Revisiting Cap-and-Trade in Presence of Publicly Owned Polluters: The Case of Italy 2006-2018 *

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Abstract

We use the example of the Italian electricity spot market to empirically document that carbon pricing schemes may not work efficiently when the major firms in the market are government-controlled. We show that government-controlled companies do not internalize emission prices implied by the European Union emissions trading system in their bids, which reduces pass-through of emission costs and decreases productive efficiency. A vast majority of electricity generators in the world are government owned and this is especially true for fossil fuel burning ones. We argue that, as a result, contrary to conventional wisdom among economists, carbon pricing is unlikely to be an efficient way to regulate and mitigate emissions in the electricity sector. Command-and-control approach, involving emission standards, might be more suitable, especially since reliable estimates of the production functions of electric generators are readily available.

Keywords: electricity, emission permits, multiunit auctions, cap-and-trade regulation

JEL Classification: D44, H23, Q40, Q52

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1 Introduction

Climate change mitigation is a top policy priority. Carbon pricing is considered by economists and experts as an alternative that is superior to command and control regulation (see, among others, Borenstein (2012), Institute for Policy Integrity (2015), Borenstein, Bushnell, Wolak and Zaragoza-Watkins (2019), Andersson (2019)). Carbon pricing, through carbon taxes or through cap-and-trade systems, is also gaining traction as a policy. In 2019, about 15% of global greenhouse gases emissions were priced (World Bank 2019).[1] About half of them were traded within one of the 20 cap-and-trade arrangements active around the world (Icap 2019). Overall, the yearly value of permits consumed in 2018 in the cap-and-trade systems around the world totalled €144 billion (Refinitiv 2019), with a 250% increase over 2018. At the same time, in 2018, governments raised more than $44 billions in carbon taxes. In 2020, the scheduled massive expansion of China's cap-and-trade system will give emissions trading system an additional remarkable boost. As a result, by the end of 2020, 14% of global GHG emissions are projected to be covered by cap-and-trade (and a total 20% of emissions is projected to be priced by 2020).

We empirically document that carbon pricing schemes do not work efficiently when the major firms in the market are government-controlled. We use the Italian electricity spot market example to show that government-controlled companies are not profit-maximizers. They do not internalize emission prices implied by the European Union emissions trading system (EU ETS henceforth) in their bids, which reduces pass-through of emission costs and decreases productive efficiency. They also exhibit a different pattern of investment in emissions abatement as a function of emission prices vis-à-vis their private counterparts. We show that government control of firms is of paramount importance in the energy production sector, which originated more than 40% of global CO2 emissions from fuel combustion in 2019 (International Energy Agency 2019)[2], as well as more than 60% of verified emissions in the EU ETS (Naegele and Zaklan 2019). We argue that, as a result, carbon pricing is not an efficient way to regulate and mitigate emissions in the electricity sector. A command-and-control approach, involving emission standards, might be more suitable, especially

[1] This figure does not include implicit carbon taxes, such as fuel taxes. Overall, in 2019, 57 carbon pricing initiatives were in place around the world.

[2] The figure includes electricity generation, combined heat and power generation and non residential heat generation.

given the reliability of the estimates of the production functions in the electricity generation sector.

The efficiency of carbon pricing rests on the presumption that regulated firms are profit-maximizers. This assumption is necessary for carbon pricing to deliver an efficient abatement pattern across firms in the industry. In the short run, profit-maximizing firms consider the tax or the permits (direct or opportunity) cost in their production and pricing decisions, and, on aggregate, marginal abatement costs are equalized across firms and across sectors.[3] Under plausible assumptions on the competitive environment, carbon price yields higher equilibrium prices and lower equilibrium quantities, which also contribute to an emission reduction through a decrease in electricity demand. In the long run, expected returns to investments in emissions reduction, determined by expectations on the evolution of carbon prices, are equalized across sectors.

Simple example: When firms are not profit-maximizers, carbon pricing fails to provide the correct incentives, and its static and dynamic efficiency properties diminish or vanish altogether. To see the failure of static efficiency, consider a simple case of two firms producing output q using a single input x and emissions e, so that $q = f(x, e)$, with $\frac{\partial q}{\partial x} > 0$ and $\frac{\partial q}{\partial e} > 0$. They operate in a perfectly competitive environment, where they face a price p. Both companies also face a regulated price per unit of emissions p_e, which they take as given (the price could be set through a tax or through tradable permits). Assume firm i is profit-maximizing, while firm j is not. In particular, firm j does not fully respond to the environmental policy, and internalizes only a portion $\phi \in [0, 1)$ of the price per emission p_e. The objective function for firm i is then:

$$\max_{x_i, e_i} \pi_i = pf(x_i, e_i) - C(x_i) - p_e e_i$$

The objective function for firm j is instead:

$$\max_{x_j, e_j} \pi_j = pf(x_j, e_j) - C(x_j) - \phi p_e e_j$$

[3]The resulting increase in prices, in turn, induces consumers to reduce demand, perhaps by adopting energy saving measures.

The first order conditions for the optimal choice of e, for i and j respectively, require:

$$\begin{aligned}\frac{\partial \pi_i}{\partial e_i} &= p\left(\frac{\partial f}{\partial e_i}+\frac{\partial f}{\partial x_i}\frac{\partial x_i}{\partial e_i}\right)-\frac{\partial C}{\partial x_i}\frac{\partial x_i}{\partial e_i}-p_e=0\\ \frac{\partial \pi_j}{\partial e_j} &= p\left(\frac{\partial f}{\partial e_j}+\frac{\partial f}{\partial x_j}\frac{\partial x_j}{\partial e_j}\right)-\frac{\partial C}{\partial x_j}\frac{\partial x_j}{\partial e_j}-\phi p_e=0\end{aligned}$$

The two FOCs may be rewritten as:

$$p\left(\frac{\partial f}{\partial e_i}+\frac{\partial f}{\partial x_i}\frac{\partial x_i}{\partial e_i}\right)-\frac{\partial C}{\partial x_i}\frac{\partial x_i}{\partial e_i} = p_e \quad (1)$$

$$p\left(\frac{\partial f}{\partial e_j}+\frac{\partial f}{\partial x_j}\frac{\partial x_j}{\partial e_j}\right)-\frac{\partial C}{\partial x_j}\frac{\partial x_j}{\partial e_j} = \phi p_e \quad (2)$$

It follows directly from (1) and (2) that the marginal abatement costs for firm i and j, represented by the left hand sides of the above equations, are, at the optimum, equal to two different amounts (p_e and ϕp_e). The larger the difference $p_e - \phi p_e$, i.e., the smaller ϕ, the larger the difference between the marginal abatement costs of the two companies in equilibrium, and the larger the inefficiency.

In addition, since policy makers set carbon taxes under the implicit presumption that firms internalize them in their objective function, a carbon tax applied to firms that are not maximizing profits may fail to achieve the desired target of emission abatement altogether.

Hortaçsu, Luco, Puller and Zhu (2019) have identified one reason of departure from profit maximization in that generators seem to be lacking strategic sophistication. They use the Texan electricity market, where firms are private, as their example. They find that strategic sophistication is positively related to firms' size and to managerial education. We identify an additional, and perhaps even starker, source of deviations from profit-maximizing behavior: the government control of firms. We show that Enel, the major Italian generating company, is not fully internalizing the emission costs in its bids, differently from its rivals. This holds true in general, and even when we compare very similar generator units, with roughly identical cost functions, and subject to the same residual demand. We argue, as a result, that Enel's objective function must be different from that of its rivals. Enel is partially government owned, with the government owning a controlling

stake and de facto appointing the management. Government ownership is at 23.6%.[4] This is not an exception. In 2018, in 18 out of the 30 countries that are part of EU-ETS, the government owns a share of the largest electricity generation (which is typically even larger than Enel in terms of the share of installed generation capacity) equal or above that held by the Italian government in Enel.[5] Around the world, the 7 largest electricity generating companies by installed capacity (and 13 out of the 14 largest) are more than 50% owned by the national governments (International Energy Agency 2018).[6] Government ownership of large electricity generators is thus the rule, with some prominent exceptions, including United States, Germany and Spain. The two papers that, up to now, estimated the internalization and the pass-through of allowance prices to final prices in the EU-ETS framework (Fabra and Reguant (2014) and Hintermann (2016)) analyze two of the exceptions, Spain and Germany. The behavior of non-government controlled companies in Italy confirms the results of these studies. However, the result, that emission prices are fully internalized and fully passed through, differs markedly in case of public firms.

We demonstrate the inefficiency of carbon pricing in the short run, resulting from pricing and quantity decisions that fail to equalize marginal abatement costs across firms. We also provide evidence of differential behavior between government-owned and non government-owned companies in the long-run, in terms of investment decisions. Our paper complements Fowlie (2010), who focuses on investment decisions only. She analyzes the NO_x Budget Program, a large emissions trading program that covers 19 Eastern U.S. states. Exploiting the variation in ownership structure (pub-

[4]This gives the government a predominant role in Enel, given that other investors are fragmented (at the beginning of 2019, 57.6% of them were institutional investors, and 18.8% of them were retail investors).

[5]In particular, in 2018, out of the 30 countries (in addition to Italy - the other 27 EU member States, plus Norway, Iceland and Lichtenstein), 17 of them have their largest generator characterized by both a share of installed capacity above 30% of the total installed capacity in that country, and with the government of that country involved in that company with a share equal to or above that of Enel: Austria (Verbund), Bulgaria (BEH), Croatia (HEP Group), Cyprus (Electricity Authority of Cyprus), Czech (CEZ), Denmark (Orsted), Estonia (Eesti Energia), Finland (Fortum), France (EDF), Greece (PPC), Hungary (MVM Group), Poland (in this case the four mayor generators - PGE, Energa, Tauron, Enea - all have the government as shareholder with shares above 30%, and together they have a 90% market share), Slovakia (SE), Slovenia (HSE), Sweden (Vattenfall), Norway (Statkraft, although in that case most of the generation is hydroelectric), Iceland (Landsvirkjun).

[6]The first 7 companies by generation capacity in 2018 were: China Energy Investment Group (230 GW, fully state-owned), China Huaneng Group (172 GW, fully state-owned), China Huadian Corp (146 GW, fully state-owned), China Datang Corp (138 GW, fully state owned), Electricité de France (129 GW, 83.7% state owned), State Power Investment Corp, (China fully state owned), Korea Electric Power Corp (90 GW, 51% state-owned, by the Korea Development Bank and the Government of South Korea). Enel, ranking 8th in the list, is the first in which the government, which still has a contol stake of 23.6%, does not hold the absolute majority. The first fully private company is Duke Energy Corporation, which ranks 15th.

lic vs private) and in the regulatory regimes to which different coal-fired generators are subjected, she shows that government-owned and rate-based regulated firms are more likely to adopt capital intensive compliance options than deregulated, privately-owned plants, which are then more likely to use permits. This is consistent with a difference in the cost of capital across the types of firms. A number of additional papers have emphasized challenges due to the imperfect design of carbon pricing policies, due either to their political feasibility constraints, or to the inefficient combination of carbon pricing with other forms of regulation. Borenstein et al. (2019) argue that capping emissions in a cap-and-trade system may prove politically infeasible. The high volatility of emission prices, in turn determined by high uncertainty in the business-as-usual emissions, is likely to be politically unacceptable, thus triggering the introduction of price floor and price ceilings that end up being binding with high probability. Other papers have emphasized inefficiencies triggered by the overlap of different policies. Böhringer and Rosendahl (2010) look at the interaction between cap-and-trade and command-and-control policies to stimulate renewables, and find that it may promote the inefficient utilization of relatively polluting conventional fuels. Inefficiencies stemming from their interaction are further exacerbated when, within a multi-jurisdiction ETS system, different command-and-control policies are implemented in different jurisdictions (Grischa Perino and van Benthem 2019). Abito (2020) estimates substantial abatement inefficiencies related to the overlap of carbon pricing with suboptimal economic regulation, in the form of rate of return regulation. Calel (2020) empirically documents that the EU-ETS has not driven short-term reductions in carbon-intensity of output for regulated firms.

