discount factor, for example, implies that pay-offs in 2020 only count 60 percent of the pay-offs in 2012, whereas in Germany, 2020-payoffs still count 86 percent as much.

The dirty German thermal power plant fleet turns out as very relevant as well. Germany with the Spanish thermal power plant fleet would have had large incentives to deviate, as deviating would have been €27 billion more attractive than with the German power plant. This also implies that Spain would not have deviated, had it possessed the dirty German power plant fleet.

The extra costs of renewables are considerably lower in Spain, almost entirely driven by the higher wholesale electricity price. With the low Spanish extra costs of renewables, compliance pay-offs would have been around €60 billion higher in Germany. Figures 3-6 and 3-7 show the renewable energy levies in Spain and Germany under compliance and deviation, also taking into account the induced merit-order of

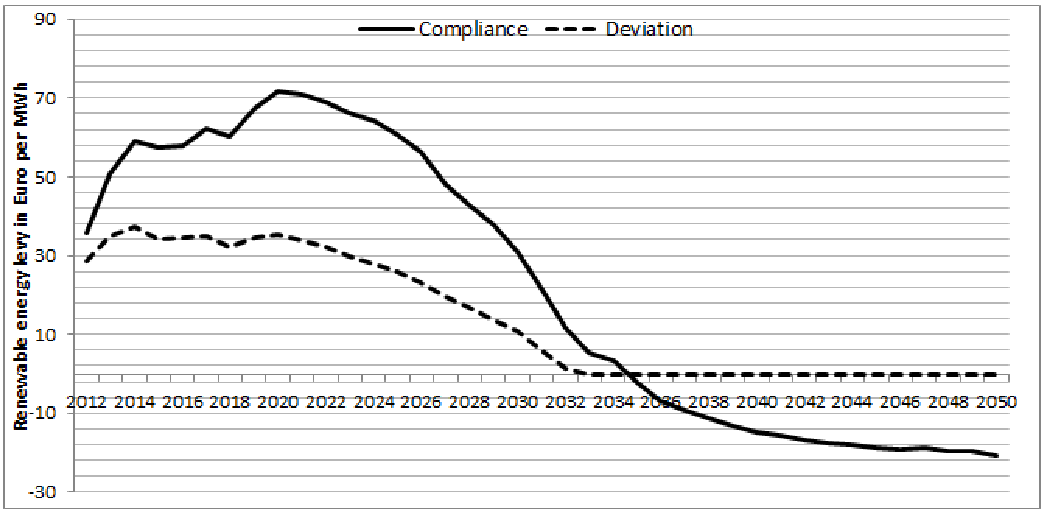

Figure 3-7: German renewable energy levy, where compliance includes benefits of the merit-order effect of renewable energies installed after 2012

new installations. In Spain, the levy after deviating is the actual Spanish levy, which we can observe between 2012 and 2017. The levy under compliance lies higher since on the one hand, costs have not been cut by 20 percent in 2012 and, on the other hand, because new installations after 2012 are supported. The levy does not increase anymore after 2013 even under compliance. The reason is the Spanish wholesale electricity price, which stood at €44 per MWh in 2012 and increased to about €51 per MWh in 2017 (OMIE, 2018), reducing support costs as the difference between power price level and support level decreases. In Germany, the opposite happened. Power prices declined strongly from €55 per MWh in 2012 to around €30 per MWh in 2017 and the levy for new investments, despite their relatively low costs, increases somewhat until the early 2020s and only falls thereafter. Therefore, the extra costs for renewable energies, i.e. the difference between the costs of new installations and the power price, is much smaller in Spain, rendering compliance more attractive there.

Due to the high Spanish price level and the falling costs of renewable energies, renewable energies become cost-competitive when considering their environmental benefits as early as 2020 for wind power and 2029 for solar power. The date for solar power is later since the costs consist of a combination of utility and small-scale installations, where utility-scale solar becomes cheaper than the power price beforehand already. In Germany, power prices are lower but environmental benefits are larger. Wind power is cost-competitive in 2020 and the mix of utility- and small-scale solar power in 2027.[15]

When adding a fine for breaching the countries' 2020 targets, both countries become more likely to comply, but the effect is considerably larger in Germany. Through Germany's low discount rate, the potential fines – only starting in 2020 – weigh 25 percent heavier than in Spain. While the pay-offs after 2020 represent almost three quarters of all pay-offs in Germany, they only represent 58 percent in Spain.

