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Market Power in Italian Electricity Auctions

Mattias Almqvist (22178)

Abstract

This study analyzes market power in the Italian adjustment market, one of the electricity auctions of the Italian electricity market, between 2005 and 2009. The purpose is to understand whether the four largest electricity producers submitted higher price offers to sell electricity when their levels of market power were higher. The study contributes by shedding light on producer behavior in a type of electricity auction that is rarely studied. It also contributes by incorporating the unusual empirical observation of price-elastic demand in the analysis. I compute hourly measures of ability and incentive to exercise market power for each producer using a theoretical model of bidding in electricity auctions and detailed auction data. Because the data include actual individual supply and demand functions, strong assumptions common in studies of imperfectly competitive markets can be relaxed. I estimate the relationship between producers' ability and incentive to exercise market power and their price offers controlling for daily changes in marginal cost. The results suggest that the producers submitted higher price offers when their levels of market power were higher. However, their levels of market power were mostly low and not all results are robust to changes in econometric specification. It is therefore unlikely that the producers distorted prices substantially in the Italian adjustment market by exercising market power.

Keywords: Market power, Electricity auctions, Adjustment market, Italy

JEL: D44, L11, L94

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Table of Contents

Table of Figures

Table of Tables

1. Introduction

Important unobservable market characteristics often limit empirical studies of firm behavior in imperfectly competitive markets. In most studies, researchers have to rely on strong assumptions regarding the functional form of market demand and the nature of strategic interaction between firms. The assumptions obscure conclusions, because they can significantly influence the results.

The recent wave of restructuring of electricity markets into auction-based markets has provided researchers with new means of studying firm behavior. Because electricity auctions generate large amounts of detailed data on individual supply and demand functions, researchers of electricity auctions can relax strong assumptions and only assume that electricity producers maximize their expected profits given the supply of their competitors and the demand of the buyers.

Cheap and reliable supply of electricity is a fundamental building block of many developed economies. However, electricity possesses many product characteristics that increase producers' ability to exercise market power to raise the price by reducing their supply. Electricity is costly to store, there are strict capacity constraints in production and transmission, supply must equal demand at every instant of time, demand is often partly or perfectly inelastic, and a small number of producers usually own a majority of the generation units. These factors imply time-separated electricity markets, scarce product availability, few sellers, and buyers that are willing to buy at almost any price. This has attracted economists to study market power in electricity auctions.

Most restructured electricity auctions operate with several sequential auctions in order to facilitate flexible production and working competition. The literature that analyzes market power in electricity auctions mostly focuses on the first of the sequential auctions, the day-ahead market, in which the largest volume of spot-market electricity is traded (e.g. Borenstein et al., 2002, Wolak, 2003a, McRae and Wolak, 2014 and Bosco et al., 2012). In general, these studies find that electricity producers have high levels of market power and that they at least partially exercise it. Hortaçsu and Puller (2008) is one of few studies analyzing market power in one of the subsequent auctions, the Texas balancing market, and it finds that some of the producers in Texas exercise market power in a profit-maximizing way.

There is still much to learn about market power in the subsequent electricity auctions, in which market concentration often is higher, before general conclusions can be drawn. In the Italian electricity market, where market concentration and prices are high, researchers have studied market power in the day-ahead market, but not in the subsequent auctions. The purpose of this thesis is therefore to contribute to the understanding of market power in the subsequent electricity auctions by studying the Italian adjustment market, which takes place after the Italian day-ahead auction. In the adjustment market, market participants adjust their sales and purchases resulting from the day-ahead market in close to real time. In particular, the purpose of the thesis is to analyze whether the four largest electricity producers in the Italian adjustment market submitted higher price offers to supply electricity when their levels of market power were higher. It is essential to know whether the producers increased the price excessively, because too high prices lead to unnecessary costs for consumers, to deadweight losses and distort the way the market price works as a signalling device for investments.

To analyze market power, I use a model of bidding in electricity auctions. The model builds on the literature analysing market power in electricity auctions, and is adjusted to take into account the characteristics of the Italian adjustment market, most notably the empirical observations that producers also buy a substantial amount of electricity from the adjustment market and that demand is price-elastic. In most of the studied day-ahead markets, demand is price-inelastic. The price-elastic demand of the adjustment market should reduce producers' market power, because it makes demand react negatively to price increases. Analysing market power in an electricity auction with price-elastic demand is one of the contributions of this paper. The fact that market concentration is high in the adjustment market, because only flexible generation units can participate with short notice, should on the other hand increase producers' market power.

The theoretical model predicts that a profit-maximizing electricity producer should submit higher price offers when its ability to exercise market power is higher. It also predicts that a vertically integrated producer, which both sells and buys electricity in the market, should submit higher price offers when its incentive to exercise market power is higher. The concept of incentive captures the intuition that a vertically integrated producer profits from higher prices on its sold quantity but loses from higher prices on its bought quantity. Based on the results derived from the theoretical model and detailed data on individual supply and demand functions, I first compute individual hourly measures of ability and incentive to exercise market power for the four largest producers in the adjustment market between 2005 and 2009. Secondly, I estimate the relationship between the producers' levels of market power and their price offers controlling for producer-specific marginal cost.

The results show that the largest producer, Enel, had considerable ability to exercise market power in the Italian adjustment market between 2005 and 2009. Enel's incentive to exercise market power was however low, because Enel also bought a substantial amount of electricity from the adjustment market. The three smaller producers, A2A, E.ON and Edison had relatively low levels of ability and incentive to exercise market power. Higher levels of ability and incentive were in general associated with higher price offers, which is in line with the hypotheses, but the relationship varied between producers. The estimates are statistically and economically significant, but smaller than the strict prediction of the theoretical model. The estimated relationship between incentive and price offer was about half of the prediction for A2A, about a third for Enel, while it was relatively close to zero for E.ON and statistically insignificant for Edison. The estimates suggest that one-standard-deviation increases in the individual measures of incentive to exercise market power would be associated with price offers that were 0.65-2.03 euro/MWh higher, which corresponds to 1.1-3.3 percent of the average market price. This could have led to inefficiencies, but it is unlikely that this led the Italian adjustment market to suffer severe distortions from producers exercising market power between 2005 and 2009. It is important to point out that these results are based on a simple model of bidding that may not capture all aspects of producer behavior. Furthermore, the results are not completely robust to changes in methods for calculating the measures of market power or to changes in econometric specification, and the relationship between price offer and market power is estimated for low levels of market power. One should therefore not necessarily take these results as predictions of how the producers would behave with high levels of market power.

The results are partly in line with previous research. Bosco et al. (2012), which study the Italian day-ahead market, find that Enel does not always exercise its market power, but that the three smaller producers do. Hortaçsu and Puller (2008), which study a market in Texas similar to the Italian adjustment market, find that the largest producers submit profit-maximizing price offers, while the smaller producers submit too high price offers. Finally, McRae and Wolak (2014), which study the New Zealand day-ahead market using a similar method as in this thesis, also find that producers submit higher price offers when their levels of market power are higher. Their estimates are also smaller than the theoretical prediction and smaller than the estimates in this thesis, while the levels of market power are higher.

The rest of the thesis is structured as follows: in Section 2, I describe the institutional setting of the Italian adjustment market, in Section 3, I discuss the related literature, and in Section 4, I model the bidding problem of an electricity producer in the Italian adjustment market. In Section 5, I describe the detailed auction data, in Section 6, I explain how I implement the theoretical model empirically, and in Section 7, I present the results of the empirical analysis. I discuss the results and the assumptions I have made in Section 8, and conclude in Section 9.

2. Italian electricity market

This thesis analyzes market power in the Italian adjustment market between February 2005 and October 2009. During this time, the adjustment market, which was a component of the Italian electricity market, consisted of one auction. From November 2009, it consisted of several simultaneous and sequential auctions. The reason for the limitation in time is that analysing the market after November 2009 would require a theoretical analysis that takes into account the dynamics between the multiple auctions. Because of the limitation in time, the description of the Italian electricity market mainly concerns market characteristics between 2005 and 2009.

Electricity generation in Italy between 2005 and 2009 was dominated by thermal sources, which included technologies based on oil, gas and carbon. Hydro-generation was relatively important in the North and the amount of electricity from other renewable sources was relatively modest between 2005 and 2009, cf. Figure 3. Electricity prices in the Italian electricity market during this period were higher than in other European markets, such as the French, German and the Spanish markets (GME, 2010, p. 59). Possible reasons could be that the Italian market was too isolated from other continental markets or had an inefficient technology mix of the generation fleet (Bosco et al., 2012). The higher prices could also be a result of the high market concentration and the dominance of Enel, the former state-owned monopoly-producer.

The restructuring and liberalization of the Italian wholesale electricity market started in 1999. Consequently, a new auction-based electricity market, the Italian Power Exchange (IPEX), was established. It opened for supply-side bidding in April 2004 and for demand-side bidding in January 2005 (Gestore Mercati Energetici, 2009).[1] The Italian power exchange consisted of a forward market and a spot market. On the forward market producers signed bilateral contracts with buyers specifying the quantity and price of electricity to be delivered at a certain time in the future. The bilateral contracts were private information of the buyers and sellers. On the spot market, market participants traded electricity in real time or near real time. Every hour represented one period in which physical delivery of electricity was traded, and market participants had to decide on how many megawatt hours (MWh) of electricity to buy or sell at different prices for every hour.

The spot market was divided into three sequential markets with separate auctions for each hour of delivery, between 2005 and 2009.[2] The auctions were the day-ahead market, the adjustment market and the ancillary services market. Most electricity was traded through the day-ahead market, which took place first. The day-ahead market opened nine days before the time of physical delivery of electricity and closed one day ahead of the time of physical delivery. After the day-ahead market had closed, the adjustment market opened and operated until shortly before the time of physical delivery. The analysis in this thesis refers to the adjustment market. In the adjustment market, sellers and buyers adjusted their sold and bought quantities in the day-ahead market by selling or buying more electricity. The main purpose of the adjustment market was for market participants to be able to respond flexibly to changes in production capacity, demand, or to other events occurring close to the time of physical delivery, and to make sure that aggregate supply and demand balanced. The traded quantities were substantially lower in the adjustment market than in the day-ahead market.[3] After the closing of the adjustment market, the ancillary services market opened. The ancillary services market was the last in the sequence of auctions in the Italian electricity market. It was a real time market in which Terna, the company in charge of electricity transmission and dispatching, procured resources to control the system and to manage transmission congestion. When the capacity of the transmission grid was not enough to transmit all electricity, congestion occurred. To resolve congestion problems, the Italian market was split into two or more zonal markets with different zonal prices, instead of one national market with one price.

The day-ahead market and the adjustment market operated as sealed bid uniform price auctions. Market participants submitted sealed bids into each hourly auction by specifying one or several

[1] If not otherwise stated, the information of this section can be found in Gestore Mercati Energetici (2009), Vademecum of the Italian Power Exchange.
[2] The organization of the spot market today is similar to what is described in this section. The main difference is that it today consists of more auctions.
[3] In 2008 for example, 12 TWh of electricity was traded in the adjustment market compared to 233 TWh of electricity in the day-ahead market (GME, 2010, p. 38).

price-quantity pairs indicating how many MWh of electricity they were willing to sell or buy at different prices. Sellers specified the minimum price and buyers specified the maximum price at which they were willing to trade a certain quantity of electricity. There was no restriction on the number of price-quantity pairs market participants could submit, and market participants could freely decide on the quantities, but prices had to be in the range of [0; 500]. A market participant could specify, for example, the following three price-quantity pairs to sell electricity: 100 MWh at 30 euro/MWh, 200 MWh at 60 euro/MWh and 300 MWh at 90 euro/MWh. By combining all price-quantity pairs of a market participants one can construct individual supply and demand functions for each hour. In the rest of the thesis, I will refer to the prices that market participants specify for a certain quantity as *price offers*. At the end of each auction, the market operator (GME) opened all bids simultaneously, ranked supply bids in increasing price order, and ranked demand bids in decreasing price order to form aggregate supply and demand functions. The market clearing price, or uniform price, was the lowest winning bid and could be found were the aggregate supply and demand functions intersected. The market clearing price applied to all trades in an hourly auction, and the lowest supply bids and highest demand bids were served first in the allocation procedure.

The ancillary services market operated as a pay-as-bid (or discriminatory price) auction. The market clearing process in the ancillary services market was similar to the procedures in the day-ahead and adjustment markets, the lowest supply bids and highest demand bids were served first in the allocation procedure, but the payments differed. In a pay-as-bid auction, market participants are paid (seller) or pay (buyer) their respective bids. I do not discuss the ancillary services market further because it is not part of the analysis of this thesis.

The market operator published demand forecasts for each hour of the day, before the closing of the day-ahead market and the adjustment market, so that producers could accurately forecast demand. The market operator published the market-clearing price and the total volumes bought and sold for each hour, shortly after the closing of each market, as well as the complete and confidential individual results to each market participant. The confidential results became public after seven days.

Before the restructuring of the Italian electricity market, the state-owned monopoly Enel controlled the whole value chain from generation of electricity to delivery to consumers. In the restructuring process, parts of Enel's production capacity were sold to new entrants to increase competition. Enel was also made a private limited company in which the Italian state remained the main shareholder. Concentration and Enel's market share in the wholesale market remained high after restructuring despite a substantial increase in the number of operators in the wholesale market (Colbalchini, 2014).

The three largest competitors of Enel, on the supply side in the adjustment market between 2005 and 2009, were E.ON, Edison and A2A, cf. Table 1. E.ON effectively entered the Italian market in 2008 through its acquisition of Endesa Italia (E.ON, 2008). A2A is the result of the merger between the municipal companies of Milan (AEM and AMSA) and Brescia (ASM), and started operation on January 1, 2008, (A2A, 2011). Edison was not involved in any major mergers or acquisitions between 2005 and 2009.

Enel was clearly dominating in the adjustment market, and even more so than in the day-ahead market, with market shares in production between 79 and 90 percent. Competition authorities often presume dominance of a company when its market share is larger than 50 percent (Motta, 2004). The three main competitors of Enel had relatively small market shares, and the rest of the producers in the adjustment market had very small market shares. Together the four largest producers had yearly market shares of between 93 and 97 percent on the supply side and between 88 and 97 percent on the demand side of the adjustment market between 2005 and 2009, cf. Table 1 and Table 2. The market shares of the four largest producers in the analysis of McRae and Wolak (2014), compared to which the method in this thesis is similar, was approximately 85 percent. The largest Italian electricity producers also had retailing branches that bought electricity from the wholesale market (forward or spot market) to sell to their retail customers. This made the producers vertically integrated firms with the unusual feature that they sold and bought from the same market.

Table 1 Market shares (%) in supply in adjustment market for the four largest producers

Producer	2005	2006	2007	2008	2009
Enel	86,7	90,0	90,2	86,6	78,6
E.ON	4,9	3,3	1,9	2,7	6,5
Edison	3,2	2,5	2,8	4,4	4,6
A2A	0,8	1,1	1,3	2,2	2,9
Total	95,7	96,9	96,2	95,9	92,7

Note: 2005 refers to the period between February 2005 and December 2005. 2009 refers to the period between January 2009 and October 2009.

Source: Own calculations based on auction data from GME.

