On the Economics of Renewable Energy Support and Market Integration of Intermittent Electricity Supply

A thesis submitted to attain the degree of

DOCTOR OF SCIENCES of ETH ZURICH

(Dr. sc. ETH Zurich)

presented by

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2020
Summary

The electricity sector is a major contributor of greenhouse gas emissions worldwide and its decarbonization is considered to be an important cornerstone of efforts to combat climate change. A carbon price in the form of a Pigouvian tax or emissions trading has been proposed as a suitable first-best policy instrument to incentivize the optimal amount of carbon abatement. So far, however, in many jurisdictions it has not been politically feasible to implement such a policy with adequate stringency. Instead, support policies for renewable energy have been widely used to increase the share of low carbon electricity production.

This thesis contains three research articles on renewable energy support and market integration of intermittent electricity supply. It addresses questions such as the following: How efficient are renewable energy support policies relative to a first-best carbon tax in achieving ambitious emissions reductions goals? How can RE support policies be optimally designed to improve their efficiency and under what conditions can they be used to reach first-best? In what ways can RE policies be designed to reduce system integration cost of large generation from intermittent renewables? What role does the resource heterogeneity of intermittent renewables (wind and solar energy) play for optimal policy design?

The first article creates a framework to compare the performance of different renewable support policies with regard to their impact on welfare and carbon emissions. A Pigouvian carbon tax is used as a benchmark for the first-best outcome and the article identifies different policy design choices which improve the efficiency of much used policies such as feed-in tariffs and market premiums. It also investigates under what conditions renewable support policies can achieve the first-best outcome. The article employs a theoretical model to provide fundamental insights and a numerical partial equilibrium model calibrated to the German electricity market for the simulations that illustrate and further develop the arguments in a more realistic setting. The analysis provides the important insight that the efficiency of renewable support policies depends crucially on the financing mechanism which can be designed in a non-revenue neutral way that moves the policy closer towards the first-best.

The second article focuses on electricity systems with a policy goal to achieve a large production share of variable renewable sources. Since the most advanced new renewable technologies, wind and solar energy, depend on the availability of their natural resource to produce electricity there is a risk for a mismatch of demand and supply. This can be the case when there is no wind or little solar radiation and demand cannot be satisfied or when there could be high production but demand is low and some share of renewable generation has to be discarded (curtailment) to ensure grid stability. In such a setting, electricity storage plays an important role in shifting generation between time periods and in this way matching demand and supply. The article analyzes how the design of renewable support policies with regard to technology-differentiation of the subsidy can reduce the cost of integrating large renewable energy shares by reducing curtailment and investment cost for storage capacity. The analysis for a partial equilibrium model calibrated again to German data shows that substantial cost-savings are possible with a subsidy scheme with optimal technology-
differentiation that takes into account the different availability patterns of wind and solar generation and their interaction with demand patterns.

The third article takes a broader research approach by adopting a multi-country model which features international electricity trade and storage. It analyzes the potential benefits of increasing system flexibility along regulatory (policy design), temporal (storage), and spatial (cross-country trade) dimensions. For the numerical simulations it employs a bottom-up model calibrated to 18 European countries. The analysis finds that a suitable combination of flexibility measures significantly reduces the investment cost necessary for reaching an ambitious renewable energy goal. The cost-saving potential of the different flexibility channels depends on the natural resource availability of the respective countries and on the technology mix of the existing conventional generation capacity. The same is true for the emissions reduction achieved through the policy. Even with a fixed renewable energy target emissions can vary up to 50% because of the interaction of the choice of flexibility measures with the conventional generation technologies.
Zusammenfassung


Die vorliegende Arbeit präsentiert drei Forschungsartikel zur Förderung erneuerbarer Energien und der Marktintegration intermittierender Stromproduktion. Sie stellt die folgenden Forschungsfragen: Wie efﬁzient ist Erneuerbarenförderung verglichen mit einer optimalen Emissionssteuer, um ambitionierte Emissionsreduktionsziele zu erreichen? Wie kann die optimale Gestaltung einer Erneuerbarenförderpolitik ihre Efﬁzienz erhöhen und unter welchen Umständen erreicht sie das ﬁrst-best Optimum? Wie sollten Politiken zur Förderung erneuerbarer Energie gestaltet werden, um die Integrationskosten großer Anteile intermittierender Stromproduktion aus erneuerbaren Quellen zu reduzieren? Welchen Einﬂuss hat die Ressourcenheterogenität intermittierender erneuerbarer Energiequellen (Wind- und Sonnenenergie) auf die optimale Förderpolitikgestaltung?


Der zweite Artikel legt den Fokus auf Elektrizitätssysteme mit dem Politikziel, einen großen Anteil erneuerbarer Energien an der Gesamtproduktion zu erreichen. Da die technologisch am weitesten entwickelten neuen erneuerbaren Energiequellen, Wind- und Sonnenenergie, von der Verfügbarkeit ihrer natürlichen Ressource abhängig sind, um Strom zu produzieren, besteht ein Risiko für ein Missverhältnis zwischen Angebot und Nachfrage. Das ist der Fall, wenn es windstill oder dunkel beziehungsweise stark bewölkt ist und die Stromnachfrage nicht befriedigt werden kann oder wenn eine hohe Stromproduktion möglich wäre, aber die Nachfrage gering ist und ein Teil der Produktion abgeregt werden muss, um die Netzstabilität zu gewährleisten. In einer solchen Situation spielen Stromspeicher eine wichtige Rolle, indem sie produzierten Strom aus einer Zeitperiode in
eine andere verschieben, um so Nachfrage und Angebot auszugleichen. Der Artikel beschäftigt sich mit der Frage, wie die Gestaltung von Erneuerbarenförderpolitiken mit einem nach der Technologie differenzierten Subventionsschema die Integrationskosten für große erneuerbare Anteile an der Gesamtproduktion verringern kann, indem die Abregelung und die nötigen Investitionskosten für Stromspeicher reduziert werden. Die Analyse wird wieder im Rahmen eines numerischen partiellen Gleichgewichtsmodells mit Daten für Deutschland durchgeführt und zeigt, dass beträchtliche Kostenersparnisse möglich sind, wenn die Subventionen so nach Technologien differenziert werden, dass die verschiedenen Verfügbarkeiten von Wind- und Sonnenenergie und ihre Interaktion mit der variablen Stromnachfrage optimal berücksichtigt werden.

Acknowledgements

I would like to thank Sebastian Rausch, my supervisor, for giving me the opportunity to do the PhD at his chair, his support, and for giving me so many valuable insights into economics and research in general. I could learn so much from you as a co-author, most of all how to present an argument really well.

I would like to say thank you to Jan Abrell for teaching me so much about GAMS, Python, the electricity market, and economic thinking. The discussions in front of the whiteboard and all the countless times you had good advice were such a great help.

Next, I am grateful to Hannes Weigt who kindly agreed to be my co-examiner and to Massimo Filippini for acting as the chairperson in my doctoral examination.

I would also like to mention Florian Landis and Renger van Nieuwkoop who at times provided the best GAMS support that anyone could hope for, thank you!

A special thanks goes to all my colleagues from ETH who contributed to the great work environment. Mirjam, my longest serving office mate, thank you for going so much of the way together with me and for always having an open ear. Giacomo, Oliver, Gustav thanks for all the good moments in the office. Rina, thank you for the administrative assistance but most of all for the moral support, for brightening up the coffee breaks, and for nudging people to bring cake. Nina and Andrea, thanks for the company at ten and for the plants!

I could not have done any of this without the unwavering support of my family and friends. My mother and my grandparents always believed in me and their encouragement was vital for so many things. My friends made sure that life outside the office provided me with the balance that I needed. And Peter was my rock.

Clemens Streitberger
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1 Introduction

1.1 Motivation

Global warming is considered to be one of the great challenges of our time. The overwhelming scientific consensus states that the climate change processes we are observing are man-made and driven by the large amounts of greenhouse gases which have been released into the atmosphere since the beginning of the Industrial Revolution. Even as scientific evidence for the accelerated warming of the atmosphere is mounting in many places of the world, emissions of greenhouse gases (GHG) are still rising globally. The consequences of an unmitigated warming of the climate are expected to be very substantial. Potential damages from sea level rise, extensive droughts, a higher frequency and intensity of extreme weather events, and thawing perma-frost soils—to name just a few expected dangers ahead—are large and hard to quantify in monetary terms. But in any case their economic and ecological impact is expected to become a formidable challenge (see, e.g., Pachauri et al., 2014).

The international community decided to combat climate change by significantly reducing GHG emissions and established the yearly United Nations Climate Change Conferences with the aim to negotiate a viable path towards limiting global warming to a manageable dimension. Within this framework, the well-known Kyoto Protocol and the Paris Agreement are major milestones with the goal to keep the average temperatures below 2 degrees and to work towards an even more moderate warming of only 1.5 degrees (United Nations, 2015). These goals can only be achieved if the signatory countries of the Paris agreement implement comprehensive legislation and other regulatory measures to first curb and then reverse the growth of emissions from the industry, transport, agriculture, transportation, and energy sectors of their economies.

For the task of designing and evaluating such regulative measures, the results and methods of environmental economics are a useful scientific framework and can provide important insights and impulses for policy makers. The release of greenhouse gases can be viewed as a negative externality of various economic activities, that is the agents who take economic decisions do not bear the full cost of the environmental impact of the emissions caused by these decisions. A measure to internalize the external costs is a Pigouvian tax which puts a price on the damaging behavior (Pigou, 1920; Baumol, 1972). Market-based environmental policy instruments such as emissions taxes or emissions trading schemes are grounded in this research and some realized policy examples include the EU-ETS which covers roughly half of the emissions from the European Union, Sweden’s carbon tax, or the California cap-and-trade program. While these policies are important corner stones of climate policy and despite the fundamental decisions of the Paris Agreement, to this date there has not been implemented a comprehensive policy introducing a sufficiently high price on emissions and covering enough of global emissions to steer the world towards achieving the Paris climate goals due to a lack in political support. Instead, we observe a broad array of local policies with different scopes, stringency, and design choices (Meckling, Sterner and Wagner, 2017). One important class of these are support policies which encourage desired behavior rather than punishing undesired
actions with a price. These are typically more specialized and applied within a sector such as policies to boost energy efficiency in the building sector, programs with subsidies to encourage the switch to electric cars, and renewable energy support policies in the electricity sector. The wide use and large variability of these policies make them an interesting and relevant subject of study and this thesis joins the research on environmental policy design for emissions reduction by focusing on renewable energy (RE) support policies for the promotion of new low-emissions technologies in the electricity sector. This sector is especially relevant because the generation of electricity and heat is responsible for about 40% of CO$_2$ emissions from fuel combustion worldwide (International Energy Agency, 2018) and therefore a major area of emissions reduction. Moreover, the importance of this sector will further increase in the future because of the potential for emissions reduction of other sectors such as transportation through electrification, that is the substitution of fossil fuels by electricity in automobiles or the increased use of electricity in industrial processes.

Renewable support policies in the form of implicit$^1$ or explicit subsidies are relevant for research since they have been widely used in Europe and the US. They have proved to be politically more feasible than carbon pricing although they are considered second-best (Meckling, Sterner and Wagner, 2017). They are used mostly to achieve carbon emissions abatement by encouraging investment in renewable energy with low marginal generation cost which substitutes electricity generation from fossil fuels. Also subsidies addressing learning externalities can be interpreted as having a carbon abatement goal because they reduce future abatement cost through the reduction of future investment cost for capacity. Another rationale may be increasing the security of supply for countries depending on fuel imports.

Support for RE can be organized along two dimensions: which quantity is subsidized, capacity vs. generation, and what is the policy instrument, prices vs. quantities. Subsidies paid for installed production capacity are more suitable to deal with learning externalities since technological learning will mostly take place when new capacities are added. Generation subsidies are more suitable to address externalities of production, such as the emissions externality since RE production directly replaces fossil production (Andor and Voss, 2014). Price instruments such as feed-in tariffs or market premiums are direct subsidy payments (e.g., per MWh produced) while quantity instruments such as renewable quotas mandate a certain quantity of renewable generation and the respective subsidy rate is determined by the market. In the absence of uncertainty and information gaps between the regulator and the regulated industry price instruments (feed-in tariffs, market premiums) and quantity instruments (renewable quotas) can be shown to be equivalent.

The widespread implementation of renewable support policies has the potential to cause a deep structural change in the electricity system and gives rise to a plethora of economic questions about the design of the policies themselves and about the new market conditions they create. The expected large scale increase in the production share of new renewable technologies poses unique challenges. On the one hand, the electricity system has special characteristics which affect its economics. First, it is important to note that electricity as a good cannot be produced and then stored until demanded, rather it has to be either transferred to its users and consumed instantly or

$^1$Examples for implicit subsidies would be tax rebates and monetary incentives received under (renewable) technology standards or intensity standards.
it can be transformed into other forms of energy (potential energy, chemical energy) and converted back later under losses. Second, the stability of the electric grid requires that demand is met at all times by supply to avoid the risk of blackouts with substantial financial damages to the economy. On the other hand, the most advanced new renewable technologies (wind and solar energy) are non-dispatchable and have near zero marginal generation cost, which sets them apart from the existing conventional fossil technologies. Non-dispatchable means that these technologies cannot simply produce at any time when there is demand for electricity. They depend on a natural resource (wind and solar radiation) which is free—hence the near zero marginal generation cost—but varies over time with seasonal and diurnal patterns (intermittency) and has a stochastic element because it is influenced by weather phenomena which are only partially predictable. These properties provoke economic research questions focusing on several aspects. Among those are fundamental market design and missing markets if in a future system with a very high share of zero marginal cost renewable generation electricity prices decrease so much as to prevent investment into new capacity (see, e.g., Cramton, Ockenfels and Stoft, 2013; Flinkerbusch and Scheffer, 2013; Winkler et al., 2013). Another field of interest is resource heterogeneity with regard to the environmental and market values of RE generation, its influence on investment decisions and its implications for policy design (see, e.g., Kaffine, McBee and Lieskovsky, 2013; Cullen, 2013; Novan, 2015; Gowrisankaran, Reynolds and Samano, 2016; Abrell, Kosch and Rausch, 2019). Finally, the intermittency of RE generation fuels questions on how to facilitate the market integration of large amounts of RE and how to avoid a potential mismatch between demand and intermittent supply.

Within this broad field of research I concentrate on the economics of renewable energy support and market integration of intermittent renewable energy. I address the following research questions:

- How efficient are renewable energy support policies compared to a first-best carbon tax in achieving ambitious emissions reductions goals?
- How can RE support policies be optimally designed to improve their efficiency and under what conditions can they be used to reach first-best?
- In what ways can RE policies be designed to reduce system integration cost of large generation from intermittent renewables?
- What role does the resource heterogeneity of intermittent renewables (wind and solar energy) play for optimal policy design?
- What are the most important channels of flexibility (temporal, spatial, regulatory) to facilitate cost-effective system integration when the policy goal requires high shares of RE generation?

To address these questions I use numerical economic modeling approaches rather than empirical (i.e., econometric) methods because they pertain to large transformations and future market conditions with not yet existing policy instruments and thus there are no historical data available for empirical ex post analysis. This ex ante approach based on structurally explicit economic models and economic theory allows to evaluate policies before their implementation and provides valuable lessons for regulators. There are various modeling approaches for simulating energy markets with
different scopes and degrees of technical and economic detail. Most of these can be classified either as top-down or bottom-up models. Top-down models are highly aggregated and cover either several sectors or a whole economy, frequently in the form of computable general equilibrium models which can be multi-regional or even global. They are suitable for the study of interaction effects of the energy sector with the rest of the economy and for long-term modeling spanning even decades (see, e.g., Bergman, 2005, for an introduction to CGE modeling). Usually they lack technological detail in the energy sector and do not have a finely grained time resolution for dispatch decisions within the electricity market. These are features of bottom-up models which concentrate on a subset of the economy, one or several sectors, and are therefore often called partial equilibrium models. These models can cover short-term production decisions of agents with several technologies and also long-term investment planning. In recent years, there have also been made efforts to combine both types of models (see, e.g., Böhringer and Rutherford, 2008, 2009). An overview over current modeling approaches in the energy sector can be found in Krysiak and Weigt (2015).

The study of the design of support policies for renewables and the impact of intermittency on their market integration calls for a high degree of detail in the modeling of the electricity sector and a high time resolution to cover intra-day and seasonal variations in availability. Therefore, I develop numerical partial equilibrium models of the electricity market which can be categorized as bottom-up models. They capture the essential features of the electricity market and the special properties of intermittent renewable energy sources. Intermittent renewables are represented by introducing availability profiles based on past generation over the course of a year. The models feature dispatch and investment decisions of profit maximizing or cost minimizing economic agents within different regulatory regimes and markets with marginal cost pricing and merit-order supply curves. To answer quantitative questions, I calibrate them to data from Germany and Europe.

The research program of the thesis is organized in three articles which address different aspects of the above mentioned research questions. The first paper evaluates the efficiency of renewable support policies with respect to welfare impact and emissions reduction. I create a framework that allows us to compare different designs of support policies and set their efficiency in relation to a Pigouvian carbon tax as a first-best instrument. I identify key elements which improve the efficiency of commonly used RE support policies such as feed-in tariffs or market premiums and under what conditions they come close to a first-best outcome. For this paper, I use the German electricity market as a basis for the calibration of the model.

I then expand the reach of our analysis in the second paper by taking into account questions of storage requirements for the integration of large amounts of intermittent renewable energy. Due to the potential temporal mismatch between supply and demand caused by intermittency, systems with a high share of RE generation risk having to discard parts of this generation to ensure grid stability (curtailment). I stay in the framework for a single electricity market in one country (again Germany) and analyze how a suitable design of support policies with a technology-differentiated subsidy allows to cost-efficiently integrate large generation shares of RE into the electricity system.

These models differentiate themselves from technical models in the engineering literature by explicitly covering the economic aspects of the electricity sector with markets, demand, supply, cost-minimization and profit maximizing decisions by economic agents, and regulatory policy interventions, while reducing the technological detail.
by reducing curtailment and at the same time keeping investment cost into new storage capacity low.

The third paper broadens my approach again by considering a multi-country model with international electricity trade and electricity storage possibilities. I analyze the potential benefits of increasing system flexibility along regulatory (policy design), temporal (storage), and spatial (cross-country trade) dimensions. For this approach, I calibrate the model to 18 European countries so as to capture their varying existing conventional production capacities and natural resources for renewable energy.

The following section presents the introductions to the three articles which form the remaining part of this thesis. They describe the research projects in more detail and summarize the insights they provide.

1.2 Scientific contribution

The economics of renewable energy support

This paper examines how inefficient optimally designed RE support strategies are in relation to carbon pricing. An RE support scheme comprises two essential elements: (1) implicit or explicit subsidies paid to RE firms (2) and a rule determining how such subsidies are financed. A generic way of thinking about what do optimal RE support schemes look like is therefore to ask how RE funding should be structured and financed.

Our analysis emphasizes three major issues for RE policy design which are of relevance for the decarbonization of real-world energy systems. First, wind and solar resources exhibit a large heterogeneity in terms of their temporal and spatial availability. Adding one MWh of solar electricity may thus yield very different CO₂ emissions reductions compared to adding one MWh of wind; the exact answer depends on the complex interactions between heterogeneous resource availability, time-varying energy demand, and the carbon-intensity and technology costs of installed production capacities. We investigate how RE subsidies should be structured to take into account these heterogeneous marginal external benefits. Second, most of the currently adopted forms of RE support include feed-in tariffs (FITs), guaranteeing a fixed output price per MWh of electricity sold, and market premiums which essentially are output subsidies added to the wholesale electricity price. The expenses for a FIT or output subsidy paid to RE firms are typically financed through levying a tax on energy demand of consumers. RE quotas, renewable or clean portfolio standards are widely adopted examples of technology or intensity standards which are blending constraints implicitly combining output subsidies for RE with input production taxes to finance the RE support.

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3The article is published in *Journal of Public Economics*, Volume 176, August 2019, Pages 94-117, DOI https://doi.org/10.1016/j.jpubeco.2019.06.002 with Jan Abrell (JA) and Sebastian Rausch (SR). An earlier version is available as CER-ETH Working Paper 18/286. All three authors contributed equally to the research design.

4We abstract from positive externalities related to learning, technological innovation through R&D investments, and network effects (Jaffe, Newell and Stavins, 2005; Acemoglu et al., 2012; Bollinger and Gillingham, 2014) which provide an important rationale for RE support policies. While the presence of such externalities can make RE support more attractive relative to carbon pricing, it is beyond the scope of the paper to examine how it may affect the performance of alternative RE support policies.

5Examples of widely adopted forms of RE support include feed-in tariffs (FITs), guaranteeing a fixed output price per MWh of electricity sold, and market premiums which essentially are output subsidies added to the wholesale electricity price. The expenses for a FIT or output subsidy paid to RE firms are typically financed through levying a tax on energy demand of consumers. RE quotas, renewable or clean portfolio standards are widely adopted examples of technology or intensity standards which are blending constraints implicitly combining output subsidies for RE with input production taxes to finance the RE support.
are revenue-neutral, i.e. RE subsidies are financed through energy consumption taxes—either explicitly, as under a FIT or market premium approach, or implicitly as for the case of technology or intensity standards. We analyze the implications of revenue-neutral RE support schemes in the context of optimal policy design. Third, in the absence of stringent carbon pricing and given that RE support schemes are currently the most widely adopted form of actual low-carbon policies, a future world with a dichotomous energy system—comprising either clean energy from RE sources or highly carbon-intensive "dirty" fossil fuels (i.e., coal)—is not unlikely at all. We thus investigate how the financing of RE subsidies can be designed to provide incentives for climate change mitigation.

We formulate theoretical and numerical equilibrium models of optimal policy design where society (i.e., the regulator) is concerned with the management of an environmental externality related to the use of fossil fuels. Decisions about energy supply and demand stem from profit- and utility-maximizing firms and consumers in the setting of a decentralized market economy. We first theoretically characterize the optimal structure and financing of RE subsidies as well as the conditions under which such policies can implement socially optimal outcomes. To assess different RE support schemes in an empirically plausible setting and to derive additional quantitative insights, we develop a numerical framework which extends the theoretical model and accommodates a number of features relevant for analyzing real-world electricity markets. While the model is calibrated with data for the German electricity market, our numerical simulations yield qualitative insights relevant to the decarbonization of the electricity sector in many countries.

The key insight from our analysis is that RE support policies do not necessarily have to be viewed as a costly second-best option for internalizing a carbon externality—when carbon pricing is unavailable due to political (and other) constraints. The ability of optimally designed RE support to closely approximate first-best outcomes obtained under carbon pricing crucially depends on the financing of renewables support. The basic idea is that financing rules can be designed in such a way that they almost optimally stimulate the same CO$_2$ reduction channels that would be triggered by carbon pricing—but not by a blunt subsidization of RE.

Our main findings can be summarized as follows. First, the optimal subsidy for an RE technology reflects both the environmental and market value of the underlying intermittent natural resource. The environmental value reflects the environmental damage avoided by replacing fossil-based with renewable energy supply. The market value reflects the economic rents for firms and consumers created by using intermittent resource. Accordingly, we find that the optimal RE subsidies for wind and solar differ. The quantitative analysis, however, suggests that the efficiency gains from differentiating RE subsidies across technologies are negligible. Second, under an optimal RE support scheme, the revenues raised from an energy demand tax exceed the expenses for RE subsidies. The important implication for policy design is that revenue-neutral support schemes, such as the widely adopted FIT or RE quota policies, cannot implement a social optimum. We find that revenue-neutral RE support schemes entail large efficiency losses compared to a first-best carbon pricing

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6. These include, among others, hourly wholesale markets, multiple energy technologies, time-varying and price-responsive demand, temporally and spatially heterogeneous quality of wind and solar resources, and output-dependent marginal cost and CO$_2$ emissions to reflect flexibility and efficiency constraints at the power plant level.
policy as they fail to appropriately incentivize the energy conservation channel. Third, we show that a RE support policy can implement the first-best outcome only if achieving the social optimum does not require a change in the fossil-based technology mix (relative to the unregulated market outcome). Fourth, the efficiency of RE support schemes importantly depends on the way in which RE subsidies are financed. We find that combining RE subsidies with an optimal tax on energy demand or using intensity or technology standards which link the financing of RE subsidies to the carbon intensity of fossil-based energy suppliers are particularly effective ways for improving policy design.

To our knowledge, this paper is the first to investigate the optimal design of public policies to support intermittent RE resources in the presence of a carbon externality. In light of the widespread use of RE policies to help decarbonize today's energy systems, we thus believe that our analysis fills an important gap in the existing literature. At a broader level, the paper contributes to the literature in public and environmental economics focused on understanding the impacts and design choices of governmental regulation to address market failures and externalities related to pollution and technological progress through learning and R&D investments (see, for example, Fullerton and Heutel, 2005; Goulder and Parry, 2008; Fischer and Newell, 2008; Acemoglu et al., 2012). While most studies have scrutinized various market-based and “command-and-control” approaches to carbon mitigation, the issue of how to best design public policies to promote energy from intermittent RE resources has received surprisingly little attention. A notable exception is Reguant (2019) which examines the interaction between RE policies and the retail tariff design. She finds that RE policies are more cost-effective to achieve a given CO$_2$ emissions reduction if their associated renewable payments are reflected in retail prices, as compared to a situation in which consumers face flat prices and costs are recovered either by lump-sum fees or through a higher average price. While we do not compare different retail tariff designs, we assume that consumers pay the real-time price of electricity plus a constant retail fee that ensures cost recovery on the margin—thereby adopting one of the four retail tariff designs analyzed in Reguant (2019).$^7$

Recent empirical evidence (Kaffine, McBee and Lieskovsky, 2013; Cullen, 2013; Novan, 2015) has documented the temporal and spatial heterogeneity of intermittent wind and solar resources in terms of their environmental value, i.e. avoided CO$_2$ emissions per MWh of RE electricity. Based on an econometric ex-post assessment for Germany and Spain, Abrell, Kosch and Rausch (2017) find that the impacts of RE support policies on wholesale electricity prices vary substantially depending on whether wind or solar energy is subsidized. While these papers generally point out that the heterogeneous environmental and market values of different intermittent RE resources are not reflected in the prevailing policy incentives that guide investments in RE resources (Callaway, Fowlie and McCormick, 2017), the implications for policy design have not been analyzed. By typically adopting a simplified and aggregated representation of RE technologies, natural resource variability, and time-varying energy demand, most of the work analyzing RE support policies (Fischer

$^7$Relative to Reguant (2019), we contribute by investigating optimal RE policy designs instead of focusing on cost-effectiveness; in particular, we investigate how optimal RE policies should be designed beyond cost recovery, i.e. budget neutrality. To the extent that simpler retail tariff designs prevail in real-world electricity markets, in particular for residential consumers, our estimates of the welfare gains for carbon pricing and all RE policy designs should be viewed as upper bounds. In future markets with an increasing role for smart metering devices, we expect a situation more similar to real-time pricing.
and Newell, 2008; Rausch and Mowers, 2014; Kalkuhl, Edenhofer and Lessmann, 2015; Goulder, Hafstead and Williams, 2016) has abstracted from the fact that wind and solar resources are heterogeneous—thereby ignoring the idiosyncratic ways in which distinct intermittent RE resources interact with energy supply and demand. Our framework investigates the optimal design of RE support schemes in the context of multiple intermittent RE resources.

A small and recent literature has started to examine the effects of intermittent energy sources for the provision of electricity employing the peak-load pricing model (Crew and Kleindorfer, 1976; Crew, Chitru and Kleindorfer, 1995). Ambec and Crampes (2012) and Helm and Mier (2016) analyze the optimal and market-based mix of intermittent RE and conventional dispatchable energy technologies. They do not, however, investigate the question of government support for RE resources. Ambec and Crampes (2017) theoretically examine optimal RE policies in a setting with one intermittent RE resource, i.e. either wind or solar—thus not permitting to investigate the implications of multiple heterogeneous RE resources for optimal policy design. Fell and Linn (2013) and Wibulpolprasert (2016) take into account the temporal and spatial resource heterogeneity, but focus on comparing RE policies in terms of their cost-effectiveness to achieve a given and exogenously determined emissions target. In contrast, our analysis explicitly considers a carbon externality and analyzes optimal RE policy design when the choice of environmental quality is endogenous.

Buffering volatility: storage investments and technology-specific renewable energy support

Much of the academic literature and ongoing discussions among policymakers have focused on the question how energy storage can serve as a buffering mechanism to cope with the volatility and system integration costs induced by intermittent RE sources (Hirth, 2015; Gowrisankaran, Reynolds and Samano, 2016; Sinn, 2017; Zerrahn, Schill and Kemfert, 2018). At the same time, there are considerable uncertainties as well as concerns about the costs, availability, and potentials of future storage technologies, in particular when deployed at the large scales required for deep decarbonization.9

Instead of focusing on a pure technological solution for buffering volatility (i.e., through energy storage), this paper examines the suitability of a regulatory or public policy mechanism as a means for coping with the impacts of large shares of highly volatile RE sources in future energy systems: the design of technology-specific RE support schemes. Specifically, we ask to what extent the economic cost of integrating a large amount of highly volatile wind and solar energy can be reduced by modifying the design of RE support schemes—such as subsidies on output or investment—to

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8 The article is published in *Energy Economics*, Volume 84, Supplement 1, October 2019, 104463, DOI https://doi.org/10.1016/j.eneco.2019.07.023. An earlier version is available as CER-ETH Working Paper 19/310. Jan Abrell (JA), Sebastian Rausch (SR), and Clemens Streitberger (CS) contributed equally to the research design. The modeling was conducted by JA and CS. The analysis was carried out by all three authors equally. The exposition was written by CS and SR.

9 As of today, the only energy storage technology for electricity used at large scale is hydroelectric pumped-storage power (Schwab, 2009), representing about 99% of the worldwide installed storage capacity (Rastler, 2010).
take into account the heterogeneous value of different RE technologies with respect to system integration costs. Current policy approaches tend to favor technology-neutral support schemes. A recent example are German joint tenders for wind and solar energy, the last of which saw a dominance of solar bids over wind (BNetzA, 2019). In contrast to such policy designs our fundamental proposal is to improve existing energy market regulation in a way which exploits the complementarities of wind and solar technologies in terms of their underlying heterogeneous resource profiles and the correlation with time-varying electricity demand. We also investigate how the need for energy storage changes when this alternative buffering mechanism is optimally exploited. To the best of our knowledge, we are the first to examine the potential role of policy design for reducing the cost of integrating volatile RE supply.

To provide a conceptual and empirically-grounded framework for thinking about the economics of integrating high shares of volatile RE sources into an electricity market, we develop a numerical partial equilibrium model of a wholesale electricity market which resolves output decisions on hourly markets, time-dependent demand and resource availabilities of wind and the sun, investments in RES production capacity, curtailment decisions to maintain system stability, and a detailed representation of the functioning of electricity storage. Storage capacity is varied exogenously in order to gauge its impact on overall system integration cost of renewables. The decentralized market model is embedded in a welfare-maximizing problem of a benevolent regulator who chooses RE support policies (through subsidies on RE output which we model as a feed-in premium on top of the market price) in order to implement an electricity market with a high share of intermittent RE at the lowest cost to society. While we calibrate the model to stylized conditions of the German electricity market, we think that the main insights from our analysis are also relevant for the electricity market context of many other countries.

Our analysis provides several important insights. First, we find that the storage capacity needed to accommodate high shares of intermittent RE output is relatively moderate, even under a technology-neutral RE support scheme. This implies that the potentially high costs of providing storage at large scale in the future need not jeopardize the achievement of environmental targets (i.e., the reduction of CO₂ emissions through increasing the share of low-carbon renewables). Second, we find that the design of a RE support policy can have a significant impact on system integration cost as well as storage capacity needs when there are several intermittent renewable technologies with heterogeneous availability patterns of the underlying natural resources (such as wind and solar energy). The smart differentiation of RE subsidies affects investment patterns in a way which can effectively reduce the curtailment of excess generation, in turn lowering the need for costly investment in energy storage. We use a simple cost-benefit framework to show that optimal subsidy differentiation significantly reduces the level of optimal storage. In this sense, concerns about the costs and availability of storage technologies in order to enable the integration of high shares of intermittent RE supply in future electricity markets and to achieve environmental goals are even more diminished if a smart design of RE support policies is chosen. Third, within our modeling framework which captures high RE shares up to 80% but not a completely decarbonized
system, we find that the type of storage most likely needed is short-term to medium-term storage. The additional benefits from long-term seasonal storage are relatively modest and most likely much smaller than its investment costs.

This paper contributes to the existing literature in several ways. First, we add to the main insight, supported by a growing body of economic and technical studies (see, for example, Zerrahn, Schill and Kemfert, 2018, and references therein), that in order to integrate large shares of volatile RE supply in future energy systems only moderate levels of energy storage are needed.

Second, there is a growing literature on storage capacity in electricity markets and its connection to the expanding renewable generation capacities. Linn and Shih (2016) investigate the impact of the introduction of large storage capacities into current electricity systems using numerical modeling of the Texas ERCOT region and stylized theoretical considerations to assess the impact on total carbon emissions of a system with dirty base load producers (coal), cleaner peak load producers (gas), and renewables (wind, solar). Carson and Novan (2013) use a theoretical model and empirical methods to show the same effect in the ERCOT region, and, in addition, an adverse impact of increased storage capacities on renewables with high production correlation to peak demand (solar) and a positive impact on renewables which produce at base-load hours (wind) due to a price-leveling effect of storage. Crampes and Moreaux (2010) use a theoretical model of a hydro pumped-storage operator and a fossil generator to determine optimal joint usage of both technologies; they do not consider intermittent RE sources. Helm and Mier (2018) examine the effect on CO$_2$ emissions of subsidizing energy storage. In contrast to the above-mentioned papers, we focus on market conditions as we expect in a future electricity market with a very high level of intermittent RE supply and highlight the role of regulatory design, besides energy storage, for buffering volatility.

Third, we also make a connection to the emerging literature investigating the consequences of the fundamental heterogeneity of RE technologies with respect to availability patterns. Abrell, Rausch and Streitberger (2019b) consider the environmental value and market value of different renewables and define an environmental motive for differentiating subsidies by technology, while Fell and Linn (2013) and Wibulpolprasert (2016) investigate the impact of resource heterogeneity on cost-effectiveness of different abatement policies. Empirical studies like Abrell, Kosch and Rausch (2019) evaluate different market values and environmental values of RE sources ex-post. While these studies highlight the need for improved policy design to incorporate external effects at the system or market level, they focus on CO$_2$ emissions but abstract from storage investments and the issue of the cost of integrating volatile RE supply for decarbonizing the electricity sector.
The value of flexibility in green electricity markets: energy storage, international trade, and tradable quotas

On a global scale, about 40% of CO₂ emissions from fuel combustion could be attributed to electricity and heat production in 2016 (International Energy Agency, 2018). The demand for electricity is expected to grow substantially in the coming decades due to the trend of electrification of other emissions intensive sectors such as transportation. This makes the electricity sector one of the most important areas for policies aimed at mitigating climate change worldwide. Major industrialized world regions such as the European Union are planning to massively reduce their emissions from electricity generation within the coming decades as outlined in the EU’s Energy Roadmap 2050 (European Commission, 2011). At the core of the proposed measures is a large increase in generation from renewable energy (RE) sources meant to replace electricity production from conventional fossil generation technologies. Since the two most promising RE technologies, wind and solar energy, are intermittent (i.e., their production at any time depends on the availability of the natural resource, wind or solar irradiation.), the risk for a mismatch of supply and demand at a given point in time increases considerably when these RE sources replace dispatchable technologies like natural gas or coal fired power plants without major adjustments to the functioning of the electricity system. One such measure to better integrate the intermittent generation from RE is a substantial increase of electricity storage capacities, which has been discussed intensively in the scientific literature and in policy debates. However, there remain many uncertainties regarding costs of storage, potentials of different technologies and the actual need for storage capacities (see, e.g. Zerrahn, Schill and Kemfert, 2018; Sinn, 2017; Abrell, Rausch and Streitberger, 2019a). This discussion is put into a broader context if we consider that within the EU (but also potentially in other jurisdictions like the U.S.) the plan to tackle the challenges of mitigating emissions is proposing a multi-regional approach across member states with greatly varying conventional generation technology mixes, natural RE resource potentials, and a varying degree of cross-border trade and market integration. In such a multi-country setting, trade between regions facilitated by enlarged net transfer capacities at the borders emerges as another, potentially effective approach to better integrate intermittent renewables either as a substitute or as a complement to investment into storage capacity.

It is therefore of interest for the debate about RE integration to adopt a multi-region perspective and extend the discussion about the required storage investment by a study about the possible benefits of trade. On a more abstract level, such an approach amounts to an analysis of different modes of adding the necessary flexibility to the electricity system to cope with large shares of RE. Storage has the capacity to shift generation across time periods and is thus referred to as a temporal flexibility channel. Trade between countries enables a pooling of natural resources and different availability profiles for RE, conventional generation capacities, and also demand over larger distances and therefore we will refer to it by spatial flexibility. As a third dimension of flexibility, we add the regulatory regime since it will also affect the ways in which renewables can be effectively

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11 Jan Abrell (JA), Sebastian Rausch (SR), and Clemens Streitberger (CS) contributed equally to the research design. The modeling and analysis was conducted by CS and JA with contributions from SR. The exposition was written by CS with contributions from SR.
integrated into the existing system. From an economic perspective, the natural question is about the optimal increase of flexibility in each of the three dimensions to maximize public welfare while achieving the environmental goal. In order to answer this, a comprehensive cost benefit analysis for each of the three flexibility channels would be needed. However, the cost side of such an analysis exhibits a high degree of uncertainty because the investment costs for storage technologies are highly uncertain. Also, the estimation of cost and impact on net transfer capacities of additional transmission infrastructure is characterized by a high degree of uncertainty. Instead, we focus on an analysis of the potential benefits of the three flexibility channels and adopt a cost minimization framework where the value or, alternatively, the benefits of flexibility manifest themselves as savings in total system cost.