3.6 Conclusion

Time inconsistency can arise for renewable energy investments and deter investments. In light of large investment needs, it is crucial that policy-makers address time inconsistency issues through policy frameworks.

We develop a dynamic regulatory game where the regulator optimizes welfare by announcing and setting renewable energy support, while firms invest in renewable energies. While, with open loop strategies, the regulator always deviates, trigger strategies can induce compliance if environmental benefits of future investments outweigh the costs of old and new investments. Governmental behavior, thus, hinges on the environmental benefits of future investments. If the expected renewable energy output and its environmental pay-offs are sufficiently large and firms do not invest after regulatory deviations, governments do not deviate from their announced policies.

Some policies make it easier for the regulator to deviate, whereas others tie the hands of the regulator more tightly. Firstly, sliding premia and feed-in tariffs that stress specific support levels together with grandfathering rules guaranteed by the constitution leave the least space for regulatory deviations. Secondly, sliding premia and feed-in tariffs with a more vague expectation of general profitability based on certain power market characteristics, like the wholesale electricity price, give the

[15] Assuming that due to simultaneity of supply, renewable energies produce at only 80 percent of the wholesale power price.

regulator some flexibility with respect to remuneration levels. Through legal changes, remuneration levels can be adjusted to a certain extent. Thirdly, green certificate schemes provide regulators with the ability to adjust support levels *ex-post* more easily still. The rules of the system, like the number of certificates for new installations or the obligations for electricity retailers, can be adjusted relatively easily without explicitly interfering with firms' property rights.

Moreover, we show that national, binding deployment targets stemming from a supranational entity like the EU can make compliance more attractive for governments as their stakes are increased. However, we also demonstrate that this holds exclusively when only limited renewable resources are available to reach those targets as governments can otherwise simply shift the focus to other renewables.

In a numerical application, we identify the reasons why Spain conducted retrospective cuts to its renewable energy support, while Germany did not. The model suggests that on the one hand, the extra costs of renewable energies were actually considerably lower in Spain due to the higher wholesale electricity price, rendering compliance more attractive in Spain. However, on the other hand, this is outweighed by the dirtier German conventional power plants, which increase the environmental benefits of renewable energies in Germany. Most importantly, the larger myopia of the Spanish regulator, caused by high discounting during the financial crisis of future benefits of sustained renewable energy deployment, rendered deviating more attractive. These factors were combined with an enabling policy regime that left some space for retrospective changes.

Questions remain how to make compliance more attractive for regulators. One approach might be Contracts for Differences – existing in the UK – where firms have to pay back the regulator when power prices lie above support levels. If the general power price level increases while costs of renewables decrease, regulators have incentives to keep renewables inside support schemes and deviating becomes less attractive. Additionally, the effects of differing discount rates between the regulator and firms might extend the existing analysis and allow for interesting scenario analyses.

3.7 Appendix

3.7.1 Levy condition

We assume that in the absence of investments into renewable energies, the regulator optimally sets the levy to zero since any positive support level would decrease welfare. The rational is that such additional levies on the electricity price might well be in place, but they exist independently of the renewable energy levy. A simple example is an energy efficiency levy, which seeks to curb demand, that is implemented independently of the renewable energy levy. However, the renewable energy levy still also curbs demand, but the regulator will only set a positive level if the investments into renewable energies “are worth it”.

This assumption means that any increase in the levy p_t that is not accompanied by an increase in the investment level at some point has a negative impact on welfare. As this must hold in every individual period, it also holds in the (discounted) sum of period pay-offs. We assume the following holds in every period t:

$$\frac{\partial W_t}{\partial p_t}|(\frac{\partial x}{\partial p_t}=0)=\frac{\partial}{\partial p_t}\int_{p_t}^{p_t'}Q(z)dz-e\frac{\partial Q_s}{\partial p_t}<0 \tag{3.21}$$

It follows that without investments into renewables, curbing demand decreases consumer surplus more than it increases environmental benefits. Welfare from setting a zero levy $W_t(x=0,p_t=0)$ is larger than welfare with any positive levy $W_t(x=0,p_t\neq 0)$ when there are no investments into renewable energies.

$$\int_0^{p_t'}Q(z)dz-ea>\int_{p_t}^{p_t'}Q(z)dz-eQ_t \tag{3.22}$$

3.7.2 Limited deviations

With limited deviations, as of period $t+2$, the pay-offs are the same as under full deviations and only the pay-offs in t and $t+1$ are altered. The impact of renewable energy investments remains the same as before in any case as no new investments take place after a deviation.