Another stream of papers has, instead, emphasized the positive effects of carbon pricing. Calel and Dechezleprêtre (2016) and Calel (2020) show that the EU-ETS boosts patenting of low-carbon technologies, while not crowding out patenting for the other technologies. Gerarden, Reeder and Stock (2020) find that the efficiency of carbon pricing is not undermined by its interaction with upstream policies, such as the royalty surcharge on US federal coal.

It is conceivable that the objective function of government-controlled firms differs from profit maximization, and that government-controlled enterprises may pursue political goals (Shleifer and Vishny 1994). A government-controlled company affects the government's benefit function not only

through the stream of profits it can extract from it, but also through its effects on the government's perception in the eyes of the public opinion, which, in turn, may impact the probability of the government to remain in power. There is evidence on the differential behavior between government-controlled and private firms. Clò, Ferraris and Florio (2017) show that public ownership in Europe has always improved environmental performance, and the differential behavior persisted even after the introduction of EU-ETS.

Our results imply that cap-and-trade in the electricity sector is an inefficient policy, both statically, because it does not equalize abatement costs across sectors, and dynamically, because it does not equalize expected returns from emission-abatement incentives across sectors. Cap-and-trade, however, by capping emissions, mitigates them by design, unless firms grossly violate the emission rules (Martin, Muuls and Wagner 2016). However, our findings have perhaps an even starker implication if applied to an environment with a carbon tax. When firms are profit-maximizing, carbon tax and cap-and-trade, as long as they are both carefully designed and politically accepted, are both equivalent (Stavins 2020). We show that, instead, if firms do not internalize the carbon price, they do not adjust their emissions to changes in taxes, and hence the carbon tax may become ineffective as an instrument to mitigate emissions, both in the short and in the long run.

Finally, based on our findings, we can draw the clear implication that the upcoming expansion of cap-and-trade in China, where the seven major generators are fully government-owned, is likely to bring about inefficiencies. A more efficient mitigation policy, in China, should involve a command-and-control approach.

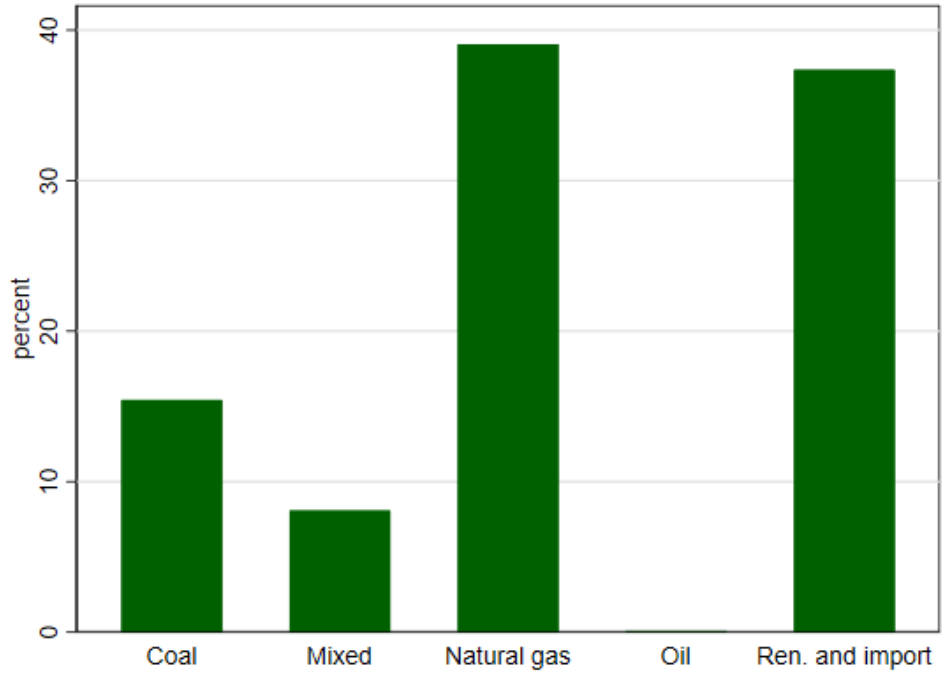
2 Primer on the Italian Electricity Market

The Italian market is a fairly representative one in Europe, not only because of the ownership structure of its main players, but also because of its size, its fuel mix, its organization and the timing of its liberalization.

In 2017, with a net generation of 285.1 TWh and a consumption of 320.4 TWh, Italy was the fourth largest electricity market in Europe. The fuel mix of the Italian electricity generation in 2017 is dominated by natural gas (44.27%), followed by renewables (40.83%), coal (13.47%) and

oil (1.44%). In the last 15 year, the share of renewables has markedly increased (from levels of 18.26% and of 31.48% in 2006 and in 2012, respectively), mostly at the expense of oil (whose share exceeded 10% in 2006), and partly at the expense of coal (whose share peaked at 16.4% in 2012, and then declined). Hydro power has traditionally been by far the largest renewable source. In 2017, it still was the largest, albeit by a smaller margin, covering slightly more than a third of all renewables. Figure 1 illustrates the percentages of different type of generation units being marginal in the Italian generation.

Figure 1: Share of marginal production



NOTE: This figure shows the share of marginal production by technology. Renewables include solar, hydro and wind energy. The shares are computed using bidding data and realized supplied quantities for each generator.

The Italian electricity sector started its transition from a vertically integrated monopoly run by Enel to a liberalized market in 1999.[7] Entry of generators competing with the incumbent was gradual but steady. Enel's share of generating capacity declined, from 44.97% in 2006 to 34.74% in 2012 and 27.52% in 2018.[8] Coal (for a bit less than 40%) and hydro (for about a third) are the

[7] See 1999 Decreto Bersani, available at:
`https://it.wikipedia.org/wiki/Decreto_legislativo_16_marzo_1999,_n._79`.

[8] See ARERA (Various years).

two primary sources in Enel's generation mix in 2018.[9] Compared to the average Italian generation mix, Enel is more focused on coal (in 2018, 80% of the Italian coal-fueled generation comes from Enel), and less on natural gas.

Along with generation, competition intensified in the retail sector as well. In 2004, as a fundamental step in the liberalization process, Italy started a designed power exchange market, where transactions occur under the coordination of a system operator.[10] Besides the organized spot market, electricity transactions in Italy can also occur via bilateral physical forward contracts. Many electricity markets around the world are now deregulated and transactions, similarly to Italy, occur both in a spot market, and through bilateral contracts.[11] About two thirds (ranging from 58% in 2011 to 72% in 2013, 2017 and 2018) of electricity is traded in the power exchange, about one third via bilateral forward contracts.[12]

The power exchange includes three major markets, the day-ahead, the intraday and the re-dispatch market. The day-ahead market plans for essentially all of the expected electricity. It is organized around multi-unit uniform price auctions where generators submit their hourly bids via a supply schedule. Generators are paid the market-clearing prices specific to each hour and each zone,[13] while the demand side pays a quantity-weighted average of the different zonal prices for the hour.[14] The intraday market allows for re-trading to update positions closer to the delivery time. In the re-dispatch market, the system operator requires power units to change their initial commitments (by increasing or decreasing them), so as to solve congestion issues that persist after the day-ahead and the intraday markets. The day-ahead market clears a lion's share in the power exchange. In 2018, about 213 TWh were traded in the day-ahead, a little more than a tenth of that

[9] See Enel (2018).

[10] By 2007, all Italian consumers have been entitled to choose their suppliers. Previously, supply for residential consumers was operated by a monopolistic government-owned procurement company, called the Single Buyer.

[11] Examples of countries whose electricity markets are organized similarly to the Italian one include all the major European countries (e.g., Germany, France, Great Britain, Italy, Spain, the Netherlands, Poland), several regions in the United States covering approximately 70% of the U.S. population (with the six exchanges ERCOT, PJM, CAISO, MISO, NYSO, ISO-NE, see `https://www.eia.gov/todayinenergy/detail.php?id=40913`), Australia, New Zealand, Japan. Other power exchanges, such as, for instance, the Colombian and the Brazilian one, have different rules (Cramton 2017).

[12] (n.d.).

[13] There are two major exceptions to this rule. First, renewable generation satisfying certain conditions is paid a fixed rate.

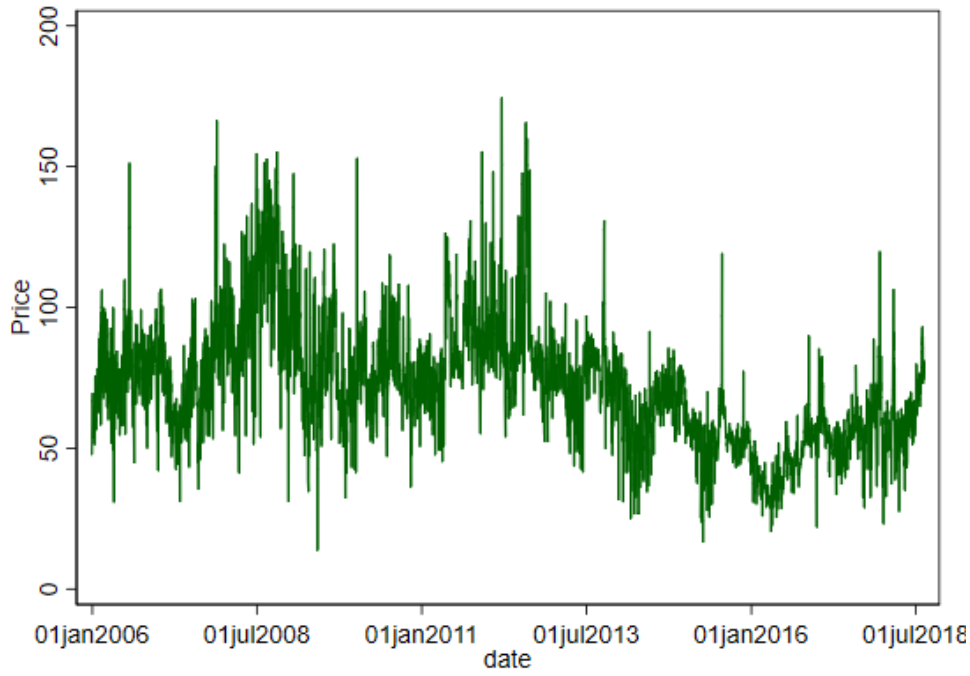
Second, some units, designated by the System Operator as essential for a smooth network operation, must be ready to produce whenever asked to by the SO, and receive a fixed remuneration based on their average cost.