Table 2 Market shares (%) in demand in adjustment market for the four largest producers

Producer	2005	2006	2007	2008	2009
Enel	87,6	92,7	92,6	88,5	79,5
E.ON	3,3	1,4	0,8	1,5	4,2
Edison	1,7	2,0	1,3	2,1	2,3
A2A	0,5	0,6	1,0	1,5	2,4
Total	93,2	96,6	95,7	93,5	88,4

Note: 2005 refers to the period between February 2005 and December 2005. 2009 refers to the period between January 2009 and October 2009.

Source: Own calculations based on auction data from GME.

3. Literature

In this section, I review the relevant literature. I first review the literature about market power in electricity auctions in general, and continue with the relevant literature studying the Italian electricity auctions.

3.1 Market power in electricity auctions

In competition economics, market power is defined as the ability of a firm to profitably raise the price above a competitive level.[4] A commonly used theoretical measure of market power is the *Lerner index,* defined as the difference between price and marginal cost divided by price, $L_i = (p_i - C_i')/p_i$. An alternative and theoretically equivalent way of defining the Lerner index is as the inverse elasticity of residual demand faced by a firm, $L_i = 1/\epsilon_i$, which is sometimes preferred in empirical applications (Motta, 2004, p. 40-41).[5] [6] The measures of market power computed in this thesis relate to the inverse elasticity of residual demand. Because prices often exceed the marginal cost of production, firms in most markets seem to have some degree of market power (Motta, 2004, p. 116-117).

Electricity auctions can be characterized as multi-unit auctions in which multiple units of a homogenous good is traded. The literature on competition in electricity auctions often model electricity auctions using the theoretical framework of "share auctions" introduced by Wilson (1979) and the more general but related framework of supply function equilibria developed by Klemperer and Meyer (1989). Most restructured electricity auctions operate with a uniform pricing rule, meaning that one market price applies to all trades in one auction. A bid for one unit of the good, in a multi-unit uniform price auction, may therefore affect the price of all units purchased. Buyers in such an auction therefore have incentive to reduce their demand to decrease the price (Ausubel et al., 2014). This "bid shading" or exercising of market power leads to ex-post inefficient allocations of resources.

Von der Fehr and Harbor (1993) were the first to analyze this type of exercising of market power theoretically in the context of electricity producers' price offers into electricity auctions. Fabra et al. (2006) built on their work and showed theoretically that when demand for electricity is low relative to available production capacity, competition is intense and the market price therefore equals the marginal cost of the least efficient of the producing plant. However, when demand is high relative to available production capacity, competition is less intense and the market price can

[4] In this thesis, I only consider unilateral market power, which refers to the actions a firm can take on its own to profitably increase the price. I do not consider multilateral market power, e.g. collusion.
[5] A firm's residual demand is defined as the total demand in the market subtracted by its competitors' total supply.
[6] $L_i = (p_i - C_i')/p_i$ can be problematic to implement empirically, because firms with high degrees of market power may be able to operate inefficiently with high costs and still sell their products. With an inflated marginal cost the Lerner index can become equal to zero, suggesting that the firm is a price-taker when it in fact has substantial market power.

be infinitely high or alternatively equal to the price cap. The uniform price rule as well as auctions taking place every hour, which implies lower demand uncertainty, increases the probability of scenarios with excessively high prices. Conversely, the existence of demand-side bidding and a regulatory price cap decrease the probability of excessively high prices, because it counters producers' market power.

Most of the empirical research on multi-unit auctions, and in particular on electricity auctions based on Wilson's framework, follow one or a combination of two different econometric approaches (Hortaçsu, 2011). In the first approach, the researcher tries to identify producers' marginal cost of production. This approach relies on strong assumptions such as expected profit-maximization, Bayesian-Nash-equilibrium play and private-values environments. In the second approach, the researcher tries to test these strong assumptions. This can be problematic because it for each observed price-quantity pair exists a marginal cost that would rationalize a producer's price offer under expected profit-maximization. Therefore, the researcher often needs complementary information about producers' marginal costs.

The restructuring of electricity markets in the 1990s and 2000s attracted considerable interest from empirical economists. Because electricity auctions generate large amounts of data on individual supply and demand functions, economists can analyze producer behavior in electricity markets, without having to rely on strong assumptions about the functional form of demand functions or the nature of strategic interaction between firms, as in most studies of imperfectly competitive markets. It suffices to assume that producers maximize their expected profit given the realization of their residual demand, which is observable in the data. Electricity markets that have been studied include the market in California (Borenstein et al., 2002 and Wolak, 2003b), England and Wales (Wolfram, 1999 and Sweeting, 2007), Australia (Wolak, 2003a), Texas (Hortaçsu and Puller, 2008), New Zealand (McRae and Wolak, 2014), Spain (Ciarreta and Espinoa, 2010), Italy (Bosco et al., 2012) and New York (Schwenen, 2015).

The studies of market power in electricity auctions find that electricity producers in general have substantial ability to exercise market power during certain periods, in particular when demand is high, and the producers partially use it to raise market prices above competitive levels. Most of the studies follow the econometric approaches outlined above and build on the framework presented in Wolak (2003a), which model restructured electricity markets in a way such that marginal cost functions or other unobservables can be recovered depending on the available data.

Hortaçsu and Puller (2008) is one of few empirical studies that analyze producer behavior in another electricity auction than the day-ahead market, which makes it relevant for this thesis. The authors test whether producer-behavior in the Texas balancing market, taking place after the day-ahead market, is consistent with the assumption of ex-post profit-maximization. Because participants in the Texas balancing market adjust their supply and demand schedules resulting from the day-ahead market, the Texas balancing market is similar to the Italian adjustment market. The authors use data on individual supply and demand functions, data on producer-level marginal costs and the framework of Wolak (2003a). They find that large producers bid supply functions that are close to ex-post profit-maximizing, while small producers deviate from ex-post profit-maximizing behavior by bidding too steep supply functions. Ito and Reguant (2015) study all the sequential auctions in the Spanish electricity market, including the auctions taking place after the day-ahead market. They find that market power can explain some of the price differences between the markets. Even though the study uses a different method than what is used in this thesis, the findings suggest that producers have market power also in other auctions than the day-ahead market.

The literature analysing producers that buy electricity from the same market they supply, in order to cover demand from their retail customers, show that this type of vertical integration has important implications for the analysis of market power in uniform price auctions. Bushnell et al. (2008) find theoretically and empirically that producers with large retail obligations relative to their production may have incentive to drive down the market price to reduce the cost of covering their retail obligations.

The theoretical and empirical framework of this thesis builds largely on McRae and Wolak (2014), which analyzes how electricity producers' levels of ability and incentive to exercise market power in the hydro-dominated New Zealand day-ahead market relates to their price offers. The authors compute half-hourly measures of the four largest producers' ability and incentive to exercise market power, defined as the inverse semi-elasticity of each producer's realized residual and net residual demand function. They find that the producers have considerable market power in certain hours. Estimations controlling for marginal cost, also suggest that there was a clear positive relationship between these measures of market power and producers' price offers. To strengthen the results further, they use data to calculate each producer's marginal cost and can conclude that the producers do not submit prices equal to marginal cost.

3.2 Market power in Italian electricity auctions

The transparent rules regarding publication of data in the Italian electricity market have enabled detailed analyses of producer behavior and market dynamics. Floro (2009) concludes that a Stackelberg leader-follower model, with Enel as the leader, best characterized the market in the summer of 2005 and winter of 2006, but there were some indications in favor of a change to Cournot competition in 2006. Bollino and Polinori (2008) examine the degree of competition in the Italian day-ahead market between April and December 2004.[7] In a first explorative econometric analysis, they find indications that suggest that producers exercise market power. Computing individual Lerner indices for the Italian producers, they find that Enel had substantial ability to exercise market power, and that the smaller producers had some degree of ability to exercise market power in 2004.

The study of the Italian electricity market that is most relevant for this thesis is Bosco et al. (2012). It estimates marginal cost functions and Lerner indices for the four largest electricity producers in

[7] The electricity market opened up for demand-side bidding on January 1, 2005. As discussed above, demand-side bidding should increase competition according to Fabra et al. (2006).

the Italian day-ahead market between 2005 and 2008, but does not consider the adjustment market. The authors generalize the model of profit-maximizing bidding behavior developed by Wolak (2003a) and Hortaçsu and Puller (2008) to allow for vertically integrated producers, which both buy and sell electricity on the day-ahead market, and use data on producers' individual supply and demand functions. The most notable result is that the largest and dominant producer, Enel, often had large incentive to exercise market power, but did not use all of its market power. The observed behavior violates the assumption of short-run profit-maximization. Consequently, the estimated marginal cost functions for Enel, which rely on the assumption, are biased. In most hours, E.ON, Edison and A2A had negligible levels of market power, but when they had market power, they successfully exercised it. The results contradict the findings of Hortaçsu and Puller (2008) that large producers profit-maximize while small producers do not. The fact that Enel is partially state-owned could explain the results. Boffa et al. (2010) argue that Enel's objective function is a combination of short-run profit-maximization and consumer welfare, which can explain why Enel refrains from raising prices as much as it could do.

Bigerna and Bollino (2016) analyze market power of buyers in the Italian day-ahead market in 2010 and 2011. Computing Lerner indices and inferring marginal costs from residual supply functions observed in the data, they find evidence of that buyers exercise market power to drive down prices. The price mark-down was in the range of 3 - 10 percent. These findings show that it is important to consider both supply and demand when analysing market power in electricity auctions.

While there have been some studies on the price dynamics between the sequential auctions in the Italian electricity market (Gianfreda et al., 2016), no study has, as far as I am aware, analyzed market power in the Italian adjustment market. This is in spite of the attention given to market power analyses in the Italian day-ahead market. To properly understand producer behavior in the Italian electricity market, we need to know whether producers exercise market power in the Italian adjustment market.

4. Model of bidding in the Italian adjustment market

To model market power in the Italian adjustment market, I use a simple model of a profit-maximizing electricity producers bidding in a uniform price electricity auction to supply electricity. The model builds on the work of Wolak (2003a) and McRae and Wolak (2014). Because I have access to hourly data on individual supply and demand functions, I neither have to make assumptions about the strategic interaction of the electricity producers nor the functional form of demand.[8] I only need to assume that producers maximize their profits given the realization of the bids of the other market participants. I treat each hour as a separate auction. This is possible in a fossil-fuel dominated market because production of a fossil-fuel generated plant in one hour does not affect production in another hour, as it does for hydroelectric plants that face inter-temporal decisions regarding their water levels, cf. McRae and Wolak (2014). Throughout this section, I

[8] The data I use are explained in Section 5.

assume that there are no transmission losses and no congestion in the Italian electricity transmission grid. I also assume that there is no limit on the set of possible prices in the adjustment market.[9]

4.1 Ability to exercise market power

Consider a profit-maximizing and risk-neutral electricity producer that only sells electricity. The producer has been scheduled to produce some quantity of electricity in the day-ahead market. The producer can now offer to produce more quantity in the adjustment market, which is a uniform price auction, in order to supply more electricity. Assume that the producer takes the result of the day-ahead market as given, and in any other respect treats the adjustment market as a separate market from the day-ahead market.

Define producer *i's* residual demand curve $RD_i(p)$, in the adjustment market in a certain hour, as the aggregate demand function in the adjustment market subtracted by the sum of its competitors' supply functions in the adjustment market: $RD_i(p) = D(p) - \sum_{i \neq j} S_j(p)$. Let ϵ_i be a stochastic shock that affects producer *i*'s residual demand function in an additive way.[10] $RD_i(p, \epsilon_i)$ is then the actual realization of producer *i*'s residual demand function taking into account the shock. It is a continuous function for which $RD_i'(p, \epsilon_i)$ exists. There is no need to make other functional form assumptions regarding the residual demand function because the researcher can observe it in the data ex-post. I contrast to most of the previous literature, I allow for price-elastic demand, because data from the adjustment market shows that demand is elastic in many hours. The practical implication is that producer *i*'s residual demand function becomes more elastic. Assume that the producer maximizes its realized profits given the realization of its residual demand $RD_i(p, \epsilon_i)$.

Further, assume that producer *i* has marginal cost $c_i(q_{DA})$ for the unit with the highest cost that it uses for production. I assume that $c_i(q_{DA})$ is constant for the range of quantities relevant in the adjustment market, and it only depends on the scheduled quantity to produce q_{DA}, resulting from the day-ahead market. The scheduled quantity in the day-ahead market shifts the marginal cost function to the left so that higher levels of q_{DA} increase the level of marginal cost in the adjustment market. The assumption of constant marginal cost does not restrict the functional form of the marginal cost function in general, but only for the relatively small quantities traded in the adjustment market. The assumption should be reasonable, since the marginal cost for fossil-fuel generated plants is proportional to fossil-fuel cost for quantities within limited intervals. Estimates of marginal cost functions of Italian electricity producers based on plant data, in addition, show that the slopes of the marginal cost functions are relatively flat (Guerci and Sapio, 2011).

[9] In reality, there is a price cap, but the assumption simplifies the analysis. I discuss the effect of several of the simplifying assumptions in Section 8.

[10] The residual demand shock could be the result of a shock to aggregate demand or a shock to its competitors' supply functions. For the analysis, the source of the shock is irrelevant, see Wolak (2003a) for a discussion.

Producers do not have forward contract obligations to supply additional electricity into the adjustment market. The reason is that the adjustment market is a market in which producers adjust their production schedules resulting from the day-ahead market, cf. Wolak (2003b). Therefore, producer *i*'s realized variable profit function from offering its quantity into the adjustment market is simply $\pi_i = (p - c_i(q_{DA}))RD_i(p, \epsilon_i)$. Producer i has monopoly on its residual demand, because it is the demand that is left for the producer after all other producers' supply has been considered. Producer i therefore sets the price to maximize its realized profits. I find the best-response price offer by taking the first order condition of the realized profit function with respect to price:[11]

$$p = c_i(q_{DA}) + \frac{RD_i(p, \epsilon_i)}{-RD_i'(p, \epsilon_i)}$$

The best-response price offer, or optimal market price, of firm *i* is the sum of the marginal cost of its unit with highest marginal cost and a mark-up which depends on the properties of the residual demand function. If electricity is a normal good, the residual demand curve is downward sloping so that $RD_i'(p, \epsilon_i) < 0$, and the mark-up term is positive.[12] The validity of this derivation depends on the assumption that the producer is able to set the price that maximizes its profits given the realization of the residual demand function for every ϵ_i. It is however unlikely to hold strictly, because producers' supply functions in the adjustment market are step functions, but should hold approximately. From the equation above, I find the inverse semi-elasticity of residual demand $\eta_i^A = \frac{1}{100} * \frac{RD_i(p,\epsilon_i)}{-RD_i'(p,\epsilon_i)}$, which is the mark-up term divided by 100. This is a simple measure of producer i's ability to exercise market power (McRae and Wolak, 2014). η_i^A measures by how much producer *i* can increase the market price by reducing its supplied quantity by one percent, and this will be referred to, in the rest of the thesis, as producer *i*'s *ability* to exercise market power. η_i^A is non-negative by definition, and the larger is η_i^A, the larger is the producer's ability to exercise market power.