As some share of the levy remains in place in period t and period $t+1$, the left hand side of equation (3.16) decreases because of the environmental benefits of reduced demand. In period t, these benefits are $2eb\gamma p^*$, i.e. per period the same as before but multiplied with γ and, thus, lower than under full deviations. In $t+1$, only the effect of p_t prevails, which is discounted and, therefore, accrues to $\delta\gamma bep^*$.

Analyzing the right hand side of equation (3.17), in period t, the regulator pays out γp_t for investments from period t and γp_{t-1} for investments from the previous period. Therefore, the benefits of deviating decrease as some costs remain. The negative effect on consumer surplus is $\gamma ap^* - \gamma^2 {p^*}^2$. In period $t+1$, γp_{t-1} continues to depress demand by $\gamma ap^* - \frac{1}{2}\gamma^2 {p^*}^2$. Demand reaches the same level as under full deviations as of period $t+2$.

3.7.3 Levy calculation

To calculate the levy under compliance for Germany, we adjust the model in several ways: First, we update the cost estimates for renewable energies in light of the country's most recent auction results. Generally, this implies lower costs than previously assumed. We assume wind onshore to cost €41 per MWh by 2025, PV on average between small-scale roof-top installations and ground-mounted installations €67 per MWh and offshore wind power €45 per MWh. Following Öko-Institut (2017), the new installations follow the national target corridors of 2500 MW of onshore wind power annually, 2500 MW photovoltaics, and a total of 14 GW of offshore wind power capacity between 2017 and 2030. We assume that after 2035 support is no longer required, simplifying the calculations and resembling the current cost trends. Knowing the support lifetimes of the new installations through 2035, we can derive the support levels until 2050.

For Spain, we combine data from multiple sources to derive the potential renewable energy levy until 2050: we assume a simplistic capacity expansion of 1500 MW of new wind power and of 750 MW of PV per year, roughly reflecting the higher national weight on wind power deployment and the lower overall installation volume than in Germany. The deployment costs are derived from differences in costs in 2012: New wind power installations were about four percent more expensive per kWh in Spain than in Germany, PV was 16 percent more expensive. Spanish wind and solar conditions are superior to Germany's, but the policy regime leaves more room for retrospective changes, thus increasing the costs of financing.

Renewable energy generation reduces the overall power price. We impute this implicit merit order effect, which dampens the renewable energy levy. Cludius et al. (2014) show that in 2015, Germany's 176 TWh of renewable energy generation dampened the power price by about €15. This effect varies with the generation mix and the flexibility of the system. For simplicity, we assume the merit order effect of €0.085 per TWh as constant.[16] We add this merit-order effect to the renewable energy levy in order to capture the entire electricity price effect of renewable energies.

3.7.4 Demand calculation

Following Öko-Institut (2017), German demand develops until 2021 according to the TSO's trend scenario (Energy Brainpool, 2014, Leipziger Institut für Energie, 2016, Prognos, 2014); i.e. the demand paying the renewable levy decreases slightly from 356 TWh in 2016 to 322 TWh in 2021. We assume subsequent demand remains constant due to the counter-acting effects of increased energy efficiency and self-consumption of PV power, on the one hand, and electrification of the transport and heating and cooling sectors, on the other hand. However, these values are realized demand values that take into account the existing renewable energy levy. Accordingly, we calculate the demand level without renewable energy levy, a.

In 2015 and, thus, after the deviation, Spanish demand was 232 TWh (Eurostat, 2018), which we for simplicity assume as constant in the following years. Calculating

[16] Spain's electricity sector is smaller than Germany's, thus, we would expect a larger merit-order effect there. However, to the authors' best knowledge, no existing research analyzed both countries' merit-order effects with one approach. Analyses with different methodologies reach vastly different results, e.g. Gelabert et al. (2011) and Sáenz de Miera et al. (2008), who find much larger effects.

the electricity demand under compliance needs to be done vice versa as Spain did deviate in the early 2010s, such that the realized demand is based on a levy that is already reduced by 20 percent. We start with the realized demand values, based on Eurostat (2018), which gives us the demand Q after deviation. Knowing the renewable energy levy p under deviation and compliance and b, we can thus calculate how large demand would have been without deviation. For example, Q would have been 229 TWh in 2015.

