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The Iberian exception: Estimating the impact of a cap on gas prices for electricity generation on consumer prices and market dynamics

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ABSTRACT

As the volatility of short-term energy market prices increases due to exogenous shocks and the changing nature of the energy mix, market interventions are gaining importance in the policy debate. Accurate and robust quantification of their impact is becoming therefore essential. This paper conducts a causality analysis to evaluate the Spanish "gas cap" for electricity generation during the 2022 energy crisis. We use Bayesian structural time series models to isolate its impact on affected consumers, primarily those under the regulated tariff, from June to December 2022. Our results show that the mechanism successfully lowered prices compared to a counterfactual scenario without the intervention. However, the policy also led to an increase in electricity generation from gas-fired combined cycle plants. In addition, exports to France increased by over 80% after implementation, as Spanish wholesale prices became cheaper than French prices. Our analysis (1) provides an accurate quantification to date of one of the most consequential energy market interventions in recent years; (2) demonstrates the fruitful use of a novel evaluation method for energy policy; (3) highlights the trade-off between the short-term goal of consumer price relief and the long-term goals of fossil fuel reduction and decarbonisation.

1. Introduction

The energy landscape in Europe has experienced a turbulent time in recent years, marked by the coincidence of several crises. Beginning with the outbreak of the global pandemic and followed by the geopolitical shockwaves of the Russian invasion of Ukraine and the subsequent aim of reducing European energy dependence from Russia, the continent has faced an unprecedented surge in energy prices. These were especially intense for natural gas, given the continent's dependence on the source from foreign partners, especially Russia itself, which accounted for almost half the imports of this fossil fuel. As a result, in December 2021, the price of the Dutch TTF[1] was ten times higher than in 2019.

This escalation shook the European electricity markets, especially the day-ahead markets, due to two interacting factors: (1) the use of natural gas for electricity generation and (2) its usual role as a marginal technology in this market. Combined cycle power plants provide flexibility in the system by meeting peak demand when renewable generation is low. During these hours, they are the most expensive technology and determine the market price. As gas is a necessary input for their production, any increase in its price is immediately reflected in their bids and consequently in the price of electricity. Moreover, since it takes on average two MWh of gas to produce one MWh of electricity,[2] the electricity market amplifies the impact of a price shock for this fossil fuel, as shown in Fig. 1.

Faced with increasing economic and social hardship caused by escalating electricity prices, national governments and the European Commission proposed emergency measures to reduce these prices and mitigate their negative effects. Several alternatives were discussed that had a direct impact on the functioning of the day-ahead market, such as setting a price cap, limiting the selling price of low-margin technologies or compensating fossil-fuelled power generators (European Commission, 2022). However, none of these measures were ultimately adopted at the EU level. Instead, the supranational focus shifted to initiating

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[1] The Dutch TTF, or Title Transfer Facility, is a system registering the delivery of gas in the Dutch gas system and also the main index used in Europe for long-term contracts.

[2] This ratio may vary depending on the efficiency of each power plant.

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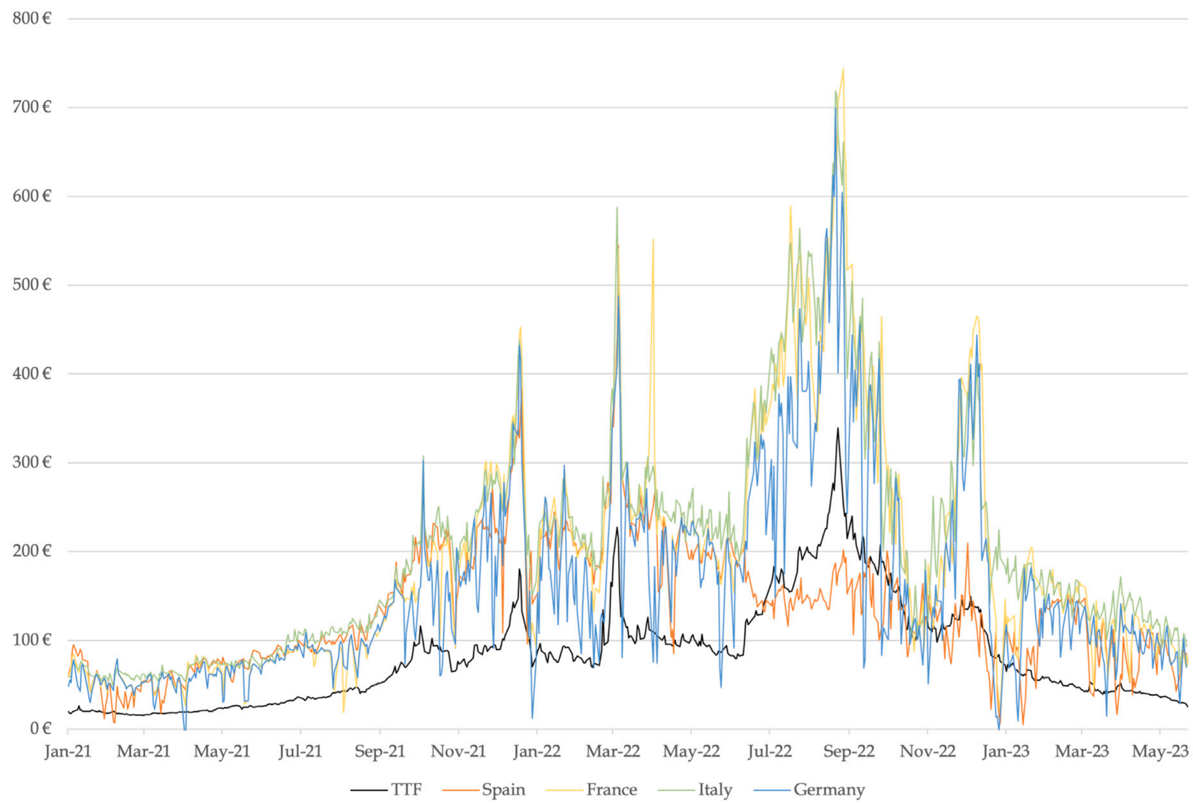


Fig. 1. Evolution of wholesale electricity and gas prices in Europe (in €/MWh).
Source: ESIOS, Investing.com.

electricity market reform and implementing fiscal measures, including reducing VAT or excise taxes, regulating retail prices, providing transfers to vulnerable consumers and supporting industry and taxing windfall profits (Sgaravatti et al., 2021).

Despite those, the impact of soaring electricity prices in Spain gained particular attention from policymakers and the general public. According to the Spanish National Markets and Competition Commission (CNMC for its Spanish acronym),[3] in early 2022 around 10 million households were under the regulated tariff, so-called Voluntary Price for the Small Consumer (PVPC for its acronym in Spanish, VPSC for its English acronym henceforth). Despite its regulated nature, the VPSC is linked to hourly wholesale market results through a dynamic pricing model. For consumers under the VPSC scheme, this means that their monthly electricity bill is a direct reflection of market conditions. However, for the 18 million households on fixed tariffs in the free segment of the retail market, prices are only updated once a year when their contracts with their suppliers come up for renewal.

This heightened concern was compounded by two additional factors: (1) the VPSC is the tariff for many vulnerable households, as it is a prerequisite for access to fuel poverty assistance,[4] and (2) its significant impact on the national Consumer Price Index (CPI), which by design was more exposed to increases in wholesale electricity prices.[5]

The combination of these factors led to the introduction, from June 2022, of a mechanism to reduce the day-ahead wholesale electricity prices, and therefore the final bill for consumers with VPSC, by decoupling them from natural gas prices through a partial modification of the market's marginal system. This paper focuses on assessing the impact of such a mechanism, referred to as the "Iberian exception" or "gas cap", although this is technically incorrect since it is not an actual cap, as explained in Section 2. Even though it was introduced by the Spanish and Portuguese governments and thus applies to the entire Iberian electricity market (MIBEL), the analysis focuses on its impact in Spain. To assess whether the policy achieved its stated goal, we conduct a causality analysis to isolate the effect of the cap from other factors. In Section 3 we explain in detail our method, departing from a model that can approximate the time series of the wholesale electricity price in the regulated market, and using it to feed Bayesian structural models able to produce a counterfactual of the wholesale electricity price without implementing the cap. In Section 4 we compare the counterfactual with the observed time series to measure the impact of the regulatory measure.

Approving and implementing the mechanism required convincing other European partners and the European Commission itself, who voiced two tangible worries aside from the more general alert of the exception risking "a distorsion on the single internal market" (Independiente, 2022): (1) whether it could incentive gas consumption, thus undermining energy savings and decarbonisation goals, leading to an actual warning by the Commission in October 2022 (Arroqui, 2022); and (2) whether the lowering of the prices could "leak" to other European countries, e.g. France, exposing the Spaniards to a potential subsidy for French consumers. Sections 5 and 6 look for proof of these outcomes extending our causal impact methodology. Section 7 concludes by highlighting what we believe is our core contribution plus indicating where further research could lead us.

[3] See CNMC (2022).
[4] This support consists of a discount on the regulated tariff.
[5] Traditionally, the Spanish National Statistics Institute has only taken the regulated tariff into account when measuring electricity prices. However, after noting that there was overexposure during the energy crisis, since January 2023 it has also included information on contracts that do not fall under the regulated tariffs.

2. The measure and existing evidence on it

The day-ahead wholesale electricity market has a marginalist design, i.e. it operates on the principle that the price of electricity is set by the most expensive energy source needed to meet current demand. Typically, this marginal source is a combined cycle power plant, which has higher operating costs due to its required inputs (e.g. natural gas). On the other hand, cleaner technologies such as solar, wind, hydro and nuclear power are the first ones to be dispatched due to their lower marginal costs. When demand exceeds what the baseline supply of these sources can provide and gas-fired power plants enter the market, any increase in the price of this fossil fuel is reflected in the wholesale price of electricity.

However, the price dynamics in the wholesale electricity market do not affect all Spanish consumers in the same way, due to the different tariffs in the retail market. Consumers on unregulated fixed tariffs experience price changes mainly during the annual renegotiation and renewal of their contracts. Conversely, households on the regulated tariff (VPSC), which is indexed to spot prices, are directly affected by short-term fluctuations in the wholesale market. This direct link exposes them to immediate price volatility, in contrast to the delayed impact felt by consumers on fixed tariffs. What is more, there are often many vulnerable consumers on the regulated tariff, as this is a condition for access to the Electricity Social Bonus - a discount on their bills designed to help combat energy poverty.

To address this short-term risk while minimising the impact on public finances and the design of electricity bills, in mid-June 2022, Spain and Portugal introduced a mechanism informally and widely known as the "gas cap". In parallel, Spain also started a process to reform the VPSC to reduce its volatility by indexing the tariff not only to the spot market but also to the futures markets. The new regulated tariff structure officially entered into force in January 2024.

The "gas cap" mechanism aimed to reduce the impact of wholesale natural gas prices to wholesale electricity market pricing. It consisted of compensation to specific electricity generation facilities using fossil energy sources in exchange for limiting their bids in the wholesale electricity market, thereby reducing the market price. Eligible plants included natural gas combined cycle power plants (CCGT), coal-fired thermal plants and certain combined heat and power (CHP) plants. The compensation was calculated as the difference between two gas prices: the Iberian wholesale market price (MIBGAS), and a reference price set by the new standard. The reference price was set at €40/MWh for the first six months and increased by €5/MWh each month thereafter until it reached €70/MWh at the end of the initial one-year application period.[6] The resulting compensation was disseminated by the market operator since its enactment, and the affected power plants included it in their energy price offers on the wholesale market. It therefore reduced the price by the difference between the market price and the pre-set price. This mechanism of internalising the compensation acted as a *de facto* cap on the cost of gas, which was passed on in the final price of electricity.

