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NAVIGATING THE ELECTRIC STORM:
ASSESSING POLICY RESPONSES TO EUROPE'S ENERGY SHOCK

by Matteo Alpino*, Emanuela Ciapanna*, Luca Citino* and Gabriele Rovigatti*†

Abstract

We take an off-the-shelf model of the day-ahead electricity market, adapted from Reguant (2019), and use it to study how different emergency policy interventions proposed in response to the 2021–2022 European energy crisis would feed into short-run wholesale electricity price and consumption dynamics. Calibrating the model to Italian data, our analysis predicts that an EU-wide cap on natural gas prices significantly lowers electricity prices, while consumed quantities increase only marginally. A mandated reduction in electricity demand during peak hours leads to modest price declines, while a national cap on gas prices for electricity generation triggers a sharper increase in consumption. These findings suggest that emergency interventions can mitigate the short-term impact of price shocks, though they may also lead to increases in energy consumption and market distortions.

JEL Classification: E10, E20, J60, K40, L50, O30.

Keywords: electricity market, wholesale prices, structural model.

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1 Introduction[1]

Since the summer of 2021, the combination of a swift post-COVID-19 recovery, an unusual weather pattern, and new geopolitical tensions has led to unprecedented surges in natural gas prices. The invasion of Ukraine by Russia in February 2022 further exacerbated this "energy crisis", significantly impacting electricity prices. These developments brought the design of the electricity market to the forefront of political discussions in Europe. To mitigate the impact of sudden electricity price spikes on households, European governments proposed and sometimes implemented various emergency relief mechanisms through market interventions.

In this paper, we take an off-the-shelf stylized competitive model of the day-ahead electricity market to quantify the effects of three of these emergency policies on short-run price and quantity developments. Specifically, we use a simplified version of the quantitative partial equilibrium model by Reguant (2019), which we calibrate with Italian data on 2022. The three policies analyzed are: (1) a EU-wide gas price cap;[2] (2) a program of mandated demand reduction during peak hours, or *peak-shaving* – this aims at reducing prices by forcing a demand decrease during the hours featuring the highest consumption; (3) a national price cap on the gas used for electricity generation (known as the *Iberian Exception* in Spain and Portugal where it was implemented). Given that all of these policies are temporary emergency interventions that could mitigate the negative effects of surging electricity prices on final consumers, we evaluate them by measuring both the effects on prices and on quantities of electricity in the short term only. Any consideration about the effects of these policies on energy security in the medium term and on fostering the green transition is thus beyond the scope of our work.[3]

We aim to develop intuition on how core economic mechanisms—cost heterogeneity, demand responses, and marginal cost pricing—interact to shape short-run wholesale electricity pricing dynamics under emergency interventions. Additionally, we seek to establish a foundation for transparently communicating their broader implications, such as challenges in signaling scarcity. By using a simple model, we can isolate and analyze the key mechanisms at play without the complexity and data requirements of more detailed models (e.g. PLEXOS). The framework nevertheless offers a strong foundation for policymakers to grasp these trade-offs, enabling informed decision-making during future energy crises. Also, a simpler model can serve as a useful benchmark against

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[2]The application follows an actual policy proposal and simulates an EU-wide cap, but the results apply to any intervention implemented by a supranational entity to cap the price of imported and within-region traded gas.

[3]For more details on potential reform of EU electricity markets for long-run objectives see Fabra (2023).

which the outcomes of more complex models can be compared.

Italy is an excellent laboratory for assessing the effects of the policies. First, it is a net importer of fossil fuel for electricity generation and is thus very exposed to changes in international gas prices. Second, it is rather interconnected with neighboring countries, so that changes in domestic prices in the day-ahead markets might influence the direction and the degree of cross-country trade. While focusing on Italy and European policies, our application and results may be relevant to any other country with a high share of imported fossil fuels in the generation mix and features a competitive day-ahead market for electricity.

Through the lens of this model, we return several interesting predictions. An EU-wide cap on natural gas prices substantially lowers electricity prices, with only a marginal increase in consumption. Such price cap leads to a reduction in consumer expenditures on electricity of 7.5%, arising from a substantial reduction in prices (7%) and a modest increase in quantities (0.6%). In contrast, a mandated 5% reduction in hourly electricity demand results in modest price decreases during peak hours (-0.6%). Meanwhile, a national cap on gas prices for electricity generation prompts a sharper rise in consumption (5%).

The rest of the paper is structured as follows: Section 2 provides background information on the electricity markets, on the energy crisis 2021-22 and the policies that have been proposed to tame it; Section 3 presents the model, while Section 4 illustrates its calibration; Section 5 reports on the results and, finally, Section 6 concludes.

2 Background information

2.1 EU electricity wholesale markets

In the European Union (EU), wholesale electricity markets operate through hourly auctions, with most electricity traded in the day-ahead market. In this market, participants submit bids and offers for each hour of the following day. Electricity producers indicate how much energy they can supply and the minimum price they are willing to accept, shaping the supply curve. At the same time, consumers submit bids specifying the quantity of electricity they are willing to purchase at various price levels, forming the demand curve.

The regional power exchanges then aggregate these bids and offers to find an equilibrium price for each hour, where the quantity of electricity supplied matches the quantity demanded. This equilibrium price is set by the cost of the last, or marginal, unit of electricity required to meet the demand. The producers whose bids fall below this price are selected to produce electricity and are paid the market-clearing price, while consumers who bid at or above this price have their demand met and pay the same equilibrium price. The marginal pricing system ensures that the most cost-efficient technologies are dispatched first, with more expensive generators only activated as demand increases. By prioritizing lower-cost producers, the system rewards efficiency and promotes innovation, creating strong incentives for the development and deployment of more advanced, cost-effective technologies.

