RENEWABLE ENERGY AT WHAT COST?
ASSESSING THE EFFECT OF FEED-IN TARIFF POLICIES ON CONSUMER ELECTRICITY PRICES IN THE EUROPEAN UNION

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By

Christopher A. Klein, M.A.(Hons)

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Thesis Advisor: J. Arnold Quinn, Ph.D.

ABSTRACT

In the last two decades, feed-in tariffs (FIT) have emerged as the dominant policy instrument for supporting electricity from renewable sources in the European Union. This paper examines the effect of such feed-in tariffs on consumer prices for electricity. While a multitude of studies examine the effects of FIT policies on electricity prices within individual countries or across countries using complicated ex-post computer simulations, there are a dearth of rigorous ex-post, cross-country econometric analyses. Using 1992-2009 panel data across 20 European countries and a dynamic panel data model estimation, this paper analyzes the effect of FIT policies for electricity generated from wind and solar photovoltaic (PV) on electricity prices at the household consumer level. The analysis finds a mild association of the support level for wind energy with higher retail prices, but no price increase for solar PV support. This finding points toward the existence of a ‘merit order effect’ and, in particular, a strong ‘time of day’ effect, where solar PV is able to replace more costly natural gas and petroleum generation because it is generated during times of peak demand, whereas electricity from wind is mostly generated at night when demand is low. However, the shares of solar PV electricity generated under the FIT are still very low; as the share of electricity generation that is covered by the FIT rises, adverse price effects may become more apparent. The paper also finds that feed-in tariffs for wind only increase retail prices in the presence of retail regulation, indicating that regulatory bodies may allow utility
companies to charge higher prices in the presence of FIT payments, whereas utility companies that are subject to retail competition are not able to pass on their additional costs to customers. In addition, the paper further finds that larger shares of electricity generated from hydro and nuclear power decrease retail rates, suggesting that, due to their similar cost profile, the same could be true for wind and solar PV in the long term, once a fleet of generation capacity from wind and solar PV is established and the initial capital costs are recovered.
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GLOSSARY

BBL  Barrel
BLUE  Best Linear Unbiased Estimators
BTU  British Thermal Unit
CHP  Combined Heat and Power
DV  Dependent Variable
EC  European Commission
EEG  Renewable Energy Sources Act (Germany)
ETS  Emissions Trading Scheme
EU  European Union
FE  Fixed Effects
FIT  Feed-in tariff
GHG  Greenhouse Gas
GMM  Generalized Method-of-Moments
GWh  Gigawatt Hour
i.i.d.  Independently and Identically Distributed
IEA  International Energy Agency
KWh  Kilowatt Hour
LNG  Liquefied Natural Gas
MWe  Megawatts
MWh  Megawatt Hour
OECD  Organization for Economic Co-operation and Development
OLS  Ordinary Least Squares
PV  Photovoltaic
RES-E  Electricity from Renewable Sources
1. Introduction

Concern over climate change, pollution reduction and fossil fuel availability has led an increasing number of industrialized countries to back public financing of renewable energies. The European Commission has been particularly aggressive about promoting electricity generation from renewable sources (RES-E), announcing the renewable energy road map, “Renewable energies in the 21st century: building a more sustainable future” (EC Roadmap 2008), which set a target to supply 20 percent of European energy consumption from renewable sources by 2020. Studies commissioned by the EU Commission estimate that in order to meet this target, about 32 percent of electricity consumed in the EU will need to come from renewable sources (RE-Financing 2011, OPTRES 2007).

Today there exists a widely accepted consensus throughout Europe that well-designed feed-in tariff (FIT) policies are the most effective way of achieving the development of electricity-generating capacity from renewable sources (RES-E). This differentiates Europe from the United States, where Renewable Portfolio Standards have been the dominant RES-E support instrument. The basic premise of all renewable energy development policies is that they create demand for climate-friendly technologies that otherwise would not exist at all or not at desired levels under current market conditions. FIT regimes are energy-supply policies intended to create demand for renewable electricity generation capacity by guaranteeing a premium price on electricity generated from renewable sources. In order to achieve this end, most FIT legislations (1) impose obligations on utilities and grid operators to purchase the full output generated by qualifying renewable energy generators, (2) guarantee an above-market payment per unit output
(\$/kWh) for the full output of the system, (3) limit these special payments to a specified time period, and (4) differentiate payments between projects based on technology type, project size, the quality of the resource or other project-specific variables.

Evidence suggests that FITs are more effective than alternative support schemes—such as minimum quota requirements and tax breaks—in promoting the deployment of RES-E generation capacity (EC 2008; OPTRES 2007; Lipp 2007; Butler and Neuhoff 2008; Lesser and Xu 2008; Alagappan, Orans and Woo 2011). This view is driven largely by the success of FIT
policies in deploying large amounts of wind, biomass and solar energy in Germany, Denmark and Spain, among other countries. The success of FIT policies can largely be traced to the high level of security that FIT schemes provide for investors in RES-E generation, mitigating future electricity market volatility and making it very likely that investors will recover their large up-front capital investment (Butler and Neuhoff 2008, Lesser and Xu 2008). This view is perpetuated by the European Commission, which—although unable to prescribe to member states which policy instruments to choose—concluded in a 2008 communication to the European Parliament (EP) and European Council (EC) that FITs “achieve greater renewable energy penetration, and do so at lower costs for consumers” (EC 2008). Since 1990, 24 EU member states have introduced FIT policies, five of which also offer a choice between a fixed and premium tariff, and three of which also have minimum quota regulations to complement their FIT policies. Only Sweden, Poland and Romania continue to rely solely on minimum quota regulations to achieve their EU targets (See Figure 1). Over this time period, RES-E generation capacity in the EU-27 countries has developed rapidly (See Figure 2).
The ongoing increase in the share of RES-E in the electricity production mix has been accompanied by a debate about the cost of supporting RES-E. As FIT payments guaranteed to RES-E producers normally are above the spot-market price for electricity, opponents of FITs have argued that these policies increase electricity prices. Such adverse price effects were less of a concern when renewable energy targets were relatively low. However, given the rapid increase in RES-E generation over the last decade and the even more substantial increase expected over the next one, if the EU is going to meet its ambitious RES targets, there are large concerns about how the cost of FIT policies may affect electricity prices and, subsequently, the competitiveness of European economies, inflation levels and social welfare. Some countries have already responded to these concerns. For example, Germany recently reduced its FIT payments for solar
photovoltaic (PV) by 15 percent for the year 2012\(^1\), while Spain has retroactively cut its solar PV FIT program by up to €3 billion.\(^2\)

In light of these concerns, the costs of European FIT programs have been analyzed by numerous ex-ante studies commissioned by the European Commission; however, there is a dearth of empirical ex-post analysis on the topic. This paper aims to fill this void by providing a rigorous ex-post econometric analysis of the effect FIT policies may have had on electricity prices at the household consumer level, across 20 European countries between 1992 and 2009. It finds a mild association of higher electricity prices with FIT programs for electricity generated from wind energy, but no significant price increase for solar PV support. This may point to the existence of the “merit order effect” (Sensfuß, Ragawitz and Barbose 2008), and, in particular, a strong ‘time of day’ effect, where solar PV is able to replace more costly natural gas and petroleum generation because it is generated during times of peak demand, whereas electricity from wind is mostly generated at night when demand is low. However, this result needs to be treated with care, as the shares of solar PV electricity generated under the FIT are still very low and most countries’ programs have only existed for a relatively short time. As the share of electricity generation that is covered by the FIT for solar PV rises, adverse price effects may become more apparent. The present study also finds that the price increases associated with FIT payments for wind are only statistically significant if end-user prices are still subject to regulation, indicating that regulatory bodies may allow utility companies to charge higher prices

\(^2\) [http://www.ft.com/intl/cms/s/0/filedc4d2-0dfb-11e0-86e9-00144feabde0.html#axzz1qEmCx5Jm](http://www.ft.com/intl/cms/s/0/filedc4d2-0dfb-11e0-86e9-00144feabde0.html#axzz1qEmCx5Jm)
in the presence of FIT payments, whereas utility companies that are subject to retail competition are not able to pass on these legitimate additional costs.

Section 2 of this paper provides an overview of the literature on price effects associated with FIT programs across the EU; Section 3 lays out the theoretical framework of this paper’s analysis; Section 4 describes the data used throughout the analysis; Section 5 provides some preliminary results; Section 6 outlines the empirical methodology and estimation techniques used; Section 7 reports the empirical results; Section 8 provides a discussion of the policy implications of the findings; and Section 9 concludes the paper’s findings.