General Conclusion

This dissertation addresses the financing and integration of renewable energies. Chapter 1 demonstrates that system-friendly wind power facilitates an easier integration of large shares of intermittent renewable energies and analyzes the incentives that investors have to install such technologies. Chapter 2 finds empirical evidence that financing costs differ across renewable energy support policies and identifies additional deployment costs that occur with private long-term contracts for renewable energy. Chapter 3 analyzes potential time-inconsistency issues, addresses how policy design and deployment targets can alleviate them and scrutinizes the reasons why Spain had incentives to conduct retrospective changes around 2012 while Germany did not.

Chapter 1 finds that system-friendly renewable energy technologies become more important in power systems with higher shares of intermittent renewables. With more wind and solar power, the technology with the lowest costs may no longer minimize overall costs. Electricity prices decrease when it is windy in power systems designed around thermal power plants. System-friendly technologies counter this effect, as they have a larger share of their production in times of low wind. Therefore, in energy systems with high shares of intermittent renewables, more system-friendly turbines are system-optimal, i.e. minimize overall costs, than in systems with lower shares of renewable energies.

The German sliding feed-in premium provides some incentives for system-friendly choices, as shown both analytically and numerically, but does not transmit sufficient incentives to install system-optimal technologies. On the one hand, system-friendly technologies that run less simultaneously with all other wind power receive a higher total support. On the other hand, though, market price signals remain suppressed in order to keep additional risks from price exposure in check. Moreover, when investors lack perfect foresight, incentives are even less system-optimal.

Based on the system-optimality criterion, a policy designed to align private incentives with system-optimality while keeping revenue risks low is analyzed. Support levels are adjusted by installation-specific adjustment factors, representing the respective expected production values. System-friendly installations receive bonuses, whereas conventional installations receive penalties. Thus, investors can consider the entire additional expected production values of system-friendly technologies without facing additional revenue risks during the installations' lifetimes. This requires the regulator to provide an expected power price profile. Further discussions of this approach, including an extension to facilitate also system-optimal locational choices, can be found in Neuhoff et al. (2017). Questions of political acceptance of the proposed reference-yield model arise, which future research might address. Large-scale power system models that are detailed enough to include the specific actions of individual investors, e.g. regarding differentiated turbine technology investment choices, would facilitate comparing the differences to current and alternative policies in more detail. However, such large-scale energy system models are usually not detailed enough to analyze the incentives of individual players, let alone model important aspects like imperfect foresight, risk-aversion, specific financing costs, or investors' heterogeneous requirements in terms of risk-return profiles. Additionally, large-scale models commonly do not allow actors to choose between several investment alternatives in terms of technologies, as investment models like the approach in chapter 1 do, or in terms of timing of the investment, as the real-options literature does.

The analysis in chapter 2 consists of two parts: an empirical analysis focusing on empirically testing the impact of renewable energy support policies on wind power financing costs and an analytical approach concentrating on the implications of long-term contracts between investors and private off-takers. The empirical analysis finds evidence that green certificate schemes are associated with financing costs that are around 1.2 percentage points higher than those for feed-in tariffs and sliding feed-in premia. The main reasons, frequently discussed in the literature, are the higher revenue risks due to the uncertainty of wholesale power prices and certificate values. The additional risks of sliding feed-in premia compared to feed-in tariffs appear to be evaluated as rather low, which might, however, change in the future. The analysis does not support a statistical difference in financing costs between the two policies, even though sliding feed-in premia expose investors to some revenue risks and risks linked to the future development of power markets, e.g. the development of balancing costs.

In the absence of implicit long-term contracts between investors and consumers, private long-term contracts induce additional deployment costs. Sliding feed-in premia and feed-in tariffs represent implicit long-term contracts between investors and consumers, backed and facilitated by the regulator. Under green certificate schemes, as well as with investments based solely on the electricity price, no such implicit contracts exist. Private long-term contracts between investors and off-takers, frequently large utility companies, aim to take over their role. Credit rating agencies count such contracts as liabilities on off-takers' balance sheets, such that the off-takers' financial ratios worsen. Consequently, their re-financing costs increase, leading to potentially substantial implicit costs of the long-term contracts. This reduces their demand for long-term contracts, lowers the price of these contracts below the expected power price, increases the revenues required by investors additionally to the contracts, and, consequently, increases overall deployment costs. These effects are larger when the off-takers, typically large utility companies, are financially constrained. Considering European utilities' financial situations, we estimate that the overall costs of green certificate schemes are around 30 percent higher than the costs under feed-in premia and feed-in tariffs. Future research could estimate the extra costs of private long-term contracts empirically when more data on contracted volumes and contract conditions becomes available. Moreover, if more data on financing costs, e.g. over time, was known, also changes in effects of support policies on financing costs could be investigated.