An alternative to the inverse semi-elasticity for measuring ability to exercise market power is the concept of pivotal power. A producer is pivotal when its supply is necessary to satisfy aggregate demand at any possible price. More formally, a producer is pivotal if $RD_i(p, \epsilon_i) > 0$ for all possible prices. When the producer is pivotal, it is guaranteed to produce at least its pivotal quantity $RD_i(p_{max}, \epsilon_i)$, irrespective of its price offer. The producer therefore has the ability to submit an infinitely high price offer.

4.2 Incentive to exercise market power

In the adjustment market, producers often both sold and bought electricity, which means they were a special version of a vertically integrated firm.[13] Because the price that applies to sellers in a uniform price auction also applies to buyers, a vertically integrated producer will not necessarily

[11] See appendix for a derivation.
[12] However, no assumption is made regarding the sign of the derivative of the residual demand function.
[13] Vertically integrated firms usually sell and buy the same product but on different markets.

have incentive to exercise market power even though it has the ability to do so. I therefore extend the model of the profit-maximizing electricity producer to make a vertically integrated producer take into account the effect a price increase in the adjustment market has on its cost of buying electricity from the adjustment market. The purpose of the model is to analyze a vertically integrated producer's incentive to exercise market power given that it sells and buys electricity on the adjustment market, not to analyze why it both sells and buys electricity on the adjustment market. The set-up is similar to the set-up in Bosco et al. (2012), but because I allow for price-elastic demand in the adjustment market, the model is slightly different. This is a contribution of the thesis.

Define buyer *i's* (or producer *i*'s) residual supply curve $RS_i(p)$ in the adjustment market as the aggregate supply curve in the adjustment market subtracted by the sum of all other buyers' demand curves in the adjustment market: $RS_i(p) = S(p) - \sum_{i \neq j} D_j(p)$. Buyer *i*'s residual supply taking into account a stochastic shock v_i is then $RS_i(p, v_i)$, similar to residual demand. If I would assume price-inelastic demand, $RS_i(p)$ would be replaced by a fixed price-invariant quantity.

Using the assumptions from the section of ability, together with the intuition that a vertically integrated producer can choose between producing electricity at its marginal cost $c_i(q_{DA})$ or purchase electricity from the adjustment market at the market price p, the realized variable profit function of the vertically integrated electricity producer *i* is $\pi_i = (p - c_i(q_{DA}))\, RD_i(p, \epsilon_i) + (c_i(q_{DA}) - p) RS_i(p, v_i)$. The first term is the variable profit from producing electricity and selling it on the adjustment market and the second term is the variable profit from buying electricity from the adjustment market instead of producing it. The vertically integrated firm *i* has monopoly on its residual demand and on its residual supply. I find producer *i*'s best-response price offer by taking the first-order condition of the realized variable profit function with respect to the price:[14]

$$p = c_i(q_{DA}) + \frac{RD_i(p, \epsilon_i) - RS_i(p, v_i)}{-RD_i'(p, \epsilon_i) + RS_i'(p, v_i)}$$

Again, the best-response price offer, or optimal market price, is the sum of the marginal cost of the unit with highest marginal cost and a mark-up. $RD_i'(p, \epsilon_i) < 0$ and $RS_i'(p, v_i) > 0$ holds if electricity is a normal good. The mark-up term reflects the producer's incentive to exercise market power taking into account the fact that the producer is also a buyer. When the producer is a net seller, the mark-up term is positive, and when it is a net buyer, the mark-up term is negative. The incentive to exercise market power is always weakly lower than the ability.[15]

The inverse semi-elasticity of net residual demand $\eta_i^I = \frac{1}{100} * \frac{RD_i(p,\epsilon_i) - RS_i(p,v_i)}{-RD_i'(p,\epsilon_i) + RS_i'(p,\epsilon_i)}$ is the mark-up term divided by 100, and is a simple measure of producer *i*'s incentive to exercise market power

[14] See appendix for a derivation.
[15] By setting $RS_i(p, v_i)$ and $RS_i'(p, v_i)$ equal to zero, I get the definition of ability to exercise market power.

(McRae and Wolak, 2014). η_i^I measures by how much producer i can increase (decrease) the market price per MWh of electricity by reducing (increasing) its supplied net quantity by one percent and will be referred to as the incentive to exercise market power in the rest of the thesis. When $\eta_i^I > 0$ the producer is a net seller and has incentive to increase the price, and when $\eta_i^I < 0$ the producer is a net buyer and has incentive to decrease the price. The higher the absolute value of η_i^I the higher is the producer's market power.

An alternative measure of incentive to exercise market power, is net pivotal power. A producer is net pivotal when $RD_i(p, \epsilon_i) - RS_i(p, v_i) > 0$ for all possible prices. When the producer is net pivotal it is guaranteed to produce at least its net pivotal quantity $RD_i(p_{max}, \epsilon_i) - RS_i(p_{max}, v_i)$, irrespective of its price offer. The producer can therefore have incentive to submit an infinitely high price offer.

4.3 Hypotheses

The theoretical model predicts that the measures of ability and incentive to exercise market power should be linearly and positively related to a producer's price offer. More precisely, the model predicts that the measure of ability, defined as the inverse semi-elasticity of residual demand, for a producer that only sells electricity should relate to the producer's price offer in the following way:[16]

$$p = c_i(q_{DA}) + 100\eta_i^A$$

The alternative measure of ability to exercise market power, pivotal power, should also be positively related to the producer's price offer. Because a pivotal producer is necessary to satisfy aggregate demand at all possible prices, theory suggests that a pivotal producer that only sells electricity should submit an infinitely high price offer.

The measure of incentive, defined as the inverse-semi elasticity of net residual demand, for a producer that sells and buys electricity should relate to the producer's price offer in the following way:[17]

$$p = c_i(q_{DA}) + 100\eta_i^I$$

The alternative measure of incentive to exercise market power, net pivotal power, should also be positively related to the producer's price offer. Because a net pivotal producer is necessary to satisfy aggregate demand at all possible prices, after taking into account the producer's own demand, theory predicts that a net pivotal producer should submit an infinitely high price offer.

[16] Because $100\eta_i^A = \frac{RD_i(p,\epsilon_i)}{-RD_i'(p,\epsilon_i)}$.

[17] Because $100\eta_i^I = \frac{RD_i(p,\epsilon_i)-RS_i(p,v_i)}{-RD_i'(p,\epsilon_i)+RS_i'(p,\epsilon_i)}$.

The hypotheses of this thesis are therefore:

1. Producers submitted higher price offers when their measures of ability to exercise market power were higher.

2. Producers submitted higher price offers when their measures of incentive to exercise market power were higher.

Because the producers often bought electricity in the Italian adjustment market, they may not have had incentive to raise the price in all hours in which they had ability to raise the price. The second hypothesis should therefore best describe the behavior of producers in the Italian adjustment market.

There is however some reason to believe that the theoretical predictions do not hold strictly in practice, because of the simplicity of the model. The model abstracts away from several important factors, for example, the sequential dynamics between the three auctions in the Italian electricity market, it assumes that only hourly profit-maximization was relevant for producers, and it assumes that there was no price cap. For these reasons, it is unlikely that the relationship between price offer and the inverse semi-elasticities is as high as 1 to 100, and that pivotal and net pivotal producers submitted infinitely high price offers. However, because electricity is difficult to store, demand needs to be satisfied in every instant of time, and flexible fossil-fuel generating plants dominated the Italian electricity production, a model of short-run profit-maximization should be able to provide predictions of producer behavior applicable to the Italian adjustment market.

5. Data

I use detailed data on individual supply and demand bids from the Italian adjustment market and data on sold and bought quantities in the Italian day-ahead market to test the hypotheses that producers' submitted higher price offers when their measures of ability and incentive to exercise market power were higher. The data are publicly available and downloadable from the market operator's web site with a seven days delay.[18] I use data from February 2005 to October 2009 during which the Italian adjustment market operated as one single market.[19] During this period, the generation fleet was relatively homogenous with fossil-fuelled power plants more dominating than in subsequent years. The market opened for both supply and demand bidding in January

[18] The data are available from Gestore Mercati Energetici (2016) in separate XML-files for each market and each day and requires considerable data management before its ready for analysis. The analysis in this thesis is based on about 100 million raw observations of supply and demand bids into the Italian electricity market.
[19] On November 1, 2009, the adjustment market was replaced by two partly simultaneous and partly sequential markets, and on January 1, 2011 two additional simultaneous and sequential markets were added (GME, Vademecum of the Italian Power Exchange). To include auctions that took place after November 1, 2009 would complicate the analysis considerably since it would require a theoretical framework taking into account the sequential dynamics between several auctions in the adjustment markets.

2005, but I exclude the first month of operation to avoid having behavior in a newly opened and immature market bias the results. In addition, to the Italian auction data I use data on daily brent oil prices in one econometric specification.[20]

Market participants bid into the adjustment by specifying price-quantity pairs reflecting their willingness to sell or buy electricity at different prices. By collecting the pairs for each producer, one can form their individual supply and demand functions, which are step functions. Compared to the Italian day-ahead market, and most day-ahead markets studied in the literature, demand in the Italian adjustment market is price-elastic. Aggregate demand has a substantial elastic part and the market price is often determined on this elastic part, cf. Figure 4 and Figure 5 for a comparison of aggregate demand in the adjustment market and the day-ahead market. This empirical observation motivated the set-up of the theoretical model in Section 4, instead of assuming inelastic demand, as is common in the literature on day-ahead markets.

In the empirical analysis, I analyze the four largest electricity producers in the Italian adjustment market, Enel, E.ON, Edison and A2A. As discussed in Section 2, E.ON entered the Italian electricity market in 2008 when it bought Endesa Italia. What I referred to as E.ON between 2005 and 2007 is therefore Endesa Italia, while it in 2008 and 2009 is Endesa Italia's generation units now owned by E.ON. E.ON did not own any other generation units in Italy between 2005 and 2009. Furthermore, A2A was the result of the merger between AEM, AMSA and ASM. In the empirical analysis, A2A refers to the whole merged company between 2008 and 2009, while A2A between 2005 and 2007 only refers to AEM. The reason is that one cannot analyze the unmerged companies as one unit, because they may not have had aligned behavior, and AEM was by far the largest of the companies merging to A2A.[21]

Not all producers participated in the adjustment market in all hours, which means that the number of observations in the data for the four producers differs. This could imply a problem of self-selection if the producers' participation decisions depended on their levels of market power. While this is a potential problem, it is relative unlikely to be an actual problem, as is discussed in Section 8.

I restrict the analysis to hours in which Italy formed one single adjustment market, which happened when there was no congestion in the transmission grid. When Italy split into several zones, different zonal prices applied in the different zones, and market participants therefore faced a more complex decision problem than what the simple theoretical model in Section 4 can explain. An implicit assumption of this restriction is that market participants could accurately forecast when the Italian market would be national or zonal. Because the adjustment market was repeated in every hour with (almost) the same participants, the participants should have been able to learn

[20] Data of daily brent oil prices were downloaded from the website of the Federal Reserve Bank of St. Louis (Federal Reserve Bank of St. Louis, 2016), and converted into euros using data on the dollar-euro exchange rate downloaded from the website of the European Central Bank (European Central Bank, 2016).
[21] AEM was responsible for 88, 95 and 99 percent of the combined production of AEM, AMSA and ASM in 2005, 2006 and 2007 respectively (own calculations based on auction data from GME).

when there would be congestion in the grid. In addition, the market operator (GME) published demand forecasts before every auction, which should further have facilitated the participants' predictions. Between February 2005 and October 2009, Italy formed a single adjustment market in 37 percent of the hours, cf. Table 5 for the distribution of non-congested hours over the hours of the day. Bosco et al. (2012) make a similar restriction in their analysis of the Italian day-ahead market between 2005 and 2008, which formed one national market in 21 percent of the hours. Their assumption therefore implied a much stricter limitation than what is imposed in this analysis. Because congestion occurs more frequently in high-demand hours in which producers' ability and incentive to exercise market power should be higher (Fabra et al. 2006, McRae and Wolak 2014), excluding congested hours should if anything bias any findings of market power downwards.

It is worth mentioning that I do not have access to data on producers marginal cost, which for fossil-fuel generating plants should be a function of variable operating and maintenance costs, fuel price and the rate at which they convert fuel to electricity. Complete data on daily marginal cost would improve the accuracy of the analysis and enable alternative approaches to analyze market power, as is discussed in Section 8.

6. Empirical implementation

In this section, I explain how I test the hypotheses that producers submitted higher price offers when their measures of ability and incentive to exercise market power were higher. The purpose of the empirical part of this thesis is thus to determine whether there is a systematic and economically and statistically significant positive relationship between the producers' measures of ability and incentive to exercise market power and their price offers. It is important to point out that, in the analysis, I only consider price offers to supply electricity. This means that I analyze market power with the perspective of the supply side, even though I take into account that producers also buy electricity in the adjustment market. The results of the theoretical model in Section 4 form the basis of the empirical approach. I compute hourly measures of ability and incentive to exercise market power for each producer, using data on individual supply and demand functions, in order to test the hypotheses derived in Section 4.

The theoretical model predicts linear and positive relationships between a producer's price offer and both its marginal cost and its level of market power. To test the hypotheses, I therefore need to control for marginal cost to avoid potential omitted variable bias arising from marginal cost being correlated with the measures of market power. I analyze the relationship between producers' ability and incentive to exercise market power and their price offers by estimating linear fixed effects models that control for marginal cost, separately for each producer. In an ideal scenario with data on producers' actual hourly marginal cost, one could instead subtract the marginal cost from the price offers and analyze how the level of market power affects market power rents. However, the fixed effects models should control for the variation in marginal cost.

Crucial assumptions of the estimation strategy are that the linear fixed effects models completely control for the variation in marginal cost between hours, and that the computed measures of ability and incentive truly reflect producers' market power. The estimation of the relationship between market power and price offer does not rely on the assumption of profit-maximization. Rather it is an analysis of whether producers exercised their market power when they could profitably do so.

The empirical analysis below focuses on the four biggest producers, Enel, E.ON, Edison and A2A, in terms of produced quantity in the adjustment market between 2005 and 2009. The four producers together had between 93 and 97 percent yearly market share of production in the adjustment market, cf. Table 1. The analysis therefore covers almost all of the produced quantity, and only excludes small producers that are neither likely to have ability and incentive to exercise market power nor be able to affect market prices.

6.1 Measures of ability and incentive to exercise market power

In this section, I explain how I compute the hourly measures of ability η_i^A and incentive η_i^I for each producer.[22] They are the main explanatory variables in the fixed effects models. The definitions of these ability and incentive measures, derived in Section 4, are $\eta_i^A = \frac{1}{100} * \frac{RD_i(p,\epsilon_i)}{-RD_i'(p,\epsilon_i)}$ and $\eta_i^I = \frac{1}{100} * \frac{RD_i(p,\epsilon_i) - RS_i(p,v_i)}{-RD_i'(p,\epsilon_i) + RS_i'(p,v_i)}$ respectively.

To compute the measures I need the residual demand and residual supply functions of each producer. I construct the residual demand function of a producer by subtracting the supply functions of its competitors from the aggregate demand function. I construct the residual supply function of a producer in a similar way. The residual supply function is constructed by subtracting the demand functions by all other buyers from the aggregate supply function. The nominator of the expression for ability is the quantity of each producer's residual demand function evaluated at the market price. The nominator of the expression for incentive is computed by subtracting the quantity of each (vertically integrated) producer's residual supply function evaluated at the market price, from the quantity of its residual demand function evaluated at the market price.