It is a priori not clear which of the three dimensions has the highest cost-saving potential in a given electricity system and how they interact when employed simultaneously. Therefore, we ask how an increase in flexibility in one or more of these flexibility channels can contribute to achieve a given goal for RE generation in a cost-efficient way and how these channels affect total cost, choices of RE investment, dispatch decisions of conventional generators and in turn CO$_2$ emissions of the electricity sector.

We base our analysis on an empirical approach with a numerical partial equilibrium model of several interconnected electricity markets. We formulate the model as a social planner’s problem to minimize total cost while reaching an ambitious target for the share in production of renewable energy. It resolves hourly markets with marginal cost pricing for all the 8760 hours of a year to capture the large seasonal and intra-day variation of new RE sources (solar and wind energy) and demand which varies over time but is inelastic in each time period. Two essential features of the model are the possibility of trade between regions and the presence of a storage technology. The net transfer capacities for trade and storage capacities are treated as given exogenously, that is we abstract from investment decisions in grid and storage infrastructure and the associated cost. We calibrate the model to data from 2017 and cover 18 European countries with their RE resource potentials and diverse existing conventional generation capacities, which allows us to explore the interactions of electricity systems with a very wide range of mixes of generation technology under several policy scenarios. This heterogeneity of the system, with sub-systems determined by varying technology mixes and a varying degree of interconnection between them makes our findings also relevant for other areas such as large countries with considerable internal heterogeneity (like, e.g. the U.S.) or regions with a high degree of cross-border interconnection (such as, e.g. North America as a whole). Since efforts to mitigate climate change are central to the design of RE support policies we also include CO$_2$ emissions in the analysis.

We draw several conclusions from our analysis. First, regulatory flexibility as a stand-alone measure without any increase in physical infrastructure such as storage capacity or net transfer capacity may reduce curtailment and thus RE investment cost. However, at 2.5% the total cost savings relative to a scenario without any added flexibility are only moderate compared to potential cost savings from temporal or spatial flexibility, which are 5.2% and 7.5%, respectively. Even if the regulatory regime permitted a shift in RE generation to the regions with the most favorable natural resources and thus lower marginal investment cost for renewable capacity this cannot happen if there is no
possibility to store or export the additional generation. We need to keep in mind, however, that a change in the regulatory design does not entail investment cost and thus the associated cost savings can be regarded to be net benefits.

Second, the combination of two (or three) flexibility measures creates larger cost savings than those measures in isolation. However, these potential cost savings are not simply additive. For some combinations, such as regulatory flexibility and spatial flexibility, the combined savings exceed the sum of the benefits from the two single interventions, whereas a combination of temporal flexibility with either of the other two flexibility channels creates cost savings that are less than the sum of the savings associated with the two flexibility measures in isolation. This finding is relevant for the optimal choices of a regulator because these interactions should be taken into consideration to achieve a least cost outcome.

Third, decisions whether to increase spatial or temporal flexibility have direct impacts on the optimal technology mix of RE investments. Due to their differing generation profiles, wind and solar energy interact differently with storage and net transfer capacities. On the one hand, storage tends to favor solar over wind in many countries because it allows to distribute solar generation more evenly over the hours of a single day or even across seasons of the year. Increased net transfer capacities, on the other hand, tend to go well with wind generation which has more varied availability profiles across distant regions.

Fourth, even with a fixed target for the production shares of renewable energy emissions vary considerably (up to 50%) because of the interaction of flexibility measures with the conventional generation technologies. Both, temporal and spatial flexibility measures favor low-cost technologies over more expensive peak-load producers but the former shifts generation to the lower cost producers in each country whereas the latter shifts production along a supply curve which is aggregated over the entire region. If a country has emission-intensive fossil producers as the lowest cost option this means that added temporal flexibility will likely increase overall emissions even if a less costly low-emissions technology such as nuclear were available in a neighboring country. In a scenario with added spatial flexibility, this cross-border potential for reducing emissions can be exploited through trade. For the model specification in our simulations representing European data for the base year 2017, spatial flexibility reduces emissions more strongly than temporal flexibility via this mechanism.

To the best of our knowledge, this paper is the first to combine the three flexibility channels available for the market integration of RE generation in a single framework. It is connected to several strands of the literature which are mostly focusing on one flexibility channel. First, there is an ongoing debate on the necessary investments into storage to accommodate new RE generation. Sinn (2017) argues that very high shares of RE generation require prohibitively high investments into storage capacity because otherwise large percentages of possible RE generation would have to be curtailed. In contrast to that, Zerrahn, Schill and Kemfert (2018) show that already allowing for a small amount of curtailment leads to a large saving in investment cost for storage facilities. A second strand of the literature concentrates on the interaction of storage capacity with existing conventional and new renewable technologies. Crampes and Moreaux (2010) analyze the inter-
action of pumped hydro storage with conventional fossil generation technologies and derive how to optimally use the technologies together without considering investment into new RE capacity. Linn and Shih (2016) employ a numerical model of the Texas ERCOT region to analyze how new storage capacities interact with current electricity systems featuring emissions intensive generation from coal, cleaner electricity production from gas, and zero emissions electricity from wind and solar energy. They lay a focus on the resulting total carbon emissions. Similarly, Carson and Novan (2013) investigate emissions effects with data from the ERCOT region using a theoretical model and empirical methods and in addition they study the effects of new storage capacity on peak and off-peak producers. The papers in these two strands of the literature analyze temporal flexibility through storage and we contribute by adding the interaction with regulatory and spatial flexibility.

Third, there is an emerging literature on regulatory design in electricity markets with storage. Helm and Mier (2018) focus on the emissions impacts of subsidies for storage. Abrell, Rausch and Streitberger (2019a) show that costly curtailment or RE generation can be reduced by tailoring the design of the regulatory regime to achieve a better matching between renewable supply and demand patterns. Whereas these papers analyze increasing temporal and also regulatory flexibility, we contribute by extending the range of the analysis by adding spatial flexibility by means of electricity trade.

Fourth, spatial flexibility of electricity generation is discussed in the literature about international electricity trade. von der Fehr and Sandsbraten (1997) analyze the impact of increasing electricity trade in Nordic countries. Antweiler (2016) develops a theory of international trade in a homogeneous commodity, electricity, and shows how two-way trade can emerge because of temporal differences in load patterns. Abrell and Rausch (2016) investigate a multi-sector general equilibrium model with a detailed representation of the European electricity sector to assess the impact of higher shares of renewables on gains from trade and CO\textsubscript{2} emissions. This strand of the literature analyzes spatial flexibility of electricity generation but does not assess the effect of temporal flexibility by means of storage.

Fifth, we also make a connection to a growing literature investigating the consequences of the fundamental heterogeneity of RE technologies with respect to availability patterns. Abrell, Rausch and Streitberger (2019b) point out that the environmental value and market value of different renewables may vary and suggest that differentiating subsidies by technology might improve the environmental impact of RE policies, while Fell and Linn (2013) and Wibulpolprasert (2016) analyze how heterogeneity in renewable resource availability affects the cost-effectiveness of various abatement policies. Abrell, Kosch and Rausch (2019) use an empirical approach to an ex-post evaluation of market values and environmental values of RE sources. These studies focus on lessons for regulatory design emerging from the heterogeneity of renewable production profiles. In this way, they introduce regulatory flexibility. However, these papers do not assess the flexibility of the regulatory regime across regions and its relation to international trade and storage facilities.
2 The Economics of Renewable Energy Support

Abstract

This paper uses theoretical and numerical economic equilibrium models to examine optimal renewable energy (RE) support policies for wind and solar resources in the presence of a carbon externality associated with the use of fossil fuels. We emphasize three main issues for policy design: the heterogeneity of intermittent natural resources, budget-neutral financing rules, and incentives for carbon mitigation. We find that differentiated subsidies for wind and solar, while being optimal, only yield negligible efficiency gains. Policies with smart financing of RE subsidies which either relax budget neutrality or use polluter-pays financing in the context of budget-neutral schemes can, however, approximate socially optimal outcomes. Our analysis suggests that optimally designed RE support policies do not necessarily have to be viewed as a costly second-best option when carbon pricing is unavailable.

2.1 Introduction

Decarbonization of energy systems to cope with the major challenges related to fossil fuels—limiting carbon dioxide (CO$_2$) emissions to mitigate global climate change, lowering local air pollution to yield health benefits, and enhancing the security of energy supply—will require drastic changes in the future mix of energy technologies in favor of using low-carbon, renewable energy (RE). Economists seem to agree that carbon pricing is the most efficient regulatory strategy (Goulder and Parry, 2008; Metcalf, 2009; Tietenberg, 2013), along with policies to address positive externalities related to technological innovation through R&D investments and learning (Jaffe, Newell and Stavins, 2005; Acemoglu et al., 2012). Policies aimed at subsidizing the deployment of RE technologies are often considered a costly second-best option for internalizing a carbon externality. Moreover, by lowering the price of energy services, RE subsidies undermine incentives for energy conservation (Holland, Hughes and Knittel, 2009). Yet, policies promoting clean energy from RE sources such as wind and solar are the most widely adopted form of actual low-carbon policy (Meckling, Sterner and Wagner, 2017).

This paper examines how inefficient optimally designed RE support strategies are in relation to carbon pricing. An RE support scheme comprises two essential elements: (1) implicit or explicit

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13 As of 2016, about 110 jurisdictions worldwide—at the national or sub-national level—had enacted policies subsidizing wind and solar power (REN, 2017). The *Renewable Energy Directive* by the European Commission (2010) established a policy framework for the promotion of RE in the EU with the aim to meet by 2030 27% of total EU-wide energy consumption with renewables. In the United States, the federal government provides sizable production and investment tax credits for RE and more than half of the states have adopted renewable portfolio standards mandating minimum levels of RE generation (U.S. Department of Energy, 2016).

14 We abstract from positive externalities related to learning, technological innovation through R&D investments, and network effects (Jaffe, Newell and Stavins, 2005; Acemoglu et al., 2012; Bollinger and Gillingham, 2014) which
subsidies paid to RE firms (2) and a rule determining how such subsidies are financed. A generic way of thinking about what do optimal RE support schemes look like is therefore to ask how RE funding should be structured and financed.

Our analysis emphasizes three major issues for RE policy design which are of relevance for the decarbonization of real-world energy systems. First, wind and solar resources exhibit a large heterogeneity in terms of their temporal and spatial availability. Adding one MWh of solar electricity may thus yield very different CO₂ emissions reductions compared to adding one MWh of wind; the exact answer depends on the complex interactions between heterogeneous resource availability, time-varying energy demand, and the carbon-intensity and technology costs of installed production capacities. We investigate how RE subsidies should be structured to take into account these heterogeneous marginal external benefits. Second, most of the currently adopted forms of RE support are revenue-neutral, i.e. RE subsidies are financed through energy consumption taxes—either explicitly, as under a FIT or market premium approach, or implicitly, as for the case of technology or intensity standards. We analyze the implications of revenue-neutral RE support schemes in the context of optimal policy design. Third, in the absence of stringent carbon pricing and given that RE support schemes are currently the most widely adopted form of actual low-carbon policies, a future world with a dichotomous energy system—comprising either clean energy from RE sources or highly carbon-intensive “dirty” fossil fuels (i.e., coal)—is not unlikely at all. We thus investigate how the financing of RE subsidies can be designed to provide incentives for climate change mitigation.

We formulate theoretical and numerical equilibrium models of optimal policy design where society (i.e., the regulator) is concerned with the management of an environmental externality related to the use of fossil fuels. Decisions about energy supply and demand stem from profit- and utility-maximizing firms and consumers in the setting of a decentralized market economy. We first theoretically characterize the optimal structure and financing of RE subsidies as well as the conditions under which such policies can implement socially optimal outcomes. To assess different RE support schemes in an empirically plausible setting and to derive additional quantitative insights, we develop a numerical framework which extends the theoretical model and accommodates a number of features relevant for analyzing real-world electricity markets. While the model is calibrated with data for the German electricity market, our numerical simulations yield qualitative insights relevant to the decarbonization of the electricity sector in many countries.

The key insight from our analysis is that RE support policies do not necessarily have to be viewed as providing an important rationale for RE support policies. While the presence of such externalities can make RE support more attractive relative to carbon pricing, it is beyond the scope of the paper to examine how it may affect the performance of alternative RE support policies.

Examples of widely adopted forms of RE support include feed-in tariffs (FITs), guaranteeing a fixed output price per MWh of electricity sold, and market premiums which essentially are output subsidies added to the wholesale electricity price. The expenses for a FIT or output subsidy paid to RE firms are typically financed through levying a tax on energy demand of consumers. RE quotas, renewable or clean portfolio standards are widely adopted examples of technology or intensity standards which are blending constraints implicitly combining output subsidies for RE with input production taxes to finance the RE support.

These include, among others, hourly wholesale markets, multiple energy technologies, time-varying and price-responsive demand, temporally and spatially heterogeneous quality of wind and solar resources, and output-dependent marginal cost and CO₂ emissions to reflect flexibility and efficiency constraints at the power plant level.
a costly second-best option for internalizing a carbon externality—when carbon pricing is unavailable due to political (and other) constraints. The ability of optimally designed RE support to closely approximate first-best outcomes obtained under carbon pricing crucially depends on the financing of renewables support. The basic idea is that financing rules can be designed in such a way that they almost optimally stimulate the same CO₂ reduction channels that would be triggered by carbon pricing—but not by a blunt subsidization of RE.

Our main findings can be summarized as follows. First, the optimal subsidy for an RE technology reflects both the environmental and market value of the underlying intermittent natural resource. The environmental value reflects the environmental damage avoided by replacing fossil-based with renewable energy supply. The market value reflects the economic rents for firms and consumers created by using intermittent resource. Accordingly, we find that the optimal RE subsidies for wind and solar differ. The quantitative analysis, however, suggests that the efficiency gains from differentiating RE subsidies across technologies are negligible. Second, under an optimal RE support scheme, the revenues raised from an energy demand tax exceed the expenses for RE subsidies. The important implication for policy design is that revenue-neutral support schemes, such as the widely adopted FIT or RE quota policies, cannot implement a social optimum. We find that revenue-neutral RE support schemes entail large efficiency losses compared to a first-best carbon pricing policy as they fail to appropriately incentivize the energy conservation channel. Third, we show that a RE support policy can implement the first-best outcome only if achieving the social optimum does not require a change in the fossil-based technology mix (relative to the unregulated market outcome). Fourth, the efficiency of RE support schemes importantly depends on the way in which RE subsidies are financed. We find that combining RE subsidies with an optimal tax on energy demand or using intensity or technology standards which link the financing of RE subsidies to the carbon intensity of fossil-based energy suppliers are particularly effective ways for improving policy design.

To our knowledge, this paper is the first to investigate the optimal design of public policies to support intermittent RE resources in the presence of a carbon externality. In light of the widespread use of RE policies to help decarbonize today’s energy systems, we thus believe that our analysis fills an important gap in the existing literature. At a broader level, the paper contributes to the literature in public and environmental economics focused on understanding the impacts and design choices of governmental regulation to address market failures and externalities related to pollution and technological progress through learning and R&D investments (see, for example, Fullerton and Heutel, 2005; Goulder and Parry, 2008; Fischer and Newell, 2008; Acemoğlu et al., 2012). While most studies have scrutinized various market-based and “command-and-control” approaches to carbon mitigation, the issue of how to best design public policies to promote energy from intermittent RE resources has received surprisingly little attention. A notable exception is Reguant (2019) which examines the interaction between RE policies and the retail tariff design. She finds that RE policies are more cost-effective to achieve a given CO₂ emissions reduction if their associated renewable payments are reflected in retail prices, as compared to a situation in which consumers face flat prices and costs are recovered either by lump-sum fees or through a higher average price. While we do not compare different retail tariff designs, we assume that consumers
pay the real-time price of electricity plus a constant retail fee that ensures cost recovery on the margin—thereby adopting one of the four retail tariff designs analyzed in Reguant (2019).^{17}

Recent empirical evidence (Kaffine, McBee and Lieskovsky, 2013; Cullen, 2013; Novan, 2015) has documented the temporal and spatial heterogeneity of intermittent wind and solar resources in terms of their environmental value, i.e. avoided CO$_2$ emissions per MWh of RE electricity. Based on an econometric ex-post assessment for Germany and Spain, Abrell, Kosch and Rausch (2017) find that the impacts of RE support policies on wholesale electricity prices vary substantially depending on whether wind or solar energy is subsidized. While these papers generally point out that the heterogeneous environmental and market values of different intermittent RE resources are not reflected in the prevailing policy incentives that guide investments in RE resources (Callaway, Fowlie and McCormick, 2017), the implications for policy design have not been analyzed. By typically adopting a simplified and aggregated representation of RE technologies, natural resource variability, and time-varying energy demand, most of the work analyzing RE support policies (Fischer and Newell, 2008; Rausch and Mowers, 2014; Kalkuhl, Edenhofer and Lessmann, 2015; Goulder, Hafstead and Williams, 2016) has abstracted from the fact that wind and solar resources are heterogeneous—thereby ignoring the idiosyncratic ways in which distinct intermittent RE resources interact with energy supply and demand. Our framework investigates the optimal design of RE support schemes in the context of multiple intermittent RE resources.

A small and recent literature has started to examine the effects of intermittent energy sources for the provision of electricity employing the peak-load pricing model (Crew and Kleindorfer, 1976; Crew, Chitru and Kleindorfer, 1995). Ambec and Crampes (2012) and Helm and Mier (2016) analyze the optimal and market-based mix of intermittent RE and conventional dispatchable energy technologies. They do not, however, investigate the question of government support for RE resources. Ambec and Crampes (2017) theoretically examine optimal RE policies in a setting with one intermittent RE resource, i.e. either wind or solar—thus not permitting to investigate the implications of multiple heterogeneous RE resources for optimal policy design. Fell and Linn (2013) and Wibulpolprasert (2016) take into account the temporal and spatial resource heterogeneity, but focus on comparing RE policies in terms of their cost-effectiveness to achieve a given and exogenously determined emissions target. In contrast, our analysis explicitly considers a carbon externality and analyzes optimal RE policy design when the choice of environmental quality is endogenous.

The remainder of this paper is organized as follows. Section 2.2 presents our theoretical model and results. Section 2.3 describes the empirical quantitative framework to analyze RE support policies and presents our main simulation results. Section 2.4 reports on a number of robustness checks and model extensions. Section 2.5 concludes. Appendix A.1 contains additional proofs. Appendix A.2 provides a comprehensive documentation of the numerical model, data sources, and calibration

---

^{17}Relative to Reguant (2019), we contribute by investigating optimal RE policy designs instead of focusing on cost-effectiveness; in particular, we investigate how optimal RE policies should be designed beyond cost recovery, i.e. budget neutrality. To the extent that simpler retail tariff designs prevail in real-world electricity markets, in particular for residential consumers, our estimates of the welfare gains for carbon pricing and all RE policy designs should be viewed as upper bounds. In future markets with an increasing role for smart metering devices, we expect a situation more similar to real-time pricing.


2.2 Theoretical Model and Results

2.2.1 Model setup

We have in mind a situation where society is concerned with the management of an unpriced environmental externality that is related to the use of fossil fuels in energy production. Although the reasoning below fits alternative applications, we let climate change and CO₂ emissions abatement guide the modeling. We focus on the question how public policies supporting RE technologies should be best designed to address the carbon externality.

ENERGY TECHNOLOGIES AND PRODUCTION.—We consider a perfectly competitive electricity market in which in each period \( t, t' \in \{1, 2\} \) electricity can be produced by conventional technologies (e.g., coal, gas, nuclear) and intermittent renewable energy technologies (e.g., wind and solar). Output from different technologies is a homogeneous good. Conventional technologies \( i \in \{c, d\} \) are assumed to be fully dispatchable, i.e. production can be varied freely at any point in time up to the installed capacity limit. Conventional technology \( i \) produces electricity output at time \( t \), \( q_i(t) \), incurring production cost \( C_i(q_i(t)) \) where \( C \) is a continuous and weakly convex function \( (C'_i := \partial C_i/\partial q_i > 0 \text{ and } C''_i := \partial^2 C_i/\partial q_i^2 > 0) \). CO₂ emissions associated with using technology \( i \) at time \( t \) depend on the level of output and are given by \( E_i(q_i(t)) \). For all \( i \), we assume that the marginal emissions rate is strictly positive \( (E'_i := \partial E_i/\partial q_i > 0) \) and increases weakly in the level of output \( (E''_i := \partial^2 E_i/\partial q_i^2 > 0) \). Relative to the clean technology \( c \), the dirty technology \( d \) is characterized by a higher CO₂ emissions rate \( (E'_d > E'_c) \).

In addition, we assume that in the absence of environmental policy, \( C_{ct}(q_{ct}) > C_{dt}(q_{dt}) \), implying that the clean fossil-based technology \( c \) is not in the market. While it would be straightforward to relax this assumption, it helps to focus on assessing the impacts of a supply-side driven fuel switch between high- and low-carbon technologies in response to an RE policy. Our numerical analysis will scrutinize this assumption by modeling a number of (discrete) conventional energy technologies which exhibit heterogeneous emissions intensities and are present in the initial situation without RE support.

\(^{18}\) An Online Appendix provides the computer codes and all data files required to replicate the quantitative analyses.

\(^{19}\) Our framework could be extended to also consider other externalities related to fossil fuel use such as local air pollution and energy security considerations. We also abstract from explicitly representing externalities related to the deployment of RE technologies such as fostering innovation, learning, and local employment effects.

\(^{20}\) Note that conventional energy technologies can differ in terms of dispatchability, for example, due to ramping constraints and maintenance. We abstract from such considerations here.

\(^{21}\) The convex cost functions for conventional energy technologies should be viewed as an implicit representation of multiple discrete suppliers with exogenously given production capacities ordered by marginal cost.

\(^{22}\) Relaxing the assumption requires introducing capacity constraints for the two technologies. Therefore, a case-by-case analysis would be needed to analyses the case in which wither only the dirty or both technologies are in the market. Albeit this would make the model more realistic, it would complicate the further analysis but not lead to further insights.

\(^{23}\) Also, note that \( C'_c(q_{ct}) > C'_d(q_{dt}) \) together with the convexity of cost functions implies that marginal cost functions for the clean and dirty conventional technology do not intersect.
We consider two RE technologies (e.g., wind and solar) which differ with respect to resource availability and investment cost for building production capacity. Output produced with either RE technology does not cause any CO\(_2\) emissions. To reflect differences in resource availability, we index RE technologies by \(t\) and assume that RE technology \(t\) is available in period \(t\) but not in period \(t'\). While in reality wind and solar resources are often available at the same time, this assumption enables us to examine how RE support policies should be designed in light of heterogeneous RE resources. Our numerical analysis relaxes this assumption by incorporating data to characterize the empirical joint distribution of wind and solar resources.

Without loss of generality, marginal generation cost for each RE technology is normalized to zero. To produce output with RE technology \(t\), it is required to install capacity \(k_t\), creating investment cost equal to \(G_t(k_t)\). Investment cost functions are strictly convex expressing the fact that investments first take place at most productive sites (\(G'_t := \partial G_t/\partial k_t > 0\) and \(G''_t := \partial^2 G_t/\partial k_t^2 > 0\)). As RE technologies can produce output at zero marginal cost, output at time \(t\) is equal to the installed capacity \(k_t\). Energy production from RE sources does not cause any emissions.

DEMAND AND ENERGY BALANCE.—Consumers derive gross utility, \(S_t(d_t)\), from the consumption of \(d_t\) units of electricity at time \(t\). With \(p(d_t)\) denoting the inverse demand function, gross surplus at time \(t\) is \(S_t(d_t) := \int_0^{d_t} p(x) dx\). \(S_t\) is a continuous derivable function which we assume to be concave (\(S'_t := \partial S_t/\partial d_t > 0\) and \(S''_t := \partial^2 S_t/\partial d_t^2 \leq 0\)).

We assume that energy demand only responds to price in the same period. This is equivalent to assuming that the cross-price elasticity of energy demand at time \(t\) with respect to price at time \(t'\) is zero, i.e. \(\partial d_t/\partial p_{t'} = 0\), \(\forall t\). This assumption considerably eases analytical complexity as it implies that \(S_t(d_t)\) is separable across time periods. Importantly, this assumption does not rule out the possibility that consumers increase or decrease demand in response to current-period changes in the electricity price.

Energy balance requires that at any point in time total energy production equals energy demand:

\[
k_t + \sum_i q_{it} = d_t. \tag{2.1}
\]

ENVIRONMENTAL EXTERNALITY AND SOCIAL SURPLUS.—The environmental externality derives from CO\(_2\) emissions due to burning fossil fuels associated with supplying energy from conventional technologies. CO\(_2\) as a uniformly-mixed pollutant is assumed to cause time-independent and constant marginal damage equal to \(\delta\) per unit of \(E_i(q_{it})\). \(\delta\) may thus be viewed as the social cost of carbon (SCC) per ton of emitted CO\(_2\).

The regulator is concerned with maximizing social surplus which is defined as gross utility net of private production cost associated with conventional and RE supply and the environmental damage
to society caused by aggregate emissions:

$$W := \sum_t \left[ S_t(\Delta_t) - G_t(k_t) - \sum_i C_i(q_{it}) \right] - \delta \sum_t \sum_i E_i(q_{it}).$$

(2.2)

### 2.2.2 Social planner optimum

In the social optimum, the regulator chooses levels of output of conventional and RE technologies ($\hat{q}_{it}$ and $\hat{k}_t$) which maximize social surplus $W$ subject to the energy balance constraint (2.1) according to:

$$C'_t + \delta E'_t \geq S'_t \quad \forall t, i \quad (\hat{q}_{it})$$

(2.3a)

$$G'_t = S'_t \quad \forall t \quad (\hat{k}_t).$$

(2.3b)

The interpretation of the conditions for the social optimum is straightforward: energy produced by conventional technology $i$ at time $t$ ($\hat{q}_{it}$) is chosen such that the marginal social cost—comprising marginal private cost of production $C'_t$ and the marginal environmental damage $\delta E'_t$—are equal to marginal private surplus $S'_t$; energy produced with (or production capacity of) the RE technology $t$ ($\hat{k}_t$) is chosen such that marginal private investment cost $G'_t$ and the marginal private surplus are equalized. The socially optimal pollution level is then given by $\hat{E} = \sum_{i,t} E_i(\hat{q}_{it})$.

Depending on how strong the environmental motive ($\delta$) is, energy production from conventional technologies in the social optimum can take on two outcomes. If $\delta$ is “small”, then $(C_{ct}' + \delta E_{ct}')/(C_{dt}' + \delta E_{dt}') > 1$ implying that energy production with the clean technology is more costly and hence only the dirty technology is used. In contrast, for sufficiently high $\delta$, only the clean conventional technology is used. To create a meaningful problem to examine RE support policies, we assume that the social optimum involves a positive amount of energy supplied from RE technologies at every $t$, i.e. $\hat{k}_t > 0$.

### 2.2.3 The regulator’s problem in the decentralized economy

The fundamental problem of environmental regulation analyzed in this paper is to examine how RE support policies should be best designed to address the carbon externality associated with fossil-
based energy supply in a decentralized market economy where equilibrium decisions about energy supply and demand stem from profit- and utility-maximizing firms and consumers (and can hence not be directly controlled as in the social planner problem analyzed in Section 2.2.2).

Hence, the regulator’s problem is to maximize social welfare $W$ taking into account a set of constraints that describe the equilibrium responses of economic agents with respect to market information (prices) and policy choice variables:

$$
\max_{\mathbf{b} = \{s_t, \tau_t, \kappa_t\}} W(d_t, k_t, q_{it}, \delta) \tag{2.4}
$$

s.t. $(p_t, d_t, k_t, q_{it})$ solve the market equilibrium conditions:

$$
S_t' = p_t + \tau_t \quad \forall t \quad (d_t) \tag{2.4a}
$$

$$
C_{it}' + \kappa_{it} \geq p_t \quad \forall t, i \quad (q_{it}) \tag{2.4b}
$$

$$
G_t' = \psi_t \quad \forall t \quad (k_t) \tag{2.4c}
$$

$$
\psi_t = \begin{cases} 
    p_t + s_t & \text{if output subsidy or intensity standard} \\
    s_t & \text{if feed-in tariff}
\end{cases} \tag{2.4d}
$$

$$
k_t + \sum_i q_{it} = d_t \quad \forall t \quad (p_t)
$$

where $p_t$ denotes the price of energy at time $t$. Policy instruments include an output subsidy ($s_t$), a demand tax ($\tau_t$), and an input tax ($\kappa_{it}$) and are described in detail below.

For given policy choice variables $\mathbf{b}$, the equilibrium of the decentralized economy is defined by prices and quantities $\{p_t, d_t, k_t, q_{it}\}$ such that: (i) the marginal private utility from energy consumption equals the private marginal cost (2.4a), (ii) firms supplying energy with conventional technology $i$ minimize cost of production (2.4b), (iii) firms supplying energy with RE technology $t$ minimize cost (2.4c), and (iv) the wholesale energy markets clear (2.4d).²⁶

POLICY INSTRUMENTS.— Table 2.1 categorizes the different policy controls for promoting RE supply contained in $\mathbf{b}$ along two key dimensions: the structure of RE subsidies and the way RE subsidies are refinanced. RE producers can either receive a guaranteed fixed price per MWh sold ($\psi_t = s_t$), as is the case under a FIT, or they can receive the subsidy on top of the market price, as is the case under a market premium approach ($\psi_t = p_t + s_t$). Moreover, RE subsidies can be differentiated in terms of the support for each RE technology ($s_1 \neq s_2$) or they can be uniform ($s_1 = s_2$).

Several ways of financing RE subsidy payments are conceivable. Under FIT and premium systems the RE subsidies are often financed by levying a (time-constant) tax on energy demand ($\tau$). In such a case, $\tau$ is endogenously determined by the following revenue-neutrality constraint which has

²⁶Assuming perfect competition with free entry and exit and price-taking consumers, it is straightforward to derive conditions (2.4a)-(2.4c) from the individual expenditure- and cost-minimization problems of optimizing consumers and firms, respectively.
Table 2.1: Taxonomy of policy designs which explicitly or implicitly promote RE supply.

<table>
<thead>
<tr>
<th>Structure of technology-neutral or -differentiated RE subsidies ($s_t$)</th>
<th>Refinancing of RE subsidies</th>
</tr>
</thead>
<tbody>
<tr>
<td>No direct RE support</td>
<td>Carbon tax</td>
</tr>
<tr>
<td></td>
<td>Emissions trading</td>
</tr>
<tr>
<td>Guaranteed output price</td>
<td>Feed-in tariff (FIT)</td>
</tr>
<tr>
<td></td>
<td>Technology or intensity standards:</td>
</tr>
<tr>
<td></td>
<td>• RE quota or renewable portfolio standard (RPS)</td>
</tr>
<tr>
<td></td>
<td>• Green offsets</td>
</tr>
<tr>
<td>Output subsidy</td>
<td>Market premium</td>
</tr>
</tbody>
</table>

Output to be added to the upper-level problem in (2.4):

$$\sum_t \tau d_t = \sum_t s_t k_t (\tau). \quad (2.5)$$

Alternatively, it is possible to view the (time-varying) energy demand tax ($\tau_t$) as a distinct policy instrument chosen to optimally incentivize energy conservation via the demand channel. In this case, the optimal policy involves choosing both ($s_t, \tau_t$).

Yet another way of refinancing RE subsidies applies if intensity or technology standards are used. Such standards are essentially blending constraints which translate into implicit output subsidies for RE technologies ($s_t$) and implicit input taxes ($\kappa_{it}$) in energy production to finance RE subsidies (Holland, Hughes and Knittel, 2009). Consider the case of an RE quota which mandates that a certain share $\gamma$ of total energy supplied has to come from RE sources—adding the following constraint to the lower-level equilibrium problem in (2.4):

$$\sum_t k_t \geq \gamma \sum_t \left( k_t + \sum_i q_{it} \right) (p^{\text{Credits}}). \quad (2.6a)$$

The RE quota can be conceived as a system of tradable credits where $p^{\text{Credits}}$ corresponds to the post-trading equilibrium price of a credit determined by credit supply and demand.27

A tradable RE standard is by definition revenue-neutral: expenses for RE subsidies are fully financed through implicit input taxes $\kappa_{it}$ on energy producers. Output subsidies are paid to RE firms which receive one credit valued at price $p^{\text{Credits}}$ for each MWh of electricity produced. From (2.6a) it then follows that the implicit per-MWh tax under an RE quota is:

$$\kappa_{it}^{\text{RE quota}} = \gamma p^{\text{Credits}}. \quad (2.6b)$$

---

27We focus here on the case most relevant for real-world RE policy in which the standard does not differentiate between heterogeneous types of RE sources.
The interpretation is that all energy firms have to hold $\gamma$ credits for each MWh of energy produced. Because RE firms also receive one credit per MWh, their effective net support per MWh of electricity produced is

$$s_{\text{RE quota}} := p^{\text{Credits}} - \gamma p^{\text{Credits}} = (1 - \gamma) p^{\text{Credits}}.$$  \hspace{1cm} (2.6c)

We propose and analyze a new design for a tradable and revenue-neutral intensity standard which links the amount of RE energy output to overall emissions derived from using fossil fuels in energy production. We refer to such a scheme as "green offsets". The main idea is that CO$_2$ emissions have to be compensated or offset by a certain amount of energy supplied from "green" (i.e., wind and solar) RE sources according to:

$$\sum_t \gamma \sum_i E_{it}(q_{it}) (p^{\text{Credits}}).$$  \hspace{1cm} (2.7a)

$\gamma$ here represents the "offset intensity", i.e. the minimum amount of green energy required to offset overall CO$_2$ emissions from "dirty" energy production, which is chosen by the regulator. Here, $p^{\text{Credits}}$ indicates the value of a tradable "green offset" certificate. In an energy system where RE is relatively abundant, $p^{\text{Credits}}$ is small; it is zero if all energy comes from green sources. If fossil fuels are still the dominant sources of energy supply, $p^{\text{Credits}}$ is large and provides an incentive for RE producers to increase their supply.

Analogously to the case of an RE quota, the implicit input tax per MWh of electricity produced under a revenue-neutral "green offset" standard is:

$$\kappa^{\text{Green offsets}}_{it} = \gamma E_{it}(q_{it}) p^{\text{Credits}}.$$  \hspace{1cm} (2.7b)

A green offset policy is thus an RE support scheme with polluter-pays refinancing: the expenses for RE subsidies are entirely refinanced by levying production input taxes on fossil-based electricity firms which are proportional to the carbon intensity. This implies that RE firms with zero emissions receive a net support equal to the credit price:

$$s_{\text{Green offsets}} := p^{\text{Credits}}.$$  \hspace{1cm} (2.7c)

Under both forms of intensity standards, and compared to policies such as a FIT and market premium which directly choose the level of RE support, the only policy choice variable of the regulator is the level of the intensity target $\gamma$ which then implicitly determines the RE subsidy rate $s$ and refinancing taxes $\kappa_{it}$ through (2.6a) and (2.6b) in the case of an RE quota and (2.7a) and (2.7b) in the case of green offsets, respectively.

Finally, a carbon pricing policy—implemented through a CO$_2$ tax or a system of tradable emissions permits—can be represented as a specific input tax $\kappa_i$ based on the carbon content of energy production without direct support for RE (i.e., $s_t = 0$). RE supply is, however, incentivized indirectly through lowering the production cost of RE technologies relative to fossil-based generation.
We now turn to characterizing optimal policies for RE support when the regulator can use different policy designs which draw on the instruments displayed in Table 2.1. The second part of our theoretical analysis examines whether or not the various policy designs for RE support are optimal from a social perspective and characterizes the conditions under which RE policies can attain a social optimum.

### 2.2.4 Optimal policies for RE support

**CARBON PRICING.**—We begin by analyzing a carbon pricing instrument which can be implemented equivalently either through a carbon tax or a system of tradable emissions permits. While carbon pricing does not explicitly subsidize RE technologies, it establishes indirect support for RE by altering relative production cost in favor of RE technologies. The case of a carbon tax constitutes a useful benchmark against which to compare RE support policies. It is straightforward to show that:

**Lemma 1** The social optimum can be implemented by using for each energy firm $i$ an input tax equal to its marginal environmental damage at time $t$ (i.e., $\kappa_{it} = \delta E_{it}'$, $\forall i, t$).

Lemma 1 simply recaps the standard result that the environmental externality can be fully internalized with a Pigouvian pricing rule which implements the social optimum by introducing a tax equal to the marginal environmental damage $\delta$ (Baumol, 1972; Metcalf, 2009). A carbon pricing instrument is efficient for two reasons. First, it corrects the relative prices of energy technologies/fuels between fossil-based and RE technologies as well as between clean and dirty conventional technologies. At the same time, it does not distort choices for investments in RE technologies (i.e., wind vs. solar). Second, it corrects the price for energy services thereby incentivizing the optimal amount of energy conservation (i.e., the optimal level of energy demand).