2. Literature Review

One of the most debated impacts of FIT policies is their effect on electricity prices. Feed-in tariffs for RES-E can result in two potentially counteracting effects. As FIT payments are typically above the spot-market price for electricity, they burden electric utilities with additional costs, which they will then pass on to the consumer in the form of higher retail rates. However, there also is a strand of literature that finds that a higher share of electricity generation from renewable sources could replace high-cost fossil fuel generation such as natural gas and petroleum, thereby lowering spot-market prices for electricity. In this context, if FIT policies spur enough RES-E development, they can have a decreasing effect on electricity prices.

2.1. Direct Effect: Additional Costs for Utilities, Higher Retail Prices?

There have been numerous ex-ante studies commissioned by the European Commission on the additional costs incurred by utilities as a result of renewable energy support through FIT
policies. The 2011 study “Financing Renewable Energy in the European Energy Market” (RES-financing), prepared by Ecofys in cooperation with Frauenhofer ISI, the Energy Economics Group at TU Vienna and Ernst and Young, estimated the total cost of RES support in 2009 at the EU level to amount to approximately €35 billion, using the GreenX computer model.\textsuperscript{3} Employing a bottom-up estimation, the same study found a lower band of net support of €19.6 billion in the same year. According to the GreenX estimation, the levels of support differ significantly across countries, with Germany taking the ‘lead’ with almost €11 billion in RES support followed by Italy and Spain with about €5 billion, respectively. These three countries also have the strongest FIT schemes in the EU.

The 2007 study “Assessment and Optimization of Renewable Energy Support Schemes in the European Energy Market” (OPTRES 2007), also relying on the GreenX computer model, predicted that a steady rise in average EU consumer prices for electricity was necessary to finance RES-E deployment over the next ten years. The study predicted an increase from 2.1 €/MWh in 2005 to approximately 5.0 €/MWh in 2020. These estimations refer to a scenario where the current energy mix and policy environment is not changed. With the alternative “improved national policies” scenario, which is characterized by a 40 percent higher RES-E development in the investigative period 2005-2020, greater financial support is required in total.

\textsuperscript{3} The GREEN-X project developed a computer-based toolbox to facilitate the analysis of optimal promotion strategies for RES-E in a dynamic European electricity market. The project was supported by the European Commission under the 5th Framework Program and the project consortium consisted of mix of universities, research institutes, consulting companies, stakeholder and NGO from eight EU member states. The main outputs were a database of potential capacity and cost of RES-E supply, combined heat and power (CHP) production, efficiency improvement and fuel switching in the electricity sector as well as the corresponding greenhouse gas (GHG) reductions; and a dynamic computer model linking and simulating different scenarios between RES-E, CHP, demand-side activities and GHG-reduction in the electricity sector. More information at: http://www.green-x.at/ or http://www.erec.org/projects/finalised-projects/green-x.html.
to achieve the more ambitious RES-E target for 2010. Accordingly, a steeper rise of required expenditures occurs in the period up to 2017, with a peak of 7.7 €/MWh in 2017.

Among the relatively few ex-post studies that have analyzed the price effects of FIT policies, Gual and del Rio (2007) assessed the effect of the Spanish FIT between 1999 and 2003, in terms of additional costs paid by the consumer for renewable compared to conventional electricity (i.e. the share of RES-E promotion of the electricity bill). Their study found that the total RES-E support costs outweigh the external costs avoided by RES-E deployment for all technologies, in particular for solar PV. According to their estimation, the additional cost for the consumer increased annually by 23 percent during the period considered.

Frondel et al. (2008) calculated the net present value (NPV) of the cost of newly installed RES-E capacity in Germany that is covered by the Renewable Energy Sources Act (EEG), finding a NPV of the cost of wind generation capacity installed between 2000 and 2008 of €19.8 billion in real terms, and of €35 billion for PV generation. Traber and Kemfert (2009) also found an upward price effect of the German FIT, using a quantitative electricity market model that accounts for factors such as oligopolistic behavior, emission trading and restricted cross-border transmission capacities.

2.2. Indirect Effect: Lower Spot-Market Prices, Lower Retail Prices?

In addition to the literature on direct costs of supporting RES-E development through FIT programs, there is also a body of literature that postulates that higher shares of electricity generated from renewable sources decreases wholesale prices. This theory relies on what is
called the merit order effect: as wholesale electricity prices are determined by a generation technology’s marginal costs and as the feed-in tariff payment occurs outside the mechanism of the wholesale market, the marginal costs of electricity generated from wind and solar PV are practically zero. If FIT policies result in more RES-E capacity installed, higher feed-in of electricity from these sources could therefore replace other technologies with higher marginal costs and thus decrease wholesale prices, which should naturally also decrease retail prices.

Comparing such potential cost savings due to higher RES-E feed-in to direct costs of the FIT, Bode (2006) showed that power costs may decrease due to FIT schemes such as the German EEG under certain conditions. Although FIT policies result in higher electricity prices in most cases, the net effect of the FIT may become negative if supply curves become steeper, as the cost savings due to rightward shifts of the supply curve associated with increased RES-E supply become larger. Similarly, using a model in which he applies assumptions on the cost structure based on real world data, Rathmann (2007) also showed that the support for renewable energy created by the German feed-in tariff can result in lower electricity prices under certain conditions.

Some empirical analysis has confirmed that more RES-E supply can decrease spot-market prices in practice. Weigt (2009) found that wind generation had a downward impact on both spot-market prices and generation costs in Germany for the period of 2006-2008. During the observation period, the study estimated a total savings of €4.1 billion due to wind power fed into the grid. Traber and Kemfort (2011), using a mixed complementary program computational model, also found that higher wind supply reduces German market prices by more than 5
percent. Their model estimated that the reduction in the spot-market price for electricity is 0.37 Eurocents per kWh.

Similar results have also been found in the case of Spain. Gelabert, Labandeira and Linares (2011), using a multivariate regression model of hourly electricity prices for 2005-2009, found that a marginal increase of 1 GWh of electricity—which would be equivalent to a 17.5 percent increase in generation from renewable sources and 3.5 percent of total generation—produced from renewable sources is associated with a reduction of almost 4 percent (€2 per MWh) in wholesale electricity prices. Likewise, Jonsson, Pinson and Madsen (2010), using a non-parametric least squares model regressing hourly area spot-prices on wind power forecasts for January 2006 to October 2007, showed that positive wind forecasts result in lower spot-market prices for the DK-1 price area (Jutland, Funen and the islands west of the Green Belt) of the Nordpool electricity area.

Only very few studies compare these costs savings of higher RES-E generation to the direct costs of the FIT. Ragawitz, Sensfuß and Barbose (2008), offering a detailed analysis of the price effects of renewable electricity generation on German spot-market prices between 2001 and 2006, found a considerable reduction in wholesale (i.e. spot-market) prices for electricity associated with higher levels of RES-E fed into the grid. Furthermore, they found that in 2006, cost savings due to RES-E feed-in actually outweighed the direct costs of the FIT. Similarly, De Miera, del Rio Gonzalez and Vizcaíno (2008), using hourly historical data, found that the reduction of the wholesale price of electricity as a result of more RES-E generation being fed
into the grid is greater than the increase in consumer prices for electricity that arise from the FIT scheme.

In contrast, both the RES-financing (2011) and the OPTRES (2007) studies project that the direct effect of the FIT will outweigh the indirect reduction of wholesale prices. OPTRES (2007) estimates that the total amount of avoided fossil fuels in the ‘business-as-usual’ case, assuming an unchanged fuel mix, amounts to 50 percent of current natural gas used in electricity generation, 35 percent of hard coal, 9 percent of lignite and 6 percent of petroleum products, respectively. In monetary terms, these figures correspond to a reduction in the annual expenses for fossil fuels of €23 billion for the EU27 from the year 2020 onwards. Despite these massive savings, OPTRES nonetheless expects price increases due to RES-E promotion, as the costs still outweigh the benefits.

To my knowledge, there has not been a cross-country, ex-post econometric study of the negative effects of FIT regimes on consumer prices. In light of this dearth of empirical ex-post analysis on the topic, this paper aims to illuminate the current debate on adverse economic effects of renewable energy promotion—in particular, feed-in tariffs—in EU member states. It provides a rigorous ex-post econometric analysis of the effect of technology-specific FIT legislations, for wind and solar PV, on electricity prices at the household consumer level, across 20 European countries between 1992 and 2009.