The overall market of electricity consists of a series of markets operating in sequence: the first is the day-ahead market, which is only financial and does not deliver electricity. Then, there is a series of intra-day market sessions, and ultimately the re-dispatch market. The latter exchanges take place sequentially after the day-ahead auctions, and during the sessions the market participants' positions are updated in order to ensure a secure grid operation at least cost.[4]

EU electricity markets are integrated across member states, allowing countries to trade electricity through cross-border interconnections. These interconnections help balance supply and demand disparities and enable countries to take advantage of regional and temporal variations in electricity prices. By promoting competition, this integration facilitates price convergence across the EU.

However, market integration also brings certain challenges. Transmission bottlenecks, differences in national energy policies, and the intermittent nature of renewable energy sources can cause price disparities across regions. The degree of interconnectedness varies widely between countries. For example, Spain and Portugal remain relatively isolated from the rest of continental Europe, while Italy is highly interconnected with its neighbors. These differences in infrastructure and policies affect how electricity flows across borders and influence regional price dynamics.

2.2 The 2021-2022 energy crisis

Since the second half of 2021, European countries witnessed a significant increase in wholesale energy prices. On the one hand, this was due to a surge in global energy demand, as most countries emerged from the Covid-19 pandemics, and to a longer heating season in 2020-2021. On the other hand, supply was tightening, for instance because of lower volumes of liquefied natural gas (LNG) imports to Europe,[5] and unfavourable weather conditions to produce renewable energy. To a lesser extent, the rising carbon price under the EU Emissions Trading System (ETS) added further pressure on energy costs. Following Russia's invasion of Ukraine, gas and electricity prices reached unprecedented levels, sparking concerns about the impact on households and industries. In response, the European Commission (EC) introduced a range of

[4] See Graf et al. (2020b), section 2.1, for a detailed description of the Italian electricity day-ahead, intra-day and re-dispatch markets.

[5] Russian imports of LNG decreased due to the resurgence of post-Covid demand from East Asia, which partially redirected the import flows toward China. The decrease in Russian imports was also exacerbated by the international tensions which followed Ukraine's invasion in February 2022; additionally, the explosion of the Texas Gulf Coast facility for LNG compression in June 2022 dramatically reduced the supply from the US.

measures aimed at reducing the EU's reliance on Russian fossil fuels and mitigating the soaring energy prices. These included a price cap on gas across the EU, implemented in February 2023 under specific conditions, alongside a commitment to closely monitor gas storage levels across member states.

2.3 The application: three policy simulations

In order to tame the crisis, the European Commission discussed, proposed or implemented several interventions throughout 2022. These include i) a gas price cap mechanism; ii) a mandated reduction in electricity demand during peak hours; and iii) the introduction of a "Iberian Exception" model throughout Europe, similar to what was implemented in Spain and Portugal from June, 2022. We describe these in turn.

Gas Price Cap As of February 15, 2023, the European Union implemented a Market Correction Mechanism (MCM) proposed by the European Commission. This policy is designed to be activated when two conditions are met for at least three consecutive days: the one-month-ahead price of gas futures on the Title Transfer Facility (TTF)[6] is above 180 €/MWh, and the spread between the TTF price and the average price of Liquefied Natural Gas (LNG) exceeds 35 €/MWh. To assess the potential impact of this mechanism, we simulated a counterfactual 2022 scenario in which the price cap was in effect during the summer price peaks. In this simulation, gas prices were replaced with capped prices, applying the formula $P_{t,gas} = min(LNG_t + 35); 180$ for all days in which the realized price would have been capped.

Demand Reduction during Peak Hours The EU Council agreed on a mandatory target to reduce electricity consumption by 5 percent during peak hours. Under this agreement, EU member states are required to identify the top 10 percent of peak hours and reduce demand during these periods by the specified 5 percent. However, no detailed guidelines were provided on how to implement this measure. In our analysis, we conduct a counterfactual simulation by identifying the top 10 percent of peak hours across 2022 and simulating a 5 percent reduction in electricity demand during these hours.

Iberian Exception Since June 2022, Spain and Portugal have been allowed to implement a cap on gas prices for electricity generation. This policy includes a subsidy, S_t, for gas-powered plants to cover the difference between the market gas price and the capped price. The subsidy is defined as $S_t = p_{gas,t} - \bar{p}_{gas,t}$, where $\bar{p}_{gas,t}$ is the capped price, which adjusts over time at a pre-determined rate. Although the European Commission discussed extending a similar policy EU-wide, it has not been implemented.

[6]The TTF is a virtual trading point for natural gas in the Netherlands. It is the thickest gas market in the EU and, for historical as well as geographical and economic reasons, stands as the reference market for all other hubs in the EU.

In our policy scenario, we simulate the impact of capping gas prices for electricity generation plants at the same levels as in Spain and Portugal. This cap is set at 40 €/MWh from June, lasting for six months, and increases by 5 € in December. The simulation mirrors the timing and structure of the Spanish and Portuguese models.

3 The model

In order to simulate policy counterfactuals, we use a simplified version of the static partial equilibrium model of the day-ahead electricity market in Reguant (2019), which we present below.[7]

The model assumes perfect competition among electricity producers from fossil sources (coal-fired plants, oil-fired plants, open cycle gas turbines, small and large closed cycle gas turbines). As noted by Graf et al. (2020a), the Italian market is relatively unconcentrated and thus this assumption is reasonable in our context. The model takes renewable energy generation as exogenous. Foreign trade is instead modeled with a net import supply curve.

The hourly demand for electricity q is a decreasing function of the equilibrium wholesale price p^w (where w stands for *wholesale*) and takes the linear form:

$$q_{th} = \alpha_{th} - \beta_{th} p^w_{th}, \tag{1}$$

where t and h refer to the calendar day and the hour of the day, respectively, and $\beta_{th} > 0$ is the responsiveness parameter. Baseline demand might change over time as captured by the intercept α_{th}.