**DIRECT RE SUPPORT SCHEMES.**—We now assume that carbon pricing or input taxes are not available, i.e. $\kappa_{it} = 0$, $\forall i$. How should the parameters of a direct RE support scheme—comprising subsidies $s_t$ for RE firms and refinancing taxes $\tau_t$ levied on energy consumption—be chosen optimally? The following proposition characterizes the optimal policy:

**Proposition 1** The optimal RE support scheme consisting of RE subsidies $s_t^*$—structured either as a feed-in tariff or a market premium—and an energy demand tax $\tau^*_t$, is given by:

\[
\psi^*_t = p_t + \delta E_{dt}' \\
\tau^*_t = \delta E_{dt}'.
\]

**PROOF:** See Appendix A.1.2. □

The optimal RE policy support thus requires that, at the margin, consumers—in addition to paying for the non-environmental cost of using resources to supply energy ($p_t$)—bear the environmental

---

28 In the subsequent analysis, $\delta$ refers to the marginal environmental damage in the social optimum.
damage associated with using fossil-based energy \( (\tau_t^f = \delta E_{dt}^f) \).\(^{29}\) At the same time, RE supply is incentivized up to the point where the marginal private costs are equal to the marginal benefits which reflect the non-environmental and environmental value of the targeted RE resource.

An immediate implication of Proposition 1 is that:

**Corollary 1** The optimal feed-in tariff and optimal market premium policy lead to the same equilibrium allocation.

**PROOF:** Using the definition of \( \psi \) in (2.4c), Proposition 1 implies that the optimal level of the FIT and market premium is given by, respectively:

\[
\begin{align*}
 s_t^{FIT} &= p_t + \delta E_{dt}^f \\
 s_t^{Premium} &= \delta E_{dt}^f \quad \forall t.
\end{align*}
\]

and thus yields identical zero-profit conditions for RE production (2.4c) for the case of a FIT and market premium. □

The welfare-maximizing RE subsidy rate per unit of energy produced from a certain RE resource therefore depends on two factors each affecting one of the two main components in social welfare \( W \) in equation (2.2). First, it depends on how much the usage of the RE resource towards supplying energy contributes to the economic (non-environmental) surplus—this is reflected by its “market value” expressed as unit revenues or the market price \( (p_t) \). Second, it depends on the environmental damage avoided by replacing conventional fossil-based energy supply with RE supply—this is reflected by its “environmental value” given by per-unit emissions rate of the (dirty) conventional technology valued at the social cost of carbon \( (\delta E_{dt}^f) \).

If RE subsidies are structured such that firms directly receive the market income from supplying energy from the RE resource, as is the case under a market premium, the optimal RE subsidy does not need to explicitly reflect the market value of the RE resource. Hence, \( p_t \) does not appear in (2.8b) but instead shows up in zero-profit condition for RE production (2.4c). If RE firms are guaranteed a fixed price, as is the case under a FIT, the optimal subsidy rate reflects both the market and environmental value of the RE resource.

The optimal energy demand tax is equal for the FIT and market premium case and reflects the marginal environmental cost caused in each period. By imposing a tax equal to \( \delta \), the regulator pushes demand towards the first-best level of demand. The tax is higher in periods with high emissions thus causing a larger decrease in demand in high damage periods.

An important implication of (2.8a) is that the socially optimal FIT is higher for RE resources which are available in periods with high energy prices. In real-world systems, for example, electricity demand tends to peak around midday when solar resources are available. As long as the share of solar generation is low enough so as not to squeeze out the price setting conventional technology

\(^{29}\)As we show below in Proposition 2, the clean conventional technology does not enter under (optimal) RE support policies, hence the marginal environmental damage is given by the marginal emissions rate of the dirty conventional technology, \( E_{dt}^f \).
at peak times, the upshot of Proposition 1 is thus that the welfare-maximizing FITs should be higher for solar than for wind power. When solar shares in generation rise considerably so as to become the price setting technology, this effect might be reversed since solar availability is more concentrated around midday compared to wind, which would mean that prices would be lower at noon than at night. In such a situation, following Proposition 1 wind would receive higher subsidies in the optimal scheme. At the same time, however, the optimal RE subsidy in the case of a FIT or a market premium also depends on the environmental value of the RE resource that is promoted. Proposition 1 also suggests that the RE subsidies should be higher for RE resources which are available in periods in which the marginal (price-setting) conventional technology has a high CO2 emissions intensity.

Proposition 1 thus implies that optimal RE subsidies should be differentiated to reflect the market and environmental heterogeneity of the underlying resource (e.g., wind and solar). The heterogeneity of wind and solar energy resources is due to differences in resource quality (how much is available?) and temporal availability (when is it available?) which, in turn, both interact with the characteristics of energy demand (temporal variation) as well as conventional energy supply (installed production capacity and carbon intensity of conventional producers).

NON-UNIFORMITY OF RE SUBSIDIES.——The following corollary substantiates the point that optimal RE subsidies should be differentiated by type of RE resource to reflect differences in the market and environmental value:

**Corollary 2** If either the social surplus function $S_t$ is constant over time or the emissions rate of the marginal energy producer does not vary with output (i.e., $E_{dt}^t(q_{dt}) = \text{const.}$), then

(i) the optimal market premium ($s_t^{\text{Premium}}$) is uniform across RE technologies;

(ii) the optimal energy demand tax ($\tau_t^*$) is uniform over time; and

(iii) if, in addition, marginal cost of the dirty technology does not vary with output (i.e., $C_{dt}^m(q_{dt}) = 0$), the optimal FIT ($s_t^{\text{FIT}}$) is uniform across RE technologies.

**PROOF:** See Appendix A.1.3. □

A constant social surplus function over time implies that energy demand does not vary over time. Hence, the wholesale price and the marginal emissions rate are the same in every time period $t$. Under these circumstances, the optimal RE subsidies and energy demand taxes are uniform. The same result is obtained by assuming that the emissions rate of the marginal energy producer (i.e., the dirty conventional technology) does not vary with output and, in addition for the case of a FIT, that marginal costs of the marginal energy producer are constant in output. Given real-world characteristics of energy supply and demand, these conditions are quite unlikely to hold in practice. First, conventional technologies exhibit substantial heterogeneity in terms of marginal costs, heat efficiencies, emissions rates etc. Second, energy demand varies substantially over time reflecting daily and seasonal fluctuations.

If RE resources were completely identical, then the optimal RE subsidies would be uniform. In reality, however, the temporal availability of wind and solar resources differs. Heterogeneous RE resources
interact with time-varying energy demand and heterogeneous energy supply from conventional sources. Proposition 2 simply expresses the fact that under these conditions \( p_t \) and \( \delta E_{dt} \) in equations (2.8a) and (2.8b) are not independent of \( t \). Thus, the optimal FIT or market premium cannot be uniform across RE resource types. Similarly, the optimal tax on energy demand is non-uniform across time in a way that reflects the heterogeneous environmental damage in each time period thus pushing the quantity demanded towards the social optimum.

**LINKING OF RE SUBSIDIES AND REFINANCING TAXES ON ENERGY DEMAND.**—In practice, RE support schemes typically link RE subsidies and taxes on energy demand: for example, the level of the demand tax is often set in order to cover the expenses paid for RE subsidies. While Proposition 1 has characterized the optimal policy rules for RE subsidies and energy demand taxes, it does not shed light on how both instruments should be linked to one another. In particular, is it optimal to choose the energy demand tax such that it exactly yields the income needed to cover the expenses for the optimal RE subsidies? The following corollary shows that an RE support scheme designed in this way cannot be optimal:

**Corollary 3** Under an optimal RE support scheme \( \{\psi_t^*, \tau_t^*\} \), and if RE firms do not supply the entire market (i.e., \( k_t < d_t \)), the revenues raised from an energy demand tax strictly exceed the expenses paid for RE subsidies.

**PROOF:** See Appendix A.1.4. □

Corollary 3 offers yet another perspective on the rules for optimal RE support policies underlying Proposition 1. The optimal subsidy rate should, besides reflecting the market value of the targeted RE resource \( (p_t) \), subsidize RE supply according to the marginal environmental value of the resource \( (\delta E_{dt}) \). Regardless of whether the RE subsidy is structured as a FIT or a market premium, the optimal energy demand tax to finance the RE subsidy is equal to this marginal environmental value, i.e. \( \tau_t^* = \delta E_{dt} \). The intuition is that the market-value component of the optimal RE support does not have to be “re-financed”: in the case of a market premium, RE producers directly receive the market value associated with RE production when selling into the market; in the case of a FIT, the market value for social welfare is indirectly accounted for as the regulator sells the energy bought from RE firms back into the market at the equilibrium wholesale price.

As long as RE production does not make up the whole market, the base for the energy demand tax is larger than the one for RE subsidies, in turn implying that the net income (tax revenues - subsidy payments) for the regulator is positive.\(^{30}\) The important policy implication from Corollary 3 is therefore that energy demand taxes, which are typically used to refinance RE subsidies, should not be determined by considerations about revenue neutrality: requiring that the tax income equals the payments for RE subsidies, implements a demand tax which is too low. Energy demand and fossil-based energy generation then exceed their respective optimal level leading to too little energy conservation and too high environmental damage.

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\(^{30}\)Also, note that the optimal tax and subsidy rates are quantity-based, i.e. per unit of physical energy (MWh) consumed or supplied.
2.2.5 Can RE support policies implement the social optimum?

Do optimal RE support schemes \( \{ \psi^t, \tau^t \} \), comprising RE subsidies—either in the form of a FIT or a market premium—and an energy demand tax, achieve the social optimum which, in the setting of a decentralized market economy, can be implemented through carbon pricing (see Proposition 1)? And if so, what are the conditions under which an optimal RE support policy can implement a social optimum?

To answer this question, we begin by building intuition on how well (optimal) RE policies can address the environmental externality through appropriately exploiting the “fuel switch” channel for reducing pollution. Is a FIT, market premium, or an energy demand tax capable of changing the relative size of dirty to clean conventional energy producers, i.e. induce a fuel switch?

**Proposition 2** With RE support through subsidies \( \{ \psi^t \} \) or energy demand taxes \( \{ \tau^t \} \), the clean fossil-based energy technology does not enter the market despite social concerns for the environmental externality.

PROOF: See Appendix A.1.5. □

The basic intuition behind Proposition 2 is that all instruments reduce the quantity of energy supplied from conventional generation either by partially crowding out conventional generation with increased supply from RE technologies (in the case of FIT and market premium) or by reducing energy demand (in the case of a demand tax). As (dirty) conventional energy generation is the marginal price-setting technology, the (wholesale) producer price of electricity declines. The lower producer price implies that the profitability of sub-marginal energy producers using the clean conventional technology is reduced, too. As the clean conventional energy producers are not in the market initially (i.e., before introducing either one of the policy instruments), they have no incentive to enter the market with these forms of policy support. This holds for both RE subsidies which are uniform or differentiated across RE technologies as well as for a uniform or time-specific energy demand tax.

Importantly, if one assumes that the clean conventional technology is initially in the market, the necessity of a fuel switch depends on which of the fossil-based technology is the marginal generator. As long as the dirty conventional producers remain “price-setting”, no switch from dirty to clean fossil fuels is needed. If a fuel switch is needed, the RE policies would need to achieve a re-ordering of the marginal cost of conventional technologies. This, however, is impossible as with these instruments the regulator cannot directly affect the LHS of the zero-profit conditions for conventional producers \( (2.4b) \).\(^{31}\) The important implication from Proposition 2 is thus that RE support schemes comprising a combination of RE subsidies, with either a FIT or market premium

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\(^{31}\) Without policies affecting directly the marginal cost of production, there exists the possibility that the policy-induced reduction in energy demand can affect the relative marginal cost of conventional producers. For this to occur, the marginal cost functions of conventional producers, \( C'_p(q_p) \), need to intersect and the demand reduction has to move production levels from the right to the left of the intersection point. Given empirically plausible marginal cost functions for conventional, fossil-based energy technologies, such a case can be safely discarded as a mere theoretical possibility which seems to be irrelevant for studying electricity supply under real-world conditions.
Table 2.2: Ability of different RE support policies to incentivize optimal abatement.

<table>
<thead>
<tr>
<th>Can the policy correct...</th>
<th>the relative prices of energy technologies/fuels?</th>
<th>the price of energy services ($\Delta p \leq 0$)?</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>renewables vs. fossil-based</td>
<td>within renewables: wind vs. solar</td>
</tr>
<tr>
<td>Single policy instruments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon pricing</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>FIT or market premium</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>tech.-neutral</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>tech.-differentiated</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Energy demand tax</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>RE support schemes combining single instruments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FIT or market premium with energy demand tax</td>
<td></td>
<td></td>
</tr>
<tr>
<td>revenue neutral</td>
<td>Y</td>
<td>Y/N</td>
</tr>
<tr>
<td>optimal</td>
<td>Y</td>
<td>Y/N</td>
</tr>
<tr>
<td>Intensity or technology standards</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RE quota or RPS</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Green offsets</td>
<td>Y</td>
<td>Y</td>
</tr>
</tbody>
</table>

Given Proposition 2, it is straightforward to characterize the condition under which an optimal RE support scheme can attain the first-best allocation in the social optimum:

**Proposition 3** The optimal RE support scheme consisting of RE subsidies $\psi^*_t$—structured either as a feed-in tariff or a market premium—and an energy demand tax $\tau^*_t$ implements the social optimum if and only if the clean fossil-based energy technology is not required to enter the market.

PROOF: See Appendix A.1.6. □

Intuitively, if the social optimum requires an energy supply mix which involves a positive quantity of energy supplied from the clean fossil-based technology, an optimal RE support scheme will fail to implement the first-best allocation.\footnote{If the clean fossil-based technology already supplied a positive quantity of energy in the unregulated market equilibrium without concerns for environmental quality, the “no fuel-switch” condition underlying Proposition 3 can be re-stated. An optimal RE support then implements the social optimum if and only if the clean fossil-based energy technology is not required to expand its production relative to the unregulated market equilibrium.} Table 2.2 shows the four margins on which a socially optimal regulation of the environmental externality has to operate to efficiently exploit both the “fuel switch” and “energy conservation” channel. An optimal RE support scheme can only affect three of these four margins in a direct manner. By subsidizing RE firms, an RE subsidy (FIT or market premium) can correct the relative prices of energy supplied from conventional vs. RE sources. By differentiating RE subsidies to reflect heterogeneity in the environmental value, it can correct the relative prices of different types of RE resources (wind vs. solar). An energy demand tax can directly stimulate the energy conservation channel. However, an RE subsidy, an energy demand tax, or a combination of both, fails to correct the relative prices of clean vs. dirty conventional energy production.

Proposition 3 also suggests that if the clean conventional technology plays no or only a minor role in the energy supply mix, then an optimal RE support scheme can efficiently exploit both the “fuel switch” and “energy conservation” channel.
role in the social optimum, an optimally designed RE support scheme—taking into account the heterogeneous market and environmental value of the targeted RE resources as well as incentivizing the correct amount of energy conservation (possibly through time-specific demand taxes)—can achieve or come close to the first-best allocation.

How close the optimal RE support policy comes to attaining the social optimum thus depends on the extent to which a fuel switch from dirty to clean conventional energy supply is required. This, in turn, depends on the characteristics of the energy system at hand. For example, consider a system in which conventional energy supply capacities are given by natural gas and coal-fired plants only. If the gas price is “high”, only coal-fired plants are used in an unregulated equilibrium. An optimal environmental policy may then entail a fuel switch inducing coal-fired plants to be more costly than gas fired ones. In contrast, in a situation with “low” prices for natural gas, gas-fired plants may already be the cheaper technology even in the absence of environmental regulation. Adding social concerns about the environmental externality will thus not induce a switch to more costly and carbon-intensive coal-fired plants. Under such conditions, both an optimal RE support scheme and a direct carbon pricing policy can achieve the social optimum.

TECHNOLOGY OR INTENSITY STANDARDS.——RE support policies which are revenue-neutral cannot implement a social optimum—even if achieving the socially optimal allocation does not require a fuel switch between dirty and clean fossil-based generation. As intensity standards such as a green quota or green offset are by construction revenue-neutral (see Corollary 3), they fail to implement the social optimum.

**Proposition 4** An RE quota or a system of green offsets cannot achieve the social optimum.

**Proof:** For the case of an RE quota, comparing conditions (2.3a) and (2.3b), which characterize the first-best solution, with the zero-profit equilibrium conditions for RE producers (2.4b) and conventional producers (2.4c), and using the definitions for implicit input taxes from (2.6b) and the implicit subsidy rate from (2.6c), yields, respectively:

\[
C'_{it} + \delta E'_{it} = C_{it} + \gamma \rho^{\text{Credits}} = S'_{it} = p_t \quad \forall i, t \quad (2.9)
\]

\[
G'_{it} = p_t + (1 - \gamma) \rho^{\text{Credits}} = S'_{it} = p_t \quad \forall t \quad (2.10)
\]

From (2.10) it follows that \( \rho^{\text{Credits}} = 0 \) which, however, contradicts (2.9) which requires that \( \rho^{\text{Credits}} > 0 \) in order to efficiently internalize a positive marginal environmental damage \( \delta > 0 \). The proof for the case of an intensity standard with green offsets proceeds analogously using instead (2.7b) and (2.7c) for the definitions of implicit input taxes and subsidies. □

Proposition 4 bears out the important insight that technology or intensity standards cannot reach a socially optimal allocation because the (implicit) subsidy to RE firms and the (implicit) input taxes on conventional energy producers are inherently linked over the market for certificates— which in turn reflects the feature that such policy schemes are revenue-neutral. If the quota price correctly reflects the marginal damage of emissions, the implied electricity price would correctly reflect the social cost. At the same time, however, an efficient stimulation of RE production requires that
RE firms receive their market value plus an extra rent reflecting the marginal damage avoided (see Proposition 1). Thus, if the marginal damage is already reflected in the market price, the RE support should be zero. This, however, is impossible as the quota price links the tax and the support rate (i.e., the RE quota and system of green offsets are revenue-neutral). In fact, a quota price inducing an efficient tax level would imply that RE firms receive, on top of the subsidy rate, a too high market price resulting in over-investment in RE capacity. Pushing too much RE with zero marginal cost into the market would in turn cause an inefficiently low electricity price undermining the incentive for energy conservation. Thus, linking RE subsidies and refinancing taxes in a revenue-neutral manner and granting a subsidy on top of the wholesale electricity price to RE firms makes it impossible to establish policy signals which induce efficient levels of both RE investments and RE generation.

Lastly, note that the failure of technology or intensity standards to implement the social optimum does not depend on whether the RE support is differentiated across RE technologies to reflect the heterogeneity in the environmental value; rather, the inefficiency stems from the revenue-neutrality of such policy schemes.

2.3 Empirical Quantitative Framework and Results

2.3.1 Overview of numerical model

To assess alternative policy designs for RE support in an empirically plausible setting and to derive additional quantitative insights, we formulate a numerical model which extends our theoretical framework from Section 2.2 in a number of important ways. First, we include multiple discrete conventional energy technologies which differ in terms of heat efficiency, carbon intensity, and installed production capacities. Importantly, this enables us to represent the market conditions for the German electricity market in the year 2014 and to assess policy-induced changes in the technology mix and supply side of the market with finer granularity. Second, we increase the temporal resolution at which energy supply and demand decisions are modelled, thus adding realism in terms of firms’ short-term production (generation dispatch) and long-term investment decisions as well as diurnal and seasonal variations in consumers’ energy use. Importantly, this enables us to characterize with fine granularity the empirical joint distribution of wind and solar resources.

Appendix A.2 provides a comprehensive documentation of the quantitative framework, covering the following aspects: (1) model structure and the representation of alternative RE policies, (2) equilibrium conditions, (3) data sources and model calibration, and (4) computational strategy.

2.3.2 A first look at the data

Figure 2.1 plots the time-series data for temporal availability of wind and solar resources: Panel (a) shows the hourly and daily average availability by season over the course of a full year and Panel (b) shows the availability by hour over a typical day of the full year, winter, and summer.
Figure 2.1: Temporal availability of wind and solar resources ($\alpha_{it}$)
Table 2.3: Descriptive statistics for hourly distributions of key variables in unregulated market.

<table>
<thead>
<tr>
<th>Demand $D_t$ (MWh)</th>
<th>Price $P_t$ (€/MWh)</th>
<th>CO$_2$ emissions $E_t$ (thousand tons)</th>
<th>Marginal emissions $E'_{t}$ (ton/MWh)</th>
<th>Availability factor $\alpha$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>Gas</td>
<td>Coal</td>
</tr>
<tr>
<td>Mean for given percentile range$^a$</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&gt;95%</td>
<td>77.4</td>
<td>46.5</td>
<td>41.7</td>
<td>4.6</td>
</tr>
<tr>
<td>75%-95%</td>
<td>73.9</td>
<td>41.4</td>
<td>40.2</td>
<td>3.1</td>
</tr>
<tr>
<td>50%-75%</td>
<td>67.6</td>
<td>32.3</td>
<td>38.0</td>
<td>0.9</td>
</tr>
<tr>
<td>&lt;50%</td>
<td>53.4</td>
<td>20.6</td>
<td>27.2</td>
<td>0</td>
</tr>
</tbody>
</table>

Summary statistics$^b$

<table>
<thead>
<tr>
<th></th>
<th>Mean</th>
<th>St. dev</th>
<th>Median</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand $D_t$ (MWh)</td>
<td>62.2</td>
<td>30.3</td>
<td>33.2</td>
</tr>
<tr>
<td>Price $P_t$ (€/MWh)</td>
<td>10.3</td>
<td>9.7</td>
<td>7.2</td>
</tr>
<tr>
<td>CO$_2$ emissions $E_t$ (thousand tons)</td>
<td>36.3</td>
<td>0</td>
<td>17.6</td>
</tr>
<tr>
<td>Marginal emissions $E'_{t}$ (ton/MWh)</td>
<td>0.64</td>
<td>0.15</td>
<td>0.09</td>
</tr>
<tr>
<td>Availability factor $\alpha$</td>
<td>0.30</td>
<td>0.06</td>
<td>0.13</td>
</tr>
</tbody>
</table>

Notes: $^a$The definition of percentiles is based on the amount of electricity demanded per hour. $^b$Based on all hours.

It is evident that there exists substantial heterogeneity in terms of the temporal availability profiles of wind and solar resources. First, over a typical day of a year and a given season, solar resources are much more volatile compared to wind resources: while the availability profile for wind is relatively flat, solar is not available during evening and night hours and exhibits availabilities of up to 40% during the midday. Second, the seasonal availability patterns for the two resources differ. The availabilities of solar largely exceed those for wind during the summer period (apart from night hours) which is reflected in the daily averages as well as the hourly profile over a typical day. Wind, however, has a higher availability during the winter period for all hours during the day, thus exceeding the availability of solar during peak hours around midday. The hourly profiles for the spring and fall season represent intermediate cases (not shown) which are qualitatively similar to the hourly profile of an average day for the full year as shown in Panel (b).

Given variations in the hourly electricity price and the carbon intensity of electricity generation, in which ways does the heterogeneity of wind and solar resources potentially translate to different market and environmental values for RE technologies? Table 2.3 provides descriptive statistics for the hourly distributions of key price and quantity variables in a market where the environmental externality is unregulated. Two main insights emerge which, together with the documented heterogeneity in the availability of RE resources, suggest that the market and environmental values for wind and solar technologies differ. First, there is a substantial variation in the hourly electricity price, e.g. the mean for the two bottom quartiles (20.6 €/MWh) is less than half of the mean of the top five percentiles (46.5 €/MWh). Figure 2.2 visualizes the profile of hourly electricity prices over an average day. Comparing Figure 2.1, Panel (b), with Figure 2.2 further shows that over the course of a typical day solar resources tend to be available when electricity prices are high. These annual average daily patterns thus indicate that solar has a higher market value than wind for most hours between the morning and afternoon. On a seasonal scale, in particular in winter, there are times when wind has a higher market value than solar.

Second, hourly marginal emissions vary substantially driven by the fact that base-load generation tends to be more carbon-intensive relative to generation in hours with high demand, e.g. the mean for the two bottom quartiles (0.87 tons of CO$_2$/MWh) is more than twice the mean of the top
Figure 2.2: Hourly wholesale electricity prices and hourly marginal emissions rate over a typical day. Five percentiles (0.31 tons of CO$_2$/MWh). Figure 2.2 visualizes the hourly profile of marginal emissions over an average day. The daily pattern suggests that there is scope to differentiate RE subsidies based on heterogeneous environmental values for wind and solar: the high availability of wind compared to solar during night, morning, and evening times coincides with a relatively high CO$_2$ intensity of electricity generation. In addition, the availability of wind compared to solar is much higher during winter and fall (see Figure 2.1). Thus, for the given modelled system of the German electricity market, wind has a larger environmental value than solar.

Lastly, the technology mix in the unregulated outcome of the German market highly relies on coal-fired electricity: 89% of CO$_2$ emissions derive from burning lignite and hard coal while only 11% stem from gas-fired generation (Table 2.3). Moreover, in the unregulated market there exist massive excess production capacities for natural gas (only 15.2% of the installed capacity for natural gas is used for electricity generation). Together, these points suggest that there is considerable scope for CO$_2$ abatement through switching from “dirty” to “clean” fossil fuels.

2.3.3 Design of simulation-based analysis

We next use our empirical quantitative framework to compare the performance of optimal RE support schemes with regard to their ability to address the carbon externality.\textsuperscript{33} We first assess RE support policies in terms of their welfare impact and investigate how particular features of policy

\textsuperscript{33}All simulations in this section are based on the central-case parametrization of the model as laid out in Section A.2.3. More specifically, fuel prices, carbon coefficients, pre-installed production capacities, and empirically estimated marginal cost and emissions functions are specified according to Tables A.1 and A.2, and we assume intermediate values for the own-price elasticity of energy demand (i.e., $\epsilon = -0.15$) and the social cost of carbon (i.e., $\delta = 50\text{€ per ton of CO}_2$).
design affect the welfare implications. We then depart from the perspective of optimal RE policies by analyzing the policy ranking in terms of cost-effectiveness, i.e. which RE policy can achieve a given emissions reduction target at the lowest possible cost.

2.3.4 Can RE policies approximate the social optimum?

Figure 2.3 summarizes the welfare impacts of the RE support policies, measured relative to the unregulated market equilibrium, which have been categorized in Table 2.1.\textsuperscript{34} We compare constrained-optimal RE policies which entail constraints on the structure and financing of RE subsidies. It is straightforward to see that alternative regulatory designs can yield substantially different outcomes in an otherwise identical economy and given the same SCC. These differences stem from varying specific features of the RE support scheme: the structure of RE subsidies (uniform or technology-differentiated RE support), the financing of RE subsidies (demand tax vs. polluter-pays), and the way in which the expenses for RE subsidies and their financing are linked together (revenue-neutral support schemes or not).

First, carbon pricing achieves the highest welfare gain relative to the unregulated market outcome—consistent with the result that such a policy implements the social optimum (see Proposition 1).\textsuperscript{35} Second, RE support schemes which involve FIT or a market premium which are funded through a revenue-neutral tax on energy demand—marked by red triangles and circles—perform worst, yielding less than 40% of the welfare gains obtained under carbon pricing. Third, differentiating RE subsidies, under either a FIT or a market premium, only negligibly improves overall economic efficiency—comparing solid with hollow triangles and circles. Fourth, combining RE subsidies with an optimal demand tax to efficiently incentivize the energy conservation channel, and thereby relaxing the constraint that the energy demand tax is set to cover expenses for RE subsidies—comparing red with black triangles and circles—substantially enhances efficiency, yielding about twice the welfare gains relative to the revenue-neutral RE support schemes. However, such policies only achieve about 70% of the welfare gains associated with first-best carbon pricing. Fifth, changing the structure of refinancing of RE subsidies to one which charges conventional "dirty" energy producers in proportion to their emissions (i.e., polluter-pays financing), as would be the case under a green offset policy, yields an outcome that is fairly close to the social optimum (achieving 80% of the welfare gains from carbon pricing).

2.3.5 Quantifying alternative designs for RE support

What are the economic mechanisms triggered by particular choices in the design of RE support policies and how do they explain the (in)ability to approximate socially optimal outcomes? To

\textsuperscript{34}In contrast to the theoretical analysis, we focus in our numerical analysis on the case of a time-constant energy demand tax. First, a time-varying hourly demand tax is likely to be unrealistic from a real-world policy perspective. Second, the computational burden to solve for an optimal hourly demand tax would be enormous.

\textsuperscript{35}In our comparative-static analysis, reported welfare changes refer to annual values. For example, the 5.33% in the case of carbon pricing corresponds to a welfare increase equal to \(0.236\) billion per year relative to the unregulated market outcome.
Figure 2.3: Comparison of efficient RE support policies.

Notes: Assumes central case as specified in Section A.2.3. Legend: The “△” and “○” markers denote a feed-in tariff and market premium policy, respectively. Filled (hollow) triangles and circles refer to the case when RE subsidies are uniform (differentiated) across wind and solar technologies. “Red” symbols denote the case when RE subsidies are combined in a revenue-neutral manner with a non-optimal energy demand tax. “Black” symbols denote the case when RE subsidies are combined with an optimal energy demand tax.
compare policies, we define an index of abatement efficiency, \( \varepsilon^b \), which expresses the welfare change for an RE support policy \( b \) relative to the welfare change under the first-best carbon pricing policy:

\[
\varepsilon^b = \frac{W^b - \bar{W}}{W^{\text{Carbon pricing}} - \bar{W}}. 
\]  

(2.11)

where \( \bar{W} \) denotes welfare in the unregulated market equilibrium. The closer \( \varepsilon^b \) is to unity, the better the RE support policy \( b \) approximates the socially optimal outcome.

TECHNOLOGY-NEUTRAL RE SUBSIDIES.---RE support schemes based on a FIT or market premium with refinancing through energy demand taxes incentivize carbon abatement through two channels. First, by subsidizing investments into RE production capacity, they correct the relative prices between fossil-based and RE technologies. Second, the refinancing tax increases the price of energy thus contributing to energy conservation.

Table 2.4 shows that the two channels are, however, not exploited in an efficient manner. Tax-inclusive consumer prices increase only slightly (around 2%) leaving energy demand virtually unaffected (-0.8%). Consumer prices rise because of the refinancing tax for the subsidy paid to RE firms; at the same time, zero-marginal production cost of RE technologies means high marginal-cost fossil energy producers are driven out of the market implying a reduction in hourly electricity prices. The net effect is a small increase in consumer prices which is considerably smaller than under a first-best carbon pricing policy where on average consumers prices increase by 88.3% and energy demand reduces by 12.7%. As abatement cannot be achieved via the energy conservation channel, carbon abatement has be to achieved through an inefficiently high level of RE investments induced by the subsidy instrument: the combined generation share of wind and solar under a FIT or market premium is 33% compared to only 21% under carbon pricing.

While a FIT or market premium policy induces a substitution away from fossil-based generation toward renewables, they do not incentivize a fuel switch within fossil-based generation and thus fail entirely to exploit a major abatement channel: while the energy mix under (socially optimal) carbon pricing comprises a significant amount of natural gas (13%), under a FIT and market premium policy gas-fired generation is pushed out of the market and coal plants continue to produce at sub-optimally high levels.

A FIT is slightly less efficient than a market premium (i.e., \( \varepsilon^{\text{FIT}} = 0.35 \) and \( \varepsilon^{\text{Market premium}} = 0.37 \)). The reason is that under a market premium RE firms sell electricity at the hourly wholesale price whereas a FIT guarantees a constant output price for every hour. This means that the uniform FIT, in contrast to the market premium, fails to take into account the market value of the resource. A FIT thus creates incentives for over-investment in solar capacity which are particularly strong during periods of high demand (e.g., around noon) when electricity prices are high and solar availability is at its daily peak. Adding cheap solar energy, in particular around midday, implies that hourly wholesale electricity prices fall; RE firms, however, do not see these lower prices under a FIT scheme. In addition, a higher share of solar energy in total RE production under a FIT also means that in winter, when the availability of solar is considerably lower, peak energy demand is satisfied to a lesser extent with RE generation implying that more carbon-intensive fossil generation is used.
Table 2.4: Overview of key impacts for alternative efficient RE support policies.

| Support schemes based on explicit RE subsidies with refinancing via demand tax |
|-----------------------------|-----------------|-------------------|-----------------|------------------|
| Technology-neutral RE subsidies & revenue-neutral |
| FIT | 0.35 | -0.8 | 2.1 | 30 | 0 | 18 | 15 | 1 |
| Market premium | 0.37 | -0.8 | 2.2 | 30 | 0 | 20 | 13 | 1 |
| Technology-differentiated market premium |
| revenue-neutral | 0.38 | -0.9 | 2.7 | 31 | 0 | 22 | 11 | 0.93 |
| optimal refinancing | 0.71 | -12.9 | 86.1 | 36 | 0 | 16 | 7 | 0.97 |
| Technology or intensity standards |
| RE quota | 0.37 | -0.8 | 2.2 | 30 | 0 | 20 | 13 | 1 |
| Green offsets with RE subsidies paid as |
| Market premium | 0.72 | -7.8 | 55.4 | 17 | 7 | 23 | 13 | 1 |
| FIT | 0.80 | -13.0 | 89.7 | 24 | 13 | 13 | 7 | 1 |

Notes: Assumes central case as specified in Section A.2.3. Reported quantities (demand and generation) refer to annual values. aAbatement efficiency $\varepsilon^b$ is defined in equation (2.11). bDemand-weighted annual average of hourly tax-inclusive consumer prices for electricity. cSubsidy rate relative to wind. A value of 1 indicates equal subsidy rates for wind and solar.

and, hence, less carbon is abated. Together, these two effects explain the slightly lower efficiency of a FIT as compared to a market premium.

TECHNOLOGY-DIFFERENTIATED RE SUBSIDIES.—Proposition 1 states that optimal subsidies for RE technologies should be differentiated according to the environmental value of the underlying resource. The relevant question for policy design, however, is: what order of magnitude for welfare gains can be achieved by optimally differentiating RE subsidies?

We find that improving policy design to reflect the environmental value of the underlying resource only produces minor efficiency gains (i.e., $\varepsilon^{Market\, premium}$ increases from 0.37 for technology-neutral to 0.38 for technology-differentiated RE subsidies; see Table 2.4).36 The reason is that wind has a higher environmental value compared to solar over both daily and seasonal time scales (for the German electricity market; see the analysis in Section 2.3.2). The optimal differentiation of RE subsidies therefore entails a lower support rate for RE firms producing electricity, i.e. the optimal subsidy rate for solar is 93% of the optimal subsidy rate for wind (see Table 2.4). Relative to the case of a technology-neutral RE support, optimally differentiated subsidies thus lead to more investment in wind and less investment in solar capacity.

COMBINING RE SUBSIDIES WITH AN OPTIMAL ENERGY DEMAND TAX.—An optimal RE support scheme based on a FIT or market premium generates through the refinancing tax revenues which exceed the expenses for RE subsidies, i.e. an optimal FIT or market premium support policy cannot be revenue-neutral (see Corollary 3). But how large is the efficiency gain when the revenue-neutrality

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36From Corollary 1, we know that the optimal FIT and market premium lead to the same allocation. We here focus on discussing our results in terms of the market premium.
constraint is relaxed?

We find that combining RE subsidies, in the form of a FIT or market premium, with an optimal energy demand tax yields sizeable improvements more than doubling abatement efficiency (i.e., $\epsilon_{\text{Market premium}}$ increases from 0.37 for revenue-neutral to 0.71 for optimal refinancing; see Table 2.4). The optimal demand tax increases consumer prices to roughly the same levels as would be obtained under a carbon pricing policy, thus inducing similar abatement through the energy conservation channel. Importantly, we find that improving the refinancing of RE subsidies is more important than differentiating the subsidy rate by technology. While the abatement efficiency increases when revenue-neutrality is relaxed, it still is significantly below 1 because the demand tax does not affect the relative production costs of coal vs. gas-fired electricity producers leaving the fuel-switch abatement channel unexploited.

INTENSITY STANDARDS FOR RE SUPPORT.—Intensity standards are blending constraints which translate into implicit output subsidies for RE technologies and implicit input taxes on energy production to finance RE subsidies. As such, they are by construction revenue-neutral, and cannot implement the social optimum (see Proposition 4). Notwithstanding their undesirable property of revenue-neutrality, we show below that intensity standards can in principle yield an abatement efficiency fairly close to a first-best outcome depending on the structure of both (implicit) RE subsidies and the (implicit) input taxes to finance the RE support.

Under an RE quota an equal per-MWh tax on electricity is levied on all firms to finance the RE subsidies. By construction, such a policy is revenue-neutral and does not discriminate the subsidy rate across RE technologies. An RE quota is thus equivalent to a technology-neutral market premium policy which is financed through a revenue-neutral tax on energy demand. Consequently, the abatement efficiency of an RE quota is poor (i.e., $\epsilon_{\text{RE quota}} = 0.37$; see Table 2.4).

We find, however, that changing how RE subsidies are financed can greatly enhance abatement efficiency. Under a green offset intensity standard, where demand for certificates is proportionally related to $\text{CO}_2$ emissions, abatement efficiency increases (i.e., $\epsilon_{\text{Green offsets}}$ is equal to 0.72 and 0.80 when the support for RE firms is structured as a subsidy added to the market price or a guaranteed output price, respectively). With respect to the performance of a green offsets system, three main insights emerge.

