The Price Impacts of Renewable Power: A Tale of Two Sources

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Abstract

This paper examines how the rapid expansion of wind and solar generation in Spain has reshaped wholesale electricity prices, ancillary service (AS) market costs, and market structure. Using an empirical strategy that exploits exogenous variation in renewable potential, we estimate how market outcomes would have differed under lower renewable capacity (and subsequently, renewable output). We find that rising wind and solar output substantially reduced wholesale prices. However, these reductions are partially offset by increases in AS market procurement and the associated operating costs driven by congestion and other operational challenges of variable generation. We show that while renewable growth reduces concentration in the wholesale market, AS markets remain highly concentrated, with limited scope for competition in key market segments. Our results highlight both the substantial net consumer benefits of renewable expansion on final prices (wholesale plus AS markets), while demonstrating the need for AS market reforms to reduce market concentration and cost-effectively manage increasing levels of renewable generation.

Keywords: Electricity Markets, Energy Transition, Intermittency, Market Power.
JEL: L13, L50, L94, Q40

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1 Introduction

The past decade has witnessed a rapid increase in wind and solar generation capacity. Renewable generation is expected to reflect a third of all electricity generation worldwide in 2025, with recent increases driven in large part by considerable investments in solar capacity (IEA, 2024). As these technologies become central to decarbonization strategies, understanding how they affect price formation in wholesale markets, the broader costs required to maintain system reliability, and the nature of market competition have become first-order policy questions.

While the expansion of wind and solar capacity offers substantial environmental and economic benefits, the integration of large shares of renewables creates operational challenges that differ from those faced by fossil-fuel dominated systems. Variable output, the creation of sharp intraday ramps, and location-specific generation patterns require increasing reliance on ancillary service (AS) markets. AS markets consist of an array of products with different technical attributes and delivery time-scales. These products serve as key tools to ensure system reliability so that supply and demand are perfectly balanced at all points in time and locations on the grid.

There has been a considerable focus on wholesale electricity markets in the literature. There is growing evidence that renewable generation is reshaping both the nature of competition and price formation in these historically concentrated markets (Bushnell and Novan, 2021; Jha and Leslie, 2025). In contrast, there is comparatively limited empirical evidence on price formation in AS markets, and on AS market structure more broadly, particularly as renewable output grows.

In this paper, we consider the case of the Spanish electricity market over the period 2016 - 2024. Spain provides a uniquely informative setting for studying the impacts of renewable generation growth. Since 2016, the share of wind and solar generation has nearly doubled, increasing from roughly 23% to close to 44% of the market by 2024, with solar alone increasing from 8% to 28% of generation during summer months. This transition has occurred in a system characterized by limited interconnection capacity with neighboring jurisdictions and geographically concentrated renewables. Ancillary service market costs have increased considerably over this period, rising from less than 10% of the average hourly final delivery price in 2016 to 31% in 2024. The majority of these costs are driven by Spain's redispatch AS market mechanism called the restrictions market that adjusts unit schedules after the day-ahead wholesale energy market to account for technical and transmission system constraints.[1] There are rising concerns that congestion from renewables, particularly solar, is leading to increased curtailment and redispatch costs (Micheli et al., 2025).

We use detailed data for Spain's wholesale energy and AS markets to evaluate the impacts of wind and solar output growth on wholesale prices, AS market operating costs, and the final price representing the combination of the two. We use hourly unit-level bidding and supply information to quantify features of the market structure and concentration over time in the wholesale market and across the various AS markets.

We leverage an empirical framework that exploits exogenous variation in wind and solar poten-

[1] Section 2 will provide details on Spain's market design and how it compares to markets in other jurisdictions.

tial in the short-run and across multiple years, controlling for important drivers of market outcomes. This allows us to evaluate how wholesale prices, AS market operating costs, and final combined prices would have differed on days with a low level of renewable capacity (and hence, a lower level of renewable output), compared to a day with a higher level of installed renewable capacity, holding all else constant. We use this approach to quantify the multi-market impacts of the rapid renewable capacity expansion over our sample period.