[14] This reflects political concerns of regional redistribution.

(25 TWh) were traded in the intraday market, while around 33 TWh were traded in the re-dispatch market.

Prices on the Italian day-ahead market are high with respect to other major European markets, but there are indications of convergence. In 2008, the average Italian day-ahead price was 86.99 €/MWh (compared to 65.76 €/MWh in Germany, 69.15 €/MWh in France and 64.44 €/MWh in Spain), in 2013 it was 62.99 €/MWh in Italy (compared to 37.78 €/MWh in Germany, 43.24 €/MWh in France and 44.26 €/MWh in Spain), in 2018 it was 61.31 €/MWh in Italy (compared to 44.47 €/MWh in Germany, 50.20 €/MWh in France and 57.29 €/MWh in Spain). Figure 2 depicts average wholesale electricity prices in Italy.

Figure 2: Electricity prices



NOTE: This figure depicts the average daily clearing price of the Italian day-ahead market. We use bidding data and for each day average over geographical zones and hours of day.

As Figure 2 shows, prices in Italy are highly cyclical and volatile. This reflects on the one hand seasonal and daily cyclical variations, and on the other hand non cyclical changes, due, among other things, to weather conditions on both the demand and the supply side, and, on the supply side, to the availability of intermittent renewables. These are fairly established and common patterns in

the electricity markets (see, e.g., Fabra and Reguant (2014)).

The overall market is divided into a number of zones. A zone is defined as a geographical unit within which the price on the day ahead market is the same at any given point in time. In any hour, day ahead prices may differ across zones. This happens when the transmission line linking them is congested. In 2018, the South had lower average day-ahead price than the North (59.37 to 60.71), the prices vary over time with a standard deviation of 22.

The major Italian generating company, Enel, is de facto controlled by the government. The government directly controls 23.6 %, while other investors being fragmented (at the beginning of 2019, they were 57.6% institutional investors, and 18.8% retail investors). The government has had a controlling share of Enel throughout the period covered by our analysis.[15] While Italy is the major market for Enel, where it collects approximately half of its revenue and half of its profit, Enel is a global company, with a prominent presence, in particular, in Spain (where it controls Endesa), and in South America.[16] It is also the eight company by power generation in the world (IEA, 2018).

Another prominent generating company, Eni, is governmend-controlled, with the government holding, in 2018, 30.10% of shares (25.76% through the government-owned investment bank Cassa Depositi e Prestiti). The other generators are either private,[17] or controlled by foreign government-owned companies,[18] or controlled by local governments.[19]

The companies controlled by the Italian government might have an incentive to respond to political incentives in their pricing decisions, since the companies' performance affects the citizens' perceptions of the government itself. However, the dimension of performance that citizens deem important to assess the government's ability or benevolence may not necessarily coincide with profits. Companies controlled by foreign governments presumably do not face similar political

[15]Enel was fully government-onwed until 1999. Government share then declined to 68.3% after the first privatization round. It then declined further to 41.60% in 2004 (including 10.25% held by the government-controlled investment bank Cassa Depositi e Prestiti). It then gradually reduced to 31% in 2009, then to 25.5% in 2015, and to 23.6% in 2016.

[16]See Enel (2018).

[17]Examples include E.on and Sorgenia.

[18]These include Edison, controlled by the French government-owned generator Electricité de France. In 2018, Edison has been the third market player by gross electricity generation, with a 7% market share.

[19]These include A2A, where the municipalities of Brescia and Milan, in 2018, were holding 25% of the shares each. In 2018, A2A has been the fourth market player by gross electricity generation, with a 6.2 market share.

incentives, as a foreign government is not affected by the perceptions of Italian residents. In the case of companies controlled by municipalities, given zonal pricing and a single national price for buyers, a disproportionate portion of the benefits of strategies that potentially deviate from profit-maximization would be enjoyed by voters in other municipalities, while the cost of such strategies would be incurred locally in the form of lower profit. As a result, political incentives seem very much diluted, with the likely result that these companies rationally attempt to maximize profits. We will hence center our analysis around Enel.

3 Data

3.1 Wholesale Auction Market

We use detailed data on the hourly bids submitted to the Italian day-ahead electricity market from January 2006 to August 2018 that are made publicly available through the Italian system operator with a slight time delay.

Generators, each day, submit up to 24 hourly supply functions, one per-hour,[20] while traders and large consumers submit up to 24 hourly demand functions. Bids are then ordered, and aggregate demand and supply functions are constructed. When inter-zonal transmission capacity is exceeded, the market is subdivided into several zonal markets, each of which is cleared by a different zonal price. We observe all the price-quantity pairs submitted by each firm for each of their production units for each of the 24 hours of the day for the 13 years in the sample, as well as all the price-quantity pairs submitted by the buyers. The data also include the amount of electricity sold via bilateral physical contracts, so we observe the entire hourly net production of each generating unit.

We use publicly available weather data, on temperature, humidity and wind speed.[21]

[20] The maximum number of price quantity pair in a supply bid for a unit has varied over the years, from 4 to being uncapped.

[21] We use data from `https://archivio-meteo.distile.it/` for 2006-2016, and from `https://www.meteo.it/` for 2017-2018. We use data of the provincial capital of the province where the power plant is located.

3.2 Marginal costs

Our data allow us to measure the marginal costs incurred by thermal power plants. For each thermal unit, we have engineering estimates of the "heat rate", i.e., the rate at which, for each amount of instantaneous electricity supplied, the power plant converts the energy content of the fuel into electricity (provided by Ref-E). We also have engineering estimates of different fuels' heating value (Ref-E). We complement them with data on fuel costs. Fuel costs for natural gas units are the monthly natural gas spot prices in Italy plus a distribution charge. For coal units, we use the monthly average spot price for coal delivered to Italy (EIA) plus a distribution charge.

3.3 Emission Permits

The EU ETS is the largest multi-national emissions trading scheme in the world. It covers installations that are collectively responsible for almost 50% of the EU's emissions of CO_2, in the power generation sector, in aviation (as of 2010), and in other energy intensive industries (including iron and steel, pulp and paper, refineries, and cement).

Under the EU ETS, each regulated installation must surrender every year an amount of allowances corresponding to its emissions. Allowances are initially allocated by member states to industrial operators through two different methods. In the first trading period (Phase 1), covering 2005–2007, as well as in the second period (Phase 2), covering 2008–2012, the overwhelming majority of allowances (above 90%) has been initially freely allocated to industrial operators based on recent emissions, under the so-called grandfathering (Chevallier 2012). In the third trading period (Phase 3), covering 2013-2020, allowances have been primarily allocated via an auction.[22] After the initial allocation, the operators within EU ETS may re-assign or trade their allowances by several means: (i) privately, moving allowances between operators within a company and across national borders, (ii) over the counter, using a broker to privately match buyers and sellers, and (iii) trading on the spot market of one of Europe's climate exchanges. Allowances do not expire

[22]In particular, in the power generation sector all of the permits have been auctioned off in Phase 3 (with the only exception of new member states, that have received some permits for free). In the manufacturing sector, the share of auctioned permits has ranged from 20% (in 2013) to 70% (in 2020), while in the aviation industry most of the allocation (85%) has been free. Overall, these patterns have been consistent with the EU Directive 2018/410, which set a target of 57% of the permits to be allocated through auctions in Phase 3.

Table 1: Summary statistics

	mean	sd	p25	p50	p75
EUA price	11.03	7.81	4.90	9.15	16.08
Coal price	12.51	2.95	10.07	11.68	14.75
Gas price	35.43	7.59	30.25	34.96	38.98
Marginal cost of permits	12.82	13.68	3.32	8.28	17.32
Marginal fuel cost	43.85	21.21	29.76	39.09	52.30
Observations	231,662				

NOTE: This table shows the basic summary statistics for the main variables. We restrict the sample to all marginal bids as they set the electricity price, and we work with marginal bids for the bulk of this paper. The EUA price shows the price of the permit in EUR per tonne of CO2. Coal price and gas prices are in EUR per tonne. The marginal cost of permits shows the marginal cost of EUA for producing an additional MWh of electricity for the marginal generator, similarly for marginal fuel costs. Data about input costs was provided by Ref-E.

and can be transferred across time, the only relevant exception having been the impossibility to transfer allowances issued during Phase 1 to Phase 2. For our analysis we use the time series of EU ETS futures prices obtained from Reuters. The prices of a tonne of CO_2 emission exhibits substantial variation. In Phase 1, they ranged from above €30 to almost 0, at the end of 2007, before the expiration of allowances issued until then. In Phase 2 and 3, they also ranged from above €30 in 2008 to around €3 in 2013. Expectations on the future stringency of the cap, along with demand considerations, shape the market price.

4 Case Study

We begin our empirical analysis with a case study of two coal fueled generators, Fusina and Monfalcone. These generators are geographically close (as of 2012 both part of the North zone[23]), they are very similar in size and have almost identical heat curves. Crucially, they differ in their ownership. Fusina is owned by the government-controlled generator Enel, while Monfalcone by the non-government controlled company A2A. As a result, it is reasonable to think that, if we detect any differences in their behavior, this could be attributed to their ownership structure.

We show that, in fact, they differ in how they respond to changes in emission allowances prices.

[23]Until 2011, Monfalcone was part of a different, very small, zone, designated as the Monfalcone zone.

Figure 3: Emission permit prices



NOTE: This figure shows the daily price of the EUA futures based on Reuters.

To do so we project their bids[24] on the price of the EUA permit. In Columns 1-2 of Table 2, we include no controls, in Columns 3-4 we control for produced quantity. The quantity produced might alter the marginal costs and therefore affect the response to a cost shock. Finally in Columns 5-6 we control for a wide range of controls: coal prices, weather controls (wind speed, humidity, precipitation), time trends, month FE, time of day FE and day of week FE.

Our results suggest (across a wide array of specifications) that the prices of the CO2 permits affect the bidding behavior of the A2A generator (Monfalcone) more than the publicly owned generator in Fusina. The public generator's bids hence respond less to a change in emission costs. In the next chapters we show that this is a systematic behavior in the electricity market.

Table 2: Case study: Comparing private and public generators in Fusina and Monfalcone

	(1) bid	(2) bid	(3) bid	(4) bid	(5) bid	(6) bid
EUA_ price	1.312***	0.341***	1.333***	0.125***	0.687***	0.337***
	(0.0156)	(0.0112)	(0.0155)	(0.0094)	(0.0213)	(0.0132)
Controls	None	None	Quantity	Quantity	All	All
Ownership	Private	Public	Private	Public	Private	Public

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Notes: This table shows results of projecting all positive bids on price of EUA permits. Quantity controls refer to awarded quantity : proxied by a linear and quadratic term. All controls refer to coal prices, precipitation, humidity, wind speed, year trend, time of the day FE, month FE, day of week FE.