Due to the marginalist functioning described above, the mechanism acted as a limit on the benefits that inframarginal technologies (i.e. those that are expected to enter the market at a lower bid price, such as solar, wind, hydro and nuclear) would end up receiving. While the measure was in place, and until 31 December 2023, Spain also had a limit on the "windfall profits" that these technologies could receive.[7]

The cost of financing the compensation paid through this mechanism is undermined by the congestion rents generated by the interconnection with France, since lower wholesale prices would increase both the difference between Spanish and French prices and export flows after the mechanism is applied.[8] After deducting these from the costs, the remainder is distributed as a payment obligation on the wholesale market demand. At market close, the adjustment is paid to eligible generators to ensure that their marginal costs are fully recovered and the costs incurred are passed on to consumers as part of their electricity bills. This pass-on initially affected consumers at the regulated end of the retail market, but once their contracts have been updated, consumers on the free market will also internalise the costs.

However, even though consumers bear the cost of the compensation in their bills, the way the mechanism is designed, they should make net savings. This is because the remuneration foregone by inframarginal technologies is less than the compensation paid. The difference leads to lower clearing prices than if the mechanism were not in place, resulting in higher consumer surplus. Brito (2022) illustrates this comparison in Fig. 2. In the right panel, the situation without the cap is depicted, where the yellow area represents consumers' surplus, defined as the difference between the market price (100€/MWh) and their maximum willingness to pay for each unit consumed (the blue line). With the cap in place, the market price is supposed to decrease, allowing consumers to increase their surplus even with the compensation payment (red area in the left panel).

The critical question is therefore empirical: does this hold up in reality, once we look at actual prices under the new policy regime? Sancha (2022), examining the impact of the mechanism during the first 200 days of its application, concludes that the average reduction in the wholesale marginal price during the analysis period was significant at 123€/MWh. To estimate the counterfactual scenario, the study assumed inelastic demand and calculated the counterfactual electricity price as the actual price plus the subsidy that power plants receive. The author also analysed the impact on generators and concluded that, although the reduction in the wholesale price reduced the extraordinary profits of the inframarginal power plants that did not enter into forward contracts, the fossil fuel power plants did not suffer any loss of revenue, as this was offset by the contributions from MIBEL demand and congestion revenues from the interconnection between Spain and France. The study also showed that consumers' experiences varied depending on the type of contract. For example, consumers with regulated and market-indexed contracts benefited from a 17% reduction in the energy price component of their bill due to the intervention, while consumers with fixed price contracts experienced different scenarios depending on the date and structure of their contract renewal.

Other researchers assessed the impact of the intervention based on an econometrically modelled counterfactual scenario, i.e. an estimate of how the variable in question would have evolved in the absence of the policy. In Salas et al. (2022), the focus is on the impact of the intervention on the VPSC. They estimate a counterfactual that models this price with auto-regressive errors and controls for weekly seasonality. The explanatory factors of the model included the gas price, climatic variables such as wind and solar conditions, and the wholesale electricity price in France. The results of this analysis showed a cumulative average reduction in VPSC of 20.7% by the end of September 2022. Robinson et al. (2023) construct counterfactual supply and demand curves for the Iberian electricity market to assess the impact of the mechanism on Spanish consumers. To this end, the authors estimate a counterfactual supply curve representing the offers that electricity generators would have made in the absence of the intervention based

[6] The Iberian exception was later on extended until December 2023 with new reference prices. See the Royal Decree outlining the extension of the mechanism: Real Decreto-ley 3/2023, de 28 de marzo, de prórroga del mecanismo de ajuste de costes de producción para la reducción del precio de la electricidad en el mercado mayorista regulado en el Real Decreto-ley 10/2022, de 13 de mayo.

[7] See Royal Decree-Law 17/2021.

[8] See the Royal Decree that outlines the functioning of the mechanism: Real Decreto-ley 10/2022, de 13 de mayo, por el que se establece con carácter temporal un mecanismo de ajuste de costes de producción para la reducción del precio de la electricidad en el mercado mayorista.

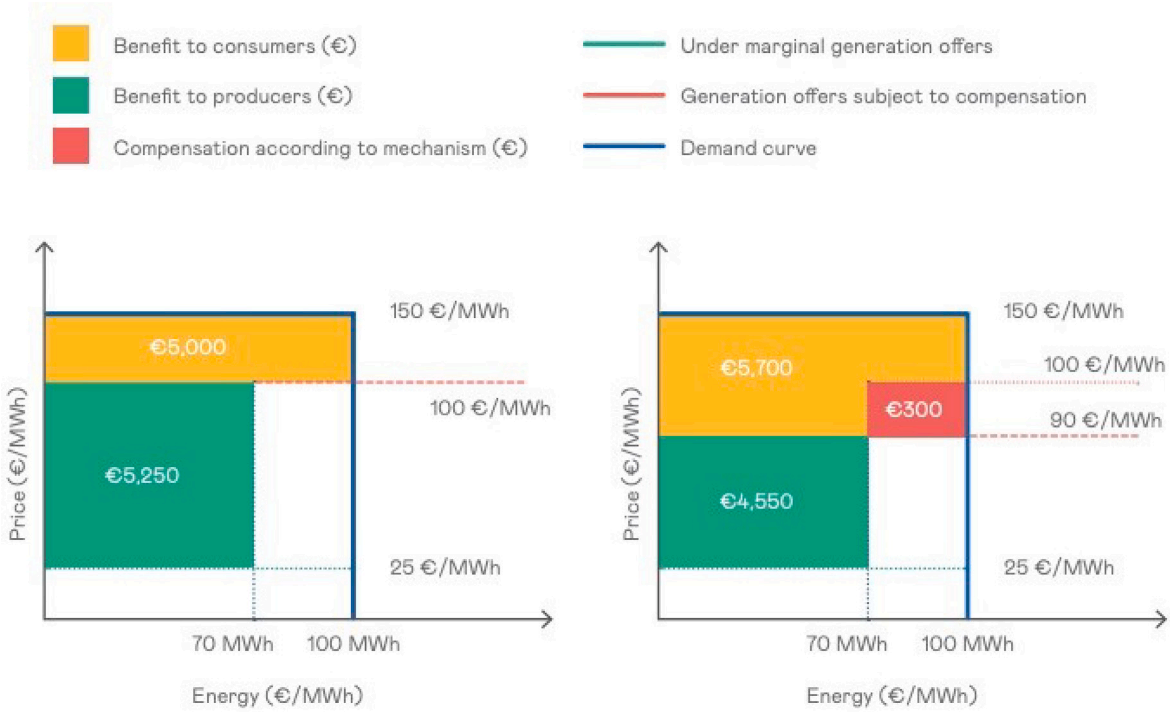


Fig. 2. Representation of potential savings for the consumer.
Source: La Excepción ibérica a debate ¿Una oportunidad perdida? Brito, P (2022).

on the actual offers made by generators during the first 100 days of implementation, together with the actual compensation received by fossil fuel generators. Real data reflecting Iberian demand offers were also used for the demand side, and actual demand contributions to finance the compensation were added to incorporate demand elasticity into the modelling. They find that under the assumption that only Iberian large consumers would have responded to the price change, the savings would have been 13%. In addition, the study considers the impact of French demand on Iberian market prices and interconnections. Under this alternative counterfactual assumption, the authors suggest that affected consumers, i.e. those subject to the VPSC or whose retail prices are linked to the wholesale price, would have paid less if the Iberian exception had not been introduced.

Our work places itself within these empirical efforts and it does so by adding two distinct elements. First and foremost, we believe that our method complements and extends the aforementioned analyses: using a causal impact methodology based on a Bayesian Structural Time Series model allows us not only to estimate a counterfactual estimate but also to perform posterior inference and assign a probability that the observed effect is a direct result of the intervention. In fact, to the best of our knowledge, ours is one of the first examples of a fruitful use of this novel evaluation method for a price-based energy policy intervention. Furthermore, we do not only measure the effects on prices but also on gas consumption for electricity generation **and exports of electricity to France**. By quantifying this dimension along with consumption savings, our contribution aims to go beyond assessing the unintended effects of a particular policy: we show how policies that affect price signals activate the trade-off between the short-term goal of reducing consumer prices and the long-term goals of decarbonisation.

3. Our method to measure the cap's actual impact

As stated above, our primary goal is to determine whether the VPSC experienced a price reduction since its onset. Additionally, it is imperative to investigate whether this price reduction, if indeed it occurred, persisted throughout the intervention. Operationalised, we aim to measure whether the intervention had a causal effect on our target time series, which is the VPSC price.

In recent years, significant progress has been made in the field of causal analysis, particularly in economics. Methodologies such as differences-in-differences, synthetic indicators and, more recently, advances based on machine learning techniques, have transformed public policy evaluation.[9] While many of these techniques were originally designed for cross-sectional or panel data to analyse causal relationships between a treatment and a variable of interest within a specific population, they have been adapted for time series analysis. The causal impact method, introduced by Google Inc. and described by Brodersen et al. (2015) (BGKNS, hereafter), is a recently developed methodology for examining how variables evolve in response to treatment using Bayesian Structural Time Series (BSTS) models.

Technically, the BSTS method extends the differences-in-differences approach to time series analysis by explicitly defining a structural model to predict the counterfactual of a time series both before and after an intervention. This modelling framework enables the estimation of the treatment effect on one or more series included in the analysis. Essentially, the effect is quantified by comparing the expected performance of the time series with its observed behaviour, thus capturing the treatment effect on the treated. To estimate the counterfactual time series, the method combines information from predictor variables in what is commonly referred to as a synthetic control (Abadie et al., 2010).

The construction of this synthetic control involves considering various sources of information, including the performance of the target time series before the treatment and its response to the intervention. Furthermore, it incorporates data from other time series that may

[9] See Hernán and Robins (2023) for a survey of this progress and applications.

predict the behaviour of the target series after the treatment, while ensuring that these variables are not influenced by the treatment itself. Additionally, it uses a Bayesian framework underlying so that the model estimated utilises prior knowledge about the model parameters and subsequently performs posterior inference on the counterfactual.

Implementing the BSTS involves several steps. Firstly, we define the structural model that approximates the historical evolution of the relevant variables for the counterfactual analysis. This process entails analysing the economic nature of the target variable (y_t), VPSC in our case, and identifying suitable covariates to be included in the model. Crucially, the selected covariates and the model must meet specific criteria, such as exogeneity for the control variables used in constructing the synthetic control.

Specifically, the BTST model belongs to the class of state-space models for time series and is represented by the following two equations:

$$y_t = Z_t^T \alpha_t + \beta X_t + \varepsilon_t \tag{1}$$

$$\alpha_{t+1} = T_t \alpha_t + R_t \eta_t \tag{2}$$

where

$$\begin{aligned} \varepsilon_t &\sim N(0, \sigma_t^2) \\ \eta_t &\sim N(0, Q_t). \end{aligned} \tag{3}$$

The Eq. (1) is the observational equation within a state space model. This equation links the data we observe, a series of one variable y_t with a set of k-dimensional latent (states) variables α_t and covariates defined by X_t. The Eq. (2) is the state equation or transition equation, which explicit the evolution of these latent variables through time. Z_t^T is a vector of dimension $kx1$ called output matrix, T_t is a matrix of dimension kxk called transmission matrix, while R_t is a control matrix of kxp dimension. Finally, $R_t \eta_t$ implies, as is explained by BGKNS, the possibility of incorporating state components of less than the full rank. All of these matrices contain unknown parameters and known values which are often set as 0 and 1.