We find that renewable generation substantially reduces average daily day-ahead wholesale prices. A 1 GWh increase in daily solar and wind output reduced average daily energy prices by 16 and 19 cents per MWh, respectively. To put these estimates into perspective, they imply that between 2016 and 2024, the expansion of solar and wind generation capacity reduced average daily wholesale prices by 18.02 €/MWh and 10.34 €/MWh, holding all else constant. These large effects are only partially eroded by the fact that we estimate that this same growth in solar and wind output led to an increase in AS market operating costs by 5.86 €/MWh and 0.98 €/MWh. The estimated AS market impacts of solar expansion are larger because solar grew more over this time period, and the marginal impact of a 1 GWh increase in daily solar output was associated with an approximately 3 times larger impact on AS market costs than the same increase in wind supply.

Combining these two effects, we find that despite the elevated AS market operating costs, the net final price effect of a 1 GWh increase in solar and wind reduced final prices by 11 and 17 cents per MWh, respectively. These estimates imply that the expansion of solar and wind output over our sample period reduced final average daily prices by 12.16 €/MWh and 9.35 €/MWh, respectively, holding all else constant. To provide a scale for these effects, the average final price in 2024 was 73.38 €/MWh, demonstrating that these effects are economically important.[2]

To test whether the marginal effects from renewable generation are sensitive to the amount of solar and wind energy, i.e., if the marginal effects can be non-linear, we run a more flexible regression in which the marginal impacts are allowed to be heterogeneous by quintile. We find that, in the case of wind, the impacts of additional generation are close to linear. On the contrary, for solar generation, the largest price reductions occur in the highest quintile of solar output, when prices tend to drop dramatically. However, on other days, the impact of solar is more muted.

We extend our analysis to decompose these effects at the hourly level. For wind generation, the impacts on the wholesale and AS markets are relatively flat throughout the day. In contrast, the wholesale price-reducing effects of solar are concentrated mid-day, and the AS operating cost increases are magnified in the early morning and evening hours that are associated with periods of solar ramps as the sun rises and sets. In these hours, the impact on AS market operating costs can fully offset the savings in the wholesale market.

We leverage our access to detailed unit-level data to document how the market structure varies over our sample. We find that the expansion of renewable output is associated with a reduction in wholesale market concentration. This is driven by the fact that the share of renewable capacity

[2]We consider an extension where we saturate our model with fixed effects to absorb long-run variation to address concerns that we are picking up unobservable drivers of prices. Our key conclusions remain robust.

owned by the big 3 firms is lower relative to the market concentration of other technologies (e.g., hydro, gas, and nuclear). In particular, we observe a considerable drop in market concentration metrics mid-day when solar generation reaches its peak.

In contrast, market concentration is considerably higher across the various AS markets, where there are often more stringent rules for participation. While there have been efforts to increase competition in Spain's AS markets via the participation of wind and solar (Martín-Martínez et al., 2018), these markets remain highly concentrated with average Herfindahl–Hirschman Index (HHI) values in excess of 4,000 in certain market segments. In the redispatch restrictions market that makes up the majority of AS market operating costs, the median number of firms with accepted bids for upward (supply-increasing) services is just 4. Despite having a large number of bidders in this market segment, it is often the case that only a handful of firms have units with the technical capabilities that are in the right locations to provide these services. These results raise concerns that absent market reforms, the increase in renewables increases our reliance on highly concentrated market mechanisms.

Taken together, our results provide new evidence that high renewable penetration generates substantial net cost savings for consumers even in systems where AS operating costs are rising. At the same time, our results highlight that the economic and operational frictions created by renewables increasingly manifest not just in the wholesale market, but in AS markets where market concentration, locational constraints, and technology-specific capabilities shape the cost of maintaining reliability. These findings have implications for AS market design, renewable siting policies, and the broader challenge of integrating high shares of variable generation into electricity systems.

Our work relates to several strands of the literature. A substantial body of research has examined how increasing shares of renewable generation influence wholesale electricity market outcomes. Early work established that wind and solar generation exert downward pressure on wholesale prices through the so-called merit-order effect (e.g., Sensfuß et al. (2008); Woo et al. (2011); Gelabert et al. (2011)). Subsequent studies have quantified these effects across a range of restructured electricity markets, documenting differences across wind and solar, heterogeneity by the location of renewable resources, and spillover effects across hours of the day (Eising et al., 2020; Mills et al., 2021; Bushnell and Novan, 2021). Recent empirical work has further emphasized the competitive implications of renewable entry on wholesale markets (Jha and Leslie, 2025).