5 Empirical Results

5.1 Pass-through of Emission Costs

In the initial step of our analysis we study pass-through of emission prices and its dependence on the ownership structure of the price setting company. Possible heterogeneity in pass-through of marginal costs might be caused by either differences in internalization of costs or by different market power. In the next section we introduce a bidding model to discuss the latter explanation.

We first look at average pass-through in our sample, without differentiating across different ownership structures. We begin by estimating the following specification:

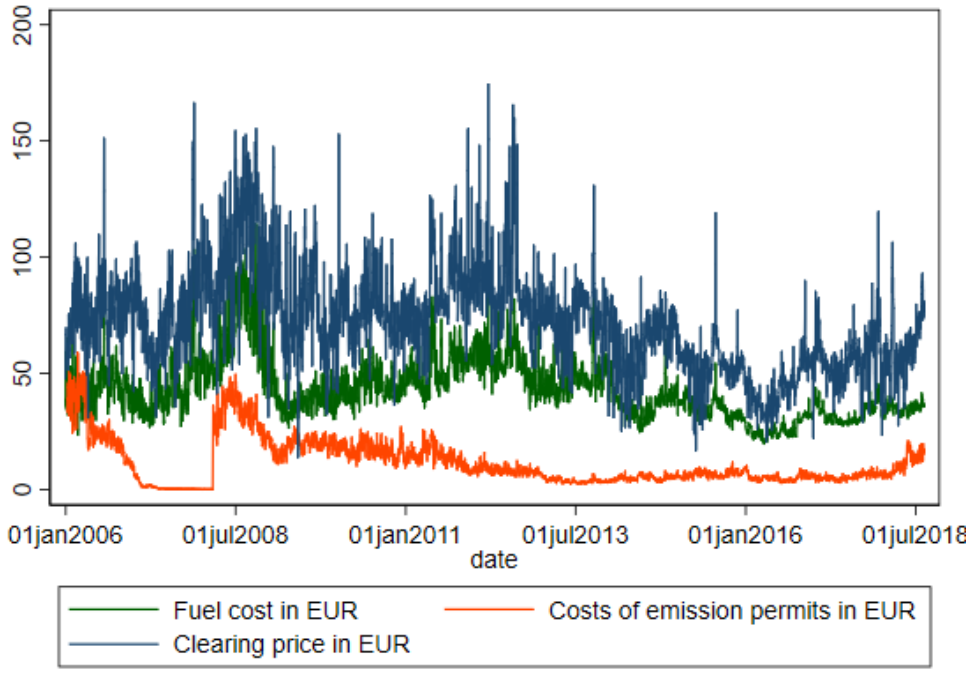
$$p_{tzh} = \rho \tau_t e_{tzh} + \beta_0 \mathbf{X}_{tzh} + \beta_1 \mathbf{I}_{tzh} + \epsilon_{tzh} \tag{3}$$

where p_{tzh} is the hourly zonal electricity price, $\tau_t e_{th}$ is the marginal emission cost for the price-setting generator in hour h and zone z, composed of the price of emission allowances τ_t and the emission rate of the marginal (price-setting) generator e_{tzh}, and the corresponding coefficient ρ is the equilibrium pass-through.

As in Fabra and Reguant (2014), we use an instrumental variable approach to identify the pass-through ρ on the marginal emission cost $\tau_t e_{tzh}$ on the marginal hourly zonal bid, which sets

[24] We include all bids that are non-zero.

Figure 4: Electricity prices and costs



NOTE: This figure compares average daily clearing price of the Italian day-ahead market with marginal costs of the corresponding marginal generator. Marginal costs are calculated using heat curve data, EUA prices and monthly coal and gas prices.

the hourly zonal price, where we instrument the marginal costs with the emission permit costs. [25]

We include year, month of sample, day of the week, and hour fixed effects. In some specifications, we additionally include month*hour fixed effects, to account for changes in sunlight across months potentially affecting demand as well as photovoltaic supply, as well as for demand shifters (temperature), and supply shifters (wind speed, given the importance of wind generation, and humidity, correlated to photovoltaic generation). We will study pass-through of both emission permit costs and fuel costs. We additionally control for prices of inputs that are not directly incorpo-

[25]The marginal emission cost in this regression is endogenous, as the marginal emission rate, depending on the identity of the marginal generator, is affected by unobserved demand or supply shocks. This is particularly problematic, since different technologies exhibit both starkly different emission rates, and starkly different fuel costs. Take the example of coal and natural gas. Natural gas is more expensive than coal, so it is more likely to be the price-setting technology when prices are high, and coal is more likely to set prices when they are low. Given coal's higher emission rate than natural gas, this may bias downward our results. We thus instrument the marginal emissions costs, $\tau_t e_{th}$ with the allowances prices τ_t. This provides us with a consistent estimate of ρ, as long as individual companies are unable to affect the allowance prices. There is some evidence that large electricity generators may have exerted market power in the allowances market at least in Phase 1 (Hintermann 2017). However, the inclusion of controls and fixed effects should mitigate at least some of these endogeneity concerns.

rated into the marginal cost of the input (meaning we control for emission prices when studying pass-through of fuel costs and fuel prices when studying pass-through of emission costs).

Results of Table 3 show that roughly one half of the allowance price is passed through to final consumers. This is in contrast with results in Fabra and Reguant (2014), who show an almost complete pass-through of about 85%. This difference could be explained in different ways. First, Fabra and Reguant (2014) cover an initial, experimental, stage of the EU-ETS, with fairly tiny price variation, and it is not clear what expectations about future emission prices market participants might have had. Second, the Spanish market might actually not be a representative market for ETS. We focus on one particularly stark dimension of difference, that is, government ownership. At the time of Fabra and Reguant (2014)'s analysis, the Spanish government had no controlling stake in the two main electricity generating companies, Endesa and Iberdrola.[26]

Our results also show that the average temperature is positively correlated with prices, consistent with the increase in demand triggered by hot days. Maximum temperature is, instead, negatively correlated with prices, consistent with the correlation between maximum temperature and supply of photovoltaic generators. Wind is negatively correlated with prices, as long as the level of wind is approximately above the mean, while it is positively correlated if wind speed is below the mean. Wind increases supply, so we expect a negative effect on prices. We obtain the expected result only when the weather is sufficiently windy. This may reflect the noise in the wind forecasts in the day-ahead-market, which turn out to be sufficiently precise only when there is more wind.

We look at whether the different ownership structure can account for the differential pass-through. We split the sample based on ownership structure. We run a first regression in which we study the cost pass-through for the government-controlled company, Enel, and a second one in which we study the pass-through for the rest of the companies.

Columns 2 and 3 of Table 3 shows a formidable difference in the estimates. Government-controlled companies pass-through less than 30% (20 to 28% in the various specifications) of the emission cost, while non-government controlled companies exhibit an almost complete pass through

[26] At the beginning of 2004, the two main generators in Spain (Endesa and Iberdrola) had a combined market share above 60% (Crampes and Fabra 2005).

(ranging from 72 in the most parsimonious specification to 93% in our preferred specification). We present the fully saturated specification in the main text and include other specifications studying pass-through in the Appendix.

A standard robustness test in this literature considers pass-through differences between peak and off-peak hours. Generators may face significant costs, among other things, when switching on and off a unit, or when ramping it up. These opportunity costs, faced primarily off-peak, are factored in by profit-maximizing generators, which may, as a result, submit bids that may differ from statically optimal ones, with an effect on pass-through across peak and off-peak.

Tables 4 and 5 show a modest difference between peak and off-peak pass-through, ranging from 15% in the most parsimonious to 5% in our preferred specification. This is a much smaller difference than the 40-60% difference between peak and off-peak in FR.

We then move to estimating the pass-through of fuel costs. In theory, the emission and the fuel cost pass-through of profit-maximizing companies could differ because of differences in the cost functions across generators (and, in particular, differences in emission rates, types of fuel, and thermal efficiency), which can give rise to different competitive conditions. The emission and the fuel cost pass-through of government owned companies could, in addition, differ because of different political incentives to respond to the two changes. The estimation of the pass-through on fuel prices suffers from an endogeneity issue similar to that faced when estimating the pass-through from emission costs. To tackle this, we instrument the fuel costs with fuel prices.

Tables 6 and 7 show that the pattern of pass-through on fuel cost is broadly consistent with that of pass-through on emission costs, albeit slightly lower. Government-controlled companies pass through less than 40% of the cost, while the other companies pass through about 80% of the cost. Measures of fuel costs are more noisy than allowance prices, since we do not observe the individual contracts that firms sign with their suppliers.

The difference in pass-through could be explained by two reasons. One could attribute it to different levels of cost internalization between government-controlled and non government-controlled generators, or to differences in market power, or both. In the next section we introduce a formal bidding model that allows us to estimate optimal markups (given the perceived uncertainty

Table 3: Pass-through Results

	(1) bid	(2) bid	(3) bid
marg. em. cost	0.515***	0.286***	0.933***
	(0.0288)	(0.0279)	(0.0917)
temperature avg	2.667***	1.302***	3.886***
	(0.1218)	(0.1684)	(0.1968)
temperature max	-0.896***	-0.356**	-1.525***
	(0.1113)	(0.1471)	(0.1864)
wind avg	0.773***	-0.411***	2.121***
	(0.0399)	(0.0435)	(0.0793)
wind squared	-0.0223***	0.00655***	-0.0534***
	(0.0012)	(0.0012)	(0.0027)
wind max squared	0.000323	0.00169***	-0.00187***
	(0.0002)	(0.0002)	(0.0004)
humidity	-0.0781***	-0.0983***	-0.0767***
	(0.0060)	(0.0065)	(0.0107)
year FE	Yes	Yes	Yes
month FE	Yes	Yes	Yes
hour FE	Yes	Yes	Yes
day FE	Yes	Yes	Yes
month/temperature	Yes	Yes	Yes
month/hour FE	Yes	Yes	Yes
input price/hour	Yes	Yes	Yes
N	169259	100633	68626

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Notes: This table shows results of estimating Equation 3 with the full set of control variables. Column 1 includes all observations. Column 2 estimates the model on the subset of data with a public marginal generator. Column 3 uses only private generators.

Table 4: Pass-through Results: Peak hours

	(1) bid	(2) bid	(3) bid	(4) bid	(5) bid
marg. em. cost	0.602***	0.570***	0.632***	0.599***	0.547***
	(0.0486)	(0.0483)	(0.0458)	(0.0455)	(0.0460)
temperature avg	3.311***	3.710***	3.248***	3.640***	3.728***
	(0.0767)	(0.1846)	(0.0739)	(0.1769)	(0.1760)
temperature max	-1.572***	-1.108***	-1.573***	-1.205***	-1.284***
	(0.0721)	(0.1779)	(0.0696)	(0.1685)	(0.1669)
wind avg	0.295***	0.195**	0.322***	0.227**	0.265***
	(0.0994)	(0.0987)	(0.0962)	(0.0955)	(0.0938)
wind squared	-0.0135***	-0.0121***	-0.0147***	-0.0134***	-0.0145***
	(0.0025)	(0.0024)	(0.0024)	(0.0024)	(0.0023)
wind max	0.366***	0.428***	0.392***	0.457***	0.467***
	(0.0534)	(0.0531)	(0.0521)	(0.0518)	(0.0510)
wind max squared	-0.00423***	-0.00474***	-0.00462***	-0.00518***	-0.00536***
	(0.0008)	(0.0007)	(0.0007)	(0.0007)	(0.0007)
humidity	-0.164***	-0.146***	-0.157***	-0.137***	-0.130***
	(0.0097)	(0.0097)	(0.0094)	(0.0094)	(0.0092)
year FE	Yes	Yes	Yes	Yes	Yes
month FE	Yes	Yes	Yes	Yes	Yes
hour FE	Yes	Yes	Yes	Yes	Yes
day FE	Yes	Yes	Yes	Yes	Yes
month/temperature	No	Yes	No	Yes	Yes
month/hour FE	No	No	Yes	Yes	Yes
input price/hour	No	No	No	No	Yes
N	91385	91385	91385	91385	91385

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 3 only during peak hour. Peak hours are defined between 8am and 8pm. Columns 1-5 vary the set of controls.