The denominator of the expression for ability is the derivative of each producer's residual demand function. Because supply and demand functions in the adjustment market are step functions, the derivative is equal to zero or infinity. To be able to compute the measures of market power, I approximate the slope of the function around the market price. I use a finite-difference approximation method, similar to the methods used in Wolak (2003b), Bollino and Polinori (2008) and McRae and Wolak (2014) to solve the problem of step functions. First, I find the highest price p_1 on each producer's residual demand function that is at least 5 percent lower than the market price $p^\star$ and has a corresponding residual quantity $RD(p_1)$ that is larger than the residual quantity at $p^\star$. Second, I find the lowest price p_2 that is at least 5 percent higher than $p^\star$ and has a corresponding residual quantity $RD(p_2)$ that is smaller than the residual quantity at $p^\star$. Third, I

[22] These are sometimes referred to as inverse semi-elasticities.

approximate the slope of the residual demand function around the market price using these two price-quantity pairs in the following way: $RD'(p^{\star}, \epsilon_i) \simeq \frac{RD(p_1,\epsilon_i)-RD(p_2,\epsilon_i)}{p_1-p_2}$. I use the same method to approximate the slope of the residual supply function around the market price. If I choose a too narrow price window, the slope can be sensitive to small steps on the step-functions, and if I choose a too wide price window, I may compute the slope between two points that are irrelevant in the producer's decision. For robustness, I therefore also compute versions of the hourly ability and incentive measures using price windows of 1 and 10 percent, as in McRae and Wolak (2014).

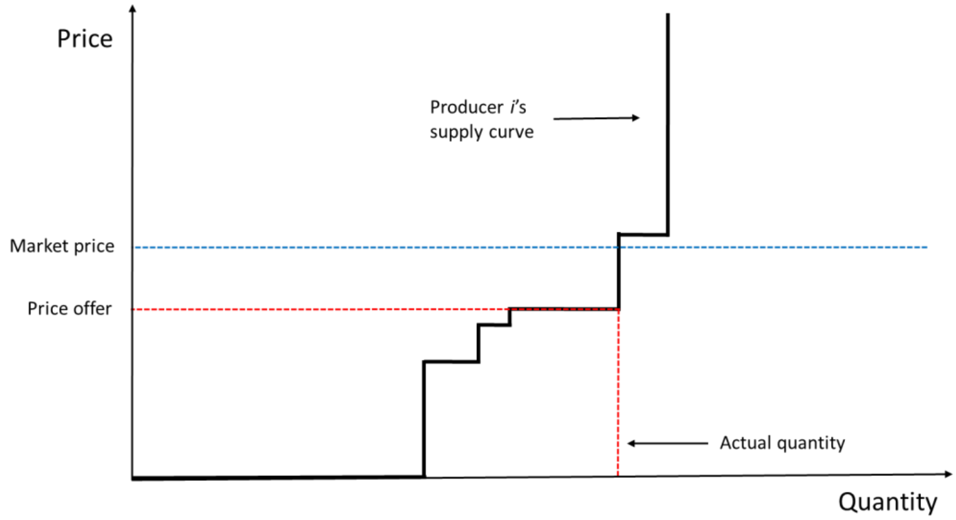
As discussed in Section 4, alternative measures of ability and incentive to exercise market power relates to whether a producer has pivotal or net pivotal power, in other words whether its supply is necessary to satisfy demand. I use two types of variables to measure pivotal power. The first type of variable is binary and indicates whether the producer is pivotal. The variable equals one if the producer's residual demand function is positive for the highest possible price (500 euro/MWh). The second variable is continuous, and measures the pivotal quantity of the producer, which is the quantity it can sell at the highest possible price. The variables described above are alternative measures of ability to exercise market power. For incentive to exercise market power, the alternative variables refer to whether a producer is net pivotal and the producer's net pivotal quantity. A producer is net pivotal when the quantity of its net residual demand function, residual demand subtracted by residual supply, is positive for the highest possible price. The quantity of the net residual demand function at the highest possible price is the net pivotal quantity.

6.2 Relationship between price offer and market power

A producer that maximizes its profits given the realization of its residual demand function (and residual supply function) *could* increase its price offer to affect the market price when its ability to exercise market power is high, and the producer *should* increase its price offer to affect the market price when its incentive to exercise market power is high. In this section, I explain how I test the hypotheses that the four largest Italian electricity producers submitted higher price offers in the adjustment market when they had higher levels of ability and incentive to exercise market power.

I define each producer's price offer in each hour as the price on the producer's actual supply function that corresponds to the actual quantity it sold in the particular hour, cf. Figure 1. The price offer is only equal to the market price when the producer submits the highest of the accepted price offers. The definition of price offer is similar to the definition in McRae and Wolak (2014).

Figure 1 Illustration: Finding a producer's price offer



Note: I find the price offer of producer *i* by finding the price on the producer's supply curve that corresponds to the actual quantity the producer sold in the particular hour. As shown in the illustration, the price offer (red line) need not be equal to the market price (blue line) if the producer is not the one setting the market price. Note that the definition applies even if the producer's price offer was so high price that it was called to produce zero MWh of electricity. The relevant price offer is then the lowest price offer, the price at which the producer supplied zero MWh.
Source: Author's creation.

I estimate the relationship between producers' ability and incentive to exercise market power and their price offers by estimating linear fixed effects models separately for each firm. The fixed effects estimation aims at controlling for changes in producer-level marginal cost. Because the purpose of the analysis is to estimate whether producers submitted higher price offers, which by definition are individual to each producer, it is necessary to estimate the model separately for each producer. The estimation is based on the method in McRae and Wolak (2014), but differs for example in the control variables and robustness checks I do. It differs because I analyze a different type of market, the Italian adjustment market instead of the New Zealand day-ahead market, with higher concentration, elastic demand, and a fossil fuel dominated generation fleet.

I estimate the following main specification of the price offer p_{ihd} for each producer *i*, in hour *h* and day *d*:

$$p_{ihd} = \alpha_{id} + \tau_{ih} + \beta_{1,i} ability_{ihd} + \beta_{2,i} q_{DA\,supply,ihd} + \beta_{3,i} q_{DA\,demand,ihd} + \epsilon_{ihd}$$

$$p_{ihd} = \gamma_{id} + \mu_{ih} + \delta_{1,i} incentive_{ihd} + \delta_{2,i} q_{DA\,supply,ihd} + \delta_{2,i} q_{DA\,demand,ihd} + v_{ihd}$$

$ability_{ihd}$ is the hourly measure of the ability to exercise market power of producer *i*. It either refers to the inverse semi-elasticity of the realized residual demand η^{A}_{ihd} or the measures of the producer's pivotal power. When the effect of the producer's pivotal power is estimated, both the binary indicator of whether the producer is pivotal and the pivotal quantity is included in place of $ability_{ihd}$, and both of the estimates are of interest. $incentive_{ihd}$ is the hourly measure of incentive of producer *i*, and similarly refers to either the inverse semi-elasticity of net residual demand η_{ihd}^{I} or both the binary indicator for whether the producer is net pivotal and the net pivotal quantity. α_{id} and γ_{id} are daily fixed effects, which implies one control for each day of the sample. Because these fixed effects are exactly collinear with any daily changes for producer *i*, they completely control for daily changes in marginal cost of producer *i*. τ_{ih} and μ_{ih} are hourly fixed-effects which account for changes in marginal cost between hours that are common across all days of the sample. $q_{DA\ supply,ihd}$ is the quantity sold and $q_{DA\ demand,ihd}$ is the quantity bought in the preceding day-ahead market. These two variables control for the shift in the marginal cost function arising from the scheduled quantity in the day-ahead market. Because the effect of bought and sold quantities on marginal cost may not be the same, I control for the quantities separately instead of controlling for the net quantity. Due to practical data limitations, bilateral contracts traded through the day-ahead market are not included in the variables. This means that the variables for day-ahead quantity does not control for all the quantity that may potentially affect marginal cost. However, it is unlikely that the quantities traded through bilateral contracts varied as much as the spot-market quantities that I control for, and the effect on marginal cost of bilateral contracts should therefore be mostly controlled for by the fixed effects. ϵ_{ihd} and v_{ihd} are regression errors with zero mean and constant variance.

The hypothesis that producers submitted higher price offers when their ability to exercise market power was higher implies that $\beta_{1,i}$ should be statistically significantly larger than zero. Similarly, the hypothesis that price offers were higher when the incentive to exercise market power was higher implies that $\delta_{1,i}$ should be statistically significantly larger than zero. The simplified theoretical model predicts that the coefficients should equal 100. This is however unlikely to be the case, because of the simplicity of the model and its strong assumptions, but it serves as a benchmark for evaluating the results. Even though the hypotheses state that the coefficients should be larger than zero, I always conduct two-sided tests against the null hypothesis that the estimated coefficient is equal to zero. This is more conservative, and takes into account the fact that the relationship, though unlikely, could be negative.

The most crucial assumptions of these fixed effects specifications are that the marginal cost of a producer is constant and serially uncorrelated after controlling for daily changes, after controlling for changes between hours that are similar across all days, and after controlling for changes due to different levels of quantity scheduled in the preceding day-ahead auction. The marginal cost of fossil-fuel generating plants is primarily a function of fossil-fuel prices, the efficiency of the plant and variable operating and maintenance costs, which are unlikely to change more than daily. The daily and hourly fixed effects should therefore control for the variation and serial correlation, which mainly stem from serial correlation in fuel prices, in marginal cost. If the assumptions are violated however, the estimates of the effect of ability and incentive are likely to be biased upwards because marginal cost as well as ability and incentive should be positively correlated with price offer, according to the theoretical model. Reasons for violation of these assumptions could be that the assumption made in Section 4, that the marginal cost is constant for the relatively small quantities of electricity traded through the adjustment market, does not hold or that the cost of operating a producer's generation fleet varies unsystematically across hours, for example because of temporary outages.

The sample used in the analysis is not random, since it is restricted to the non-congested hours. This likely biases the results, but it should bias the levels of market power downwards, which is conservative, since market power is more likely to be present in congested hours in which demand is usually higher. To make inference consistent in the presence of heteroscedasticity, I always report heteroscedasticity-robust standard errors.

As a test of robustness of the specification above, I estimate a similar linear fixed effects model in which I replace the daily fixed effects with fixed effects for every week. A potential problem with the specification with day fixed effects is that it uses many controls relative to the number of observations, which should not be a concern in the specification with week fixed effects. However, the specification with week fixed effects cannot account for daily changes in marginal cost. To control for some of the daily changes in marginal cost, I also include the daily brent crude oil price in the specification with week fixed effects, which works as a proxy for daily changes in fuel price, but does not capture all daily changes in marginal cost.[23] [24] Because of its potential inability to control for all daily changes in marginal cost, I consider this specification inferior to the one above. I estimate the following secondary specification for each producer *i*:

$$p_{ihd} = \alpha_{iw} + \tau_{ih} + \beta_{1,i}ability_{ihd} + \beta_{2,i}q_{DA\,supply,ihd} + \beta_{3,i}q_{DA\,demand,ihd} + \beta_{4,i}oil\_price_d + \epsilon_{ihd}$$

$$p_{ihd} = \gamma_{iw} + \mu_{ih} + \delta_{1,i}incentive_{ihd} + \delta_{2,i}q_{DA\,supply,ihd} + \delta_{2,i}q_{DA\,demand,ihd} + \beta_{4,i}oil\_price_d + v_{ihd}$$

The differences from the first specification are α_{iw} and γ_{iw}, which are week fixed effects, and oil_price_d which is the daily brent crude oil price. The hypotheses about the coefficients $\beta_{1,i}$ and $\delta_{1,i}$ discussed above are the same for this specification.

It is important to underline that the econometric models estimating the relationship between price offer and inverse semi-elasticity of residual demand or net residual demand are predictive. They do not strictly estimate the causal relationship between producers' ability and incentive to exercise market power and their price offers, even though economic theory clearly suggests that a higher level of market power should be the cause and a higher price offer the effect. In spite of this limitation, the estimates still provide predictive statistical evidence on whether the producers submitted higher price offers when their levels of market power were higher.

Finally, there are some extreme observations in the computed hourly measures of ability for Enel that may have a large influence on linear least squares estimation. Hours in which the measure of

[23] Not all fossil-fuel generators use oil in production, but because gas contracts were often indexed to the brent crude oil price (Bosco et al., 2012), the brent crude oil price should be a good proxy for the relevant fuel price.

[24] The daily brent oil price is exactly collinear with the day fixed effects and it is therefore not necessary to control for it in the specification with day fixed effects.

ability to exercise market power is larger than the 99.9th percentile, or in this sample measures of 208 or larger, have therefore been excluded from the main analysis not to obscure the results of the absolute majority of the hours. The exclusion only concerns Enel and corresponds to 16 of the 15,196 observations or 0.1 percent of its observations. The excluded hours have values of ability between 208 and 45,011, while most hours had values between 0 and 5. Even though the analysis concerns market power, which means high values of ability and incentive, such extreme observations are likely to distort the analysis. An ability measure of 208 implies that if Enel reduced its supplied quantity by 2.5 percent it could increase the market clearing price by 520 euros/MWh. Because the price cap is at 500 this is impossible. While this is a limitation of the theoretical model, the model should be able to explain Enel's behavior in hours with levels of ability up to the 99.9 percentile. Furthermore, these 16 observations are not representative of the vast majority of hours in which Enel had moderate to high levels of market power. The smallest excluded observation is 24 standard deviations away from the mean.[25] A common rule of thumb is to define an outlier, which potentially should be removed from the analysis, as being three standard deviations away from the mean (Osborne and Overbay, 2004). If anything this would suggest a much lower threshold, but since the analysis concerns market power and I want to refrain from discretionary manipulation of the data as much as possible, I believe this is a reasonable approach. In Section 7, I provide robustness checks to show the effect of this exclusion.

7. Results

In this section, I present the results of the empirical analysis. I first present the results of producers' levels of ability and incentive to exercise market power. Secondly, I present the results from the estimations of the relationship between the measures of ability and incentive and the producers' price offers.

7.1 Ability and incentive to exercise market power

Enel, the largest producer, had the highest levels of ability to exercise market power of the four producers. The average of Enel's ability measure between 2005 and 2009 was 2.564 with standard deviation 8.422. This means that Enel on average could increase the market price in each hour by 2.564 euro/MWh by reducing its supplied quantity by one percent. The other three producers had considerably lower levels of ability to exercise market power. E.ON had an average level of ability of 0.079 with standard deviation 0.365, Edison had an average level of ability of 0.045 with standard deviation 0.249, and A2A had an average level of ability of 0.023 with standard deviation 0.083, cf. Table 7.

The 30-day rolling average of Enel's ability measure fluctuated between close to 0 and around 9 between 2005 and 2009. The 30-day rolling average of the other three producers' ability measure was considerably lower and fluctuated between close to 0 and 0.2 for E.ON, close to 0 and 0.6 for Edison and close to 0 and 0.1 for A2A, cf. Figure 2. There is some indication of co-movement

[25] The standard deviation is computed after excluding the observations with ability measure larger than 200.

