Price Exposure and Market Power:

Learning from Changes in Renewables Regulation*

Natalia Fabra and Imelda

Universidad Carlos III de Madrid

- PRELIMINARY WORK -

Abstract

We explore the impact of firms' price exposure on market power, taking into account two countervailing incentives. On the one hand, reducing price exposure mitigates firms' incentives to increase prices. On the other, it also mitigates their incentives to arbitrage, which would ultimately weaken market power. We test this trade-off using detailed bid data from the Spanish electricity market, where regulation switched back and forth from exposing renewables to fixed prices (Feed-in-Tariffs) or to market prices (Feed-in-Premiums). Overall, we find that reducing firms' price exposure through Feed-in-Tariffs contributed to weakening the dominant firms' market power, even though it reduced price arbitrage.

Keywords: market power, forward contracts, arbitrage, renewables.

*Emails: natalia.fabra@uc3m.es and iimelda@eco.uc3m.es. This Project has received funding from the European Research Council (ERC) under the European Union Horizon 2020 Research and Innovation Programe (Grant Agreement No 772331).

1 Introduction

In a wide variety of markets, the exercise of market power often gives rise to price discrimination.[1] For instance, in the pharmaceutical industry, drug manufacturers engage in spatial price discrimination by charging higher prices in wealthier countries (Dubois and Sæthre, 2018). Similarly, in electricity markets, generators engage in price discrimination by charging higher prices in the day-ahead market than in real-time markets (Ito and Reguant, 2016). Arbitrage across markets, e.g. parallel trade in the pharmaceutical industry (Dubois and Sæthre, 2018) or virtual bidding in electricity markets (Mercadal, 2015), increases the elasticity of the residual demand faced by the dominant producers, thereby reducing their incentives to increase prices. But, is arbitrage the most effective way to mitigate market power?

Regulators have often relied on more direct measures to address market power concerns. In the pharmaceutical industry, regulatory caps or strict rules for price setting are often relied upon as a way to mitigate market power. In electricity markets, virtual divestments and forward contract obligations have also served a similar purpose (de Frutos and Fabra, 2012). These measures have two countervailing effects. By reducing firms' price exposure, they weaken their incentives to exercise market power, as intended by regulators. However, reduced price exposure also mitigates firms' incentives to arbitrage price differences across markets, thereby removing competitive pressure from the dominant producers.

In this paper we build and test a model that captures this trade-off in the context of electricity markets. Several authors have documented the existence of systematic price differences across sequential markets (Longstaff and Wang, 2004; Borenstein et al., 2008), which can be explained - among other factors - by the exercise of market power. As shown by Ito and Reguant (2016), dominant producers have strong incentives to withhold output in the day-ahead market, knowing that they will be able to sell some of the withheld quantity in real-time markets. This induces fringe producers to arbitrage price differences across markets by overselling their output at a high day-ahead price to buy it back at lower real-time prices.

In this context, as also shown by Ito and Reguant (2016), reducing firms' price exposure would diminish the fringe firms' incentives to arbitrage. However, it would also weaken the dominant firms' incentives to exercise market power, an issue which is beyond the scope of Ito and Reguant (2016)'s analysis. Since the seminal work of Allaz and Vila

[1] There are many other examples, including airlines (Borenstein and Nancy, 2009; Gerardi and Shapiro, 2009), concerts (Couty and Pagliero, 2012), yellow pages (Busse, Knittel and Zettelmeye, 2013)...

(1993), it is well understood that reducing price exposure weakens firms' incentives to raise prices given that a fraction of their sales receives a fixed price regardless of the market price.[2]

This trade-off between arbitrage and market power incentives becomes particularly relevant for the design of renewables regulation. The costs of renewable investments have dropped dramatically, but the benefits to consumers will critically depend on the pricing scheme in place. Since renewables currently concentrate most, if not all of the investment efforts in electricity generation, it is paramount to understand the effects that the renewables regulation has on their owners' bidding incentives, and ultimately, on electricity prices.

There are two commonly used pricing schemes for renewables, which differ in the degree of price exposure faced by firms. Under Feed-in-Tariffs (FiTs), renewable output receives a fixed price that is set ex-ante, regardless of the realized market prices.[3] In contrast, under Feed-in-Premiums (FiPs), renewable output is paid according to market prices plus a fixed premium.[4] As a consequence, the price exposure of firms' portfolios is lower when renewables are paid according to FiTs as compared to FiPs.

Most of the comparisons of FiT versus FiPs focus on their distinct impact on investment incentives. For instance, Newbery et al. (2018) and May and Neuhoff (2017) favour the use of pricing schemes with limited price exposure as price volatility increases the costs of financing the new projects. Without minimising the importance of such issues, our analysis of FiTs versus FiPs focuses on their market power effects given existing capacities, an issue which has largely remained unexplored and which in any event has a key impact on investment incentives to the extent that it affects market revenues.[5]

[2]Several empirical analysis have confirmed the relevance of this effect in electricity markets (Wolak, 2000; Bushnell, Mansur and Saravia, 2008; Hortaçsu and Puller, 2008). This effect has also been confirmed in lab experiments (Le Coq and Orzen, 2006; Brandts, Pezanis-Christou and Schram, 2007).

[3]In some cases, these prices are set through auctions (Cantillon, 2014); in others, they are set directly by the regulator. To some extent, FiTs are similar to the so-called Contracts-for-Differences (CfDs), under which renewable producers sell their output at the market price and receive (or pay) the difference between a *reference market* price and a strike price that is set ex-ante. However, CfDs preserve firms' incentives to arbitrage given that the financial settlement is not computed as a function of the actual market revenues obtained by the plant.

[4]There are also FIP with sliding premiums. These are computed as the difference between a strike price and the market price, and are paid to the renewable owner only if such a difference is positive. Accordingly, firms still face incentives to exercise market power by increasing prices above the reference price. Hence, for the purposes of this paper, the same conclusions apply to FIP with fixed or sliding premiums as long as the market price is above the strike price. This is likely to occur precisely when market power concerns are the greatest.

[5]An exception is Dressler (2016), who also notes the analogy between forward contracts and FiTs.

Notably, the European Commission (2013) has favoured the use of FiPs as "they make sure that market signals reach the renewable energy operators through varying degrees of market exposure." Also, the European Commission stresses that FiPs "allow renewable energy to be sold on different market places which... puts pressure on renewable energy generators to become more active market participants". Hence, the Commission highlights the role of FiPs in promoting arbitrage through price exposure, but seems to disregard the role of FiTs in mitigating market power through reduced price exposure.

We develop a model that compares equilibrium outcomes in the day-ahead and spot markets when renewables are subject to FiTs or FiPs. Our analysis extends Ito and Reguant (2016) by explicitly modelling renewables under different pricing schemes. In line with their analysis, the dominant firms have an incentive to exercise market power by setting higher prices in the day-ahead market than in the spot market. The extent by which they do so depends on the pricing scheme in place. We show that FiTs imply a *forward contract effect* that reduces equilibrium prices in both markets. The price differential across markets is also reduced, the more so the more renewable production the dominant firms have. Under FiTs, even if arbitrage is allowed, fringe renewable producers do not have incentives to do so given that they receive a fixed price regardless of where they sell their output. In contrast, FiPs imply an *arbitrage effect* that induces the fringe firms to sell their idle capacity in the day-ahead market at a high price, to buy it back at a lower price in the spot market. Thus, while FiPs push the day-ahead market price down, they also push the spot market price up, which again results in a reduced price differential.

Our comparison of FiTs versus FiPs reveals that FiTs induce more efficient production than FiPs, as the spot market price - which determines the final output allocation - is closer to marginal cost under FiTs than under FiPs. However, the comparison of day-ahead market prices across pricing schemes can go in either direction, depending on the ownership structure of renewables. To understand why, note that the *forward contract effect* under FiTs is channeled through the dominant firm's renewable production, while the *arbitrage effect* under FiPs is channeled through the fringe firms' idle renewable capacity. Hence, if the structure of renewable ownership is highly concentrated in the hands of the dominant producers, FiTs tend to induce more competitive outcomes than FiPs, and viceversa.

The changes in the renewable regulation that took place in the Spanish electricity market between 2013 and 2014 provide a unique opportunity to test the link between firms' price exposure and market power. A first regulatory change took place in February 2013, when wind producers - which up to then had been subject to FiPs - were moved to FiTs just like the other renewables. A second regulatory change took place in June 2014, when all renewables were moved into FiPs.

Access to very detailed bid data of the day-ahead and spot markets allows us to conduct an empirical analysis of the effects of such regulatory changes and the underlying drivers.[6] Our empirical analysis is made of four pieces. First, we build a structural model of price setting incentives in the day-ahead market, confirming the relevance of the *forward contract effect*. Taking the slopes of the realized residual demands as given, we show that firms under FiTs internalized the effects of price increases through their sales net of their wind output. Instead, under FiPs, they internalized the price effects through their total output, including wind. Thus, all else equal, the *forward contract effect* induced by FiTs reduced firms' markups. However, the slopes of the residual demands are an endogenous object, since they depend on the fringe firms' incentives to oversell as well as on the dominant firms' incentives to withhold output, both of which are affected by the pricing scheme in place.

To analyze the effects of pricing schemes on equilibrium outcomes, we first conduct a differences-in-differences (DiD) analysis on the fringe firms' arbitrage. An appealing feature of our analysis is that we can exploit the two regulatory changes, from FiPs to FiTs and then back to FiPs. We rely on two control groups: (i) independent retailers, which faced the same arbitrage incentives as renewables before the first and after the second regulatory change; and (ii) renewables other than wind, which faced similar arbitrage incentives as wind after the first regulatory change. Regardless of which of these two control groups we choose, our analysis confirms the relevance of the *arbitrage effect*. In line with Ito and Reguant (2016), our DiD analysis shows that wind producers stopped arbitraging price differences after the switch from FiPs to FiTs, but they resumed arbitrage once they were moved back to FiPs.

Just as the regulatory changes affected the fringe firms' arbitrage incentives, they also had an impact on the dominant firms' incentive to withhold output in the day-ahead market to resell it in real-time markets. For this reason, we analyze the determinants of withholding across markets by the dominant producers. Consistently with our theoretical predictions, the empirical analysis shows that withholding went down when wind producers were switched into FiTs and it went up again when they were moved back into FiPs.

[6] Bohland and Schwenen (2019) is the only empirical paper we are aware of that explores the market power of impact of renewables' pricing schemes. Like us, they also use data of the Spanish electricity market but focus on the early period of renewables deployment when renewables represented a smaller fraction. They provide reduced form evidence showing that a move from FiTs to voluntary FiPs led to an increase of mark-ups, but they do not explore the mechanism underlying this result.

These three pieces of evidence (price-setting incentives in the day-ahead market, and overselling and withholding across markets) highlight the trade-off between the *forward contract* and the *arbitrage effects*. A natural question arises: in the context of our study, which of these two effects dominated? To shed light on this question, we conclude our empirical analysis by leveraging on the structural estimates of optimal bidding to compute markups in the day-ahead market. We find that mark-ups were significantly lower while FiTs were in place. The average mark-up during the FiT period was 6.3%, while it was 8.3% and 10.9% under the first and second FiP regimes. A similar conclusion applies when comparing the mark-ups of each dominant firm individually. In other words, given the highly concentrated market structure in the Spanish electricity market, the *forward contract effect* dominated over the *arbitrage effect*, leading to more competitive outcomes under FiTs than under FiPs.

The remainder of the paper is organized as follows. Section 2 describes the model of optimal bidding across sequential markets, when renewable producers are subject to FiTs or FiPs. Section 3 provides an overview of the institutional setting and data used in the analysis, and takes a first look at the raw evidence. Section 4 performs the empirical analysis through four angles: price-setting incentives in the day-ahead market, overselling and withholding across markets, and mark-ups in the day-ahead market. Section 5 concludes. Proofs and additional figures are postponed to the Appendix.

2 Model Description

In this section we develop a simple model of strategic bidding that tries to mimic some of the key ingredients of electricity markets. Our model extends Ito and Reguant (2016) by explicitly modelling renewables under alternative pricing schemes.

Electricity is traded in two sequential markets: a day-ahead market ($t = 1$) and a spot market ($t = 2$). Electricity is produced by two types of technologies (renewable and conventional) and two types of firms (dominant and fringe). The dominant firm, denoted d, owns both technologies, while fringe firms own either renewable or conventional assets. Renewables, which we generically refer to as *wind*, allow firms to produce at zero marginal costs up to their available capacities. We use $w_i \leq k_i$ to respectively denote firm i's available and maximum wind capacity, $i = d, f$. The dominant firm's conventional technology has constant marginal costs of production, $c > 0$, while the fringe faces linear marginal costs. To capture the fact that the costs of adjusting production tend to be higher close to real time, we parametrize the fringe firms' marginal costs as q/b_t, where $b_1 \leq b_2$.