Table 5: Pass-through Results: Off-peak hours

	(1) bid	(2) bid	(3) bid	(4) bid	(5) bid
marg. em. cost	0.455***	0.440***	0.458***	0.444***	0.493***
	(0.0334)	(0.0332)	(0.0329)	(0.0329)	(0.0318)
temperature avg	0.827***	1.532***	0.832***	1.564***	1.421***
	(0.0615)	(0.1509)	(0.0612)	(0.1520)	(0.1485)
temperature max	-0.0866	-0.615***	-0.0894	-0.667***	-0.477***
	(0.0588)	(0.1263)	(0.0586)	(0.1296)	(0.1272)
wind avg	0.467***	0.490***	0.465***	0.487***	0.523***
	(0.0816)	(0.0814)	(0.0810)	(0.0809)	(0.0771)
wind squared	-0.0114***	-0.0123***	-0.0115***	-0.0124***	-0.0131***
	(0.0021)	(0.0021)	(0.0021)	(0.0020)	(0.0019)
wind max	0.0289	0.0560	0.0335	0.0596	0.117**
	(0.0511)	(0.0508)	(0.0511)	(0.0509)	(0.0486)
wind max squared	-0.00130	-0.00153*	-0.00136	-0.00158*	-0.00230***
	(0.0008)	(0.0008)	(0.0009)	(0.0008)	(0.0008)
humidity	-0.0507***	-0.0356***	-0.0518***	-0.0371***	-0.0271***
	(0.0073)	(0.0073)	(0.0072)	(0.0073)	(0.0071)
year FE	Yes	Yes	Yes	Yes	Yes
month FE	Yes	Yes	Yes	Yes	Yes
hour FE	Yes	Yes	Yes	Yes	Yes
day FE	Yes	Yes	Yes	Yes	Yes
month/temperature	No	Yes	No	Yes	Yes
month/hour FE	No	No	Yes	Yes	Yes
input price/hour	No	No	No	No	Yes
N	77874	77874	77874	77874	77874

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 3 only during off-peak hour. Peak hours are defined between 8am and 8pm. Columns 1-5 vary the set of controls.

Table 6: Pass-through of fuel: private

	(1) bid	(2) bid	(3) bid	(4) bid	(5) bid
fuel_cost	0.816***	0.798***	0.804***	0.784***	0.791***
	(0.0111)	(0.0115)	(0.0110)	(0.0114)	(0.0112)
EUA price	0.381***	0.367***	0.404***	0.393***	-0.759***
	(0.0415)	(0.0416)	(0.0402)	(0.0403)	(0.0842)
temperature avg	2.297***	3.369***	2.219***	3.249***	2.992***
	(0.0723)	(0.1731)	(0.0709)	(0.1684)	(0.1631)
temperature max	-0.918***	-1.416***	-0.891***	-1.397***	-1.136***
	(0.0667)	(0.1669)	(0.0656)	(0.1590)	(0.1545)
wind avg	1.055***	0.994***	1.076***	1.017***	0.879***
	(0.0989)	(0.1002)	(0.0975)	(0.0989)	(0.0968)
wind squared	-0.0319***	-0.0317***	-0.0323***	-0.0323***	-0.0283***
	(0.0027)	(0.0028)	(0.0027)	(0.0027)	(0.0027)
wind max	0.187***	0.257***	0.164***	0.241***	0.310***
	(0.0478)	(0.0490)	(0.0473)	(0.0486)	(0.0485)
wind max squared	-0.00247***	-0.00326***	-0.00219***	-0.00310***	-0.00442***
	(0.0007)	(0.0007)	(0.0007)	(0.0007)	(0.0007)
humidity	-0.0799***	-0.0704***	-0.0793***	-0.0690***	-0.0582***
	(0.0091)	(0.0091)	(0.0090)	(0.0090)	(0.0088)
year FE	Yes	Yes	Yes	Yes	Yes
month FE	Yes	Yes	Yes	Yes	Yes
hour FE	Yes	Yes	Yes	Yes	Yes
day FE	Yes	Yes	Yes	Yes	Yes
month/temperature	No	Yes	No	Yes	Yes
month/hour FE	No	No	Yes	Yes	Yes
input price/hour	No	No	No	No	Yes
N	68631	68631	68631	68631	68631

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 3. Columns 1-5 vary the set of controls. The equation is estimated on the subset of data where private companies are marginal bidders.

Table 7: Pass-through of fuel: public

	(1) bid	(2) bid	(3) bid	(4) bid	(5) bid
fuel_cost	0.390***	0.392***	0.382***	0.384***	0.380***
	(0.0066)	(0.0066)	(0.0064)	(0.0064)	(0.0064)
EUA price	0.159***	0.152***	0.183***	0.174***	0.0425
	(0.0154)	(0.0154)	(0.0142)	(0.0143)	(0.0272)
temperature avg	-0.0108	1.044***	0.0518	1.115***	1.091***
	(0.0591)	(0.1817)	(0.0569)	(0.1743)	(0.1742)
temperature max	0.114**	-0.138	0.0422	-0.309**	-0.313**
	(0.0537)	(0.1604)	(0.0518)	(0.1530)	(0.1530)
wind avg	-0.775***	-0.722***	-0.711***	-0.658***	-0.629***
	(0.0745)	(0.0740)	(0.0728)	(0.0722)	(0.0719)
wind squared	0.0127***	0.0113***	0.0108***	0.00941***	0.00882***
	(0.0018)	(0.0018)	(0.0018)	(0.0018)	(0.0018)
wind max	0.419***	0.410***	0.435***	0.427***	0.414***
	(0.0463)	(0.0458)	(0.0465)	(0.0461)	(0.0459)
wind max squared	-0.00303***	-0.00298***	-0.00346***	-0.00344***	-0.00331***
	(0.0007)	(0.0007)	(0.0007)	(0.0007)	(0.0007)
humidity	-0.0205***	-0.0109	-0.0245***	-0.0142**	-0.0128*
	(0.0071)	(0.0072)	(0.0068)	(0.0068)	(0.0068)
year FE	Yes	Yes	Yes	Yes	Yes
month FE	Yes	Yes	Yes	Yes	Yes
hour FE	Yes	Yes	Yes	Yes	Yes
day FE	Yes	Yes	Yes	Yes	Yes
month/temperature	No	Yes	No	Yes	Yes
month/hour FE	No	No	Yes	Yes	Yes
input price/hour	No	No	No	No	Yes
N	100875	100875	100875	100875	100875

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 3. Columns 1-5 vary the set of controls. The equation is estimated on the subset of data where public companies are marginal bidders.

about market clearing prices) and we show that the pass-through heterogeneity is likely caused by heterogeneity in cost internalization.

5.2 Decomposing Market Power

We decompose bids into the costs and the mark-up component. We observe costs due to detailed engineering data about heat rates that are available at the level of individual generators. We can calculate optimal markup from first order conditions for optimal bidding.

Model of Bidding

We will assume that the generators are playing a game of incomplete information. Let us assume that firms choose the offers in order to maximize expected profits. Firm i is endowed with private information, s_i, representing its contract positions, urgency of maintenance etc. The total demand, D, is a random variable with a commonly known distribution $F(D)$.

The auction rules map the submitted offers into the market clearing price and firms' market clearing quantities, both of which are random variables, since both will be functions of the other firms' signals and equilibrium strategies and the realization of demand. We will denote them by functions $P^c(S,D)$, $Q_i^c(S,D)$, respectively, and sometimes, to economize on space, we will omit their arguments.

Firm i's expected profits can thus be written as:

$$E_{s_{-i},D}\left[Q_i^c(S,D) * P^c(S,D) - C_i\left(Q_i^c(S,D)\right)\right] \tag{4}$$

where $C_i(q)$ is the total cost of producing q MWh of electricity.

Firms have to submit offer curves that are step functions, $\{b_k, q_k\}_{k=1}^K$ for each of their J generators. For the sake of simplicity, we will assume that bidding decisions are made at the generator level - and hence a bid for generator j depends on its particular private signal, rather than on signals of other generators sharing the same owner. This implies that we can write firm i's expected

revenue from the auction as

$$
\begin{aligned}
&\mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right)Q_i^c\left(S,D\right)\right] = \\
&= \Pr\left(b_{k-1} < P^c < b_k\right) q_{k-1}\mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right)|b_{k-1} < P^c < b_k\right] \\
&\quad + \Pr\left(P^c = b_k\right) b_k \mathbb{E}_{S_{-i},D}\left[Q_i^c\left(S,D\right)|P^c = b_k\right] \\
&\quad + \Pr\left(b_k < P^c < b_{k+1}\right) q_k \mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right)|b_k < P^c < b_{k+1}\right] \\
&\quad + \Pr\left(P^c \leq b_{k-1} \cup P^c \geq b_{k+1}\right) \mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right)Q_i^c\left(S,D\right)|P^c \leq b_{k-1} \cup P^c \geq b_{k+1}\right] \\
&= q_{k-1}\mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right); b_{k-1} < P^c < b_k\right] + q_k \mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right); b_k < P^c < b_{k+1}\right] \\
&\quad + b_k \mathbb{E}_{S_{-i},D}\left[Q^c\left(S,D\right); P^c = b_k\right] + \mathbb{E}_{S_{-i},D}\left[P^c\left(S,D\right)Q_i^c\left(S,D\right); P^c \leq b_{k-1} \cup P^c \geq b_{k+1}\right]
\end{aligned}
$$

where the last term does not depend on the particular step k, characterized by b_k and q_k. The only states, in which changing b_k will be relevant, are those, where the market clearing price lies in the interval (b_{k-1}, b_{k+1}).

To simplify the problem we assume that firms were choosing a continuous monotone increasing offer schedule $q_i(p)$. In this case the first order conditions reduce to: (as $q_{k+1} \to q_k$ and $b_{k+1} \to b_k$)

$$
\begin{aligned}
&\frac{\partial \mathbb{E}_{S_{-i},D|s_i}\left[C\left(Q_i^c\left(S,D\right)\right)|P^c = b_k\right]}{\partial b_k} = \\
&= \mathbb{E}_{S_{-i},D|s_i}\left[Q_i^c\left(S,D\right)|P^c = b_k\right] + b_k \frac{\partial \mathbb{E}_{S_{-i},D|s_i}\left[Q_i^c\left(S,D\right)|P^c = b_k\right]}{\partial b_k}
\end{aligned} \tag{5}
$$

which is basically the condition used in Wolak (2007) or Fabra and Reguant (2014). Equation (5) can be also written (abusing notation a bit) as $(MC - b)\,\mathbb{E}Q'(b) = \mathbb{E}Q(b)$, where $Q(b)$ is the residual demand at price b.