In contrast to the extensive evidence on wholesale markets, empirical research on AS markets and the implications of the increase in renewable capacity remains comparatively limited despite their growing economic importance.[3] Studies have been descriptive in nature (Joos and Staffell, 2018), focused on forecasting market conditions that raise the need for market redispatch to manage congestion (Titz et al., 2024), or develop simulation-based models to understand how the intermittency and location of renewables impacts system costs, including AS market costs (Gowrisankaran et al., 2015; Davi-Arderius et al., 2023; Lamp and Samano, 2023). Graf et al. (2021, 2023) push

[3]There is a large engineering literature that leverages simulation models to investigate the technical impacts of renewable generation on the operation of AS markets. See Viola et al. (2024) for a review of this literature.

our understanding forward by using the case of Italy to empirically show that renewables can increase the cost of redispatch to manage grid contraints despite lowering wholesale prices, and documents strategic spillover effects that these mechanisms have on wholesale market behavior.[4] In the context of Spain, Petersen et al. (2024) employ an empirical approach closely related to our analysis that estimates the impact of renewables on wholesale prices, AS market costs, and final combined prices. The authors focus on a period prior to the recent rapid expansion in solar and corresponding growth in AS market costs, and they do not consider the prevailing market structure across each market segment.[5] Our work builds on this growing literature by empirically analyzing how the growth in renewable capacity impacts prices and costs in the wholesale market and across various AS markets in a unified framework, as well as documenting how the market structure in each market segment has evolved.

Our paper proceeds as follows. Section 2 provides background on the Spanish electricity market and summarizes how the wholesale and AS markets operate. The data used in our analysis are presented in Section 3. Section 4 provides a descriptive analysis of the evolution of Spain's electricity sector and documents the growth in AS costs and procurement quantities. Sections 5 and 6 present our empirical methodology and results. Section 7 provides a descriptive analysis of the market structure of each market segment and how it has evolved over time. Section 8 concludes.

2 Industry Background

The Spanish electricity market operates as a series of sequential markets, starting with a day-ahead financial forward market (DAM), followed by intra-day markets running up to real-time physical delivery.[6] The day-ahead market is where the majority of electricity is traded to meet expected demand. Producers and consumers submit price-quantity offers for each of the 24 hours of the subsequent day. This market is operated as a uniform-priced auction setting a single price for each hour of the day by ordering generation units in order of least cost until as-offered supply and demand are balanced. The intra-day markets are used to facilitate re-trading from the day-ahead market outcome, permitting adjustments as market conditions change. These energy markets are operated by the Iberian electricity Market Operator (OMIE).

The Spanish day-ahead and intra-day markets are part of a broader European internal market. This market is separated into bidding zones, including treating the Spanish peninsula as a single

[4] Brown et al. (2023) and Buchsbaum et al. (2024) document spillovers that can arise due to the presence of wholesale and AS market interactions. However, neither study quantifies the impacts of renewable resource growth.

[5] There are several additional studies that empirically analyze Spain's AS markets. Batalla-Bejerano and Trujillo-Baute (2016) use time-series techniques that exploit short-run variation in renewable supply to analyze their impacts on AS operating costs at the early stages of renewable deployment (i.e., 2010 - 2014). More recently, Davi-Arderius and Schittekatte (2023) consider the impact of AS market operation on carbon emissions due to the need to redispatch natural gas units to resolve renewable-driven grid congestion, and Davi-Arderius and Graf (2025) analyze how AS market operation has changed in response to the Spanish Blackout in April 2025.

[6] For additional details on the operation of Spain's wholesale energy market, which is part of the broader Iberian electricity market, see Ito and Reguant (2016) and Fabra and Imelda (2023). Rodilla and Batlle (2015), Davi-Arderius and Schittekatte (2023), and Davi-Arderius and Graf (2025) provide further details on Spain's ancillary service markets.

zone. Energy is traded across Europe and in most cases, the market is cleared with the consideration of transmission capacity limits across zones only. Within-zone transmission constraints and other operational requirements are not considered. The limited interconnections with neighboring jurisdictions results in Spain being relatively isolated despite being part of the broader market.

In addition to the wholesale energy markets, there is an array of ancillary service (AS) markets to ensure reliability and security of supply at all locations on the grid and points in time. These markets serve several functions that differ in their objective and the time-scale of services to be delivered. AS markets are managed by the transmission system operator (TSO) Red Eléctrica de España (REE). The costs of procuring ancillary services are primarily paid by final consumers as a surcharge on their electricity bills.