The hourly supply of electricity draws from both national production and imports from foreign markets. As for the national production, there are J technologies divided into three broad classes: (i) intermittent renewable energy sources (RES); (ii) thermal generators: coal, natural gas (three types), oil; and (iii) other renewable sources: hydro, biomass and geothermal.

For intermittent RES, the supply for each technology $j \in$ [solar, wind], denoted by r_{jth}, depends on the available capacity and the intermittency factor (capacity factor) at time t and hour h. The supply constraint is defined as:

$$r_{jth} \leq \omega_{jth} K_j, \tag{2}$$

where K_j is the installed capacity for technology j, and ω_{jth} is the technology-specific

[7]The main differences from the original models are the following: a) we do not allow for endogenous entry of new generators; b) we do not model the retail market; c) we have only one sector on the demand side, instead of three (consumers, commercial and industrial).

capacity factor, capturing the intermittency of generation at each time. Thermal generators include technologies that run on coal, oil, and natural gas. For natural gas—the most common fuel in Italy—we distinguish between three technologies: small CCGT (less than 300 MW), large CCGT (300 MW or more), and OCGT. For each technology j, the supply, r_{jth}, is determined by a simple optimization rule: the plant produces up to its capacity if the wholesale price is higher than the marginal cost, and produces nothing if the price falls below the marginal cost.[8] For all technologies, the optimization rule thus is:

$$r_{jth} = \begin{cases} 0 & if\ p^w_{th} < mc_{jt}(r_{jth}) \\ [0, K_j] & if\ p^w_{th} = mc_{jt}(r_{jth}) \\ K_j & \text{else} \end{cases}$$

where K_j is the installed capacity per technology.

For non-intermittent renewable energy sources (RES), such as hydro, biomass, and geothermal ($j \in$ [hydro, biomass, geothermal]), we take a simplified approach. Since our analysis focuses on short-term policies that primarily affect thermal generation, we do not account for the dynamic factors that typically influence the production decisions of these RES technologies (as detailed in Fioretti et al. (2021)). Instead, we assume that their supply is fixed at the observed levels for each period. Therefore, for non-intermittent RES, we set:

$$r_{jth} = r^{\star}_{jth}, \quad \text{for}, j \in [\text{hydro, biomass, geothermal}], \tag{3}$$

where $r^{\star}_{jth}$ is the observed supply at time t and hour h. This allows us to concentrate on thermal generation policies while keeping the modeling of non-intermittent RES straightforward. Finally, for imports from foreign markets, we use a linear net import supply curve defined as follows:

$$I_{th} = \bar{I}_{th} + \delta_{th} p^w_{th} \tag{4}$$

where $\bar{I}_{th}$ represents the baseline import level at time t and hour h, while p^w_{th} denotes the day-ahead market equilibrium price. The parameter $\delta_{th} > 0$ indicates the responsiveness of imports to changes in the equilibrium price. This linear relationship captures how imports adjust based on price fluctuations in the day-ahead electricity market.[9]

[8] Two stylised facts justify increasing marginal costs. First, within-plant efficiency is inversely U-shaped, starts relatively low - also due to the startup costs (see Reguant (2014)) - and gradually increases, reaching its maximum before the total capacity. Second, there exists a strong degree of efficiency dispersion across plants, even within the same technologies.

[9] During the period under study, Italy is a net importer of electricity: imports account for approximately 15 percent of final consumption (Eurostat), and cross-border interconnection capacity accounts for around 10 percent of total installed capacity (IEA).

Equilibrium In equilibrium supply equals demand in each hour h of every day t. The equilibrium price $\bar{p}^w_{th}$ thus satisfies:

$$\sum_j \left(r_{thj}(\bar{p}^w_{th})\right) + I_{th}(\bar{p}^w_{th}) = q_{th}(\bar{p}^w_{th}). \tag{5}$$

This equation indicates that the total supply from all technologies, along with the imports, must match the demand for electricity. Consequently, the equilibrium price is equal to the marginal cost of the most expensive technology that is utilized in production. This ensures that the market efficiently dispatches resources according to their costs, prioritizing lower-cost technologies while accommodating higher-cost options as needed to meet demand.

4 Data and Calibration

Demand To parameterize the demand function in (1), we need a measure of the demand elasticity. Based on the empirical estimates in Ito (2014), we assume a value of 0.1.[10] With the observed prices and quantities, together with the assumed elasticity, we easily obtain the (partial derivative) parameters α_{th} and β_{th}[11]

Marginal cost of thermal generators To calculate the marginal cost of each thermal generation technology, we consider two main components: the fuel cost and the CO_2 emission cost associated with the EU Emission Trading System (EU ETS). We measure the fuel cost as the wholesale input price at the daily (natural gas and fossil oil) or monthly (coal) frequency and the emission cost as the daily price of the EU ETS certificates. To convert the unit fuel cost in terms of unit of electricity output, we rely on information on the average heat rate of Italian thermal generation plants from Graf et al. (2020a).[12] Additionally, to express the emission cost per unit of output, we gather data from Caputo (2021) on emission factors for different fuels in electricity generation in Italy.

We extend the original model by Reguant (2019) by incorporating a quadratic cost function for each technology to account for heterogeneity across plants. The marginal cost function is expressed as:

[10]The estimate in Ito (2014) is among the lowest in the literature. Since we analyze a wholesale daily market focusing on short run policies, this seems the most sensible choice, in light of the fact that demand is less elastic in the short run (Deryugina et al., 2020). In simulating wholesale daily markets, some authors even assume inelastic demand (De Frutos and Fabra, 2012; Graf et al., 2020a). We experiment with larger elasticities (up to 0.3, the highest value estimated by Deryugina et al. (2020) for the medium-run), and results are virtually unaffected.