Fringe firms are assumed to be price-takers. Accordingly, the conventional fringe producers produce whenever the market price exceeds their marginal cost. The renewable fringe producers have zero marginal costs but limited capacity. Hence, they have to decide where to sell their available capacity, either in the day-ahead market, q^w_{1f}, or in the spot market, q^w_{2f}, with two constraints: their final production cannot exceed their available capacity, $q^w_{1f} + q^w_{2f} \leq w_f$, and they are not allowed to bid above their maximum capacity, $q^w_{tf} \leq k_f$, for $t = 1, 2$. The incentives of the renewable fringe producers depend on the pricing scheme in place. We consider two commonly used pricing schemes:[7] under Feed-in-Tariffs (FiTs), renewable producers receive a fixed price for their output, regardless of where they sell it; under Feed-in-Premiums (FiPs), renewable producers receive the price of the market where they sell their output, plus a fixed premium.

The dominant firm sets prices in both markets, taking into account the production decisions of the fringe players. The residual demand faced by the dominant producer in the day-ahead market is given by $D_1(p_1) = A - b_1 p_1 - q^w_{1f}$. Total forecast demand is inelastically given by A, which is cleared in the day-ahead market, while $b_1 p_1$ and q^w_{1f} capture the supply of the fringe firms, either the conventional or the renewable producers, respectively.

The spot market allows firms to fine-tune the day-ahead positions, while total production remains fixed at A. The conventional fringe producers reduce (increase) their day-ahead commitments if the price differential across the two markets, $\Delta p \equiv p_1 - p_2$ is positive (negative),[8] while the renewable fringe producers reduce (increase) their day-ahead commitments if q^w_{2f} is negative (positive). In this way, the fringe producers add or remove demand from the spot market, which the dominant producer has to satisfy. The residual net demand faced by the dominant producer in the spot market can thus be expressed as $D_2(p_1, p_2) = b_2 \Delta p - q^w_{2f}$.

We characterize the subgame-perfect equilibria of the game under the two pricing schemes for renewables, either FiTs or FiPs. To make the analysis simpler, we assume that the model parameters are such that (i) the dominant firm is a net-seller in the spot market (i.e., $q_2 > 0$); and (ii) the dominant firm's wind availability is never enough to cover all its output (i.e., $q_1 + q_2 > w_d$). Point (i) assures that the dominant firm does not exercise monopsony power by reducing prices below marginal cost. Point (ii) assures that the marginal cost of the dominant firm is always given by c. A sufficient condition for this to be satisfied is that demand is high enough relative to total wind

[7] We focus on these two schemes since these are the ones used in the Spanish electricity market, which is the subject of our empirical investigation. (CfDs).

[8] Note that p_1 becomes their opportunity cost in the spot market.

output plus the conventional fringe's production at the dominant firm's marginal cost, $A > w_d + w_f + b_1 c$. Relaxing this assumption would force us to consider more cases, without altering the main insights of the analysis.

2.1 Benchmark Model

Before analyzing the equilibrium under FiTs and FiPs, we revisit Ito and Reguant (2016)'s first result, which will serve as our benchmark. In particular, we assume that all renewable output is paid at market prices while arbitrage across markets is not allowed, i.e., $q_{1f}^w = w_f$ and $q_{2f}^w = 0$ by construction. The residual demands faced by the dominant firm in the day-ahead market and in the spot market are thus given by

$$D_1(p_1) = A - b_1 p_1 - w_f \tag{1}$$

$$D_2(p_1, p_2) = b_2 \Delta p \tag{2}$$

We solve the game by backwards induction. In the spot market, once p_1 is chosen, the dominant firm sets p_2 so as to maximize its profits,

$$\max_{p_2} \left[p_2 q_2 - c \left(q_1 + q_2 - w_d \right) \right], \tag{3}$$

where $q_1 = D_1(p_1)$ and $q_2 = D_2(p_1, p_2)$, as characterized in (1) and (2) above.

In the day-ahead market, the profit maximization problem becomes

$$\max_{p_1} \left[p_1 q_1 + p_2 \left(p_1 \right) q_2 \left(p_1 \right) - c \left(q_1 + q_2 - w_d \right) \right] \tag{4}$$

where $q_1 = D_1(p_1)$, and $p_2(p_1)$ and $q_2(p_1)$ are given by the solution to the spot market problem (3).

Our first lemma characterizes the benchmark solution, which we denote with superscript B (for Benchmark).

Lemma 1 *If renewable producers receive market prices and arbitrage is not allowed, the day-ahead and spot market equilibrium prices are given by*

$$p_1^B = \beta \left[2 \left(A - w_f + b_1 c \right) - b_2 c \right] > \beta \left[A - w_f + \left(3b_1 - b_2 \right) c \right] = p_2^B > c,$$

where $\beta = (4b_1 - b_2)^{-1} > 0$. *This leads to a positive price differential* $\Delta p^B = \beta \left(A - w_f - b_1 c \right) > 0$. *Furthermore, comparing the final and the day-ahead positions, the dominant producer withholds*

$$q_2^B = \beta b_2 \left(A - w_f - b_1 c \right) > 0.$$

Proof. See the Appendix. ■

The dominant firm exercises market power in the day-ahead market by setting its price above marginal costs, $p_1^B > c$. When the spot market opens, its day-ahead position is already sunk. Hence, the firm has an incentive to lower the spot price below the day-ahead price in order to meet some of the unserved demand, $p_1^B > p_2^B > c$.

A larger and steeper residual demand enhances the dominant firm's market power. Accordingly, the two prices increase in A and b_2, but decrease in b_1 and w_f. The same comparative statics apply to the price differential as well as to withholding by the dominant firm. Since our focus will be on the incentives of renewable producers, note in particular that an increase in the fringe's renewable output w_f reduces the day-ahead residual demand. This induces the dominant firm to set a lower day-ahead price, thereby reducing the extent of unserved demand. In turn, this leads the dominant firm to also set a lower spot market price.

2.2 Feed-in-Tariffs

Suppose now that arbitrage is allowed and renewable producers are subject to FiTs, i.e., their output is paid at a fixed price, denoted $\overline{p}$. Hence, even if allowed, they do not have incentives to arbitrage and thus sell all their renewable output in the day-ahead market, $q_{1f}^w = w_f$ and $q_{2f}^w = 0$. This leaves the residual demands faced by the dominant firm as in equations (1) and (2).

In the absence of arbitrage, the problem faced by the dominant firm in the spot market remains as in (3). In contrast, its problem in the day-ahead market changes as its renewable output is now paid at $\overline{p}$ rather than p_1. In particular, this adds a fourth term to the day-ahead profit expression in (4),

$$\max_{p_1} \left[p_1 q_1 + p_2\left(p_1\right) q_2\left(p_1\right) - c\left(q_1 + q_2 - w_d\right) + w_d\left(\overline{p} - p_1\right)\right], \tag{5}$$

where $q_1 = D_1(p_1)$ and $p_2\left(p_1\right)$ and $q_2\left(p_1\right)$ are given by the solution to the spot market problem in (3).

Our second lemma characterizes the solution under FiTs, which we denote with the super-script T (for Tariffs).

Lemma 2 *If renewable producers are subject to FiTs and arbitrage is allowed, the day-ahead and spot market equilibrium prices are given by*

$$p_1^T = p_1^B - 2\beta w_d > p_2^B - \beta w_d = p_2^T > c,$$

where $\beta = (4b_1 - b_2)^{-1} > 0$. This leads to a positive price differential $\Delta p^T = \Delta p^B - \beta w_d > 0$. Furthermore, comparing the final and the day-ahead positions, the the dominant producer withholds

$$q_2^T = q_2^B - \beta b_2 w_d > 0.$$

Proof. See the Appendix. ■

Both prices as well as the price differential are lower than at the benchmark, as captured by the terms $-2\beta w_d$ and $-\beta w_d$ in the equilibrium price expressions. This reflects an important effect, which we refer to as the *forward contract effect*: exposing renewables to fixed prices reduces the dominant firm's market power. The dominant firm has weaker incentives to raise prices as this would not translate into higher payments for its renewable output.[9] In turn, this also implies that there is less withholding across markets than under the benchmark, as captured by the term $\beta b_2 w_d$. Just as under the benchmark, withholding is increasing in A and b_2, but it decreases in b_1, w_f and w_d.

2.3 Feed-in-Premiums

Suppose again that arbitrage is allowed but renewable producers are now subject to FiPs, i.e., their output is paid at market prices plus a fixed premium.[10] Unlike the previous case, the fringe renewable producers now have incentives to engage in arbitrage across markets. In particular, since the day-ahead market price is higher, they now find it optimal to sell k_f in the day-ahead market and buy whatever they cannot produce themselves, $k_f - w_f$, at a lower spot market price. This implies that, as compared to expressions (1) and (2), the dominant firm now faces a smaller day-ahead residual demand but a larger spot market demand. In particular,

$$D_1(p_1) = A - b_1 p_1 - k_f \tag{6}$$

$$D_2(p_1, p_2) = b_2 \Delta p + (k_f - w_f) \tag{7}$$

Other than this, the profit maximization problems are equivalent to those in the benchmark model, problems (4) and (3), with the residual demands now given by equations (6) and (7).

Our third lemma characterizes the solution under FiTs, which we denote with superscript P (for Premiums).

[9] Since the forward contract effect is channelled through the dominant firm's renewable output, the higher w_d the stronger is the reduction in both prices as well as in the price differential. An increase in the fringe firms' wind w_f also reduces both prices as well as the price differential, but this effect is just as in the benchmark.

[10] Since this is premium is fixed, it has no effect on equilibrium prices. We thus save on notation.

Lemma 3 *Assume* $(k_f - w_f) < (b_2/2b_1)\, w_d$. *If renewable producers are subject to FiPs and arbitrage is allowed, the day-ahead and spot market equilibrium prices are given by*

$$p_1^P = p_1^B - \beta\,(k_f - w_f) > p_2^B + \beta\frac{2b_1 - b_2}{b_2}\,(k_f - w_f) = p_2^P > c$$

leading to a positive price differential

$$\Delta p^P = \Delta p^B - 2\beta\,(k_f - w_f)\,\frac{b_1}{b_2} > 0.$$

Furthermore, comparing the final and the day-ahead positions, the fringe renewable producers oversell $(k_f - w_f)$ *while the dominant producer withholds*

$$q_2^P = q_2^B + \frac{2b_1 - b_2}{4b_1 - b_2}\,(k_f - w_f) > q_2^B,$$

where $\beta = (4b_1 - b_2)^{-1} > 0$, *and* p_1^B, p_2^B *and* q_2^B *are those in Lemma 1.*

Proof. See the Appendix. ■

As compared to the benchmark, allowing for arbitrage has two opposite effects: it weakens the dominant firm's market power in the day-ahead market, but it strengthens it in the spot market. Intuitively, in order to benefit from the positive price differential, the fringe renewable producers sell k_f in the day-ahead market, but then need to buy $(k_f - w_f)$ in the spot market. This reduces the residual demand in the day-ahead market, but increases the residual demand in the spot market. Since pricing incentives are directly linked to market size, the day-ahead price goes up while the spot price goes down. This effect, which we refer to as the *arbitrage effect*, is captured by the terms $-\beta\,(k_f - w_f)$ and $\beta\,(k_f - w_f)\,(2b_1/b_2 - 1)$ in the equilibrium price expressions.[11] Arbitrage reduces the price differential, as captured by the term $-2\beta\,(k_f - w_f)\,b_1/b_2$, but it does not fully close the price gap if the fringe's idle capacity is not large enough, as guaranteed by the lemma's assumption on $(k_f - w_f)$. Last, note that there is now more withholding by the dominant firm than under the benchmark. The reason is that the increase in spot market demand due to arbitrage is of first ordered as compared to the increase in the price.

Just as under the benchmark, withholding is increasing in A and b_2, but it decreases in b_1, w_f and w_d.

[11] Note that, in the case $b_1 = b_2$, the two expressions have the same magnitude but opposite sign. Otherwise, if $b_1 > b_2$, the increase in the spot price is greater than the reduction in the day-ahead price with respect to the benchmark.

2.4 Comparing FiTs versus FiPs

Having characterized the equilibria under FiTs and FiPs, we are now ready to compare equilibrium outcomes. We first assess whether FiTs or FiPs are more effective in mitigating market power in the day-ahead market. The answer is not straightforward given the countervailing effects identified above. On the one hand, for a given residual demand, the *forward contract effect* implies that the dominant firm has weaker incentives to raise prices under FiTs. On the other, the *arbitrage effect* implies that the residual demand faced by the dominant firm in the day-ahead market becomes more elastic as the demand response is enhanced by the fringe's arbitrage. Using the day-ahead equilibrium prices in Lemmas 2 and 3 and taking the difference,

$$p_1^T - p_1^P = \beta\left[(k_f - w_f) - 2w_d\right],$$

indeed shows that the comparison can go either way, depending on the renewables' ownership structure. The reason is that the *forward contract effect* under FiTs is channeled through the dominant firm's renewable output, while the *arbitrage effect* under FiPs is channelled through the fringe firms' renewable output. In the extreme case in which the dominant firm owns all the renewable capacity, $k_f - w_f = 0$ implying $p_1^T < p_1^P$. In the other extreme case in which the fringe firms own all the renewable capacity, $w_d = 0$ implying $p_1^T > p_1^P$. Away from these extremes, the higher (smaller) the share of renewables in the hands of the dominant firm, the more effective are FiTs (FiPs) in mitigating market power.[12]

In contrast to the previous comparison, the comparison of firms' behavior across markets is unambiguous. On the one hand, for reasons we have already discussed, there is more overselling by the fringe producers under FiPs than under FiTs. On the other, there is less overselling by the dominant firm under FiTs than under FiPs. Indeed, taking the difference,

$$q_2^T - q_2^P = -\beta\left[(k_f - w_f)(2b_1 - b_2) + b_2 w_d\right] < 0.$$

To understand why, it is illustrative to compare spot prices under FiTs versus FiPs,[13]

$$p_2^T - p_2^P = -\beta\left[(k_f - w_f)(2b_1/b_2 - 1) + w_d\right] < 0.$$

[12] We reach a similar conclusion when comparing the price differential under FiTs and FiPs, $\Delta p^T - \Delta p^P = \beta\left[2(k_f - w_f)\, b_1/b_2 - w_d\right]$. The price differential is smaller under FiTs when the ownership of renewables is very concentrated, but it is smaller under FiPs otherwise.