3. Conceptual Framework

Although many scholars by now have conceded that FIT policies are not only the most effective, but also the most economically efficient way of promoting RES-E due to the
elimination of uncertainty and the associated risk premium as well as their ability to move new technologies quickly along the experience curve (EC 2008, RES-financing 2011, OPTRES 2007), there remain concerns about the adverse economic impacts of FIT RES-E policies and the support of RES-E in general (RES-financing 2011, OPTRES 2007).

These concerns revolve largely around the impact of FIT policies on electricity prices and, subsequently, the competitiveness of European economies, inflation levels and societal welfare. This study examines the effect of a specific subset of FIT policies on retail electricity prices to determine the validity of these concerns. The formal hypothesis that is tested in this analysis is that higher feed-in tariffs for wind and solar PV will be associated with higher consumer electricity prices.

In particular, this study is interested in the effects of FIT policies on household consumer prices for electricity for both conceptual and technical reasons. Firstly, adverse price impacts at the household level are likely to have the most direct socio-economic consequences as they directly affect welfare and inflation levels. As all EU member states are democratic political systems, adverse price effects are also the most likely trigger for potential backlashes against such policies; retail rates thus constitute the most politically relevant pricing unit for study. Although there is the possibility that utility companies mitigate the effect of FIT policies on retail consumers by cross-subsidizing rates for small-scale consumers at the expense of commercial consumers, such cross-subsidization is difficult to capture and typically works the other way around in developed countries, with residential customers subsidizing businesses (IEA 2005). Secondly, as electricity covered by the FIT is, in most cases, not actually traded on the
spot-market (because the payment amount is fixed), analyzing effects on spot prices would stop short of the full impact of FIT policies on electricity prices. For these reasons, this study focuses on household retail prices for electricity as the main dependent variable of interest.

Like other network utilities, the electricity sector is characterized by extremely large up-front (i.e. fixed) capital costs, as well as variable costs associated with generating and delivering electricity (Newberry 1999). The fixed costs are generally much larger than the variable costs, depending on the technology employed (Stoft 2002). Fixed costs reflect the capital necessary to build and maintain the physical infrastructure such as generation facilities as well as high-voltage transmission and distribution networks. The structural costs for building generation facilities vary largely with structural characteristics of a country. In particular, fixed costs depend to a large extent on the differential between a country’s average and peak electricity demand; the more extreme a country’s electricity demand, the higher its fixed costs will be. Other factors such as construction costs, for example, depend on factors such as the cost of labor, the ability to obtain necessary permits, and the cost and availability of financing. Transmission costs depend mostly on distances between where the electricity is being generated and the demand centers; as the share of RES-E generation in the energy mix increases, these costs are likely to increase because RES-E is often generated in areas that are less-densely populated. The cost of distributing electricity within a geographic area through a low-voltage transmission network is largely dependent on the population density of the area supplied and, therefore, is likely to be lower in urban areas where more consumers can be serviced with fewer distribution lines. All these factors vary greatly from country to country; unless they are subsidized or cross-subsidized
from other sectors, household electricity prices generally allow utilities (and independent developers) to recover these capital costs (Newberry 1999).

In addition to the fixed costs, utility companies are faced with variable input costs for generating and supplying electricity. First and foremost among those are the variable costs of generating electricity, which companies pay in the form of wholesale prices, supply contracts or as direct inputs in cases where they still have generation capacity of their own. These costs include the input costs for fossil fuels as well as labor costs required for operating power plants (Newberry 1999). Typically, the power portfolio is made up of different power suppliers, generating electricity through different technologies. In liberalized wholesale markets, the ordering of each of these power suppliers depends on the amount of power they can supply at a certain price. As long as an overcapacity of power plants exists to meet electricity demand, no new power plant is necessary to meet demand. Accordingly, competition between the different generators is only determined by the marginal (variable) cost of the plant. As different plants have different marginal costs, different plants can be ordered according to the merit order or “economic dispatch,” which is an ordering of power plants from those with low marginal costs (e.g. hydro) to high marginal cost (e.g. natural gas) (Fox-Penner 1997, Newberry 1999). Therefore, the wholesale price for electricity critically depends on the marginal technology used. Similarly, utilities companies can instruct their system operators to operate whatever combination of available plants at whatever levels yield the lowest aggregate total cost of generation, which—given the nature electricity markets—are driven by variable costs (Fox-Penner 1997). As most European electricity markets are somewhat, yet not fully, restructured/liberalized, it is assumed that regardless of whether utility companies obtain their electricity on
the wholesale market, through bilateral (long-term) contracts or have generation facilities of their own, their operational decisions are determined by producers’ variable costs in the same way as they would be in a liberalized wholesale market.

Within this framework, feed-in tariffs increase utilities’ variable costs, as they oblige companies to take off electricity generated by renewable producers at a pre-determined price (the fixed tariff), which is typically above the average spot-market price for electricity. This is in contrast to the logic of a wholesale market price determined by variable costs, as renewable generators are characterized by virtually zero variable cost. The very idea of feed-in tariff schemes is to provide RES-E developers with the security that they can recover their initial capital investment. Therefore it can be assumed that the obligation to pay feed-in tariffs to renewable generators do raise utilities’ generation costs in the short-term, which they will then most likely pass on to consumers. However, this assumption only holds as long as utility companies are able to meet demand with their existing fleet of generation plants. The calculation could be reversed in the medium- and long-term if increased feed-in of renewable electricity would spare companies from building additional (traditional) generation plants and thus avoid the related large capital investment.

Some of the properties of RES-E generation could also potentially counteract this direct upward price effect associated with feed-in tariffs. In particular, there could be a substantial ‘time of day’ effect that is related to the merit order. The marginal cost of most renewable electricity generation is zero or close to zero; once a plant has been put in place and the wind is blowing, the sun is shining or the water is running, the generator produces electricity at almost
no extra cost. As the company is mandated to take off this electricity, and pay the generator a fixed price, this electricity is practically ‘free’ (in the sense of already paid for). The marginal technology therefore depends on the level of “residual demand,” which is defined as the electricity demand minus the feed in of electricity from RES-E. If the residual demand is low, for example because electricity demand is low at night or because there is a lot of RES-E feed-in, the marginal power plant will be a less expensive technology than if the residual demand is high. High feed-in of RES-E thus shifts the supply curve for electricity to the right, resulting in lower wholesale electricity prices as RES-E generation pushes more expensive marginal plants (e.g. natural gas, petroleum, etc.) out of the market, depending on the price elasticity of power demand. As plants with higher marginal costs are replaced by RES-E generation, this will not only displace the costs of generation from these generators, but also inframarginal rents earned by all non-marginal sellers in the spot-market. This is what Ragawitz, Sensfuß and Barbose (2008) termed the “merit order effect.” The merit order effect could be particularly strong during peak time, if RES-E was able to replace extremely expensive ‘super-peaker’ plants, whereas it could be almost negligible during times of low demand, such as during nighttime.

In extreme cases, the merit-order-related price savings across the entire electricity market could outweigh the costs of paying renewable generators above-market rates, depending on the magnitude of the tariff and the reduction in price. In addition, the merit order effect has implications for the long-term effects of supporting RES-E. Feed-in tariff schemes do not run infinitely; the contract duration typically lies somewhere between 12 and 20 years. The scheme is supposed to enable developers to recover their capital investment over the contract period; once the contract expires, the price for electricity from those generators is driven by their (actual)
variable costs. Therefore, the long-term price effects of feed-in tariffs may be much more beneficial to consumers if they result in a lot of renewable generation capacity installed that will still be around after the FIT contract period has ended.

This long-term effect also applies to hydro and nuclear facilities. Similar to RES-E technologies such as wind and solar PV, both technologies have extremely low operating costs compared to the high up-front capital investments required to build the plants. Once these plants have recovered the initial capital investments, they are able to generate electricity relatively cheaply. A larger share of electricity generation from hydro and nuclear sources therefore decreases wholesale prices as it replaces generation from fossil fuels with higher marginal costs.

Other factors that may influence retail electricity prices are the costs utilities incur by interacting with their customers, such as billing and metering. However, these costs are generally “exceptionally small” (Stoft 2002). National governments also levy taxes and charges on electricity consumption. In addition, utilities may be able to extract rents in the absence of competition at the retail level; if consumers have no (or only limited) choice between suppliers, companies may be able to charge higher prices.