[11]As in Reguant (2019), it is easy to show that $\beta_{th} = \epsilon \cdot q_{th}/p^w_{th}$.

[12]They consider four types of gas generation, five of coal generation and one of oil generation. We collapse some of these because we do not always have information on capacity at the same level of disaggregation.

$$MC_{jth}(q_{jth}) = f_{jt} \cdot H_j(q_{jth}) + P_t^{ETS} \cdot EF_j \cdot H_j(q_{jth}) \tag{6}$$

where the first term refers to the fuel cost and the second term to the emission cost. Starting with the first term, f is the unit cost of the fuel used by technology j and $H_j(q_{jth})$ is the number of fuel units that are necessary to produce one MWh of electricity (the *heat rate*). We model the heat rate of a given thermal technology j as an increasing function of q_{jth} to capture efficiency differences across plants. To fix ideas, this is like assuming that for each technology class, power plants are heterogeneous in their heat rate; thus $H_j(\cdot)$ orders them from the most to the least efficient. We assume $H_j(\cdot)$ to be linear, with parameters reported in Graf et al. (2020a).[13] P^{ETS} is the price (per ton of CO2) that needs to be paid for the CO2 emissions produced in the electricity generation under the EU ETS. EF_j is the emission factor, that is how many tonnes of CO_2 are required to produce one MWh of electricity with technology j. Table 1 reports the average heat rate $\bar{H}_j$ (column 2) and the average emission factor (column 3) for each technology j.

It is important to note that our natural gas price series comes from the Italian gas exchange hub, known as *Punto di Scambio Virtuale* (PSV). During peak periods, prices at PSV diverged from those at the TTF (Title Transfer Facility), which serves as a significant benchmark for most production plant supply contracts. Therefore, our results may represent a lower bound on actual effects, as most supply contracts are indexed to TTF prices. Nevertheless, it is important to stress that PSV and TTF are generally very correlated (see Appendix) because the European market is quite integrated. In 2022 the highest PSV vs TTF spread at the monthly average frequency was 6 euro.

Finally, note that our modeling assumptions implicitly implies that generators are not well hedged against fluctuations in the price of fuel and of carbon, and thus such swings map directly in to their marginal cost. Information gathered from the Survey of Industrial and Service Firms run annually by the Bank of Italy confirms that hedging was not widespread among electricity utilities in 2021 and 2022.[14]

Capacity We use micro-data from ENTSOE, which include information on fuel and capacity at the plant level, but lack information on the exact technology in the case of gas (CCGT or OCGT). Hence, we link them to the Open Power System Data to include this information. For each thermal technology j, Table 1 reports the total capacity K_j of the Italian fleet (column 1).

Import Using the observed wholesale price and import quantity, we need to assume a value of the import elasticity to calibrate the two parameters in equation (4) in the same way as we did for demand.

[13] This is akin to assuming that technology-specific heat rates are uniformly distributed.

[14] For additional information on the survey questions see Alpino et al. (2023) and Alpino et al. (2024). While the survey covers the entire industrial sector, the analyses in these papers exclude the electricity sector to focus on manufacturing and non-energy utilities.

Table 1. Thermal generation: calibration

Technology	K_j (MW)	$\bar{H}_j$	EF_j (ton CO^2/MWh)
Small CCGT	1,500	0.47	0.365
Large CCGT	31,000	0.52	0.365
OCGT	7,700	0.29	0.365
Oil	1,500	0.3	0.55
Coal	6,376	0.34	0.88

Note: data sourced from ENTSOE, Open Power System in 2022 and ISPRA.

To estimate the import elasticity, we follow the methodology of Bushnell et al. (2008) and Reguant (2019), regressing the logarithm of total Italian imports against the logarithm of the national wholesale price (PUN). The national wholesale price is instrumented using the forecasted load levels, which serve as a demand shifter needed to trace out supply. Imports and load 2016-2019 are sourced from ENTSOE, while we use the hourly wholesale price from the Gestore dei Mercati Energetici. In the hour-level regression, we control for binned maximum daily temperature and use different combinations of time fixed effects. The estimates of import elasticity across specifications are somewhat unstable, with values ranging from 0.9 to 2.8 (Table 2). For our baseline exercises, we use the lower estimate of 0.9, but we switch to the higher estimate of 2.8 for other simulations.

Table 2. Import supply elasticity estimates

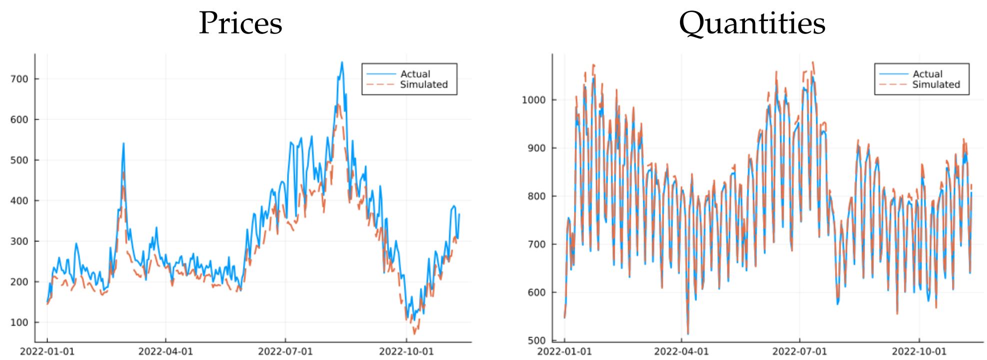
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
log(PUN)	0.9	0.9	0.8	0.5	2.0	0.8	2.2	2.8
	(0.02)	(0.02)	(0.02)	(0.02)	(0.04)	(0.02)	(0.03)	(0.05)
Year FE		✓	✓	✓	✓			
Month FE			✓	✓	✓			
Day-of-Week FE				✓	✓			
Hour FE					✓			
Year/month FE						✓	✓	✓
Hour/month FE							✓	
Hour/Day-of-Week FE								✓
Observations	35,011	34,747	34,747	34,747	34,747	34,747	34,747	34,747

Note: 2SLS regression of log(imports) on log(wholesale price), instrumented with the forecasted level of load. Standard errors are reported in parentheses. Fixed effects levels are reported in the lower panel.