[13] Importantly this implies that productive efficiency is unambiguously higher under FiTs than under FiPs. The reason is that productive efficiency solely depends on the final commitment, i.e., on mark-ups in the spot market.

Intuitively, the *arbitrage effect* under FiP increases the spot price as the renewable producers undo their overselling by increasing their spot market demand. Instead, the *forward contract effect* under FiT translates into lower spot prices, following the weaker incentives of the dominant producer to raise the day-ahead price. From $p_2^T < p_2^P$, plus the fact that the spot demand faced by the dominant firm is smaller under FiTs than under FiPs, it immediately follows that $q_2^T < q_2^P$, i.e. the dominant firm withholds less across markets under FiTs than under FiPs.

2.5 Testable predictions

The above analysis provides some theoretical predictions which we will test in the empirical section of the paper. We group them in four blocks:

(*i*) **Price-setting incentives in the day-ahead market:** Under FiTs, the *forward contract effect* implies that, for a given residual demand, the mark-up of the dominant firm is decreasing in its own wind. Since this effect is not present under FiPs, the mark-up of the dominant firm should be independent of its own wind.

(*ii*) **Overselling by fringe firms across markets:** Under FiPs, the *arbitrage effect* implies that fringe producers oversell in the day-ahead market as compared to their final commitments. Their incentives to do so are greater the larger the price differential across markets. Since this effect is not present under FiTs, any differences between the fringe producers' day-ahead and final commitments should be orthogonal to the price differential.

(*iii*) **Withholding by dominant firms across markets:** All the factors that enhance the dominant producer's market power should enlarge the extent of withholding across markets (e.g., a larger demand and a steeper residual demand). Furthermore, the extent of withholding is expected to be larger under FiPs than under FiTs.

(*iv*) **Market power in the day-ahead market:** If the above predictions are satisfied, the interplay between the *forward contract* and the *arbitrage effects* imply that the comparison of market power under FiTs or FiPs could go either way, depending on market structure. Hence, the relative effects of pricing schemes on market power should be assessed empirically.

Before we take these predictions to the data, we move on to describing some of the institutional details of the Spanish electricity market.

3 Context and Data

In this section we describe the institutional setting, which is key for understanding the pricing incentives faced by the Spanish electricity producers, and we describe our data sources.

3.1 Market design and regulation

The Spanish electricity market is organized as a sequence of markets: the day-ahead market, seven intraday markets that operate close to real time, and several balancing mechanisms managed by the System Operator. In order to participate in these markets, plants must have offered their output in the day-ahead market first. Electricity producers and consumers can also enter into bilateral contracts whose quantities have to be communicated to the Market Operator, or auctioneer, on an hourly basis one day-ahead.

In our empirical analysis, we analyze bidding in the day-ahead market and arbitrage between the day-ahead market and the first intraday market (which we refer to as the spot market). Both markets concentrate the vast majority of all trades, contributing to approximately 80% of the final electricity price. The day-ahead market opens everyday at 10am to determine the exchange of electricity to be delivered each hour of the day after. It is organized through a uniform-price central auction mechanism. On the supply side, producers submit price-quantity offers specifying the minimum price at which they are willing to produce with each of their units. The demand side works as a mirror image. The auctioneer ranks the supply bids in increasing order and the demand bids in decreasing in order to construct the aggregate supply and demand curves, respectively. The market clears at the intersection of the two: the winning supply (demand) units are those that bid below (above) the market clearing price. All winning units receive (pay) such price.

The intraday markets work in a similar fashion as the day-ahead market, with the difference being that all units - regardless of whether they are supply or demand units - can enter both sides of the market in order to fine-tune their day-ahead commitments. For instance, if a supplier wants to sell less (more) than its day-ahead commitment, it can submit a demand (supply) bid in the intraday markets. The same applies to consumers.[14] Firms face a fine if their actual production deviates from their final commitment, which provides strong incentives to avoid imbalances.

In some cases, non-strategic reasons can give rise to differences between the day-ahead and the final commitments. For instance, a plant might suffer an outage after the

[14]See Ito and Reguant (2016) for a more detailed description of how the intraday markets work.

day-ahead market has closed, forcing it to buy back whatever it committed to produce. Similarly, a renewable producer might have to buy or sell additional output if its day-ahead wind or solar forecast turned out to be wrong.

However, in other cases, such differences might be explained by strategic considerations. In particular, if market agents expect a positive price difference between the day-ahead and intraday markets, they might want to engage in arbitrage: producers oversell in the day-ahead market at a high price and buy back their excess production in the intraday market at a lower price, while retailers delay their purchases to the intraday market as much as they can. However, the rules of the Spanish electricity market impose some constraints on arbitrage. In particular, supply (demand) bids have to be tied to a particular generation (consumption) unit, and the quantity offered (demanded) cannot exceed their maximum production (consumption) capacity. This implies that renewable plants (or big consumers and retailers) have relatively more flexibility to arbitrage than coal or gas plants. For instance, renewables can offer to produce at capacity in the day-ahead market even when they forecast that their actual available capacity will be lower. Likewise, retailers can commit to consume below or above their expected consumption knowing that they will have more opportunities to trade in the intraday markets.

Beyond differences in the ability to arbitrage, regulation also introduces differences in their incentives to do so, across technologies and market agents. Big customers and retailers face full price exposure, as they pay the market price and can keep any potential profits from arbitrage. Instead, the incentives of renewable producers to arbitrage depend on the pricing scheme they are subject to, which determines their price exposure. We next describe the pricing schemes of Spanish renewables, which are key for our identification strategy.

3.2 Pricing schemes for renewables

The pricing schemes for Spanish renewables have been subject to various regulatory changes.[15] In our empirical analysis we will exploit the occurrence of the two most recent regulatory changes affecting wind operators, which will allow us identify how pricing incentives changed over time and how this affected market outcomes.

Prior to February 2012, the existing regulation (Royal Decree 661/2007) gave all wind producers the choice between two pricing schemes: either a Feed-in-Premium (FiP) or a Feed-in-Tariff (FiT). Under the FiP option, wind producers had to sell their electricity directly into the wholesale market and would receive a premium payment on top. Under

[15] See del Rio (2008) for an overview of the changes up to 2007, and Mir-Artiguesa, Cerda and del Rio (2014) for the 2013 reform.

the FiT option, wind producers were obliged to bid their output at a zero price into the wholesale market and would receive a fixed price for it (RD 661/2007; article 31). Since expected payments under the FiP option were notably higher than under the FiT option, the vast majority of wind operators opted for the former. Hence when, on 2 February 2013 (Royal Decree Law 2/2013), the Government decided to abolish the FiP option "without any former notice",[16] all wind producers were *de facto* moved from FiPs to FiTs.

The FiT regime only lasted until June 2014, when the government published the details for computing a new remuneration for each type of renewable installation (Royal Decree 413/2014 published on June 6, and Ministerial Order IET 1045/2014 that came into force on June 21). In two earlier pieces of legislation (Royal Decree 9/2013 on July 14, 2013 and Law 26/2013 on December 27, 2013), the Government had already announced the main guidelines of the new regulation, but it did not actually implement it until June 2014. In general terms, the new scheme (which is still in place) moved all renewable generators to FiPs.[17] They have to sell their production into the Spanish electricity wholesale market, and receive the market price for such sales plus additional regulated payments.[18] The latter are based on technology and vintage specific standards, and are thus independent of the actual market revenues made by each firm. In particular, the old wind farms (i.e., those that were commissioned before 2005) do not receive any additional payment under the premise that they had previously received enough revenues to cover their investment costs.

3.3 Data

We use different sources of data on bids, costs, actual and forecast renewable production, and weather data. First, we use detailed bid data from the Iberian market operator (OMIE), which reports all the supply and demand functions submitted by all plants,

[16]The quotes are taken from 'Pain in Spain: New Retroactive Changes Hinder Renewable Energy', published in April 2013 at www.renewableenergyworld.com. Similar quotes can be found in other industry publications.

[17]There are significant differences between the FiPs that were in place until February 2013 and the new FiPs that were introduced in 2014. However, such differences refer mainly to the level of the support that firms receive on top of the market price, which is what matters for our empirical analysis.

[18]These include a remuneration per MW of installed capacity, meant to compensate those investment costs that cannot be reasonably recovered through the market, and a remuneration per MWh produced, meant to cover the costs of operating the plants. These two regulated payments are based, not on the actual investment costs or market revenues of the plant, but rather on those of a so-called *efficient and well-managed company* subject to technology-dependent standards.

every hour, in the day-ahead market as well as in the intraday markets. We can match the plants' bid codes with the plants' names to obtain information on their owners and types (e.g., if supply units, we know their technology and maximum capacity; if demand units, we know whether they are big customers with direct market access, retailers of last resort, or liberalized retailers). With these bid data, we can construct each firm's residual demand by subtracting the supply functions of all its competitors from the aggregate demand curve. We also observe the market-clearing price, the marginal unit that set it, and the units that submitted prices close to it.

Second, we have data on the cost characteristics of all the coal plants and Combined Cycle Gas Turbines (CCGTs), including their efficiency rates (i.e., how much fuel they burn per unit of electricity) and their emission rates (i.e. how much carbon they emit per unit of electricity). Together with Bloomberg daily data on coal prices (API2), gas prices (TTF), and CO2 prices (ETS), we compute engineering based estimates of each thermal plant's marginal cost, on a daily basis.[19] While these are reliable sources of cost data,[20] we cannot rule out measurement errors. For instance, the price of coal and gas in international markets need not reflect the correct opportunity cost firms face when burning their fossil fuels. This might be due to transaction costs, transportation costs, or contractual constraints on firms' ability to resell the gas they buy on long term contracts. Indeed, large disparities between the load factors of various CCGTs in the market suggest that one of the dominant firms might have had access to cheaper gas, well below the price of gas in the international exchanges.[21]

Third, we use publicly available data provided by the System Operator (REE) on the hourly production of all the plants in the Spanish electricity market, including the

[19]A 7% tax was levied at the start of 2013 on all electricity producers, including both conventional and renewable renewables. We take this into account when computing marginal costs in our empirical analysis.

[20]The cost parameters were provided to us by the Spanish System Operator (REE). We previously used them in Fabra and Toro (2005) and Fabra and Reguant (2014), and we have recently updated them to include the new capacity additions. The efficiency and emission rates are in line with standard measures for each technology, but incorporate finer heterogeneity across plants, e.g., reflecting their vintage, or, for the coal plants, incorporating the exact type of coal they burn which affects both their efficiency as well as their emission rate.

[21]For instance, as reported by REE, in 2014 Gas Natural's CCGTs had the highest load factors (22% on average, as compared to 4% of all the other CGGTs). Notably, this was true also for twin CCGTs (i.e. at the same location and same vintage, owned by different companies). For instance, Besos 4 owned by Gas Natural operated at a 65% load factor, while Besos 3 owned by Endesa operated at an 8% load factor. The same was true for San Roque 1 (owned by Gas Natural, 59% load factor) and 2 (owned by Endesa, 12% load factor).

fraction that they sold through the market or through bilateral contracts.[22] These data allows us to compute, on an hourly basis, the market shares of the various technologies (including renewables) and firms. Since we observe the supply and demand allocated to the vertically integrated firms, we can compute their hourly net positions, i.e., their production net of their bilateral contracts and vertical commitments.[23] Furthermore, by computing each plants' day-ahead and final commitments, we can assess whether firms engaged in arbitrage across the sequential markets. The System Operator also provides detailed information on the hourly demand and wind forecasts one day-ahead, right before the market opens.

Last, we also use publicly available weather data (including temperature, humidity, wind speed, and precipitation) provided by the Spanish Meteorological Agency (AEMET).