Chapter 3 demonstrates, analyzing the dynamic game between the regulator and renewable energy investors, that time-inconsistency issues can arise for renewable energy investments. Regulators can have incentives to revoke previous support promises after investments have been made in order to benefit from new installations and low electricity prices. In an open loop game, where players only consider the current period, no compliance can be attained since the regulator anticipates no disadvantages when deviating. As firms foresee this, no investments are made in the first place. Trigger strategies, i.e. where players react to other players' previous actions and take future consequences into account, can sustain commitment outcomes depending on a variety of factors, including the regulator's discount rate, costs of old installations, costs of new installations, the wholesale electricity price level, and the environmental benefits of renewable energy deployment.

We show that support policies and deployment targets can support the attainment of commitment outcomes. Policies granting investors legal rights to specific support levels, combined with constitutional grandfathering rights, decrease the regulator's pay-offs when deviating and thus render compliance more attractive. Feed-in premia, unlike feed-in tariffs, leave some limited space for adjustments, as structural changes to balancing costs and general power market design questions can impact renewable energy operators. Moreover, systems where "general profitability" is stressed, rather than specific support levels, leave more space for retrospective changes. Green certificate schemes make adjustments even easier as they can be implemented through rather simple changes to the number of certificates in circulation or the obligations for retail companies. Besides, deployment targets support commitment when they are technology-specific or few alternative technologies exist.

A numerical example identifies the reasons why Spain conducted retrospective changes around 2012 while Germany did not. On the one hand, in Spain, the regulator valued the long-term benefits of sustained renewable energy expansion much less due to its high discount rate as the country was severely financially constrained. On the other hand, Germany faced very low interest rates, leading to high valuations of future pay-offs. Additionally, the environmental benefits differ: Germany's existing power plant fleet emitted considerably more carbon dioxide than Spain's, increasing the benefits of renewable energies in Germany. However, these differences are partially countered by the much higher Spanish power prices, implying lower extra costs for renewable energies. In sum, the model confirms that retrospective changes were more attractive than compliance in Spain, whereas in Germany, compliance was more attractive than deviating. Once more cases against the Spanish government have been closed, future research could analyze how profitable the retrospective changes have after all been for the Spanish government.

With falling deployment costs, the costs of renewable energies come closer to power prices and in some periods and countries even lie below them, raising a set of open research questions. When the reference price under conventional sliding feed-in premia falls below the long-term expected power price, an increasing share of revenues is subject to price risks. Costs covered through revenues from these uncertain revenues above the reference price are difficult to finance through debt. Consequently, project developers might need to secure private long-term contracts with off-takers for these revenues or use equity to finance these costs, both increasing overall deployment costs and possibly posing barriers to entry for small players. Alternatively, two-sided sliding premia, like the UK's Contracts for Differences, oblige operators to repay the regulator when power prices are high, such that revenues are fixed in advance. However, project developers then potentially have incentives to abstain from any support and sell their output via private long-term contracts. Questions arise as to how these two systems, installations both within and outside the support system, can co-exist, as well as how these systems influence each other, e.g. how to steer volumes in order to fulfill deployment targets. Another open question is how large the demand for such long-term contracts is; i.e. how large a market outside the support system can become.

The evolution of the power price signal leads to another set of open research questions. On the one hand, in the long-term, power prices might increase, as demand for electricity picks up due to the coupling of sectors, higher carbon prices and power systems becoming more flexible. On the other hand, the value of wind and solar power production might continue to fall because of their simultaneous production, aggravated by the increasing shares of renewable energies. In any case, if the power price fluctuates more strongly between times with wind and sun and times without, the questions of time and location of production become ever more important. This also raises the question of how the locational choices of investors should be managed: Administratively, as currently the case for wind power in Germany, through the expected value of output at different locations, as sketched in Neuhoff et al. (2017), not at all as the case in most countries, or via the splitting of price zones and respective exposure to power prices. This showcases that with evolving power markets and with technologies that exhibit learning, both renewable energy support policies and power market design need to be addressed in order to facilitate the transformation to a carbon-neutral energy system.

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Chapter 2: Financing Power: Impacts of Energy Policies in Changing Regulatory Environments

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