First, regardless of how the RE subsidies are structured, there is an advantage for conventional energy producers with low emissions intensity due to the lower costs for buying offset certificates for each MWh of electricity produced. Specifically, this helps to exploit carbon abatement through the fuel-switch channel by incentivizing electricity generation from natural gas.

Second, when the subsidies for RE firms are structured as a market premium, the abatement efficiency of a green offset system is only slightly higher than under an optimal policy with technology-differentiated market premium and demand tax refinancing. The reason is that when the marginal damage of emissions is reflected through the implicit input taxes, the wholesale electricity price already reflects the external cost. There is thus no need to further subsidize RE investments, i.e. the subsidy rate for RE firms should be zero. This, however, is not what happens under green offsets policy: revenue neutrality implies that positive tax revenues translate into a positive subsidy rate
which is added on top of the wholesale electricity price, thus yielding inefficiently high unit revenues per MWh of electricity produced from wind and solar resources. In addition, the inefficiently high subsidy rate dampens the price signal for energy conservation. We find that when RE subsidies are paid as a market premium, the advantage of implicitly taxing CO₂ emissions under a green offsets system, which induces a partial fuel switch to natural gas, is almost entirely outweighed by too high investments into RE technologies and a too low energy demand reduction.

Third, as under a FIT investors do not receive the wholesale price, the abatement efficiency increases because the induced over-investment in wind and solar is much smaller as compared to a market premium. At the same time, the need for refinancing is higher when RE support is paid in the form of a guaranteed output price relative to a market premium. A higher need for refinancing, however, implies a stronger carbon price signal established through the implicit input taxes. This explains why the green offsets system with FIT can come closer to the socially optimal outcome obtained under carbon pricing.

2.3.6 Cost-effective RE support policies

Rather than choosing optimal RE support policies under an endogenous environmental target (and given information about the SSC), policymakers may also be concerned with the question which policy designs can achieve a given emissions reduction target at lowest economic cost. To scrutinize the cost-effectiveness perspective on optimal policy choice, this section considers a simplified version of the general problem of optimal regulation laid out in (2.4), or its numerical equivalent (A.2), by assuming that RE support policy has to achieve an exogenously determined and fixed level of emissions reductions, \( \overline{\dot{E}} \).

Figure 2.4 shows the percentage welfare change relative to the unregulated market outcome (i.e., \( 100 \times [\mathbb{W}^b / \mathbb{W} - 1] \)) for different RE support schemes \( b \) for different levels of emissions. Unsurprisingly, carbon pricing is the most cost-effective policy irrespective of policy stringency as it efficiently exploits all abatement channels. The “cost-effectiveness ranking” of RE support policies, however, varies largely depending on policy stringency. Generally speaking, the reason is that alternative policy designs exploit various abatement channels (see Table 2.2) differently while the relative importance of each abatement channel for total abatement varies depending on targeted emissions reductions.

Analyzing the policy ranking under cost-effectiveness considerations yields the following additional insights with respect to the performance of different RE support schemes. First, the technology differentiation of RE subsidies according to the heterogeneous environmental value of the underlying resource is empirically not important for policy design at any level of emissions reductions. This underscores the similar finding we obtained in the context of optimal RE policies with endogenous environmental quality.

\[^37^\text{Specifically, we add the following constraint to the upper-level part of the optimal policy problem in (A.2):} \sum_u \int_0^{\overline{\dot{E}}} E_u(\bar{x}) d\bar{x} \leq \overline{\dot{E}}. \text{ This amounts to evaluating policy choices solely on the basis of economic surplus—while the differences in environmental benefits from averted pollution are muted across the policy options given a constant environmental quality.}\]
Second, for high abatement levels (i.e., emissions reductions relative to the unregulated market outcome are in excess of 50%), it becomes crucial to link the financing of RE support to carbon-intensive generation, for example, as achieved through an intensity standard with green offset certificates. The reason is that the higher policy stringency, the more important becomes CO$_2$ abatement through switching from coal to natural gas. As RE support schemes based on either a FIT or market premium fail to incentivize such a fuel switch, they perform poorly. This holds regardless of whether such policies are combined with an optimal demand tax for refinancing or not. With increasing policy stringency, green offsets with RE subsidies paid through a FIT outperform a green offset scheme with a market premium as a guaranteed output price under a FIT avoids over-investment in RE capacity (this is similar to the context of optimal RE support with endogenous environmental quality; see Section 2.3.4).

Third, for intermediate abatement levels (between 20% and 50%), abatement is mainly achieved through RE capacity investments and reductions in energy demand; the switch with fossil-based technologies is not important. For this range of emissions reductions, RE subsidies with an optimal energy demand tax are thus the second-best policy (after carbon pricing). In particular, they outperform all policy designs which require revenue-neutrality between RE subsidies and refinancing. The reason is that the revenue-neutrality requirement limits the scope for exploiting abatement through the energy conservation channel. With increasing policy stringency, the green offset policies begin to outperform the RE support schemes with revenue-neutral demand tax refinancing as the efficiency gains from incentivizing a fuel-switch increase.

Fourth, for low abatement levels (less than 20%), cost-effective abatement under a carbon pricing policy mainly occurs through energy conservation. The performance of revenue-neutral RE policies is therefore rather poor for low policy stringency as they entail inefficiently high incentives for
2.3.7 RE support policies under incomplete carbon pricing

In practice, carbon pricing is incomplete, i.e. the carbon price is below its first-best level. The question arises what combinations of alternative RE support policies would be optimal or cost-effective given incomplete carbon pricing. The answer depends on how much the carbon price deviates from its first-best level.

First, if the carbon price is low so that it triggers no or only a small fuel switch between coal and natural gas, adding any of the analyzed RE support policies on top would yield welfare rankings similar to those shown in Figure 2.3 and Table 2.4. Second, if the carbon price is close to its first-best level, adding RE support policies is redundant and only increases policy costs. The reason is that a high carbon tax already efficiently exploits all abatement channels—subsidizing in addition RE technologies has a distorting effect (for example, by inducing over-investments in RE production capacities).

Third, if the carbon price falls in an intermediate range, there is scope for RE support policies to improve welfare. However, any of revenue-neutral RE policies would be not be effective due to failing to incentivize abatement through the demand channel. Optimal combinations of non-revenue neutral RE policies (see black dots and triangles in Figure 2.3) and a below-first-best carbon price yield abatement efficiencies $E$ that are similar to those obtained with a Green offsets policy. The intuition is simply that a Green offsets policy precisely amounts to a combination of an implicit carbon tax and RE output subsidy. As it is revenue-neutral by design, adding an optimal demand tax to a Green offsets policy can in principle further enhance abatement efficiency but the potential for improvements remains small as abatement through the demand channel is already strongly incentivized by the implicit carbon tax and (the intermediate level of) the explicit carbon price.

2.4 Robustness Checks and Model Extensions

Here we consider the sensitivity of results to parameters and model extensions affecting the relative importance of the different channels for abatement including the price responsiveness of energy demand, fuel prices and the composition of installed fossil-based production capacities, the social cost of carbon, environmental damages due to non-CO$_2$ greenhouse gases, and a higher temporal resolution.

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$^{38}$The case of the market premium with optimal demand tax refinancing is not shown for low abatement levels as this policy would essentially involve taxing energy demand with a zero subsidy rate for RE technologies.
Table 2.5: Sensitivity of abatement efficiency $e^b$ of different RE support policies$^a$.

<table>
<thead>
<tr>
<th>Support schemes based on explicit RE subsidies with refinancing via demand tax</th>
<th>Central case</th>
<th>Demand elasticity $\epsilon$</th>
<th>Low natural gas price$^c$</th>
<th>Monolithic FE supply $\delta = 100$</th>
<th>High SSC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology-neutral RE subsidies &amp; revenue-neutral</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FIT</td>
<td>0.35</td>
<td>0.37</td>
<td>0.38</td>
<td>0.71</td>
<td>0.37</td>
</tr>
<tr>
<td>Market premium</td>
<td>0.44</td>
<td>0.45</td>
<td>0.46</td>
<td>0.63</td>
<td>0.45</td>
</tr>
<tr>
<td>Technology-differentiated market premium</td>
<td>revenue-neutral</td>
<td>0.26</td>
<td>0.29</td>
<td>0.30</td>
<td>0.76</td>
</tr>
<tr>
<td>optimal refinancing</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.68</td>
<td>0.42</td>
</tr>
<tr>
<td>Technology or intensity standards</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RE quota</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.68</td>
<td>0.42</td>
</tr>
<tr>
<td>Clean Energy Standard</td>
<td>0.42</td>
<td>0.42</td>
<td>0.42</td>
<td>0.72</td>
<td>0.72</td>
</tr>
<tr>
<td>Green offsets with RE subsidies paid as</td>
<td>Market premium</td>
<td>0.29</td>
<td>0.72</td>
<td>0.72</td>
<td>0.72</td>
</tr>
<tr>
<td>FIT</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.97</td>
<td>0.97</td>
</tr>
</tbody>
</table>

Notes: $^a e^b$ is defined by equation (2.11). $^b$ The central-case values are: $\epsilon = -0.15$ and $\delta = 50$ € per ton of CO$_2$. $^c$ Assumes that the fuel price for natural gas is reduced from the central-case value of 21.16 €/MWh to 5 €/MWh.

2.4.1 Price responsiveness of energy demand

Columns (1)–(3) in Table 2.5 compare the abatement efficiency $e^b$ of the different RE support schemes for different assumptions about the price elasticity of energy demand ($|\epsilon|$). The stronger demand responds to price, the easier it is to induce abatement through the energy conservation channel for a given consumer price increase. Hence, the gap in abatement efficiency between carbon pricing and policies which subsidize RE technologies without refinancing rules that counteract too low energy prices, i.e. RE subsidies with revenue-neutral demand tax financing and RE quota, is larger (smaller) for the case of a high (low) $|\epsilon|$. In contrast, the abatement efficiency of RE support schemes which combine RE subsidies with an optimal demand tax depends positively on $|\epsilon|$ as such a policy can directly incentivize abatement through reductions in energy demand.

For a market where energy demand is relatively price-elastic, Table 2.5 shows that green offsets policies can closely approximate the socially optimal outcome (i.e., $e^{Green offsets} = 0.82$ and 0.92 for the case of FIT and market premium, respectively). Intuitively, if the energy conservation channel is relatively important, the distortion induced by such policies—due to the fact the environmental damage is already reflected in electricity prices and that RE firms receive in addition a positive subsidy rate leading to abatement through an over-investment in RE capacity—becomes less important. On the other hand, the abatement efficiency of such policies can be poor, when $|\epsilon|$ is low.
2.4.2 Low natural gas prices and “monolithic” fossil-based energy supply

An important question is how our assessment of alternative policy designs for RE support changes when it becomes less important or even not necessary at all to switch from coal to natural gas in order to reach a social optimum. To explore this question, we analyze the two additional cases assuming (1) a substantially lower natural gas price (reducing central-case value of 21.16 €/MWh to 5 €/MWh) and (2) that all coal-fired (lignite and hard coal) capacity is rededicated as natural gas capacity.

Both perspectives are useful to reflect the conditions of current and likely future energy systems. First, the costs of supplying natural gas may decline further due to increased exploitation of shale gas resources and enhanced infrastructure and market integration due to liquified natural gas. Second, systems with “monolithic” fossil-based energy (FE) supply not only depict the current situation of a number of countries with abundant oil resources (for example, Middle Eastern countries such as Iran, Saudi Arabia, Egypt) but may also describe future electricity systems for countries where coal use has already been banned or where nuclear power in an otherwise zero-carbon generation mix will be replaced with natural gas (for example, Sweden and Switzerland).

In the case with a “Low natural gas price” (comparing columns (1) and (4) in Table 2.5), the technology mix in the unregulated market outcome, compared to the central case (see Table 2.4), is tilted towards natural gas (generation share of 29.7%) but coal is still part of the mix (generation share of 32.2%). While this reduces the scope for CO₂ abatement through a fuel switch between coal and gas, the important implication of low natural gas prices is another one: for the socially optimal policy with carbon pricing, the tax-inclusive fuel price of coal is higher than the one for natural gas. This implies that coal-fired plants become price-setting with the result that the increase in the consumer price of electricity is substantially larger than in a situation with high natural gas prices. Consequently, the abatement efficiency of RE support policies which do not exploit the energy conservation channel relative to carbon pricing significantly worsens. The important implication for policy design is that as long as coal-based generation remains in the system, the efficiency loss associated with using RE support schemes, without modifying the financing structure to reflect the carbon intensity of fossil-based generation, may be substantial.³⁹

In contrast, when no fuel switch is needed, as is the case for systems with “Monolithic FE supply”, RE support schemes have the ability to closely approximate the socially optimal outcome obtained with carbon pricing. The extent to which this is possible, however, depends on whether the RE support scheme can trigger abatement through the energy conservation channel. If this is possible only to a limited extent, as under a revenue-neutral FIT or market premium system, the abatement efficiency remains poor (i.e., $E_{FIT} = E_{Market premium} = 0.42$). A policy combining optimal RE subsidies with optimal refinancing yields an abatement efficiency which closely approximates those obtained under first-best carbon pricing (i.e., $E_{Market premium with optimal demand tax} = E_{RE quota} = 0.68$).

³⁹One exception is the RE policy which combines RE subsidies with an optimal demand tax. Here, the possibility to directly incentivize energy conservation somewhat dampens the efficiency loss (i.e., $E_{Market premium with optimal demand tax} = 0.68$).
With an optimal time-varying hourly demand tax such policies would achieve the first-best solution (see Proposition 3); the remaining efficiency loss thus derives from constraining the optimal demand tax to be uniform over time.

2.4.3 Social cost of carbon

The higher the SCC, the higher is in general the abatement efficiency of RE support schemes, i.e. $E^b$ increases for all policies (comparing column (6) to column (1) in Table 2.5). The simple reason is that with higher SCC abatement mainly occurs through subsidizing RE investments and conserving energy demand while the importance of a fuel switch among fossil-based generation is diminished.\textsuperscript{40}

But even with high SCC, the question of policy design remains important. Support schemes that either establish incentives for energy conservation or are based on polluter-pays financing of RE subsidies can closely approximate socially optimal outcomes (i.e., the abatement efficiency exceeds 80%) whereas revenue-neutral FIT or market premium policies entail efficiency losses of around 30% (i.e., $E^{FIT} = 0.67$ and $E^{FIT} = 0.72$).

2.4.4 Technology standards with partial credits for natural gas

In practice, it may not be possible to differentiate implicit input taxes according to the fuel-specific CO\textsubscript{2} content as is the case under our Green offsets policy. A politically more feasible policy may thus use a more coarse design giving partial credits to natural gas. Such a policy, known as a Clean Energy Standard, has been proposed in the US (see, for example, Goulder, Hafstead and Williams, 2016, for an analysis of the Bingaman proposal which we implement here, too). Following the approach taken by these authors, we adopt a design\textsuperscript{41} of the CES as a quota system similar to the one described in equations (2.6a), (2.6b), and (2.6c) with the difference that here all generation which is deemed clean (RES, hydro, nuclear, gas) is granted credits per MWh generated. Generation from RES, hydro, and nuclear receives 1 credit per MWh whereas gas receives 0.5 credits per MWh to account for the fact that it is not emissions-free.

The CES policy scheme shares characteristics with both, an RE quota and a green offsets scheme. Being a quota system, it is revenue neutral and lacks an instrument to address the demand channel independently. Accordingly, its abatement efficiency increases (decreases) if the elasticity of demand, $|\eta|$, is low (high) and the demand channel is less (more) important to achieve the first best policy outcome, as can be seen from Table 2.5. In contrast to an RE quota and similar to green offsets it favors gas over production from coal which does not receive any credits and thus a CES exploits the fuel switch channel better than a quota. This accounts for its relatively good

\textsuperscript{40}In the case of a very high SSC, or the limiting case of $\delta \rightarrow \infty$, the difference between RE support policies and carbon pricing vanishes. The intuition is that once no CO\textsubscript{2} emissions are tolerated in the system, RE support policies are sufficient to steer firms' decisions on the only relevant margin, i.e. to correct the relative prices between renewable and fossil-based energy.

\textsuperscript{41}The original proposal by former US senator Jeff Bingaman did not have a provision to give credits to generation from hydro and nuclear power.
performance in all the scenarios where the fuel switch channel is important (i.e., "Central case") with $\varepsilon^{\text{CES}} = 0.76$, the cases with higher and lower demand elasticity with $\varepsilon^{\text{High elasticity}} = 0.72$ and $\varepsilon^{\text{Low elasticity}} = 0.80$, respectively, and for a high social cost of carbon with $\varepsilon^{\text{High SCC}} = 0.87$.

The performance decreases relative to the central case in scenarios where the importance of the fuel switch channel is weaker ("Low natural gas price") or non-existent ("Monolithic FE supply").

2.4.5 Non-CO$_2$ greenhouse gases

Motivated by the fact that CO$_2$ is the principal anthropogenic greenhouse gas (GHG) being emitted by the power sector, we have so far abstracted from other non-CO$_2$ GHGs relevant in the context of electricity generation such as methane (CH$_4$) and nitrous oxide (N$_2$O). The potential concern is that not accounting for other GHGs may underestimate the potential benefits from RE support schemes relative to carbon pricing policies. While a carbon pricing policy provides incentives for removing coal, it potentially leaves a significant amount of natural gas, and hence methane emissions, in the system. In contrast, a stringent RE support policy provides incentives for removing fossil fuels altogether.

Although these GHGs are more potent than CO$_2$, we find that including them explicitly in our analysis does not affect our main insights—and, in fact, only has small quantitative effects (for example, on abatement efficiency $\varepsilon^b$ as our main metric for comparing policies). The robustness of our results with respect to the inclusion of non-CO$_2$ GHGs can be understood as follows. First, the amounts of non-CO$_2$ GHGs are several orders of magnitude smaller than for CO$_2$. Second, the ordering of energy technologies in terms of emissions intensity is not altered. More specifically, for the case of CH$_4$, the emissions coefficient for natural gas and different types of coal is roughly identical; for N$_2$O, natural gas has a lower emissions coefficient than coal.$^{42}$

Consequently, including non-CO$_2$ GHGs in our model slightly increases, on average, the damage caused by a MWh of electricity produced. The upshot is that under all policies considered a higher level of abatement is optimal (as compared to ignoring non-CO$_2$ GHGs). As the ordering of energy technologies, including the costs due to environmental damage caused, does not change, the qualitative ranking among different regulatory designs for addressing the GHG externality are unaffected.

2.4.6 Temporal resolution

While we model electricity supply and demand decisions at the hourly level, we use for each season the hours of an average week to reduced computational complexity (rather than using all 8760 hours of a year). The potential concern is that this may smooth out some of temporal variation with respect to the availability of RE resources and energy demand. While solving the model for 8760 hours is computationally not feasible, we have carried out sensitivity analysis based on a model

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$^{42}$Using standard emissions coefficients and CO$_2$-equivalence factors of global warming potentials for CH$_4$ and N$_2$ from the IPCC (see tables 2.2 and 2.14 in Eggleston et al., 2006), the emissions factors for coal and natural gas increase by only 0.5% and 0.09%, respectively.
with 12 (instead of four) representative weeks. We find that this increases the temporal variation of marginal hourly emission rates thus potentially pronouncing the scope for technology-differentiated RE subsidies. We do find, however, that the optimal differentiation of the subsidy rate between wind and solar is only slightly affected, suggesting that four representative weeks are sufficient to capture the variability of resource availability and demand relevant for our analysis.

2.5 Conclusions

Public policies aimed at promoting clean energy from intermittent RE resources such as wind and solar are the most widely adopted form of actual low-carbon policy—yet the question of how to best design support schemes for wind and solar has received surprisingly little attention. This paper aims to fill this gap by examining optimal support schemes for intermittent RE resources in the presence of a carbon externality. We have characterized optimal policies and the conditions under which RE support schemes can achieve socially optimal outcomes. To assess different policies in an empirically plausible setting and to derive additional quantitative insights, we have developed a numerical equilibrium framework of optimal policy design which incorporates a number of features relevant for analyzing real-world electricity markets.

We have emphasized three issues for policy design: the heterogeneity of intermittent natural resources, budget-neutral financing rules, and incentives for carbon mitigation. We show that optimal subsidies for wind and solar should be differentiated to reflect the heterogeneous environmental value of the underlying resource. We find, however, that the differentiation of RE subsidies is only of minor importance for policy design. Rather, the way RE subsidies are financed is critical: RE policies relying on smart financing by either using polluter-pays financing in the context of budget-neutral schemes (such as, for example, RE quotas and technology or intensity standards for clean energy) or by giving up budget neutrality can approximate socially optimal outcomes. We have further assessed the performance of RE policies under different market conditions (including the price responsiveness of energy demand and the composition of fossil-based supply) and assumptions about the social valuation of environmental damages (including the social cost of carbon and inclusion of non-CO$_2$ greenhouse gases). Overall, our analysis suggests that—when carbon pricing is unavailable due to political (and other) constraints—optimally designed RE support policies do not necessarily have to be regarded as a costly second-best option for internalizing a carbon externality.

Some limitations of our analysis should be kept in mind. First, our analysis has focused on how to design RE support policies in the presence of a carbon externality. In doing so, we have deliberately abstracted from the positive externalities related to learning, technological innovation through R&D investments, and network effects (Jaffe, Newell and Stavins, 2005; Acemoglu et al., 2012; Bollinger and Gillingham, 2014) which may provide an important rationale for choosing RE support schemes over carbon pricing policies. Incorporating such positive effects would obviously play in favor of RE support policies. Second, these benefits would, however, have to be weighed against the additional system integration and back-up cost of intermittent RE generation (Borenstein, 2012; Marcatonini and Ellerman, 2014; Gowrisankaran, Reynolds and Samano, 2016). While it is beyond the scope of this paper to provide a comprehensive cost-benefit analysis, our estimates could be viewed as a first
indication of how large the net benefits from other external effects would have to be to provide a rationale for decarbonization through RE support policies. Third, our analysis abstracts from tax interactions effects which have been shown to improve the efficiency of revenue-neutral RE support policies with small increases in output prices as compared to revenue-raising RE support policies (or carbon pricing) triggering large price increases (Goulder, Hafstead and Williams, 2016). Consequently, we may thus overestimate (underestimate) the efficiency of RE policy refinancing with a demand tax (under a RE quota or Green offsets system). The importance of fiscal tax distortions, however, rapidly diminishes with increasing policy stringency (Goulder, Hafstead and Williams, 2016). This suggests that non-negligible emission reductions—we compare RE support strategies that reduce emissions by about half—are unlikely to affect our key qualitative insights.

Notwithstanding these caveats, our analysis demonstrates that optimally designed policies to support RE from intermittent wind and solar resources, in particular with regard to the financing of RE subsidies, can substantially enhance the efficiency of decarbonization policies in the electricity sector. At the same time, this diminishes the importance of arguments relying on positive (and difficult to quantify) learning and technology externalities for rationalizing the public policy support for renewable energy.
3 Buffering Volatility: Storage Investments and Technology-Specific Renewable Energy Support

Abstract

Mitigating climate change will require integrating large amounts of highly intermittent renewable energy (RE) sources in future electricity markets. Considerable uncertainties exist about the cost and availability of future large-scale storage to alleviate the potential mismatch between demand and supply. This paper examines the suitability of regulatory (public policy) mechanisms for coping with the volatility induced by intermittent RE sources, using a numerical equilibrium model of a future wholesale electricity market. We find that the optimal RE subsidies are technology-specific reflecting the heterogeneous value for system integration. Differentiated RE subsidies reduce the curtailment of excess production, thereby preventing costly investments in energy storage. Using a simple cost-benefit framework, we show that a smart design of RE support policies significantly reduces the level of optimal storage. We further find that the marginal benefits of storage rapidly decrease for short-term (intra-day) storage and are small for long-term (seasonal) storage independent of the storage level. This suggests that storage is not likely to be the limiting factor for decarbonizing the electricity sector.

3.1 Introduction

The combat against climate change requires to substantially reduce worldwide carbon dioxide (CO₂) emissions in the electricity sector over the next decades by profoundly shifting energy supply towards renewable energy (RE) sources. At the global level, the required share of electricity coming from RE sources to restrict global warming to 1.5°C is estimated to be between 70% and 81% by 2050 (IPCC, 2018). For Europe, the European Commission (2011)'s Energy Roadmap 2050 foresees RE shares as high as 64% to 97% to be consistent with EU climate policy targets. Such high amounts of energy supplied from RE sources pose significant challenges to existing energy systems as the economically most viable and carbon-free RE technologies (i.e., wind and solar) are highly volatile in their output.

Figure 3.1 shows the temporal variation of electricity demand and resource availability of wind and solar over the course of a day (Panel a) and a year (Panel b). It serves to illustrate the well-known and fundamental issue which also motivates our analysis: a future low-carbon energy system which relies on a large share of volatile RE energy will likely face the challenge of substantial periodic mismatches between energy demand and supply. To cope with the high volatility of daily and seasonal resource availability, a mechanism is needed to shift supply between hours of the day and possibly between seasons (for example, by either shifting solar generation from day to night or from...
Figure 3.1: Hourly variation of electricity demand, wind generation, and solar generation.

Notes: Resource availability is measured in percentage terms relative to the maximum electricity generation that would be possible under ideal conditions for solar and wind. “By hour over a day” shows the hourly values for each variable averaged over the whole year. “By month over a year” shows the hourly values for each variable averaged for a given month. Electricity demand is based on data for the German electricity market in 2014 taken from ENTSO-E (2016). Resource availability for wind and solar is calculated as observed market production for a given hour relative to nominally installed capacities based on data from German transmission system operators (50Hertz, 2018; Ampriön, 2018; Tennet, 2018; TransnetBW, 2018).

Much of the academic literature and ongoing discussions among policymakers have focused on the question how energy storage can serve as a buffering mechanism to cope with the volatility and system integration costs induced by intermittent RE sources (Hirth, 2015; Gowrisankaran, Reynolds and Samano, 2016; Sinn, 2017; Zerrahn, Schill and Kemfert, 2018). At the same time, there are considerable uncertainties as well as concerns about the costs, availability, and potentials of future storage technologies, in particular when deployed at the large scales required for deep decarbonization.

Instead of focusing on a pure technological solution for buffering volatility (i.e., through energy storage), this paper examines the suitability of a regulatory or public policy mechanism as a means for coping with the impacts of large shares of highly volatile RE sources in future energy systems: the design of technology-specific RE support schemes. Specifically, we ask to what extent the economic cost of integrating a large amount of highly volatile wind and solar energy can be reduced by modifying the design of RE support schemes—such as subsidies on output or investment—to take into account the heterogeneous value of different RE technologies with respect to system integration costs. Current policy approaches tend to favor technology-neutral support schemes.

44The profile of solar largely coincides with the demand peak around midday; during nighttime, however, demand is still large (although being at its lowest level), while solar generation is zero. The correlation coefficient between demand and solar availability is 0.48. In contrast, wind shows a relatively flat availability pattern, implying an advantage during night hours when there is no generation from solar. At the same time, however, wind is ill-suited to meet demand over the day, in particular during peak hours. The correlation coefficient for wind is 0.23. Over the course of a year, seasonal changes in the monthly average of demand and resource availabilities show a different picture: solar generation is negatively correlated with demand (with a coefficient of -0.74) whereas wind closely follows demand exhibiting a strong positive correlation (with a coefficient of 0.72).

45As of today, the only energy storage technology for electricity used at large scale is hydroelectric pumped-storage power (Schwab, 2009), representing about 99% of the worldwide installed storage capacity (Rastler, 2010).
A recent example are German joint tenders for wind and solar energy, the last of which saw a dominance of solar bids over wind (BNetzA, 2019). In contrast to such policy designs our fundamental proposal is to improve existing energy market regulation in a way which exploits the complementarities of wind and solar technologies in terms of their underlying heterogeneous resource profiles and the correlation with time-varying electricity demand. We also investigate how the need for energy storage changes when this alternative buffering mechanism is optimally exploited. To the best of our knowledge, we are the first to examine the potential role of policy design for reducing the cost of integrating volatile RE supply.

To provide a conceptual and empirically-grounded framework for thinking about the economics of integrating high shares of volatile RE sources into an electricity market, we develop a numerical partial equilibrium model of a wholesale electricity market which resolves output decisions on hourly markets, time-dependent demand and resource availabilities of wind and the sun, investments in RES production capacity, curtailment decisions to maintain system stability, and a detailed representation of the functioning of electricity storage. Storage capacity is varied exogenously in order to gauge its impact on overall system integration cost of renewables. The decentralized market model is embedded in a welfare-maximizing problem of a benevolent regulator who chooses RE support policies (through subsidies on RE output which we model as a feed-in premium on top of the market price) in order to implement an electricity market with a high share of intermittent RE at the lowest cost to society. While we calibrate the model to stylized conditions of the German electricity market, we think that the main insights from our analysis are also relevant for the electricity market context of many other countries.

Our analysis provides several important insights. First, we find that the storage capacity needed to accommodate high shares of intermittent RE output is relatively moderate, even under a technology-neutral RE support scheme. This implies that the potentially high costs of providing storage at large scale in the future need not jeopardize the achievement of environmental targets (i.e., the reduction of CO₂ emissions through increasing the share of low-carbon renewables). Second, we find that the design of a RE support policy can have a significant impact on system integration cost as well as storage capacity needs when there are several intermittent renewable technologies with heterogeneous availability patterns of the underlying natural resources (such as wind and solar energy). The smart differentiation of RE subsidies affects investment patterns in a way which can effectively reduce the curtailment of excess generation, in turn lowering the need for costly investment in energy storage. We use a simple cost-benefit framework to show that optimal subsidy differentiation significantly reduces the level of optimal storage. In this sense, concerns about the costs and availability of storage technologies in order to enable the integration of high shares of intermittent RE supply in future electricity markets and to achieve environmental goals are even more diminished if a smart design of RE support policies is chosen. Third, within our modeling framework which captures high RE shares up to 80% but not a completely decarbonized system, we find that the type of storage most likely needed is short-term to medium-term storage. The additional benefits from long-term seasonal storage are relatively modest and most likely much

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46 i.e., agents in the model make decisions on electricity dispatch and investment into RE capacity for several given storage levels without taking investment cost for storage into consideration. Storage cost is then accounted for in an ex-post cost-benefit analysis with cost estimates for current storage technologies.
This paper contributes to the existing literature in several ways. First, we add to the main insight, supported by a growing body of economic and technical studies (see, for example, Zerrahn, Schill and Kemfert, 2018, and references therein), that in order to integrate large shares of volatile RE supply in future energy systems only moderate levels of energy storage are needed.

Second, there is a growing literature on storage capacity in electricity markets and its connection to the expanding renewable generation capacities. Linn and Shih (2016) investigate the impact of the introduction of large storage capacities into current electricity systems using numerical modeling of the Texas ERCOT region and stylized theoretical considerations to assess the impact on total carbon emissions of a system with dirty base load producers (coal), cleaner peak load producers (gas), and renewables (wind, solar). Carson and Novan (2013) use a theoretical model and empirical methods to show the same effect in the ERCOT region, and, in addition, an adverse impact of increased storage capacities on renewables with high production correlation to peak demand (solar) and a positive impact on renewables which produce at base-load hours (wind) due to a price-leveling effect of storage. Crampes and Moreaux (2010) use a theoretical model of a hydro pumped-storage operator and a fossil generator to determine optimal joint usage of both technologies; they do not consider intermittent RE sources. Helm and Mier (2018) examine the effect on CO\textsubscript{2} emissions of subsidizing energy storage. In contrast to the above-mentioned papers, we focus on market conditions as we expect in a future electricity market with a very high level of intermittent RE supply and highlight the role of regulatory design, besides energy storage, for buffering volatility.

Third, we also make a connection to the emerging literature investigating the consequences of the fundamental heterogeneity of RE technologies with respect to availability patterns. Abrell, Rausch and Streitberger (2019b) consider the environmental value and market value of different renewables and define an environmental motive for differentiating subsidies by technology, while Fell and Linn (2013) and Wibulpolprasert (2016) investigate the impact of resource heterogeneity on cost-effectiveness of different abatement policies. Empirical studies like Abrell, Kosch and Rausch (2019) evaluate different market values and environmental values of RE sources ex-post. While these studies highlight the need for improved policy design to incorporate external effects at the system or market level, they focus on CO\textsubscript{2} emissions but abstract from storage investments and the issue of the cost of integrating volatile RE supply for decarbonizing the electricity sector.

The remainder of this paper is structured as follows. Section 3.2 presents the electricity market model. Section 3.3 provides detail about the empirical specification of the model (against the context of the German electricity market). Section 3.4 presents the main findings from the simulations investigating the trade-offs between storage capacity and the role of technology-differentiated RE support policy as potential buffering mechanisms. Section 3.5 presents a simple cost-benefit analysis to gauge the level of optimal energy storage needed to implement a market with a high share of volatile RE supply under different assumptions about RE policy design. Section 3.7 concludes by discussing implications and caveats of our analysis.
3.2 The Model

To assess alternative strategies for integrating a large share of intermittent RE into an energy system, we employ a partial equilibrium model of the wholesale electricity market which resolves output decisions on hourly markets, time-dependent demand and resource availabilities of wind and sun, investment decisions in production capacity, curtailment decisions to maintain system stability, and the functioning of electricity storage. The decentralized equilibrium model is embedded in a welfare-maximizing problem of a benevolent regulator who aims to implement an electricity market with a high share of intermittent RE at lowest cost.

3.2.1 The regulator’s problem

The model comprises two levels. At the top level, a benevolent regulator is concerned with the problem of implementing an exogenous and given minimum level of RE generation in the market at the lowest attainable total system cost $C$ to society. The choice variable is a RE support scheme which can take on the form of either a technology-neutral support or technology-differentiated support. In implementing the RE support scheme, the regulator has to take into account the equilibrium conditions of the electricit y market. Formally, the regulator’s problem is then given by:

$$\min_b C(P(b), X(b))$$

s.t. $P(b), X(b) \in \mathcal{E}$.

where $b$ denotes the policy choice of the regulator, $P(b), X(b)$ are the prices and quantities constituting the market equilibrium in the electricity market for a given choice of the regulator, and $\mathcal{E}$ is the set of all feasible equilibrium allocations in the wholesale electricity market.

3.2.2 Feasible equilibrium allocations $\mathcal{E}$ of the wholesale electricity market

We formulate the equilibrium conditions of the wholesale electricity market as a mixed complementarity problem (MCP, see Mathiesen, 1985; Rutherford, 1995) which is cast as a system of inequalities which derive from the decision problems of profit-maximizing agents with two types of conditions: zero-profit conditions that are complimentary to quantity variables $X$ and market-clearing conditions complementary to price variables $P$. The economic agents in our model are electricity suppliers which produce either from renewable or from conventional sources. Production technologies are denoted by $i \in \mathcal{I}$ with subsets $\mathcal{G}$ for renewable technologies and $\mathcal{B}$ for conventional. We indicate time periods by $t \in \mathcal{T}$.
ENERGY SUPPLY AND INVESTMENT.—Agents maximize their profits by choosing investments \( I_i \) and generation for each time period \( X_{it} \). The profits are given by

\[
\Pi_i = \sum_t \left[ (P_t + \omega_i S)X_{it} - c^g(X_{it}) \right] - c^I(I_i),
\]

where \( P_t \) denotes the market price at time \( t \), \( S \) is the RE subsidy per MWh produced which firms receive and \( \omega_i \) is a policy choice variable for the regulator which allows to differentiate the subsidy by technology if \( \omega_i \neq \omega_j \). For conventional technologies, \( i \in B, \omega_i = 0 \). The functions \( c^g(X_{it}) \) and \( c^I(I_i) \) denote generation cost and investment cost, respectively.

Output can never exceed installed capacity, so the following condition needs to be fulfilled:

\[
\alpha_{it} \left( \bar{k}_i + I_i \right) \geq X_{it} \quad \forall i, t.
\]

The parameter \( \alpha_{it} \) denotes the fraction of available capacity of technology \( i \) at time \( t \), which captures downtime of conventional generators due to, for example, maintenance and the time-varying availability of renewable technologies (intermittency). \( \bar{k}_i \) denotes already installed capacity.

For an agent who maximizes profits (eq. 3.2) subject to the capacity constraint (eq. 3.3), we obtain the following first order conditions (FOCs):

\[
\frac{\partial c^g(X_{it})}{\partial X_{it}} + P^I_{it} \geq P_t + \omega_i S \quad \perp \quad X_{it} \geq 0 \quad \forall i, t
\]

\[
\frac{\partial c^I(I_i)}{\partial I_i} \geq \sum_t \alpha_{it} P^I_{it} \quad \perp \quad I_i \geq 0 \quad \forall i
\]

\[
\alpha_{it} \left( \bar{k}_i + I_i \right) \geq X_{it} \quad \perp \quad P^I_{it} \geq 0 \quad \forall i, t.
\]

\( P^I_{it} \) is the shadow value of capacity which is complementary to eq. 3.3, which is expressed by the perpendicular operator \( \perp \). The perpendicular operator indicates that in equilibrium a variable is non-zero when the associated condition holds with equality, whereas it has to be zero when the condition is a strict inequality.