In order to encompass the two main regulatory changes affecting renewables in the Spanish electricity market, the time frame of our empirical study runs from February 2012 until February 2015. During this period, there were no major capacity additions or other relevant changes in the market structure. There were three main vertically-integrated firms, which we refer to as the *dominant firms*: Iberdrola (firm 1), Endesa (firm 2), and Gas Natural (firm 3). They all owned various technologies, with differences in the weight of each technology in their portfolios. Notably, Iberdrola was the largest wind producer, while Gas Natural was the main owner of CCGTs. There was also a fringe of conventional producers, renewable producers, and independent retailers. The market structure in the renewable segment was more fragmented than in the conventional segment. The market shares for the dominant firms and the fringe were (60%, 40%) in the renewable segment and (80%, 20%) in the conventional segment. Annual renewable production ranged from 42% to 45% of total generation, and the rest came from nuclear (19%), hydro (10% to 18%), coal (13% to 15%) and CCGTs (3% to 9%).

Table 1 reports the summary statistics. There were a total of 26,534 hourly observations, split into 8,765 observations for the first period with FiPs (1 February 2012 to 31 January 2012), 11,590 observations for the period with FiTs (1 February 2013 to 20 June 2014) and 6,179 observations for the second period with FiPs (16 June 2014 to 28 February 2015). The day-ahead price ranged between 40 to 50 Euro/MWh, being lower on average but also more volatile during the FiT period. The spot market price was

[22] One drawback of these data is that it does not include information on the units located in Portugal. However, as these plants were not affected by the regulatory changes implemented by the Spanish Government, we exclude them from the analysis.

[23] We do not include the vertical commitments due to regulated sales since these are simply pass through market prices to the final consumers.

consistently lower than the day-ahead price. The average price differential across the two markets ranged between 0.5 and 1.1 Euro/MWh, being lower during the FiP II period. Demand and wind forecasts were similar on average across all three periods.

Table 1: Summary Statistics

	FiP I		FiT		FiP II	
	Mean	SD	Mean	SD	Mean	SD
Price DA	47.2	13.8	39.6	20.9	50.3	13.9
Price ID 1	46.3	14.0	38.5	20.8	49.8	14.4
Price premium	0.9	5.0	1.1	5.7	0.5	4.1
Marginal Cost	49.1	6.4	46.6	7.2	40.1	4.1
Demand Forecast	28.7	5.0	27.9	4.7	28.5	4.8
Wind Forecast	5.8	3.3	6.3	3.4	5.5	3.5
Dominant wind share	0.6	0.0	0.7	0.0	0.6	0.0
Fringe wind share	0.4	0.0	0.3	0.0	0.4	0.0
Dominant non-wind share	0.8	0.0	0.8	0.1	0.8	0.1
Fringe non-wind share	0.2	0.0	0.2	0.1	0.2	0.1

Notes: Sample from February 2012 to February 2015. FiP I is from 1 February 2012 to 1 February 2013; FiT 2013 is from 2 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 1 February 2015, for three three dominant firms. Prices are in Euro/MWh. Demand and wind forecasts are in GWh.

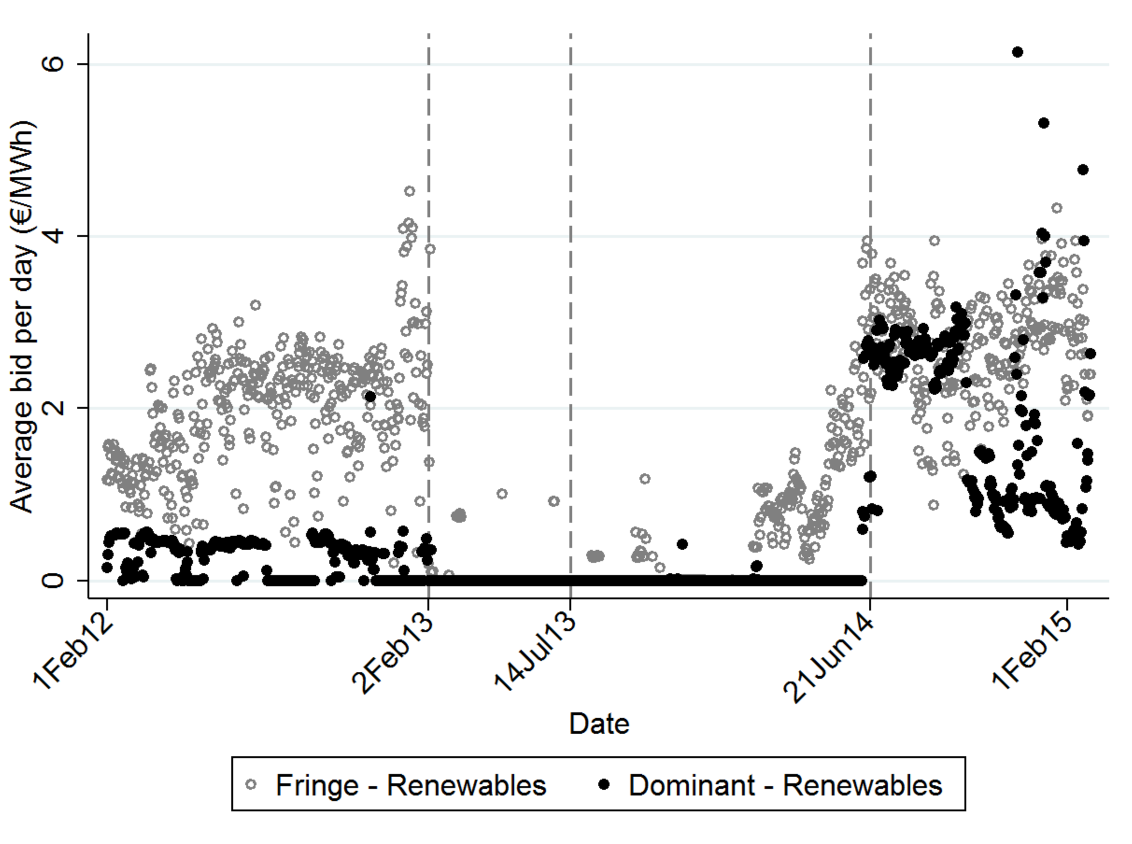
3.4 A first look at the data

Since we will be analyzing how regulatory changes to renewables' pricing schemes affected market performance, it is illustrative to provide a first look at the raw data showing the impacts on bidding and on arbitrage across markets.

Figure 1 plots the average bids submitted per day by the renewable plants belonging to the dominant firms and the fringe producers, during the sample period. As can be seen, the average bids were all positive during both FiP periods, in stark contrast with the bids during the FiT period, when they all went down to zero.

This should not come as a surprise given that the FiT rules required renewable plants to be at zero. Nevertheless, it is informative of the time when firms realized that the FiT period was *de facto* over. While the date of the first regulatory change is clear-cut, the date of the second one is not as the end of the FiT system was announced in July 14, 2013 but it was not actually implemented until June 16, 2014. As it can be inferred from the Figure, the dominant firms waited until that same date to start bidding positive prices, while the fringe producers did so four months before. However, the evidence also shows that the fringe firms did not engage in arbitrage until late June 2014, as shown in Figure 2.

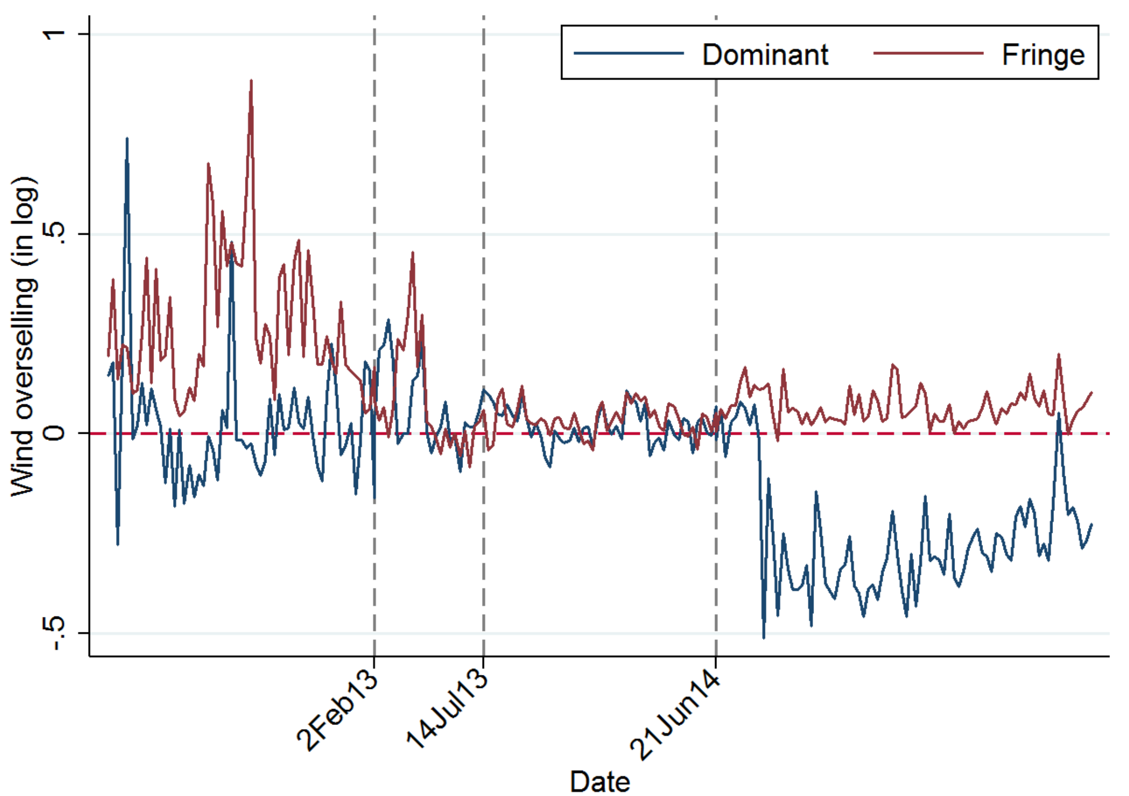
Figure 1: Bids of renewable producers in the day-ahead market



Notes: Sample from February 2012 to February 2015. The y-axis is the average hourly price offered, on a daily basis, by the renewable plants.

Figure 2 illustrates the impacts of the regulatory changes on output allocations across sequential markets. In particular, it plots the difference between the day-ahead and the final commitments for wind plants belonging to the fringe and to the dominant firms (positive numbers reflect overselling while negative numbers reflect withholding in the day-ahead market). As it can be seen, during the first and second FiP periods, the fringe producers oversell their wind output, while the dominant firms withhold it. In line with Ito and Reguant (2016)'s analysis, this is consistent with the dominant firms' exercise of market power and the fringe firms' attempt to arbitrage price differences across markets. However, both of these patterns disappear when FiTs come into play. Indeed, one cannot reject the null hypothesis of no structural breaks (in both time series, at the 1% level), at the date of the first regulatory change (February 1, 2013) as well as the second (June 16, 2014). As discussed above, this reflects the fringe's lack of incentives to engage in arbitrage when they receive a fixed price. However, why are the dominant firms no longer withholding their wind output? If they were willing to withhold wind output under FiPs when doing so had an opportunity cost (i.e., losing the price differential), why would they no longer do it under FiTs when wind farms faced no price loss from moving some of their sales to the intraday markets?[24] Clearly, one cannot assess this question without an equilibrium analysis: overselling and withholding are endogenous objects that depend on the dominant firms' incentives to exercise market power, which are also affected by the pricing schemes. To dig deeper into these issues, we now turn to the empirical analysis.

Figure 2: Overselling and withholding across markets by wind producers



Notes: This figure plots the weekly average of the day-ahead commitment minus the final commitments of wind producers belonging to both the dominant and the fringe firms. Positive numbers reflect overselling, while negative numbers reflect withholding. The vertical lines date the changes in the pricing schemes for renewables. The sample ranges from February 2012 to February 2015.

[24]Furthermore, as shown in Figure 5 in the Appendix, the dominant firms are not compensating this with an increase in their withholding of non-wind plants, which remains fairly constant on average during the sample period.

4 Empirical Analysis

In this section we perform an empirical analysis of the impacts of renewables pricing schemes on market power. To disentangle the drivers, we decompose the analysis in four steps. First, we perform a structural analysis of the determinants of the dominant firms' price-setting incentives in the day-ahead market. Second, we use a differences-in-differences approach to assess the effects of pricing schemes on the fringe's incentives to engage in arbitrage across markets. Third, we analyze the determinants of withholding by the dominant firms, including the impact of changes in the pricing schemes. Last, we leverage on our structural estimates to construct estimates of market power under the two price schemes.

4.1 Price-setting incentives in the day-ahead market

We use a structural approach to assess whether the changes in the renewables' pricing schemes affected the price setting incentives of the dominant producers in the day-ahead market.

Building on our theoretical analysis, and in line with standard oligopoly models, the first order condition of profit maximization can be written as

$$p = c_i + \left| \frac{\partial DR_i}{\partial p} \right|^{-1} (q_i - I_t w_i) \tag{8}$$

where $I_t = 1$ under FiTs and $I_t = 0$ under FiPs. In words, the market price p equals the marginal cost c_i of the price-setting firm, plus a markup component which captures the firm's ability to exercise market power. The markup is decreasing in the slope of the residual demand faced by the firm, DR_i, and it is increasing in the firm's output that is exposed to market prices. Under FiPs, this includes the firm's total sales, net of its vertical and forward contract commitments, i.e., q_i. Under FiTs, it only includes its non-wind net sales, i.e., $q_i - w_i$.