Between 1995 and 2007, all European Union member countries liberalized their energy markets, consistent with the requirements of the three internal electricity market directives issued in 1996, 2003 and 2009. Under these directives, industrial markets were opened in 2004 with full market opening, including all residential customers scheduled for July 2007. However, in practice many European countries maintain some form of price regulation, at least for domestic and small commercial consumers. According to the EU commission, 14 of 23 Member States
with open household markets continue to regulate some tariffs through regulatory bodies (ECME 2010). This has limited effective retail competition from developing in several of these market segments; therefore, retail prices may be higher in the presence of retail price regulation.

4. Data

The dataset used in this study covers 20 European Union member states for the period of 1992-2009, and consists of data related to and representing the factors influencing electricity prices identified above. Initially, I intended to include all 27 member states; however, some countries had to be excluded due to problems with obtaining the necessary data. Romania and Bulgaria have been EU members since 2007, but they have not yet become members of the Organization for Economic Co-operation and Development (OECD) and the data from the International Energy Agency (IEA) was not available for those countries. Similarly, Cyprus, Malta, Latvia, Lithuania and Luxembourg had to be excluded because of unavailability of certain variables.

Table 1: EU member states included in the dataset

<table>
<thead>
<tr>
<th>Austria</th>
<th>Finland</th>
<th>Ireland</th>
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4.1. Dependent Variable Selection

The main interest of this study is the effect of feed-in tariffs on consumer prices for electricity. Therefore, the dependent variable for this analysis is average yearly retail prices for
electricity in €cents/ kWh, for household consumers with an annual consumption of 3,500 kWh, including all taxes and levies. The data are obtained from EUROSTAT (2012) for EU member states for the time period 1992-2009.

4.2. Main Policy Variables

The main independent variables of interest are the tariff amounts for feed-in tariffs in €cents/kWh in EU member states. I obtained data on tariff amounts for on-shore wind and solar PV from Groba, Indvik and Jenner (2011). Their dataset was constructed on the basis of the Energy Economics Group at Vienna University of Technology’s GreenX toolbox, supplemented with data from RES-Legal (2011), REN21 (2010) and the IEA Policies and Measures Database. The dataset reports the mean value of the PV tariff across all size, location and ownership categories, but fails to capture the complete extent of heterogeneity in FIT policies across countries. However, as the unit of analysis is the country level, this shortcoming has to be accepted.

In an attempt to cover a little more of the existing policy heterogeneity, I also multiplied the tariff amount by the number of years generators receive the FIT under a country’s respective policy regime and used the result as an alternative specification of the main policy variable. Data on contract duration was again obtained from Groba, Indvik and Jenner (2011). As the exact amount of electricity generation under the FIT is not constant over the years due to changes in weather conditions, this measure fails to capture the exact annual payments made under the program. Future payments were also not discounted to the present, thus failing to capture the time value of money at the point of investment due to the lack of knowledge on actual annual
income and ease of calculation. Nonetheless, introducing contract duration adds a critical dimension to the measure of overall payments provided by the respective policies.

4.3. Fossil Fuel Input Costs

In order to approximate the variable costs for generating electricity in the economy, I include the costs for generating electricity from fossil fuels. The most important (variable) cost factor of generating electricity, and thus of the electricity wholesale price, is the costs of the fossil fuel inputs into the generation process. To approximate these generation costs, I constructed a measure of fossil fuel input costs by multiplying the shares of electricity generation from coal, natural gas and petroleum with those inputs’ respective import prices, as most European countries import those fossil fuels. Both import prices and shares were obtained from the IEA’s Electricity Information Statistics database; the shares of electricity production by technology were aggregated from smaller sub-categories into the categories coal, gas and petroleum. As IEA did not report import prices for each of the 20 member states and/or all 16 years in the panel, some values had to be imputed based on strong assumptions about member states’ characteristics in terms of import costs. I recognize that these represent imperfect methods of imputation, which could potentially bias the error term, yet in the absence of alternatives this method had to be relied on.

4.3.1 Coal

As coal is traded in a global market, import prices depend mostly on the availability of shipping capacity as well as other transport costs, such as the cost of rail transportation between
the port of landing and destination. Countries with similar geographic characteristics can thus be assumed to also be relatively similar with respect to these import cost factors, and import prices for coal were imputed based on the prices for neighboring states with similar import characteristics.

For coal import prices, IEA did not report import prices for Portugal, Sweden, Austria, Poland, Czech Republic, Slovakia, Slovenia, Hungary and Estonia. Accordingly, Finish prices were imputed for Estonia; Spanish prices were used for Portugal; Danish prices were used for Sweden; German prices were used for Austria, Poland and Czech Republic; and the Average European Union price was used for Slovakia, Slovenia and Hungary. As coaking coal is mostly used in industrial processes rather than electricity generation, prices for steam coal were used for coal input costs, and prices were transformed from $/ton into €/ton based on average yearly exchange rates, also obtained from OECD.

**4.3.2 Petroleum**

A similar methodology to that used to impute import prices for coal was applied to import prices for petroleum in cases where data was not available. Finish prices were imputed for Estonia; Slovakian prices were used for Hungary; and the European Average was imputed for Slovenia.

Poland, Slovakia and the Czech Republic did not report petroleum import prices for all years included in the panel. In order to generate values for this variable for these countries, I calculated an average ‘spread’ multiplier between the existing observations and the European
average, and then multiplied the European average by this ‘transportation’ multiplier. This method assumes that the transport costs from the ports of entry to Europe and the destination are (relatively) constant; they are driven by geographic factors and do not change drastically over time. If import cost characteristics change over time, this may bias the error term. The spreads (multipliers) for Poland, Slovakia and the Czech Republic were 0.984, 0.973 and 0.967, respectively. I used prices for crude oil and transformed $/barrel (bbl) into €/barrel based on average yearly exchange rates, also obtained from OECD.

### 4.3.3 Natural Gas

Natural gas prices were not reported for Denmark, Estonia, Ireland, Poland, Portugal, Slovenia and the Slovak Republic. Natural gas used for electricity generation generally consists both of gasified natural gas imported by pipeline and liquefied natural gas (LNG). As LNG only accounted for significant portions of electricity generation in Belgium and France, I used pipeline import prices for all natural gas. All import prices for natural gas is given in €/ million British thermal units (MBTU).

Denmark and the Netherlands are the only net-exporters of natural gas in the EU. As data were readily available for the Netherlands, but not for Denmark, I assumed that the gas prices merely represent the extraction costs, and subsequently are similar across the two countries as neither country faces transport costs. If indeed the extraction costs for natural gas are markedly different in the two countries, this may bias the error term.
In the case of Poland, I imputed the European averages. This was largely driven by the assumption that Poland’s supply characteristics are largely similar to those of Germany, and German values were very close to the European average. One caveat to this methodology is that pipeline capacity—namely, the Northstream pipeline—bypasses Poland and goes straight from the Russian Federation to Germany. Based on similar reasoning, the European average was also employed for Slovenia and the Slovak Republic. For geographic reasons, I used Spanish prices for Portugal, UK prices for Ireland, and Finish prices for Estonia.

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Table 2: Natural Gas Import Spreads

Similar to the methodology for crude oil, missing values for Sweden, the UK, France, Finland, Greece, Germany, Austria, Czech Republic and Spain were calculated using the European average multiplied by the average difference for existing observations over this average. This is particularly problematic with respect to countries like Czech Republic, Austria and Hungary, which only reported values toward the end of the panel. Therefore, this methodology may not account for changes in factors that influence natural gas import prices, for example pipeline capacity, between the beginning and the end of the panel. Average spreads are reported in Table 2.

4.4. Additional Explanatory Variables

In order to complete the energy mix, the shares of electricity generated from hydro and nuclear power were also included. As the variable costs of these technologies are very low, those
shares were not multiplied by any input prices, although nuclear power relies on materials such as uranium or plutonium for nuclear fission. The shares of electricity generated from hydro and nuclear power were also obtained from the EIA electricity information statistics database.

I also included a capacity factor variable to capture the relative capital-intensity of electricity generation. The measure was constructed by dividing total “net electricity production” by “net electrical capacity.” Both measures were obtained from the IEA electricity information database. Because “net electrical capacity” was recorded in Megawatts (MWe), whereas “net electricity production” was recorded in Gigawatt Hours (GWh) per year, net electrical production was first divided by 8,760 to obtain MWe, and then divided by net capacity in order to obtain a variable that reports the average percentage utilization of a country’s generation capacity (Stoft 2002). The capacity factor is the only variable in the model that is really capturing the structural costs of generation. Of course, the capacity factor cannot fully capture the capital costs embedded in retail electricity prices. Nonetheless, it can capture some cross-country differences in relative capital intensity of electricity generation and some year-to-year changes in the variable costs that are related to non-structural changes in demand, for example those related to weather.