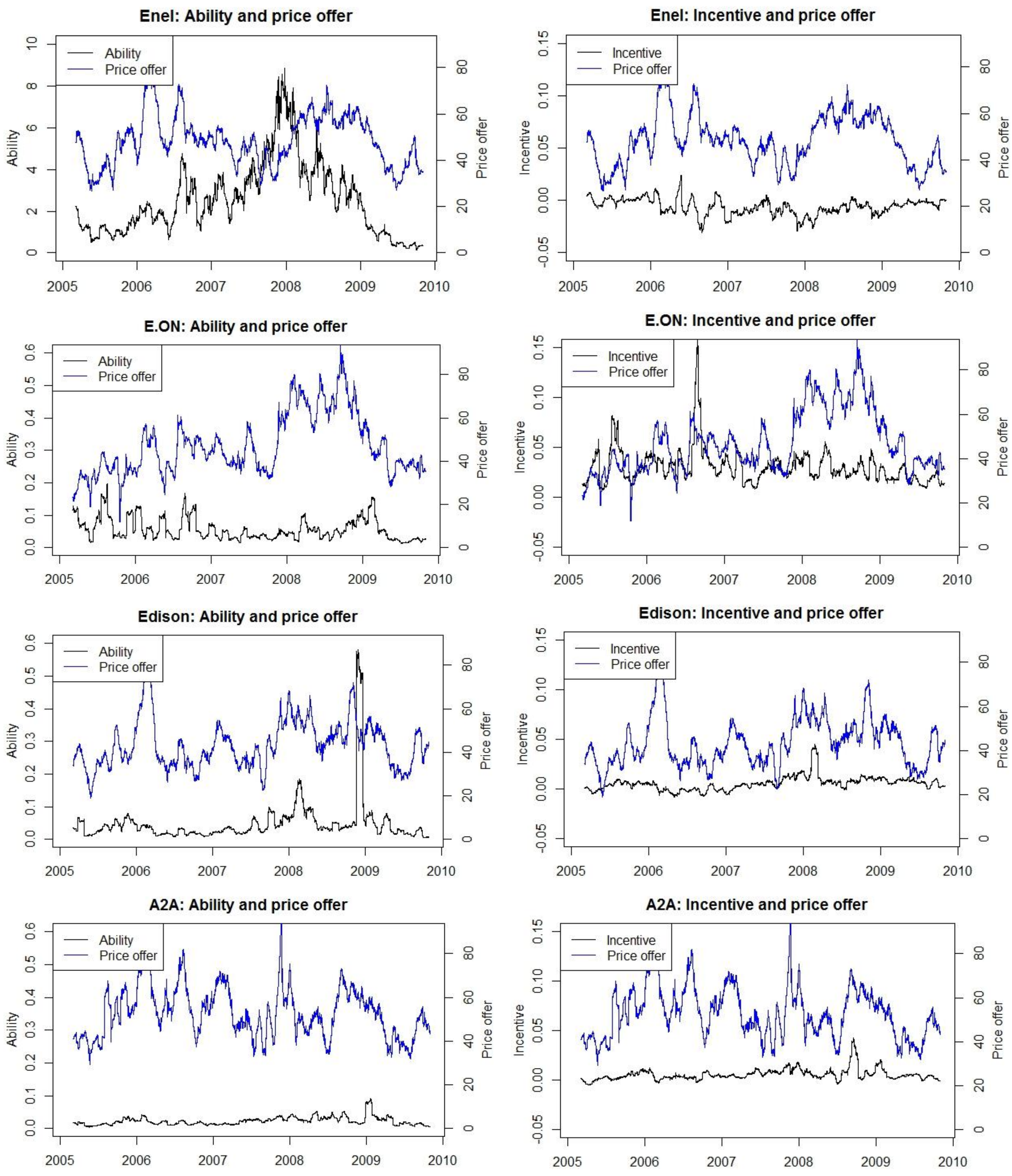
between the producers' ability measures and their individual price offers, as predicted by the theoretical model. However, the level of co-movement differed over time and there seems also to have been other factors driving the price offer other than the ability to exercise market power. Between late 2007 and early 2008, for instance, Enel's average price offer was low when its average ability measure was high. It is important to keep in mind however that the 30-day rolling average consists of many hours and can disguise substantial variation in the levels and co-movement of the ability measure and the price offers.

In contrast to ability, Enel had the lowest level of incentive to exercise market power between 2005 and 2009, and was the only producer with negative average level of incentive. This means that Enel on average had incentive to decrease the market price. Enel's average incentive was –0.006 with standard deviation of 0.049, cf. Table 7. Thus, Enel on average had a slight incentive to decrease the market price by 0.006 euro/MWh by increasing its supplied net quantity, which is its supplied quantity subtracted by its demanded quantity. The substantial difference between Enel's ability and incentive measures stems from the fact that Enel bought a considerable amount of electricity in the adjustment market, which reduced its gains from increasing the market price. The negative average incentive between late 2007 and early 2008 could explain why Enel submitted low price offers during this period.

The other three producers similarly had lower levels of incentive than ability, because they also bought electricity from the adjustment market in many hours. However, the differences were not as pronounced as for Enel. For E.ON the average incentive was 0.035 with standard deviation 0.169, for Edison the average was 0.006 with standard deviation 0.068, and for A2A the average was 0.06 with standard deviation 0.037.

Despite the low levels of incentive to exercise market power for all producers, there is some indication of co-movement between the 30-day rolling averages of incentive and price offers, cf. Figure 2. It is important to remember that despite the fact that the levels of incentive were close to zero in most hours, they were much higher (or lower) in some hours.

Figure 2 Rolling average of price offer and ability and incentive to exercise market power



Note: The rolling averages are calculated using observations from all non-congested hours in which the relevant producer participated in the auction. For Enel, 16 observations with extreme levels of ability have been excluded. Note that the axes for the sub-figure of Enel's ability and price offer differ from axes of the corresponding sub-figures of E.ON, Edison and A2A. The axes for the sub-figures of incentive and price offer are the same for all four producers.

Source: Own calculations based on auction data from GME.

The ability and incentive of a producer to exercise market power can also be measured by pivotal (ability) and net pivotal (incentive) power. I measure pivotal and net pivotal power with a binary variable indicating whether a producer is pivotal or net pivotal and a continuous variable measuring its pivotal or net pivotal quantity. Enel was pivotal in 4,173 or 27.5 percent of the non-congested hours in which Enel participated in the adjustment market, cf. Table 6. This is a substantial share of all hours. In those hours Enel could have increased the market price to the price cap by submitting price offers of 500 euro/MWh, and still be called to produce its pivotal quantity. Enel's average pivotal quantity when Enel was pivotal was 482 MWh. The other three producers were rarely pivotal. E.ON was pivotal in 19 hours, Edison was pivotal in 3 hours, and A2A was never pivotal. The average pivotal quantity for E.ON was 131 MWh and the average pivotal quantity for Edison was 13 MWh. Enel was the only producer who was net pivotal between 2005 and 2009, and Enel was net pivotal in only 2 hours.

7.2 Estimation of relationship between price offer and market power

In this section, I present results of the estimated relationship between producers' price offers and their measures of ability and incentive to exercise market power. The hypotheses are that producers submitted higher price offers when there levels of ability and incentive were higher. The theoretical model supports these hypotheses, and predicts that the estimates of the effect of ability and incentive should equal 100.[26]

The regression results suggest that a higher value of the ability measure in general was associated with a higher price offer, after controlling for marginal cost. Because higher price offers imply higher market prices this can have had implications for the price consumers and companies paid for electricity. For most of the producers, the estimates of the effect of ability and incentive on the price offer are positive and statistically significantly different from zero, which is in line with the hypotheses. However, the estimates are substantially lower than the model prediction of 100, differ in magnitude between the four producers and are not completely robust to changes in econometric specification.

The discussion in this section mostly refers to results from the main specification with day and hour fixed effects, if not otherwise stated. Table 3 and Table 4 provide summaries of the most important results from the main specification, while tables in the appendix provide more detailed results and comparisons to the secondary specification with week and hour fixed effects, results from the specification with day and hour fixed effects without other controls, as well as results from ordinary least squares estimations.

The estimates for the relationship between ability, measured as the inverse semi-elasticity of residual demand η_i^A, and price offer are positive for all four producers. The estimates are highly statistically significant for Enel, Edison and A2A, but statistically insignificant for E.ON, cf. Table

[26] The ability and incentive measures are identical for a producer that only sold on the adjustment market.

3.[27] [28] The effects are estimated using the main specification with day and hour fixed effects. A one-unit increase in the ability measure for Enel is associated with a higher price offer of 0.108 euro/MWh, for Edison it is associated with a higher price offer of 9.149 euro/MWh, and for A2A it is associated with a higher price offer of 36.626 euro/MWh, holding marginal cost constant. A standard deviation change in each producer's ability measure would imply a higher price offer by Enel of 0.910 euro/MWh, by Edison of 2.278 euro/MWh and by A2A of 3.040 euro/MWh, cf. Table 7 for standard deviations.

Table 3 Relationship between price offer and ability to exercise market power

	Enel	E.ON	Edison	A2A
Estimate ability	0.108***	0.378	9.149***	36.626***
Std. error	(0.034)	(0.593)	(2.056)	(6.646)
Day-ahead quantity	Yes	Yes	Yes	Yes
FE Hour	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes
FE Week	No	No	No	No
Adj. R^2	0.556	0.636	0.426	0.433

Note: This table summarizes the results from the main specification (model 4) with day and hour fixed effects in Table 8, Table 9, Table 10 and Table 11. The dependent variable is each producer's price offer. Ability is the inverse semi-elasticity of residual demand η^A computed with 5 percent price window.

Source: Own calculations based on auction data from GME.

Theory predicts that a producer should submit higher price offers in hours in which it is pivotal or net pivotal compared to hours in which it is not pivotal or net pivotal. This is because the producer is guaranteed to produce at least its pivotal or net pivotal quantity, irrespective of the price offer. Enel was the only producer that was pivotal in a substantial share of the hours. The estimates from the main specification with a binary indicator for hours in which Enel was pivotal and the continuous variable for Enel's pivotal quantity are positive and highly statistically significant, cf. Table 12. The estimate for the binary indicator is 11.224 and the estimate for pivotal quantity is 0.017. This suggests that Enel would submit a 19.41 euro/MWh higher price offer in an hour in which Enel was pivotal and had its average pivotal quantity, compared to an hour in which Enel was not pivotal.[29] The estimates for Enel from the secondary specification with week fixed effects are almost identical. The estimates from the main specification for E.ON are negative and highly statistically significant, and even more so from the secondary specification. However, E.ON was only pivotal in 19 hours, and in 14 of these hours E.ON bought the same quantity that it sold. Furthermore, E.ON's average incentive in the 19 hours was negative, which means that E.ON had no incentive to increase the price. Therefore, the negative estimate should not be given much importance. I do not estimate the effects of pivotal power for Edison and A2A or the effect

[27] All presented standard errors in the thesis are heteroscedasticity-robust standard errors.

[28] In general, I only refer to statistically significant estimates.

[29] Effect of being pivotal + effect of pivotal quantity $*$ pivotal quantity $= 11.224 + 0.017 * 481.5 = 19.4095$.

of net pivotal power for any producer, because of the low or non-existent amount of hours in which this occurred, cf. Table 6.

The estimates for the relationship between incentive, measured as the inverse semi-elasticity of net residual demand η_i^I, and price offer are positive for all four producers. The estimates are highly statistically significant for Enel, E.ON and A2A, but statistically insignificant for Edison, cf. Table 4. One-unit increases in the individual incentive measures are associated with a higher price offer by Enel of 37.137 euro/MWh, by E.ON of 3.831 euro/MWh and by A2A by 54.907 euro/MWh. The estimate for the effect of Enel's incentive is substantially higher than the estimate for the effect of ability, because the incentive measure takes into account that Enel bought a considerable amount of electricity from the adjustment market, and incentive should thus be a more relevant measure of when Enel should exercise its market power. For E.ON the estimate for the effect of the incentive measure is statistically significant, but not the estimate for the effect of the ability measure. The reverse is true for Edison. Changes of one standard deviation in the individual incentive measures imply that Enel's price offer would be 1.820 euro/MWh higher, that E.ON's price offer would be 0.647 euro/MWh higher, and that A2A's price offer would be 2.032 euro/MWh higher. This should be compared with the average market price of 60.84 euro/MWh during all non-congested hours. Thus, effects of one standard deviation changes correspond to between 1.1 and 3.3 percent of the average market price. It is important to keep in mind, however, that the effects are estimated based on low levels of incentive. Therefore, it is not certain that one can extrapolate these results to higher levels of incentive, which should be of primary concern for regulators.

According to the theoretical model, the estimates for the effect of ability and incentive to exercise market power should be 100. However, using the estimates from the main specification, it can be rejected that any of the four producers had such a strong relationship between its ability or incentive and its price offer. The estimate for the effect of A2A's incentive on its price offer (54.907) is closest to 100, but it is still more than three standard deviations lower than 100, cf. Table 4. Of all the estimated models, only the estimate for the effect of A2A's incentive on its price offer from the specification with hour and week fixed effects (82.768) is within a reasonable confidence interval (one standard deviation) from 100, cf. Table 16. However, this specification may be biased because it does not control for all daily changes in marginal cost. This should provide sufficient evidence to conclude that the simple theoretical model cannot completely explain behavior in the Italian adjustment market, even though its predictions can be useful in guiding the analysis.

Table 4 Relationship between price offer and incentive to exercise market power

	Enel	E.ON	Edison	A2A
Estimate incentive	37.137***	3.831***	15.970	54.907***
Std. error	(7.224)	(1.323)	(12.114)	(13.807)
Day-ahead quantity	Yes	Yes	Yes	Yes
FE Hour	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes
FE Week	No	No	No	No
Adj. R^2	0.558	0.637	0.424	0.432

Note: This table summarizes the results from the main specification (model 4) with day and hour fixed effects in Table 13, Table 14, Table 15 and Table 16. The dependent variable is each producer's price offer. Incentive is the inverse semi-elasticity of net residual demand η^I computed with 5 percent price window.

Source: Own calculations based on auction data from GME.

I allow demand to be price-elastic, because this is the empirical reality of the adjustment market. This implies that the vertically integrated producers were willing to buy different amounts of electricity at different prices in the adjustment market. In studies of day-ahead markets, vertically integrated producers are often assumed to buy fixed amounts of electricity at any price (price-inelastic demand), because this best fits the data from day-ahead markets. The measure of incentive to exercise market power derived from falsely assuming that vertically integrated electricity producers in the Italian adjustment market bought fixed amounts of electricity is $\eta_i^I = \frac{1}{100} * \frac{RD_i(p,\epsilon_i) - Q_{i,D}}{-RD_i'(p,\epsilon_i)}$, where $Q_{i,D}$ is the fixed quantity demanded by the producer.[30] Using this measure substantially changes the estimates of the effect of incentive to exercise market power for Enel, Edison and A2A, but not for E.ON, cf. Table 17. The estimate in the main specification for Enel's incentive is 37.137, which is significant at the 1-percent level. With the fixed-quantity assumption, the estimate is – 1.056, which is significant at the 5-percent level. Compared to the main specification, the fixed-quantity assumption changes the estimate for Edison from 15.970, which is statistically insignificant, to 5.491, which is statistically significant at the 1 percent level. For A2A, the fixed-quantity assumption changes the estimate from 54.907, which is statistically significant at the 1-percent level, to 6.017, which is insignificant. For E.ON the magnitude of the estimate and the statistical significance is almost identical. Since the data suggest that demand in the adjustment market is price-elastic, it is reasonable to trust the estimates from the main specification but not the estimates based on the assumption of price-inelastic demand.