5.3 Decomposition Results

We take to data a linear approximation of the relationship in Equation (5).

$$
bid_{i,g,m} = \gamma MC_{emission,i,g,m}(q) + \beta MC_{fuel,i,g,m}(q) + \theta \widehat{M}_{i,g,m} + \epsilon_{i,g,m} \tag{6}
$$

where $bid_{i,g,m}$ is the bid i of generator g in market m. $\widehat{M}_{i,g,m}$ is the equilibrium mark-up over marginal cost, which depends on the elasticity of residual demand, hence on market power. Marginal costs are composed of marginal fuel cost and marginal emission costs. The error term captures potential errors in measurement of marginal costs, or other idiosyncratic shocks.

To estimate the optimal markup we use the resampling method based on Kastl (2011), where we draw from the empirical distribution of bids to simulate different realizations of the residual demand function. We provide details of the estimation in the Appendix.

The goal of our analysis is estimating γ, β, and θ for government-controlled and non-government controlled companies. γ and β measure the extent to which firms incorporate shocks to the emission cost and to the fuel cost respectively in their behavior, while θ measures the extent to which firms capture the mark-up opportunities. Notice that allowances cost is an opportunity cost, as it represents their current spot market price, which does not depend on the price at which allowances were acquired (which could also be zero under the grandfathering regime).

We restrict the sample of bids for the analysis, by removing the first and the last step of the bid function. By excluding the first step, we mitigate concerns with startup costs, while, by excluding the last step, we mitigate concerns with capacity constraints. We also restrict the analysis to bids that, ex post, turn out to be marginal.

The consideration of bids that, ex post, turn out to be marginal raises endogeneity concerns similar to those faced in the reduced form estimation of pass-through. The identity of the marginal technology depends on unobserved demand or supply shocks. For example, under a negative unobserved demand shock, it is more likely that the marginal technology is coal, characterized by a higher emission intensity. This would bias our markup estimate downward. We, therefore, instrument emission costs with permit prices, fuel costs with input prices (of coal, gas and oil), and markup with shifters of residual demand (temperature and wind).

Similarly to Fabra and Reguant (2014) we first regress bids on marginal costs (while fixing $\gamma = 1$), and then we instrument the optimal markup with shifters of residual demand (wind speed and temperature). Tables 8 and 9 show a striking difference in behavior between government-controlled and non-government controlled generators. Government-controlled generators internalize

Table 8: Bid decomposition: private firms

	(1) OLS	(2) 3SLS	(3) 3SLS+controls
marg. em. cost	0.764***	1.084***	0.766***
	(0.0730)	(0.0512)	(0.0437)
marg. fuel cost	0.278***	0.800***	0.745***
	(0.0170)	(0.0144)	(0.0122)
optimal markup		0.541***	0.704***
		(0.0249)	(0.0194)
N	32233	26017	26017

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 6 on the set of private generators. The first column fixes the coefficient on markup to 1 and estimates the coefficients on marginal costs via OLS. Column 2 projects bids on marginal costs and markups via 3SLS. Marginal emission costs are instrumented with emission allowances costs. Marginal fuel costs are instrumented with fuel costs and markups are instruments with shifters of residual demand; wind speed and temperature. Column 3 uses the same specification but also includes month fixed effects to control for seasonal effects.

only about 15% of marginal emissions costs, and about 25% of marginal fuel costs. Non government-controlled generators internalize about 75% of both marginal costs. Also, while markup for non government-controlled generators is broadly in line with profit maximization (with approximately 70% of the profit-maximizing increase in bids realized), government controlled companies do not seem to bid strategically. Taken together, our results imply that the government-controlled generators are not maximizing profit, and are not internalizing marginal emission costs. The fact that government-controlled companies do not maximize profits implies that marginal abatement costs are not equalized across companies (let alone the equalization across sectors), which clearly undermines the effectiveness of the regulation.

5.4 Discussion of heterogeneous behavior

We find that government-owned companies, unlike their private counterparts, fail to internalize costs in their bids, and do not optimally respond to their rivals' bids. We advance several possible motivations behind this heterogeneous behavior.

Table 9: Bid decomposition: public firms

	(1) OLS	(2) 3SLS	(3) 3SLS+controls
marg. em. cost	0.207***	-0.0109	0.151***
	(0.0221)	(0.0224)	(0.0167)
marg. fuel cost	0.140***	0.241***	0.243***
	(0.0061)	(0.0076)	(0.0055)
optimal markup		-0.00793	0.0126
		(0.0369)	(0.0257)
N	36128	33679	33679

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating Equation 6 on the set of public generators. The first column fixes the coefficient on markup to 1 and estimates the coefficients on marginal costs via OLS. Column 2 projects bids on marginal costs and markups via 3SLS. Marginal emission costs are instrumented with emission allowances costs. Marginal fuel costs are instrumented with fuel costs and markups are instruments with shifters of residual demand; wind speed and temperature. Column 3 uses the same specification but also includes month fixed effects to control for seasonal effects.

First, public companies may also attach some weight to consumer surplus. In such a scenario the levels of bids might indeed differ for public generators, nevertheless they should still supply energy at the minimum costs, which requires internalization of all input costs. Such explanation could not rationalize differences in pass-through.

A second potential motivation might lie in Enel's antitrust concerns. Throughout the period in our sample, Enel has been the largest generator, albeit by an increasingly smaller margin over time. A model of antitrust concerns would generate similar predictions to a model of attachment of a positive weight to consumer surplus. As a result, similarly to above, this model would be consistent with a difference in levels of bids, but not with a difference in pass-through.

An alternative explanation might consist of differential strategic sophistication. Different firms could have a different ability at predicting their residual demand and at placing optimal bids. Hortaçsu et al. (2019) show that strategic sophistication is positively correlated with firm's size. This is inconsistent with our results, where the largest firm, Enel, exhibits a much smaller degree of sophistication than its smaller rivals. In addition, differential strategic sophistication would not

explain the lack of cost internalization. A similar explanation, but potentially explaining the lack of cost internalization as well, has to do with the adjustment costs. Companies do not adjust their bids in response to the opportunity cost of allowances or of the actual input costs as frequently as predicted by the model (or their actual costs for fuel costs) because bid adjustments are costly (in terms of people and software to be employed for the activity). Adjustment costs, however, are, in this case as well, presumably subject to economies of scale, given the fixed cost involved in setting up a pricing unit. Hence, a model of adjustment costs would predict that, if anybody, the smallest firms would be more inclined to give up the higher markup to avoid the adjustment costs. Our results are inconsistent with this explanation, since they would imply, instead, that the largest firms face large adjustment costs, while the smaller ones, who pass costs through more accurately, do not.

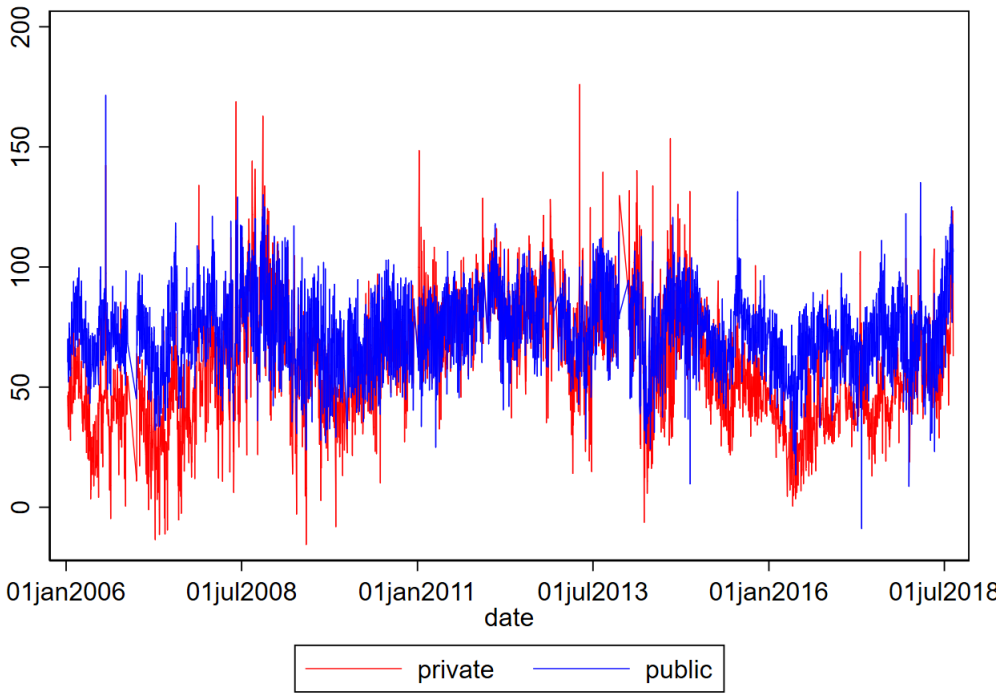
Additional explanations for why the emission price is not passed through have been put forward. One of them (Goeree, Holt, Palmer, Shobe and Burtraw 2010) involves the lack of understanding that permits have an opportunity cost. Another one involves transaction costs in the emissions market (Stavins 1995). Again, it seems unlikely that the largest, and longest-living, company suffers from such lack of understanding, or that it faces higher transaction costs vis-à-vis comparable smaller firms, as the internalization patterns in our data suggests. If anything, it should be smaller and less established company that have a smaller understanding of the market, and face higher transaction costs.

Another possible motivation is that government-owned companies try to decrease the volatility of market prices for political reasons. A government-controlled company, especially if its strategies are visible and important for its citizens, affects the probability of the government to remain in power, as it potentially affects citizens' perception of government ability and accountability. These political incentives might lead government-controlled companies to target a reduction in price volatility, possibly because poorly informed consumers, who have a preference for lower costs, might perceive small price volatility as an indicator of a more cost-reflective price. This is consistent with previous evidence in 2004, right at the beginning of the liberalization process, that Enel was smoothing out prices across different geographical areas with respect to the profit-maximizing

outcome (Boffa, Pingali and Vannoni 2010).

To test this motivation, we perform an analysis based on our decomposition results, in which we compare a situation in which we treat all the bids as coming from non-government controlled companies, and as if all bids were coming from government-controlled companies. Our results show that the standard deviation of market clearing prices would decrease considerably, by about 22% (from 46 to 36 Euros).

Figure 5: Variability of electricity prices



NOTE: This figure predicts electricity prices under a counterfactual ownership structure. The blue line shows predicted electricity prices under the assumption that all marginal generators bid according to the bidding equation of the public generators. Analogously the red led predicts prices for private generators. For simplicity we hold the set of marginal generators fixed.