STORAGE.—The storage operator maximizes profits \( \Pi_S \) from selling (release from storage) and buying (injection into storage) electricity. The profit function is given by:

\[
\Pi_S = \sum_t \left( P_t R_t - P_t J_t \right).
\]

where \( R_t \) denotes release from storage and \( J_t \) injection into storage. We distinguish three types of capacities which are needed for the storage process: release capacity \( \bar{k}^R \), injection capacity \( \bar{k}^I \), and storage capacity \( \bar{k}^S \). Similar to production, the installed storage capacities constitute constraints to the profit maximization problem of the storage operator, which can be characterized by the
following FOCs:

\[
M_t + P_t^E \geq M_{t+1} \quad \perp \quad \Sigma_t \geq 0 \quad \forall t \quad (3.8)
\]
\[
P_t \geq \psi M_t - P_t^J \quad \perp \quad J_t \geq 0 \quad \forall t \quad (3.9)
\]
\[
M_t + P_t^R \geq P_t \quad \perp \quad R_t \geq 0 \quad \forall t \quad (3.10)
\]
\[
\tilde{k}^E \geq \Sigma_t \quad \perp \quad P_t^E \geq 0 \quad \forall t \quad (3.11)
\]
\[
\tilde{k}^J \geq J_t \quad \perp \quad P_t^J \geq 0 \quad \forall t \quad (3.12)
\]
\[
\tilde{k}^R \geq R_t \quad \perp \quad P_t^R \geq 0 \quad \forall t. \quad (3.13)
\]

\( P_t^E, P_t^J, \) and \( P_t^R \) are the shadow values of storage capacity, injection capacity, and release capacity, respectively. The storage efficiency parameter \( \psi \) captures roundtrip losses of the storage cycle and \( M_t \) is the shadow value associated with the following condition which ensures time consistency of storage across periods:

\[
\Sigma_t + \psi J_t - R_t = \Sigma_{t+1} \quad \perp \quad M_t \text{ free} \quad \forall t. \quad (3.14)
\]

CURTAILMENT.—For the curtailment \( C_{it} \) of excess RE generation, we model a system operator who is bound by the RE policy to buy all generation from RE producers paying the market price and a subsidy \( P_t + \omega_i S \) and then sells the electricity in the market at market price \( P_t \). They choose how much of RE generation to curtail to maintain system stability. Thus, the system operator maximizes the following profit function with choice variable \( C_{it} \):

\[
\Pi_{sys} = \sum_{i,t} [P_t(X_{it} - C_{it}) - (P_t + \omega_i S) X_{it}]. \quad (3.15)
\]

under the condition that curtailment cannot exceed production in any period. This leads to the following FOCs:

\[
P_t + P_{it}^C \geq 0 \quad \perp \quad C_{it} \geq 0 \quad \forall i, t \quad (3.16)
\]
\[
X_{it} \geq C_{it} \quad \perp \quad P_{it}^C \geq 0 \quad \forall i, t. \quad (3.17)
\]

where \( P_{it}^C \) denotes the shadow value of curtailment.47

MARKET CLEARING AND ELECTRICITY PRICE.—At any time \( t \) electricity demand \( \bar{d}_t \) needs to be fulfilled. This is expressed by the market clearing condition which is associated with the electricity price \( P_t \):48

\[
\sum_i (X_{it} - C_{it}) + R_t - J_t = \bar{d}_t \quad \perp \quad P_t \text{ free} \quad \forall t. \quad (3.18)
\]

---

47 Note that \( \tilde{k}^E, \tilde{k}^J, \) and \( \tilde{k}^R \) are parameters, i.e. we do not model investment decisions in energy storage but rather the problem of how to optimally operate a given storage capacity. Section 3.5 then turns to the broader problem of choosing an optimal level of storage capacity given associated costs and benefits.

48 The market clearing condition holds with strict equality which implies that its dual variable is free in sign. We continue to use the perpendicular operator \( \perp \) to indicate the complementarity \( \left[ \sum_i (X_{it} - C_{it}) + R_t - J_t - \bar{d}_t \right] P_t = 0 \).
where generation net of curtailment plus release from storage minus injection into storage equals demand.

**RE SUPPORT.**—The regulator’s policy choice \( b = \{ \omega_i \}_{i \in \mathcal{I}} \) concerns the relative subsidy for different renewable technologies \( \omega_i, S \) in eq. 3.4. The overall level of the subsidy is determined by the exogenous target \( \gamma \) for the share of RE generation in total production. Even though demand remains inelastic total production changes with increasing use of storage capacity because a part of the generation going into storage, \((1 - \psi) J_t\), is lost over the storage cycle. Thus, we introduce the following condition to the MCP problem to capture the notion that a given percentage of production over all technologies needs to originate from RE sources:

\[
\sum_{i \in \mathcal{G}, t} (X_{it} - C_{it}) \geq \gamma \sum_{i, t} (X_{it} - C_{it}) \quad \Downarrow \quad S \geq 0. \tag{3.19}
\]

which formalizes the notion that renewable generation net of curtailment needs to reach a given share \( \gamma \) of total net generation.

**DEFINITION OF EQUILIBRIUM.**—The set of feasible equilibrium allocations \( \mathcal{E} \) is defined by prices and quantities \( \{ p(b), x(b) \} \) with prices \( p(b) = \{ P_t, P_{\Sigma t}, P_{I t}, P_{J t}, P_{R t}, P_{C it}, M_t \} \) determined by market-clearing conditions (3.18), (3.6), (3.11), (3.12), (3.13), (3.17), and (3.14) and quantities \( x(b) = \{ X_{it}, C_{it}, I_t, \Sigma_t, J_t, R_t \} \) determined by zero-profit conditions (3.4), (3.16), (3.5), (3.8), (3.9), and (3.10).

### 3.2.3 Total system cost \( C \) and system integration cost

Total system cost \( C \) is defined by the sum of investment cost for RES and generation cost:

\[
C = \sum_i c^1_i (I_i) + \sum_{i, t} c^0_{it} (X_{it}). \tag{3.20}
\]

We now turn to a discussion how we measure system integration cost of intermittent renewables within our model. Generally, system integration cost comprises uncertainty cost, grid expansion cost, and intermittency cost. As intermittency cost is found to make up the largest share in total integration cost (see Hirth, Ueckerdt and Edenhofer, 2015; Hirth, 2015; Gowrisankaran, Reynolds and Samano, 2016), our model abstracts from stochastic weather changes and associated forecast errors and from modeling the electric power grid.

Intermittency cost, i.e. the cost associated with foreseeable variations in resource availability over time, manifests itself in the model as investment inefficiency of RE capacity. The RE target \( \gamma \) demands a certain percentage of total consumption of electricity from RE sources but their availabilities, \( \{ \alpha_{it} \}_{i \in \mathcal{G}} \) for \( i \in \mathcal{G} \), prohibit them from flexibly satisfying demand \( \bar{d}_t \) in each period. If \( \gamma \) is high, generation from hours with high availability does not suffice to fulfill the overall target. Consequently, investments need to be chosen such that RE capacity contributes, also in hours with low resource availability, substantial amounts of electricity to satisfy demand. In hours with high resource availability, RE generation exceeds demand and the excess generation needs to be shed.
The linear fit is used as supply curve for conventional in the simulations of section 3.4. according to condition (3.16).

This mechanism thus links curtailment $C_t$ to intermittency cost: the more inefficient the investment and the more total curtailment, the higher the intermittency cost. Our measure for intermittency cost precisely exploits this mechanism by focusing on average investment cost. We calculate investment cost, $c_i^j(I_i)$, per net generation, i.e. RE generation net of curtailment, $\sum_t (X_{it} - C_{it})$:

$$\kappa_i = \frac{c_i^j(I_i)}{\sum_t (X_{it} - C_{it})} \quad \forall i \in g.$$ (3.21)

$\kappa_i$ measures the efficiency of RE capacity use and is never zero as long as there is investment into RE capacity. As an average value, $\kappa_i$ is also useful in comparing system integration cost across situations with different levels of storage investment.

### 3.3 Data and Model Calibration

This section describes the data sources used for the calibration of the model presented in Section 3.2. To calibrate the model we need to specify the following parameters: hourly demand $d_t$, the time-varying availability factors for RE $\alpha_{it}$, the efficiency parameters and capacities for storage $\psi$, $\kappa^F$, $\kappa^J$, and $\kappa^R$. We also need to choose the functional forms of the cost functions for generation and investment, $c_i^g$ and $c_i^f$, and estimate their functional parameters based on available data.

For the calibration, an important question regarding the time perspective arises: on the one hand, we want to model the dispatch decisions of economic agents in a market with a very high share of intermittent renewables as is expected to be the situation in a future electricity market (for
Table 3.1: Production capacities $\bar{k}_i$ and OLS-fitted linear functions for marginal generation cost $\partial c^g_i/\partial X_{it}$ and marginal investment cost $\partial c^i_i/\partial l_i$.

<table>
<thead>
<tr>
<th>Energy supply technologies</th>
<th>Electricity Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Conventional Wind</td>
</tr>
<tr>
<td>Installed capacities $(\bar{k}_i, \bar{k}^W_i, \bar{k}^S_i, \bar{k}^R_i)$</td>
<td>MW</td>
</tr>
<tr>
<td>MWh</td>
<td>0</td>
</tr>
<tr>
<td>Marginal generation cost functions $(\partial c^g_i(X_{it})/\partial X_{it})$</td>
<td>Intercept $(\frac{c^g_i}{\text{MWh}})$</td>
</tr>
<tr>
<td>Slope $(\frac{c^g_i}{\text{MWh}^2})$</td>
<td>$2.2 \times 10^{-3}$</td>
</tr>
<tr>
<td>Marginal investment cost functions $(\partial c^i_i(l_i)/\partial l_i)$</td>
<td>Intercept $(\frac{c^i_i}{\text{MW}})$</td>
</tr>
<tr>
<td>Slope $(\frac{c^i_i}{\text{MW}^2})$</td>
<td>0.24</td>
</tr>
</tbody>
</table>

Example, in the year 2050) in which energy regulation steps in to meet strict emission goals; on the other hand, the investment decisions we model need to be taken well before 2050 under market conditions which resemble more closely the current state of the energy system. In order to obtain a stylized and yet fairly realistic representation of RE investment, we thus calibrate the model to the current (i.e., year 2014) conditions of the German electricity market. Since conventional capacity is usually long-lived, we use the current technology mix as a basis for the calibration of the conventional supply curve but use fuel prices in line with predictions for 2050 which would govern future electricity market dispatch decisions.

DEMAND AND RE RESOURCE AVAILABILITY. — In order to capture the seasonal variation of demand and resource availability of RE technologies, we model an entire year with hourly time resolution. To keep the model numerically tractable we restrict the total number of hours modeled to 8 weeks (1344 hours) which are chosen to represent all four seasons of the year. We take hourly demand $d_t$ from the European Network of Transmission System Operators (ENTSO-E, 2016). To obtain the availability of RE sources $\alpha_{it}$ we assume that wind and solar having very low variable production cost will produce electricity whenever the natural resource is available. The fraction of actual production at any given hour and the nominally installed capacity provides us then with a percentage value of resource availability. For this, we use generation data of renewables from German transmission system operators (50Hertz, 2018; Amprion, 2018; Tennet, 2018; TransnetBW, 2018).

STORAGE. — Given the considerable uncertainties about which storage technologies will dominate in the future and about their cost and technical limitations we aim to keep our model framework as flexible as possible for storage. The model setup with the storage equations (3.8) - (3.14) is generic in the sense that any storage technology will have some kind of capacity for injection, storage, and release of electricity and time consistency will always have to be guaranteed. For the capacities associated with storage (storage capacity $\bar{k}^S_i$, injection capacity $\bar{k}^J_i$, and release capacity $\bar{k}^R_i$), we use the values reported by Hartmann et al. (2012) to specify the storage capacity of the reference case. In the numerical simulation, we vary these values exogenously, that is economic agents do not make endogenous investment decisions for storage capacity but rather treat it as given. Finally,

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49 We can even include demand side management in such a framework in that it is understood as shifting load over time just as physical storage technologies do.
we adopt a 75% roundtrip efficiency for storage, \( \psi \), which is in line with values from the literature for pumped hydro storage (PHS) (see, e.g. Egerer et al., 2014; Newbery, 2016). In their table B1, Zakeri and Syri (2015) report a range of 70% - 82% for PHS and a larger range (60% to 95%) for other technologies, such as compressed air energy storage (CAES) and different kinds of batteries. We will perform a sensitivity analysis for \( \psi = 60\% \) and \( \psi = 90\% \) to capture the impact of storage efficiency of different technologies on the results (see section 3.6).

**CONVENTIONAL GENERATION.**—We aggregate all fossil-based generation (gas, coal, oil) into one conventional supply curve. We start out by constructing a merit order curve for German power stations with data from Open Power System Data (2017). Electricity generating plants are ranked by marginal production cost taking into account fuel cost and heat efficiencies. Estimates for future fuel prices are taken from IEA’s World Energy Outlook (International Energy Agency, 2018). We then fit \( \partial c^g / \partial X^i_t \) as a linear marginal cost curve to the data, which accounts for the rising marginal cost of a heterogeneous fleet of power plants. We report the coefficients of the estimate in table 3.1. The original data of the merit order curve and the linear fit are shown in Figure 3.2.

We assume that the existing conventional generation capacity is large enough (similar to the current situation in Germany) so as to be able to fulfill demand at any time (see Table 3.1 for the numerical value of \( k_{\text{conventional}} \). This is tantamount to abstracting from investment decisions in the generation capacity of conventional technologies (i.e., \( I^i = 0 \) for \( i \in B \)).

**RENEWABLE GENERATION.**—Renewable generators incur zero variable generation cost and hence we assume \( c^g(X^i_t) = 0 \) for \( i \in G \). The most important cost parameter for RE sources is investment cost \( c^i_i(I^i) \). Since wind and solar energy depend on a natural resource, there is geographical heterogeneity of site quality for installations. Assuming that investments are made in favorable sites first and then continue in locations with decreasing wind and solar resources we model investment cost to be increasing in total investment \( I^i \) even though nominal investment cost per MW capacity is constant\(^{50} \). Thus, we choose a linear functional form for marginal investment cost \( \partial c^i_i / \partial I^i \). To estimate the parameters of this function we use data on full load hours\(^{51} \) and total capacity potential for each German state from Agentur für Erneuerbare Energien (Agentur für Erneuerbare Energien, 2017) to construct a curve showing resource quality vs. investment into capacity. When starting with the potential with the highest full load hours and continuing in decreasing order the resulting curve is also decreasing in \( I^i \). We obtain the investment cost curve by dividing nominal annualized investment cost per MW from Kost et al. (2013) by full load hours. The final investment cost curve obtained in this way is increasing in \( I^i \) and we report the estimated parameters in Table 3.1\(^{52} \).

We adopt a green field approach for RE, that is pre-installed renewable capacity is zero (i.e., \( k^i = 0 \) for \( i \in I \)). Investors choose the amount of investment \( I^i \) according to zero-profit condition (3.5)

---

\(^{50}\)For our analysis, we abstract from technological progress and a connected positive learning externality. While this would have an impact on the level of the optimal RE subsidy, the motivation for subsidy differentiation to reduce integration cost would be unchanged.

\(^{51}\)Full load hours are a measure for the resource quality at a given site. They translate the total production over a year from a RE generator into the number of hours needed to generate the same amount of electricity at fully employed installed capacity.

\(^{52}\)See Abrell, Rausch and Streitberger (2019b) for a more detailed description of the calibration method of the investment curves.
and the RE target (3.19).

**COMPUTATIONAL STRATEGY.**—We conclude this section with a short description of the numerical solving strategy that we employ in the simulations. The top-level problem of the regulator, the cost minimization in equation 3.1, is formulated as a *Mathematical Program under Equilibrium Constraints* (MPEC), that is cost is minimized subject to constraints stemming from an equilibrium problem (Luo, Pang and Ralph, 1996) which we denoted by the set of feasible allocations $\mathcal{E}$ in section 3.2. We express the lower-level equilibrium problem as a mixed complementarity problem (MCP) (Mathiesen, 1985; Rutherford, 1995). Due to the lack of robust solvers for MPECs (Luo, Pang and Ralph, 1996) we solve the lower level MCP problem over a suitable grid to find the minimum cost and thus the solution to the MPEC using the PATH solver (Dirkse and Ferris, 1995) for complementarity problems and the General Algebraic Modeling System (GAMS).

### 3.4 Buffering Volatility: Storage Investments vs. Differentiated Renewable Energy Support

This section presents the results of our numerical simulations. First we briefly explain the scenarios considered and the simulations that we performed. We continue by summarizing the main findings and then go on to explain the underlying market mechanisms in more detail in the remaining subsections.

#### 3.4.1 Design of counterfactual experiments

To examine the role of the storage investments and differentiated renewable support schemes, we model the following three scenarios:

- **No policy** assumes that (i) RE support policy is absent and that (ii) storage capacity is equal to the currently installed pumped hydro storage capacity in Germany (37.7 GWh as of 2014). This scenario serves as a suitable reference point for analyzing the additional costs and benefits of future expansions of storage.

- **Neutral subsidy** assumes that the RE target is implemented by a technology-neutral subsidy (modeled as a market premium) for RE generation.

- **Differentiated subsidy** assumes that the RE target is implemented by a market premium which is optimally differentiated by RE technology so as to minimize total system cost.\(^{53}\)

Under *No policy*, generation from RE makes up 42% of total generation, which can be broken down further into 22.5% generation from solar and 19.5% from wind. Since the RE share in this

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\(^{53}\) Note that by design investors receive payments for possible generation even if the system operator curtails parts of the RE generation. Thus, investment decisions in RE capacity do not take into account curtailed energy. It is beyond the scope of the paper to study to what extent other policy design, for example, RE subsidies based on installed capacity (i.e., MW instead of MWh), can address integration costs in terms of curtailment.
3.4.2 Overview of main results

Figure 3.3 shows the total system cost $C$ for different levels of the given storage capacity under the three scenarios. Three main insights emerge. First, it is evident that an increase in storage capacity strongly reduces system cost for low levels of installed storage capacity but marginal benefits (i.e., avoided cost) rapidly diminish as storage capacity increases. Marginal benefits from storage quickly approach zero at capacity levels of around 400 GWh, corresponding to 10.6 times the installed storage capacity in 2014, or, equivalently, 6.5 average demand hours. This indicates that further discussion about the costs and benefits of storage capacity should concentrate on low to moderate levels of storage investment.

Second, the behavior of the storage operator for low to medium storage capacities (i.e., up to 400 GWh) shows exclusively intra-day storage cycles and no shifts of generation over seasons. We observe seasonal storage only for considerably higher installed storage capacities. Since the

Note that unlike our RE target, these percentages also include electricity from hydro sources and biomass.
Table 3.2: Overview of key impacts for alternative efficient RE support policies.

<table>
<thead>
<tr>
<th>Storage factor</th>
<th>Curtailment, ( \sum C_i ) [TWh]</th>
<th>Gen. share by tech. (%)</th>
<th>Av. investment cost, ( \kappa ) EUR/MWh</th>
<th>( \sum c_i ) [EUR]</th>
<th>Gen. cost, ( X_i ) [B. EUR]</th>
<th>Tot. cost, ( C ) [B. EUR]</th>
<th>Subsidy diff. (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neutral subsidy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 (37.7 GWh)</td>
<td>46.3</td>
<td>94.0</td>
<td>30.5</td>
<td>39.5</td>
<td>94.2</td>
<td>84.9</td>
<td>15.5</td>
</tr>
<tr>
<td>5 (188.5 GWh)</td>
<td>12.5</td>
<td>21.3</td>
<td>27.4</td>
<td>42.6</td>
<td>74.8</td>
<td>62.2</td>
<td>11.3</td>
</tr>
<tr>
<td>10 (377 GWh)</td>
<td>1.8</td>
<td>3.6</td>
<td>24.6</td>
<td>45.4</td>
<td>67.7</td>
<td>57.9</td>
<td>9.4</td>
</tr>
<tr>
<td>unlim.</td>
<td>0</td>
<td>0</td>
<td>20.1</td>
<td>49.9</td>
<td>64.4</td>
<td>58.1</td>
<td>7.4</td>
</tr>
<tr>
<td>Differentiated subsidy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 (37.7 GWh)</td>
<td>44.7</td>
<td>29.4</td>
<td>39.4</td>
<td>39.8</td>
<td>39.8</td>
<td>20.3</td>
<td>10.5</td>
</tr>
<tr>
<td>5 (188.5 GWh)</td>
<td>12.0</td>
<td>11.5</td>
<td>31.3</td>
<td>38.7</td>
<td>76.0</td>
<td>58.8</td>
<td>13.2</td>
</tr>
<tr>
<td>10 (377 GWh)</td>
<td>1.8</td>
<td>2.3</td>
<td>26.4</td>
<td>43.6</td>
<td>68.6</td>
<td>57.2</td>
<td>10.2</td>
</tr>
<tr>
<td>unlim.</td>
<td>0</td>
<td>0</td>
<td>21.7</td>
<td>48.3</td>
<td>65.2</td>
<td>57.7</td>
<td>8.0</td>
</tr>
</tbody>
</table>

Notes: \( ^a \) Storage factor denotes storage capacity in multiples of the currently installed capacity (37.7 GWh). \( ^b \) Note that the generation shares always add up to the policy target of 70%. \( ^c \) Average investment cost is measured in annuitized investment cost per generation net of curtailment. \( ^d \) We report the percentage value of the subsidy per MWh for PV relative to wind.

The marginal benefits of storage capacity from avoided curtailment are zero for high values of installed capacity (i.e., beyond 400 GWh), it seems possible that the costs of seasonal storage exceed benefits, even in scenarios where the share of RE generation is as large as 70%. This suggests that investments into short-term storage technologies will possibly play a more important role as compared to longer-term, seasonal storage.

Third, the cost curve associated with a technology-specific RE support scheme shows that for low to medium storage capacities substantial savings in total system costs are possible. For low levels of storage capacity these can be as high as 11.4% of total system cost in a scenario without storage capacity and 7.7% if the current, installed storage capacity is assumed. This indicates that, given a fixed target for RE generation, improving the design of RE support schemes can either reduce total system cost in a scenario with given storage capacity or partially substitute for storage investment.\(^{55}\)

The following subsections provide more detail about the market mechanisms behind these insights and provide further explanations and detailed results.

### 3.4.3 The effects of adding storage capacity

Storage capacity can act as a complement to intermittent renewables in that a storage operator has an incentive to fill the storage with cheap electricity in low-price hours, when there is abundant renewable generation, and to release electricity from storage in hours with high prices, when wind and solar generation is scarce. What is the value of adding storage capacity at the system or

\(^{55}\)Note that this result is independent from the actual need for RE support policies in the future. If in a situation where RE shares are high even without a subsidy policy integration cost can be lowered by altering the relative investment cost ratio of renewables the regulator can resort to a policy where the “subsidy” is zero for one technology and non-zero for the other.
TOTAL AND MARGINAL BENEFITS OF STORAGE.—Figure 3.3 provides measures for the total and marginal benefits of installing storage capacity: the total benefits of a given storage level are measured by the cost difference relative to a situation with zero storage; the marginal benefits are given by the negative derivative of the total system cost curve. With increasing storage capacity the total cost curves for the no-policy scenario as well as the two policy scenarios go towards a steady state which is reached when the constraints on storage are all non-binding and the intermittency of renewables is buffered by storage as much as possible. At this point, intermittency cost of RE is minimal and comparing total system cost at this point with total system cost for zero storage capacity allows us to gauge the maximum potential gains from storage (and, at the same time, total intermittency cost). Performing this calculation for the scenario with a Neutral subsidy to achieve a 70% RE target, we find that the maximum cost savings due to storage are 37% of total system cost with zero storage or 30% when using the currently installed storage capacity of our reference case. This number shows that from a system perspective, potential cost savings from storage are substantial but it also serves as an upper bound for the economically viable level of investment into storage.

For the actual storage investment decision of economic agents, marginal benefits of storage (alongside marginal cost) are crucial. Since the total cost curves go towards a steady state, their derivatives and thus marginal benefits go to zero. The decrease in marginal benefits of storage is steep so that from a system-wide perspective, most of the potential cost savings through storage capacity are achieved up to roughly 200 GWh. If we assume non-zero capital cost for storage, above this threshold, the incentives to add further storage capacity decrease rapidly even though cost savings in total system cost are still possible. We will further substantiate this argument in the cost-benefit analysis below.

We now take a closer look at what drives the benefits from additional storage. Storage reduces total system cost by preventing curtailment of generation from RE sources, thereby reducing the need for investment into RE capacity to meet a given RE target, i.e. investments into RE capacity are used more efficiently. Table 3.2 collects the relevant numerical results from our simulations. We report the values for key quantities such as total cost $C$ and average investment cost $\bar{c}$ for both policy scenarios, Neutral subsidy and Differentiated subsidy, and storage capacity increasing from currently installed levels to unlimited storage. As shown in Figure 3.3, there is a 30% decrease in total cost with increasing storage for a Neutral subsidy from 40.8 Billion Euro to 28.5 Billion Euro. Together with total cost we report its two components, total investment cost per technology, $c^i_t(l_i)$ for $i \in G$, and conventional generation cost, $\sum_t c^g_t(X_{it})$ for $i \in B$. With increasing storage, generation cost decreases due to storage substituting expensive conventional generation in peak hours, which results in overall lower fuel cost. As the numbers in table 3.2 show, this is a reduction by 35% from current storage levels to unlimited storage, but the cost savings in absolute terms are

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56 Even if storage capacity is unconstrained energy loss over the storage cycle cannot be avoided because its roundtrip efficiency is below 100%. This is a potential source for intermittency cost other than curtailment. The technology which is more likely to go into storage due to its availability pattern (in our case PV) then will contribute more to the remaining intermittency cost. For the impact of this effect on optimal subsidy differentiation see sections 3.4.4 and 3.6.
small compared to cost savings in total renewable investment cost. The driver of cost reductions is total curtailment, $\sum_t C_{it}$ for $i \in G$, which decreases with increasing storage capacity and goes to zero. This is mirrored in the evolution of our efficiency measure $\kappa_i$ which reports average investment cost per net generation. For both RE technologies the average investment cost shows a decreasing trend with increasing storage consistent with the decrease in curtailment.$^{57}$

Figure 3.4 illustrates the impact of increasing storage capacity on RE investment by technology. We observe a steep decline in installed capacity for both technologies (associated with the increasing utilization efficiency) when storage is first introduced, which corresponds to a large marginal benefit of storage in this early stage of investments. As storage capacity increases until finally reaching a steady state, the relative share of solar power increases compared to wind as can also seen by the generation shares reported in Table 3.2. This is the case because solar has cheaper investment cost per MW but is also inherently more volatile in its availability (having a daily period of zero output during nighttime and strong production peaks around noon). With rising storage capacity the disadvantages of this volatility disappear and make it more competitive relative to wind power.

**VOLATILITY OF EQUILIBRIUM ELECTRICITY PRICES.**—The diminishing volatility for an increasing storage capacity is also reflected by a reduced dispersion of equilibrium electricity prices on hourly wholesale markets. A comparison across the Panels (a)–(d) in Figure 3.5 shows that the price volatility sharply reduces as storage capacity increases, reaching its theoretical minimum when storage capacity is unlimited.$^{58}$

**INTRA-DAY VS. SEASONAL STORAGE.**—The maximally observed reduction in price volatility is only possible when storage capacity is very large or unlimited and the storage operator engages in shifting

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$^{57}$The slight increase in average investment cost for PV under unlimited storage stems from the fact that overall investment in solar is growing with increasing storage capacity and that rising marginal investment costs with degrading resource quality offset the gains from better utilization of capacity.

$^{58}$The remaining price variation under unlimited storage capacity is due to roundtrip efficiency losses. As we assume a 25% loss of energy over the storage cycle, there needs to be a price spread between periods of injection into and release from storage for the storage activity to be economically viable.
Figure 3.5: Hourly electricity price for a 70% RE target with a technology-neutral RE subsidy and increasing storage capacity measured in multiples of the currently (i.e., year 2014) installed level.

(a) Storage level 1 (37.7 GWh).  
(b) Storage level 5 (188.5 GWh).  
(c) Storage level 10 (377 GWh).  
(d) Unlimited storage.

Figure 3.6: Electricity generation stored over the course of a year.

Note: The horizontal lines indicate the maximum storage capacity available in the two cases of constrained (377 GWh) and unlimited storage capacity. Under unlimited storage, the capacity of 6032 GWh is never exhausted.

electricity generation over seasons in addition to shorter storage cycles. To illustrate the two principal ways how storage operates in the electricity market over the different time scales, Figure 3.6 contrasts the behavior of a profit-maximizing storage operator for a situation with constrained (equal to 377 GWh) and unlimited (equal to 6032 GWh) storage capacity. The following insights
emerge.

First, there is a short-term consideration associated with the intra-day storage of electricity which aims at exploiting the price differentials between low-price and high-price periods over a typical day. Optimization over this short-term cycle is closely associated with solar generation and shifts excess PV generation from daytime hours to hours with little or no solar availability. Intra-day storage optimization is present for cases with both constrained and unlimited storage capacity. Second, when constraints on storage are lifted, we observe a long-term behavior with seasonal storage where reserves are filled over the summer months (mostly with solar generation) and depleted in winter and spring periods when solar energy is scarce. When the storage level is 10 times the base-year level (377 GWh), the marginal cost savings have become small and are rapidly decreasing towards zero. This suggests that, even with a relatively aggressive RE target of 70%, seasonal storage is not feasible as the necessary capacity investments will neither pay off for investors nor do they substantially reduce the total system cost (or increase the market surplus) to society.

3.4.4 Differentiated renewable energy support schemes

Mandating that a large share of electricity has to come from intermittent RE has been shown to cause substantial system integration costs (see Section 3.4.3 and the text around Figure 3.3). One strategy for buffering volatility and to reduce system integration cost (i.e., curtailment) is to increase storage capacity. Coping with volatility through this channel, however, is subject to a trade-off between the cost savings in system integration cost and the rising cost for storage investment—and we have shown that the marginal benefits from additional storage investments rapidly diminish at the system level. An alternative buffering mechanism is through optimizing the regulatory design of the RE support scheme in order to take advantage of the complementarity of the underlying natural resources and their correlation with time-varying electricity demand.

Our key finding here is that a technology-neutral RE support scheme (for example, implemented as a per MWh subsidy on RE output) is not a cost-effective strategy to reach a given RE target at lowest cost to society. The cost of achieving a given RE target can be significantly lowered by optimally differentiating the policy support among RE technologies.\footnote{Note, however, that technology-differentiation is not the only possible way to address these issues. Other subsidy designs such as a per MW subsidy or a subsidy per MWh which is only given for generation which is not curtailed could also be considered.}

As there are interdependencies between both buffering strategies (i.e., differentiated RE subsidies and enhanced storage capacity), we analyze the potential of differentiated RE support for different levels of storage capacity. Table 3.2 reports the optimal differentiation of the subsidy for solar compared to wind. For the current storage capacity, solar receives only 62% of wind subsidy per MWh produced. Solar energy has lower investment cost per MW and its resource availability is highly concentrated during a few hours of the day. With a high targeted share of RE and with low storage capacity, this implies a much higher curtailment of solar energy as compared to wind. The lower subsidy leads to a shift of investment from PV to wind, thereby lowering the average investment cost for solar as the remaining solar capacity can be used more efficiently. Accordingly,
average investment cost $\kappa_i$ for solar for each storage level is lower than the corresponding value with a neutral subsidy. As a direct consequence, with an optimally differentiated subsidy we observe lower total system cost for low to medium storage capacities where curtailment of RE generation is necessary. With increasing storage, curtailment is reduced to zero and the motive for differentiation vanishes almost completely and remains at 91%. This moderate differentiation is explained by storage efficiency losses because generation from solar is more likely to go into storage than generation from wind.

Similar to increased storage capacity, differentiated RE support brings about a reduction in curtailment—however, the mechanism is different. Under a neutral RE subsidy, investments into RE technologies are chosen such that marginal investment costs are equal across the two technologies. Due to the intermittent nature of RE sources this causes demand and supply to be mismatched in a large number of periods with the implication of high (and costly) curtailment. Since the subsidy is designed in a way that generators receive additional revenue for each unit produced, even though this unit may have to be curtailed, agents do not take into account the mismatch of demand and supply, i.e. they do not properly internalize the curtailment costs associated with more volatile RE supply when taking their investment decisions. In contrast, optimal differentiation of the RE subsidy induces investment patterns such that the marginal investment costs can differ between the two intermittent RE technologies. Total system costs are reduced as curtailment decreases due to a “better usability” of electricity, i.e. by exploiting the complementarities with respect to the availability of the underlying natural resource and its correlation with electricity demand. To a smaller extent, when storage efficiency is below 100%, differentiation favors the technology which is less dependent on storage, reducing energy losses and thus total system cost are also reduced.

### 3.5 How Much Energy Storage?—A Simple Cost-Benefit Analysis

This section explores the question how much energy storage is optimally needed to achieve a certain share of intermittent RE at the lowest cost to society. In trying to tackle this question, we keep the conceptual framework deliberately simple and adopt a canonical cost-benefit analysis based on the equalization of marginal benefits and marginal costs. The main idea is as follows. First, we make use of the detailed electricity simulation model presented in Section 3.4 to characterize the marginal benefits of energy storage. Second, we obtain estimates for the marginal costs of energy storage by briefly reviewing the relevant literature. Third, the optimal level of energy storage capacity is then determined based on a comparison of marginal costs and benefits. We also examine how the choice of regulatory design—with respect to a technology-neutral or technology-specific support mechanism which has been shown to act as a potential buffer against the market volatility induced by intermittent RE technologies—affects the optimal level of storage.
Table 3.3: Estimates taken from the literature to construct the marginal cost curve for storage.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Cost [Million EUR/GWh]</th>
<th>Potential [GWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>Medium</td>
</tr>
<tr>
<td>Pumped Hydro Storage</td>
<td>96</td>
<td>137</td>
</tr>
<tr>
<td>Compressed Air Energy Storage</td>
<td>48</td>
<td>92</td>
</tr>
<tr>
<td>Power to Gas</td>
<td>227</td>
<td>262</td>
</tr>
<tr>
<td>Batteries(^a)</td>
<td>368</td>
<td>427</td>
</tr>
</tbody>
</table>

Notes: Cost estimates are taken from Zakeri and Syri (2015) and estimates of potentials from Hartmann et al. (2012).

\(^a\)The values for batteries are own calculations of average values over different battery technologies in Zakeri and Syri (2015).

\(^b\)Since batteries are not subject to similar physical restrictions as mechanical storage technologies, their maximum potential is likely to be very high. We refrain from reporting a value on this since it is highly uncertain.

### 3.5.1 Marginal costs curve

For the construction of the marginal costs of installing different levels of energy storage, we refer to empirical estimates documented in the literature. Characterizing marginal costs over a large range of storage levels is, of course, fraught with large difficulties. First, the investment costs for both current and future storage technologies are highly uncertain. Second, reliable estimates for the potential of different storage technologies are also subject to considerable uncertainty.

We rely on cost estimates for storage technologies from Zakeri and Syri (2015) and on estimates for the potential of different technologies from Hartmann et al. (2012). Table 3.3 summarizes these estimates which provide the basis for deriving a marginal cost curve for storage capacity. We construct the marginal cost curve as a step function with horizontal steps corresponding to the installation cost of the respective storage technology and with the length of the horizontal lines corresponding to the respective potential. Figure 3.7 shows the cost curves for the Low and Medium cost assumptions. Note that we show only the lowest step which represents the cheapest option—compressed air energy storage. The other parts of the step-function to the right of the lowest step are not relevant for our discussion given the range of storage level spanned by the marginal benefits curves.

### 3.5.2 Marginal benefits curve

We construct the marginal benefits curve for energy storage based on the simulations of the wholesale electricity market model described in Section 3.4. Specifically, we use model estimates of how total system costs change with different levels of energy storage (see Figure 3.3). The marginal benefit of adding a small amount of storage capacity is equal to the negative derivative

\[\text{Comparing to other studies, cost estimates by Zakeri and Syri (2015) are at the lower end of the cost range. Using rather low cost estimates, our results are conservative in the sense of being favorable for storage investments. However, the available studies cannot incorporate highly uncertain future cost reductions due to technological breakthroughs. Thus, the given cost estimates represent a current state for these technologies.}\]
of the total cost curve. Numerically, this is approximated by the difference quotient of total cost with respect to storage capacity evaluated for different storage levels. Let $C'(\hat{k}^\Sigma)$ denote the equilibrium cost for a given storage level $\hat{k}^\Sigma$. The marginal benefits of energy storage, $\beta(\hat{k}^\Sigma)$, are then given by:

$$\beta(\hat{k}^\Sigma) = \frac{C'(\hat{k}^\Sigma) - C'(\hat{k}^\Sigma - h)}{h},$$

(3.22)

where $h$ denotes the step size, i.e. the difference between single points on the storage capacity axis. Figure 3.7 depicts the numerical marginal benefits function for each of the two RE policy cases (i.e., Neutral subsidy and Differentiated subsidy).

### 3.5.3 Optimal storage capacity and the impact of technology-specific RE policy

The simple cost-benefit framework depicted by Figure 3.7 enables us to draw several conclusions. First, given the available cost estimates for storage, the economically optimal storage capacity to integrate intermittent RE supply consistent with a 70% RE target is moderate in any case: under Medium cost assumptions, and a technology-neutral RE support, roughly doubling the level of existing capacities would be sufficient for the German electricity market; under Low cost assumptions, the optimal storage level is about 150 GWh or four times larger than the currently installed level. These findings are in line with large parts of the literature; see, for example, Zerrahn, Schill and Kemfert (2018) and the studies cited therein. Zerrahn, Schill and Kemfert (2018) find that for a RE target of 70%, the optimal storage level is 230 GWh which lies both within the range of estimates obtained by our approach as well as the bulk of the literature.