The above first-order condition is valid for the price-setting unit, but also for those units with an ex-ante positive probability of setting the market price. Accordingly, in our analysis we include all the units with bids around the market-clearing price (within a 5 Euro/MWh range),[25] belonging to one of the dominant firms.[26] We exclude (i) hydro units (since it is difficult to assess the true opportunity costs of using their stored

[25]Results are robust to narrowing down this range. In the Appendix we report the results using a 1 Euro/MWh range.

[26]If a dominant firm owns more than one unit with these characteristics, we include them all in the analysis.

water), as well as (ii) units that operate on either the first or last step in their bidding functions (since their constraints for reducing or increasing their output might be binding, invalidating the use of the above first-order condition).[27]

Our detailed bid data allows us to construct all the variables in the first order condition (8), as described in Section 3. Notably, since we observe all bids, we can build the realized residual demand curve faced by each firm and compute its slope at the market-clearing price. We fit a quadratic function to the residual demand curve and obtain a local slope at the market-clearing price.[28]

Pricing schemes might affect the slope of the residual demand through several channels, as they affect equilibrium bidding in the day-ahead market as well as arbitrage by the fringe and/or withholding by the dominant firms across markets. However, since we can control for the slopes of firms' residual demands, our focus is on whether the dominant firms internalize the changes in their wind output when setting prices, and whether this depends on the pricing scheme in place, as predicted by our theory model.

For this purpose, we estimate the following empirical equation in those hours in which firm i is bidding at or close to the market-clearing price:

$$b_{ijt} = \alpha_{ij} + \rho c_{ijt} + \beta \left| \frac{q_{it}}{DR'_{it}} \right| + \theta \left| \frac{w_{it}}{DR'_{it}} \right| I_t^s + \gamma_t + \epsilon_{ijt}, \tag{9}$$

where b_{ijt} is the marginal bid of firm i when bidding at or close to the market-clearing price with unit j at time t; c_{ijt} is the marginal cost of the price-setting unit j belonging to firm i at time t; q_{it} is firm i's total sales net of its vertical and forward commitments at time t; DR'_{it} is the slope of firm i's residual demand at time t at the market-clearing price; w_{it} is firm i's wind output at time t; I_t^s is an indicator variable that takes the value 1 when the pricing scheme at time t is $s =$ FIP I, FIT, FIP II and 0 otherwise;[29] γ_t are time fixed effects, and ϵ_{ijt} is the error term.

Since we want to understand whether firms' markups are affected by their wind output, our parameter of interest is θ. We expect it to take a negative value under FiTs, but we expect it to be not significantly different from zero under FiPs. This would reflect that firms do not internalize the price effects on their wind output under FiTs, in contrast to FiTs.

[27] We follow a similar approach as Fabra and Reguant (2014) and Reguant (2014).

[28] Approximating the slope of residual demand is straightforward and common in the existing literature, see also Wolak (2003) and Ito and Reguant (2016).

[29] We define the FiP I, FiT, and FiP II indicator variables using the February 2, 2013 and June 21, 2014 cutoffs, respectively, which is when the regulatory changes were fully implemented and when firms reacted to those changes, as described in Section 3.4.

We include unit and quarterly fixed-effects, while month, day-of-the-week, and hour fixed effects are added in a cumulative fashion. We force the intercept to be zero to satisfy our structural equation (i.e., when the marginal cost and mark-up terms equal zero, we expect the price to be zero as well). The standard errors are clustered at the plant level to allow errors to be correlated within plant.[30]

When estimating equation (9), it is important to realize that marginal costs are likely to be endogenous. Indeed, the identity of the marginal unit, and thus its marginal cost, is potentially affected by supply and demand shocks, some of which might be unobservable. Indeed, the marginal of the marginal unit is highly negatively correlated with wind: the more wind there is, the smaller is the residual demand that has to be satisfied with the remaining non-wind units, and thus the lower is the marginal cost of the price setting unit. Similarly, the slope of the residual demand at the market clearing price might be endogenous, thus making the markup terms endogenous as well.

To address these concerns, we instrument the marginal cost of the marginal unit and the slope of the day-ahead residual demand with wind speed and precipitation as residual demand shifters, and commodity prices (carbon, gas and coal) as the key components of marginal costs.[31] We then use 2SLS to estimate equation (9).

The results are shown in Table 5. In columns (1)-(3), we constrain the coefficient on the firm's markup over its total output to be equal to one. Column (1) confirms that wind output has a significant price-depressing effect under FiTs, but it has a zero effect during any of the two FiPs regimes, consistently with our predictions. The coefficient for marginal cost is positive and significant, also as expected. Moreover, these coefficients are stable across the different specifications, reassuring robustness regardless of the set of fixed effects we use. In column (4), we allow the coefficient for the firm's total output markup to vary. The estimated coefficient for the FiTs indicator variable is still similar, although smaller relative to the other specifications. The sign of the coefficient for the firm's total output markup is positive as expected, as more output and a steeper residual demand enhance market power.

[30] We also provide robustness checks to show that results are still consistent regardless of the level of the cluster.

[31] These variables are all likely to be exogenous. This is clearly so for the first two, wind speed and precipitation. Commodity prices are set in international markets, thus independently of what happens in the Spanish electricity market.

Table 2: Forward Contract Effects

	2SLS			
	(1)	(2)	(3)	(4)
Marginal Cost$_{it}$	1.86***	2.01***	2.05***	1.43***
	(0.33)	(0.42)	(0.44)	(0.27)
FiP I $\times \frac{w_{it}}{DR'_{it}}$	-10.4	0.84	-1.36	9.18
	(6.50)	(5.63)	(5.65)	(6.70)
FiT $\times \frac{w_{it}}{DR'_{it}}$	-38.0***	-37.7***	-37.8***	-26.1***
	(9.20)	(12.2)	(12.5)	(8.03)
FiP II $\times \frac{w_{it}}{DR'_{it}}$	-8.96	2.94	0.00049	16.2
	(6.12)	(10.9)	(10.7)	(10.7)
$\frac{q_{it}}{DR'_{it}}$				6.42***
				(0.76)
Month and DoW FE	N	Y	Y	Y
Hour FE	N	N	Y	Y
Observations	21,530	21,530	21,530	21,530

Notes: This table shows the estimation results of equation (9). We constrain the β coefficient to be one in columns (1)-(3), and allow it to vary in column (4). We use bids within a 5 Euro/MWh range around the market price. The pricing scheme dummies – FiP I, FiT, FiP II – are indicators for days during 1 February 2012 - 1 February 2013, 2 February 2013 - 21 June 2014, and 22 June 2014 - 28 February 2015. We instrument the markup components and marginal cost with wind speed, precipitation, and their interactions with pricing scheme dummies, carbon, gas and coal prices. All regressions include unit and quarterly dummies, while month, day-of-the-week, and hour fixed effects are added in a cumulative fashion in columns (2) to (4). The standard errors are clustered at the plant level.

4.2 Arbitrage across markets

Since day-ahead prices were systematically higher than prices in subsequent markets, fringe producers had an incentive to engage in arbitrage by overselling in the day-ahead market at high prices and buying back their excess supply at low prices in the intraday markets. However, differences between the day-ahead and the final commitments could also be explained by non-strategic reasons, such as wind forecast errors. What distinguishes arbitrage from such non-strategic reasons is that the former are linked to price differences across markets, whereas the latter are not. Accordingly, in order to understand whether pricing rules affected firms' incentives to engage in arbitrage, we examine whether the response of overselling to the price differential differed under the FiP and FiT regimes.[32]

One approach would be to regress the differences between the day-ahead and the final output commitments on the price differential, interacted with a dummy variable for each pricing regime. However, one potential concern of this approach is that other unobservable time-variant factors might be also influencing arbitrage through the price differential. Not properly accounting for these factors might result in an omitted variable bias. To address this concern, we compare the price response of wind producers' with that of two potential control groups: (i) non-wind renewable producers (i.e., solar, small hydro and cogeneration units), and (ii) retailers in the liberalized market. On the one hand, the non-wind renewable producers were subject to FiTs until the second regulatory change, when they were also moved into FiPs just like wind. Hence, their incentives to engage in arbitrage should be similar to those of wind during the FiT and the FiP II regimes, but should differ during FiP I. On the other hand, retailers should always have incentives to engage in arbitrage, just like wind under the FiP regimes, and unlike wind during the FiT regime.

We want to understand how the fringe firms reacted to changes in the price differential across markets that they could forecast at the time of bidding. To avoid potential endogeneity between arbitrage and the price premium, we first construct a forecasted price premium using two exogenous variables: demand and wind forecasts. Specifically, we regress demand and wind forecasts, hourly dummies and date dummies on the price premium.[33] We then use the regression coefficients to obtain the forecasted price premium at time t, $\hat{p}_t$.

In order to show the similarities and differences between the price response of wind producers, non-wind renewable producers, and retailers, we first document the response of each group's arbitrage to the predicted price premium on a quarterly basis. We regress the forecasted price premium, $\hat{p}_t$, on the log of the difference between the day-ahead and the final commitments of firms in group g (wind producers, non-wind renewable producers and retailers), $\Delta \ln q_{tg}$. We control for demand and wind forecast errors, denoted D_t^{er} and w_t^{er}, as these could give rise to differences between day-ahead and final com-

[32]Our results are consistent with Ito and Reguant (2016), who show that after the first regulatory change, from FiPs to FiTs, fringe producers stopped arbitraging. We further show that the second regulatory change, from FiTs to FiPs, had the opposite effect. Unlike their analysis, we rely on a differences-in-differences approach using two possible control groups.

[33]The estimating equation is $p_t = \alpha D_t^{fc} + \beta w_t^{fc} + X_t + Y_t + \epsilon_t$, where the two first regressors are the demand and wind forecasts. We allow errors to be correlated within day.

mitments which are unrelated to arbitrage. We also control for seasonality (i.e., through dummies for days-of-the-week and week of sample dummies), for daily solar radiation, daily precipitation and temperature. The estimating equation is

$$\Delta \ln q_{tg} = \alpha + \theta_g \hat{p}_t + \gamma D_t^{er} + \delta w_t^{er} + \rho \mathbf{X}_t + \eta_{tg} \tag{10}$$

where η_{tg} is the error term. We cluster standard errors at the week of sample. Our coefficient of interest is θ_g, which captures the response of arbitrage by group g to the predicted price differential.

Figures 3 and 4 plot the θ_g coefficients for each quarter. As expected, the price response of arbitrage by the non-wind renewable producers is very similar to that of the wind producers during the FiT regime (Q1 2013 to Q2 2014). On the other hand, the price response of the retailers' arbitrage is very similar to that of the wind producers during the FiP regimes (2012 and Q3 2014 onwards).[34] Equipped by this graphical evidence, we proceed to analyze the overselling behavior of wind fringe using the difference-in-difference (DiD) approach.

To measure the impact of renewables pricing schemes on arbitrage, we split the sample in two, each of which contains one regulatory change. The first sample ($d = 1$), which ranges from February 1, 2012 to February 1, 2014, contains the change from FiPs to FiTs that took place on February 2, 2013. The second sample ($d = 2$), which ranges from February 1, 2013 to February 28, 2015, contains the change from FiTs to FiPs that took place on June 21, 2014.