5.5 Anecdotal evidence on political incentives for government-controlled firms

Another potential explanation for the different behavior of public versus private firms is that top level managers might get rewarded by the government for responding to political incentives. This argument is consistent with the existence of two separate labor markets for managers, one for "pub-

lic" managers and one for private managers. A casual look into the history of government-controlled companies in Italy, and in particular into the history of the two government-owned generators Enel and Eni, provides strong anecdotal support for this theory. Public managers in the energy sector very rarely move to private energy companies, while mostly moving to other government-controlled companies operating in different sectors, or remaining with the same employer for very long spells.

We first look at Enel. Paolo Scaroni, Enel's CEO between 2002 and 2004, was then appointed ENI's CEO (for the spell 2005-2014), moving between the two most prominent Italian government-owned companies.[27] His successor, Fulvio Conti (who was Enel's CEO in 2004-2014), before joining Enel, was chief financial officer at the fully government owned Italian railway monopoly (owner of the infrastructure and, back then, monopolistic provider of the railways services) Ferrovie dello Stato, and, immediately after, was CFO at Telecom, which had just been privatized, and whose CEO was Franco Bernabè, previously Eni's CEO (1992-1999). After this tenure at Enel, Conti again held other top managerial positions at Telecom.[28] Conti's successor, Francesco Starace, whose tenure started in 2014, had a long experience in Enel, which he joined in 2000. He had previously worked for Alstom, a French multinational operating primarily in the rail transport and in the power markets, controlled by the French government.[29]

Between Scaroni and Bernabé, Vittorio Mincato was Eni's CEO. He kept his post between 1999 and 2005. Afterwards, he became Chairman of the Board of Poste Italiane, the Italian fully government-owned postal services company.[30] Finally, the current Eni's CEO, Claudio Descalzi, has been with Eni since 1981, right after his degree.[31]

Even Enel's Chairmen of the Board are deeply entrenched with the public management system. Chicco Testa (who served in the 1996-2002 spell) was previously chairman of the multiutility company, controlled by the Rome municipality, ACEA, while being a member of the Italian House of Representative elected with the Comunist (and then Social-Democratic) party. His successor was Piero Gnudi, who served between 2002 and 2011, and was previously chairman of IRI, the Italian

[27] https://www.acmilaninfo.com/who-is-paolo-scaroni-the-new-president-of-ac-milan/

[28] See https://www.telecomitalia.com/content/dam/telecomitalia/organigramma/curriculum/it/ContiFulvio.pdf .

[29] https://www.enel.com/investors/governance/board-of-directors/francesco-starace-chief-executive-officer-general-

[30] https://www.referenceforbusiness.com/biography/M-R/Mincato-Vittorio-1936.html

[31] https://www.eni.com/en-IT/about-us/our-management/biographies.html/claudio-descalzi

fully government-owned holding company in charge of the portfolio of the government-owned Italian manufacturing and service companies, until its dissolution in 2002. After his tenure at Enel, he went on to become the Minister for Tourism, and Sport in the Monti government.

Paolo Andrea Colombo served between 2011 and 2014, and then went on to become chairman of Saipem (starting in 2015), a company involved in infrastructures and services for the oil and gas sector, controlled by Eni and by the fully government-owned investment bank Cassa Depositi e Prestiti.

To summarize, it is very common for "public" managers to move between publicly owned firms. It thus seems very likely that managers within this market might follow very different goals than those of their non-government counterpart, as their incentives might be more aligned with politicians.

6 Long Term versus Short Term Effects

Failure to maximize profits results in the short term in different power plants being used than optimal. This implies that equality of marginal abatement costs - one of the major arguments in favor of carbon pricing - does not hold. We now turn to the long-run differential investment incentives between government-controlled companies and their counterpart. There is evidence of a differential response to ETS between government-owned and private companies (Clò et al. 2017) in Europe, in terms of greenhouse-gas emissions and carbon intensity. Fowlie (2010) also finds a positive effect of public ownership on the probability of adopting more capital intensive environmental compliance options.

6.1 Differential response of emission intensity

We study the differential medium and long-run response, between public and private generators, to variation in ETS prices in terms of changes in the emission intensity of their generation facilities. We first consider coal-fired power plants, and look at how they differentially adjust, based on ownership, their input choices as ETS prices vary. Different types of coal differ in their burning efficiency, which affects the power plant's emission intensity.

Table 10: Emission intensity responses

	(1) intensity	(2) intensity	(3) Δ intensity	(4) Δ intensity
Average EUA price	0.654	-1.858**		
	(0.8146)	(0.8598)		
Δ EUA price			0.763	-1.663***
			(0.5072)	(0.4505)
Model	FE	FE	FD	FD
Ownership	Public	Private	Public	Private
Controls	Linear time trend	Linear time trend	Linear time trend	Linear time trend
N	68	46	60	42

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

NOTE: This table shows results of estimating the Equation 7 and 8. We split the sample by whether the generator is owned by a public or private company. The number of observations differ in FE and FD models because we do not have a balanced panel and cannot use some observations for estimation of the FD model.

We collect data on average yearly CO2 emission intensity (emission per MWh) for coal-fired power plants in Italy. We use a fixed effect model and a first differences model to argue that there is, even on this margin, a differential response to these incentives between public and private generators. We estimate the following two models:

$$intensity_{i,t} = \beta \cdot eua\ price_t + \delta_i + time\ trend_t + \epsilon_{i,t} \tag{7}$$

$$intensity_{i,t} - intensity_{i,t-1} = \beta \cdot (eua\ price_t - eua\ price_{t-1}) + \epsilon_{i,t} \tag{8}$$

where i denotes a generator and t a year. *time trend* controls for a possible linear trend, while we cannot allow for a more flexible approach due to the frequency of observations. Both emission intensity and allowances price are calculated as yearly averages. Despite the low frequency of observations, Table 10 clearly shows that both models show the same relationship. Public generators do not respond to incentives, whereas private generators adjust their intensity based on the EUA prices.

As mentioned above, the differential response between public and private generators could be motivated by the differential incentives to respond to political pressure. Marco and Macchiavelli (n.d.) and Ongena, Popov and Horen (2019) show that government ownership affects European

banks behavior, in terms of the amount of sovereign bond holdings during sovereign crises. Similar forms of government "moral suasion" on government-owned companies are likely to have occurred in the Italian electricity sector, and to have affected the timing and the extent of Enel's investments. For example, when Francesco Starace was appointed as CEO in 2014, the then Italian Prime Minister Matteo Renzi emphasized his mandate to increase investments, and to decarbonize production.[32] The government has also strongly supported, and advertized to voters, the most prominent environmental investments undertaken by Enel. For instance, a 120 million Euros two-domed coal storage facility started in 2012 in its Brindisi plant, as well as the still ongoing project of a carbon capture and storage facility, again in Brindisi.[33] Evidence of the involvement of the Italian government in Enel's strategy is also provided by the current debate on the opportunity to directly involve Enel in the highly funded investment plan that will invest the financial resources allocated to the Italian government, partly in the form of subsidies, partly in the form of loans, through the European Recovery Fund.[34]

6.2 Investment into renewables

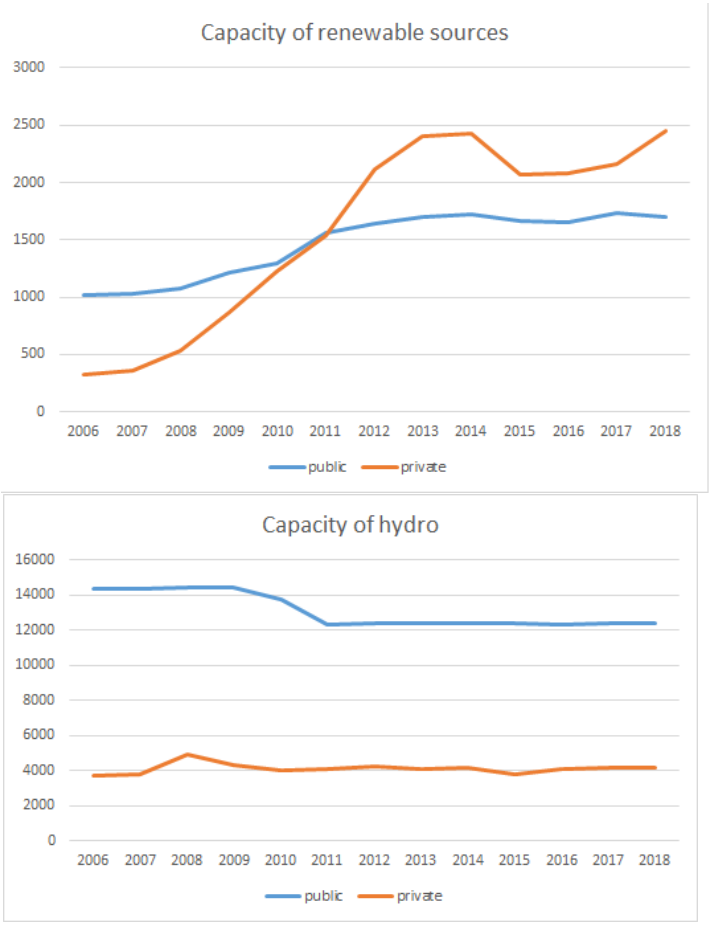
In Subsection 6.1 we looked at how firms respond to ETS prices by modifying emission intensity in existing coal-fired power plants through a different input choice. An alternative way to reduce the emission intensity of generators' generation facilities lies, in the long-run, in building less polluting power plants. In this section we focus on the long-term trend of investment into renewables. Figure 6 shows the evolution of the stock of renewable generation, separately considering the hydro power plants, which on average have a significantly longer history, and all the other sources, primarily photovoltaic and wind. While it is hard to causally link such investment to the existence and intensity of the European Trading Scheme, the investment patterns for public and public generators appear remarkably different, in particular for renewable sources different than hydro, which have been most dynamic in recent years.

[32] See, for instance, https://www.publicpolicy.it/lo-spillo-29-39636.html.

[33] See, for instance, https://www.minambiente.it/comunicati/il-ministro-prestigiacomo-brindisi-linaugurazione-dellimpi

[34] See, for instance, https://www.repubblica.it/economia/2020/07/01/news/un_comitato_di_esperti_e_missioni_strategiche_quinquennali_per_le_grandi_imprese_di_stato_-260677886/.

Figure 6: Investment into capacity



NOTE: This figure shows the evolution over the years of the stock of renewable and hydro capacity by generator ownership (government controlled versus non-government controlled), using data from (ARERA Various years).

7 Discussion

Our findings question the ability of market-based environmental policies to achieve an efficient outcome, when firms are not profit-maximizing. This is especially troublesome given that the market-based emissions trading system that is due to start by the end of 2020 in China. Historically, China's electricity sector was operated by a single state-owned vertically integrated company. The 2002 reform has unbundled generation, transmission and distribution. In addition, it has organized generation around five major state-owned regional generators (Xu and Chen 2020), four of which, as of 2018, ranked in the first four places by installed generation capacity world-wide (International Energy Agency 2018).