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61 For practical reasons, we choose $h$ to coincide with the numerical step size that was used to obtain the simulations in Section 3.4.
Second, Figure 3.7 visualizes the striking impact of carefully designed technology-specific RE support on the optimal level of energy storage. Optimal differentiation of RE subsidies reduces curtailment and thus the marginal benefits from storage. As a result, the optimal level of storage capacity is considerably lower: under Medium cost assumptions, no additional investment into storage beyond current installations is needed; under Low storage cost, a storage capacity of approximately 90 GWh is optimal—almost half of what would be optimally needed under a technology-neutral RE support. This suggests that coping with the volatility induced by intermittent RE sources can be achieved to a large extent through smart policy design which subsidizes RE technologies according to their heterogeneous value for system integration cost (rather than determining the level of subsidies based on a narrow consideration of investment costs per MW of production capacity).

3.6 Sensitivity Analysis

We check the robustness of our main findings by varying parameter values along two important dimensions, the policy target for the RE share in production (denoted by \( \gamma \) in section 3.2) and the round trip efficiency of storage (denoted by \( \psi \) in section 3.2). Table 3.4 reports values for several key variables of our analysis for the parameter choice in our main results section (\( \gamma = 70\% \), \( \psi = 75\% \)) which we denote as core case and for several alternative scenarios: high efficiency (\( \gamma = 70\% \), \( \psi = 90\% \)), low efficiency (\( \gamma = 70\% \), \( \psi = 60\% \)), and high RES (\( \gamma = 80\% \), \( \psi = 75\% \)).

3.6.1 Higher required RE share

With rising shares of RE generation the impact of the intermittency of wind and solar resources on the total electricity system becomes more pronounced and the mismatch between demand and supply more severe. We explore the implications of a 10% increase in RE generation from 70% to 80% of total generation and report the results in table 3.4 in columns four and eight (H. RES) for a neutral subsidy and a differentiated subsidy, respectively. Due to the higher RE share requirements total cost and curtailment increase considerably when the available storage capacity is low. We find, however, very similar characteristics as in the core case. As expected, rising storage capacity decreases cost of curtailment (as can be seen from the decrease in total cost when storage capacity increases). In line with our findings for the core case, differentiation of the subsidy has the potential to reduce total cost considerably for low levels of storage capacity. At current levels of storage (storage factor 1), subsidy differentiation reduces total system cost by 30%, which is a larger effect than was observed in the core case. Because more generation from renewables needs to be integrated in the system our cost-benefit analysis yields also considerably higher optimal storage capacity (309 GWh, roughly eight times the current capacity) which can be reduced by 29% through subsidy differentiation. Figure 3.8 is an updated version of figure 3.6 for the high RES scenario and we observe that at a storage capacity of 377 GWh (ten times the currently installed capacity) and well above the optimal capacity with a neutral subsidy scheme (309 GWh) we do not observe a clear seasonal storage behavior as the one we observe for unlimited storage capacity (6786 GWh) in the same figure.
3.6.2 Efficiency of storage

The efficiency of storage (capturing the energy losses over one full storage cycle of injection, storage, and release of electricity) varies considerably over different storage technologies and is a major determinant of their overall performance and impact on the electricity system. The efficiency $\psi = 75\%$ which is used for the core case simulations is in line with values reported for hydro storage (see, e.g. Egerer et al., 2014; Newbery, 2016; Zakeri and Syri, 2015). For other promising technologies such as compressed air energy storage and batteries, efficiency varies within a wide of about 60% to 90% (see Table B1 in Zakeri and Syri, 2015). We therefore add two scenarios with these extreme values for efficiency, high efficiency and low efficiency, to our sensitivity analysis capturing different technology choices for storage. The results are reported in table 3.4 in columns two and three for a neutral subsidy and columns six and seven for a differentiated subsidy.

A comparison of the results for high and low storage efficiency with the core case shows relatively small changes for most variables. The overall effect on total cost compared to the core case is small for limited current storage capacity (e.g., with neutral subsidy and high efficiency total cost increases by 0.2% and with low efficiency it decreases by 0.2%) and for the extreme case of unlimited storage total cost decreases by 4.9% and increases by 5.6% for high efficiency and low efficiency, respectively. Not surprisingly, when efficiency is higher (lower), the optimal storage capacity is also higher (lower), both for the case of a neutral subsidy and a differentiated subsidy. In both scenarios, subsidy differentiation reduces total cost by a similar amount than in the core case and the optimal storage capacity can be significantly reduced compared to a neutral subsidy scheme. It is interesting to note, that the optimal differentiation depends on the storage efficiency. In the core case, we still observe an optimal differentiation that reduces the subsidy from solar even if storage capacity is unlimited and curtailment is zero. This is because electricity from solar energy is more likely to go into storage compared to wind due to its highly concentrated availability pattern. If storage losses are nonzero this makes solar less valuable than wind and a small differentiation of
the subsidy persists in the optimum. Accordingly, we observe that with a higher storage efficiency, the optimal differentiation for unlimited storage capacity is closer to a neutral scheme and vice versa for lower efficiency. The numerical changes in differentiation remain small. For unlimited storage, when the effect is strongest, higher efficiency reduces optimal differentiation by 5 percentage points, while lower efficiency increases its value by 10 percentage points. For current storage capacities, the difference is less than 1% for higher efficiency and 3% for low efficiency.

3.7 Concluding Remarks

The ongoing decarbonization of the electricity sector in many countries will substantially increase the share of energy supplied from volatile, intermittent RE sources such as wind and solar. A key challenge, also for bolstering policy support for the decarbonization through more renewables, is to achieve the integration of large amounts of highly volatile generation in electricity markets at moderate costs. Much of the ongoing discussions in both the academic literature and among policy-makers have focused on how increased volumes of electricity storage can serve as a buffering mechanism to cope with market volatility and system integration cost. In light of large uncertainties about the cost, availability, and potential of future storage technologies when deployed at large scales, this paper has examined the suitability of an alternative mechanism for buffering volatility that is based on modifying the design of RE support schemes to take into account the heterogeneous value of different RE technologies in terms of their system integration costs.

To provide a conceptual and empirically-grounded framework for thinking about the economics of integrating high shares of volatile RE sources into an electricity market, we have developed a numerical partial equilibrium model of the wholesale electricity market which resolves output decisions on hourly markets, time-dependent demand and resource availabilities of wind and the sun, investment decisions in production capacity, curtailment decisions to maintain system stability, and a detailed representation of short-term and longer-term electricity storage. The decentralized market model is embedded in a welfare-maximizing problem of a benevolent regulator who chooses RE support policies (through subsidies on RE output which we model as a feed-in premium on top of the market price) in order to implement an electricity market with a high share of intermittent RE at the lowest cost to society. While we have calibrated the model to current market conditions of the German electricity market, we believe that the main insights emerging from our analysis largely carry over to the electricity market context of other countries, too.

Our analysis provides several important insights. First, we find that the storage capacity needed to accommodate a high share of intermittent RE output is relatively moderate, even under a technology-neutral RE support scheme. This implies that the potentially high costs of providing storage at large scale in the future need not jeopardize the achievement of environmental targets (i.e., the reduction of CO2 emissions through increasing the share of low-carbon renewables). Second, we find that the design of a RE policy can have a significant impact on system integration cost as well as storage capacity needs when there are several intermittent renewable technologies with heterogeneous availability patterns of the underlying natural resources (such as wind and solar energy). The smart differentiation of RE subsidies affects investment patterns in a way which
can effectively reduce the curtailment of excess generation, in turn lowering the need for costly investment in energy storage. We use a simple cost-benefit framework to show that optimal subsidy differentiation significantly reduces the level of optimal storage. In this sense, concerns about the costs and availability of future storage technologies to be able to integrate a high share of intermittent RE output in electricity markets and to achieve environmental goals are even more diminished if a smart design of RE support policies is chosen. Third, within our modeling framework which captures high RE shares up to 80% but not a completely decarbonized system, we find that the type of storage most likely needed is short-term to medium-term storage. The additional benefits from long-term seasonal storage are relatively modest and most likely much smaller than its investment costs. 

The necessary abstraction and assumptions of the electricity market model imply that several caveats should be kept in mind when interpreting our results. Future costs and benefits of RE and storage technologies are highly uncertain in the present. We therefore make use of current cost estimates in our model calibration and cost-benefit analysis and thus cannot and do not aim to predict exact numbers for future systems. We focus on one policy scheme (a feed-in premium per MWh of renewable energy produced). There are several other possibilities of designing RE subsidies, including a subsidy scheme where the subsidy goes to zero whenever the electricity price reaches zero and a subsidy per MW of installed capacity. We leave the role of technology-differentiation in such alternative policy designs to future research. Our findings rely on the assumption of fixed renewable production profiles taken from the base year of our simulation which might not be the best approximation of future profiles. Therefore, we cannot address questions of different predictability of RE technologies and its implications for optimal subsidy differentiation. The marginal benefits curve of storage capacity which we construct does not capture all potential benefits. We focus on the biggest contributor to system integration cost, curtailment of RE generation, but storage will also reduce cost originating from stochastic variation of weather conditions and—if it is organized in smaller decentralized units—storage can also reduce the need for costly transmission grid extensions. At the same time, a greater interconnection via transmission capacities to neighboring markets has the potential to reduce the marginal benefits from storage investment because it permits a more efficient use of existing RE capacities and storage capacities over a larger geographical area. The combined effect on the marginal benefit curve depends on specific details of the electricity market in question and is beyond the scope of this work. The same is true for additional benefits from ancillary services storage could provide (see, e.g. Newbery, 2016, for an evaluation of earnings from ancillary services). We also abstract from complications from natural water inflow that might arise in a system with substantial capacities of large-scale hydro dams. Our generic storage technology does not depend on external weather phenomena but in such a real-world system hydrological constraints could very well interact with intermittency from wind and solar power. These could only be addressed by a more complex model incorporating the hydrological cycles of a specific region which is beyond the scope of this article. Similarly, an extension of the model could explicitly incorporate demand-side management as an alternative form of energy storage. This would require careful modelling of the different types of participants and system costs.
Our analysis should thus not be viewed as a comprehensive cost-benefit assessment but rather stresses the point that policy design greatly matters for minimizing the economic cost of achieving CO₂ emissions reductions through integrating large amounts of energy supply from carbon-free but volatile RE technologies. While this point has been overlooked so far, it should be taken into account when discussing ways to reduce system integration cost from intermittent RE. The potential benefits of subsidy differentiation may also lead the way to re-thinking future RE policy design in terms of specific features of technologies (such as its impact on system stability, interaction with storage or transmission grids) rather than being technology-neutral or tailored to each technology individually. One example for this could be a subsidy for system stability or supply flexibility. We leave an analysis of such policies for future research. With regard to future storage needs, we concur with Zerrahn, Schill and Kemfert (2018) who show that the expansion of energy storage capacity will arguably not constitute a limiting factor to integrate large shares of volatile RE supply in electricity markets needed to combat climate change.
Table 3.4: Sensitivity Analysis

<table>
<thead>
<tr>
<th>Variable</th>
<th>Tech.</th>
<th>Storage factor&lt;sup&gt;a&lt;/sup&gt;</th>
<th>Neutral</th>
<th>Differentiated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total cost</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[B. EUR]</td>
<td>1 (37.7 GWh)</td>
<td>40.8</td>
<td>40.9</td>
<td>40.7</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>32.3</td>
<td>32.0</td>
<td>33.2</td>
</tr>
<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>28.5</td>
<td>27.1</td>
<td>30.1</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Curtailment</strong></td>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>46.3</td>
<td>58.9</td>
<td>44.7</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>12.5</td>
<td>19.9</td>
<td>12.9</td>
</tr>
<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>1.8</td>
<td>1.9</td>
<td>2.2</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PV</strong></td>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>94.0</td>
<td>84.9</td>
<td>90.6</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>21.3</td>
<td>18.5</td>
<td>21.8</td>
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<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>3.6</td>
<td>4.2</td>
<td>3.0</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Generation share by technology (%)&lt;sup&gt;b&lt;/sup&gt;</strong></td>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>30.5</td>
<td>28.4</td>
<td>30.6</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>27.4</td>
<td>26.5</td>
<td>27.6</td>
</tr>
<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>24.6</td>
<td>24.3</td>
<td>25.5</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Average Wind Investment Cost [EUR/MW h]&lt;sup&gt;c&lt;/sup&gt;</strong></td>
<td>PV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>94.2</td>
<td>102</td>
<td>93.3</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>74.8</td>
<td>78.6</td>
<td>75.3</td>
</tr>
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<td></td>
<td>10 (377 GWh)</td>
<td>67.7</td>
<td>67.2</td>
<td>68.8</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PV</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>84.9</td>
<td>81.4</td>
<td>83.7</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>62.2</td>
<td>61.4</td>
<td>62.4</td>
</tr>
<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>57.9</td>
<td>57.8</td>
<td>57.8</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Subsidy diff. (%)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1 (37.7 GWh)</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>5 (188.5 GWh)</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>10 (377 GWh)</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>unlim.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Optimal Storage Capacity [GWh]</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>143</td>
<td>150</td>
</tr>
</tbody>
</table>

Notes:  
<sup>a</sup> Storage factor denotes storage capacity in multiples of the currently installed capacity (37.7 GWh).  
<sup>b</sup>Note that the generation shares always add up to the policy target of 70%.  
<sup>c</sup>Average investment cost is measured in annuitized investment cost per generation net of curtailment.  
<sup>d</sup>We report the percentage value of the subsidy per MWh for PV relative to wind.
4 The value of flexibility in green electricity markets: energy storage, international trade, and tradable quotas

Abstract

Decarbonizing the electricity sector is a central piece in the efforts to reduce carbon emissions worldwide and as a consequence, high shares of renewable energy (RE) from intermittent sources will be a new reality for electricity systems. This paper develops a multi-country numerical model of interconnected electricity markets featuring tradable green quotas (regulatory flexibility), cross-country trade (spatial flexibility), and electricity storage (temporal flexibility) possibilities to study the cost implications of integrating large amounts of new RE. We show that in general, there is no clear ranking for the cost-saving benefits of either measure but for a given system an appropriate combination of these flexibility channels can substantially reduce integration cost of RE and at the same time reduce emissions from the remaining conventional production. Calibrating the model to European data, we adopt a renewable energy target of 70% of electricity demand to be met either for each country individually or aggregated over all countries. We then assess potential savings in total cost (excluding investment cost in trade and storage capacity) when introducing one or more of the flexibility options. We find that relative to a system with no added flexibility, increasing trade flexibility has the highest potential benefits (-7.5%) followed by enhanced storage capacity (-5.2%). These benefits, however, require uncertain and potentially high investment cost into infrastructure to materialize. Improving the regulatory regime by introducing a tradable green quota system has the smallest potential benefits (-2.5%) but it does not require any additional investment.

4.1 Introduction

On a global scale, about 40% of CO$_2$ emissions from fuel combustion could be attributed to electricity and heat production in 2016 (International Energy Agency, 2018). The demand for electricity is expected to grow substantially in the coming decades due to the trend of electrification of other emissions intensive sectors such as transportation. This makes the electricity sector one of the most important areas for policies aimed at mitigating climate change worldwide. Major industrialized world regions such as the European Union are planning to massively reduce their emissions from electricity generation within the coming decades as outlined in the EU’s Energy Roadmap 2050 (European Commission, 2011). At the core of the proposed measures is a large increase in generation from renewable energy (RE) sources meant to replace electricity production from conventional fossil generation technologies. Since the two most promising RE technologies, wind and solar energy, are intermittent (i.e., their production at any time depends on the availability of the natural resource, wind or solar irradiation.), the risk for a mismatch of supply and demand at a given point in time increases considerably when these RE sources replace dispatchable technologies like natural gas or coal fired power plants without major adjustments to the functioning
of the electricity system. One such measure to better integrate the intermittent generation from RE is a substantial increase of electricity storage capacities, which has been discussed intensively in the scientific literature and in policy debates. However, there remain many uncertainties regarding costs of storage, potentials of different technologies and the actual need for storage capacities (see, e.g. Zerrahn, Schill and Kemfert, 2018; Sinn, 2017; Abrell, Rausch and Streitberger, 2019). This discussion is put into a broader context if we consider that within the EU (but also potentially in other jurisdictions like the U.S.) the plan to tackle the challenges of mitigating emissions is proposing a multi-regional approach across member states with greatly varying conventional generation technology mixes, natural RE resource potentials, and a varying degree of cross-border trade and market integration. In such a multi-country setting, trade between regions facilitated by enlarged net transfer capacities at the borders emerges as another, potentially effective approach to better integrate intermittent renewables either as a substitute or as a complement to investment into storage capacity.

It is therefore of interest for the debate about RE integration to adopt a multi-region perspective and extend the discussion about the required storage investment by a study about the possible benefits of trade. On a more abstract level, such an approach amounts to an analysis of different modes of adding the necessary flexibility to the electricity system to cope with large shares of RE. Storage has the capacity to shift generation across time periods and is thus referred to as a temporal flexibility channel. Trade between countries enables a pooling of natural resources and different availability profiles for RE, conventional generation capacities, and also demand over larger distances and therefore we will refer to it by spatial flexibility. As a third dimension of flexibility, we add the regulatory regime since it will also affect the ways in which renewables can be effectively integrated into the existing system. From an economic perspective, the natural question is about the optimal increase of flexibility in each of the three dimensions to maximize public welfare while achieving the environmental goal. In order to answer this, a comprehensive cost benefit analysis for each of the three flexibility channels would be needed. However, the cost side of such an analysis exhibits a high degree of uncertainty because the investment costs for storage technologies are highly uncertain. Also, the estimation of cost and impact on net transfer capacities of additional transmission infrastructure is characterized by a high degree of uncertainty. Instead, we focus on an analysis of the potential benefits of the three flexibility channels and adopt a cost minimization framework where the value or, alternatively, the benefits of flexibility manifest themselves as savings in total system cost.

It is a priori not clear which of the three dimensions has the highest cost-saving potential in a given electricity system and how they interact when employed simultaneously. Therefore, we ask how an increase in flexibility in one or more of these flexibility channels can contribute to achieve a given goal for RE generation in a cost-efficient way and how these channels affect total cost, choices of RE investment, dispatch decisions of conventional generators and in turn CO₂ emissions of the electricity sector.

We base our analysis on an empirical approach with a numerical partial equilibrium model of several interconnected electricity markets. We formulate the model as a social planner’s problem to minimize total cost while reaching an ambitious target for the share in production of renewable energy.
It resolves hourly markets with marginal cost pricing for all the 8760 hours of a year to capture the large seasonal and intra-day variation of new RE sources (solar and wind energy) and demand which varies over time but is inelastic in each time period. Two essential features of the model are the possibility of trade between regions and the presence of a storage technology. The net transfer capacities for trade and storage capacities are treated as given exogenously, that is we abstract from investment decisions in grid and storage infrastructure and the associated cost. We calibrate the model to data from 2017 and cover 18 European countries with their RE resource potentials and diverse existing conventional generation capacities, which allows us to explore the interactions of electricity systems with a very wide range of mixes of generation technology under several policy scenarios. This heterogeneity of the system, with sub-systems determined by varying technology mixes and a varying degree of interconnection between them makes our findings also relevant for other areas such as large countries with considerable internal heterogeneity (like, e.g. the U.S.) or regions with a high degree of cross-border interconnection (such as, e.g. North America as a whole). Since efforts to mitigate climate change are central to the design of RE support policies we also include CO$_2$ emissions in the analysis.

We draw several conclusions from our analysis. First, regulatory flexibility as a stand-alone measure without any increase in physical infrastructure such as storage capacity or net transfer capacity may reduce curtailment and thus RE investment cost. However, at 2.5% the total cost savings relative to a scenario without any added flexibility are only moderate compared to potential cost savings from temporal or spatial flexibility, which are 5.2% and 7.5%, respectively. Even if the regulatory regime permitted a shift in RE generation to the regions with the most favorable natural resources and thus lower marginal investment cost for renewable capacity this cannot happen if there is no possibility to store or export the additional generation. We need to keep in mind, however, that a change in the regulatory design does not entail investment cost and thus the associated cost savings can be regarded to be net benefits.

Second, the combination of two (or three) flexibility measures creates larger cost savings than those measures in isolation. However, these potential cost savings are not simply additive. For some combinations, such as regulatory flexibility and spatial flexibility the combined savings exceed the sum of the benefits from the two single interventions, whereas a combination of temporal flexibility with either of the other two flexibility channels creates cost savings that are less than the sum of the savings associated with the two flexibility measures in isolation. This finding is relevant for the optimal choices of a regulator because these interactions should be taken into consideration to achieve a least cost outcome.

Third, decisions whether to increase spatial or temporal flexibility have direct impacts on the optimal technology mix of RE investments. Due to their differing generation profiles wind and solar energy interact differently with storage and net transfer capacities. On the one hand, storage tends to favor solar over wind in many countries because it allows to distribute solar generation more evenly over the hours of a single day or even across seasons of the year. Increased net transfer capacities, on the other hand, tend to go well with wind generation which has more varied availability profiles across distant regions.
Fourth, even with a fixed target for the production shares of renewable energy emissions vary considerably (up to 50%) because of the interaction of flexibility measures with the conventional generation technologies. Both, temporal and spatial flexibility measures favor low-cost technologies over more expensive peak-load producers but the former shifts generation to the lower cost producers in each country whereas the latter shifts production along a supply curve which is aggregated over the entire region. If a country has emission intensive fossil producers as the lowest cost option this means that added temporal flexibility will likely increase overall emissions even if a less costly low-emissions technology such as nuclear were available in a neighboring country. In a scenario with added spatial flexibility this cross-border potential for reducing emissions can be exploited through trade. For the model specification in our simulations representing European data for the base year 2017, spatial flexibility reduces emissions more strongly than temporal flexibility via this mechanism.

To the best of our knowledge, this paper is the first to combine the three flexibility channels available for the market integration of RE generation in a single framework. It is connected to several strands of the literature which are mostly focusing on one flexibility channel. First, there is an ongoing debate on the necessary investments into storage to accommodate new RE generation. Sinn (2017) argues that very high shares of RE generation require prohibitively high investments into storage capacity because otherwise large percentages of possible RE generation would have to be curtailed. In contrast to that, Zerrahn, Schill and Kemfert (2018) show that already allowing for a small amount of curtailment leads to a large saving in investment cost for storage facilities. A second strand of the literature concentrates on the interaction of storage capacity with existing conventional and new renewable technologies. Crampes and Moreaux (2010) analyze the interaction of pumped hydro storage with conventional fossil generation technologies and derive how to optimally use the technologies together without considering investment into new RE capacity. Linn and Shih (2016) employ a numerical model of the Texas ERCOT region to analyze how new storage capacities interact with current electricity systems featuring emissions intensive generation from coal, cleaner electricity production from gas, and zero emissions electricity from wind and solar energy. They lay a focus on the resulting total carbon emissions. Similarly, Carson and Novan (2013) investigate emissions effects with data from the ERCOT region using a theoretical model and empirical methods and in addition they study the effects of new storage capacity on peak and off-peak producers. The papers in these two strands of the literature analyze temporal flexibility through storage and we contribute by adding the interaction with regulatory and spatial flexibility.

Third, there is an emerging literature on regulatory design in electricity markets with storage. Helm and Mier (2018) focus on the emissions impacts of subsidies for storage. Abrell, Rausch and Streitberger (2019a) show that costly curtailment of RE generation can be reduced by tailoring the design of the regulatory regime to achieve a better matching between renewable supply and demand patterns. Whereas these papers analyze increasing temporal and also regulatory flexibility, we contribute by extending the range of the analysis by adding spatial flexibility by means of electricity trade.

Fourth, spatial flexibility of electricity generation is discussed in the literature about international electricity trade. von der Fehr and Sandsbraten (1997) analyze the impact of increasing electricity
trade in Nordic countries. Antweiler (2016) develops a theory of international trade in a homogeneous commodity, electricity, and shows how two-way trade can emerge because of temporal differences in load patterns. Abrell and Rausch (2016) investigate a multi-sector general equilibrium model with a detailed representation of the European electricity sector to assess the impact of higher shares of renewables on gains from trade and CO$_2$ emissions. This strand of the literature analyzes spatial flexibility of electricity generation but does not assess the effect of temporal flexibility by means of storage.

Fifth, we also make a connection to a growing literature investigating the consequences of the fundamental heterogeneity of RE technologies with respect to availability patterns. Abrell, Rausch and Streitberger (2019b) point out that the environmental value and market value of different renewables may vary and suggest that differentiating subsidies by technology might improve the environmental impact of RE policies, while Fell and Linn (2013) and Wibulpolprasert (2016) analyze how heterogeneity in renewable resource availability affects the cost-effectiveness of various abatement policies. Abrell, Kosch and Rausch (2019) use an empirical approach to conduct an ex-post evaluation of market values and environmental values of RE sources. These studies focus on lessons for regulatory design emerging from the heterogeneity of renewable production profiles. In this way, they introduce regulatory flexibility. However, these papers do not assess the flexibility of the regulatory regime across regions and its relation to international trade and storage facilities.

The remaining part of this paper is organized as follows. Section 4.2 introduces a graphical model to build basic intuition. Section 4.3 formalizes our modeling approach and reports the social planner’s cost minimization problem, while the following section, sec. 4.4 explains the empirical calibration to European data for the year 2017. In section 4.5 we provide a detailed analysis of our simulation results and section 4.6 concludes with a summary of our findings.

## 4.2 Conceptual Framework

In this section we analyze a simple graphical model to guide our intuition about the numerical simulations in the following sections. The model serves to illustrate the effects of introducing two of the three channels of flexibility we investigate in this paper, storage capacity within a country and net transfer capacities between countries. The insights we gain here will help to explain our simulation results while at the same time the limitations of this approach serve to illustrate the advantages of the numerical simulations.

### 4.2.1 A basic graphical model

Figure 4.1 depicts a stylized electricity market for two countries, $A$ and $B$. Quantities for country $A$ are measured on the x-axis going left and for country $B$ going right. Prices are measured on the vertical axis common to both. The two supply curves $S^A$ and $S^B$ reflect marginal generation cost for both countries and are markedly different. Country $B$ has a much flatter supply curve which indicates that it features either a technology mix with low-cost generation technologies (e.g.,
(a) Introduction of unrestricted storage capacity. (b) Introduction of unrestricted net transfer capacity.

Figure 4.1: Cost savings for a two-country electricity market with differing marginal cost curves when either unrestricted storage capacity or unrestricted net transfer capacities are introduced.

renewables), lower fuel cost than country A, or a combination of both. Demand $D$ is assumed to be inelastic and we start from an initial situation with neither storage capacities nor NTCs between the two markets.

In figure 4.1a we depict the two model markets with two time periods, a peak hour with high demand in both countries denoted by $D^A_p$ and $D^B_p$, respectively, and an off-peak hour with low demand $D^A_{op}$, $D^B_{op}$. Country A relies on high-cost generation technology and exhibits higher prices $P^A_p$, $P^A_{op}$ than country B both in peak and off-peak periods. We introduce unconstrained storage capacity to this situation and abstract from efficiency losses of the storage cycle. A profit maximizing storage operator buys electricity in times of low prices and sells electricity at peak demand creating profits from the arbitrage of the price difference $P^A_p - P^A_{op}$ ($\Delta P$). This can be described as introducing temporal flexibility into the system. Generation is shifted from off-peak hours to peak hours thus reducing residual demand for generators in the peak period and increasing demand in the off-peak period. As a consequence, $\Delta P$ is reduced until it reaches zero, peak prices and off-peak prices are the same, demand is smoothed between time periods, and the storage operator has no further incentive to provide more storage services. We denote the resulting price for country A by $P^A_S$.

Making use of this flexibility channel brings about cost savings in total generation cost. In the peak period, generation cost equivalent to the area $ABEF$ in figure 4.1a is saved while cost in the off-peak period goes up by the area $BCDE$. The net difference between cost increases and cost savings is given by the rectangle $HIEG$. The situation is equivalent for country B but we note that the size of possible cost savings depends on the slope of the supply curve with higher savings for steeper supply curves.

The second panel, fig. 4.1b, describes a situation with two countries and one time period only where we introduce the geographical flexibility channel. Before we allow trade, the price in country $A$, $P^A$, is higher than the price in country $B$, $P^B$. If trade between the two countries is unrestricted and existing generation capacities are large enough country A becomes an importer and country

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62 Potential generation cost savings also depend on the difference of demand between peak and off-peak hours
an exporter. The volume of trade increases until prices in both countries converge to a single price, \( P_{\text{NTC}} \). Generation cost savings in the importing country \( A \) are given by the area \( ABCD \) and generation cost increases in the exporting country \( B \) are equivalent to the area \( EFGH \). The net cost savings from trade flexibility for the total system are then given by the difference of those two areas. Given enough generation capacity, the possible cost savings depend on the respective demands and the relative slopes of the two supply curves: if the slopes are identical there is no incentive for trade and thus no possible cost savings while they are increasing with the difference in the slopes.

### 4.2.2 Insights and limitations of the graphical model

From our analysis of the graphical model we take away three insights. First, both kinds of flexibility we analyzed, temporal flexibility and geographical flexibility, potentially reduce total generation cost. The size of the effect, however, depends crucially on the structure of the existing generation capacity in the market, on intertemporal demand patterns within countries, and on demand correlations between neighboring countries. Second, as a consequence, it is theoretically possible that for some systems the potential gains from increasing storage capacity are larger than from increasing net transfer capacities and for others the opposite is true. In other words, it is not possible to rank the two flexibility options a priori with regard to their cost-saving potential. Third, since new renewable energy technologies have very low marginal generation cost, introducing large amounts of RE capacity to an existing system will on average decrease the slope of the supply curve. The magnitude of the effect depends on the natural geographical resource potential of a given country. As we have seen, this will have an impact on potential cost savings created by storage and trade since both depend on the absolute value of the slope of the supply curves or the relative slopes of the supply curves of two countries, respectively. Arbitrage from storage may decrease as peak price setting technologies are squeezed out of the market and trade flows between countries may increase, decrease or revert direction depending on the absolute and relative sizes of RE potentials across countries.

The simple graphical representation of the electricity market we chose for our analysis of the basic mechanisms at play cannot address several relevant effects which will impact the outcomes in more realistic settings. We are interested in systems with more than two countries with considerable variation in size where finite generation capacities have a decisive influence on trade and storage possibilities. Electricity markets and especially renewable energy sources exhibit a very pronounced temporal variation over days and seasons of the year, which makes it desirable to analyze a model covering all the 8760 hours of a year instead of only one peak hour and one off-peak hour. When introduced at the same time we expect also interaction effects between temporal and geographical flexibility (e.g., the reduction of arbitrage possibilities of a storage operator if trade squeezes out the peak producer in a country) and additionally also with the third dimension of flexibility, regulatory measures. There will also be feedback mechanisms on curtailment of RE generation and investment decisions for new RE generation (e.g., impacts on the ratio of investment into solar versus investment into wind energy). Finally, a numerical analysis with a model calibrated to data...
from a specific region will allow us to rank the cost-saving potential of different flexibility channels for this electricity system. In order to address these points more fully in our analysis we employ the numerical simulation model calibrated to the European electricity market which we describe in detail in the following sections.

4.3 Numerical Model

In this section, we describe the numerical cost minimization model that we use for a quantitative analysis of the potential benefits of enhancing spatial, temporal, and regulatory flexibility in an interconnected multi-region wholesale electricity market with high shares of renewable energy. The model features an hourly time resolution for the 8760 hours of a year to capture seasonal changes in time-dependent demand and availability of RE sources, several model regions which are connected by limited transfer capacities for trade, investment in new RE capacity, curtailment of RE production if necessary to ensure system stability, and a generic storage technology.

4.3.1 The social planner’s problem

The model can be formulated as a social planner’s problem. The planner aims at providing sufficient electricity to meet total demand at lowest cost $C_{\text{tot}}$ to the public while achieving an exogenously given target for generation from renewable sources subject to a set of constraints $B$ reflecting the specific properties of the electricity market. Formally, this may be written as:

$$\min_{Q} C_{\text{tot}}(Q) \quad \text{s. t.} \quad B(Q). \quad (4.1)$$

where the choice variables are given by a vector $Q$ comprising the quantity variables of the model, conventional hourly generation $X$, yearly renewable generation $G$, curtailment $C$, storage level $S$, injection into storage $J$, release from storage $R$, and trade $T$.

Total cost is given by the sum of generation cost for electricity, $C_{\text{gen}}$, and investment cost for new renewable capacity, $C_{\text{inv}}$:

$$C_{\text{tot}} = C_{\text{gen}} + C_{\text{inv}} \quad (4.2)$$

The model features generation from conventional, dispatchable technologies which we denote by $i \in I$, intermittent generation from new renewable sources $r \in R$ and storage technologies $s \in S$. Time periods are denoted by $t \in T$ and the regions constituting the submarkets are identified by $c \in C$. 

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4.3.2 Generation and investment

Generation from conventional energy sources, $X_{ict}$ is dispatchable and needs to be chosen for each time period such that it cannot exceed the available installed capacity

$$\alpha_{ict} \tilde{k}_{ic} \geq X_{ict}, \quad \forall i, c, t. \quad (4.3)$$

where $\tilde{k}_{ic}$ denotes the installed capacity of technology $i$ in region $c$ and $\alpha_{ict}$ is a factor describing the percentage of actually available production capacity due to factors such as maintenance of conventional power plants.

Generation from new renewable sources (wind and solar), $G_{rc}$, is intermittent, that is depending on the availability of the natural resource and thus not dispatchable. The social planner chooses to invest into a capacity which will produce a total quantity of $G_{rc}$ per year on top of already existing capacity equivalent of generating $r_{rc}^{\text{tot}}$ per year, the sum of which cannot exceed the technically feasible potential, $\pi_{rc}$, for each technology $r$ in region $c$:

$$\pi_{rc} \geq r_{rc}^{\text{tot}} + G_{rc}, \quad \forall r, c. \quad (4.4)$$

4.3.3 Curtailment

Hourly generation from RE sources is determined by an exogenous factor, $\alpha_{rcit}$, which takes into account daily and seasonal changes in resource availability. The planner can also decide to discard part of the RE generation to ensure net stability at times when RE generation would be larger than demand. This curtailment, $C_{rcit}$, cannot exceed total RE generation at any given time:

$$\alpha_{rcit} \left( r_{rc}^{\text{tot}} + G_{rc} \right) \geq C_{rcit}, \quad \forall r, c, t. \quad (4.5)$$

4.3.4 Trade

The model permits electricity trade between regions. The variable $T_{ccit}$ indicates that electricity was traded from region $c$ to region $c'$ at time period $t$. At any time trade volume between regions cannot exceed the given net transfer capacity, $\nu_{ccit}$:

$$\nu_{ccit} \geq T_{ccit}, \quad \forall c, c', t \quad \text{and} \quad c \neq c'. \quad (4.6)$$
4.3.5 Electricity storage

The possibility to store electrical energy is provided by storage technologies which are described by a capacity to inject energy into the storage, \( \bar{J}_s \), a capacity to store a certain amount of energy, \( \bar{S}_s \), and a capacity to release energy from storage, \( \bar{R}_s \). The associated quantity variables \( J_{sct} \), \( S_{sct} \), and \( R_{sct} \) are bounded by these capacities at all times \( t \):

\[
\begin{align*}
\bar{J}_s & \geq J_{sct}, \quad \forall s, c, t \quad (4.7) \\
\bar{S}_s & \geq S_{sct}, \quad \forall s, c, t \quad (4.8) \\
\bar{R}_s & \geq R_{sct}, \quad \forall s, c, t \quad (4.9)
\end{align*}
\]

In addition to these constraints time consistency between periods needs to be ensured. This is achieved by introducing a so-called law of motion for storage which states that the storage level, \( S_{sct} \), at time \( t \) depends on the storage level at time \( t-1 \), injection and release and natural water inflows \( \varphi_{sct} \) if the storage technology is represented by hydro reservoirs. Formally, this reads as:

\[
S_{sct(t-1)} + \eta_{sc} J_{sct} - R_{sct} + \varphi_{sct} = S_{sct}, \quad \forall s, c, t. \quad (4.10)
\]

where \( \eta_{sc} \) denotes the round-trip efficiency of the storage technology and thus captures energy losses due to the storage cycle.

4.3.6 Renewable energy policy

The social planner defines a goal for the quantity of renewable energy which can be (a) region-specific or (b) encompass all modeled regions:

\[
\begin{align*}
\sum_r \left( \sum_{t} \left( r_{ct} \right)^{\text{tot}} + G_{rc} - \sum_{t} C_{rct} \right) = \tau_c, \quad \forall c \quad (4.11a) \\
\sum_{r,c} \left( \sum_{t} \left( r_{ct} \right)^{\text{tot}} + G_{rc} - \sum_{t} C_{rct} \right) = \tau, \quad (4.11b)
\end{align*}
\]

where \( \tau \) is the goal for generation from RE sources.