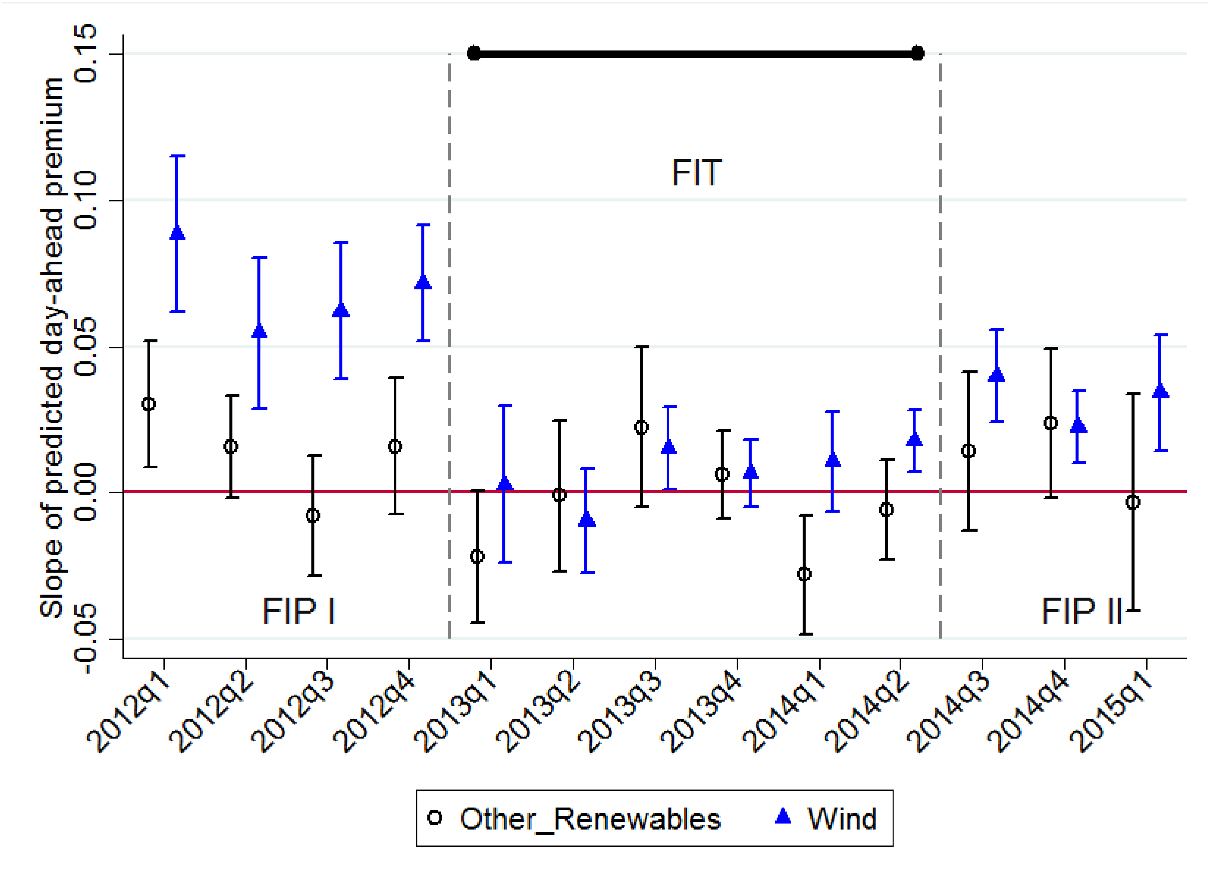
Following a DiD approach, we run four separate OLS regressions, one for each sample $d = 1, 2$ and each control group g= non-wind renewables, retailers. The estimating equation is as follows,

$$\begin{aligned}\Delta \ln q_t = & \alpha + \beta_1 W R_t^d \hat{p}_t + \beta_2 W \hat{p}_t + \beta_3 W R_t^d + \beta_4 R_t^d \hat{p}_{ht} + \beta_5 \hat{p}_t + \\ & \beta_6 W + \beta_7 R_t^d + \rho \mathbf{X}_t + \eta_t\end{aligned} \tag{11}$$

As discussed earlier, we use the forecasted price premium to measure the price response of arbitrage. For sample $d = 1$, which contains the switch from FiPs to FiTs, R_t^1 is an indicator for FiTs. Similarly, for sample $d = 2$, which contains the switch from to FiTs to FiPs, R_t^2 is an indicator for FiPs. For both samples, W is an indicator for the treated group, i.e., wind producers. We include a set of control variables such as the hourly demand forecast error, the hourly wind forecast error, week of sample fixed effects and days-of-week fixed effects. Standard errors are clustered at the week of sample.

[34] We expect to see some noise for some periods as the sample for each coefficient is only three months.

Figure 3: Arbitrage behaviour of wind vs non-wind renewables



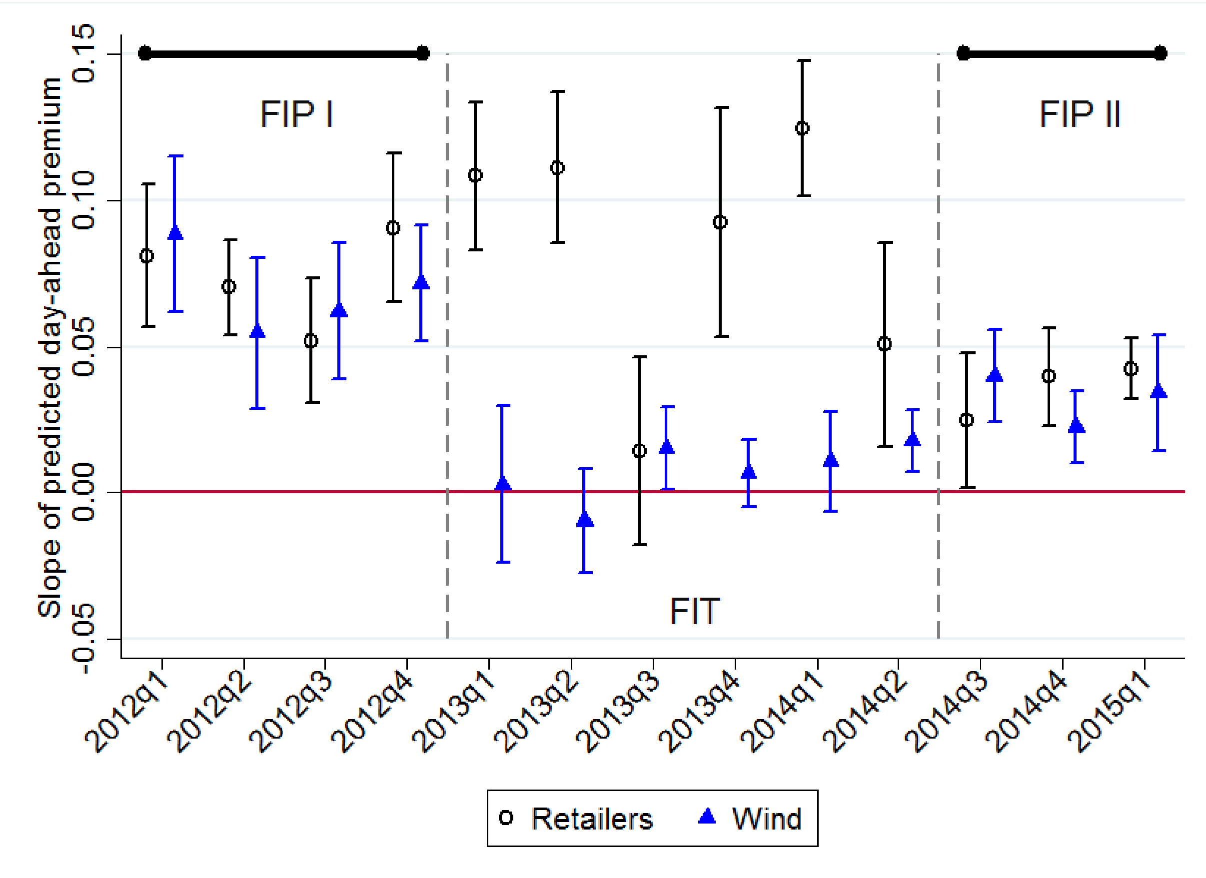
Notes: This figure plots the coefficients of the OLS regression in equation (10) for wind and other non-wind renewable producers (i.e., solar, small hydro and co-generation production units).

Our coefficient of interest, β_1, captures the change in the price response of arbitrage by wind producers relative to the control group. We expect the sign of this coefficient to be negative under sample 1, as the switch from FiPs to FiTs should reduce the wind producers' incentives to engage in arbitrage. On the contrary, we expect the coefficient for β_1 to be positive under sample 2, as the switch from FiTs to FiPs should induce wind producers to engage in arbitrage again.

We report the β_1 coefficients in Table 3.[35] The impact of the switch from FiPs to FiTs is shown in columns (1) and (3), depending on whether we use non-wind renewables or retailers as the control group, respectively. In both cases, the negative coefficients show

[35]The complete results with the DiD coefficients are reported in the Appendix Table 6 (using other renewables as the control group) and Table 7 (using retailers as the control group). In column (1) in each table, we also show how the parallel trend assumptions required in a DiD setting are satisfied. The other coefficients for the price premium are broadly consistent with the existing evidence by Ito and Reguant (2016).

Figure 4: Arbitrage behaviour of wind vs retailers



Notes: This figure plots the coefficients of the OLS regression in equation (10) for wind producers and independent retailers.

that the move from FiPs to FiTs reduced arbitrage relative to both control groups, and by a similar magnitude. In contrast, the impact of the switch from FiTs to FiPs, which is shown in columns (2) and (4), was positive, thus indicating that the move from FiTs to FiPs brought wind producers back to arbitrage. Note that the move from FiTs to FiPs II affected all renewables, but this change seems to have enhance the wind producers' incentives to arbitrage more, as compared to the non-wind renewables. Indeed, in column (2), we see that the switch had a positive effect on wind arbitrage, which is smaller than that on column (4). Overall, these results are all consistent with our predictions.

4.3 Market power in the day-ahead market

Our previous results show that, given the observed residual demands, firms had weaker incentives to increase day-ahead prices under FiTs than under FiPs. However, this alone does not allow us to conclude that FiTs mitigated market power in the day-ahead

Table 3: The Impact of Changes in the Pricing Schemes on Overselling by Wind

	Non-wind renewables		Retailers	
	(1)	(2)	(3)	(4)
$\hat{p}\times$ Wind $\times$ FiT	-0.08***		-0.07***	
	(0.007)		(0.02)	
$\hat{p}\times$ Wind $\times$ FiP		0.03***		0.06***
		(0.006)		(0.01)
Observations	Renewables	Renewables	Retailers	Retailers
N	34,478	32,780	34,478	32,780

Notes: This table shows the β_1 coefficients from equation (11). Each column is a different regression with the log of overselling as the dependent variable. Non-wind renewables is the control group in columns (1)-(2), retailers in columns (3)-(4). Columns (1) and (3) use sample $d = 1$ from 1 February 2012 to 1 February 2014, with the FiT indicator equal to one for days after 1 February 2013. Columns (2) and (4) use sample $d = 1$ from 1 February 2013 to 28 February 2015, with the FiP equal to one for days after 21 June 2014. All regressions include hour of day fixed effects and week fixed effects. The standard errors are clustered at the week of sample.

market. As our previous results also show, the pricing schemes also affected these residual demands through the impacts on overselling and withholding across markets. Therefore, to evaluate the overall impact of the pricing schemes on market power, in this section we compute and compare firms' markups across pricing regimes.

Using the first-order condition of profit-maximization, equation (8), mark-ups can be expressed as

$$\frac{p - c_i}{p} = \left|\frac{\partial DR_i}{\partial p}\right|^{-1} \frac{q_i - I_t w_i}{p}$$

for $I_t = 1$ under FiTs and $I_t = 0$ under FiPs.

Leveraging on the structural estimates obtained in Section 4.1, Table 4 reports firms' markups.[36] Markups are always lower under FiT as compared to FiP periods: the average

[36]An alternative approach to computing mark-ups is simply to rely on the observed prices and on engineering estimates for marginal costs. This approach is common in the literature. For example, Borenstein, Bushnell and Wolak (2002), Fabra and Toro (2005), or Fabra and Reguant (2014), among others. However, this approach leads to noisier markups due to potential measurement error in the marginal cost estimates. For instance, we see some negative markups which could be explained by firms buying coal and gas through long-term contracts at prices below the spot market price. Nonetheless, our overall conclusion - namely, that mark-ups were lower under the FiT regime, similarly holds under this approach (results available upon request).

mark-up during FiT was 6.3%, while it was 8.3% and 10.9% under FiP I and FiP II, respectively. A similar conclusion applies when comparing the mark-ups of each dominant firm individually. A two-sample Kolmogorov–Smirnov test rejects at 1% significance level the hypothesis that the mark-up distributions are the same across pricing regimes. This is also consistent with the slopes of the residual demands being larger under FiTs relative to FiPs, thus indicating that the weaker incentives to exercise market power under FiTs induced firms to submit flatter supply functions. This effect was stronger than the absence of significant arbitrage.

Table 4: Average Markups on Day-ahead Market

	FiP I		FiT		FiP II	
	Mean (%)	SD	Mean (%)	SD	Mean (%)	SD
Markups (in euros/MWh)						
All	8.3	3.3	6.3	3.3	10.9	3.7
Firm 1	7.0	2.2	7.0	2.6	11.9	4.4
Firm 2	12.3	4.1	8.2	5.1	14.4	4.6
Firm 3	7.7	2.3	6.0	3.3	10.5	3.4
Slope of day-ahead residual demand (in MWh/euros)						
All	524.2	78.2	553.6	120.7	422.9	74.5
Firm 1	506.6	50.5	458.4	72.7	412.1	62.7
Firm 2	508.5	71.8	556.4	165.0	466.3	100.9
Firm 3	538.2	88.7	573.3	117.2	422.7	74.2

Notes: Sample from February 2012 to February 2015, includes the mark-ups for those units bidding within a 5 Euro/MWh range around the market price, for hours with prices above 25 Euro/MWh. FiP I is from 1 February 2012 to 1 February 2013; FiT is from 2 February 2013 to 20 June 2014; FiP II is from 21 June 2014 to February 2015, for the three dominant firms except for EDP (which is under FiT for all periods in the sample).

5 Conclusions

In this paper we have explored the impact of firms' price exposure on market power, taking into account two countervailing incentives. On the one hand, as first pointed out by Allaz and Vila (1993), reducing price exposure reduces firms' incentives to increase prices. On the other hand, if firms are insulated from price changes they face weaker incentives to arbitrage price differences, which would ultimately mitigate the incentives of the dominant producers to exercise market power through price discrimination.