The extent to which utilities will be able to pass on any additional costs incurred due to feed-in tariff policies also depends on whether the end-user price is regulated by a government agency. I therefore include a binary indicator variable on whether end-user prices are regulated. This information has been obtained from the country profiles of the IEA 2011 Electricity
Information and a 2010 report by the Directorate General on Health and Consumers (ECME 2010).

In addition, I included a binary control variable for whether countries also (or exclusively) have enacted a requirement on utilities to generate a minimum share of the electricity they distribute to consumers from renewable sources. Data for this variable came from RE-financing (2011) and OPTRES (2007).

Initially, a measure for distribution losses was also included to control for some of the costs of transmitting and distributing electricity. However, this measure does not capture some elements of delivery costs related to how far generators are from primary demand centers and construction and maintenance of the transmission and distribution systems. In contrast to theory, when including this measure, the coefficients were extremely high and negative throughout all model specifications, indicating that it was picking up country specific effects that were omitted in the model. However, distribution losses should only be a relatively minor portion of total costs and likely not to vary year by year (Stoft 2002). Therefore, they were not included in the base model. Not including distribution losses did not alter the results on the other coefficients much, as the effects that were previously captured by the distribution loss variable were likely picked up by the country specific effect. There is also no apparent reason why distribution losses should be correlated with the amount of feed-in tariff.
5. Preliminary Findings

The data show several clear trends that provide insights into relationships between consumer prices for electricity and the policy variables outlined in the conceptual framework. Figure 3 illustrates that there is a clear upward trend in electricity prices across the EU for the panel period, rising from just under 12 cents/kWh in 1992 to 16 cents/kWh in 2009. This trend is matched by a similar upward trend in the average feed-in tariff amounts for both wind and solar PV across the sample, although the average tariff amount for wind starts decreasing slightly after 2007 (see Figure 4). Interestingly, the trend within the member states with the most successful FIT programs is less clear. For example, in Germany, tariff amounts for both wind and solar PV in particular have been decreasing throughout the sample. This decrease is particularly pronounced for the tariff for solar PV, which decreased from an outlandish 190 €cents/kWh in 1992 to a still considerable 41 €cents/kWh in 2009. The steady increase in average tariff amounts can be traced to additional member states introducing FIT regimes, rather than rising tariff amounts within successful FIT programs. Particularly between the years 2000 and 2004, many member states introduced new FIT policies.

\[\text{Table 5 in Appendix A reports the number of observations, mean values standard deviation as well as the minimum and maximum values for the variables included in the model.}\]
Figure 3: EU Average Consumer Price for Electricity

EU Average consumer Electricity Price

€cents/kWh

Figure 4: Feed-in Tariffs for wind and solar PV over time

Feed-in Tariff Solar PV - EU Average

Feed-in Tariff Solar PV - Major Member States

Feed-in Tariff Wind - EU Average

Feed-in Tariff Wind - Major Member States
These parallel trends between FIT payments and retail rates indicate an association between tariff amounts paid to RES-E generators under a FIT regime and higher retail prices. In order to further illuminate this relationship, Figure 5 provides a scatter graph of the feed-in tariff amounts for electricity generated from wind and solar PV against the consumer price for electricity. For both the tariff amounts on wind and solar PV, the scatter graphs reaffirm the upward association between the FIT and consumer electricity prices. This is consistent with the intuition of the conceptual framework; higher FITs are expected to drive up retail rates. However, for solar PV, the relationship is somewhat less obvious. It has to be noted that all observations with tariff amounts greater than 60 cents are from one country (Germany), and thus the somewhat downward trend at this end of the scatter graph may not be causal.

Figure 5: Scatter Consumer Price vs. Tariff Amounts
However, feed-in tariffs may not be the only factor driving retail electricity prices. Figure 6 shows that the upward trend in household electricity prices is also matched by a continuous increase in fossil fuel import prices. Although fossil fuel prices dropped sharply after 2008 due to reduced demand as a result of the 2008 financial crisis, the conceptual framework suggests that they are a major driver of retail rates and thus may be responsible for a large share of the upward trend of electricity prices over the sample period. The econometric part of this analysis explores the relationships between FITs and retail rates in more detail, while controlling for factors such as fossil fuel input costs.
6. Methods and Model Specification

To more rigorously investigate this study’s primary research question and test the stated null hypothesis, I estimate a linear dynamic panel-data model that includes a lag of the dependent variable as a covariate as well as unobserved panel-level fixed effects.
As described earlier, the electricity sector is characterized by extremely large up-front (fixed) capital costs, as well as variable costs of generating and supplying electricity. The fixed costs are generally much larger than the variable costs; however, they also differ greatly by country because they reflect the capital necessary to build and maintain generation facilities, transmission lines and distribution networks, which largely depend on a country’s weather-driven demand profile, geography and population density. For example, a small country with relatively moderate weather and high population density such as the Netherlands will have relatively low structural costs compared to large countries with extremely cold winters or extremely hot summers and low population density. These factors are unlikely to show much year-to-year variation. In order to capture some of these underlying capital costs that are omitted from the model due to the lack of data, all models I estimate control for individual country-level fixed effects (FE).

While there is a relatively clear indication of a country fixed effect that is omitted from the model, there is much less evidence that there are year-specific fixed effects that are consistent across countries but which are not captured by the variables I have constructed. Although there are certain yearly effects related to input fuel prices that are felt the same way across all countries, notably the costs for fossil-fuel inputs such as coal and petroleum (both traded on a global market and dependent on availability of shipping capacity in the global economy, despite some differences in delivery costs related to geographic location and transport infrastructure), most time effects related to electricity prices occur within individual countries. For example, the competitiveness of wholesale and retail markets for electricity differs vastly by country. However, as these effects are largely dependent on a country’s market structure and political
system, they are not fixed, but show some variation over time. These changes in the competitiveness of wholesale or retail markets do not happen at the same time across countries. The UK wholesale market saw multiple restructurings during the panel period 1992-2009, and, as a result, competitiveness increased considerably. Other markets have seen fewer changes in competitiveness, and such changes have been driven by domestic political events rather than external forces (Cooke 2011). This also holds true for changes in electricity retail markets. Even the costs for natural gas are largely dependent on structural factors within a country, such as pipeline and storage capacity, rather than year-specific effects. Although these factors do change over time, they change differently across countries. Therefore, controlling for year fixed effects would likely pick up some country-specific factors and bias the coefficient estimates of the policy and control variables.

Omitting within-country structural changes in the costs of generating and supplying electricity (or any variable that can capture it) is likely to introduce auto-correlation into the error term of the model, as countries that have low embedded capital costs in year \( t \) are very likely to also have low embedded capital costs in year \( t-1 \). Coefficients generated through ordinary least squares (OLS) estimation are therefore no longer best linear unbiased estimators (BLUE) in the presence of serial correlation, and the usual OLS standard errors and test statistics are no longer valid (Wooldridge 2009). Specifically, the variance estimator will usually be biased downward, decreasing the OLS estimates of the standard errors and thus increasing the \( t \) statistic, implying that the parameter estimates in the model are more significant than they actually are. Thus there will be a tendency to reject the null hypothesis when it should not be rejected. In addition, such models would be likely to over-estimate the year-effects as well as the effects of the policy and
control variables in both year t and t-1. F and LM statistics for testing multiple hypotheses are also invalid. However, goodness of fit of the model is not affected; the R-squared and adjusted R-squared of the models remains valid (Wooldridge 2009).

Accordingly, the Wooldridge test for first-order auto-correlation strongly rejected the null hypothesis of no first order auto-correlation when omitting the embedded capital costs.

To capture the country- and year-specific underlying capital costs, eliminate the serial correlation and also address the clear upward trend in the dependent variable, I estimated a linear dynamic panel-data model that included a lag of the dependent variable as a covariate as well as unobserved panel-level fixed effects. Bond (2002) emphasized that even when coefficients on lagged dependent variables are not of direct interest, allowing for dynamics in the underlying process may be “crucial for recovering consistent estimates of other parameters.” In my model, the previous year’s retail price is understood to capture the unobserved variation in the embedded capital costs due to the strong relationship between retail prices and capital costs. As underlying capital costs are likely to only change slowly over time, the prior year’s retail price offers a good approximation of the changes in embedded capital costs.