5 Results

Model performance In Figure 1 we present the daily averages of the hourly simulated and observed price and quantity series for 2022. The left panel shows the price data, while the right panel displays the quantity data. Overall, the simulation closely aligns with the actual series, demonstrating a strong correlation between the two. However, simulated price is on average 10 per cent lower than the observed price, and the gap temporarily widens when the price spikes upward. This gap may be attributed to factors not modeled in our baseline framework, such as maintenance and startup costs, as discussed in Reguant (2014). Additionally, the presence of market power among producers — an aspect that our model simplifies by assuming perfect competition — could also in part contribute to the observed discrepancies.[15] Note that we always compare our policy scenarios to the *simulated* baseline, rather than the actual baseline. This ensures that the differences between the policy scenarios and the baseline (the results) are not driven by the imperfect performance of our model in predicting the true price and quantities.

Figure 1. Simulated model for prices and quantities - 2022 data



Note: Actual and simulated prices (left panel) and quantities produced (right panel) in Italy during 2022. Observed and estimated hourly series are aggregated at the average daily level.

5.1 Policy scenarios

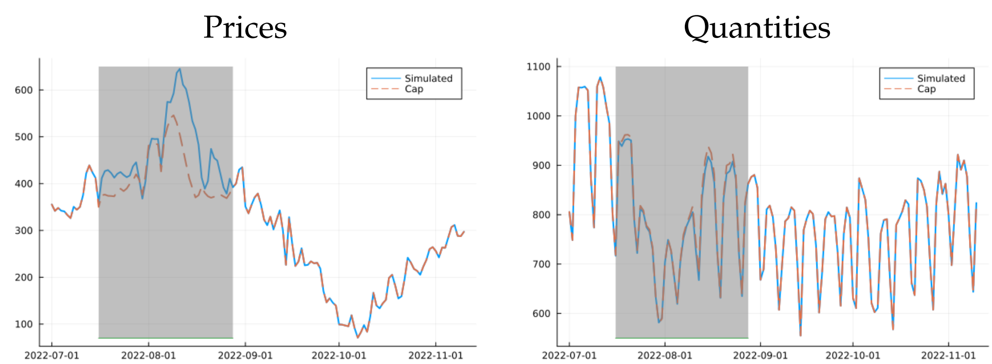
Price cap In Figure 2 we plot simulated prices and quantities of electricity between July and September of 2022, with and without a price cap. When interpreting results from this simulation, we recognize that a gas price cap could trigger various strategic responses from gas suppliers, such as supply disruptions or price gouging prior to the cap's imposition. In our counterfactual scenario, we simplify by assuming that the supply at capped prices would not be disrupted. This assumption is less strong than it appears in the current scenario. Indeed, under imperfect competition, the EU monopsony power could counterbalance the suppliers' market power and impose lower prices without triggering supply shortages (Ehrhart et al., 2022). The differences between the "Cap" and the "Simulated" baseline series highlight notable adjustments in both prices (left panel) and quantities (right panel), particularly during the peak period

[15] As noted by Graf et al. (2020a) the Italian market is relatively unconcentrated, limiting the presence of market power. However, it is still possible that in certain hours of the year, especially in times of high demand when some producers are capacity constrained, market power arises (Borenstein et al., 2002). However, we find unlikely that market power in the electricity market arises in connection of geopolitical tensions in the natural gas interantional market.

in August. Overall, the introduction of the price cap led to a 7% reduction in total electricity expenditure (calculated as prices multiplied by quantities) compared to the baseline simulation. This decrease was primarily driven by a 7.5% drop in average prices. However, this reduction was only partially countered by a modest increase of approximately 0.6% in electricity consumption. This limited increase in demand can be attributed to the low elasticity of demand, which characterizes wholesale electricity markets.[16] In our simulation thus the cap appears to be an effective tool to mitigate the increase in electricity cost.

When interpreting the results, it is crucial to recognize that our model treats the supply of fossil fuels as exogenous. This means that the model does not account for potential supplier reactions to a gas price cap, which could include halting gas flows. In our framework, we assume that gas supply remains uninterrupted, effectively implying that gas producers are willing to supply at the capped price. This assumption simplifies the analysis but may overlook important dynamics that could arise in a real-world scenario, where suppliers might respond to price controls in ways that could impact overall supply.

Figure 2. Policy Simulation: the Price Cap



Note: Simulated series of prices for the baseline (orange line) and counterfactual price cap model (blue line) between July and September 2022. The shaded area corresponds to the period of imposition of the gas price cap.

Demand Reduction In 2022, the top 10% of hours with the highest electricity prices consistently occurred during the July-August period, coinciding with the peak of the energy crisis as European countries worked to replenish their gas stocks for the upcoming winter. Simply ranking the observed wholesale prices from 2022 to identify these peak hours would be misleading, given that prices were artificially inflated due to supply constraints.