There are four AS markets that we will consider in our analysis: the technical restriction (redispatch), frequency regulation (secondary and tertiary), and the deviation (imbalance) market. We briefly summarize how each market functions as we will present descriptive evidence in this paper on their market structure, providing insights into the competitive environment.

First, within a bidding zone (e.g., mainland Spain), the wholesale energy market-clearing does not require the physical flows that balance supply and demand to be within the capacity limits of the transmission network, nor does it account for the need to satisfy certain voltage, inertia, or security requirements that are necessary for the reliable operation of the grid. After the clearing of the DAM, Spain's market relies on a redispatch mechanism referred to as the day-ahead restrictions market. In this market, generators submit bids for their output to be adjusted upward or downward from the DAM schedule. Upward bids reflect the €/MWh that resources need to be paid to provide more output, while downward bids reflect the €/MWh generators are willing to pay back (relative to the day-ahead energy price received) for adjusting their units downward.[7] Unlike the wholesale market, the redispatch market is a pay-as-bid format where the TSO selects bids to minimize the cost of redispatch, while satisfying locational and security constraint requirements.[8] There is also a real-time restrictions market that undertakes another round of redispatch in near-real-time to manage technical constraints that arise between day-ahead and real-time delivery.[9]

There are two additional AS market mechanisms to manage system frequency.[10] Immediately

[7] Demand-side resources can also provide upward and downward redispatch, and certain AS products more broadly. However, our focus is on generation units that make up the majority of AS supply.

[8] Spain's day-ahead redispatch market is unique in that there are two phases. In phase 1, the TSO redispatches units to solve congestion constraints and other security criteria. Phase 2 redispatch then aims to rebalance supply and demand, subject to technical constraints. During phase 1, units that are selected for downward redispatch pay back the day-ahead market price (i.e., they are not compensated). In contrast, phase 2 downward generation bids only have to pay back their pay-as-bid offer which could be below the day-ahead price. Upward generation bids are paid-as-bid in either phase.

[9] The use of a redispatch mechanism differs from market designs such as those employed in the United States that leverage an integrated market design. In this setting, the physical realities of the grid and security constraints are explicitly accounted for in the day-ahead market-clearing mechanism. Unlike Spain's single zone-wide price for wholesale energy, these jurisdictions employ locational marginal pricing across nodes on the network (Graf, 2025).

[10] Frequency represents the rate at which the alternating current oscillates, capturing the balance between electricity supply and demand down to the subsecond level. It plays a critical role in grid stability. When supply exceeds demand, frequency rises, and when demand exceeds supply, frequency falls, prompting actions by the TSO to restore the frequency level.

after the day-ahead redispatch market is cleared, in advance of real-time operation, there is the secondary regulation frequency market. Generators submit capacity-based bids (in €/MW) that represent their willingness to provide a band of upward and downward adjustments to their generation levels to manage frequency deviations. For each hour of the coming day, the TSO clears this market for these regulation bands as a uniform-priced auction with a single price to satisfy a pre-specified quantity of secondary regulation. Secondary regulation is an automatic service that adjusts resources within seconds to minutes to restore system frequency after a deviation. This service requires a more stringent qualification given its fast and automatic-response requirements.[11]

In contrast, the tertiary frequency market is a manual service that occurs over a longer time scale (requiring a response within 15 minutes) to balance generation and demand and restore used secondary reserves. The tertiary market clears near real-time and only when additional frequency services are required. Generators provide price-quantity bids (in €/MWh) representing the compensation required to provide upward and downward adjustments in their output. The TSO clears the market as a uniform-priced auction separately for upward and downward services. Prices for upward bids are payments for the provision of the service, while downward bids represent the €/MWh paid back (e.g., relative to day-ahead price) for reducing scheduled supply.

Finally, in the hour prior to real-time delivery, when there are supply and demand imbalances that are sufficiently large (e.g., in excess of 300 MWh), the deviation (imbalance) market is employed. In this market, generators submit price-quantity offers for upward and downward adjustments. Similar to the tertiary market, this market is cleared as a uniform-priced auction to settle system imbalances in either upward or downward directions.

AS markets are seen as a key tool to reliability integrate the increasing amount of wind and solar generation. Variable renewable resources have also been integrated into AS markets, particularly through the provision of downward services reflecting a reduction (e.g., curtailment) of output. In addition to managing local transmission constraints, starting in early 2016, Spain implemented control strategies to permit qualifying variable renewable generators to bid into tertiary and deviation markets (Martín-Martínez et al., 2018). This has been viewed as an approach to increase competition in these markets, maintain stability as the market transitions to increasing variable resources, and comply with broader EU regulations (European Union, 2017). In our analysis below, we will document the extent to which renewables participate in each AS market segment.