In all regressions, the bought and sold quantity of each producer in the preceding day-ahead auction affects producers' price offers in the predicted way. The estimate for sold quantity in the day-ahead market is positive and highly statistically significant in all regressions and the estimate for bought quantity in the day-ahead market is negative in all, and highly statistically significant in

[30] The measure is derived in a similar way as the main incentive measure, but with the differing assumption that producers buy fixed quantities. The estimates for ability are not affected by assuming that producers buy fixed quantities, because the ability measure does not take into account that producers buy electricity.

almost all, fixed effects regressions. These estimates are consistent with the assumption that the higher is the sold quantity in the preceding day-ahead market the higher is the marginal cost in the adjustment market and as a consequence the price offer. The opposite holds for bought quantity. Controlling for the day-ahead quantity does not significantly change the estimates for ability and incentive in the fixed effects regressions. It is likely that controlling for quantities traded through bilateral contracts would have had a similar effect on the estimates for ability and incentive. Therefore, the fact that they are not controlled for should not have biased the results.

The regressions for E.ON, Edison and A2A include all observations from the non-congested hours in which the relevant producer submitted at least one bid.[31] The regressions for Enel differ only in that they exclude 16 extreme observations of the ability measure that are larger than 200. The observations are excluded because they may obscure the results of the absolute majority of the relevant hours. The exclusion has effect on the results. Including all observations in the main specification with ability yields statistically insignificant results, cf. Table 18. However, including all observations in the main specification with incentive yields almost identical results as when they are excluded, because the incentive levels are not extreme. For reasons of comparability, the hours with extreme ability levels have been excluded in the main regressions of the effect of Enel's incentive. Regressing the logarithm of the price offer on the logarithm of the ability measure in the main specification also yields a small, positive and statistically significant estimate of the elasticity of price offer with respect to ability.[32] This suggests that all observations could be included with non-linear transformations. However, because the theoretical model predicts a linear relationship between ability (and incentive) and price offer, linear estimation models should be preferred. Regressions that exclude observations with ability measures larger than 100 and 500 produce similar results as the main specification that excludes ability measures larger than 200.

The specification with weekly fixed effects instead of daily fixed effects partly changes the estimates compared to the main specification, cf. column 5 in Table 8 - Table 11 for ability, and Table 13 - Table 16 for incentive, defined as the inverse semi-elasticity, as well as column 2 and 4 in Table 12 for pivotal power. All estimates for the effect of ability become slightly lower. The estimate for the effect of Enel's ability is only statistically significant at the 10-percent level and the estimate for E.ON changes from positive and statistically insignificant to negative and highly statistically significant. In contrast, all incentive estimates become larger with the specification with weekly fixed effects. The estimate for the effect of incentive for Edison changes from positive and statistically insignificant to positive and significant at the 10-percent level. The most plausible reason for why the estimates change is because the week fixed effects model do not completely control for daily changes in marginal cost, as the day fixed effects model do. However, controlling for the daily brent oil price in the specification with week and hour fixed effects does not change the estimates, as in McRae and Wolak (2014), which is surprising. The daily brent oil price is only statistically significant in the regressions for E.ON, in which it has the expected positive effect on

[31] Not all producers participated in the adjustment market in all hours. Naturally, there are no observations for a producer who did not participate.

[32] Before taking the logarithm of the price offer and the ability measure, 0.1 is added to avoid taking the logarithm of zero.

price offer reflecting higher marginal cost. It could be the case that the daily brent oil price is not a good proxy for daily fuel costs. Finally, the Augmented Dickey-Fuller test rejects that any of the time series, except the daily brent oil price, used in any regression are unit roots. The risk of estimating spurious regressions should therefore in general be small.

As a last test of robustness, I estimate the relationship between producers' price offers and their measures of ability and incentive computed using price windows of 1 percent and 10 percent. In general, the estimates change compared to the main results in terms of magnitude but not in terms of sign or statistical significance. Estimates of ability and incentive measures calculated using the 1 percent price window are smaller in magnitude than those presented above, and estimates of measures calculated using the 10 percent price window are larger in magnitude. A potential explanation is that the measures of ability and incentive calculated with the 1 percent window are larger, and the measures calculated with the 10 percent window are smaller than those calculated with the 5 percent window are. It could be the case that measures of ability and incentive with smaller values thus yield larger estimates to explain the same observed behavior. Irrespective of the reason for why the estimates change, this calls for some caution in interpreting the magnitudes of the estimates of the effect of ability and incentive to exercise market power on producers' price offers. However, the fact that the effects go in opposite directions provide some evidence of robustness of the conclusions that can be drawn from this analysis.

8. Discussion

This thesis analyzes whether the four largest electricity producer in the Italian adjustment market submitted higher price offers for their supplied electricity when their levels of market power were higher. The analysis uses a theoretical model and an empirical method established in the literature of electricity auctions. Because of access to data on individual supply and demand functions, no assumptions regarding the functional form of demand or the nature of strategic interaction between producers have been necessary. The contribution of the thesis is to analyze market power in a type of market that is rarely studied, but is still an important component in the design of many restructured electricity markets. The thesis also contributes by incorporating the unusual empirical observation that demand for electricity is price-elastic in the Italian adjustment market. This contribution can also be important for analyses of day-ahead markets, because it is likely that even demand in day-ahead markets responds to prices in the medium and long term.

The fact that demand is price-elastic, would suggest that the producers had lower levels of market power than in electricity markets analyzed in other studies, because demand would respond negatively to price increases. On the other hand, market concentration between 2005 and 2009 in the Italian adjustment market was higher than in most markets studied in the relevant literature, e.g. the New Zealand day-ahead market (McRae and Wolak, 2014), the Texas balancing market (Hortaçsu and Puller, 2008), or even the Italian day-ahead market (Bosco et al., 2012). Therefore, one would expect the electricity producers to have had high levels of market power and profitably submit high price offers.

Enel, the largest producer, had high levels of ability to exercise market power during almost the whole period between 2005 and 2009. During the same period, the other three producers had relatively low levels of ability, and considerably lower levels than Enel had. Compared to the levels of ability of the four largest producers in the New Zealand day-ahead market (McRae and Wolak (2014), Enel's level of ability was substantially higher, and the other three producers' levels of ability were substantially lower. Different market structure could explain this difference. Enel had a larger market share in the Italian adjustment market than any of the producers in New Zealand, and E.ON, Edison and A2A had lower market shares than the four producers in New Zealand.

The levels of incentive to exercise market power were lower for all four producers in the Italian adjustment market than for the producers in the New Zealand day-ahead market (McRae and Wolak (2014).[33] There are two likely reasons for this. The first reason is that the Italian producers' also bought large amounts of electricity, often making their net sold quantity negative or close to zero, while the producers in New Zealand mostly had positive net sold quantities. The second reason is that demand in the Italian adjustment market was price-elastic, while it was price-inelastic in the New Zealand day-ahead market. The difference between Enel's incentive to exercise market power in the adjustment market, found in this thesis, and its incentive to exercise market power in the day-ahead market, found in Bosco et al. (2012), is striking.[34] In the adjustment market, Enel had low incentive to increase or decrease the market price, while it had substantial incentive to increase or decrease the market price in the day-ahead market. The reason is that Enel's net sold quantity in most hours in the adjustment market was close to zero leading to no incentive to increase or decrease the price, which was not the case in the day-ahead market. For E.ON, Edison and A2A, the levels of incentive were also low, but more in line with the levels in the day-ahead market.

The hypotheses of the thesis are that higher levels of ability and of incentive are positively related to higher price offers. The hypotheses derive from a simple theoretical model that predicts that the estimate for relationship between ability to exercise market power and price offer should equal 100 for a producer that only sells electricity. The estimates from the main specification are partly consistent with the hypothesis for ability, but substantially lower than 100 and it can be rejected that any of the estimates for ability equal 100. The estimate for Enel is 0.1, the estimate for E.ON is statistically insignificant, the estimate for Edison is 9.1 and the estimate for A2A is 36.6. The estimates for ability for the four largest producers in New Zealand were between 0.46 and 3.81, which is also considerably lower than the model prediction (McRae and Wolak, 2014). The most apparent explanation for the lower-than-expected estimates for ability in the adjustment market is that all producers also bought a considerable amount of electricity from the adjustment market, which should bias the estimates for ability downwards.

[33] The measure of incentive to exercise market power is defined differently in McRae and Wolak (2014) because it applies to a day-ahead market, but it captures much of the same intuition as the measure of incentive to exercise market power in this paper does.

[34] Bosco et al. (2012) analyze the Italian day-ahead market between 2005 and 2008.

Enel was the only producer who had pivotal power, which also measures ability to exercise market power, in a large enough fraction of the hours to provide meaningful estimates. The estimates suggest that Enel would submit a 19.41 euro/MWh higher price offer when it was pivotal with its average level of pivotal power compared to when it was not pivotal. This is consistent with the hypothesis for ability, but lower than the theoretical model prediction. No producer was net pivotal, the alternative measure of incentive, in enough hours to draw any conclusion regarding the effect of net pivotal power.

All four producers had larger estimates for the effect of incentive, in terms of magnitude, than for the effect of ability, which is reasonable since the incentive to exercise market power should affect price offers more than ability, because it more accurately describes what influence producers' decisions. The estimate for Enel was 37.1, the estimate for E.ON 3.8, the estimate for Edison was insignificant, and the estimate for A2A was 54.9. This means that the results were consistent with the hypothesis for Enel, E.ON and A2A, but not for Edison. The estimates were however lower than what the model predicted and it can be rejected that any of the estimates of incentive from the main specification equal 100. The suggested relationships are economically significant, but it is unlikely that they affected the functioning of the adjustment market substantially. One standard-deviation changes in the incentive measures are associated with higher price offers of 1.82, 0.65 and 2.03 euro/MWH for Enel, E.ON and A2A respectively, which corresponds to 1.1-3.3 percent of the average market price during the non-congested hours. It is worth noting that only one of the estimates for ability and incentive is statistically significant for E.ON and Edison respectively. E.ON's and Edison's estimates for incentive are also the lowest of the four producers. This suggests that the price offers of E.ON and Edison may have been less affected by market power than the price offers of Enel and A2A. Finally, the estimates for incentive in the New Zealand day-ahead market were lower than the estimates found in this thesis and were in the range of 4.02 to 21.63 (McRae and Wolak, 2014).

The results for Enel, in the adjustment market, are in line with the findings of Bosco et al. (2012). They find that Enel did not exercise all of its market power in the day-ahead market between 2005 and 2008. The estimate for Enel suggests that the relationship between Enel's incentive and its price offer is only about a third of the profit-maximizing relationship (37.1 compared to 100). It is also in line with Boffa et al. (2010), which suggest that the state-owned Enel has an objective function that is a combination of short-run profit-maximization and consumer welfare. While Enel's behavior is consistent with the hypotheses and previous literature, the results for E.ON, Edison and A2A are more difficult to interpret. I find that they all have low levels of market power, which is similar to the finding in Bosco et al. (2012). However, Bosco et al. (2012) find that all three effectively exercised their market power when they had the possibility to do so. Only A2A can be said to have exercised much of its market power in the adjustment market, while E.ON and Edison may have exercised only fractions of their market power. Because I analyze the same producers during almost the same time as Bosco et al. (2012), I would have expected similar results. One explanation for the deviation could be that the quantities in the adjustment market were so low that E.ON and Edison did not find it worthwhile to exercise their market power, but this does not explain the behavior of A2A, the smallest producer. A second explanation could be that knowing with certainty that they would be able to adjust their production schedules in the desired way was considered more important for E.ON and Edison than to potentially raise the price while risking to not be able to adjust their production schedules.

In addition, the results in this thesis, as well as the results of Bosco et al. (2012), partly contradict Hortaçsu and Puller (2008). They find that the largest producers in the Texas balancing market profit-maximize, while the smaller producers submit too high price offers. Too high price offers would correspond to estimates larger than 100 in this study, which is far from the estimates for E.ON, Edison and A2A. However, Hortaçsu and Puller (2008) analyze a market with price-inelastic demand, which should give producers more market power. They also use a different method to analyze producer behavior and have access to data on actual marginal cost, which may explain some of the differences.

There are several reasons to be cautious about the findings in this thesis. The first is that the theoretical model used to derive the measures of ability and incentive is very simple. It cannot account for all complexities of the Italian electricity market, such as the sequential dynamics between the day-ahead, the adjustment and the balancing market. In addition, the model treats each hour in isolation, assumes there is no price cap, and disregards that producers' may base their decisions on differing long-run objectives. However, because it is difficult to store electricity, demand needs to be satisfied in every instant of time, and fossil-fuel generation dominated the Italian market, which makes production flexible, a model of short-run profit-maximization should apply relatively well to Italian electricity producers.

Second, there may be problems of selection in the data. Naturally, the results only apply to hours with no transmission congestion, since the analysis excludes hours with congestion. The exclusion is not only simplifying, but also conservative regarding the levels of ability and incentive, since market characteristics under congestion should give rise to higher levels of market power for producers (Fabra et al., 2006 and McRae and Wolak, 2014). The analysis also excluded 16 hours in which Enel had extremely high levels of ability, but as already discussed, this exclusion should make the least squares estimates less biased. The biggest concern should instead be whether the producers selected in which hours they participated in the adjustment market, based on their levels of market power. If that was the case, it would make the results biased and unrepresentative. Enel, Edison and A2A participated in most of the non-congested hours, but E.ON only participated in 9,845 of the 15,252 hours, which could indicate selection. However, given that the main purpose of the adjustment market is for participants to adjust production schedules according to their real-time needs, and that the producers had relatively low levels of market power, self-selection based on the levels of market power should not be a big concern.

Third, the results are not entirely robust to econometric specification or to alternative methods for computing the market power measures. The estimates from the secondary specification with week fixed effects for ability are lower than the estimates from the main specification, while the estimates for incentive are higher. A probable reason for the discrepancy is that the secondary specification cannot control for all daily changes in marginal cost, which biases the results. The results from the main specification could also be biased if the simplifying assumption that marginal cost is constant for the low quantities in the adjustment market is violated. Such a bias would however affect the secondary specification more than the main. Using a 1-percent price window for computing the market power measures results in higher levels of market power and smaller estimates. Using a 10-percent price window, conversely, yields lower levels of market power and larger estimates. While this is unfortunate, it is good that the change in levels of market power and the change in estimates go in opposite directions. Because the changes go in opposite direction, the effect the computation method has on the conclusion should be limited. Finally, the results are estimated for low levels of market power, especially the results for incentive. One should therefore be careful with drawing conclusions about producer behavior at high levels of market power based on these results.