4.3.7 Market clearing

Finally, electricity markets need to clear at all times in order to avoid a blackout, that is generation from all technologies, injection into storage, net trade, and curtailment must equal hourly demand \( g_{ct} \) in every region \( c \) and every period \( t \):

\[
\begin{align*}
\sum_{r,c} \left( \sum_{t} \left( r_{ct} \right)^{\text{tot}} + G_{rc} - \sum_{t} C_{rct} \right) = g_{ct}, \quad \forall c, t
\end{align*}
\]
Table 4.1: Model specifications: regions and technologies covered in the model framework.

| Regions \( c \in C \) | Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, United Kingdom |
| Technologes | Hard Coal\(^a\), Lignite\(^a\), Nuclear\(^a\), Other\(^a\), Biomass\(^b\), Reservoir\(^b\), Run-off-River\(^b\), Wind Onshore\(^c\), Wind Offshore\(^c\), Rooftop Solar\(^c\), Storage |

**Notes:**
- \(^a\) Conventional technologies
- \(^b\) Renewable conventional technologies
- \(^c\) New renewable technologies
- \(^d\) In the remainder of this paper solar is short for rooftop solar.

\[
\sum_{t} X_{ict} + \sum_{s} (R_{sct} - J_{sct}) + \sum_{c'} [(1 - \lambda_{c't}) T_{c'ct} - T_{cct}] + \sum_{r} \left[ \alpha_{rct} (r^{bct} + G_{rc}) - C_{rct} \right] = d_{c't} \quad \forall c, t. \tag{4.12}
\]

### 4.4 Data and Model Calibration

In this section, we describe the empirical specification of the model introduced in section 4.3. We choose the year 2017 as our base year and collect all the relevant electricity market data for this year. The model features an hourly time resolution and to capture the seasonal variations in the demand and RE generation cycles we model all the 8760 hours of the year, which means that the set \( T \) of time periods is \{\( t_1, \ldots, t_{8760} \)\}. The model covers 18 European countries and 13 electricity generation and storage technologies which are listed in table 4.1. For each of these countries and technologies we need to specify the relevant model parameters.

#### 4.4.1 Generation and storage

**CONVENTIONAL GENERATION.**—The capacities for conventional technologies and storage, \( \bar{k}_{ic}, \bar{k}_{sc} \), \( \bar{k}_{sc}, \bar{k}_{sc} \) are taken from the database of the European Network of Transmission System Operators (ENTSO-E, 2017c). For the dispatchable fuel-based technologies (Hard coal, Lignite, Gas, Oil, Other) the reported capacities can be treated as net generation capacities and we choose the availability factor \( \alpha_{ict} = 1 \), accordingly. The effective net generation capacity of hydro power (Run-of-River, Reservoir) depends on complex and geographically diverse hydrological processes. We capture the seasonal production patterns of Run-of-River plants by treating their generation as exogenous and use the generation data from ENTSO-E for the base year (ENTSO-E, 2017b) reflecting the fact that Run-of-River as a low marginal cost technology is dispatched whenever available. For Reservoirs, we obtain weekly reservoir levels from the ENTSO-E database (ENTSO-E, 2017b) and calculate natural inflows \( \varphi_{st} \) on this basis. We require initial and terminal reservoir levels to be equal and thus reservoir net generation capacity is completely determined by seasonal inflows. For generation from biomass and nuclear we choose the availability factors such that their output is in line with actually observed generation rather than their considerably higher theoretical maximum output. Conventional producers incur marginal generation cost, \( \partial C_{gen}/\partial X_{ict} \), when generating electricity. We specify the marginal generation cost function as the sum of fuel cost.
and variable operation and maintenance (O&M) cost:

$$\frac{\partial c_{\text{gen}}}{\partial X_{ic}} = \frac{c_{ij}^f}{\eta_{ij}} + c_{ij}^{\text{O&M}}. \quad (4.13)$$

where the heat efficiencies, $\eta_{ij}$, are taken from Nuclear Energy Agency, International Energy Agency and OECD (2015)\(^{63}\) and the fuel cost, $c_{ij}^f$, is taken from International Energy Agency (2019) for the countries where data is available. For the remaining countries, the missing data was filled with cost information from neighboring countries (see table B.4 for details). We take the same approach for the variable O&M costs, $c_{ij}^{\text{O&M}}$. Where available, data is taken from Nuclear Energy Agency, International Energy Agency and OECD (2015) and the remaining values are filled as given in table B.5.

NEW RENEWABLE GENERATION.—Yearly generation from existing new renewable capacity, $p_{\text{tot}}$, is taken from ENTSO-E (2017b) and the same data is used to calibrate the hourly availability factors for new renewables, $\alpha_{rct}$, as the share of each hour in total generation. In this way, $\alpha_{rct}$ captures both the intra-day and seasonal variations in resource availability for new RE. For countries with missing data, we fill the gaps with data from neighboring countries as given in table B.3.

Producers of wind and solar energy face near zero marginal generation cost and the dominating cost factor is marginal investment cost $\partial c_{\text{inv}} / \partial G_{rc}$. The maximally possible generation from new renewable energy sources (wind and solar energy) depends on the available natural resource at the geographical position of the installation. Between countries and also within their territory, this natural resource quality varies considerably and we need to take this into account when calibrating the marginal investment cost curves for RE technologies. We assume that in each region the best suited sites for RE generation will be used first and with increasing cumulative installed capacity site quality of new installations deteriorates, which is equivalent with stating that the yearly generation in MWh of an additional MW of RE capacity decreases, or that the marginal investment cost per MWh increases with increasing installed capacity. We capture this characteristic by choosing a linear functional form for the marginal investment cost with a positive slope:

$$\frac{\partial c_{\text{inv}}}{\partial G_{rc}} = c_{rc}^{\text{inv}} + d_{rc}^{\text{inv}} (G_{rc} + p_{rct}^{\text{tot}}). \quad (4.14)$$

where the intercept, $c_{rc}^{\text{inv}}$, and the slope, $d_{rc}^{\text{inv}}$, are determined from data on renewable potential provided by Tröndle, Pfenninger and Lilliestam (2019a). The data are published in Tröndle, Pfenninger and Lilliestam (2019b). For each region in the model, this data set contains estimates for the investment potential for capacity (in MW) and for annual generation (in MWh) on the municipal level. From this data we obtain a finely grained step function\(^{64}\) for marginal investment cost in four steps. First, we order the geographical entities in decreasing order by full load hours (i.e., the ratio

\(^{63}\)For technologies such as hydro power the heat efficiency is set to 1.

\(^{64}\)Each step corresponds to a municipality covered in the data set.
between annual generation and capacity investment) which gives us the cumulative investment path described above. Second, we calculate cumulative annualized investment cost for each piece of the step function by multiplying the municipality’s cumulative capacity potential with the cost per MW for each technology found in the literature (see Kost et al., 2018). Third, we divide this cumulative cost by the estimated annual generation in MW to obtain marginal investment cost per MWh. Fourth, we fit a linear function to the marginal investment cost curve and thus get the parameters $c^{inv}_{rc}$ and $d^{inv}_{rc}$. Next, we obtain the maximally feasible potential RE generation for each model region in eq. (4.4), $\pi_{rc}$, by aggregating the generation potentials from Tröndle, Pfenninger and Lilliestam (2019a) to the country level. Finally, where necessary we impose an adjustment on the intercepts $c^{inv}_{rc}$ making sure that no investment takes place on top of the actually existing quantities in the base year 2017. In this way we ensure a consistent link between the marginal investment cost curves we obtained from the method described above and the actual observation for your base year system.

STORAGE.—Electricity storage is modeled on pumped hydro power storage (PHP) in the sense that in the no-policy base case scenario we use the generation capacities, $k^j_{sc}$, $k^s_{sc}$, and $k^r_{sc}$, and the roundtrip efficiency, $\eta_{sc}$, of this technology in the calibration. The release capacity $k^{r}_{sc}$ is given by the net generation capacity for pumped hydro from ENTSO-E (2017c) and we set $k^{J}_{sc} = k^{R}_{sc}$ for the injection (i.e., pumping) capacity. For the storage level capacity we assume a six hour time frame for complete depletion of the reservoir and set $k^{S}_{sc} = 6 \times k^{R}_{sc}$. The roundtrip efficiency $\eta_{sc}$ is set to 75% which is found in the literature (see Egerer et al., 2014; Newbery, 2016). For the simulation scenarios we take a more general approach to storage and relax the capacity constraints which is equivalent to exogenously adding the necessary amount of storage capacity so that the constraints (4.7), (4.9), and (4.8) are slack. The storage can then be seen to be generic in that any storage technology has a capacity to inject electricity into and release it from storage and a certain efficiency.

4.4.2 Demand and trade

DEMAND.—Demand $d_{ct}$ is modeled to be inelastic and we take its values from ENTSO-E (2017a) for all model regions and all of the hours of the year to capture seasonal and intra-day variations in demand.

TRADE.—Electricity trade between neighboring model regions is possible where net transfer capacities, $\nu_{ct}$, exist. We take net transfer capacities from the Agency for the Cooperation of Energy Regulators (ACER, 2018) supplemented by values taken from the Ten year network development plan 2018 (ENTSO-E, 2018) where necessary.

---

This is, each municipality’s capacity potential is added to the potential of all the preceding municipalities in this ordering to obtain total installed potential up to the respective point in the list.
4.4.3 Investment cost and potentials of renewables

Figure 4.2: Potential and intercept of marginal investment cost new RE generation technologies in Europe.

Figure 4.2 shows the resource potential for onshore wind and solar energy in subfigures 4.2a and 4.2c and the intercept of marginal investment cost in subfigures 4.2b and 4.2d. It illustrates the distribution of RE resources in Europe and allows us to make first observations. Both potential generation from wind and from solar resources are distributed unevenly across Europe, which in turn has an impact on marginal investment cost. A good measure for this geographical variation is given by the mean ($\mu$) and standard deviation ($\sigma$) taken over all countries and RE technologies of marginal investment cost $\frac{c^{\text{inv}}_{rc}}{\partial G_{rc}}$. For a no-policy case, as is depicted in figure 4.2 these values are:

\[
\mu = 41.84 \frac{\text{€}}{\text{MWh}} \quad \text{(4.15)}
\]
\[
\sigma = 6.50 \frac{\text{€}}{\text{MWh}} \quad \text{(4.16)}
\]

In the case of no imposed RE policy, marginal investment cost of the next MWh is equivalent to the intercepts depicted in figures 4.2b and 4.2d.
In a cost-optimal economic equilibrium marginal investment cost will be equalized across countries and technologies as much as the model constraints permit. Thus, we expect that these values will increase or decrease for different simulation scenarios and serve as a good comparison (next to total cost) for the overall optimality of a scenario choice.

4.4.4 Computational strategy

The last part of this section is dedicated to the computational strategy we employ for our numerical simulations. The model described in section 4.3 is classified as a Quadratic Program (QP) with a quadratic objective function and linear constraints. We formulate the model equations in the General Algebraic Modeling System (GAMS) and use the built in CPLEX 12 solver GAMS/CPLEX to solve the quadratic program.

4.5 Simulation Results

In this section, we present the outcome of our simulations based on the numerical model described in the previous section. We begin by explaining the structure of our counterfactual scenarios and then we sum up the main findings. We conclude the analysis in the remaining subsections by taking a closer look to the main drivers of our results.

4.5.1 Scenario structure

We design our counterfactual scenarios such as to be able to gauge the impact on total cost of the three flexibility dimensions we investigate in this article. We analyze temporal flexibility provided by the demand shifting possibilities of storage technologies, geographical flexibility due to increased net transfer capacities between model regions and regulatory flexibility induced by a more flexible design of RE quotas. To cover all three dimensions of flexibility, we perform nine simulation runs, eight counterfactual scenarios plus one run with no policy implemented. Table 4.2 summarizes the scenario specifications for reference. We consider two policy specifications, National policies and Tradable green quota (TGQ). National policies is a policy scheme which requires a fixed RE share of final demand in each model region covered by the policy and no possibility of green permit trade between regions. We choose a uniform target of 70% renewable energy for all the regions covered (i.e., all countries in our data base except for Norway and Switzerland which are not part of the European Union). In the policy specification Tradable green quota, the policy is designed such as to achieve the goal of 70% RE generation in final demand over all the modeled regions combined (again with the exception of Norway and Switzerland) representing a situation where countries may trade green permits so as to equalize marginal investment cost over the whole model region.

For each policy scheme, we investigate four specifications of storage capacity and net transfer capacity with either both constraints binding at current capacity levels or both nonbinding or with one of them binding and the other nonbinding. In this way we can go from the most restricted
Table 4.2: Simulation design

<table>
<thead>
<tr>
<th>Scenario name</th>
<th>Regulation</th>
<th>Storage</th>
<th>NTC</th>
</tr>
</thead>
<tbody>
<tr>
<td>National constrained</td>
<td>National policies</td>
<td>Constrained(^a)</td>
<td>Constrained</td>
</tr>
<tr>
<td>National NTC</td>
<td>Constrained</td>
<td>Unconstrained(^b)</td>
<td>Unconstrained</td>
</tr>
<tr>
<td>National storage</td>
<td>Unconstrained</td>
<td>Constrained</td>
<td>Unconstrained</td>
</tr>
<tr>
<td>National unconstrained</td>
<td>Unconstrained</td>
<td>Unconstrained</td>
<td>Unconstrained</td>
</tr>
<tr>
<td>TGQ constrained</td>
<td>(Cross-border) tradable green quota</td>
<td>Constrained</td>
<td>Constrained</td>
</tr>
<tr>
<td>TGQ NTC</td>
<td>Constrained</td>
<td>Unconstrained</td>
<td>Unconstrained</td>
</tr>
<tr>
<td>TGQ storage</td>
<td>Unconstrained</td>
<td>Constrained</td>
<td>Unconstrained</td>
</tr>
<tr>
<td>TGQ unconstrained</td>
<td>Unconstrained</td>
<td>Unconstrained</td>
<td>Unconstrained</td>
</tr>
</tbody>
</table>

Notes: \(^a\) Capacities as in calibration from input data. \(^b\) Capacity limits of the respective dimension (storage, NTC) are fully relaxed so that the associated model constraints are slack.

Table 4.3: Percentage change of cost parameters and CO\(_2\) emissions relative to the reference scenario.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total cost ((C^\text{tot}))</th>
<th>Conv. cost ((C^\text{gen}))</th>
<th>RE cost ((C^\text{inv}))</th>
<th>Marg. inv. cost ((\frac{\delta C}{\delta G}))</th>
<th>Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>National constrained</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>National NTC</td>
<td>-7.5</td>
<td>-6.7</td>
<td>-8.0</td>
<td>-1.0</td>
<td>-11.3</td>
</tr>
<tr>
<td>National storage</td>
<td>-5.2</td>
<td>1.6</td>
<td>-8.8</td>
<td>-1.5</td>
<td>-12.8</td>
</tr>
<tr>
<td>National unconstrained</td>
<td>-8.6</td>
<td>-7.8</td>
<td>-9.0</td>
<td>-1.8</td>
<td>-14.8</td>
</tr>
<tr>
<td>TGQ constrained</td>
<td>-2.5</td>
<td>0.3</td>
<td>-4.1</td>
<td>-0.01</td>
<td>-5.9</td>
</tr>
<tr>
<td>TGQ NTC</td>
<td>-13.1</td>
<td>-6.2</td>
<td>-16.7</td>
<td>-2.0</td>
<td>-27.5</td>
</tr>
<tr>
<td>TGQ storage</td>
<td>-6.7</td>
<td>1.0</td>
<td>-10.8</td>
<td>-1.4</td>
<td>-16.4</td>
</tr>
<tr>
<td>TGQ unconstrained</td>
<td>-13.8</td>
<td>-7.7</td>
<td>-17.0</td>
<td>-2.1</td>
<td>-27.6</td>
</tr>
</tbody>
</table>

Notes: Percentage changes are measured relative to scenario N.C., National constrained. \(^a\) \(\mu\) and \(\sigma\) are the mean and standard deviation of marginal investment cost as described in section 4.4.3.

4.5.2 Main results

Table 4.3 reports aggregated cost parameters related to the generation of electricity from conventional and renewable sources for all scenarios. Total cost, the sum of fuel cost for existing conventional generation and investment cost for new RE capacity, is of prime interest to our analysis. It represents the cost for satisfying demand without taking into account investment cost in infrastructure like the domestic transmission grid but also net transfer capacities and investment into storage capacity. As our reference case we choose scenario National constrained, the most constrained scenario. Overall cost is highest in this scenario with 83 Billion Euro. This is expected because the goal of 70% RE in final demand in each country has to be achieved with current levels of storage capacity and net transfer capacities and without the possibility of trading green permits.
between countries. All the other scenarios with higher levels of flexibility in at least one of the three flexibility dimensions exhibit lower total cost. The relative cost savings can be interpreted as a measure for the potential benefits of costly investments in the respective area of flexibility. Importantly, there is a considerable variation in these benefits for the different flexibility channels and their combinations.

Our findings lead us to four important insights. First, if the capacities for storage and NTCs are insufficient and thus the associated constraints are binding a more flexible regulatory framework on its own does not create large cost savings. Total cost in scenario \textit{TGQ constrained} is down by only 2.5% compared to the reference case \textit{National constrained}. A tradable green quota system increases efficiency by allowing participants with high investment cost to buy permits from those with lower investment cost and thus equalizing marginal investment cost across regions. The remaining physical obstacles, the lack of storage capacity and constrained NTCs, however, prevent further savings because curtailment of RE generation cannot be avoided as can be seen from table 4.4. Curtailment is reduced by 33.8% in scenario \textit{TGQ constrained}, which is a considerably smaller reduction than in all other scenarios.

Relaxing one of the other two flexibility restrictions, storage and NTCs, respectively, we arrive at scenarios \textit{National storage} and \textit{National NTC}. Comparing these two cases, we see that both, storage and NTC, have larger cost saving potential when employed as a single measure to enhance flexibility than a tradable green quota. They reduce curtailment and thus are able to achieve the RE goal with less costly investment into RE capacity. Both have similar cost savings for RE investment (8.8% for N. ST. and 8.0% for N. NTC) but they differ with respect to conventional cost. This difference is due to costly energy losses over the storage cycle, whose exact numerical value depends crucially on the efficiency factor $\eta_{sc}$ of the storage technology.

Second, the combination of several flexibility channels is always better than one but the benefits are not simply additive. Not surprisingly, all three flexibility measures applied together yield the highest cost savings in scenario \textit{TGQ unconstrained}, namely 13.8%. But scenario \textit{TGQ NTC} with no further investments into storage capacity and a combination of a permit trading system with no restrictions on NTCs comes very close with cost savings of 13.1%. A combination of unrestricted storage and unrestricted NTCs without tradable green permits fares notably worse with cost savings of 8.6% in scenario \textit{National unconstrained}, which is only one percentage point higher than the cost savings of unrestricted NTCs alone in scenario \textit{National NTC}. Taken together, these observations point to the conclusion that flexibility over time periods which is provided by storage on its own is not the most promising flexibility channel if storage losses are non-negligible and if it is not accompanied by other measures. Given a large and geographically diverse electricity market geographical flexibility can be more suited to equalize marginal investment cost and marginal generation cost over the entire region.

Third, the new renewable technologies, wind and solar, interact differently with the flexibility channels. Table 4.4 reports investment into new RE capacities for each scenario. Regardless of geographical position, solar energy is highly concentrated around noon and zero during the night.

\textsuperscript{67}In this study, investment cost for each country is determined by the geographical potentials for new RE technologies and resource availability profiles.
Therefore, high shares of solar energy in total production are only favorable when storage capacity is high. Solar generation increases compared to the reference scenario *National constrained* when restrictions on storage are lifted and other flexibility channels are not available. In scenario *National storage* where storage is the only flexibility improvement, solar investment is up by 41.4% and wind is down by 25.2% because every country has to achieve its 70% RE goal independently and storage favors solar generation. Wind generation patterns are more diverse in different parts of Europe and thus wind has an advantage over solar in scenarios with unrestricted NTCs, especially when also the regulatory framework enables an efficient use of geographical advantages for countries with high resource potentials and allows countries with lower potentials to buy permits.

Fourth, CO$_2$ emissions vary considerably over the different scenarios even though the RE share is constant at 70%. As can be seen from table 4.3, emissions in the reference scenario *National constrained* (188.2 Mt, see table B.1 for emission values of other scenarios) are more than double the emissions in scenario *TGQ unconstrained* while emissions for scenario *TGQ constrained* go up with the introduction of regulatory flexibility as a single measure. The emissions reduction depends on the structure of the conventional generation sectors in the different countries and their interaction.

Increased storage capacity favors base load producers in each country and disadvantages peak load producers as was demonstrated in section 4.2. As a consequence, there is a shift in production to each country’s low-cost technologies. Since many European countries have coal or nuclear energy as cheap base load technologies, the impact on emissions from storage may either be positive or negative in a given country.

The effect of unconstrained trade capacity is different in that it creates a single supply curve for the whole model region and in such a scenario the absolutely cheapest technologies are dispatched first rather than the relatively cheapest production capacity in each country. This favors nuclear and hydro installations over coal and causes larger emissions reductions compared to the scenarios with unconstrained storage.

Lastly, the increase in emissions in scenario *TGQ constrained* stems from the fact that countries with high marginal investment cost for renewables will buy tradable green permits from other countries and increase production from cheap but dirty fossil capacity compared to the reference scenario *National constrained* where an ambitious target has to be met in each country separately.

### 4.5.3 Regional effects

In this section, we take a closer look at the effects of the different flexibility channels that we analyze in our model. Rather than presenting the aggregate perspective over the whole model region we present here the outcomes for the individual countries in order to gain further insights on what drives the results that we observe.
Table 4.4: Percentage changes of RE investment and curtailment relative to the reference scenario.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Wind Onshore</th>
<th>Wind Offshore</th>
<th>Solar</th>
<th>Total</th>
<th>Curtailment</th>
</tr>
</thead>
<tbody>
<tr>
<td>National constrained</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>National NTC</td>
<td>-3.8</td>
<td>-100</td>
<td>-1.9</td>
<td>-5.9</td>
<td>-99.9</td>
</tr>
<tr>
<td>National storage</td>
<td>-25.2</td>
<td>-100</td>
<td>41.4</td>
<td>-5.9</td>
<td>-100</td>
</tr>
<tr>
<td>National unconstrained</td>
<td>-22.1</td>
<td>-100</td>
<td>35.3</td>
<td>-5.9</td>
<td>-100</td>
</tr>
<tr>
<td>TGQ constrained</td>
<td>2.8</td>
<td>-92.2</td>
<td>-2.5</td>
<td>-1.5</td>
<td>-33.8</td>
</tr>
<tr>
<td>TGQ NTC</td>
<td>11.5</td>
<td>-100</td>
<td>-32.8</td>
<td>-5.9</td>
<td>-99.8</td>
</tr>
<tr>
<td>TGQ storage</td>
<td>-17.4</td>
<td>-100</td>
<td>25.8</td>
<td>-5.9</td>
<td>-100</td>
</tr>
<tr>
<td>TGQ unconstrained</td>
<td>5.3</td>
<td>-100</td>
<td>-20.3</td>
<td>-5.9</td>
<td>-100</td>
</tr>
</tbody>
</table>

Notes: Percentage changes are measured relative to scenario N. C., *National constrained*.

Figure 4.3: Introducing regulatory flexibility via a tradable green quota system affects all principal parameters. We depict here the changes in RE investment and conventional generation per country.

4.5.3.1 Regulatory flexibility

Regulatory flexibility as we understand it is the possibility of reaching the policy goal of 70% RE generation for all countries combined as opposed to a system where each country has a separate and fixed RE goal. Figure 4.3 shows the numerical changes for generation related variables of the electricity markets we model when going from the reference scenario *National constrained* to the scenario *TGQ constrained*. This amounts to introducing regulatory flexibility while holding fixed the other two channels of flexibility, storage and NTC. The sub-figures show the changes in investment into RE generation and generation from conventional sources.

From figure 4.3a we see that compared to the reference case the introduction of a tradable green quota causes a shift in RE generation from countries with high marginal investment cost due to unfavorable natural RE potentials to countries with more favorable conditions. Countries with high marginal investment cost, such as Belgium or Italy, reduce RE generation in favor of buying green permits from the countries with already existing large RE generation or advantageous potentials such as Sweden or Austria which increase their RE share thus ensuring that on the whole the target is met. As seen from the mean and standard deviation of marginal investment cost in table 4.3, this shift in RE generation moves the system closer towards equalizing marginal cost across all countries. However the displacement of generation is limited by the constraints on net transfer capacity and storage capacity so that the overall impact of regulatory flexibility and cost savings

---

\[\text{Compared to a no-policy case with no further RE investment where CO}_2\text{ emissions are 676.3 Mt, all scenarios constitute a strong reduction in emissions ranging from 70.4\% to 86.4\%.}\]
in this scenario are smaller than in the remaining scenarios. The changes in RE generation are mirrored by changes in conventional generation in figure 4.3b.

4.5.3.2 Temporal flexibility

![Graphs showing changes in RE investment and conventional generation](image)

(a) Changes in RE investment.  
(b) Changes in conventional generation.

Figure 4.4: Introducing temporal flexibility via increased storage capacity affects all principal parameters. We depict here the changes in RE investment and conventional generation per country.

Figure 4.4 is analogous to fig. 4.3 and depicts the changes relative to the reference case National constrained when we introduce temporal flexibility between periods in the form of storage capacity in scenario National storage. As can be seen from figure 4.4a, investment patterns with storage change significantly. In countries where there is a large untapped potential for solar energy compared to wind we see a switch from wind to solar, such as in France or Italy. This is possible because storage can shift highly concentrated solar generation from mid-day hours to other time periods thus substituting wind generation in night hours, for example. Other countries, such as Spain or Poland see the opposite switch from solar to wind generation. In these cases wind becomes more viable with storage because it enables a shift of wind production from off-peak to peak hours where it can replace solar generation (which is more expensive in a given country either because there exists already a large solar capacity as in Spain or the natural potential is not very favorable as in Poland). Since in this scenario each country has to meet the 70% RE target and net transfer capacities are constrained, we observe investment shifts within countries and not between them. As a consequence of these shifts in investment, RE potentials across Europe are used more efficiently: the mean and standard deviation of marginal investment cost are reduced in table 4.3.

Figure 4.4b shows the impact of storage on conventional generation and we observe a shift towards cheaper base load technologies such as nuclear or lignite and away from expensive peak load technologies like gas and coal in some countries.

4.5.3.3 Spatial flexibility

The impact of the third flexibility channel, spatial flexibility, realized by unconstrained net transfer capacities is given in figure 4.5. It shows the changes going from the reference scenario National constrained to a scenario with unconstrained trade, National NTC. Similarly to the scenario with added unconstrained storage, National storage, also here the mean and standard deviation of marginal investment cost are reduced (see table 4.3). The mechanism to achieve this, however,
Figure 4.5: Introducing spatial flexibility via increased net transfer capacity affects all principal parameters. We depict here the changes in RE investment and conventional generation per country. Rather than storing electricity in each country when necessary, here RE investment is chosen such that the geographical heterogeneity of resource availability for renewables is most efficiently exploited to avoid curtailment. At the same time the policy goal of 70% RE generation in each country needs to be fulfilled. This explains why in figure 4.5a we observe mostly technology shifts within countries and no large scale shift of RE production capacities between countries. For conventional generation, however, this restriction does not apply and accordingly we see significant relocation of production between countries in figure 4.5b. A country with low marginal cost generation technology like France shows a notable increase of generation and trading partners whose supply curve is steeper like Germany, the UK, and Italy see a decreasing domestic production.

### 4.5.3.4 Regional impacts on CO₂ emissions

Figure 4.6: Changes in CO₂ emissions relative to National constrained when introducing regulatory, temporal, or spatial flexibility.

Figure 4.6 shows the regional impact on emissions when we introduce one of the respective flexibility channels. Even though overall RE shares remain at 70% of demand emissions are not constant
over the different scenarios we investigate. We see a reduction by 21.3% for temporal flexibility and by 42.5% for spatial flexibility relative to the reference scenario National constrained. Contrary to that, we notice a rise in emissions by 6.2% in the scenario with regulatory flexibility (TGQ constrained). The impact on emissions depends on the nature of the conventional generation that is replaced by RE generation or vice versa. In order to better understand the impact of regulatory flexibility we refer to figure 4.3b. In Sweden, for example, the country with the largest growth in RE generation emissions are not reduced because the new renewables replace almost exclusively nuclear generation, whereas in Spain a notable share of electricity from coal is squeezed out of the market and thus emissions decrease strongly. The net emissions change is positive, however, because RE generation in Italy, the Netherlands and Poland is (partly) replaced by fossil generation.

With temporal flexibility, that is added unconstrained storage capacity in scenario National storage, we observe in figure 4.4b a shift of production within countries towards the low-cost technologies. When the least-cost technology is nuclear such as in Spain or in the UK, we observe falling emissions, whereas emissions increase in countries like Poland or Germany where part of the base-load generation favored by storage comes from lignite.

The large emissions reductions due to spatial flexibility in scenario National NTC are possible because in such a scenario the shift in conventional generation as seen in figure 4.5b takes place between countries rather than within each country separately and the conventional technology with lowest marginal generation cost in an aggregate supply curve for Europe is nuclear rather than coal. Taken together these observations serve to emphasize that the impact on emissions of the different system configurations in our framework depend crucially on the conventional generation mix existing alongside the renewables.

4.6 Conclusions

As the discussion about climate change and emissions reduction in general continues, the decarbonization of the electricity sector remains a central building block in the efforts to decrease CO₂ emissions worldwide. The necessary measures need to be implemented on national and also on transnational levels, for example in the European Union. In this context, integration of national electricity markets and the removal of physical barriers in the electricity system go hand in hand with climate policy in the form of ambitious renewable energy investment targets which mandate the integration of large amounts of intermittent RE generation into the electricity system. With this in mind, this paper aims to shed light on some of the cost effects to be expected from interventions along several dimensions (regulatory design of RE policies, temporal flexibility, and spatial flexibility) in a complex multi-regional electricity generation system. We investigate the potential benefits from RE policy improvements, added storage capacity, and enlarged net transfer capacities between countries when a high share of electricity needs to be generated from renewable sources and analyze the impacts of these three flexibility channels on both new renewable and conventional generators.

---

69 See table B.1 for total values of CO₂ emissions and their percentage changes relative to the reference case for all scenarios.
We find that the three flexibility channels have different potentials for total cost savings when used as stand-alone measures. Within our framework tailored to the European electricity market, the ranking of potential benefits from flexibility measures places spatial flexibility (net transfer capacities) first, followed by temporal flexibility (storage capacity) and then regulatory flexibility (RE policy design). Improving RE policy design, however, does have one major advantage over the other two possible flexibility channels: it does not entail substantial additional and as of yet highly uncertain investment cost that needs to be considered in a full cost-benefit analysis.

Our analysis also shows that a suitable combination of flexibility measures such as regulatory flexibility with spatial flexibility will be superior to stand-alone approaches and increase the potential cost savings.

Finally, the impact of policy design and flexibility channels used on emissions reduction depends crucially on the technology mix and capacities of the existing conventional technologies.

To the best of our knowledge, this paper is the first to combine regulatory, spatial, and temporal flexibility in a unified economic market framework. Our analysis aims to better understand the different mechanisms governing the interaction of flexibility options with the existing electricity system and with each other. Our findings emphasize that in the context of RE market integration, it is vital to consider all the relevant system components. The results of such a broad analysis are needed for a regulator to efficiently manage the transition to a RE dominated complex new electricity system and to help bolster social acceptance of RE support policies and other measures to facilitate RE integration by emphasizing their potential benefits. We understand our study as a first step towards this goal given the limitations of our approach.

We need to keep in mind that some of our results also depend on numerical values of parameters which might change in the future or are subject to policy decisions. The cost savings and emissions impacts of the temporal flexibility channel depend crucially on the assumptions for the round trip efficiency of storage technologies. For this study we adopted an efficiency of 75% which is suitable for pumped hydro storage but other technologies such as batteries or compressed air storage have higher or lower efficiencies, respectively. The goal for the RE share which we set at 70% of final demand will also have an impact on our outcomes. An even more stringent goal of 80% or 90% might increase the relative cost savings of temporal flexibility compared to spatial flexibility if trade alone cannot compensate for curtailment anymore. To better understand the dependence of the ranking of benefits from flexibility channels we leave a sensitivity analysis for these parameters for future work.

To keep the model numerically tractable we introduce several important simplifications and abstractions. We completely abstract from investment cost for storage and net transfer capacities which are uncertain for future technologies and vary widely according to geographical circumstances. Thus, our study is not to be understood as a cost-benefit analysis but rather illustrates potential benefits. In this way, we gauge the potential impacts of flexibility measures and rank them according to their performance on the benefits side of the equation alone. We leave a comprehensive cost-benefit-analysis to future research once the data on storage potential and cost is more definitive. We also abstract from stochastic effects due to uncertainty regarding RE generation profiles, which is mainly associated to changing weather conditions. Other restrictions to the model lie
in the data availability for hydrological inflows which affect hydro power which we treat similar to new RE generation by imposing observed generation profiles on reservoirs. Another area for future research is the interaction of RE support policies with carbon policies such as the EU-ETS which is not covered in this study. Especially the conventional sector and its interaction with storage and net transfer capacities will be affected by the presence of an emissions trading scheme, which in turn will have an impact on our findings regarding the CO$_2$ emissions in different scenarios.

Some of these caveats point the way for future research on this topic. So far, we have analyzed the potential benefits of completely relaxing the constraints on storage and net transfer capacities. In future work, this approach should be expanded by cost estimates for storage and NTC investments such as to permit a more comprehensive cost-benefit analysis. This would allow to investigate optimal investment in either flexibility channel to minimize overall cost and help to better understand i) how far the current system is from the optimum and ii) if currently planned investment paths for NTCs will bring the system close to this state. Another possible extension would be a regional welfare analysis. Any policy measure increasing flexibility in the electricity system will create winners and losers among the countries covered and a thorough impact analysis in terms of welfare can point to possible equity issues and also point a way to find suitable compensation measures.
References


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A Appendix Article 1

A.1 Appendix A: Proofs

A.1.1 Proof of Lemma 1

Let $t^e = \kappa_i, \forall i$, denote the uniform emissions tax. Maximizing the social surplus (2.2) with respect to $\kappa$ yields the following first-order condition:

$$\sum_t \left[ S_t \left( \partial d_t \over \partial t \right) - G_t \left( \partial k_t \over \partial t \right) \right] = \sum_i \left( C'_t + \delta E'_t \right) \left( \partial q_t \over \partial t \right).$$

(A.1)

From the equilibrium conditions for conventional energy production (2.4b) and RE generation (2.4c), we obtain, respectively: $C'_t \geq C'_dt = p_i - t^e E'_t$, and $S'_t = G'_t = p_i$. Differentiating the market-clearing condition (2.4d) with respect to $t^e$ yields: $\sum \left( \partial d_t \over \partial t \right) = \sum \left( \partial d_t \over \partial t \right)$. Substituting terms into (A.1) gives:

$$\sum_t \rho_t \sum_i \left( \partial q_t \over \partial t \right) = \sum_t \left( p_i - t^e E'_t + \delta E'_t \right) \sum \left( \partial q_t \over \partial t \right).$$

which can be simplified to yield:

$$t^e = \delta.$$

From comparing the conditions for the social optimum (2.3a) with the equilibrium conditions (2.4b) under the case of carbon pricing only (i.e., $s^e = \tau^e = 0$), it follows that a uniform carbon tax $\kappa_i = t^e = \delta, \forall i$, implements the social optimum. $\square$

A.1.2 Proof of Proposition 1

We present the proof for the case of an RE support scheme consisting of a FIT and tax on energy demand. The proof for the case of a market premium proceeds analogously.

As we know from Proposition 2 that the clean technology does not enter the market, we can focus on the dirty conventional generation technology, i.e. we can simplify notation by dropping the index for conventional technologies. Differentiating the equilibrium conditions (2.4a)–(2.4d) for the case of a FIT with respect to
the RE subsidy ($s_t$) yields:

\[
\begin{align*}
\frac{\partial k_t}{\partial s_t} &= \frac{1}{C_t^*} \\
\frac{\partial d_t}{\partial s_t} &= \frac{C_t^*}{C_t^* - S_t^*} \frac{\partial k_t}{\partial s_t} \\
\frac{\partial q_t}{\partial s_t} &= \frac{S_t^*}{C_t^* - S_t^*} \frac{\partial k_t}{\partial s_t} \\
\frac{\partial p_t}{\partial s_t} &= \frac{C_t^* S_t^*}{C_t^* - S_t^*} \frac{\partial k_t}{\partial s_t}.
\end{align*}
\]

and with respect to a change in the energy demand tax ($\tau_t$) yields:

\[
\begin{align*}
\frac{\partial k_t}{\partial \tau_t} &= 0 \\
\frac{\partial d_t}{\partial \tau_t} &= \frac{\partial q_t}{\partial \tau_t} = \frac{1}{S_t^* - C_t^*} < 0 \\
\frac{\partial p_t}{\partial \tau_t} &= -\frac{C_t^*}{S_t^* - C_t^*} < 0.
\end{align*}
\]

From the regulator’s problem in (2.4), we can derive the following first-order conditions for optimal feed-in tariffs ($s_t$) and energy demand taxes ($\tau_t$), respectively, as:

\[
\begin{align*}
S_t \frac{\partial d_t}{\partial s_t} - (C_t^* + \delta E_t) \frac{\partial q_t}{\partial s_t} - C_t^* \frac{\partial k_t}{\partial s_t} &= 0 \\
S_t \frac{\partial d_t}{\partial \tau_t} - (C_t^* + \delta E_t) \frac{\partial q_t}{\partial \tau_t} - C_t^* \frac{\partial k_t}{\partial \tau_t} &= 0.
\end{align*}
\]

Since the RE firm only receives the feed-in tariff, the RE capacity $k_t$ does not respond to a change in the demand tax, i.e. $\frac{\partial k_t}{\partial \tau_t} = 0$. Substituting the marginal private surplus, conventional cost, and marginal investment cost from the equilibrium conditions and using the partial derivatives of conditions (2.4d) for clearing of the energy spot markets with respect to the RE subsidy and demand tax yields:

\[
\begin{align*}
(p_t - s_t) \frac{\partial k_t}{\partial s_t} + t \frac{\partial d_t}{\partial s_t} - \delta E_t \frac{\partial q_t}{\partial s_t} &= 0 \\
(t_t - \delta E_t) \frac{\partial d_t}{\partial \tau_t} &= 0.
\end{align*}
\]

From the second equation above, the socially optimal level of the energy demand tax can be derived as:

\[\tau_t^* = \delta E_t^* .\]

Inserting $\tau_t^*$ into the first equation above and using the derived terms for the equilibrium responses of $k_t$, $d_t$, and $q_t$ with respect to RE subsidies $s_t$ yields:

\[s_t^* = p_t + \delta E_t^* .\]

$\square$
A.1.3 Proof of Corollary 2

Proof of parts (i) and (iii): A constant surplus function $S_t$ implies that energy demand is constant over time. Hence, conventional energy production is constant over time, too. Given that cost function $C_t(q_{it})$ and the emissions function $E_t(q_{it})$ are time-invariant, this implies that the wholesale energy price and the emissions level do not change over time. From the formula for the optimal FIT in equation (2.8a) it then follows that the FIT rate has to be differentiated by $t$, i.e. across RE technology or RE resource. Similarly, if marginal costs (the emissions rate) are constant, the wholesale energy price (the emissions rate) takes on the same value for all $t$, implying that the optimal FIT is constant over time, i.e. $s_1^{FIT} = s_2^{FIT}$. The proof for the case of an optimal market premium proceeds analogously.