3 Data

We use a range of publicly available data from the transmission system operator (REE) and the Iberian market operator (OMIE). Our sample period ranges from 2016 - 2024. This time horizon allows us to evaluate how the wholesale and AS market outcomes have varied as wind and solar

[11] If units are called upon to supply secondary services, they are paid based on the uniform marginal price of the tertiary market's price that would have been required to replace the secondary energy used (Rodilla and Batlle, 2015).

capacity has increased and been integrated into AS markets.[12]

We have access to a rich array of information on wholesale and ancillary service market outcomes and unit-level bidding behavior. At the aggregate market-level, we have information on the hourly wholesale energy price, market demand, and generation schedules by technology for both the DAM and final outcomes. We have data on the hourly AS market operational costs that represent the costs in €/MWh incurred across all AS markets, and for each AS market segment. The AS market costs are computed as the average over demand served, and reported in €/MWh. Along with the cost of wholesale energy, AS market costs are passed through as a component in the final price of electricity that consumers pay. These data sets allow us to analyze how DAM energy prices and AS operating costs vary over time, particularly as wind and solar output vary.

We complement these aggregate data with the detailed unit-level information. For the wholesale energy market, we have access to unit-level quantity schedules in the DAM and final outcomes. For each AS market, we have access to unit-level price-quantity bids and information on which bids are accepted. We combine this with information on the ownership of each unit over time. This data provides us with the ability to understand the structure and concentration of each market, and compute technology-specific quantities across all markets. In addition, this provides us with the ability to investigate the nature of competition and how it has evolved in each market segment.

In our analysis, we include several variables to capture variation in renewable energy potential and key exogenous drivers of market demand. To capture hydroelectric potential, we use the REE's daily hydroelectric potential index. This index gives the total GWh that could be produced during a day with the available hydraulic resources, taking into account the impact of water flows and stocks in the basins. We leverage data on solar irradiance and wind speed made available by NASA. We use MERRA-2 reanalysis dataset at a roughly 50 x 50 km resolution and match it with the location of current installed wind and solar capacity in Spain.[13] We also collect data published by REE on the amount of monthly wind and solar capacity installed in Spain. We use the solar irradiance, wind speed, and installed capacity data to capture variation in solar and wind generation potential, with capacity-weighted measures of wind speed and solar irradiance. We also obtain hourly temperature data from MERRA-2, which we weight by municipal population to create an average hourly temperature measure that reflects underlying demand conditions for heating and cooling.

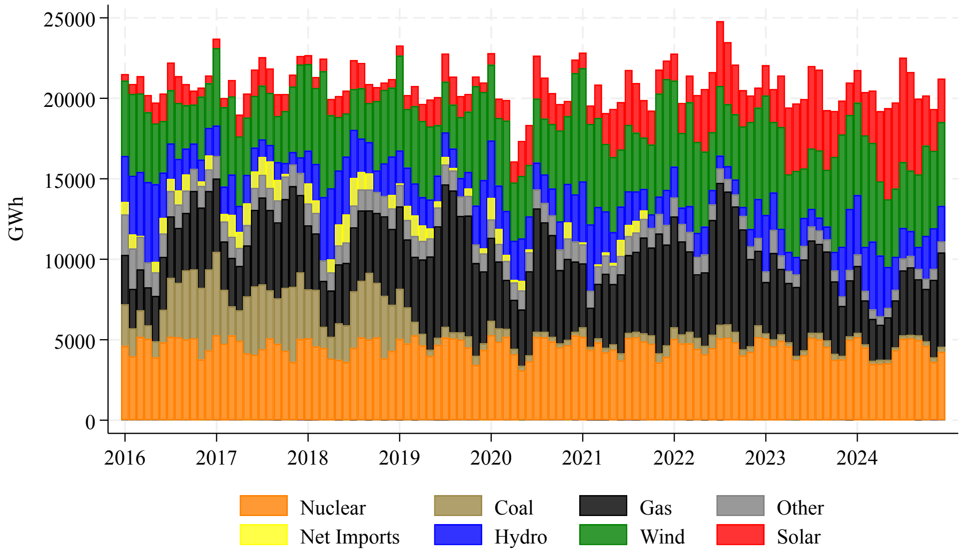
Finally, we use data from the daily natural gas price index published by MIBGAS, the major natural gas exchange in Spain. Natural gas prices are a particularly important potential driver of electricity market outcomes over our sample period due to the broader European energy crisis that occurred between 2021 - 2023. As we will detail in the analysis below, we account for policies that occurred over this time period, referred to as the *Iberian Solution*, that effectively capped gas prices paid by natural gas power plants in Spain during the energy crisis.[14]

[12]Our sample period ends before the April 2025 blackout in Spain. For a detailed analysis of how this event impacted AS markets, see Davi-Arderius and Graf (2025).