By varying the matrices Z, T, G and R and defining different latent variables we can model several distinct behaviours for the time series (including the more well-known such as ARMA or ARIMA). In this exercise, we interpret the model previously presented by the following:

$$y_t = \mu_t + \gamma_t + \beta X_t + \epsilon_t \tag{4}$$

$$\mu_{t+1} = \mu_t + \eta_{\mu,t} \tag{5}$$

$$\gamma_{t+1} = -\sum_{s=1}^{S-1} \gamma_t + \eta_{\gamma,t} \tag{6}$$

In this particular scenario, Z_t^T, R_t, and T_t are equal to one, while α_t is reduced to two latent variables ($k = 2$), a random variable denoted by μ_t, governed by a random walk model and is conventionally referred to as the 'local level' component and increases independently as the other parameters do not contribute significantly to explaining the data, and γ_t variables, which model seasonal components, and in our model we include two of them specifically representing weekdays and months ($S = 7$ and $S' = 12$).[10] This choice is motivated by structural components associated with different days of the week and the traditional seasonality in a year in electricity price data.

The linear regression is presented using covariates X_t that further help to explain observed data. The better this component works in the prediction task, the lower the local level component should be. Our objective, therefore, is to minimise the role of the latent variable in such a way that the covariates in X_t explain the largest possible proportion of the evolution of the variable y_t.

Finally, the parameters ϵ_t and $\eta_{\mu,t}$ represent noises which are related to measuring y_t and μ_t and they follow a normal distribution with zero means and σ_ϵ and σ_η standard deviation respectively.

To estimate the model, the first step, following the Bayesian approach, involves specifying prior distributions for each model parameter. In this case, the initial step is to define the prior distributions for the errors, which entails assigning values to the error variances. The second step leads to the acquisition of posterior distributions. To obtain them, and given the Eqs. (4) to (6) numerical methods based on simulation techniques must be employed. Specifically, for the estimation of our model, we will use a Monte Carlo Markov Chain algorithm (Hamiltonian Monte Carlo). Once the model is estimated, we obtain a posterior distribution of the counterfactual time series. Finally, we subtract the predicted from the observed response during the post-intervention period, giving us a semiparametric Bayesian posterior distribution for the causal effect.

4. Estimating the impact of the gas cap on final electricity prices

To assess the measure, we must focus on the main stated objective of the gas cap: reduce the final bill of the regulated market consumer. Then, the logical course of action is to examine whether, since its enactment, there has indeed been a significant reduction in the VPSC. However, the cap may have other effects, which have been observed since it came into operation and are also worth evaluating, such as a possible increased use of combined cycle power plants or an increase in exports to France. Both outcomes would result in a rise in gas consumption. Consequently, we believe it is necessary to expand the analysis to these two areas to enrich the present and future debate regarding the measure or potential reforms. In this section we confine ourselves to the first objective and leave the rest to the following sections.

Fig. 3 depicts the evolution of the daily VPSC series[11] in Spain from January 1, 2020 to December 31, 2022. With the onset of the energy crisis, prices increased markedly from the summer of 2021, diverging from the historical pattern. As explained in Hidalgo-Pérez et al. (2022), the marginalist design of the wholesale electricity market and the indexation of the VPSC to it, as described in the introduction, is the main reason for this increase, as electricity generated from gas and other fossil fuels typically sets the daily price.

The cap should lead to a lower VPSC, partially altering the marginalist market system, from June 15, 2022 onward. To estimate the effect of the gas cap, we require a model that best approximates the historical evolution of prices (defined by Eq. (1)). This process comprises two steps:

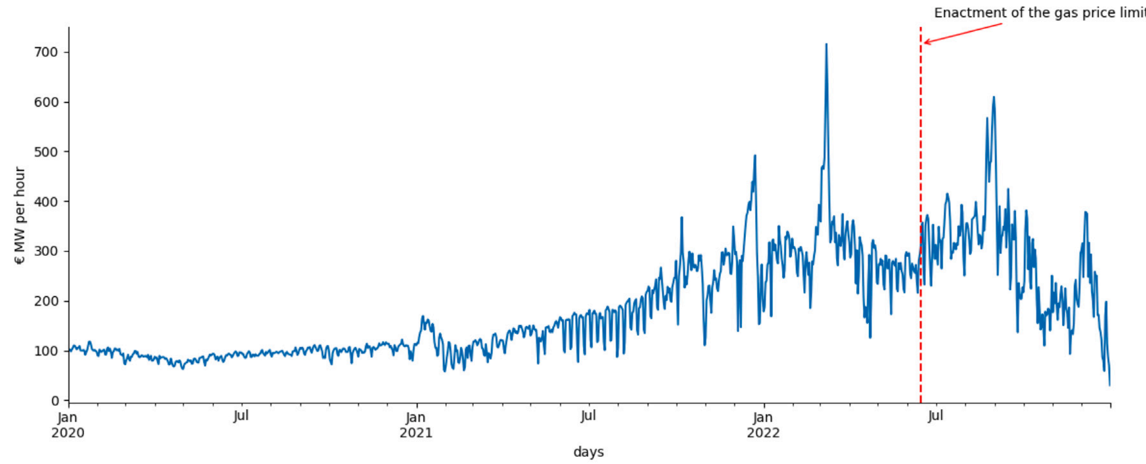
1. First, we select the variables (covariates) that, together with a model like (1), enable us to extrapolate the series shown in Fig. 3 with minimal error.
2. Next, we estimate a BSTS model to obtain the counterfactual scenario and a posterior probability that the enactment of the gas cap could reduce the VSPC, obtaining a measure of ascertaining the likelihood that it is or is not due to the policy.

4.1. Step 1: The hypothetical price series

Thus, the first step should focus on designing a model, together with selecting appropriate variables, that enables predicting the VPSC as closely as possible over the available time series. To accomplish this, we begin by determining which gas price series to utilise as a

[10] We must think of γ_t as a regression with seasonal dummy variables, in this case, with S = 7 with six dummy variables to capture the week seasonal cycle.

[11] In addition to energy costs, the VPSC price series also includes tolls and charges, which are regulated prices designed to cover the costs of transmission and distribution networks and other regulated costs.



Source: Red Eléctrica.

Fig. 3. Evolution of VPSC.
Source: Red Eléctrica.

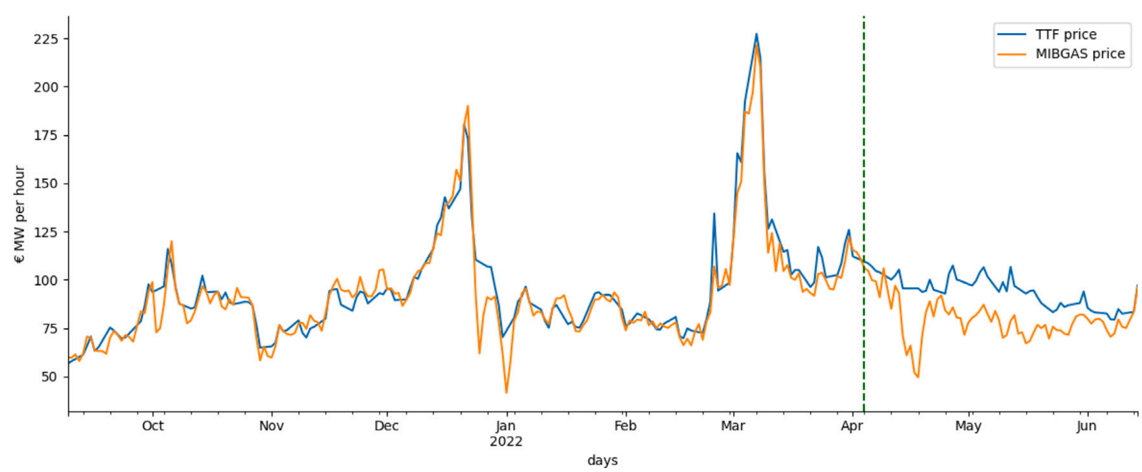


Fig. 4. Evolution of gas price: MIBGAS y TTF.
Source: Own elaboration based on data from Red Eléctrica and REFINITIV.

benchmark for estimating the VPSC. This choice is critical given the current existence of two possible references: the gas price on the virtual market in the Netherlands (Dutch TTF) and the price on the Iberian Gas Market (MIBGAS). Objectively, there is no evidence for a final decision, as the gas supply of combined cycle power plants could be linked to one of the two prices and this is private information. Therefore, we initially let the data dictate: our primary selection criterion was that the gas price used to build the model should be the one that best approximated the VPSC price series statistically.

For most of the period where both gas prices are available, it is observed that the TTF and MIBGAS have evolved similarly (Fig. 4). However, this parallel evolution diverges from 4 April 2022. One potential explanation is the enactment of sanctions against Russia a few days later, which both markets had already anticipated by that date. Thus, the increase in uncertainty over gas supply to Europe was less pronounced for the Iberian Peninsula due to the existence of more diversified channels for gas supply outside the Russian orbit. It is in the divergence described over this period that we find the opportunity to carry out a quantitative exercise that helps to discriminate between the two prices in terms of their ability to emulate the evolution of the VPSC.

To determine which gas price more closely tracks the evolution of the VPSC, we conducted a quantitative modelling exercise. We split the data into a training set from September 9, 2021, to April 4, 2022, and a test set from April 5, 2022 to June 14, 2022. We then built two linear regression models to predict the VPSC price — one using the Dutch TTF gas price and another with the MIBGAS price. The models were trained and then used to generate predictions on the test data. We evaluated the predictions using root mean squared error (RMSE). Once the two models were estimated we obtained that the TTF model achieved a RMSE of 39.15 while the MIBGAS model had a RMSE of 53.64. Based on the lower RMSE, we can conclude that the TTF gas price enables more accurate predictions of the VPSC over the study period.

Therefore, TTF should be the price featured as a covariate in the structural model. However, although the data indeed discriminates in favour of TTF, during the year before the intervention MIBGAS has growingly increased its share of new contracts within the Spanish gas and electricity system. It may then be appropriate to test alternative price series resulting from a weighting of TTF and MIBGAS prices, as the two series follow different paths. To evaluate this, we test gas price series that result from applying a continuum of weightings ranging from 0% to MIBGAS (therefore 100% to TTF) to 100% to MIBGAS (0% to TTF). For each option, the mean squared error has been calculated and is represented in Fig. 5.