We have used the electricity sector as a lab to explore this trade-off. First, the availability of very detailed data makes this exercise feasible. Second, the current debate about renewables regulation makes this analysis particularly relevant. In particular, the choice between Feed-in-Tariffs and Feed-in-Premiums is equivalent to choosing whether producers should be partially or totally exposed to spot price volatility.

Our empirical analysis confirms, in line with Ito and Reguant (2016), that dominant producers attempt to exercise market power by withholding output in the day-ahead market at the expense of depressing prices in the real time market. Under FiPs, independent wind producers make this strategy more costly, as they oversell their idle capacity in the day-ahead market to arbitrage price differences. Facing renewables with FiTs reduces arbitrage, but mitigates the dominant producers incentives to withhold output in the first place. In the context of the Spanish electricity market, the latter effect dominated, giving rise to lower markups under FiTs than when FiPs were in place.

This results shed light on the current debate in electricity markets, but more broadly, they uncover the mechanisms giving rise or avoiding price discrimination as a tool for market power.

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Appendix

Appendix A: Proofs

Proof of Lemma 1 (Benchmark model):. We solve the profit maximization problems in (3) and (4). We do so by backward induction, with $D_1(p_1) = A - b_1 p_1 - w_f$ and $D_2(p_1, p_2) = b_2 \Delta p$.

For given p_1, the spot market solution is given by

$$p_2 = \frac{p_1 + c}{2}, \text{ implying } q_2 = b_1 \frac{p_1 - c}{2}. \tag{12}$$

Using this, for $\beta = (4b_1 - b_2)^{-1}$, the day-ahead market solution is

$$p_1^B = \beta \left[2 \left(A + b_1 c - w_f \right) - b_2 c \right], \text{ implying } q_1^B = \beta \left(2b_1 - b_2 \right) \left(A - w_f - b_1 c \right).$$

Plugging this back into the spot market solution gives

$$p_2^B = \beta \left[A - w_f + \left(3b_1 - b_2 \right) c \right], \text{ implying } q_2^B = \beta b_2 \left(A - w_f - b_1 c \right)$$

Taking the difference between the two prices,

$$\Delta p^B \equiv p_1^B - p_2^B = \beta \left(A - w_f - b_1 c \right).$$

Since we have assumed that parameters are such that the dominant firm is a net-seller in the spot market, $q_2^B > 0$, we have that $A - w_f - b_1 c > 0$. This implies $\Delta p^B > 0$. Also, $p_2^B > \beta \left(4b_1 - b_2 \right) c = c$ so that $p_1^B > c$. Note that the solution is the same as Ito and Reguant (2016)'s Result 1, with $(A - w_f)$ here in the place of A there.

Last, using the above expressions, we obtain

$$q_2^B = \beta b_2 \left(A - w_f - b_1 c \right).$$

■

Proof of Lemma 2 (FiTs):. We now solve the profit maximization problems in (3) and (5), with $D_1(p_1) = A - b_1 p_1 - w_f$ and $D_2(p_1, p_2) = b_2 \Delta p$.

The spot market solution is still given by (12) as the spot-market problem remains as before. The day-ahead market solution is

$$p_1^T = \beta \left[2 \left(A - w_d - w_f \right) + \left(2b_1 - b_2 \right) c \right] = p_1^B - 2\beta w_d$$

implying

$$q_1^T = \beta \left[\left(2b_1 - b_2 \right) \left(A - w_f - c b_1 \right) + 2 b_1 w_d \right]$$

where $\beta = (4b_1 - b_2)^{-1} > 0$.

Plugging this back into the spot market solution gives

$$p_2^T = \beta \left[A - w_d - w_f + (3b_1 - b_2)\, c\right] = p_2^B - \beta w_d$$

implying

$$q_2^T = \beta b_2 \left(A - w_d - w_f - b_1 c\right) = q_2^B - \beta b_2 w_d$$

Interestingly, note that $q_1^T - q_2^T = \beta b w_d$, in contrast to $q_1^B - q_2^B = 0$. This is another reflection of the forward contract effect.

Taking the difference between the two prices,

$$\Delta p^T = \beta \left(A - w_f - w_d - b_1 c\right) = \Delta p^B - \beta w_d > 0.$$

Since we have assumed that $A > w_d + w_f + b_1 c$, it follows that the dominant firm is a net-seller in the spot market, $q_2^T > 0$. This also implies $\Delta p^T > 0$, and using the above condition on A, $p_2^B > c$ so that $p_1^B > c$. Last, using the above expressions, we obtain

$$q_2^T = \beta b_2 \left(A - w_f - w_d - b_1 c\right) = q_2^B - \beta b_2 w_d < q_2^B,$$

which is increasing in A and b_2, and decreasing in w_f, w_d and b_1. ∎

Proof of Lemma 3 (FiPs):. We now solve the profit maximization problems in (4) and (3), with $D_1(p_1) = A - bp_1 - k_f$ and $D_2(p_1, p_2) = b\Delta p + (k_f - w_f)$. The spot market solution is now given by

$$p_2 = \frac{p_1 + c}{2} + \frac{k_f - w_f}{2b}, \text{ implying } q_2 = b\frac{p_1 - c}{2} + \frac{k_f - w_f}{2}.$$

The day-ahead market solution is

$$p_1^P = \beta \left[2A + c\,(2b_1 - b_2) - k_f - w_f\right] = p_1^B - \beta\,(k_f - w_f)\,,$$

implying

$$q_1^P = \beta \left[(2b_1 - b_2)\,(A - w_f - b_1 c) - (3b_1 - b_2)\,(k_f - w_f)\right].$$

Plugging this back into the spot market solution gives

$$\begin{aligned}
p_2^P &= \beta \left(A + (3b_1 - b_2)\, c - \frac{k_f + w_f}{2}\right) + \frac{1}{2b_2}\,(k_f - w_f) = p_2^B + \beta\,(k_f - w_f) \\
q_2^P &= \beta b_2 \left(A - b_1 c - \frac{k_f + w_f}{2}\right) + \frac{1}{2}\,(k_f - w_f)
\end{aligned}$$

Taking the difference between the two prices,

$$\Delta p^P = \beta \left(A - b_1 c - \frac{k_f + w_f}{2}\right) - \frac{k_f - w_f}{2b_2} = \Delta p^B - 2\beta\,(k_f - w_f)$$

For this solution not to fully close the price gap, we require $\Delta p^P > 0$, which holds true for $A > (2b_1/b_2)(k_f - w_f) + w_f + b_1 c$. Since through the analysis we have assumed $A > w_d + w_f + b_1 c$, a sufficient condition for $\Delta p^P > 0$ is that $w_d + w_f + b_1 c > (2b_1/b_2)(k_f - w_f) + w_f + b_1 c$, i.e., $(k_f - w_f) < (b_2/2b_1) w_d$. In turn $\Delta p^P > 0$, implies $q_2^P > 0$ and, using the above condition on A,

$$p_2^P > \frac{k_f - w_f}{b_1} + c > c$$

So that $p_1^B > p_2^B > c$. Last, using the above expressions, we obtain

$$\begin{aligned} q_2^P &= \beta b_2 \left(A - c b_1 - \frac{k_f + w_f}{2} \right) + \frac{k_f - w_f}{2} \\ &= q_2^B + \frac{2b_1 - b_2}{4b_1 - b_2} (k_f - w_f) > q_2^B, \end{aligned}$$

which is increasing in A and b_2, and it decreasing in w_f and b_1. ■

Appendix B: Additional Figures and Tables

Appendix B.1: Additional Figures

Appendix B.2: Additional Tables

Appendix B.3: Differences-in-Differences for Overselling

In order to test the parallel trends assumption between the arbitrage of wind producers versus the control groups (non-wind renewables and retailers), we estimate the following equation:

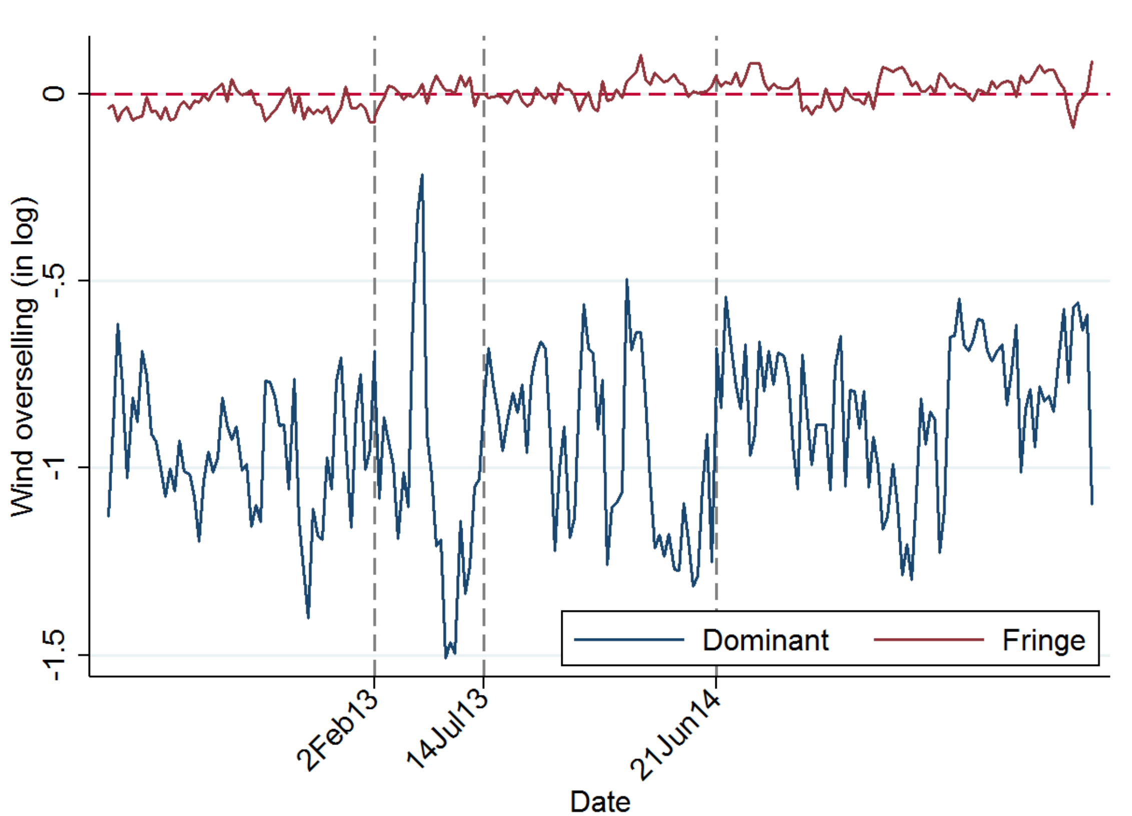
$$\Delta \ln q_{htd} = \alpha + \beta_2 \hat{p}_{htd} W + \beta_5 \hat{p}_{htd} + \beta_6 W + \gamma D_{htd}^{er} + \delta w_{htd}^{er} + \rho X_{td} + \eta_{htd} \qquad (13)$$

where W is the indicator for the wind producers. We cluster standard errors at the week of sample. Our coefficient of interest is the response of overselling to the price differential of group g, θ_g.

The coefficient β_2 shows the price response of overselling under different pricing schemes. It indicates whether the pre-trends assumption holds. Specifically, β_2=0 means that the overselling behavior of wind firms and those belonging to the control group (either other renewables or retailers) are similar during the period(s) when they face similar arbitrage incentives.