However, although such linear dynamic panel-data models address the previously omitted within-year structural changes in generation and distribution costs, the introduction of the lag of the dependent variable as a covariate again in a fixed effects model gives rise to more serial correlation, as the unobserved panel-level effects are by construction correlated with the lagged dependent variables, which makes the standard estimators inconsistent (Stata Corp. 2007). This can be seen in equation 1.
A dynamic panel model has the form:

\[ Y_{it} = \sum_{j=1}^{j-1} a_j y_{i,t-j} + x_{it} \beta_1 + v_i + \epsilon_{it} \]  

(1)

Where:

The \( a_j \) are parameters to be estimated,

\( x_{it} \) is a \( 1 \times k_1 \) vector of strictly exogenous covariates;

\( \beta_1 \) is a \( k_1 \times 1 \) vector of parameter to be estimated;

\( v_i \) are the panel-level effects (which may be correlated with the covariates); and

\( \epsilon_{it} \) are independently and identically distributed over the whole sample with variance \( \sigma_\epsilon^2 \).

The \( v_i \) and \( \epsilon_{it} \) are assumed to be independent for each \( i \) over all \( t \).

Following this framework, I subsequently estimated the following base model:

\[
RETAIL \, PRICE_{it} = \beta_1 RETAIL \, PRICE_{i,t-1} + \beta_2 FIT(\,wind\,)_{it} + \beta_3 FIT(\,solar\,)_{it} \\
+ \beta_4 Coal \, Input \, Cost_{it} + \beta_5 Natural \, Gas \, Input \, Cost_{it} \\
+ \beta_6 Petroleum \, Input \, Cost_{it} + \beta_7 Hydro_{share} + \beta_8 Nuclear_{share} \\
+ \beta_9 Capacity\,factor + \beta_{10} RPS + \beta_{11} Regulator + v_i + \epsilon_{it}
\]  

(2)

As the panel level effect \( v_i \) is the same across time periods, it is by construction correlated with the lagged dependent variable because the dependent variable in year \( t-1 \) is also affected by \( v_i \), making the standard estimators inconsistent.

In order to address this problem, I used the Arellano and Bond (1991) generalized method-of-moments (GMM) estimator, which was first proposed by Holtz-Eakin, Newey and Rosen (1988). This method uses estimators constructed by first differencing to remove the panel-
level effects and further lags of the dependent variable to create instruments of the lagged dependent variables and remove the autocorrelation. When the idiosyncratic errors $\varepsilon_{it}$ are independently and identically distributed (i.i.d.), the first differenced errors are first-order serially correlated in the Arellano-Bond specification.\(^5\) However, assuming that $\varepsilon_{it}$ serially uncorrelated, the predetermined initial conditions imply that the lagged level $y_{i,t-2}$ will be uncorrelated with $\Delta \varepsilon_{it}$ and thus available as an instrument for the first differenced equation (Bond 2008). Serial correlation at order 1 thus does not invalidate the moment conditions used by the Arellano-Bond estimator, because only lags of two time periods and further are used as instruments. Only serial correlation at an order higher than 1 makes the moment conditions invalid; the model is therefore only mis-specified in the presence of serial correlation at order 2 or higher (Stata Corp 2007).

All models were tested for second-order auto-correlation with the Arellano-Bond post-estimation test for zero autocorrelation. The test is applied to the differenced residuals, and the null hypothesis is that there is no autocorrelation. The test for autocorrelation at order 1 in the first differences rejects the null hypothesis of zero auto-correlation, as was expected. However, the test fails to reject the null hypothesis of zero auto-correlation at the second order, presenting no significant evidence of serial correlation in the first-differenced errors at order two or higher. The tests for auto-correlation thus present no evidence for model misspecification.

The Arellano-Bond method constructs the GMM estimator uses as many lags of $\Delta \varepsilon_{it}$ as are available in the panel. For long panels (panels with a large amount of time periods $t$) this

\(^5\) As $\Delta \varepsilon_{it} = \varepsilon_{it} - \varepsilon_{it-1}$ and $\Delta \varepsilon_{i,t-1} = \varepsilon_{i,t-1} - \varepsilon_{i,t-2}$, both terms contain $\varepsilon_{i,t-1}$. Therefore the test for AR(1) is expected to be failed, and the test for AR(2) is decisive.
potentially leads to over-identification. Over-identification in itself is generally desirable; however, there is potential danger of correlation between the over-identifying instruments and the residuals. Yet, the central assumption of the Arellano-Bond estimation is that the instruments as a group need to be exogenous. In order to avoid such correlation and thus maintain instrument exogeneity, the number of lags used as instruments may need to be restricted. This can be tested with the Sargan test, which tests whether the over-identifying restrictions are valid by testing whether the residuals are uncorrelated with the set of constructed instruments. If the instruments are truly exogenous, the null hypothesis of the Sargan test is that the instrumental variables are uncorrelated with the residuals and therefore are acceptable instruments. When using all available lags of the dependent variable as instruments, the model did not pass the Sargan test. As I wanted to use the highest possible number of lags to construct the instruments while still avoiding instrument endogeneity, I tested various specifications and found that the maximum number of lags of the dependent variable that could be used as instruments while passing the Sargan test was 10. Subsequently, lags from two time periods back to 11 time periods are used to create the GMM type instruments described by Arellano and Bond (1991), in order to ensure instrument exogeneity.

Apart from the lagged dependent variable, the first difference of all exogenous variables is used as standard instruments.

All models also soundly reject the null-hypothesis that all coefficients except the time trend (lagged DV) are zero, tested through the chi-squared test reported by Arellano and Bond,
and showing that the rest of the model has explanatory power that goes considerably beyond the time trend.

The results are displayed in Table 3 next to the results of standard FE regression. The results for the Arellano-Bond and OLS estimations are relatively closely matched, though the coefficient estimate for the feed-in tariff for solar PV is significant under OLS, but not under the Arellano-Bond estimate. This similarity can be explained by the fact that the Arellano-Bond estimator was designed for panels with many observations and only few time periods. However, the panel used in this analysis, although consisting of more n than t, was relatively evenly matched, covering 20 countries over 16 years. According to Rodman (2006), the correlation of the time trend with the error term will be less significant in panels with many time periods, as a shock to the country fixed effect that could affect the error term will decline over time.

7. Empirical Results

Table 3 Error! Reference source not found. displays the empirical results of several alternative specifications of the main regression outlined in Equation (2). The results indicate that supporting electricity generation from wind through feed-in tariffs raises electricity retail prices, whereas supporting RES-E generation from solar PV does not. Furthermore, the results show that feed-in tariffs for wind only raise electricity prices in the presence of retail price regulation. The empirical results related to the main policy variables of interest are discussed in more detail below, followed by a discussion of the fossil fuel inputs and the other control variables.
Table 3: Empirical Results

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Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1
7.1. Main Policy Variables

The results from model 1 show that an extra cent feed-in tariff for wind raises the retail electricity prices for residential consumers by approximately 0.06 cents. This corresponds to roughly 0.5 percent of the average retail price for electricity throughout the panel. Given that the mean FIT tariff for wind is 3.6 cents, this implies that the presence of a FIT that pays exactly the mean tariff amount results in an electricity price that is 0.22 cents per kWh higher than in the absence of the FIT, which is approximately 2 percent of the average retail rate. For countries with successful FIT programs, such as Germany, that paid an average tariff of approximately 8 cents over the period of the panel, this corresponds to an increase in electricity prices of 0.48 cents per kWh, which is approximately 3 percent of the average retail price in Germany. Figure 7 shows the development of retail electricity prices and feed-in tariff amounts in the countries that have been most successful at spurring RES-E capacity installation: Denmark, Germany and Spain. In the Danish case, the movement of the FIT closely matched those of consumer prices. In the Spanish case, both consumer prices and FITs peaked relatively simultaneously at the end of the panel. Only in the German case do prices seem to move independently of FITs.
The coefficient of FIT for wind is highly statistically significant throughout all models and sensitivity tests, and the magnitude of the coefficient remains relatively unchanged. This indicates that there are clear adverse price effects associated with supporting electricity generation from wind through feed-in tariff schemes, although they are relatively small in magnitude. The coefficient decreases considerably when using the total payment amount over
the contract duration, to approximately 0.04 percent of average retail prices in the panel. This effect is a little harder to interpret, mostly because of the artificial nature of the value of the payments over the contract duration. As the exact amount of electricity generation under the FIT is not constant over the years due to changes in weather conditions, this value is approximated by multiplying the FIT tariff amount by the number of years the producer is legally entitled to receive the tariff. Therefore, increasing this value by 1 unit (either by increasing the tariff or by extending the contract period) increases retail electricity prices by 0.005 cents per kWh.