Proof of part (ii): With the same reasoning, if the surplus is constant in time or the marginal emissions rate is constant, the marginal social costs are constant in time and, thus, the demand tax is constant in time, i.e. $\tau_1^* = \tau_2^*$. □

A.1.4 Proof of Corollary 3

The revenues from an energy demand tax (weakly) exceed the expenses for an RE subsidy which is structured as a market premium if:

$$\sum_t \tau_t d_t \geq \sum_t s_t k_t$$

and for an RE subsidy which is structured as a FIT if:

$$\sum_t \tau_t d_t \geq \sum_t (s_t - \rho_t) k_t.$$ 

Using the respective optimal RE subsidy rate and demand tax from Proposition 1 yields:

$$\sum_t \delta E_{it} d_t \geq \sum_t \delta E_{it} k_t$$

which always holds since marginal emissions rates are positive and energy demand (weakly) exceeds the production of renewable sources. If the market penetration of RE is incomplete, i.e. $k_t < d_t$, the tax revenues under an optimal RE support scheme is strictly larger than the expenses for optimal RE subsidies. □

A.1.5 Proof of Proposition 2

We prove Proposition 2 for the case of a FIT. Differentiating the equilibrium conditions (2.4a)-(2.4d) under the case of a FIT (i.e., $\kappa_1 = \tau_t = 0$) with respect to feed-in rates $s_t$ and solving for the policy-induced

---

70 The proof for the case of a market premium proceeds analogously and is omitted for reasons of brevity.
changes in equilibrium quantities and prices yields:

\[
\frac{\partial k_t}{\partial s_t} = \frac{1}{G_{00}^t} > 0
\]

\[
\frac{\partial d_t}{\partial s_t} - \frac{\partial k_t}{\partial s_t} = \frac{\sum C''_{ij}^t - S_{ij}^t}{\sum C''_{ij}^t - S_{ij}^t} > 0
\]

\[
\frac{\partial q_t}{\partial s_t} - \frac{\partial k_t}{\partial s_t} = \frac{\sum C''_{ij}^t - S_{ij}^t}{\sum C''_{ij}^t - S_{ij}^t} G_{ij}^t < 0
\]

\[
\frac{\partial p_t}{\partial s_t} - \frac{\partial k_t}{\partial s_t} = \frac{\sum C''_{ij}^t}{\sum C''_{ij}^t - S_{ij}^t} G_{ij}^t < 0.
\]

The FIT thus implies an increase in demand and a reduction in the price of electricity. Moreover, it unambiguously increases generation from RE technologies and reduces output from the clean and dirty conventional technology. Recalling that the clean conventional technology is initially not in the market implies that it does not enter the market due to a FIT. The weaker statement of this result—if one were to relax the assumption that the clean technology is initially not in the market—is to say that the output of the clean technology decreases due to the introduction of a FIT. As long as the cost functions of the conventional technologies are convex and do not intersect, however, it holds that the FIT does not lead to a fuel switch between clean and dirty conventional technologies.

Similarly, equilibrium changes in response to a change in demand taxes are given by:

\[
\frac{\partial k_t}{\partial t^*} = 0
\]

\[
\frac{\partial q_t}{\partial t^*} = \frac{\prod_i C''_{ij}^t}{\sum_i C''_{ij}^t - \prod_i C''_{ij}^t} < 0
\]

\[
\frac{\partial d_t}{\partial t^*} = \sum \frac{\partial q_t}{\partial t^*} < 0
\]

\[
\frac{\partial p_t}{\partial t^*} = \frac{\prod_i C''_{ij}^t}{\sum_i C''_{ij}^t - \prod_i C''_{ij}^t} < 0.
\]

Applying the same argumentation as above, it is straightforward to see that a demand tax does not create a fuel switch between the two conventional technologies. □

### A.1.6 Proof of Proposition 3

Suppose the social optimum does not require a fuel switch, that is, the cleaner conventional energy technology \( c \) does not enter the market following a direct or indirect RE support policy, i.e. \( q_{ct} = 0 \). From Proposition 2, it follows that the clean conventional technology never enters the market under an RE subsidy. Substituting the optimal RE subsidy, either for the case of a FIT or a market premium, as well as the optimal energy demand tax from Proposition 1 into the equilibrium conditions (2.4a)-(2.4d) yields:

\[
S_t^c = p_t + \delta E_t^c
\]

\[
C_t^c = p_t
\]

\[
G_t^c = p_t + \delta E_t^c
\]

\[
\Rightarrow S_t^c = C_t^c + \delta E_t^c = G_t^c
\]
which is equivalent to the conditions characterized by (2.3a) and (2.3b). In contrast, suppose the social optimum implements an allocation in which production of the clean conventional energy technology \( c \) is positive, i.e. \( q_{ct} > 0 \). From Proposition 2 technology \( c \) never enters the market under an RE subsidy; an RE subsidy therefore does not implement the social optimum.
A.2 Appendix B: Quantitative Empirical Framework

This appendix documents the numerical model which extends the stylized theory model presented in Section 2.2. The overall structure of the problem of optimal regulation remains identical: the regulator seeks to maximize social welfare \( W \), including the valuation of environmental damage at social marginal cost \( \delta \), by choosing an RE support scheme \( b \) subject to market equilibrium conditions for energy supply and demand:

\[
\max_b W(p(b), x(b); \delta) \\
\text{s.t.} \quad p(b), x(b) \in A.
\]  

(A.2)

\( A \) is the set of feasible allocations defined by equilibrium prices \( p(b) \) and quantities \( x(b) \) associated with energy generation and investments embodying firms' and consumers' behavioral responses to policy choices \( b \).

The remainder of this section describes our quantitative empirical framework including the derivation of the market equilibrium conditions which define \( A \). We also provide detail on data sources, model calibration, and the computational strategy employed to solve the problem of optimal RE support policies.

A.2.1 Feasible equilibrium allocations \( A \)

Our characterization of the partial equilibrium model of electricity supply and demand uses a complementarity based formulation, i.e. a system of nonlinear inequalities with two classes of equilibrium conditions: zero-profit and market-clearing. Zero-profit and market-clearing conditions exhibit complementarity with respect to quantities \( x \) and prices \( p \), respectively.\(^{71}\) We now describe in detail the structure and decision problems of economic agents to derive the conditions that define \( A \). While the structure of the quantitative model is largely identical to the one of the theoretical model, we introduce a self-contained notation for the numerical model. In particular, note that to reduce notational complexity, we redefine the technology index \( i \) in the quantitative model to include both conventional and RE technologies.

PRODUCTION AND INVESTMENT.——Electricity can be supplied from conventional and renewable energy technologies. Different technologies are indexed by \( i \in I \) where \( G \subset I \) contains RE technologies and \( B \subset I \) contains conventional (non-renewable) technologies. Time (i.e., hours) is denoted by \( t \in T = \{1, \ldots, T\} \). Firms using technology \( i \in I \) choose quantities of investment \( I \) and energy output \( X \) in order to maximize total profits from selling electricity in wholesale markets \( t \). Total profits \( \Pi \) for energy producers using technology \( i \) are defined as:

\[
\Pi_t(X_t, \ldots, X_{T}, I_t) = \sum_i \left[ (\pi_{it} - \kappa_{rt})X_{it} - c^0(X_{it}) \right] - c(I_t).
\]  

(A.3)

\( \pi_{it} \) denotes the wholesale price of electricity inclusive of any direct RE support. Conventional generators receive no RE support and sell their output at wholesale market price \( p_t \) at time \( t \); RE firms receive a subsidy per MWh electricity sold \( S \) which can either take on the form of a FIT or a market premium which is

\(^{71}\) A characteristic of economic equilibrium models is that they can be cast as a complementarity problem (Mathieson, 1985; Rutherford, 1995), i.e. given a function \( F: \mathbb{R}^n \rightarrow \mathbb{R}^n \), find \( x \in \mathbb{R}^n \) such that \( F(x) \geq 0, z \geq 0, \) and \( z^T F(z) = 0 \), or, in short-hand notation and using the "\( \perp \)" operator to indicate complementarity between equilibrium conditions and variables, \( F(x) \geq 0 \perp z \geq 0 \).
constant over the year:
\[
\pi_t = \begin{cases} 
P_t, & \text{if } i \in B \\
P_t + \omega S, & \text{if } i \in G \text{ and RE support with a market premium} \\
\omega S, & \text{if } i \in G \text{ and RE support with a feed-in tariff.}
\end{cases}
\]

\(\omega_i\) and \(\kappa_i\) are policy choice variables which can be controlled by the regulator but are viewed as given by firms. \(\omega_i\) implements a technology-specific differentiation of the RE support scheme; \(\omega_i = 1, \forall i\), represents the case of uniform RE support across wind and solar technologies. \(\kappa_i\) is an input tax per MWh of electricity which can either represent an emissions tax or implicit taxes under an intensity standard. \(c^0(X_i)\) denote total generation cost associated with output, reflecting technology-specific heat efficiencies and fuel costs. For each technology category \(i\), \(\text{CO}_2\) emissions \(E(X_i)\) are a function of the output level. While we model electricity generation at the technology level, we specify \(c^0(X_i)\) and \(E(X_i)\) as quadratic functions to account for within-technology heterogeneity among individual electricity plants. Thus, the marginal cost and marginal emissions rate per MWh of electricity produced increase with output reflecting efficiency changes at the plant level. \(c^i(I)\) denote investment costs for installing capacity \(I_i\).

Profit-maximizing output and investment choices have to satisfy the following constraint expressing that output at any time \(t\) cannot exceed available capacity:
\[
\alpha_i (K_i + I_i) \geq X_i \forall i, t
\]

where \(\alpha_i\) measures the availability of capacity which reflects the fact that conventional generators can be temporarily offline (due to, for example, maintenance and outages) and that the production of renewable generators depends on weather conditions. \(K_i\) denotes existing production capacities for each technology.

Maximizing (A.3) subject to (A.4) yields the following FOCs for optimal firm behavior, which can be written in complementarity notation as follows:
\[
\frac{\partial c^i(I)}{\partial I} \geq \sum_t \alpha_i P^t_i \perp I_i \geq 0 \forall i 
\]

\[
\frac{\partial c^0_i(X_i)}{\partial X_i} + \kappa_i + P^t_i \geq \pi_t \perp X_i \geq 0 \forall i, t
\]

\[
\alpha_i (K_i + I_i) \geq X_i \perp P^t_i \geq 0 \forall i, t.
\]

\(P^t_i\) is the shadow price of production capacity and is determined in equilibrium by (A.7). In equilibrium, \(I_i = 0\) if the marginal cost of investment \(\left(\frac{\partial c^i(I)}{\partial I}\right)\) exceeds marginal revenues for investment—condition (A.5) then holds with a strict inequality. A positive equilibrium level of investment results if marginal investment cost equals marginal revenue which are given by the availability-weighted income created by renting out production capacity at price \(P^t_i\). Similarly, a positive quantity of energy is supplied at time \(t\) by using technology \(i\) if marginal cost of generation equals marginal revenue including RE subsidies—condition (A.6) then holds with equality.

DEMAND AND WHOLESALE ELECTRICITY PRICES.——Electricity demand at time \(t\), \(D_t(P_t, \tau_t)\), is a function of the wholesale electricity price at time \(t\) and an energy demand tax \(\tau_t \geq 0\). The market-clearing condition for balancing energy supply and demand at time \(t\) determines the wholesale electricity price at time \(t\):
\[
\sum_i X_i = D_t(P_t, \tau_t) \perp P_t "free" \forall t.
\]
Note that the we allow for the possibility of negative prices in situations where, for example, due to a high availability of RE sources, consumers have to be compensated for demanding a positive quantity of energy.

DEFINITION OF EQUILIBRIUM AND WELFARE.—Given an RE support policy \( b = \{\omega, S, \pi_t, \kappa_i\} \), the set of feasible equilibrium allocations \( A \) is characterized by \( (i) \) prices \( p(b) = \{P^t_i, P_t\} \) for production capacity and wholesale energy output determined by market-clearing conditions (A.7) and (A.8) and \( (ii) \) quantities \( x(b) = \{X_{it}, I_t\} \) of energy outputs and investments into production capacity determined by zero-profit conditions (A.5) and (A.6).

Analogously to the definition of social welfare in the theoretical model, welfare comprises the economic surplus net of environmental damage:

\[
\mathcal{W} = \sum_t \left[ \int_0^{D_t} \tilde{P}_t(x)dx - \sum_i \left( c'(I_t) + c''(X_{it}) \right) \right] - \delta \sum_t \int_0^{X_{it}} E_i(x)dx, \tag{A.9}
\]

where \( \tilde{P}_t = D^{-1}(P_t, \pi_t) \) is the inverse demand function. Note that the definition of the economic surplus also includes potential rents to the public sector due to excess revenues earned from the regulation of the externality (for example, from carbon pricing or an RE support scheme where revenues of the refinancing tax exceed the expenses for RE subsidies).

CONSTRAINED-OPTIMAL RE SUPPORT SCHEMES.—To represent real-world policies for RE support, we include additional constraints in the lower-level partial equilibrium problem which restrict the regulator’s choice of policy parameters \( b \).

Under a FIT and market premium support scheme the expenses for RE subsidies are fully covered by revenues generated with a time-independent energy demand tax \( \tau \) which adjusts endogenously to ensure the following constraint is met:

\[
\sum_t \tau D_t \geq \sum_{i,t} (\pi_t - P_t)X_{it} \quad \perp \quad \tau \geq 0. \tag{A.10}
\]

Under a revenue-neutral FIT or market premium support scheme the regulator chooses \( b = \{\omega, S\} \) subject to the system of equilibrium constraints (A.5)–(A.8) and refinancing rules (A.10). Setting \( \omega_i = 1 \) would impose the additional constraint that RE subsidies cannot be differentiated among RE technologies.\(^\text{72}\)

Analogously to the conditions (2.6a) and (2.7a) for representing intensity standards in the theoretical model, an intensity standard for RE relates the amount of “green” energy supplied in the economy \( \sum_{i,t} X_{it} \) in a specific way to total energy supply \( \Psi = \sum_{i,t} X_{it} \):

\[
\sum_{i \in G, t} X_{it} \geq \gamma \mathbb{P}(\Psi) \quad \perp \quad S \geq 0, \tag{A.11}
\]

where for the case of an RE quota and a system of green offsets \( \mathbb{P} \) is given by, respectively:

\[
\mathbb{P}(\Psi) = \begin{cases} 
\sum_{i,t} X_{it}, & \text{if RE quota} \\
\sum_{i,t} \int_0^{X_{it}} E_i(x)dx, & \text{if Green offsets.}
\end{cases}
\]

Under RE support through an intensity standard (RE quota or green offsets), the regulator chooses \( b = \{\gamma\} \) subject to the system of equilibrium constraints (A.5)–(A.8) and the intensity constraint (A.11) with the

\(^{\text{72}}\)Note that \( \omega, S \) corresponds to the policy choice variable \( s_t \) in the theoretical model in Section 2.2.
respective implicit input taxes given by: $\kappa_{it}^{\text{RE quota}} = \gamma S$ and $\kappa_{it}^{\text{Green offsets}} = \gamma E'(X_{it})S$.

A.2.2 Computational strategy

The regulator's problem of designing optimal RE support policies stated in (A.2) represents a Mathematical Program under Equilibrium Constraints (MPEC), i.e. a bi-level optimization problem which maximizes an objective function subject to a lower-level constraint set that contains an equilibrium problem (Luo, Pang and Ralph, 1996). We cast the equilibrium problem in the lower-level part as a mixed complementarity problem (MCP) (Mathiesen, 1985; Rutherford, 1995) solving for primal and dual variables (i.e., quantities and prices). The advantage of this approach is that it naturally accommodates equilibria with corner solutions, for example, zero technology-specific investments at a given point in time or non-binding capacity constraints in electricity production.

Owing to the lack of robust solvers (Luo, Pang and Ralph, 1996) for solving MPECs, we reformulate the MPEC problem as a gridded MCP for which standard solvers exist. Specifically, we use the MCP to perform a grid search over policy choice variables $b$ using the PATH solver (Dirkse and Ferris, 1995) for complementarity problems and the General Algebraic Modeling System (GAMS).

A.2.3 Empirical specification

This section describes how we specify our quantitative model to be consistent with year-2014 conditions of the German electricity market. The main idea is to construct an empirically plausible "no policy" reference case of the partial equilibrium model of German electricity supply and demand as described by the zero-profit and market-clearing equilibrium conditions (A.5)-(A.8). To cleanly investigate the economic and environmental impacts of alternative policy designs for RE support, the "no policy" reference case assumes that market decisions about energy supply and demand ignore the presence of the environmental externality, i.e. the equilibrium in the "no policy" benchmark represents an unregulated market outcome.\[73\]

To bring our model to the data, we need to specify the following parameters and functions: resource availability of RE (wind and solar) resources over time ($\alpha_{it}$); cost and emissions functions for generation with technology $i$ ($c^g_i$ and $E_i$); cost functions for investments in production capacity for technology $i$ ($c_i^c$); installed production capacities for conventional energy technologies in the benchmark ($K_i$); and demand functions for energy at time $t$ ($D_t$). We now describe in turn how these functions and parameters are specified based on data.

TEMPORAL RESOLUTION AND AVAILABILITY OF RE RESOURCES.—We model one year with hourly resolution to capture the temporal heterogeneity of RE supply and interactions with hourly energy demand and supply (dispatch) decisions of conventional energy producers. To reduce computational complexity, we select $T = 672$ representative hours. Based on data for all hours of the year, we construct for every season an average week. Each hour contained in an average week is obtained by averaging over the respective hour over all days belonging to that season.\[74\]

---

\[73\] For $\delta = 0$, the regulator effectively maximizes market surplus (ignoring environmental damage) in which case the solution of the regulator's problem in (2.4) coincides with the market outcome of the partial equilibrium model.

\[74\] In light of the concern that this procedure for selecting representative hours of the year may unintentionally smooth out hours with extremely low or high resource availability, Section 2.4 reports on robustness checks with respect to the number of hours.
### Table A.1: Carbon coefficients and fuel prices.

<table>
<thead>
<tr>
<th></th>
<th>Hard coal</th>
<th>Natural gas</th>
<th>Lignite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon coefficients(^a) (tCO(_2)/MWh)</td>
<td>0.202</td>
<td>0.354</td>
<td>0.364</td>
</tr>
<tr>
<td>Fuel price(^b) (€/MWh)</td>
<td>8.58</td>
<td>21.16</td>
<td>4.39</td>
</tr>
</tbody>
</table>

**Notes:**
- \(^a\)Based on IPPC (Eggleston et al., 2006).
- \(^b\)Yearly average of daily spot market prices for 2014 based on price data provided by Bloomberg. For coal and natural gas prices, we use the “ICE CIF ARA Near Month future” and “NBP Hub 1st day futures”, respectively. All prices are converted to 2014 Euros using daily exchange rates provided by the European Central Bank.

To characterize the daily and seasonal variation of wind and solar resources, we use hourly generation of wind and solar energy from the German transmission system operators (Amprion, 2018; Tenet, 2018; TransnetBW, 2018; 50Hertz, 2018). Similarly, hourly availability of hydro resources is based on hourly generation of hydro power from the Energy Charts (2015) provided by the Fraunhofer Institute for Solar Energy Systems. To derive hourly availability profiles for wind and solar resources (\(\alpha_{it}\)), we assume that wind mills and solar panels would produce an energy output equal to their respective installed production capacity. This enables us to calculate \(\alpha_{it}\) by relating observed hourly generation data for solar and wind to the maximally feasible energy output given installed capacities. \(\alpha_{it}\) thus indicates the fraction of installed RE capacity available for production given the weather conditions that prevailed in 2014.

### NON-RENEWABLE ENERGY TECHNOLOGIES.

The technological options for supplying electricity from different non-renewable fuel sources (\(i \in B\)) are resolved at the technology level comprising lignite, hard coal, natural gas, nuclear, hydro, and others (i.e., mainly biomass and some electricity generated from oil and waste). To take into account the heterogeneity of fossil-based and CO\(_2\)-emitting plants in terms of heat efficiencies and emissions intensity, we assume that generation cost functions \(c_i^g(X_{it})\) and emissions functions \(E_i(X_{it})\) for lignite, hard coal, and natural gas are quadratic in output. The corresponding functions for all other non-renewable energy technologies are assumed to be linear.

To calibrate the functions \(c_i^g(X_{it})\) and \(E_i(X_{it})\), we first obtain plant-level heat efficiencies for German power plants from Open Power System Data (2017). Second, we assemble data on fuel prices and emissions coefficients by fuel. For the former, we take yearly averages of daily spot market prices for the year 2014 as provided by Bloomberg. The latter are based on IPPC standard emissions coefficients (Eggleston et al., 2006) for each fuel. Table A.1 shows the data for carbon coefficients and fuel prices. Third, we construct plant-level fuel costs and CO\(_2\) emission rates by multiplying the heat efficiency for each plant with the respective fuel price and emissions coefficient. Lastly, ordering all plants from low to high marginal cost, we then use ordinary least squares (OLS) to estimate the intercept and slope coefficients of the marginal generation costs and emissions functions. Table A.2 reports the estimated coefficients.

Installed generation capacities for conventional energy technologies \(\overline{K}_i\) in 2014 are taken from Open Power System Data (2017). We assume that conventional energy firms do not invest in new capacity (i.e., \(I_i = 0\) for \(i \in B\)); production is thus restricted to what is feasible given pre-installed capacities.

### INVESTMENT COSTS AND HETEROGENEOUS RESOURCE QUALITY.

While the costs for fossil fuels and emissions associated with energy supply from wind and solar are zero, i.e. \(c_i^g(X_{it}) = E_i(X_{it}) = 0\) for \(i \in G\), the major cost incurred is the capital cost for installing production capacity. At the same time, there is considerable spatial variation regarding the resource availability of wind and solar. Investors choose locations with the highest resource qualities first and then successively use sites with lower quality. We capture resource heterogeneity by assuming that investment cost per MWh electricity produced with wind
Table A.2: Benchmark production capacities $\bar{K}_i$ and OLS-fitted quadratic functions for generation cost $c_i^g$, emissions $E_i$, and investment cost $c_i^i$.

<table>
<thead>
<tr>
<th>Energy supply technologies</th>
<th>Gas</th>
<th>Coal</th>
<th>Lignite</th>
<th>Hydro</th>
<th>Nuclear</th>
<th>Wind</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed production capacities in “no policy” reference case ($K_i$)</td>
<td>MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>26'900</td>
<td>34'378</td>
<td>23'319</td>
<td>10'320</td>
<td>12'696</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Marginal generation cost functions ($d c_i^g(X_i)/d X_i$)</td>
<td>Intercept ($\frac{c_i^g}{\text{MWh}}$)</td>
<td>28.41</td>
<td>17.24</td>
<td>9.38</td>
<td>4</td>
<td>9.09</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Slope ($\frac{c_i^g}{\text{MWh}^2}$)</td>
<td>$1.4 \times 10^{-3}$</td>
<td>$3.04 \times 10^{-4}$</td>
<td>$2 \times 10^{-4}$</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Marginal emissions functions ($d E_i(X_i)/d X_i$)</td>
<td>Intercept ($\frac{E_i}{\text{MWh}}$)</td>
<td>0.27</td>
<td>0.71</td>
<td>0.78</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Slope ($\frac{E_i}{\text{MWh}^2}$)</td>
<td>$1.33 \times 10^{-5}$</td>
<td>$1.25 \times 10^{-5}$</td>
<td>$1.66 \times 10^{-5}$</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Marginal investment cost functions ($d c_i^i(I_i)/d I_i$)</td>
<td>Intercept ($\frac{c_i^i}{\text{MWh}^2}$)</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>60'618</td>
</tr>
<tr>
<td></td>
<td>Slope ($\frac{c_i^i}{\text{MWh}^2}$)</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>0.24</td>
</tr>
</tbody>
</table>

Figure A.1: Empirically estimated functions for marginal generation cost and marginal emissions rate by technology assuming central-case value for natural gas price (21.16 €/MWh).

We assume that pre-installed production capacities for wind and solar in the initial no-policy reference case are zero, i.e. $\bar{K}_i = 0$ for $i \in G$, but that new capacity can be added if the return on these investments is positive according to the profit condition (A.5).

HOURLY ENERGY DEMAND.—To specify $D_t(P_t, \tau)$, we assume that electricity demand at time $t$ reacts linearly to the tax-inclusive wholesale price at time $t$. We use historical data on hourly electricity demand ($D_t$) from the European Network of Transmission System Operators (ENTSO-E, 2016) and hourly day-ahead

---

$^{75}$ We adopt the following approach. We use the concept of full load hours which translates the yearly electricity production of a site into the number of hours needed to generate this amount of electricity at full use of the capacity. This number will decline with deteriorating wind or solar resource quality due to geographical variation of the sites. We capture this geographical variation by assembling full-load hours (averaged over a period of four years to account for varying weather conditions) for each German state from Agentur für Erneuerbare Energien (2017). This information together with an estimation of total resource potential for each state (from the same source) allows us to construct a full-load hour curve by ordering the potentials of the states from highest to lowest. Assuming that the most favorable sites are developed first, we then obtain a resource curve describing a negative relation between full-load hours and the level of investment, $I_i$. In a second step, we adjust annualized investment cost for resource potential by dividing reported investment cost per installed MW for wind and solar from Kost et al. (2013) with full-load hours. Since the full-load hour curve, describing resource potential, declines with investment, the marginal investment cost curve we obtain increases in $I_i$. Finally, we fit quadratic investment cost functions for wind and solar using OLS.
Marginal cost functions.

Marginal emissions rate as function of output

Figure A.2: Empirically estimated functions for marginal generation cost and marginal emissions rate by technology assuming a low price for natural gas (5 €/MWh).

electricity prices ($P_t$) from European Power Exchange (EPEX, 2015) to calibrate for each time period $t$ the following linear demand function:

$$D_t(P_t, \tau_t) = D_t \left[ 1 - |\varepsilon| \left( \frac{P_t + \tau_t}{P_t} - 1 \right) \right].$$

where $\varepsilon < 0$ denotes the price elasticity of energy demand. We assume $\varepsilon = -0.15$ for the central case.\textsuperscript{76}

SOCIAL COST OF CARBON.—We choose $\delta$ to be consistent with a plausible range of estimates obtained from integrated assessment modelling exercises (Interagency Working Group on Social Cost of Greenhouse Gases, 2016). Specifically, we use €50 and €100 per ton of CO$_2$ for our central and a high-damage case, respectively.\textsuperscript{77}

\textsuperscript{76} Given the lack of clear-cut empirical evidence on the variation of the price-responsiveness of energy demand over hours of a day or seasons, we assume that $\varepsilon$ is uniform across $t$. We take the linear demand specification as a good enough approximation of possible non-linearities between demand and price. We use sensitivity analysis to scrutinize the implications of different magnitudes in the price responsiveness of demand to price (given a linear demand specification).

\textsuperscript{77} We use the year-2015 estimates from Interagency Working Group on Social Cost of Greenhouse Gases (2016) which are closest to our modelled base year. Our central-case value for $\delta$ is close to the reported mean of $56 per ton of CO$_2$ in the study); our high value for $\delta$ is based on a high-impact, low-probability scenario with “catastrophic” climate events.
A.3 Online appendix: Documentation of computer codes to reproduce quantitative analyses

This online appendix provides a brief documentation of computer codes—using the GAMS (General Algebraic Modeling System) and Python software—which can be used to reproduce the quantitative empirical analyses presented in Sections 2.3 and 2.4 of the paper. All files, including model and data, can be downloaded here.\textsuperscript{78}

This Online Appendix is structured as follows. We first list the software programs and solvers needed to execute the computer codes. We then describe the folder structure, file names, and functionality of each program in the overall package.

Software prerequisites

The following solvers are needed to solve the GAMS routines:

- *PATH*: To solve the complementarity-based economic equilibrium problem.

The following Python packages are needed to implement the grid search for optimal policies:

- *GAMS API*: To interface GAMS and Python. Delivered with GAMS.
- *NumPy*: Used for numerical computations.
- *Pandas*: Used for data processing.
- *Jupyter Notebook*: For calibration and result processing.

Folder structure and file names

The folder named “model” contains files of the core GAMS model:

- *main.gms*: Main file to run the model
- *dataload.gms*: Loads data files, calibration and assignment of model parameters.
- *policies.gms*: Defines parameters for policy implementation and assigns default values.
- *model.gms*: Definition and assignment of model equations and variables.
- *initialize.gms*: Initialization of variables depending on policy parameters.
- *report.gms*: Assignment of reporting parameters.

The folder named “Iteration_parallel” contains Python files to perform grid search for optimal policies using parallel processing.

\textsuperscript{78}The electronic version of this document contains a hyperlink. The address is: https://www.ethz.ch/content/dam/ethz/special-interest/mtec/der-eth/economics-energy-economics-dam/documents/people/srausch/Online_Appendix_TheEconomics_of_RenewableEnergySupport.zip.
- iteration.py: Main file to run grid search over optimal policies. Functions within the file are named after the scenario to solve, e.g., solve_core_cases, determines all optimal policies for the central results used in the paper.

- scenarios.py: Functions to implement policies and report results.

- model.py: Functions to run GAMS model using Python.

- Process_results.py: Reporting of model results in pivot-table friendly format.

- results: Folder for model results.

The folder named “data” contains data input files for the GAMS model:

- DE_season_average.xlsx: Time series for electricity demand and generation.

- Technology_data.xlsx: Cost and generation characteristics of power plants.

- Technology_data_elas0.05.xlsx: Cost and generation characteristics of power plants. Case of low elasticity.

- Technology_data_elas0.5.xlsx: Cost and generation characteristics of power plants. Case of high elasticity.

- Technology_data_cf_nofuelswitch.xlsx: Cost and generation characteristics of power plants. Case of low natural gas price.

- Technology_data_no_coal.xlsx: Cost and generation characteristics of power plants. Case of no coal capacity.

- investments_cost_res.xlsx: calibrated parameters of investment cost function.

The folder named calibrate_cost_curves contains file to calibrate marginal cost and emission curves:

- ipython/Calibrate_cost_curve.ipynb: Jupyter notebook to calibrate cost and emission curves for the central case.

- ipython/Calibrate_cost_curve_counterfactual.ipynb: Jupyter notebook to calibrate cost and emission curves for the case of low natural gas prices.

- ipython/Fit_Investment_Curves.ipynb: Jupyter notebook to calibrate investment cost functions for wind and pv installations.

- source_data/conventional_power_plants_DE.csv: List of German power plants.

- source_data/fuel_prices.csv: Time series of daily fuel and emission prices.

- source_data/RES_investment_curves.xlsx: Cost characteristics, potential, and generation of wind and pv power in Germany used to calibrate investment cost curves.

- figures: Folder to store figures of cost and emission curves.
### B Appendix Article 3

#### B.1 Full Results Tables

The following tables B.1 and B.2 are analogues to their counterparts in section 4.5 but they report the absolute values of the various parameters.

**Table B.1: Values of cost parameters and CO₂ emissions.**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total cost ($C_{\text{tot}}^\text{tot}$) [B. €]</th>
<th>Conv. cost ($C_{\text{gen}}^\text{tot}$) [B. €]</th>
<th>RE cost ($C_{\text{inv}}^\text{tot}$) [B. €]</th>
<th>Marg. inv. cost ($\gamma G_r^\text{tot}$)</th>
<th>Emissions [Mt]</th>
</tr>
</thead>
<tbody>
<tr>
<td>National constrained</td>
<td>82.6</td>
<td>28.8</td>
<td>53.8</td>
<td>44.1</td>
<td>7.6</td>
</tr>
<tr>
<td>National NTC</td>
<td>76.3</td>
<td>26.8</td>
<td>49.5</td>
<td>43.7</td>
<td>6.7</td>
</tr>
<tr>
<td>National storage</td>
<td>78.3</td>
<td>29.2</td>
<td>49.1</td>
<td>43.4</td>
<td>6.6</td>
</tr>
<tr>
<td>National unconstrained</td>
<td>75.5</td>
<td>26.5</td>
<td>49.0</td>
<td>43.3</td>
<td>6.5</td>
</tr>
<tr>
<td>TGQ constrained</td>
<td>80.5</td>
<td>28.8</td>
<td>51.6</td>
<td>44.1</td>
<td>7.2</td>
</tr>
<tr>
<td>TGQ NTC</td>
<td>71.8</td>
<td>27.0</td>
<td>44.8</td>
<td>43.2</td>
<td>5.5</td>
</tr>
<tr>
<td>TGQ storage</td>
<td>77.1</td>
<td>29.1</td>
<td>48.0</td>
<td>43.5</td>
<td>6.4</td>
</tr>
<tr>
<td>TGQ unconstrained</td>
<td>71.2</td>
<td>26.5</td>
<td>44.7</td>
<td>43.1</td>
<td>5.5</td>
</tr>
</tbody>
</table>

**Table B.2: Values of RE investment and curtailment [TWh].**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Wind Onshore</th>
<th>Wind Offshore</th>
<th>Solar</th>
<th>Total</th>
<th>Curtailment</th>
</tr>
</thead>
<tbody>
<tr>
<td>National constrained</td>
<td>802.5</td>
<td>34.1</td>
<td>395.7</td>
<td>1232.2</td>
<td>52.5</td>
</tr>
<tr>
<td>National NTC</td>
<td>772.1</td>
<td>0.0</td>
<td>388.0</td>
<td>1160.1</td>
<td>0.1</td>
</tr>
<tr>
<td>National storage</td>
<td>600.7</td>
<td>0.0</td>
<td>559.5</td>
<td>1160.2</td>
<td>0.0</td>
</tr>
<tr>
<td>National unconstrained</td>
<td>624.8</td>
<td>0.0</td>
<td>535.4</td>
<td>1160.2</td>
<td>0.0</td>
</tr>
<tr>
<td>TGQ constrained</td>
<td>825.1</td>
<td>2.7</td>
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<td>265.7</td>
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<td>TGQ storage</td>
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<td>TGQ unconstrained</td>
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<td>0.0</td>
<td>315.4</td>
<td>1160.1</td>
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</table>

*Notes: Investment is measured as yearly generation in TWh from installed capacity.*

#### B.2 Data Quality and Missing Observations

For some countries we do not have data for availability profiles of renewable technologies, fuel prices, and variable operation and maintenance (O&M) cost. In such cases we take data from neighboring, similar countries to fill the gaps. The tables B.3, B.4, and B.5 show when this is the case.
### Table B.3: Availability Factors for New Renewable Energy Sources

<table>
<thead>
<tr>
<th>Technologies</th>
<th>Wind Onshore</th>
<th>Wind Offshore</th>
<th>Solar</th>
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<tbody>
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<tr>
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<td>DK</td>
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</tbody>
</table>

**Notes:** The availability factors for technology $r$ in country $c$ in the left column, $\alpha_{rct}$, are taken from data for the country indicated in the columns below the technologies. A dash indicates that data for this country and technology were available.

### Table B.5: Variable O&M Cost for Conventional Technologies

<table>
<thead>
<tr>
<th>Technologies</th>
<th>Hard coal</th>
<th>Lignite</th>
<th>Gas</th>
<th>Nuclear</th>
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</thead>
<tbody>
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</table>

**Notes:** The variable O&M costs for technology $i$ in country $c$ in the left column, $c_{i\text{ct}}^{\text{O&M}}$, are taken from data for the country indicated in the columns below the technologies. A dash indicates that data for this country and technology were available.
<table>
<thead>
<tr>
<th>Technologies</th>
<th>Hard coal</th>
<th>Lignite</th>
<th>Oil</th>
<th>Gas</th>
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</thead>
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Notes: The fuel prices for technology $i$ in country $c$ in the left column, $c_{i,c,t}$, are taken from data for the country indicated in the columns below the technologies. A dash indicates that data for this country and technology were available.