To accurately determine the top 10% of hours for potential demand reduction, we conducted a regression of the wholesale electricity price (PUN) using fixed effects at both the quarter-by-hour and date levels. The estimated fixed effects at the quarter-

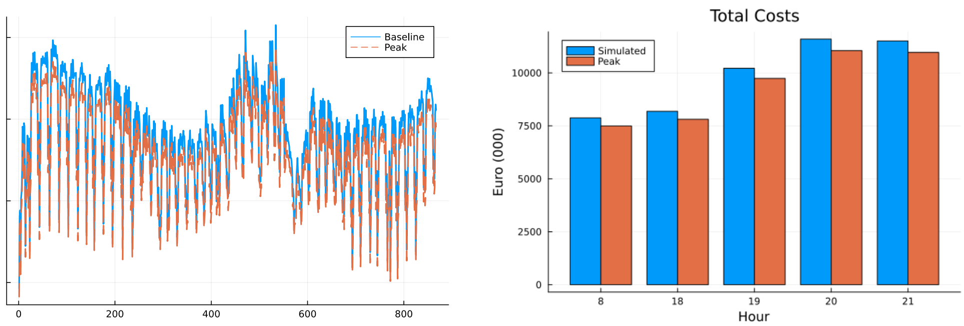
[16]We parametrize this elasticity equal to 0.1 (Ito, 2014), which is a sensible value in this context. Often, wholesale electricity market models even assume inelastic demand (De Frutos and Fabra, 2012).

by-hour level allowed us to identify the highest-priced hours for each quarter while leveraging only the within-date variation. We then ranked these fixed effects to select the top 10% of hours with the highest prices. In our counterfactual analysis, we implemented the mandated 5% reduction in demand during these identified peak hours.

In the left panel of Figure 3, we plot the equilibrium quantities (q^w_{ht}) for each hour subject to the peak shaving for both the baseline simulation (blue lines) and the counterfactual scenario (orange lines). The right panel reports the average difference in total costs in the hours which should have been subject to the measure in 2022. The measure effectively reduces total costs, and this effect is predominantly driven by quantity reductions - by design, -5%. While this result was expected, given the nature of the intervention focused on demand, we also observe modest price reductions resulting from the marginal pricing mechanism, averaging around 0.6%. Specifically, during peak hours, the marginal generating plants operate with reduced efficiency, meaning that even small demand cuts can lead to decreases in equilibrium prices.[17].

It is important to note that neither the EU Council's proposed measure nor our counterfactual scenario considers potential dynamic responses in demand curtailment. For example, if the government were to implement consumption reductions in industrial sectors during peak hours (such as partial disconnections), firms might shift their consumption to unconstrained hours, which could inadvertently raise demand and prices during those non-peak hours. Therefore, our estimates represent an upper bound of the measure's overall effect, which amounts to a reduction in total costs of approximately 0.05%.

Figure 3. Policy Simulation: Demand Peak Shaving



Note: The left panel reports simulated series of quantities for the baseline (blue line) and counterfactual peak shaving model (orange line) for the hours in which the demand shaving of 5% should have been in place in 2022. The right panel reports the difference in total costs per hour between baseline (blue bar) and peak-shaved experiment (orange bar) for the hours in which the demand shaving should have been in place in 2022.

The discussion regarding the effectiveness of the demand reduction measure cannot

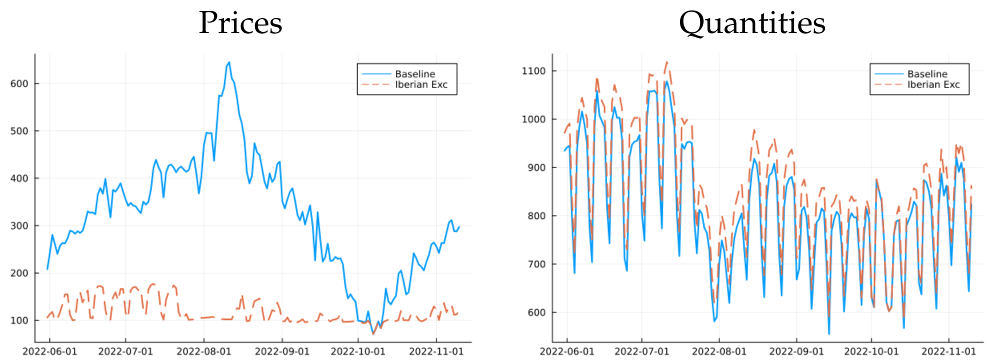
[17]The dynamics of efficiency reduction during peak hours is captured through the quadratic technology-level cost function, as detailed in section 3

overlook the methods employed for its implementation. The 5% cut in consumption can be achieved through various approaches, each with distinct implications. One approach is to impose mandatory reductions on specific firms or individuals, such as rationing energy-intensive activities during peak hours. Alternatively, providing incentives for consumers to shift their energy consumption away from peak hours encourages more efficient use of resources. Another method focuses on redistributing demand, aiming to spread energy consumption more evenly across non-peak hours to reduce strain during peak demand periods.

These methods can coexist and interact in different ways, leading to varying impacts on production. The effectiveness of each approach will depend on factors such as within- and across-sector energy substitutability, firms' ability to delay or adjust production schedules, and the extent of available storage capacity. Therefore, the choice of implementation method is crucial for determining the overall effectiveness of the demand reduction policy.

Iberian Exception In Figure 4, we illustrate the estimated effects of the "Iberian exception" measure on prices and quantities. The left panel shows that the introduction of this measure results in a stable price level of approximately 100 Euro, aligning with the subsidy's intended goal. Meanwhile, the right panel indicates an average increase of 5% in overall electricity consumption compared to the baseline counterfactual. As anticipated, the subsidy dampens the price signals from the market, leading to consistently higher electricity consumption than the baseline level.