Interestingly, the coefficient for the feed-in tariff on solar PV is negative throughout all model specifications. Although statistical significance decreases when estimating the Arellano-Bond estimator, the sign and magnitude of the effect remain relatively unchanged. Nonetheless, the magnitude of the coefficient is so small that it does not appear economically relevant. However, this may also result from the fact that, currently, a much smaller share of electricity is generated from solar PV, and many European countries have only put FIT policies in place relatively recently. The mean share of electricity generated from solar PV is only 0.03 percent. This result may change once countries develop greater solar generation capacity. Nonetheless, my estimations indicate that, to date, supporting electricity generation from solar PV has had no effect on electricity retail prices.

7.2. Other Policy Variables of Interest

The main policy variables of interest in this study are the feed-in tariff amounts for wind and solar PV. However, the variables for retail price regulation and the shares of hydro and
nuclear power also wield considerable explanatory power in explaining the price effects of FIT policies.

Higher shares of hydro and nuclear power in the electricity generation mix are associated with lower retail electricity prices. The coefficients for shares of electricity generated from both hydro and nuclear power were extremely large and negative across all models, with high to moderate levels of statistical significance. This is also expected, as both technologies are known to have extremely low marginal costs, but very high fixed (investment) cost. However, as most hydro and nuclear facilities in Europe are relatively seasoned and the fixed costs have mostly been paid, only the extremely low variable costs need to be covered, and electricity production from these sources is comparatively cheap.

Retail price regulation is also associated with lower retail electricity prices. The coefficient on end-user price regulation is statistically significant and negative throughout all models. If end user prices are regulated by a government agency, they are approximately 0.7 cents per kWh lower than if they are not regulated. This result is in contrast to the literature on retail price deregulation, which suggests that market liberalization should lower prices rather than increase them. However, in the absence of functioning retail markets, utilities may be able to charge higher prices and thus extract rents from consumers. This is particularly true if retail electricity prices have previously been subsidized. Therefore, retail price regulation might shield consumers from higher prices.

The regulator variable is also of particular importance to the FIT debate. Models 3 and 4 show that in countries with retail price regulation, the effect of the FIT is highly statistically
significant. In contrast, the effect of the FIT becomes insignificant for countries that do not regulate retail rates. This suggests that regulators, if retail rates are regulated, accommodate for the FIT by allowing utilities to charge higher prices. This result is particularly interesting in the light of recent developments in Spain, where the energy regulator CNE has failed to raise consumer prices appropriately for utilities to recover their costs. The Economist reports that the resulting annual “electricity-tariff deficit”—the differential between utility companies’ costs and revenue—has risen dramatically to €5.6 billion ($8.3 billion). As a result, FIT payments have been cut retrospectively to alleviate utilities’ burdens, although the likely main cause for the “deficit” is rising raw material prices. Nonetheless, if retail rates regulation works properly, utility companies should be able to pass on the costs that are incurred due to the FIT scheme.

7.3. **Fossil Fuel Input Costs**

Higher fossil fuel input costs are generally associated with higher retail prices for electricity. The coefficients for fossil fuel input costs (import price*share) were mostly positive, as expected. Coal input costs were insignificant in most models (although negative when using only price per ton). This is consistent with the theory of economic dispatch, as electricity generated from coal should never be the marginal plant under a system of economic dispatch, regardless of whether wholesale markets are liberalized or not. The input price for coal should thus not affect wholesale electricity prices and therefore only raise utilities’ costs if they own generation facilities or have long-term contracts with electricity producers. Even if this is the

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6 [http://www.economist.com/node/21524449](http://www.economist.com/node/21524449)
case, which is often, the fact that coal remains the cheapest fossil fuel in electricity generation makes the effects of an increase in coal import prices relatively negligible.

It is similarly surprising that the coefficient of petroleum input costs are negative under some specifications using the Arellano-Bond estimator, although very small and comprehensively insignificant. In contrast, when I employed crude oil import prices instead of share*price, coefficients were positive and highly statistically significant. The reason for this behavior can be found in petroleum’s nature as a peaking fuel; it is only used to generate electricity when demand is highest and its share of overall electricity generation is very small in most member states. The coefficient of petroleum share*cost may be small, but the price itself has a disproportionate effect on wholesale prices because its share as the marginal unit may be much greater than its share of overall generation.

The coefficient for natural gas input prices is positive, as would be expected, and highly statistically significant throughout all specifications. In a conceptual framework assuming economic dispatch, this is not surprising. Natural gas often represents the marginal plant and is therefore highly deterministic of wholesale electricity prices and, subsequently, also of retail rates. Nonetheless, it appears that, overall, the direct effects of increases in fossil fuel prices affect household electricity prices only to a limited degree. This indicates that utility companies are largely able to shield themselves (and thus consumers) from the effects of changes in fossil fuel prices; perhaps due to forward options and long-term contracts.
7.4. Other Control Variables

The base model included two other controls: (1) a variable for capacity factor and (2) a binary dummy variable for whether there was a minimum quota policy in place for renewable generation. In addition, the model included the lagged consumer price for electricity as well as fixed country-specific effects.

The coefficient for capacity factor is large, negative and relatively constant throughout all specifications, although not or only mildly statistically significant. This is consistent with intuition, as the more extreme the variations in a country’s electricity demand, for example the higher the differential between different seasons, the larger the difference is between average and peak demand. This requires large investment into facilities that are able to satisfy peak demand, but are idle for relatively long periods. Therefore, capacity factors are lower and the embedded costs for generating and supplying electricity are higher. In turn, the higher the capacity factor, the lower electricity prices should be.

Interestingly, the coefficient on the dummy for whether a minimum-quota for renewable electricity generation is in place is negative, although not statistically significant. This result needs to be regarded with care, given that only six countries have such quota obligations in place, and only three of the countries solely rely on quotas to support RES-E generation. The three countries are the UK, Sweden and Poland, which have among the lowest electricity prices in the sample. However, it appears that these coefficients are driven by structural factors within these countries, rather than by the enactment of quota regulations, which only happened once during the panel.
The lagged consumer electricity price is highly statistically significant in all specifications; an increase in electricity prices by 1€/kWh in t-1 increases electricity prices in t by 73 to 75 cents. This large positive effect is consistent with intuition, as the reason for including a lagged dependent variable was to capture the underlying capital costs of generating electricity for a given economy in a given year.

In terms of the fixed effects, the countries with the highest coefficients were France, Sweden and Belgium, followed at some distance by Germany. The French case is particularly interesting as it stands in stark contrast to the previous results, given France’s large nuclear fleet. The countries with the lowest fixed effects were Greece, Estonia and Ireland, followed by Portugal, the Netherlands and Poland. No immediate pattern is apparent; however, all of the lowest FE countries still regulate end-user electricity prices.

8. Discussion and Policy Implications

The empirical results of this study suggest that there is a distinct difference in the effect on prices of different FIT legislations depending on which type of renewable electricity generation is supported. In particular, the study shows that support for RES-E generation from wind in the past two decades in Europe has been associated with a mild increase in consumer prices for electricity, whereas support for RES-E generation from solar PV has not. However, given the large overall increase in retail electricity prices over the sample period and the substantial increase in electricity generation from wind in some of the leading countries, the effect of feed-in tariffs for wind is comparatively small.
The diverging findings for wind and solar PV can be explained by the actual timing of electricity generation from these sources. Wind notoriously blows at night, and often in areas that are far removed from population centers, whereas the sun typically shines during hot summer and cold winter days, when electricity is needed the most. This finding points to the existence of the so-called merit-order effect as described by Ragawitz, Sensfuß and Barbose (2008). This effect implies that electricity from renewable generation can replace electricity generated from fossil fuels and thus reduce electricity prices on the spot (wholesale) market. As RES-E generation from wind is mostly produced during off-peak periods at night, it only replaces electricity generated from base-load coal, hydro and nuclear plants. These plants have comparably low marginal costs, which means the positive effects from replacing them is relatively small, if these plants can even be shut down. In contrast, solar PV generates electricity during times when electricity demand is actually high, such as during clear, cold winter days and hot summer days. Therefore, RES-E generated from solar PV can replace more costly natural gas and petroleum plants.