Fourth, one should not interpret the estimates as strictly causal, even though economic theory suggests that higher market power should be the cause of a higher price offer, and not vice versa. McRae and Wolak (2014) provide evidence in favor of a causal interpretation of the estimation method used in this thesis. Using actual data on electricity producers' marginal cost, they can strongly reject that any of the large producers on New Zealand set prices equal to marginal cost, and can conclude that the producers exercise their market power. If their results are transferable to the Italian adjustment market, there is some evidence in favor of a causal interpretation of the estimates. With access to detailed data on individual marginal cost, one could test whether the Italian electricity producers exercised market power by using a different method. That method would test whether the producers submitted price offers substantially above their individual marginal costs, calculated from the data.

9. Conclusion

The purpose of this study is to analyze whether the largest electricity producers in the Italian adjustment market submitted higher price offers when their levels of market power were higher. The study is based on an established theoretical and empirical framework. Detailed data on individual supply and demand functions from the Italian adjustment market between 2005 and 2009 make it possible to relax strong assumptions that often influence results in studies of imperfectly competitive markets. The study contributes to the literature by shedding light on producer behavior in a type of market that is rarely studied, albeit important for the design of competitive electricity markets. The study further contributes by incorporating the empirical observation of price-elastic demand in the analysis.

I distinguish between two types of market power, ability and incentive to exercise market power. The results suggest that this distinction is important, because electricity producers also bought a substantial amount of electricity from the adjustment market in addition to the electricity they sold. This reduced their incentive to raise the market price. Enel, the largest producer, had substantial ability to exercise market power. However, Enel's incentive to exercise market power was very low, because it was often a net buyer of electricity. The other three large producers in the adjustment market, E.ON, Edison and A2A had relatively low levels of ability to exercise market power. Their levels of incentive were also low, but not as low as Enel's incentive.

The econometric analysis suggests that higher levels of ability and incentive in general were associated with higher price offers. This is consistent with the hypotheses. More specifically, the estimate for the relationship between ability and price offer is positive and statistically significant for Enel (including pivotal), Edison and A2A, while it is statistically insignificant for E.ON. The estimate for the relationship between incentive on price offer is positive and statistically significant for Enel, E.ON and A2A, but not for Edison. Because the measure of incentive to exercise market power better reflects what influences producers' decisions, most emphasis should be given to these estimates. The estimated relationships between price offer and incentive are also stronger than the estimated relationships between price offer and ability. One-standard deviation changes in the individual incentive measures are associated with higher price offers of 1.82, 0.65 and 2.03 euro/MWh respectively for Enel, E.ON and A2A. This corresponds to 1.1 to 3.3 percent of the average market price in the adjustment market.

There are however reasons to be cautious about the findings. First, the estimates are smaller than the model prediction, which suggests that the theoretical model may be too simplistic to describe producer behavior in the Italian adjustment market completely. Second, the results are estimated based on low levels of market power, and therefore the estimates do not necessarily reflect how the producers would have behaved with high levels of market power, which should be of primary concern for regulators. Third, the regressions do not strictly estimate causal relationships, but rather provide predictive statistical evidence of the relationship between market power and price offer. Fourth, while the sign and statistical significance of the estimates are generally robust to changes in the method for computing the levels of market power and to changes in the econometric specification, the magnitudes are not. Fifth, even though the estimation method controls for daily changes in individual marginal cost and changes in individual marginal cost that are systematic across hour, it cannot control for unsystematic changes across hours which could bias the results.

Despite these words of caution, one can draw some general conclusions from the analysis. The observed behavior is generally consistent with the hypotheses that producers submitted higher price offers when their levels of ability and incentive to exercise market power were higher, even though the relationships varied between producers. However, the producers mostly had low levels of market power, which suggests that any effect on market prices should have been small. Therefore, it is unlikely that the four largest electricity producers substantially distorted prices in the Italian adjustment market between 2005 and 2009 by exercising market power. If this conclusion can be generalized to other electricity markets, this study has contributed to the literature on market power in electricity auctions by showing that producers' market power may be less of a concern in the auctions following the day-ahead market than in the day-ahead market. An alternative interpretation of the conclusion is that producers' market power may be less of a concern in electricity auctions with price-elastic demand. Regulators should therefore devote most effort to combatting market power in day-ahead markets, in which most of the electricity is traded, and in electricity auctions with price-inelastic demand. However, more research on market power in the electricity auctions following the day-ahead market is necessary to assess whether these claims can be generalized beyond the Italian adjustment market.

Future research could also improve our understanding of the Italian electricity market in several ways. First, theoretical models that can handle the simultaneous and sequential dynamics of the auctions in the Italian adjustment market from November 1, 2009, could analyze market power in recent years when E.ON, Edison and A2A had larger market shares than between 2005 and 2009. Second, with access to detailed data on actual marginal costs, one could analyze whether the producers submitted price offers substantially above their actual marginal cost. Third, researchers could use data from the Italian adjustment market to estimate unbiased marginal cost functions for the Italian electricity producers to compare with the biased estimates in Bosco et al. (2012). Because producers in the adjustment market often sold and bought similar amounts of electricity, their net traded quantity was often zero. Therefore, one only needs to assume that producers submitted price offers equal to marginal cost when they had no incentive to exercise market power, to estimate unbiased marginal cost functions.

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11. Appendix

11.1 Model derivation

In this section, I show the derivation behind the results of the theoretical model of how the price offer should relate to marginal cost and ability to exercise market power, for a producer that only sells electricity, and incentive to exercise market power, for a vertically integrated producer. I begin by considering ability to exercise market power.

The realization of the short-term profit function of a producer that only sells electricity in the Italian adjustment market is $\pi_i = (p - c_i(q_{DA})\ )RD_i(p, \epsilon_i)$. Because the producer has monopoly on its realization of residual demand it chooses the price that maximizes its monopoly profits. Taking the first order condition of the profit function with respect to price, and setting the expression equal to zero gives:

$$\frac{\partial \pi_i}{\partial p} = RD_i(p, \epsilon_i) + \left(p - c_i(q_{DA})\right)RD_i'(p, \epsilon_i) =^! 0$$

Rearranging the expression with price on the left hand side, gives the relationship between price, marginal cost and ability to exercise market power.

$$p = c_i(q_{DA}) + \frac{RD_i(p,\epsilon_i)}{-RD_i'(p,\epsilon_i)}\,.$$

Next, I consider incentive to exercise market power. The realization of the short-term profit function of a vertically integrated producer that both sells and buys electricity in the Italian adjustment market is $\pi_i = (p - c_i(q_{DA})\ )\ RD_i(p, \epsilon_i) + (c_i(q_{DA}) - p)RS_i(p, v_i)$. Similarly, the vertically integrated producer has monopoly on the realization of its residual demand (as a seller) and monopoly on the realization of its residual supply (as a buyer). Taking the first order condition of the profit function with respect to price, and setting the expression equal to zero gives:

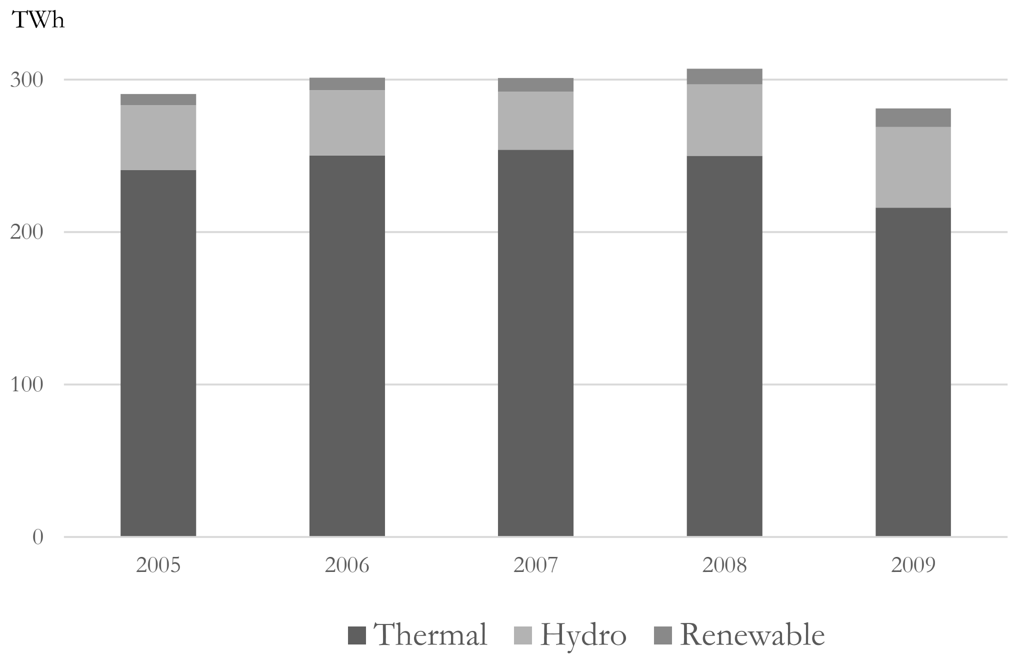
$$\frac{\partial \pi_i}{\partial p} = RD_i(p, \epsilon_i) + \left(p - c_i(q_{DA})\right)RD_i'(p, \epsilon_i) - RS_i(p, v_i) - (p - c_i(q_{DA}))RS_i'(p, v_i) =^! 0$$

Rearranging the expression with price on the left hand side, gives the relationship between price, marginal cost and incentive to exercise market power.

$$p = c_i(q_{DA}) + \frac{RD_i(p,\epsilon_i) - RS_i(p,v_i)}{-RD_i'(p,\epsilon_i) + RS_i'(p,v_i)}\,.$$

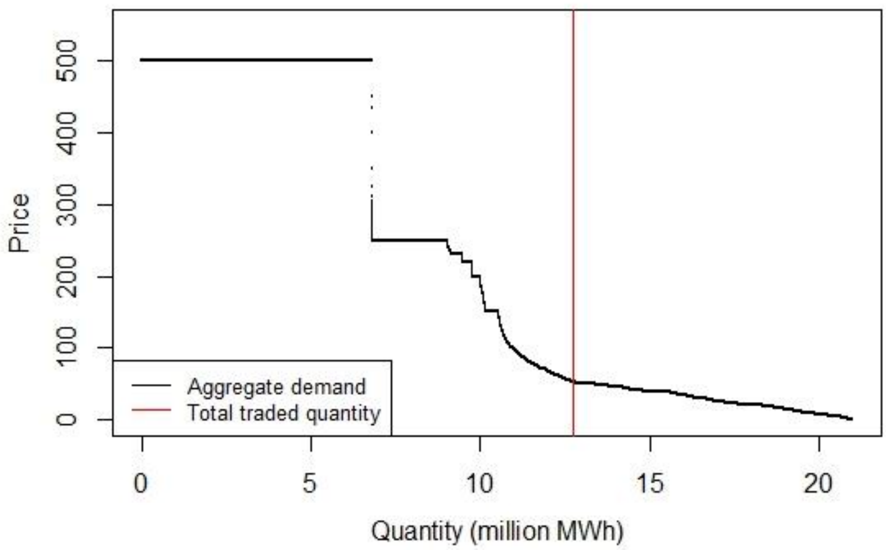
11.2 Figures

Figure 3 Net electricity generation in Italy by power source and year



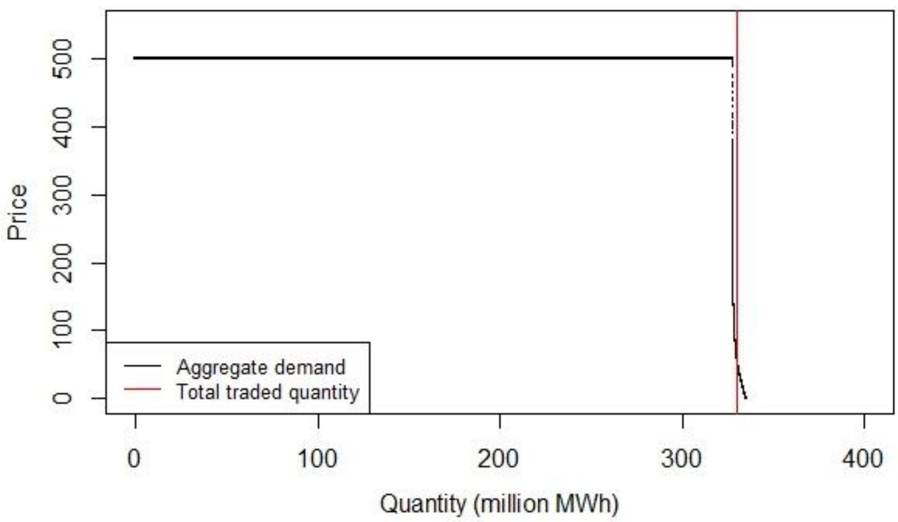
Note: Renewable includes geothermal, wind and photovoltaic generation.
Source: Author's own creation based on data from GME Annual Report 2010.

Figure 4 Elastic demand in the adjustment market (year 2007)



Note: The figure shows the aggregate demand function and total traded quantity in the adjustment market during 2007. The maximum allowed price was 500 euro/MWh. Because the yearly traded quantity intersects the total aggregate demand function far to the right from the inelastic part, the market price must have been set on the elastic part of the demand function in a substantial fraction of the hours in 2007. The result also holds for the rest of the years in the sample.
Source: Author's own creation based on auction data from GME.

Figure 5 Inelastic demand in the day-ahead market (year 2007)



Note: The figure shows the aggregate demand function and total traded quantity in the day-ahead during 2007. The maximum allowed price was 500 euro/MWh. Because the aggregate demand in the day-ahead market is visualized as a straight line, demand must have been completely inelastic in most of the hours in 2007. The result also holds for the rest of the years in the sample.
Source: Own calculations based on auction data from GME.

11.3 Tables

Table 5 Distribution of non-congested hours

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Frequency	939	995	999	999	998	964	962	842	584	457	430	448
Percentage	6.16	6.52	6.55	6.55	6.54	6.32	6.31	5.52	3.83	3	2.82	2.94
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Frequency	435	527	578	590	540	472	378	274	240	340	549	711
Percentage	2.85	3.46	3.79	3.87	3.54	3.09	2.48	1.8	1.57	2.23	3.6	4.66

Note: If the non-congested hours were equally distributed across hours, each hour would have a frequency of approximately 635 and a percentage of approximately 4.17.

Source: Own calculations based on auction data from GME.

Table 6 Pivotal power – Descriptive statistics

	Enel	E.ON	Edison	A2A
Pivotal no. hours	4,173	19	3	0
Pivotal share of all hours	0.275	0.002	0.000	0.000
Pivotal quantity avg.*	482	131	13	0
Pivotal quantity std. dev.*	399	131	7	0
Net pivotal no. hours	2	0	0	0
Net pivotal share of all hours	0.000	0.000	0.000	0.000
Net pivotal quantity avg.*	20	0	0	0
Net pivotal quantity std. dev.*	24	0	0	0

Note: * In this table, (net) pivotal quantity is the (net) pivotal quantity in the non-congested hours that the producer was (net) pivotal.

Source: Own calculations based on auction data from GME.