Figure 4. Policy Simulation: the *Iberian Exception*

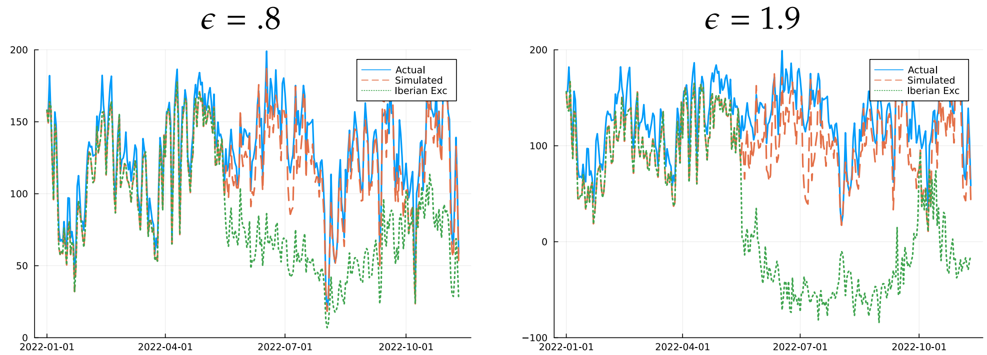


Note: Simulated series of prices and quantities for the baseline (blue line) and counterfactual "Iberian Exception" model (orange line) between June and November 2022.

We can compare the cost of financing the subsidy with the resulting reduction in the total electricity bill. The subsidy during the period is calculated using the formula

$$\sum_{t=1}^{T}\sum_{h=1}^{24} q_{gas,th} \times (p_{gas,t} - \bar{p}_{gas,t}), \tag{7}$$

Figure 5. Net import series for different elasticities



Note: net import: actual values (blue line), simulated value (orange line), and simulated value in case of *Iberian Exception* (green line) between January and December 2022.

where $q_{gas,th}$ represents the quantity of gas consumed by the three gas-powered technologies to produce energy in hour h at time t, and the difference between the gas price $p_{gas,t}$ and the capped price $\bar{p}_{gas,t}$ constitutes the subsidy for each KHw produced with gas. In total, it amounts to 1.9 billion Euro. In contrast, we estimate the overall reduction in total electricity costs, calculated as

$$\sum_{t=1}^{T}\sum_{h=1}^{24}(p_{th,baseline} \times q_{th,baseline}) - (p_{th,Iberian} \times q_{th,Iberian}) \tag{8}$$

to be about 29 billion Euro. According to this exercise, the benefits for the consumers would vastly exceed its cost.

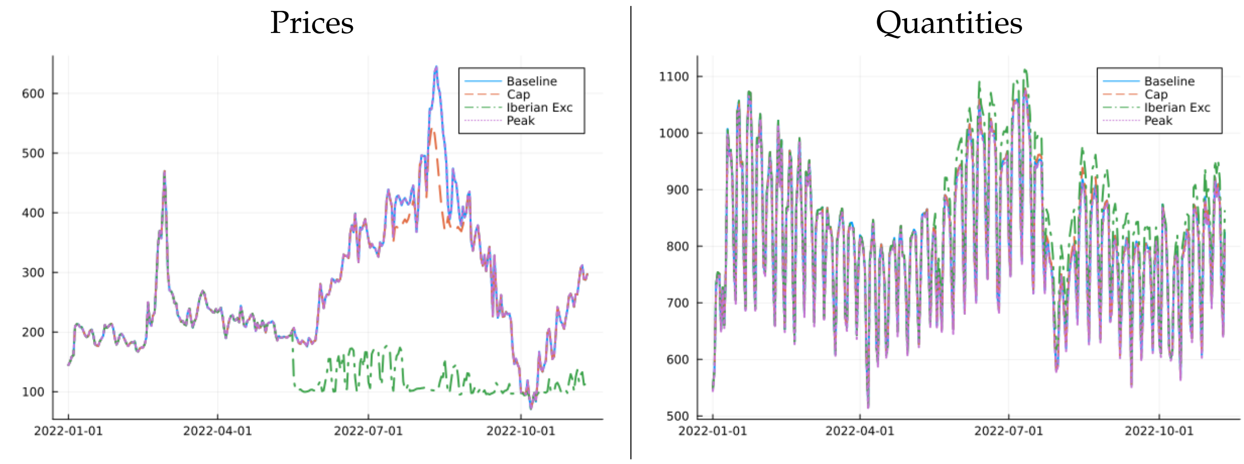
When interpreting the counterfactual simulation, it is crucial to recognize the significant impact of the import elasticity on the quantitative results. In figure 5 we illustrate the net import series (in green) for two different values of import elasticity ϵ: our baseline 0.8 (left panel) and 2.8, the highest value estimated in Table 2 (right panel). While dynamics are qualitatively similar, when using a very high elasticity net imports turn negative in the summer - i.e., gas-powered generators use subsidized gas to export electricity abroad. In contrast, with the baseline elasticity of 0.8, net imports decrease significantly but remain higher than exports. This shift to negative net imports signifies that the domestic government effectively subsidizes foreign electricity consumption. Moreover, with the 2.8 elasticity, the cost of the subsidy increases to 2.4 billion euros, which is 26% higher than the cost estimated using the baseline elasticity.

The results of our exercise strongly support the two main criticisms that hindered the wider implementation of the measure. First, while subsidizing gas-powered production results in a significant reduction in final prices, it simultaneously sterilizes the price signals from the market. This lack of informative prices diminishes the incentives for consumers to lower their consumption in both the short and medium term. Our model quantitatively confirms this, showing that counterfactual demand remains consistently higher than in the baseline scenario. Implementing this measure across the EU would have led to a dramatic increase in gas consumption during a period marked by shortages and uncertainties about future supply, thereby exacerbating the security of supply issues that the EU was already facing.

Second, as previously mentioned, subsidizing electricity production creates strong incentives to export to markets where gas-powered production is not subsidized, leading to distortionary effects on both sides. The EU Commission allowed the Iberian countries to proceed with the "Iberian Exception" primarily due to their relatively low degree of interconnectedness with neighboring countries, which limited the volume of subsidized electricity that could be exported.