[13]To be precise, MERRA-2 provides estimates in grid cells of 0.5 degrees latitude and 0.625 degrees longitude.

[14]For a detailed discussion and analysis of the Iberian Solution and the broader context of the European energy

Figure 1: Wholesale Generation by Month and Technology



Notes. The reported data represent the total final generation output by technology at the monthly level (in GWh). Net Imports are only reported if they are positive to capture net generation within Spain.

4 Descriptive Analysis

In this section, we present descriptive statistics to describe how the wholesale and ancillary service market outcomes have evolved over our sample period, and the extent to which wind and solar participate in these markets. We begin by presenting changes in the wholesale market over time. Figure 1 presents the monthly wholesale generation by technology. While nuclear has provided a baseline level of generation of approximately 20% of total output, and hydroelectric supply fluctuates seasonally, the mix of remaining generation has changed considerably. In particular, wind and solar output has nearly doubled from 23% of total output to approximately 44% between 2016 and 2024. Solar output has increased rapidly in recent years, representing 28% of total wholesale supply in the summer months of 2024 (up from 8% in summer 2016). In the spring months when combined solar, wind, and hydro supply is highest (e.g., 64% of total supply in May 2024), wholesale market gas supply can be as low as 11% of total output.[15,16]

Figure 2 presents a 7-day moving average of wholesale prices in Spain's DAM. We can see that over our sample period, there is a considerable change in wholesale prices. Prior to 2021, prices

crisis, see Fabra et al. (2025).

[15]Figure A.1 presents monthly installed generation capacity by technology. From this figure, we can see considerable growth in wind and solar capacity, leading both technologies to have more GW of installed capacity than any other individual technology in Spain. Nuclear, hydro, and natural gas capacity remain constant over our sample period, while there was a large reduction in installed coal capacity.

[16]Figure A.2 provides the percentage of total generation by technology and quarter. In addition to demonstrating the growing percentage of wholesale supply being met by wind and solar, this figure demonstrates seasonal patterns in renewable supply.

Figure 2: Day-Ahead Market Wholesale Price (7-day Moving Average)

Notes. The reported data present a 7-day moving average wholesale price in Spain's DAM market.