Table 7 Descriptive statistics

	No. obs.	Mean	St. Dev.	Min	Max
Enel					
Price offer	15,180	49.71	33.85	0	205.34
Ability	15,180	2.566	8.426	0	193.237
Pivotal dummy	15,180	0.275	0.446	0	1
Pivotal quantity	15,180	132.365	299.986	0	3,838.899
Incentive	15,180	-0.006	0.049	-1.426	1.77
Net pivotal dummy	15,180	0.0001	0.011	0	1
Net pivotal quantity	15,180	0.003	0.299	0	36.647
Day-ahead quantity sold	15,180	8,053	3,222	1,367	34,347
Day-ahead quantity bought	15,180	4,580	3,398	406	26,236
E.ON					
Price offer	9,845	47.02	32.62	0	321.81
Ability	9,845	0.079	0.365	0	18.239
Pivotal dummy	9,845	0.002	0.044	0	1
Pivotal quantity	9,845	0.252	8.013	0	391.347
Incentive	9,845	0.035	0.169	-0.466	7.03
Net pivotal dummy	9,845	0	0	0	0
Net pivotal quantity	9,845	0	0	0	0
Day-ahead quantity sold	9,845	959	693	5	4,867
Day-ahead quantity bought	9,845	112	124	0	741
Edison					
Price offer	14,821	45.09	36.95	0	278.26
Ability	14,821	0.045	0.249	0	13.716
Pivotal dummy	14,821	0.0002	0.014	0	1
Pivotal quantity	14,821	0.003	0.202	0	21.15
Incentive	14,821	0.006	0.068	-0.702	7.013
Net pivotal dummy	14,821	0	0	0	0
Net pivotal quantity	14,821	0	0	0	0
Day-ahead quantity sold	14,821	1,220	1,242	4	13,572
Day-ahead quantity bought	14,821	1,107	1,012	21	10,017
A2A					
Price offer	14,022	53.72	48.59	0	499.00
Ability	14,022	0.023	0.083	0	3.02
Pivotal dummy	14,022	0	0	0	0
Pivotal quantity	14,022	0	0	0	0
Incentive	14,022	0.006	0.037	-0.646	1.897
Net pivotal dummy	14,022	0	0	0	0
Net pivotal quantity	14,022	0	0	0	0
Day-ahead quantity sold	14,022	892	938	0	10,740
Day-ahead quantity bought	14,022	587	658	26	5,552

Note: Ability is the inverse semi-elasticity of residual demand η^A and incentive the inverse semi-elasticity of net residual demand η^I. Both ability and incentive are computed with the 5 percent price window. Enel's 16 extreme observations have been excluded.

Source: Own calculations based on auction data from GME.

Table 8 Enel: Relationship between price offer and ability to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Ability	0.047	0.098***	0.143***	0.108***	0.060*
	(0.033)	(0.030)	(0.035)	(0.034)	(0.034)
Day-ahead quantity sold		0.004***		0.004***	0.005***
		(0.0001)		(0.0002)	(0.0001)
Day-ahead quantity bought		-0.001***		-0.001***	-0.001***
		(0.0001)		(0.0002)	(0.0002)
Daily oil price					-0.337
					(0.214)
Constant	49.591***	19.358***			
	(0.287)	(0.719)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	15,180	15,180	15,180	15,180	15,180
Adjusted R2	0.0001	0.162	0.537	0.556	0.459

Note: Ability is the inverse semi-elasticity of residual demand η^A, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 9 E.ON: Relationship between price offer and ability to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Ability	-6.403***	-6.655***	0.550	0.378	-5.294***
	(0.899)	(0.841)	(0.536)	(0.593)	(1.636)
Day-ahead quantity sold		0.009***		0.011***	0.007***
		(0.0005)		(0.001)	(0.001)
Day-ahead quantity bought		0.096***		-0.015*	-0.002
		(0.003)		(0.009)	(0.007)
Daily oil price					0.893**
					(0.353)
Constant	47.519***	27.939***			
	(0.335)	(0.677)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	9,845	9,845	9,845	9,845	9,845
Adjusted R2	0.005	0.132	0.630	0.636	0.342

Note: Ability is the inverse semi-elasticity of residual demand η^A, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 10 Edison: Relationship between price offer and ability to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Ability	15.254***	11.024***	9.494***	9.149***	8.757***
	(1.212)	(1.179)	(2.126)	(2.056)	(1.515)
Day-ahead quantity sold		0.011***		0.008***	0.005***
		(0.0003)		(0.001)	(0.001)
Day-ahead quantity bought		-0.008***		-0.011***	-0.004***
		(0.0004)		(0.002)	(0.001)
Daily oil price					-0.237
					(0.284)
Constant	44.413***	40.302***			
	(0.307)	(0.441)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	14,821	14,821	14,821	14,821	14,821
Adjusted R2	0.011	0.076	0.421	0.426	0.253

Note: Ability is the inverse semi-elasticity of residual demand η^A, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 11 A2A: Relationship between price offer and ability to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Ability	41.625***	36.732***	36.309***	36.626***	27.043***
	(4.915)	(4.761)	(6.767)	(6.646)	(4.824)
Day-ahead quantity sold		0.023***		0.021***	0.017***
		(0.001)		(0.002)	(0.001)
Day-ahead quantity bought		-0.029***		-0.046***	-0.030***
		(0.001)		(0.004)	(0.003)
Daily oil price					0.245
					(0.365)
Constant	52.759***	49.226***			
	(0.425)	(0.556)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	14,022	14,022	14,022	14,022	14,022
Adjusted R2	0.005	0.075	0.420	0.433	0.193

Note: Ability is the inverse semi-elasticity of residual demand η^A, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 12 Relationship between price offer and pivotal power

	Dependent variable: Price offer			
	Enel	Enel	E.ON	E.ON
	(1)	(2)	(3)	(4)
Pivotal dummy	11.224***	11.134***	-21.767***	-38.197***
	(0.872)	(0.870)	(5.877)	(4.635)
Pivotal quantity	0.017***	0.014***	-0.087***	-0.061***
	(0.002)	(0.002)	(0.032)	(0.023)
Day-ahead quantity sold	0.002***	0.003***	0.011***	0.007***
	(0.0002)	(0.0001)	(0.001)	(0.001)
Day-ahead quantity bought	-0.001***	-0.001***	-0.016*	-0.002
	(0.0002)	(0.0002)	(0.009)	(0.007)
Daily oil price		-0.333		0.947***
		(0.208)		(0.354)
FE Hour	Yes	Yes	Yes	Yes
FE Day	Yes	No	Yes	No
FE Week	No	Yes	No	Yes
Observations	15,196	15,196	9,845	9,845
Adjusted R2	0.589	0.494	0.638	0.342

Note: Results in columns 1 and 3 in are estimated with the main specification with hour and day fixed effects. Results in columns 2 and 4 are estimated with the secondary specification with hour and week fixed effects.

*p<0.1, **p<0.05, ***p<0.01

Table 13 Enel: Relationship between price offer and incentive to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Incentive	48.942***	39.833***	37.131***	37.137***	52.202***
	(5.629)	(5.167)	(7.266)	(7.224)	(8.497)
Day-ahead quantity sold		0.004***		0.004***	0.005***
		(0.0001)		(0.0002)	(0.0001)
Day-ahead quantity bought		-0.001***		-0.001***	-0.001***
		(0.0001)		(0.0002)	(0.0002)
Daily oil price					-0.306
					(0.212)
Constant	50.000***	19.838***			
	(0.276)	(0.715)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	15,180	15,180	15,180	15,180	15,180
Adjusted R2	0.005	0.165	0.538	0.558	0.464

Note: Incentive is the inverse semi-elasticity of net residual demand η^I, computed with 5 percent price window.

*p<0.1, **p<0.05, ***p<0.01

Table 14 E.ON: Relationship between price offer and incentive to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Incentive	5.697***	7.136***	3.818***	3.831***	5.412***
	(1.946)	(1.818)	(1.319)	(1.323)	(1.622)
Day-ahead quantity sold		0.009***		0.011***	0.007***
		(0.0005)		(0.001)	(0.001)
Day-ahead quantity bought		0.096***		-0.015*	-0.003
		(0.003)		(0.009)	(0.007)
Daily oil price					0.913***
					(0.354)
Constant	46.817***	27.279***			
	(0.335)	(0.681)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	9,845	9,845	9,845	9,845	9,845
Adjusted R2	0.001	0.128	0.630	0.637	0.339

Note: Incentive is the inverse semi-elasticity of net residual demand η^I, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 15 Edison: Relationship between price offer and incentive to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Incentive	21.206***	19.574***	15.040	15.970	22.929*
	(4.450)	(4.291)	(11.906)	(12.114)	(13.812)
Day-ahead quantity sold		0.011***		0.008***	0.005***
		(0.0003)		(0.001)	(0.001)
Day-ahead quantity bought		-0.008***		-0.011***	-0.004***
		(0.0004)		(0.002)	(0.001)
Daily oil price					-0.233
					(0.284)
Constant	44.970***	40.523***			
	(0.304)	(0.441)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	14,821	14,821	14,821	14,821	14,821
Adjusted R2	0.001	0.072	0.418	0.424	0.252

Note: Incentive is the inverse semi-elasticity of net residual demand η^I, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 16 A2A: Relationship between price offer and incentive to exercise market power

	Dependent variable: Price offer				
	OLS	OLS	FE	FE	FE
	(1)	(2)	(3)	(main)	(5)
Incentive	49.626***	88.691***	49.600***	54.907***	82.768***
	(11.190)	(10.831)	(12.952)	(13.807)	(19.086)
Day-ahead quantity sold		0.024***		0.021***	0.017***
		(0.001)		(0.002)	(0.001)
Day-ahead quantity bought		-0.029***		-0.046***	-0.030***
		(0.001)		(0.004)	(0.003)
Daily oil price					0.251
					(0.363)
Constant	53.422***	49.188***			
	(0.415)	(0.556)			
FE Hour	No	No	Yes	Yes	Yes
FE Day	No	No	Yes	Yes	No
FE Week	No	No	No	No	Yes
Observations	14,022	14,022	14,022	14,022	14,022
Adjusted R2	0.001	0.075	0.418	0.432	0.195

Note: Incentive is the inverse semi-elasticity of net residual demand η^I, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 17 Relationship between price offer and incentive - Assuming that producers buy fixed amounts of electricity

	Dependent variable: Price offer			
	Enel	E.ON	Edison	A2A
	(1)	(2)	(3)	(4)
Incentive (inelastic)	-1.056**	3.866***	5.491***	6.017
	(0.430)	(1.183)	(2.096)	(4.704)
Day-ahead quantity sold	0.004***	0.011***	0.008***	0.021***
	(0.0002)	(0.001)	(0.001)	(0.002)
Day-ahead quantity bought	-0.001***	-0.015*	-0.011***	-0.046***
	(0.0002)	(0.009)	(0.002)	(0.004)
FE Hour	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes
FE Week	No	No	No	No
Observations	15,180	9,845	14,821	14,022
Adjusted R2	0.556	0.637	0.424	0.430

Note: Incentive (inelastic) is the inverse semi-elasticity of net residual demand computed with 5 percent price window, and assuming that producers buy a fixed amount of electricity in the adjustment market. All results are based on the main specification with hour and day fixed effects. *p<0.1, **p<0.05, ***p<0.01

Table 18 Robustness: Effect of removing Enel's extreme observations of ability to exercise market power

	Dependent variable: Price offer				
	FE levels all	FE log all	FE levels < 500	FE levels < 200	FE levels < 100
	(1)	(2)	(3)	(4)	(5)
Ability	-0.0001	0.023***	0.085***	0.108***	0.124***
	(0.0003)	(0.007)	(0.027)	(0.034)	(0.041)
Day-ahead quantity sold	0.004***	0.0001***	0.004***	0.004***	0.004***
	(0.0002)	(0.00001)	(0.0002)	(0.0002)	(0.0002)
Day-ahead quantity bought	-0.001***	-0.00004***	-0.001***	-0.001***	-0.001***
	(0.0002)	(0.00001)	(0.0002)	(0.0002)	(0.0002)
FE Hour	Yes	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes	Yes
FE Week	No	No	No	No	No
Observations	15,196	15,196	15,185	15,180	15,158
Adjusted R2	0.555	0.347	0.556	0.556	0.557

Note: Ability is the inverse semi-elasticity of residual demand η^A, computed with 5 percent price window. *p<0.1, **p<0.05, ***p<0.01

Table 19 Robustness: Effect of method of computing ability to exercise market power

	Dependent variable: Price offer							
	Enel	Enel	E.ON	E.ON	Edison	Edison	A2A	A2A
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Ability 1 % window	0.146***		0.554		5.032***		19.679***	
	(0.032)		(0.430)		(1.458)		(4.885)	
Ability 10 % window		0.101***		-0.588		10.804***		55.737***
		(0.037)		(1.123)		(3.349)		(11.573)
Day-ahead quantity sold	0.004***	0.004***	0.011***	0.011***	0.008***	0.008***	0.021***	0.021***
	(0.0002)	(0.0002)	(0.001)	(0.001)	(0.001)	(0.001)	(0.002)	(0.002)
Day-ahead quantity bought	-0.001***	-0.001***	-0.015	-0.015*	-0.011***	-0.011***	-0.046***	-0.046***
	(0.0002)	(0.0002)	(0.009)	(0.009)	(0.002)	(0.002)	(0.004)	(0.004)
FE Hour	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
FE Week	No	No	No	No	No	No	No	No
Observations	15,170	15,183	9,845	9,845	14,821	14,821	14,022	14,022
Adjusted R2	0.557	0.556	0.636	0.636	0.425	0.427	0.432	0.435

Note: In this table, tests for robustness of the ability measure to the method of computation are presented. In contrast to other estimates for ability, these estimates are based on ability measures computed using 1 and 10 percent price windows. All results are estimated using the main specification with hour and day fixed effects. *p<0.1, **p<0.05, ***p<0.01

Table 20 Robustness: Effect of method of computing incentive to exercise market power

	Dependent variable: Price offer							
	Enel	Enel	E.ON	E.ON	Edison	Edison	A2A	A2A
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Incentive 1 % window	32.467*** (7.851)		1.328* (0.742)		11.381 (7.173)		14.246* (7.472)	
Incentive 10 % window		32.334*** (6.936)		12.737*** (3.458)		19.056 (14.762)		72.296*** (15.287)
Day-ahead quantity sold	0.004*** (0.0002)	0.004*** (0.0002)	0.011*** (0.001)	0.011*** (0.001)	0.008*** (0.001)	0.008*** (0.001)	0.021*** (0.002)	0.021*** (0.002)
Day-ahead quantity bought	-0.001*** (0.0002)	-0.001*** (0.0002)	-0.015* (0.009)	-0.015 (0.009)	-0.011*** (0.002)	-0.011*** (0.002)	-0.046*** (0.004)	-0.046*** (0.004)
FE Hour	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
FE Day	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
FE Week	No	No	No	No	No	No	No	No
Observations	15,170	15,183	9,845	9,845	14,821	14,821	14,022	14,022
Adjusted R2	0.557	0.557	0.636	0.637	0.423	0.424	0.431	0.432

Note: In this table, tests for robustness of the incentive measure to the method of computation are presented. In contrast to other estimates for incentive, these estimates are based on incentive measures computed using 1 and 10 percent price windows. All results are estimated using the main specification with hour and day fixed effects.

*p<0.1, **p<0.05, ***p<0.01