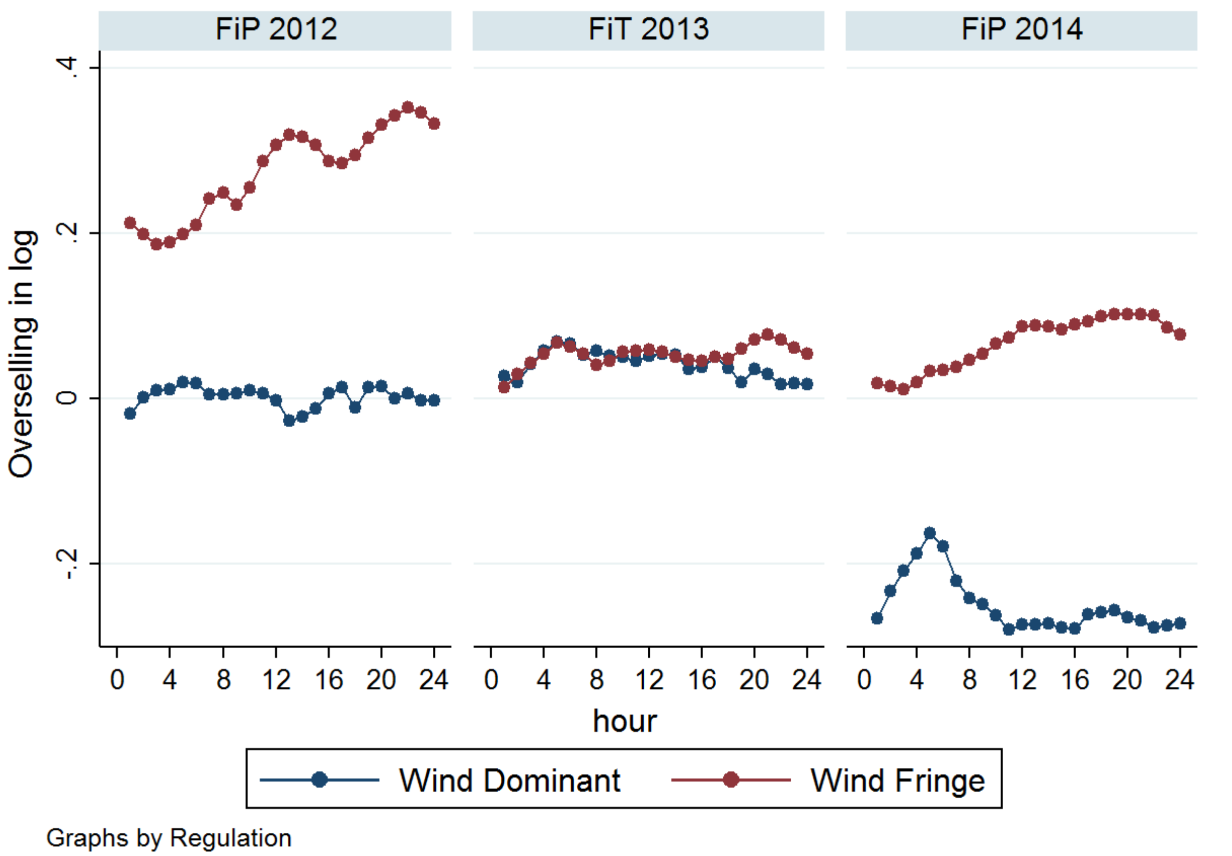
Column (1) in Table 6 provides evidence on the pre-trends. The coefficient for $\hat{p}\times$ Wind (β_2 in equation (13)) indicates that during the time when wind and other renewables face the same arbitrage incentives (FiT period), their overselling behavior is not

Figure 5: Overselling and withholding across markets by non-wind producers



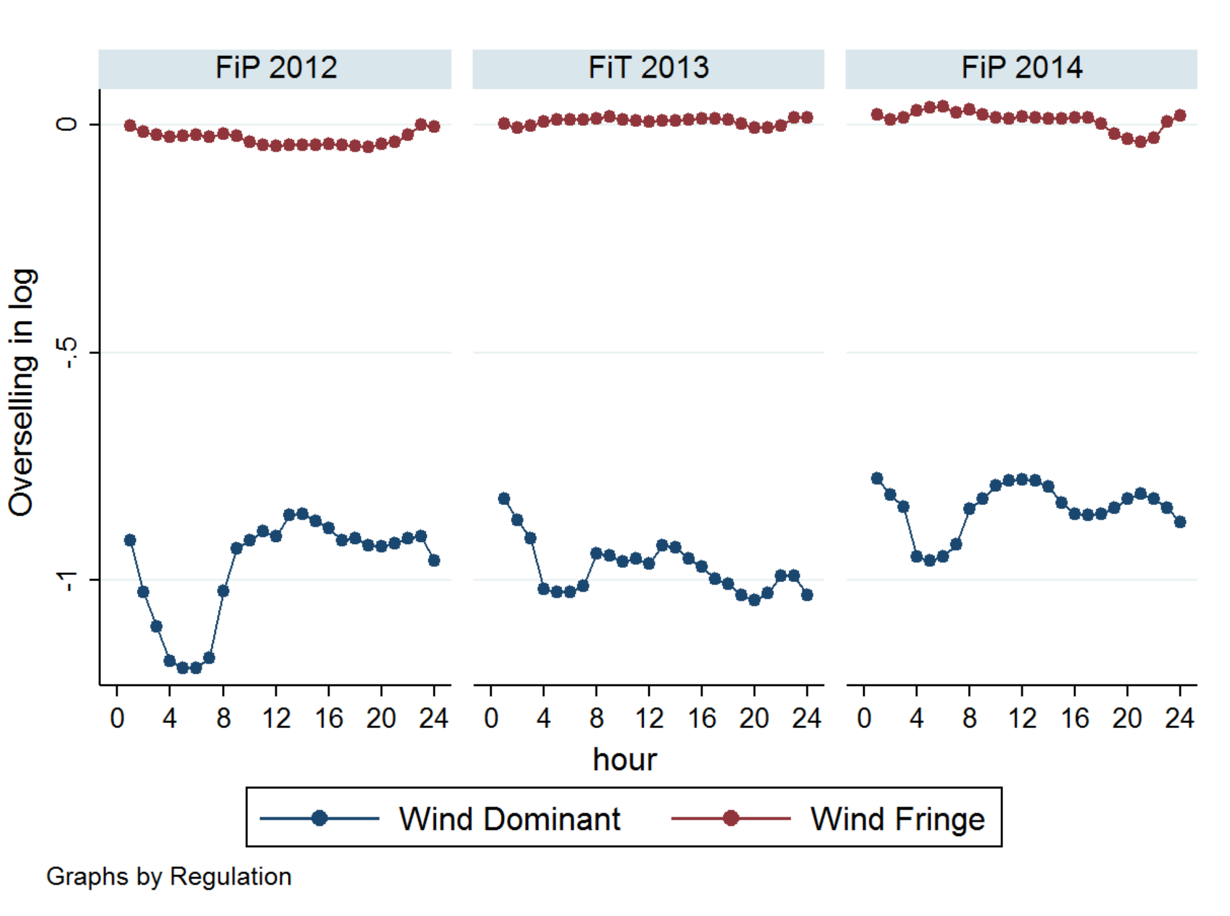
Notes: This figure plots the weekly average of the day-ahead commitment minus the final commitments of non-wind producers belonging to both the dominant and the fringe firms. The vertical lines date the changes in the pricing schemes for renewables. Positive numbers reflect overselling, negative numbers reflect withholding. The sample ranges from February 2012 to February 2015.

Figure 6: Overselling and withholding by wind producers



Notes: This figure shows the hourly average of the day-ahead commitments minus the final commitments of the wind producers, split in three regulatory regimes. Sample is from February 2012 to February 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 28 February 2015.

Figure 7: Overselling and withholding by non-wind producers



Notes: This figure shows the hourly average of the day-ahead commitments minus the final commitments of the non-wind producers, split in three regulatory regimes. Sample is from February 2012 to February 2015. FiP I is from 1 February 2012 to 31 January 2013; FiT 2013 is from 1 February 2013 to 21 June 2014; FiP II is from 22 June 2014 to 28 February 2015.

statistically different, thus validating the parallel trends assumption. The other coefficients on the price premium are broadly consistent with the evidence provided by Ito and Reguant (2016). For example, the positive coefficient for Wind indicates that the wind fringe producers engage in arbitrage. The coefficient for $\hat{p}$ by the other renewable producers shows that their overselling does not respond to the price premium.

Column (2) and (3) in Table 6 report the main results of the differences-in-differences analysis of the main text (Table 3 only reports the treatment effects captured by β_1). In column (2), the coefficient for $\hat{p}\times$ Wind $\times$ FiT (β_1 in equation (11)) shows that overselling by the wind fringe producers goes down after the switch from FiPs to FiTs. In column (3), the coefficient for $\hat{p}\times$ Wind $\times$ FiP shows that wind fringe producers are back to arbitrage after the switch from FiTs to FiPs. These results are all consistent with our predictions.

We find similar results when using retailers as the control group, as reported in Table 7. In column (1), the coefficient for $\hat{p}\times$ Wind (β_2 in equation (13)) indicates that during the time when wind producers and retailers face the same arbitrage incentives (FiP I period), their overselling behavior is not statistically different. The other coefficients, such as the coefficient for Wind (β_6 in Equation 13), indicate a lower price response of overselling by the wind fringe producers as compared to that of retailers. The coefficient for $\hat{p}$ shows a positive response to the price premium by the retailers. In column (2), the coefficient for $\hat{p}\times$ Wind $\times$ FiT (β_1 in equation (11)) shows that the price response of overselling from the wind fringe producers went down after the switch from FiP to FiT. In column (3), the coefficient for $\hat{p}\times$ Wind $\times$ FiP shows that wind fringe producers resumed arbitrage when they were switched back from FiTs to FiPs. The magnitude of these effects is similar to those in Table 6, indicating that the effects of overselling due to the changes in the pricing scheme are robust regardless of the control group we use.

Table 5: Forward Contract Effect

	2SLS			
	(1)	(2)	(3)	(4)
Marginal Cost_{it}	1.56***	1.78***	1.79***	1.48***
	(0.24)	(0.35)	(0.37)	(0.21)
FiP I $\times$ $\frac{w_{it}}{DR'_{it}}$	-17.7**	2.75	0.75	11.1
	(8.04)	(6.00)	(5.87)	(7.23)
FiT $\times$ $\frac{w_{it}}{DR'_{it}}$	-32.7***	-35.3***	-35.5***	-30.4***
	(6.51)	(9.57)	(9.91)	(6.33)
FiP II $\times$ $\frac{w_{it}}{DR'_{it}}$	-5.83	3.54	0.41	8.13
	(4.45)	(9.36)	(9.61)	(10.7)
$\frac{q_{it}}{DR'_{it}}$				3.95***
				(0.99)
Month and DoW FE	N	Y	Y	Y
Hour FE	N	N	Y	Y
Observations	14,495	14,495	14,495	14,495

Notes: This table shows the estimation results of equation (9). We constraint the coefficient for markups from all firm's output to be one in columns (1) to (3), and we relax this by allowing the coefficient for markups to be varied in column (4). We limit hourly prices to be within 1 Euro/MWh range relative to the market price. We instrument markups and the marginal cost with wind speed, precipitation, co_2, gas and coal prices. FiP I, FiT, FiP II are indicators for days during 1 February 2012 - 1 February 2013, 2 February 2013 - 21 June 2014, 22 June 2014 - 28 February 2015. All regression include unit and quarterly dummies, while month, day-of-the-week, and hour fixed effects are added in a cumulative fashion in columns (2) to (4). The standard errors are clustered at plant level.

Table 6: Overselling Effects: Wind vs Other Renewables

	Pre-trends	FiT	FiP
	(1)	(2)	(3)
Wind	0.05***	0.2***	0.03***
	(0.01)	(0.009)	(0.009)
$\hat{p}$	-0.002	-0.002	-0.004**
	(0.002)	(0.002)	(0.002)
$\hat{p}\times$ Wind	-0.004	0.08***	0.005
	(0.004)	(0.006)	(0.003)
FiT		0.09***	
		(0.01)	
Wind $\times$ FiT		-0.1***	
		(0.02)	
$\hat{p}$ $\times$ FiT		0.0001	
		(0.003)	
$\hat{p}\times$ Wind $\times$ FiT		-0.08***	
		(0.007)	
FiP			-0.01
			(0.010)
Wind $\times$ FiP			-0.04***
			(0.01)
$\hat{p}\times$ FiP			-0.003
			(0.004)
$\hat{p}\times$ Wind $\times$ FiP			0.03***
			(0.006)
Control	Renewables	Renewables	Renewables
Observations	16,900	34,478	32,780

Notes: This table shows the estimation results of equation (11). The dependent variable is the log of overselling. Column (1) uses the sample from 1 February 2013 - 1 February 2014, when wind and other renewables face the same incentives not to oversell as they are all subject to FiTs. Column (2) uses the sample from 1 February 2012 - 1 February 2014, where FiT is equal to one for days after 1 February 2013. Column (3) uses sample from 1 February 2013 - 28 February 2015, where FiP is equal to one for days after 21 June 2014. All regressions include hour of day fixed effects and week fixed effects. The standard errors are clustered at the week of sample.

Table 7: Overselling Effects: Wind vs Retailers

	Pre-trends	FiT	FiP
	(1)	(2)	(3)
Wind	-0.4***	-0.4***	-0.3***
	(0.02)	(0.02)	(0.02)
$\hat{p}$	0.07***	0.07***	0.08***
	(0.006)	(0.006)	(0.007)
$\hat{p}\times$ Wind	0.006	0.006	-0.06***
	(0.009)	(0.009)	(0.010)
FiT		-0.01	
		(0.02)	
Wind $\times$ FiT		0.1***	
		(0.03)	
$\hat{p}$ $\times$ FiT		0.003	
		(0.01)	
$\hat{p}\times$ Wind $\times$ FiT		-0.07***	
		(0.02)	
FiP			0.04***
			(0.02)
Wind $\times$ FiP			0.08***
			(0.02)
$\hat{p}\times$ FiP			-0.04***
			(0.008)
$\hat{p}\times$ Wind $\times$ FiP			0.06***
			(0.01)
Control	Retailers	Retailers	Retailers
Observations	17,578	34,478	32,780

Notes: This table shows the estimation results of equation 11. The dependent variable is the log of overselling. Column (1) uses sample from 1 February 2012 - 1 February 2013, when wind producers and retailers face the same incentives to oversell given that wind producers are subject to FiPs. Column (2) uses sample from 1 February 2012 - 1 February 2014, where FiT is equal to one for days after 1 February 2013. Column (3) uses sample from 1 February 2013 - 28 February 2015, where FiP is equal to one for days after 21 June 2014. All regressions include hour of day fixed effects and week fixed effects. The standard errors are clustered at the week of sample.