Again, it appears that the highest explanatory power of the price series is achieved with the TTF price series. The evolution of RMSE is

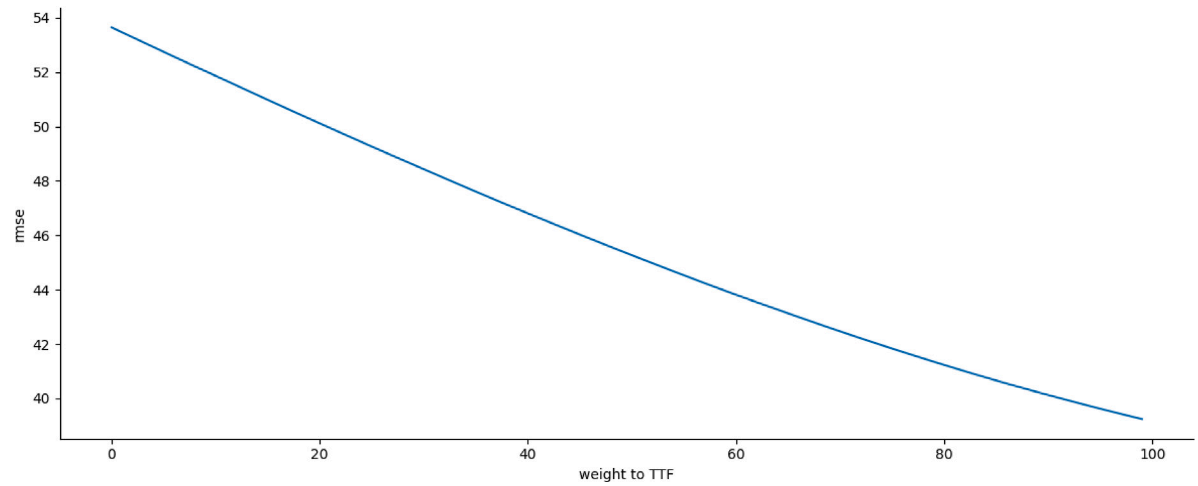


Fig. 5. Mean squared error of VPSC prediction by different weights to gas prices.
Source: Own elaboration.

monotonic concerning the weight assigned to TTF, with the minimum value occurring when this weight is set to 100 for this gas price series.

However, the growing presence of MIBGAS on contracts during 2022 should be reflected in our analysis. As a balanced solution, given that this gain in the share of MIBGAS in 2022 reached 20%, we believe that using this weight to obtain a weighted price series from April 2022 is appropriate at a low potential loss based on what is represented in Fig. 5, and in compensation further shielding our results from unobservable inaccuracies. We thus follow a 80/20 weight for TTF/MIBGAS starting when both prices are available, i.e., from September 7, 2021. As long as both series have evolved similarly, there will be no difference between this weighted price and either of the two separately. By the time the two series separate, the weighted series will be nonetheless substantially closer to TTF, ensuring that TTF takes precedence over MIBGAS, but still allowing the aforementioned extra safe room.

4.2. Step 2: estimating the effect of the cap on the VPSC

In the next step, we must choose which other variables will accompany the gas prices for the model estimation. Several possibilities arise here that must be taken into account for a proper estimation of the causal effect.

First, we estimate three groups of models, each including one of the gas prices (TTF, weighted average of TTF, and MIBGAS prices with lags of 1 and 2 days). Second, an autoregressive variable of order one (the VPSC price itself with a lag of 1 day) aims to capture the structure of the time series. Third, two interventions corresponding to the reforms of June 1, 2021 (reform 1) and September 15, 2021 (reform 2) could have a significant impact on the price. The first relates to a change in the so-called “tolls”, regulated prices designed to cover the costs of the transmission and distribution networks and set by the Spanish national regulator. On 1 June 2021, the different tolls were unified so that all domestic consumers pay the same price, which will also include hourly discrimination for power and energy. The second reflects a reduction in fees, regulated prices set by the Ministry of Ecological Transition and the Demographic Challenge to cover other regulated costs of the system, which began on 15 September 2021. Additionally, we include controls for days of the week and months of the year to account for seasonality.

From this point, we introduce two different sets of variables that control for the various technologies used to produce electricity, providing two distinct estimations of the causal effect. In the first group, we use the daily production volumes of wind and solar power plants to consider the influence of the supply mix in price determination. The reason why we use the production volumes of wind and solar power plants as explanatory variables and not other technologies such as combined cycle or CHP plants is simple. We assume that the former, especially wind and solar power plants, are exogenous to market conditions, as their market entry depends mainly on meteorological factors. As explained in Section 3, the variables included must be independent of the measure or intervention whose impact is being assessed for the BSTS model to work properly. Using the production data of these plants instead of gas plants implies that the reasons for their operation go beyond market conditions and are more related to the availability of their environmental factors. However, as a robustness check, we estimate a second set of models, replacing the production of wind and solar plants with daily average meteorological variables for Spain. Specifically, based on AEMET data, we have included in our analysis, following Mosquera-López et al. (2017) data on average temperature, precipitation, minimum and maximum temperature, average wind speed, maximum wind gust, as well as insolation. Furthermore, by eliminating production by technologies, we can include, to control for market dynamics, the total energy demand for each day, captured by the total production of electrical energy. This provides us with six different models to estimate the causal effect of the gas cap on the evolution of electricity prices.

The results of the OLS regressions between VPSC and the different gas prices (with a combination of the covariates mentioned above) are shown in Tables A.1 and A.2 located in the appendix. The regressions suggest that VPSC could be well approximated with only a few regressors and that the best model is obtained when the TTF price is used alone or in combination with MIBGAS (with the above weights). Moreover, the ability of the models to approximate the daily evolution of the VPSC since January 2014 is very high, above 94% if TTF the same if weighting is used and 90% if MIBGAS is used. So, once it is proven that it is possible to develop a model that can accurately approximate (and predict) the evolution of the price series, the next step is to use these models to analyse the impact of the gas cap intervention on prices.

The estimated causal effect varies depending on the chosen model, although it remains highly significant (Fig. 6). Additionally, in all six models (three incorporating wind and solar photovoltaic plant production data in blue and three using meteorological and total generation data in red), the likelihood of observing the effect in the VPSC without the gas cap is extremely low: the one-sided Bayesian tail-area probability for all models is 0.0%. Consequently, the causal effect can be deemed statistically significant in all instances.

In view of this and depending on the reference gas price used, the effect of the electricity price reduction varies. Using the TTF or the weighted gas price as reference implies a larger downward adjustment

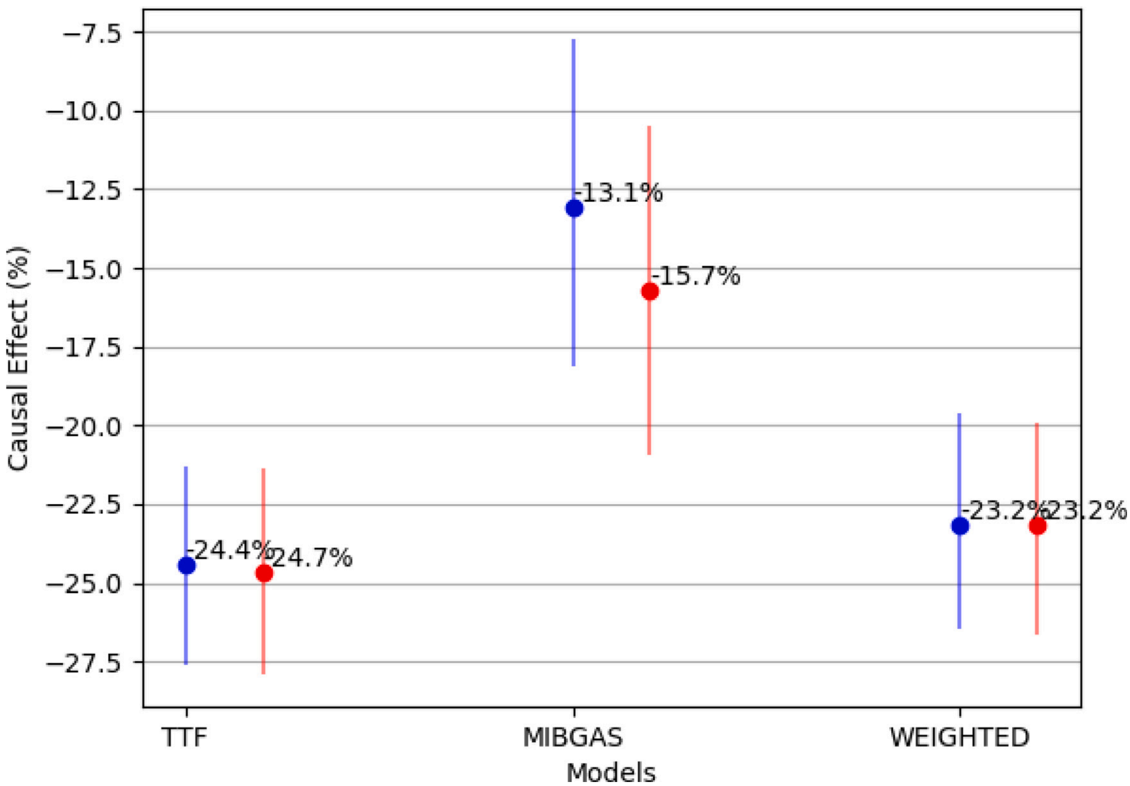


Fig. 6. Estimated causal effect on VPSC for each model — 90% confidence interval.
Note: The blue results refer to the models that include electricity generation from wind and solar plants, while the red ones pertain to the use of meteorological variables and the total system generation. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Own elaboration.

of electricity prices, between 20% and 28%, consistent with those of Salas et al. (2022) who estimate a cumulative saving of 20.8%, while using MIBGAS as reference implies a smaller effect, between 7% and 18%. These differences result from taking into account a price such as TTF, which was higher than MIBGAS, which was significantly lower, during the period of the gas cap studied here. If the Spanish combined cycle power plants had the Iberian gas price as a reference, the savings would have been much lower.

Fig. 7 shows the estimated savings in euros as the difference between the lines shown in Fig. 3 and the counterfactual estimated by the different BSTS models using wind and solar photovoltaic plant production data.[12] Until 14 June, the "savings" fluctuate around zero, indicating that we are dealing with a random error corresponding to a model that meets the minimum requirements for its correct estimation. However, from 15 June onwards, all lines for each estimated model diverge significantly into negative territory, suggesting that the gas cap has led to an apparent reduction in the VPSC prices that customers pay in this tariff. Moreover, this saving grew over the weeks, reaching a maximum of almost 250 euros in the last week of August.

In monetary terms, the average saving since 15 June would be around 130€/MWh. If we assume, based on the information collected by the Spanish National Competition Authority's household panel, that an average household consumes about 8 kWh per day, we could estimate the average household savings since 15 June to be about 206€. Assuming that around 9 million households were under the VSPC (as estimated by the aforementioned Authority in May 2022[13]), the savings since its implementation would range close to 1.9 billions. Considering that household expenditure on electricity exceeded 18 billions in 2022[14] these total savings are of relevance.

5. Effect on the use of the combined cycle

The gas cap may not only have affected price developments, but also the use of the different technologies used to generate electricity in the Spanish electricity system, and thus the potential savings that could have been achieved through the measure. Therefore, the above analysis was repeated in parallel to see if the introduction of the cap created incentives to divert production to or away from certain technologies. Given that the marginal system was originally designed to incentivise the use of clean energy and discourage the use of more polluting energy, it is important to assess whether and to what extent a change as severe as this cap undermines this objective. This is particularly important in the context on which the policy was enacted: European countries were striving to reduce gas consumption both in terms of independence and the energy transition, with the EU setting ambitious targets for reducing consumption by 2022, up to 15% in some countries (7% for Spain).

Intuitively, the application of the gas cap could create an incentive for the use of a combined cycle plant. Before the cap came into force, producers were exposed to rising gas prices and therefore had to be more conservative in their production decisions. With the cap, consumers are exposed to the risk of gas price increases through compensation payments. Thus, combined cycle plants have a greater incentive to bid in the market.

To quantitatively evaluate this possibility, we follow the same procedure used for the VPSC analysis. First, we define our underlying

[12] The results using meteorological data and total generation are very similar; therefore, for the sake of space economy, they are not displayed.
[13] See CNMC (2023).
[14] Data extracted from the Spanish Household Budget Survey for 2022.