Before the 2015 reform, wholesale price in electricity was administratively set by the central government, through benchmark tariffs. Generators belonging to the same technology class, where a technology class includes generators sharing similar average costs, share the same tariff (Kahrl, Williams, Jianhua and Junfeng 2011). The tariff was meant to be adjusted to reflect changes in input prices, while incentivizing improvements in efficiency. Political considerations reduced the frequency of adjustment of the benchmark tariff, thereby distorting the price signal (Lin, Kahrl, Yuan, Liu and Zhang 2019). Dispatch has followed the general principle of maintaining equal shares among generators and ensuring revenue sufficiency (Davidson and Perez-Arriaga 2020).[35], where the (government owned) locally monopolistic grid companies act as single buyers. Measures aimed at increasing the efficiency of the dispatch in economic terms (by making it more cost-reflective) or in environmental terms (by prioritizing renewable or less polluting sources), have been experimentally deployed, as pilots, in local markets starting in 2007.[36] The 2015 reform has laid out general principles and guidelines to expand the role for the market in the Chinese electricity sector. While its implementation has been, up to now, only partial, it is expected that the reform will ultimately expand the role for the market in electricity, in particular by favoring the transition to a dispatch based on economic principles, through the expansion of trading opportunities between generators and final customers, intermediated by power exchanges or by competitive retailers (Davidson and Perez-Arriaga 2020).

The market will play a larger role in environmental policy as well. Announced on December 19th, 2017, emissions trading is poised to become the world's largest cap and trade program (Zeng, Weishaar and Vedder 2018) following some experimentation on a regional scale. China is currently by far the world's biggest greenhouse gases emitter. With approximately 10.1 Gt of carbon dioxide[37] in 2018, it is well ahead of the second emitter, the United States (at 5.42 Gt). China has the largest electricity system in the world, with an installed capacity of roughly 1800GW at the end of 2018 (China Electricity Council 2019). The fuel mix is still dominated by coal, which accounts for

[35] A few experiments, of limited geographic scope, have introduced cost principles or renewables priority in the dispatch criterion.

[36] For example, the government experimented, in five provinces (Jiangsu, Henan, Sichuan, Guangdong and Guizhou), the introduction of the fuel efficiency criterion in the alghoritm governing dispatch (Zhong, Xia, Chen and Kang 2015). The province of Guangdong has also introduced competitive retailing (Davidson and Perez-Arriaga 2020).

[37] See: `http://www.globalcarbonatlas.org/en/content/welcome-carbon-atlas)`.

more than 60% - although with a declining trend - of total generation. The electricity sector contributes substantially, for about a third, to China's carbon dioxide emissions (Goulder and Morgenstern 2018). The system is expected to cover companies emitting more than 26 Gt of carbon dioxide in eight sectors, including electricity.[38] Approximately half of China's total carbon dioxide emission (and about 40% of total GHG emissions) from around 6500 enterprises will be covered.

Crucially, the program will not place an aggregate cap invariant to output, but will set an emission standard, that is a standard emissions rate per unit of output (Pizer and Zhang 2018). A company is allocated allowances based on the emission standards and on the units of output. The program differs markedly from mass-based systems, such as EU ETS, which put a limit on total emissions, and takes instead the form of a tradable performance standard (TPS). The main economic difference between mass-based systems and TPS is that, while mass-based policies raise unit costs by abatement costs plus the carbon price applied to all emissions, a TPS provides a rebate on those costs equal to the carbon price applied to the established performance standards. Hence, a TPS tends to have smaller effects on product prices ((Boom and Dijkstra 2009)).Finally, a TPS, even when companies are profit-maximizing and operate in a market-based environment, does not achieve efficiency, because it does not equate the marginal abatement costs across firms. Consider the following example representing a situation of perfect competition, in which firms maximize profit in a market-based environment, based on (Goulder and Morgenstern 2018). A firm produces output q as a function of a single input x and emissions $e : q = f(x, e)$, with $\frac{\partial q}{\partial x} > 0$ and $\frac{\partial q}{\partial e} > 0$.

Assume that the firm is within a TPS system, faces the benchmark emissions - output ratio β, and regards its output price p, the cost of input c, and the price of emissions allowances p_e as exogenous.

Under a TPS, each firm's profit π^{TPS}, is given by

$$\pi^{TPS} = pq - cx - p_e\left(e - q\beta\right) \tag{9}$$

[38]The others being building materials, iron and steel, non-ferrous metal processing, petroleum refining, chemicals, pulp and paper, and aviation (Pizer and Zhang 2018).

The corresponding expression for each firm's profit under a conventional mass-based system MBS, π^{MBS}, is:

$$\pi^{MBS} = pq - cx - p_e e$$

One can immediately see that the first order conditions for profit maximization under TPS and MBS are different. For TPS, first order conditions read:

$$\frac{\partial \pi^{TPS}}{\partial e} = p\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right) - c\frac{\partial x}{\partial e} + p_e\beta\left(\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right)\right) - p_e = 0$$
$$\underbrace{p\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right) - c\frac{\partial x}{\partial e}}_{MAC} + p_e\beta\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right) = p_e$$

The first order condition for the emissions choice under an MBS instead reads as:

$$\begin{aligned}\frac{\partial \pi^{MBS}}{\partial e} &= p\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right) - c\frac{\partial x}{\partial e} - p_e = 0 \\ &= \underbrace{p\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right) - c\frac{\partial x}{\partial e}}_{MAC} = p_e\end{aligned}$$

Under an MBS, each firm equates its marginal abatement cost to the allowance prices. In equilibrium with profit-maximizing firms, all marginal abatement cost are therefore equal, implying the system is efficient. Under a TPS, each firm equates its marginal benefits - composed of the abatement cost, plus the change in allowances resulting from the increase in output - to the allowances prices. Hence, except in the special case in which the marginal benefit from an emission through the increase in allocated allowances (given by $\left(\frac{\partial f}{\partial e} + \frac{\partial f}{\partial x}\frac{\partial x}{\partial e}\right)$) is equal across the various firms, marginal abatement costs are not equalized across firms.

A system such as the TPS, albeit inefficient, may better suit the transition from an administratively regulated environment to a market-based dispatch system. In particular, except for the few above mentioned local experimentation, wholesale prices in China are regulated, which prevents firms from passing through the permits prices to final customers. Pass-through of permit prices, while being an essential ingredient for the efficient operation of an MBS such as the EU ETS, is much less important in a TPS, due to the above illustrated output-based rebate component. Hence,

the TPS might be an only temporary solution until market reforms in the wholesale and dispatch segments will be fully phased in. It might then bound to be replaced by a conventional MBS.

Summing up, it is conceivable to think of at least three reasons why emissions trading in China could trigger inefficiencies. Two of them have been emphasized already in previous work, and might be only temporary: the above described design of the Chinese ETS system as a TPS, and the fact that, as we have seen above, market reforms in the dispatch sector in China have not yet been fully implemented (Davidson and Perez-Arriaga 2020).

Our work emphasizes a third - perhaps more important - source of inefficiency, which will likely persist in the long-run, at least as long as Chinese generators will not be privatized, something that is not even part of the current debate in China. Our findings indeed suggest that, when generators are government controlled, inefficiencies emerge even under a conventional MBS, which up to now has been regarded as being effective and leading to an efficient abatement pattern. We have shown that these inefficiencies occur both in the short run - in terms of failure of the equality of marginal abatement costs among firms - and in the long run - in terms of failure of optimal investment patterns.

8 Conclusion

Carbon pricing is usually regarded as an essential tool for an efficient abatement of carbon dioxide emission (Stavins 2020). Its efficiency and its desirability, however, rest on the presumption that regulated firms internalize the emission costs and are profit-maximizers, something that is generally taken for granted in the policy debate. There are, however, reasons to believe that this is not necessarily the case, at least in the electricity sector, one of the major contributors to carbon dioxide emissions. With the exceptions of those located in the United States, Spain and Germany, the major electricity companies around the world are government-controlled.

We use the example of Italy to show that Enel, the major government-controlled electricity generator, behaves differently than privately owned companies. It does not internalize and pass through emission costs stemming from the EU ETS system, and it does not maximize profit. Marginal abatement costs are therefore not equalized across firms. This undermines what is gener-

ally considered the pre-eminent benefit of a carbon pricing system, that is its short run efficiency. We then show that Enel reacts much less than its private counterpart to prices of emission allowances in terms of emission intensity of its inputs. This is suggestive of the EU ETS's inability to induce an efficient pattern of investment in emission reduction, and, as a result, of the failure of its efficiency properties even in the medium and long run.

Our results cast serious doubts on the efficiency properties of the ETS system that is due to be introduced in China, where all the electricity generation is government controlled, by the end of 2020.

While we study a cap-and-trade system, our results apply equally to a carbon tax - the alternative form of carbon pricing. In fact, a carbon tax might have even more adverse welfare effects than a cap-and-trade under government controlled companies. While, under a cap-and-trade, the amount of pollution reduction is fixed by construction, a carbon tax applied to firms that are not maximizing profits may fail to achieve the desired target of emission abatement altogether.

Contrary to conventional wisdom, our paper suggest that a command and control approach, in the form of emission standards, might be more suitable especially given the reliability of the estimates of the production functions in the electricity generation sector. The suboptimality of emission standards, resulting from their inability to efficiently accommodate heterogeneous abatement costs, are well-known, but they should be traded off against the inefficiencies of carbon pricing under government controlled companies.

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A Resampling algorithm

Our algorithm builds on Kastl (2011). We compute the expected residual demand for each bid in the data and use the first order condition to invert the optimal markup. Denote (b_k, q_k) the k^{th} step of the supply schedule of generator i. We calculate the markups in the following steps:

1. We define the market on the hour / day /zone level. Where we reduce all possible zones in the Italian electricity market into two main zones: North and South. This is a valid approximation for almost all of our data. The zones might be occasionally further decomposed even into smaller regional markets (within our two zones) if the electricity transmission is overloaded, but this is very rare.

2. We calculate the total demand in our markets. The electricity market needs to clear in any point of time so we calculate the aggregate demand by summing up all actually supplied electricity. For the purpose of our model we assume that quantities of bilateral contracts and renewable energy are common knowledge. We therefore subtract these supply schedules from the realized demand to obtain demand $Q_D^{'}$.

3. Denote n_1 the number of supply schedules by private generators and by n_2 the number of supply schedules in the market. Denote these supply schedules by s_j. For public generators we sample with replacement n_1 bid schedules from the set of all schedules submitted by privately owned generators and n_2 from those submitted by publicly owned ones. The residual demand is $D_{R,S-i}(p) = Q_D^{'} - \sum_{-i} s_j(p)$

4. We intersect the residual demand with the supply schedule of generator i and obtain a market clearing price P^c and quantity by i $Q_i^C(p)$.

5. Repeat the steps 3 and 4 many times to obtain a distribution of the market clearing prices and quantities.

6. Perturb the offer of i to calculate $\frac{\partial \mathbb{E}_{S_{-i},D|s_i}\left[Q_i^c(S,D)|P^c=b_k\right]}{\partial b_k}$

7. Calculate the markups $M(b_k, q_k)= \frac{\mathbb{E}_{S_{-i},D|s_i}\left[Q_i^c(S,D)|P^c=b_k\right]}{\frac{\partial \mathbb{E}_{S_{-i},D|s_i}\left[Q_i^c(S,D)|P^c=b_k\right]}{\partial b_k}}$