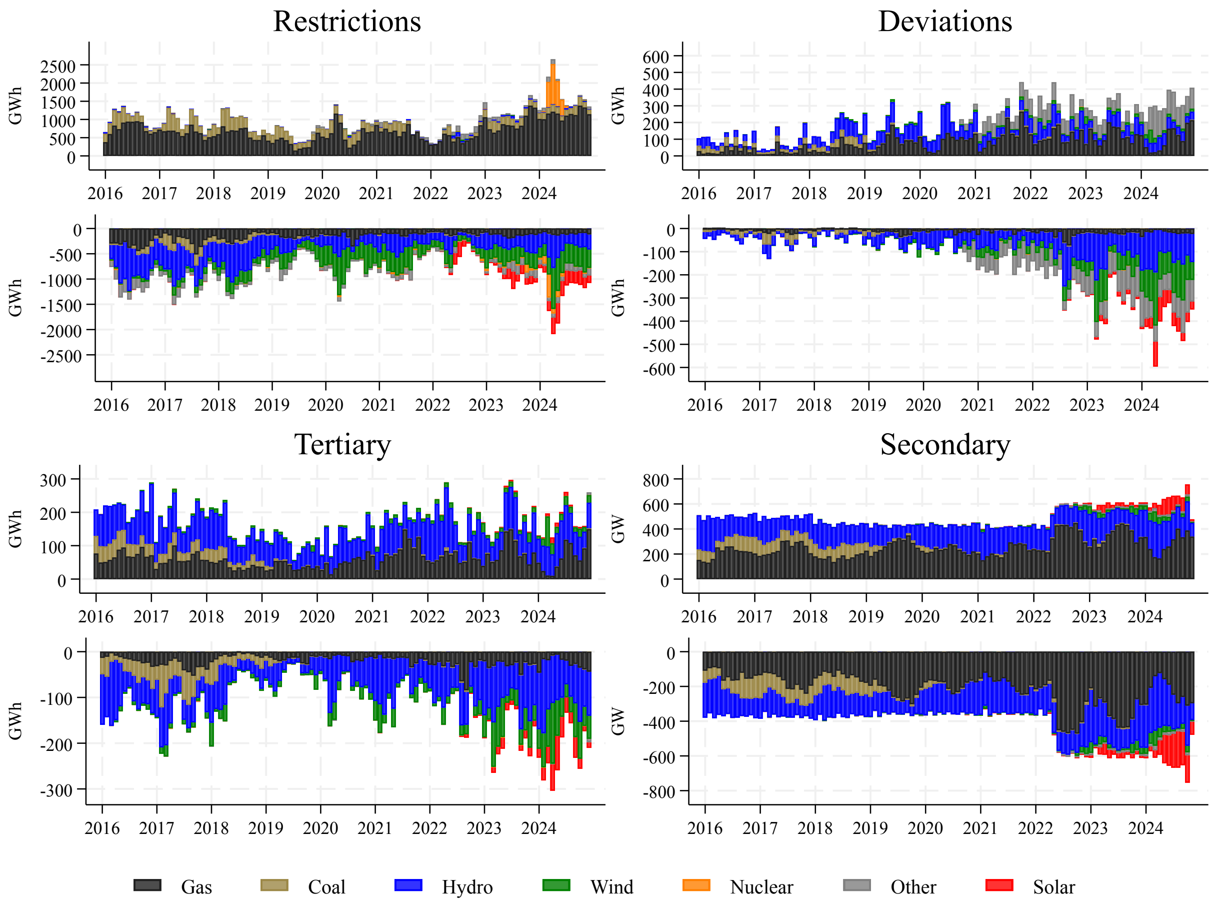
remained relatively stable at levels consistently below €60/MWh. Starting in 2021 and continuing through 2022, average wholesale prices have sustained periods in excess of €200/MWh. These high wholesale prices correspond with the broader energy crisis in Europe. After this period of extreme price spikes, prices have remained elevated and volatile in the latter part of our sample period.

This figure demonstrates that the expansion of renewable generation in Spain also corresponds with other important wholesale energy price drivers. Consequently, it is not possible to disentangle the impacts of the growth in these technologies using descriptive statistics alone. This motivates the need for a regression analysis to control for confounding factors, including but not limited to, variation in natural gas prices that had an important impact on wholesale energy prices during the energy crisis (Fabra et al., 2025).

Next, we will summarize how AS market quantities and the associated procurement (operating) costs have varied over our sample period. Figure 3 presents the monthly supply across the four AS products for upward and downward services by technology. The restrictions market represents the largest quantity of AS procurement. Recall from Section 2, the restrictions market is used to solve constraints on the grid such as congestion and local power quality (e.g., to manage voltage security). Redispatch quantities have increased in recent years, reaching volumes of over 1,000 GWh per month in 2024 in both directions. Downward redispatch is dominated by renewables, and increasingly solar curtailments. These downward redispatch quantities are being used to manage grid congestion due to high renewable generation in local export pockets (Micheli et al., 2025). This corresponds with the geographical concentration of solar and wind capacity on Spain's grid.

Because supply and demand must always be balanced, we observe a symmetric increase in

Figure 3: Ancillary Service Supply by Month, Product, and Technology



Notes. Negative (positive) GWh represents the provision of downward (upward) services. Restrictions includes both day-ahead and real-time restrictions redispatch quantities.

upward redispatch. Upward redispatch has been largely met by natural gas generation. The large upward redispatch of nuclear in the spring of 2024 corresponds with a period of high solar, wind, and hydro supply that are redispatched downward. This led to several nuclear facilities not clearing the DAM, but were dispatched in the restrictions market to satisfy their technical constraints, given the inflexibility of nuclear generation, which has high minimum technical generation requirements and cannot change its output rapidly. These patterns indicate that the growth in wind and solar output correspond with an increasing need to adjust resources to manage locational and technical security constraints, which are not accounted for in the DAM clearing process.