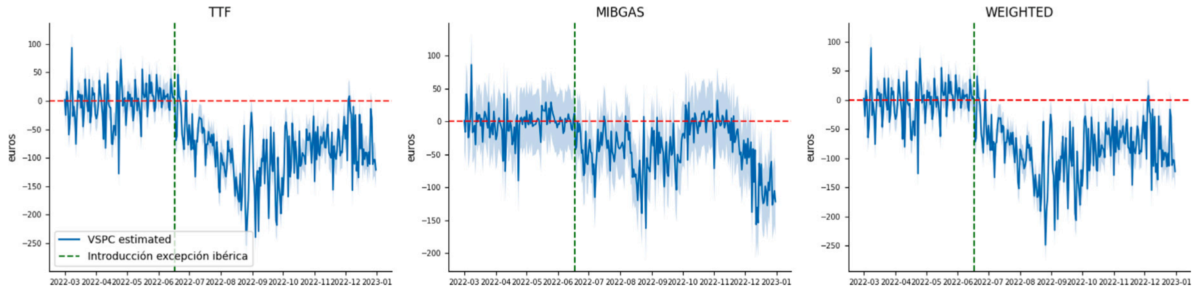


Fig. 7. Estimated causal effect on VPSC for each model — 90% confidence interval.
Source: Own elaboration.

model, paying particular attention once again to our choice of explanatory variables. The new dependent variable is the production in combined cycle power plants, measured in gigawatt-hours (GWh). The covariates remain the same as in the previous section, to which we add another: hydropower generation. Its inclusion is motivated by its unique market dynamics and potential influence on CCGT production. Hydropower is typically supplied to the market based on its opportunity cost, which becomes particularly relevant when more expensive technologies, especially gas, are next in line for dispatch. Furthermore, given the other covariates included in the model and the fact that hydropower operational decisions are largely dependent on hydrological conditions and not directly influenced by other unobservable market factors affecting gas generation, hydropower generation can be considered exogenous. In addition, we evaluate different models using different prices, production in wind and solar photovoltaic farms, meteorological variables and total generation. The results of the model estimations are presented in Tables A.3 and A.4

Fig. 8 illustrates the impact on electricity generation in combined cycle power plants as a result of the introduction of the gas cap. Regardless of the price used in the analysis, we detect a significant and positive increase using wind and photovoltaic production (blue ones). However, the estimated size of the causal effect is slightly different, ranging between 7% and 27%.

Fig. 9 shows the difference between the observed series of electricity generation in GWh from combined cycle plants and what would have been observed had the gas cap not existed. Its effects are apparent already in the first months after its adoption. These results are consistent with those of Eicke et al. (2022) in their critical assessment of the export of the gas cap model to other EU countries: they note that gas-fired electricity generation has increased by up to 42% in the first few weeks, and highlight the tension between such increases and the combined goal of reducing gas consumption and decarbonisation. However, this effect seems to have disappeared within a few weeks of the introduction of the Iberian gas cap and there does not seem to be a significant impact on the use of combined cycle power plants in the last months of 2022.

Nonetheless, it should be noted that the counterfactual estimate assumes that electricity generation with this technology depends only on exogenous factors, such as the market price, or the gas price, plus photovoltaic and wind production. In reality, the greater or lesser use of combined cycle power plants in a marginal wholesale electricity market may also be affected by the use of other technologies beyond solar and wind farms. In particular, it may depend on whether alternative technologies are available and able to generate electricity on a given day and at a given time. Although our analysis above shows a clear impact of the cap on the use of combined cycle power plants, it is useful to conduct a parallel analysis looking at these technologies.

Looking at what happened in Spain with alternative technologies, a first thing to note is that, with the available information, it is not possible to rule out that the lower use of some of these (such as hydroelectric and, especially, cogeneration in favour of combined cycle) is due to the incentives created by the gas cap, nor that there may be other reasons for this. For example, in a year characterised by a persistent drought, the low use of hydropower during the summer months could explain part of the shift to the combined cycle of the space left in electricity generation, independently of the introduction of the gas cap.

Fig. 10 offers clues that may support this possible explanation. From June 15 onward there is a divergent behaviour in the weight that each technology represents in the total daily energy generated. On the one hand, hydro and cogeneration show a significant drop, while wind and solar do not seem to show any particular reaction beyond what can be attributed to mere seasonality. This divergence between groups would be a strong candidate to be part of the effects created by the gas cap's incentives. Taking for instance the drop in cogeneration, there are strong reasons to consider that its lower use since the start of the cap may indeed be due to a direct consequence of the design of the measure itself: the fact that cogeneration plants have been excluded from the compensation deriving from the cap may have created incentives to divert part of the production previously generated by cogeneration towards combined cycle power plants. Under the measure, part of these plants would operate in the new regulatory context at a loss, which has led to the paralysis of a significant portion of the cogeneration fleet.[15]

As for its effect on gas consumption, although it is true that these plants also use gas in production, they do so quite efficiently: while combined cycle plants have an efficiency of 50%–60%, cogeneration plants tend to have an efficiency of 90%. Thus, it seems at least *a priori* could contribute to reducing gas consumption.

However, concerning hydropower, there are reasons to believe that we may be experiencing a combined effect of several factors operating in the same direction, making it impossible to differentiate the actual weight attributable to each. The cap and a concurrent drought that occurred during the summer of 2022 in Spain could explain part of the reduction in generation by this technology during the summer months, conflating both effects. This does not imply that there were no incentives to reduce hydro generation in favour of combined cycle power plants. Still, it does mean that an undetermined part of the increase in the latter, observed in the previous estimate, is not due to the cap but to the climate event. The combination of these two factors suggests that hydropower generation would have been different without them.

Because of these doubts, it is possible that the variables used in our model to capture the causal effect are not fully exogenous. For

[15] As a matter of fact, the Spanish Cogeneration Association (ACOGEN) called for cogeneration to be included in the compensatory mechanism. By early September, Prime Minister Pedro Sánchez announced a modification to the regulation of the cogeneration remuneration system to allow facilities that so wish to temporarily waive it and receive the adjustment resulting from the Iberian exception. The Council approved this regulatory change of Ministers on September 20, so there will likely be an upturn in the participation of these technologies in electricity generation. This could explain why the effect on increased usage of combined-cycle power plants appears to fade away from October 2022 onwards.

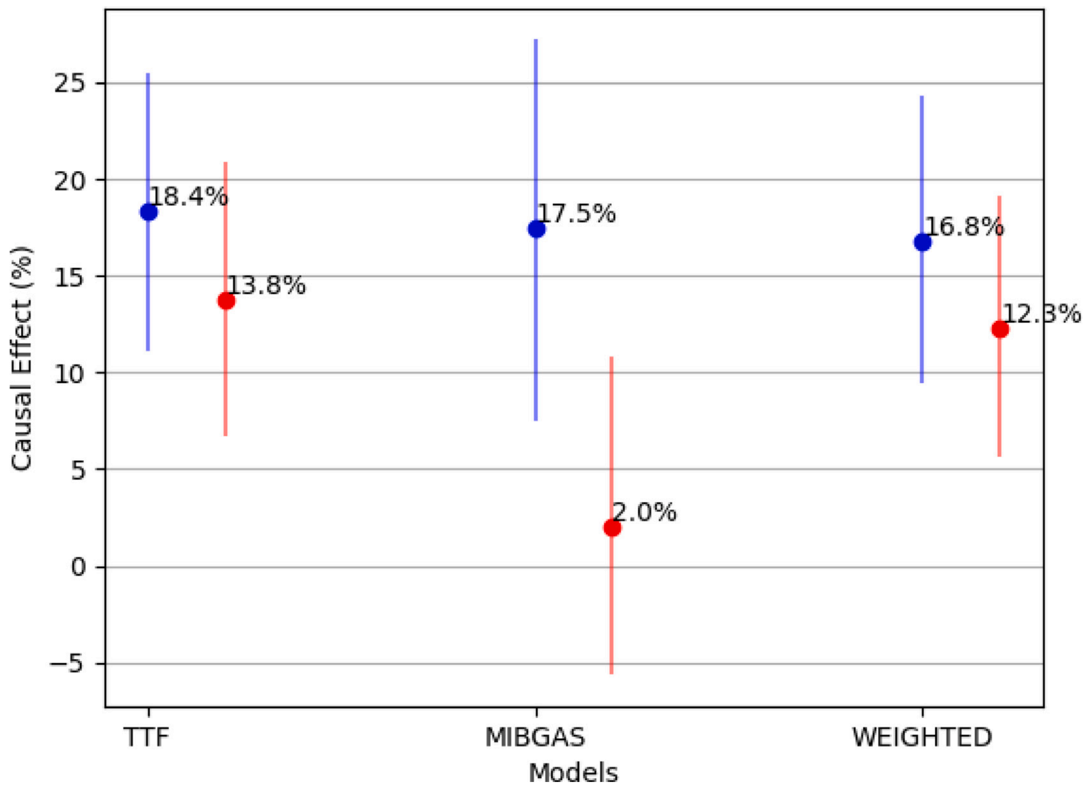


Fig. 8. Estimated causal effect for each model with 90% of significant interval. Combined cycles generation.
Note: The blue results refer to the models that include electricity generation from wind, solar plants and hydropower, while the red ones pertain to the use of meteorological variables and the total system generation. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Own elaboration.

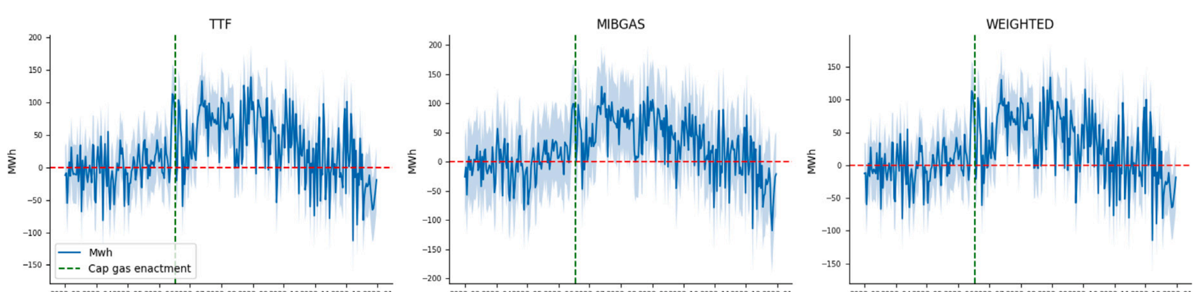


Fig. 9. Estimated causal effect for each model. Estimated increase in electricity generation in combined cycles centrals.
Source: Own elaboration.

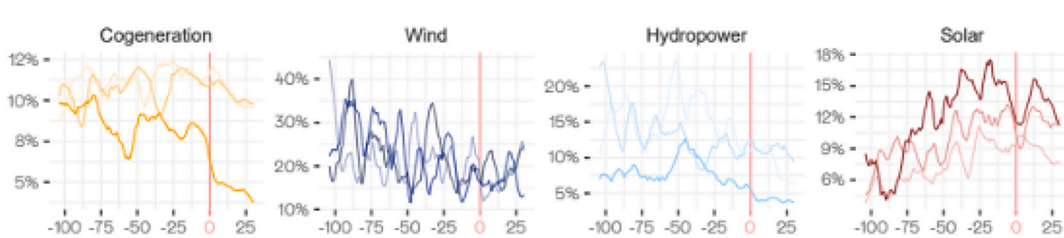


Fig. 10. Weight of the different technologies in the total amount generated in 2019, 2021 and 2022.
Note: The 7-day moving average is calculated from March 1 to August 31. The lightest colour stands for 2019, the darkest for 2022. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Own elaboration.

this reason, we present the same causal estimation but using only meteorological variables and total generation as the red lines in Fig. 8.