Comparison across policies In figure 6 we plot the baseline simulated model (light blue line) alongside the cap (orange line), the Iberian exception (green line) and peak-shaving (purple line), for both prices and quantities. The graph highlights the dramatic effects of the "Iberian Exception" in terms of prices, which is also reflected in an increase in quantity demanded.

Figure 6. Results of policy simulations



Note: The left panel reports price results of the baseline and all policy simulations. The right panel reports quantity results of the baseline and all policy simulations.

We also compute changes in consumer and producer surplus (CS and PS, henceforth) for each policy simulation, and present them in percentage deviations from the baseline simulation in Table 3. Note that such welfare calculations abstract from distortions that policies might cause in *other* markets (e.g. retail natural gas market for heating, LNG international market, wholesale natural gas market, electricity market in neighboring countries, etc.), leaving us unequipped to say what happens to total economic surplus.

Under the price cap, annual total surplus increases by 0.6%, though this small change is achieved through a reduction in PS of 4.6% and an increase in CS by 2.1%. Overall surplus increases under this policy because natural gas is now cheaper, which also explains the greater increase in welfare for electricity consumers. Conversely, since natural gas is the marginal technology, a decrease in the input cost depresses the electricity price, creating a decrease in the competitive rent for other inframarginal producers.

In the case of the "Iberian exception", we find that total surplus in the electricity market increases by 16.8%, following a large decrease in PS (-30.2%) and a corresponding large increase in CS (+30.5%). Consumers are heavily subsidized in their electricity consumption and inframarginal producers lose a large part of their competitive rents because of lower equilibrium electricity prices.

In the case of peak-shaving, the effects are felt mostly by consumers, who lose 10.4% of their surplus by means of lower consumed quantities in peak hours.

Table 3. Surplus Analysis for Different Policies

Scenario	**Welfare impacts** (%Δ from baseline)		
	Consumer	**Producer**	**Total**
Cap	+2.1%	-4.6%	+0.6%
Iberian Exception	+30.5%	-30.2%	+16.8%
Peak shaving	-10.4%	+0.3%	-8%

Note: The table reports percentage changes in annual welfare indicators under the three policies, compared to the "Baseline" scenario, with no policy in place for 2022.

6 Conclusion

This paper develops a stylized model of the day-ahead wholesale electricity market, adapted from Reguant (2019) and calibrated with 2022 Italian data, to assess the impact of emergency policy interventions implemented during the European energy crisis. We examine the effects of an EU-wide gas price cap, a mandated reduction in electricity demand during peak hours, and a national cap on gas prices for electricity generation, known as the "Iberian Exception".

Our simulations highlight key dynamics at play in the short-run response of electricity markets to these interventions. An EU-wide gas price cap reduces wholesale electricity prices by 7.5%, with electricity consumption increasing only marginally by 0.6%, reflecting the inelastic nature of demand. The mandated 5% reduction in electricity demand during peak hours lowers prices by 0.6% and reduces total costs by 0.05%. The Iberian Exception decreases prices to around 100 EUR/MWh — a sharp drop compared to the baseline — while raising electricity consumption by 5%, driven in part by incentives for cross-border trade that may amplify market distortions.

These findings shed light on the immediate effects of short-term policy measures, offering a clear comparison of their impacts on prices, quantities, and welfare outcomes. While each intervention mitigates the effects of price shocks to varying degrees, they also introduce distinct trade-offs between cost containment and energy consumption.

The framework outlined here provides a solid foundation for policymakers to better understand these trade-offs, supporting informed decision-making in the face of future energy crises.

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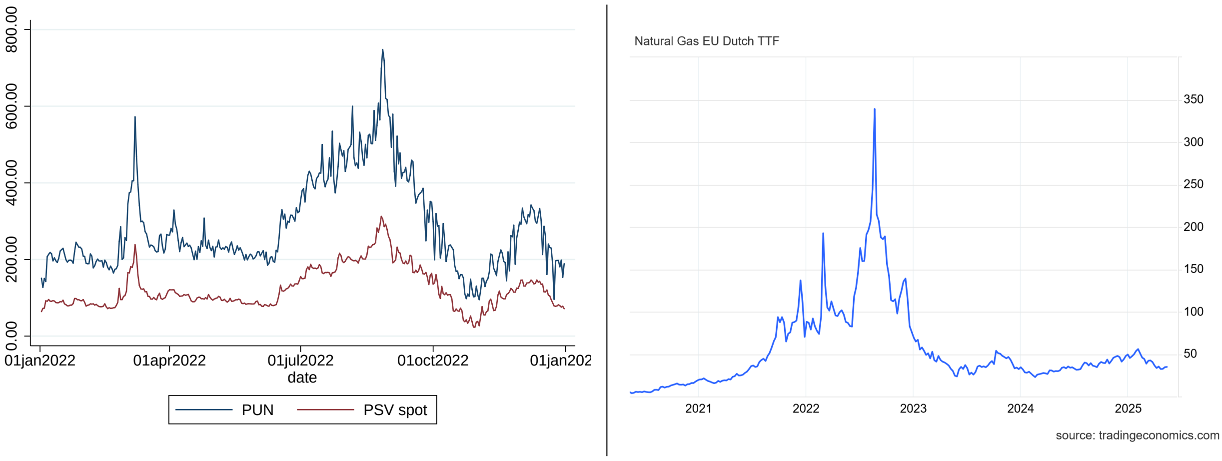
A *Title Transfer Facility* (TTF), *Punto di Scambio Virtuale* (PSV) and *Prezzo Unico Nazionale* (PUN)

Figure 7. Italian gas/electricity prices and TTF prices



Note: left panel - average daily electricity price (PUN, blue line) and daily gas price (PSV, red line) in 2022. Sourced from GME. Right panel: TTF daily gas price, 2021-2023. Sourced from `https://tradingeconomics.com/commodity/eu-natural-gas`.

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