However, the results for solar PV need to be treated with particular care. The total amount of electricity generated from solar PV is still extremely small; the mean is 0.03 percent of total generation, although in market leaders Germany and Spain it is over 0.17 percent. Table 4 shows the shares of electricity generated from wind and solar PV of key countries.
Table 4 shows that only a very small proportion of electricity generation is covered by the FIT for solar PV. In contrast, the mean for wind generation is considerably higher at approximately 1.4 percent, with leaders Denmark and Spain at 10.3 and 3.9 percent, respectively. At the end of the panel, these two countries had increased their share of electricity generation from wind to 19 and 12 percent of total electricity generation, respectively. With such larger shares of generation covered by the FIT, adverse price effects may be much more pronounced for wind than they are for solar PV. This finding is supported by consistently large negative coefficients when including the share of electricity generated from solar PV in my model.

The fact that the price increases associated with feed-in tariffs for wind as only statistically significant when retail prices are still regulated suggest that regulators accommodate for increased costs incurred by utilities by allowing them to charge higher retail rates. However, given that there is no significant effect of the FIT for wind if retail markets are liberalized (in fact, the coefficients throughout all models are negative), the empirical results indicate that efficiency gains from competition prevent retail rates to rise in the presence of FITs. This finding points toward a positive interaction between market liberalization at the retail level and RES-E support through FIT policies, which warrants some more focused exploration in the future.
This study also consistently found that both hydro and nuclear power are associated with lower retail electricity prices across all model estimations. This implies that the extremely low variable costs of such plants seem to outweigh their considerable up-front capital costs. However, this result should also be interpreted with care. These results could largely be driven by the fact that most nuclear and hydro plants are relatively old and thus have already paid off their enormous capital costs. This is particularly true for hydro plants, as most suitable locations on the continent have been exploited for a long time. The same largely holds true for nuclear, although nuclear power development continues in France, Finland and some of the new EU member states. Nonetheless, most European states have not added new nuclear plants in the last decade. Therefore, it remains questionable whether adding new nuclear and hydro plants, with their large capital investments, will decrease retail electricity rates in the short run. Even in the long-term, favorable cost calculations for these two technologies assume that the full costs of development are completely borne by utilities; however, this remains highly unlikely at least for nuclear, where the public sector routinely absorbs costs such as disaster insurance and the storage of radioactive waste.

The results for hydro and nuclear may also have other implications for supporting wind and solar PV through feed-in tariffs. With respect to their high up-front capital costs and the extremely low variable costs, electricity generation from wind and solar is very similar to hydro and nuclear. Seeing that larger shares of hydro and nuclear generation are associated with a large decrease in retail rates in the long term, the same may hold true for wind and solar, once the initial investments necessary to expand capacity to significant levels are paid off. In this context, feed-in tariff schemes could play an instrumental part in getting this capacity installed and
allowing for such low-cost generation in the future. The first FIT programs were not established until the early 1990s. Germany lead the way with the Stromeinspeisegesetz in 1991, and most other member states did not follow suit until the early 2000s. Since contracts generally last between 12 and 20 years, most countries have not even completed the first cycle of FIT contracts. Moreover, payments often decline over the contract period—if not nominally, then in real terms, as they are usually not adjusted for inflation. Therefore, it is unlikely that renewable capacity installed under any FIT regime has already recovered the initial capital investment. Nonetheless, the large expansion in capacity installed under successful FIT schemes could move electricity generation from wind and solar into a situation where consumers can benefit from the extremely low variable costs sooner than without subsidization. In addition, the favorable lending rates developers enjoy—at least in the case of established and successful programs—may spur development at lower costs than in the absence of the FIT program.

Lastly, this study finds that regulating end-user prices for electricity is also associated with lower prices across all models. This result is not consistent with the logic of de-regulation of retail markets. In liberalized retail markets with sufficient competition of suppliers for retail customers, the profit motive should result in internal (production) and external (market) efficiency, thus driving down prices rather than raising them. Experience from electricity market liberalization around the world has produced a degree of consensus over some generic measures for realizing these efficiency gains. First and foremost among these are sector restructuring and the introduction of competition in both wholesale generation and retail supply (Jamasb and Politt 2005, Newberry 2002).
However, with a few notable exceptions, such as the UK and the Nordic countries, liberalization of electricity markets in the EU has been centrally driven by the EU Commission rather than national governments. This may have resulted in some countries having removed price regulation due to pressures from Brussels without having sufficient competition in place, thus allowing utilities to exploit monopolistic or oligopolistic market structures to extract rents from consumers. In the absence of full cross-border market openings, smaller countries may also just not have enough suppliers to provide sufficient competition. In addition, some countries such as Germany have so far resisted proper market restructuring. In these conditions, it is less surprising that end-user price regulation is associated with lower overall retail prices. It is critical that policy makers not remove end-user price regulation until properly functioning liberalized retail and wholesale markets are in place, in order to protect customers. In liberalized retail markets, FIT schemes do not appear to raise end-user prices. At the same time, it appears that regulators across Europe allow utilities to recover additional costs incurred as part of the FIT schemes.

9. Conclusion

Overall, European feed-in tariff programs for electricity generated from wind and solar PV have had relatively little effect on retail consumer electricity prices. This stands in stark contrast to the success of well-established FIT programs in spurring installation of renewable electricity generation capacity, mostly through the drastic reduction of investment risk for developers.
The price increases associated with feed-in tariff policies (for wind) found by this analysis should not concern European policy makers too much. In light of the price-decreasing effects of the shares of hydro and nuclear power in a country’s energy mix, and both wind’s and solar PV’s extremely similar cost profile (i.e. large up-front capital costs and the negligible variable costs), substantial investment into these technologies could actually result in lower electricity prices in the long run. In particular, once the enormous up-front capital costs have been recovered (as is assumed has been the case for European hydro and nuclear installations) and—in the case of wind—the necessary transmission infrastructure has been built, the extremely low variable costs could allow wind and solar generators to replace more expensive natural gas and/or petroleum generation plants.

In addition, the introduction of the EU Emissions Trading Scheme (ETS) and other reform efforts aimed at reducing carbon emissions could soon result in an increase in the price for carbon and thus make fossil-fuel-based technologies more expensive, which in turn would make both solar and wind more competitive. This, of course, depends on whether European policy makers can muster the political will to actually reduce the supply of carbon permits by a meaningful amount for the third trading period, which is scheduled to start in 2013.
## Appendix A: Summary Statistics

Table 5: Descriptive Statistics

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Observations</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
<th>Min</th>
<th>Max</th>
</tr>
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<tbody>
<tr>
<td>Consumer Price including all taxes</td>
<td>€cents/kWh</td>
<td>311</td>
<td>12.812</td>
<td>4.457</td>
<td>3.225</td>
<td>27.100</td>
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<tr>
<td>Feed-in tariff amount onshore wind</td>
<td>€cents/kWh</td>
<td>360</td>
<td>3.439</td>
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<td>Feed-in tariff amount solar PV</td>
<td>€cents/kWh</td>
<td>360</td>
<td>17.562</td>
<td>28.347</td>
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<td>Coal input cost</td>
<td>€/ton*share</td>
<td>360</td>
<td>19.559</td>
<td>17.432</td>
<td>0.311</td>
<td>125.321</td>
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<tr>
<td>Petroleum input cost</td>
<td>€/bbl*share</td>
<td>360</td>
<td>1.776</td>
<td>2.376</td>
<td>0.077</td>
<td>14.668</td>
</tr>
<tr>
<td>Natural Gas input cost</td>
<td>€/BTU*share</td>
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<td>0.657</td>
<td>0.829</td>
<td>0.000</td>
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<td>Coal import price</td>
<td>€/ton</td>
<td>360</td>
<td>70.237</td>
<td>42.968</td>
<td>27.282</td>
<td>221.479</td>
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<td>Petroleum import price</td>
<td>€/bbl</td>
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<td>43.477</td>
<td>34.748</td>
<td>13.072</td>
<td>151.566</td>
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<td>Natural Gas import price</td>
<td>€/BTU</td>
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<td>3.615</td>
<td>1.674</td>
<td>1.520</td>
<td>8.574</td>
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<td>Share Coal</td>
<td></td>
<td>360</td>
<td>0.360</td>
<td>0.268</td>
<td>0.004</td>
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<td>Share Petroleum</td>
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<td>0.093</td>
<td>0.001</td>
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<td>Share Gas</td>
<td></td>
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<td>0.162</td>
<td>0.000</td>
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<td>Share hydro</td>
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<td>0.134</td>
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<td>Share nuclear</td>
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<td>0.392</td>
<td>0.000</td>
<td>1.000</td>
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