It can be observed that the effect remains positive, although slightly smaller and even insignificant when MIBGAS is used as the reference

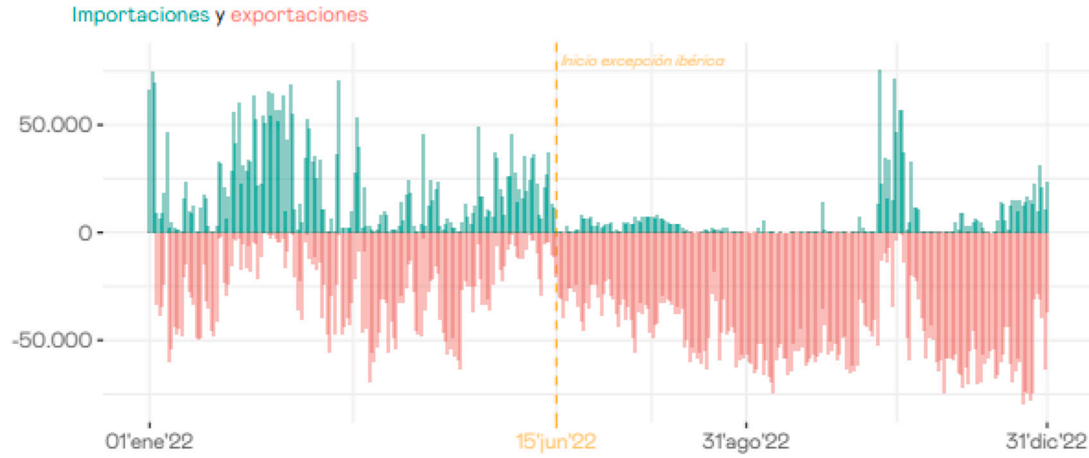


Fig. 11. Use of the Spain–France interconnection.
Source: Own elaboration from REE.es data.

gas price. The results vary between 25% and 10% when using TTF or the weighted index, and are not significant when using when MIBGAS is used

Although, as mentioned above, we consider the TTF or the weighted index to be the best indicators of gas prices, for which the effect is positive and significant, the non-significant effect in the case of MIBGAS should not go unnoticed. However, in the case of the TTF, the changes in our estimate of the causal effect of gas production are higher than those of the VPSC price. This implies some evidence of the partial endogeneity of wind and photovoltaic production in the modelling of CCGT production.

6. Current impact in other countries: possible leakage from the system

Beyond the impact of the mechanism on prices and the generation mix in Spain, it was widely speculated among policymaking circles how its implementation may have a significant impact in France, the country that holds virtually all European energy interconnections towards the Iberian peninsula. Although the proposal drafted by Spain and Portugal initially envisaged a different wholesale price for interconnections, the European Commission finally ruled out this possibility to avoid restricting cross-border trade, or discriminate between consumers. Thus, the lower prices in the Iberian market, together with a series of unscheduled stoppages in the French nuclear fleet that took place simultaneous to the cap implementation, and hydroelectric production at a minimum due to the aforementioned drought, could have increased the import demand from France.

Fig. 11 gives us an idea of the magnitude of the change in the trade balance between Spain and France. Since the entry into effect of the cap, Spain became a net exporter. In particular, exports more than doubled in 2022 compared to 2021 and imports almost halved. This completely reversed the traditional trade balance between the two countries, while trade itself increased by 56.3%.

This effect could have been even greater had export capacity not been limited. Export capacity between France and Spain was reduced by an average of 30% since June 15 compared to the average values recorded up to that date. Given that the available interconnections were used at maximum existing capacity since the mechanism became operational, exports would most likely have been even higher had they not been restricted.

Assessing the possible impact of the gas cap on exports to France beyond observational indicative evidence requires adopting an indirect strategy. First, we estimate a model for the wholesale spot prices (not VPSC) that would have prevailed in Spain in the absence of the cap for TTF, MIBGAS and the 80/20 combination. Results can be found in Tables A.5 and A.6. Once obtained, we contrast the three counterfactual wholesale prices in Spain with the French spots. The intuition behind this exercise is to assume that exports of electricity to France are due to a lower spot price in our country and, by estimating the counterfactual, we can visualise whether, even without the existence of the cap, Spanish prices would have been cheaper, specifically cheaper than those in France. We should not forget that the price difference does not allow us to fully distinguish between the cap effect and the seasonal effects already mentioned, which dominated the French electricity market during the months under analysis.

Fig. 12 shows the estimated effect of the gas cap on, in this case, the spot price for Spain. Once again, it can be seen that the cap led to a reduction in the spot price in Spain. This reduction is greater than that of the VPSC because, as we know, the latter includes compensation for power plants that use gas for electricity generation. With these results, we can estimate the counterfactual spot price for Spain in the absence of a gas cap and compare it with the observed one. This is illustrated in Fig. 13 for each of the gas prices used.

Finally, we compare the three counterfactual spot price series for Spain with the observed price for France. This comparison is shown in Fig. 14. It appears that the French price would have been higher than the Spanish price for most of the weeks since June 15 independent of the gas price we use.

What is striking, however, is the marked change in the behaviour of French prices, particularly since the introduction of the gas cap. Although it could also be due to other reasons that are difficult to model, we cannot rule out the possibility that the cap may have led to a strategic shift in the production of the French electricity system. Let us not forget that the technical shutdown of a number of nuclear power plants in France came into effect at the end of April, which would explain why the remaining operating plants were able to more than cover demand on weekends but were unable to do so adequately on other days. It is therefore reasonable to consider that the increase in exports to France was not only and exclusively a direct consequence of the increase in spot price differentials between the two countries, since these incentives would most likely have existed even without the cap, but also due to a French shift in response to the cap. In any case, it should be borne in mind that the French system is highly interconnected and therefore does not set prices in isolation.

It is certainly difficult to discern conclusively whether the gas cap has caused changes in export flows or not. But what is unquestionable (and mechanic) is that it has generated an economic benefit for French

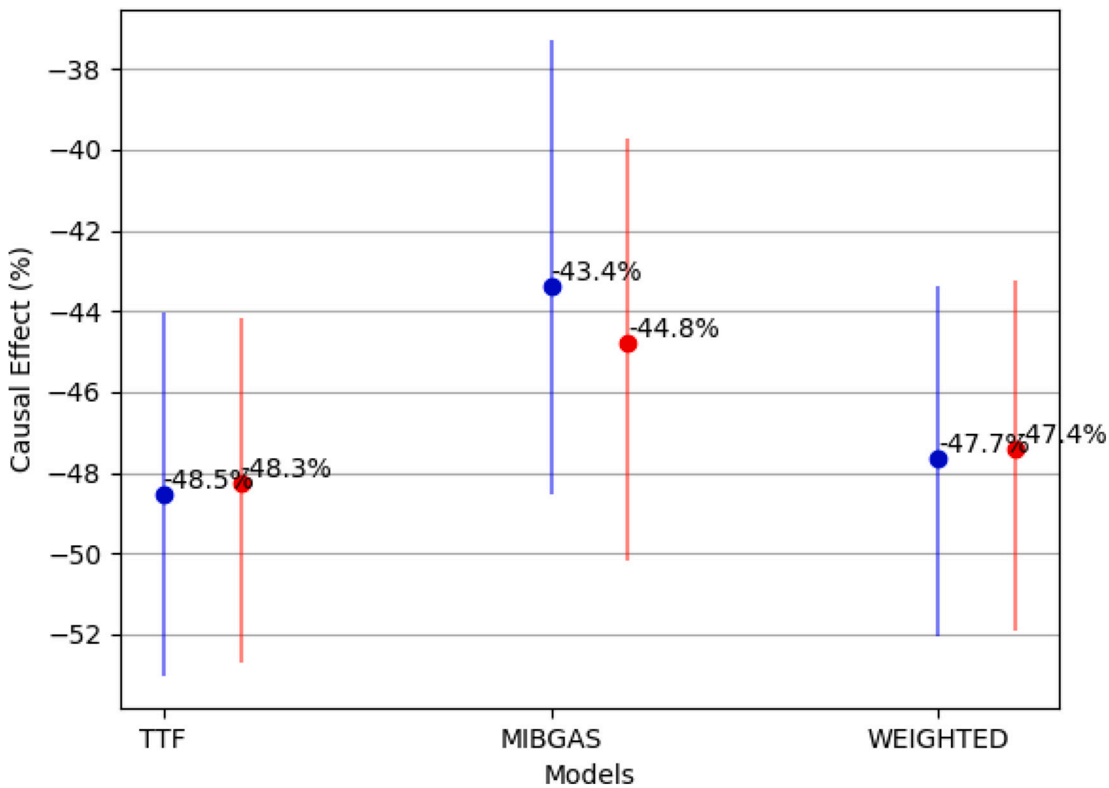


Fig. 12. Causal impact of gas cup in wholesale price in Spain.
Note: The blue results refer to the models that include electricity generation from wind and solar plants, while the red ones pertain to the use of meteorological variables and the total system generation. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Own elaboration.

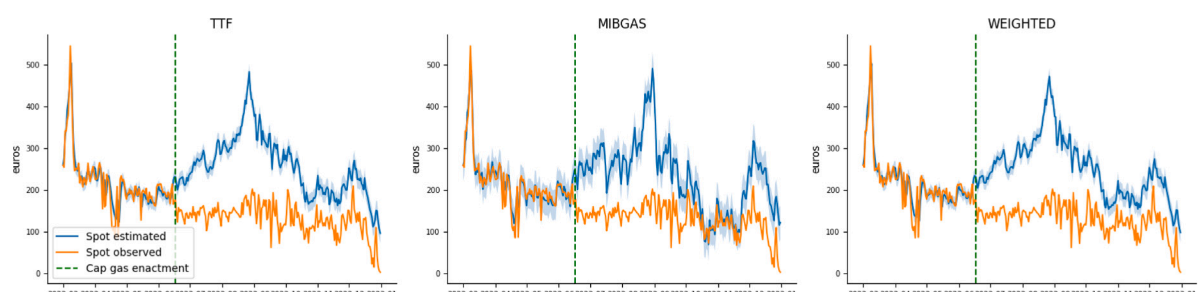


Fig. 13. Observed wholesale price in Spain and estimated price without the gas cap.
Source: Own elaboration.

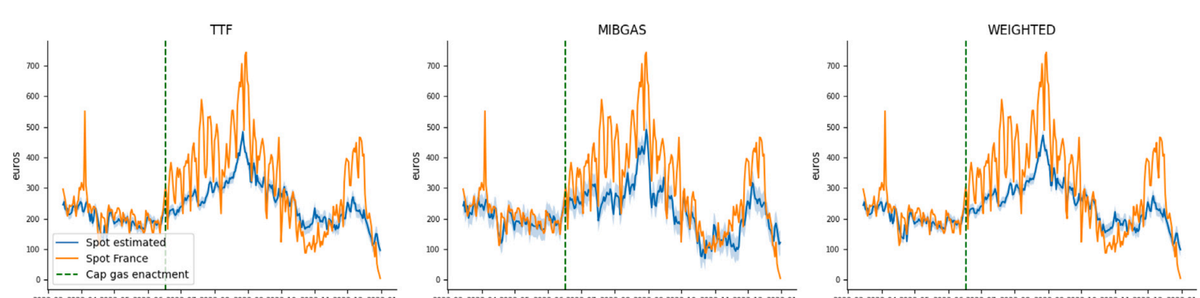


Fig. 14. Estimated wholesale price for Spain and observed for France. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Own elaboration from REE.es data.

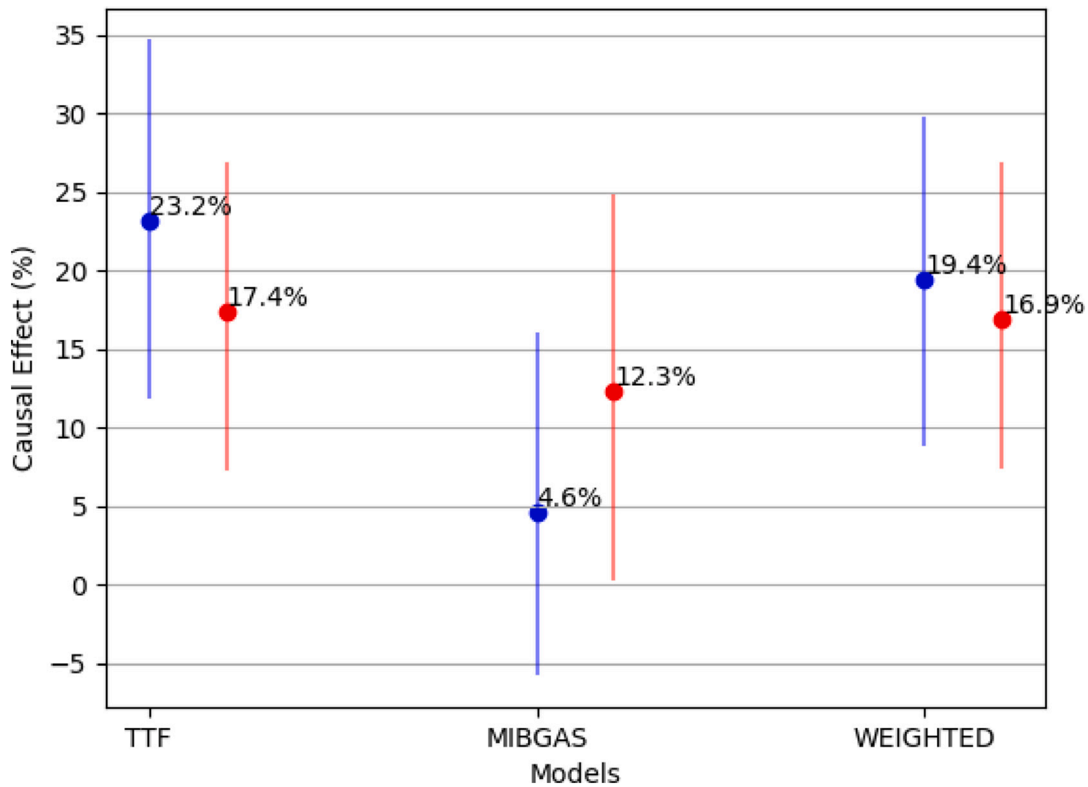


Fig. 15. Causal impact of gas cap in electricity exports to France.
Source: Own elaboration.

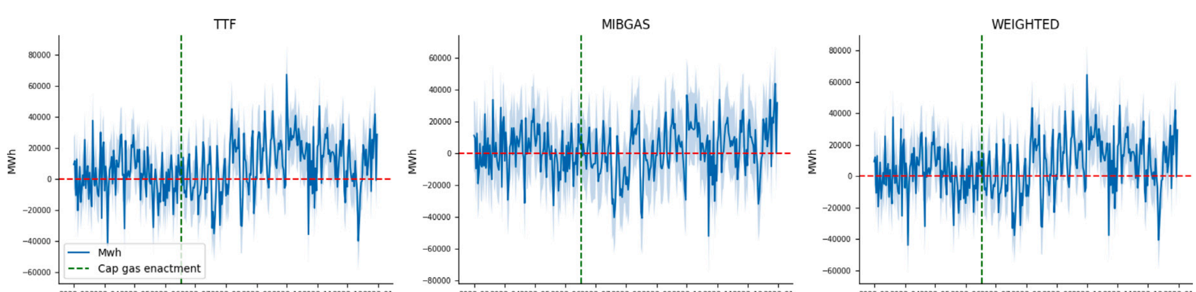


Fig. 16. Causal impact of gas cap in electricity exports to France.
Source: Own elaboration.

and Portuguese consumers. And, in any case, the result observed is that French imports and their price have clearly changed since the measure came into effect. This would support the fear expressed by Eicke et al. (2022) of "leakage" to non-member states of the money spent on compensation. A leakage that may be significantly higher than that observed between Spain and France simply because the connections from EU countries to non-EU countries are more intense.

It is with this possibility in mind, and with the aim of understanding whether there is evidence to support it, that we carry out a final exercise, this time to analyse the impact on the series of exports from Spain to France. Tables A.7 and A.8 show the regression used in the estimation of the causal impact in exports and Fig. 15 the causal impact using both sets of covariables.

While the use of TTF or weighted gas prices shows evidence of an increase in exports of between 8% and 35%, with MIBGAS as the reference price, the evidence is inconclusive when renewable production is used as a covariate, but not when meteorological variables are used.

However, as observed in Fig. 16, this impact seems to concentrate only between the months of August and November, coinciding with the months with lower nuclear and hydroelectric generation in France during 2022.

7. Conclusion and policy implications

According to our estimates based on a causal identification model, the exceptional gas cap for electricity generation in Spain and Portugal, the most drastic measure taken in Europe to deal with the escalation in energy prices following the Russian invasion of Ukraine, had a measurable effect. Prices of the regulated VPSC tariff were, on average, between 20% and 28% lower than they would have been without the measure. This lower price, despite the compensation included in the bill, has resulted in average savings of 129€/MWh per day since June 15 until the end of December 2022.

However, the introduction of the cap may have had other unintended effects. The first of these is a significant increase in the use of combined cycle power plants at the expense of a reduction in the use of (non-CO_2 emitting) hydro and (more efficient) CHP plants. Although it is not so evident that, particularly in the case of hydro, the substitution of these technologies by combined cycle plants is exclusively caused by the cap, it is no less true that the introduction of the measure in a particular context that raises incentives to burn gas may be amplifying the undesired effects described above. This highlights the inherent trade-offs policymakers must navigate between short-term economic relief and long-term decarbonisation.

Finally, while the introduction of the cap may have increased the incentives to export to France, these would have remained in place even without the cap. However, we cannot rule out that France's decisions on its electricity market production may have been equally strategic given the existence of an implicit subsidy, as the compensation to combined cycle plants is paid mostly by Spanish consumers. An exercise has been conducted, and there is some evidence that the gas cap may have contributed to boosting exports. Therefore, it is feasible that the increase in exports to France is due both to a lower relative price created by the cap and to a change in the neighbouring country's strategy to take advantage of this eventual situation.

Our methodology provides a robust causality analysis through the utilisation of Bayesian structural time series models, a novel approach in this field of energy economics. We have not only quantified the financial impact on consumers but also expanded the analysis to include the effects on energy sources, effectively capturing both intended and unintended impacts of the policy. These contributions offer a rigorous framework for evaluating similar energy market interventions in the future, illustrating how price-based policy mechanisms can have far-reaching implications beyond immediate economic effects.

It is crucial to acknowledge the limitations of our study. Specifically, the method had difficulty in discerning the direct effects on the increased use of combined cycle plants and on exports to France due to temporally correlated confounding factors. These limitations suggest caution in interpreting the study's results as definitive evidence of causality in these particular areas.

Given these findings and limitations, future research should aim to better understand the nuanced impacts of such policies on the energy mix and on international trade relations. Exploring heterogeneous effects on different types of households can also enrich our understanding of the policy's broader socio-economic implications. The quest to achieve both economic stability and environmental sustainability in the energy sector is a complex and urgent challenge, one that demands further rigorous, empirical investigation.

CRediT authorship contribution statement

Manuel Hidalgo-Pérez: Conceptualization, Investigation, Methodology, Software, Supervision, Writing – original draft, Writing – review & editing. **Natalia Collado:** Conceptualization, Investigation, Supervision, Writing – original draft, Writing – review & editing,. **Jorge Galindo:** Conceptualization, Supervision. **Ramón Mateo:** Conceptualization, Writing – original draft.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: MANUEL HIDALGO reports financial support was provided by ESADE ECPOL. MANUEL HIDALGO reports a relationship with ESADE ECPOL that includes: consulting or advisory. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix

See Tables A.1–A.8.

Table A.1
OLS regressions for VPSC. Results for different gas price models specifications using eolic and photovoltaic production.

	TTF	MIBGAS	Weighted
const	21.66***	36.30**	22.64***
	(1.91)	(14.20)	(1.88)
Gas price (TTF)$_{t-1}$	1.21***		
	(0.09)		
Gas price (TTF)$_{t-2}$	−0.95***		
	(0.09)		
Gas price (MIBGAS)$_{t-1}$		1.39***	
		(0.12)	
Gas price (MIBGAS)$_{t-2}$		−0.18	
		(0.14)	
Gas price (Weighted)$_{t-1}$			1.49***
			(0.09)
Gas price (Weighted)$_{t-2}$			−1.17***
			(0.09)
VPSC$_{t-1}$	0.78***	0.46***	0.76***
	(0.01)	(0.03)	(0.01)
Wind farms	−0.07***	−0.20***	−0.07***
	(0.00)	(0.02)	(0.00)
Solar Photovoltaic	−0.06**	−0.22***	−0.06***
	(0.02)	(0.08)	(0.02)
Reform 1	10.42***		9.94***
	(2.00)		(1.97)
Reform 2	5.12**	−12.61	3.06
	(2.39)	(12.74)	(2.35)
R-squared	0.94	0.90	0.95
R-squared Adj.	0.94	0.90	0.94
No. observations	3214	479	3214

Note: The dependent variable is VPSC. Each regression uses a gas price indicated in the name of each column. 'Weighted' refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.2
OLS regressions for VPSC. Results for different gas price models specifications using meteorological and total generation variables.

	TTF	MIBGAS	Weighted
const	23.38***	22.29	25.30***
	(4.89)	(23.49)	(4.82)
Gas price (TTF)$_{t-1}$	1.17***		
	(0.09)		
Gas price (TTF)$_{t-2}$	−0.93***		
	(0.09)		
Gas price (MIBGAS)$_{t-1}$		1.33***	
		(0.12)	
Gas price (MIBGAS)$_{t-2}$		−0.19	
		(0.14)	
Gas price (Weighted)$_{t-1}$			1.46***
			(0.09)
Gas price (Weighted)$_{t-2}$			−1.16***
			(0.09)
VPSC$_{t-1}$	0.78***	0.45***	0.76***
	(0.01)	(0.04)	(0.01)
average temperature	−72.98	−48.55	−58.88
	(85.95)	(350.34)	(84.51)
precipitation	−0.11	−2.20**	−0.10
	(0.21)	(0.93)	(0.21)
minimum temperature	36.53	22.35	29.43
	(42.98)	(175.12)	(42.26)
maximum temperature	35.70	24.66	28.70
	(42.98)	(175.19)	(42.26)
average wind speed	−11.31***	−38.55***	−11.03***
	(1.61)	(6.94)	(1.59)
maximum wind gust	1.04*	3.31	0.96*
	(0.55)	(2.40)	(0.54)

(continued on next page)

Table A.2 (*continued*).

	TTF	MIBGAS	Weighted
insolation	0.14	−3.72**	0.11
	(0.36)	(1.67)	(0.35)
total demand	0.03***	0.13***	0.02***
	(0.01)	(0.03)	(0.01)
Reform 1	8.28***		7.63***
	(1.83)		(1.80)
Reform 2	4.33*	−22.41*	2.32
	(2.38)	(12.51)	(2.35)
R-squared	0.94	0.91	0.95
R-squared Adj.	0.94	0.90	0.94
No. observations	3214	479	3214

Note: The dependent variable is VPSC. Each regression uses a gas price indicated in the name of each column. ‘Weighted’ refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.3
OLS regressions for combined cycles generation. Results for different gas prices specifications.

	TTF	MIBGAS	Weighted
const	19.69***		19.60***
	(3.21)		(3.21)
Combined cycles$_{t-1}$	0.75***	0.59***	0.75***
	(0.01)	(0.03)	(0.01)
Gas price (TTF)$_{t-1}$	−0.03		
	(0.14)		
Gas price (TTF)$_{t-2}$	0.12		
	(0.14)		
Gas price (MIBGAS)$_{t-1}$		0.19	
		(0.16)	
Gas price (MIBGAS)$_{t-2}$		0.00	
		(0.16)	
Gas price (Weighted)$_{t-1}$			0.08
			(0.15)
Gas price (Weighted)$_{t-2}$			0.01
			(0.15)
Wind farms	−0.17***	−0.39***	−0.17***
	(0.01)	(0.03)	(0.01)
Solar Photovoltaic	0.15***	−0.33***	0.16***
	(0.04)	(0.11)	(0.04)
Hydropower	−0.02	−0.01	−0.02
	(0.02)	(0.15)	(0.02)
Reform 1	−2.50	84.04***	−2.69
	(3.14)	(25.63)	(3.15)
Reform 2	12.04***	9.15	12.39***
	(3.84)	(16.88)	(3.87)
R-squared	0.84	0.84	0.84
R-squared Adj.	0.84	0.83	0.84
No. observations	3214	479	3214

Note: The dependent variable is production in combined cycles centrals. Each regression uses a gas price indicated in the name of each column. ‘Weighted’ refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.4
OLS regressions for combined cycles generation. Results for different gas price models specifications and using meteorological and total generation variables.

	TTF	MIBGAS	Weighted
const	23.38***	22.29	25.30***
	(4.89)	(23.49)	(4.82)
Gas price (TTF)$_{t-1}$	1.17***		
	(0.09)		
Gas price (TTF)$_{t-2}$	−0.93***		
	(0.09)		
Gas price (MIBGAS)$_{t-1}$		1.33***	
		(0.12)	

Table A.4 (*continued*).

	TTF	MIBGAS	Weighted
Gas price (MIBGAS)$_{t-2}$		−0.19	
		(0.14)	
Gas price (Weighted)$_{t-1}$			1.46***
			(0.09)
Gas price (Weighted)$_{t-2}$			−1.16***
			(0.09)
Average temperature	−72.98	−48.55	−58.88
	(85.95)	(350.34)	(84.51)
Precipitation	−0.11	−2.20**	−0.10
	(0.21)	(0.93)	(0.21)
Minimum temperature	36.53	22.35	29.43
	(42.98)	(175.12)	(42.26)
Maximum temperature	35.70	24.66	28.70
	(42.98)	(175.19)	(42.26)
Average wind speed	−11.31***	−38.55***	−11.03***
	(1.61)	(6.94)	(1.59)
Maximum wind gust	1.04*	3.31	0.96*
	(0.55)	(2.40)	(0.54)
Insolation	0.14	−3.72**	0.11
	(0.36)	(1.67)	(0.35)
Total demand	0.03***	0.13***	0.02***
	(0.01)	(0.03)	(0.01)
Reform 1	8.28***		7.63***
	(1.83)		(1.80)
Reform 2	4.33*	−22.41*	2.32
	(2.38)	(12.51)	(2.35)
R-squared	0.94	0.91	0.95
R-squared Adj.	0.94	0.90	0.94
No. observations	3214	479	3214

Note: The dependent variable is combined cycles generation. Each regression uses a gas price indicated in the name of each column. ‘Weighted’ refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.5
OLS regressions for wholesale (spot) price. Results for different gas prices specifications.

	TTF	MIBGAS	WEIGHTED
const	8.67***	29.92**	8.53***
	(1.12)	(11.91)	(1.11)
Spot price$_{t-1}$	0.87***	0.78***	0.87***
	(0.01)	(0.03)	(0.01)
Gas price (TTF)$_{t-1}$	0.87***		
	(0.06)		
Gas price (TTF)$_{t-2}$	−0.85***		
	(0.06)		
Gas price (MIBGAS)$_{t-1}$		1.10***	
		(0.10)	
Gas price (MIBGAS)$_{t-2}$		−0.85***	
		(0.10)	
Gas price (Weighted)$_{t-1}$			1.07***
			(0.06)
Gas price (Weighted)$_{t-2}$			−1.05***
			(0.06)
Wind farms	−0.05***	−0.12***	−0.05***
	(0.00)	(0.01)	(0.00)
Solar Photovoltaic	−0.04**	−0.14**	−0.04**
	(0.01)	(0.07)	(0.01)
Reform 1	9.51***		9.19***
	(1.42)		(1.40)
Reform 2	8.61***	−0.72	7.73***
	(1.69)	(10.59)	(1.66)
R-squared	0.95	0.87	0.96
R-squared Adj.	0.95	0.86	0.96
No. observations	3214	479	3214

Note: The dependent variable is the Spanish wholesale price (spot price). Each regression uses a gas price indicated in the name of each column. ‘Weighted’ refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.6
OLS regressions for wholesale (spot) price. Results for different gas price models specifications and using meteorological and total generation variables.

	TTF	MIBGAS	WEIGHTED
const	19.14***	93.15***	19.77***
	(3.27)	(19.60)	(3.22)
Spot price$_{t-1}$	0.88***	0.77***	0.88***
	(0.01)	(0.03)	(0.01)
Gas price (TTF)$_{t-1}$	0.84***		
	(0.06)		
Gas price (TTF)$_{t-2}$	−0.83***		
	(0.06)		
Gas price (MIBGAS)$_{t-1}$		1.07***	
		(0.10)	
Gas price (MIBGAS)$_{t-2}$		−0.84***	
		(0.10)	
Gas price (Weighted)$_{t-1}$			1.05***
			(0.06)
Gas price (Weighted)$_{t-2}$			−1.03***
			(0.06)
Average temperature	−39.72	−81.91	−32.12
	(57.63)	(288.10)	(56.87)
Precipitation	−0.05	−0.70	−0.05
	(0.14)	(0.77)	(0.14)
Minimum temperature	20.24	40.68	16.45
	(28.82)	(144.02)	(28.44)
Maximum temperature	18.81	38.94	15.02
	(28.82)	(144.07)	(28.44)
Average wind speed	−8.86***	−21.73***	−8.74***
	(1.08)	(5.71)	(1.07)
Maximum wind gust	1.02***	1.91	1.01***
	(0.37)	(1.97)	(0.36)
Insolation	0.64***	0.22	0.66***
	(0.24)	(1.37)	(0.23)
Total demand	0.01*	−0.01	0.01
	(0.00)	(0.02)	(0.00)
Reform 1	7.69***		7.31***
	(1.28)		(1.26)
Reform 2	7.99***	−8.01	7.12***
	(1.68)	(10.34)	(1.65)
R-squared	0.96	0.87	0.96
R-squared Adj.	0.95	0.87	0.96
No. observations	3214	479	3214

Note: The dependent variable is the Spanish wholesale price (spot price). Each regression uses a gas price indicated in the name of each column. 'Weighted' refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.7
OLS regressions for exports to France. Results for different gas prices specifications.

	TTF	MIBGAS	WEIGHTED
const	−6753.67***	−3596.64	−6708.59***
	(837.86)	(5991.36)	(838.96)
Exports$_{t-1}$	0.66***	0.66***	0.66***
	(0.01)	(0.03)	(0.01)
Spot price France	50.80***	28.53*	53.78***
	(9.06)	(14.63)	(9.22)
Spot price France$_{t-1}$	−15.51*	18.32	−13.43
	(9.16)	(14.58)	(9.33)
Gas price (TTF)$_{t-1}$	77.18		
	(50.49)		
Gas price (TTF)$_{t-1}$	−74.24		
	(51.10)		
Gas price (MIBGAS)$_{t-1}$		−60.84	
		(54.53)	
Gas price (MIBGAS)$_{t-1}$		−3.97	
		(54.23)	
Gas price (Weighted)$_{t-1}$			−89.59*
			(54.16)
Gas price (Weighted)$_{t-1}$			76.51
			(53.58)
Wind farms	54.77***	34.77***	54.78***
	(2.52)	(7.47)	(2.52)
Solar Photovoltaic	68.17***	46.97	68.46***
	(12.39)	(35.67)	(12.37)
Reform 1	−4810.61***		−4702.93***
	(1100.26)		(1103.79)
Reform 2	494.18	2494.60	894.46
	(1316.51)	(5459.68)	(1323.82)
R-squared	0.77	0.73	0.77
R-squared Adj.	0.77	0.71	0.77
No. observations	3214	479	3214

Note: The dependent variable is the exports to France. Each regression uses a gas price indicated in the name of each column. 'Weighted' refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

Table A.8
OLS regressions for exports to France. Results for different gas prices specifications.

	TTF	MIBGAS	WEIGHTED
Const	−39245.00***	−61791.56***	−39231.29***
	(2690.05)	(10288.81)	(2690.50)
Exports$_{t-1}$	0.66***	0.58***	0.66***
	(0.01)	(0.03)	(0.01)
Spot price France	39.15***	17.90	43.09***
	(8.97)	(14.16)	(9.13)
Spot price France$_{t-1}$	−20.49**	12.45	−17.99*
	(9.05)	(14.08)	(9.22)
Gas price (TTF)$_{t-1}$	−57.48		
	(50.24)		
Gas price (TTF)$_{t-1}$	69.87		
	(49.74)		
Gas price (MIBGAS$_{t-1}$		−47.22	
		(52.89)	
Gas price (MIBGAS)$_{t-1}$		1.95	
		(52.26)	
Gas price (Weighted)$_{t-1}$			−82.41
			(53.28)
Gas price (Weighted)$_{t-1}$			75.30
			(52.80)
Average temperature	48 051.58	167 968.60	46 723.74
	(46896.01)	(142873.38)	(46898.29)
Precipitation	250.03**	449.25	237.72**
	(116.12)	(381.67)	(116.14)
Minimum temperature	−23988.69	−82910.46	−23315.05
	(23446.84)	(71415.52)	(23447.95)
Maximum temperature	−23870.62	−83906.12	−23203.74
	(23451.66)	(71444.45)	(23452.79)
Average wind speed	5673.16***	3406.55	5610.52***
	(880.89)	(2839.03)	(881.13)
Maximum wind gust	−562.21*	−489.33	−530.19*
	(297.88)	(977.70)	(298.01)
Insolation	−59.79	248.92	−61.00
	(193.38)	(679.83)	(193.38)
Total demand	43.70***	74.29***	43.43***
	(3.79)	(13.33)	(3.79)
Reform 1	531.08		663.78
	(978.78)		(982.63)
Reform 2	752.76	8105.49	1232.88
	(1293.28)	(5205.71)	(1301.40)
R-squared	0.78	0.76	0.78
R-squared Adj.	0.78	0.74	0.78
No. observations	3214	479	3214

Note: The dependent variable is the exports to France. Each regression uses a gas price indicated in the name of each column. 'Weighted' refers to a weighted average price, with 80% for TTF and 20% for MIBGAS. All regressions include controls for days of the week and months of the year.
Standard errors in parentheses *p<0.1, **p<0.05, ***p<0.01.

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