Figure 3 demonstrates that other AS products have smaller volumes and alternative resource mixes. Several interesting patterns emerge. The deviations market has observed increasing quantities, particularly downward, demonstrating the need for last-minute rebalancing of supply and demand. This can arise in part from unexpectedly high wind and solar supply. We observe a similar increasing use of downward tertiary supply through downward wind and solar curtailments to manage excess supply situations resulting in frequency levels that are too high. Despite the ability to provide upward tertiary and deviations supply as of early 2016, wind and solar participation in this market segment has been minimal.

The secondary market is distinct from the other markets due to its pre-specified capacity-based bands. Further, while firms submit unit-level bids over the majority of our sample, if firms that supply this product are called upon to provide the underlying energy, they can manage this internally with their broader portfolio of units. Acknowledging this feature, the accepted bids in this market has been dominated by gas and hydro generation. In recent years, we observe certain firms using solar and wind units as part of their portfolios to meet the capacity requirements. The increase in the quantities procured in 2022 reflects added capacity procurement requirements to meet solar and wind ramps (REE, 2024).[17]

To begin to understand how these dynamics translate into changes in energy and AS market costs, Table 1 summarizes the average hourly costs (in €/MWh) associated with wholesale energy and AS markets by year. These are the costs passed down to end-users and calculated as a cost per gross demand, so that it can be directly compared to the wholesale price. We are able to disentangle the costs by several key AS market segments using detailed cost files from REE.[18] In brackets, we report the average hourly percentage of the total market costs (i.e., energy plus AS costs) passed down to end-users that comes from each market segment.[19]

From Table 1 we can clearly see the considerable increase in wholesale energy costs in 2021 and 2022 during the energy crisis, leading to annual average hourly energy costs as high as approximately €168/MWh. This is a considerable increase from pre-2021 levels that were consistently below €60/MWh. In 2024, average hourly wholesale energy costs have declined but remain elevated compared to the pre-2021 levels.

Throughout our sample, we see a steady increase in the per unit costs arising from AS markets. In 2024, the average hourly percentage of total costs represented by AS markets was over 30%. This corresponds with the increase in AS procurement quantities observed in Figure 3. These averages mask the fact that there are an increasing portion of hours of the year where the majority of total costs are from AS markets. To illustrate, in 2020 AS market costs represented over 50% (75%) of total costs in less than 0.5% of hours (only 1 hour). In contrast, in 2024 AS market costs represented 50% (75%) of total costs in 21% (13%) of all hours. These statistics demonstrate that

[17] The secondary market data presented in Figure 3 end on November 19, 2024. After this date REE transitioned away from unit-bidding to portfolio bidding as it integrates its frequency regulation markets with broader EU markets.

[18] The dataset used to obtain AS operating costs in Petersen et al. (2024) is discontinued in June 2023. We obtain data from day-ahead restrictions, real-time restrictions, and secondary bands consistently from 2016-2024. For total costs, we use an alternative measure of total costs from June 2023 to December 2024. This variable is available since 2021 and it is very highly correlated to the other measure of total costs, with a coefficient of correlation of 0.915 at the hourly level and 0.96 at the daily level. The category Others is simply the residual from the two, and captures additional AS costs, such as tertiary reserves and last-minute balancing services (called deviations).

[19] The average hourly percentage of total cost in brackets can differ from using the annual average hourly costs from each market segment and dividing this by the annual average hourly total costs. For example, in 2024, the average hourly percentage of total costs arising from ancillary service costs is 31%. In contrast, the percentage of total costs using the annual average costs per MWh is $(11.80)/(11.80 + 63.04) \approx 0.16$. This difference is driven by a non-trivial portion of hours where AS costs represent the majority of total costs (i.e., the distribution is rightward skewed).

Table 1: Average Hourly Cost of Energy and Ancillary Services by Market Segment

	Energy	Total AS	DA Restrictions	RT Restrictions	Secondary	Other
2016	39.67	3.33	2.19	0.13	0.76	0.26
	[0.90]	[0.10]	[0.07]	[0.00]	[0.03]	[0.01]
2017	52.24	2.59	1.57	0.09	0.66	0.26
	[0.95]	[0.05]	[0.03]	[0.00]	[0.01]	[0.00]
2018	57.29	2.51	1.56	0.07	0.58	0.31
	[0.95]	[0.05]	[0.03]	[0.00]	[0.01]	[0.00]
2019	47.68	1.62	1.03	0.04	0.39	0.16
	[0.96]	[0.04]	[0.03]	[0.00]	[0.01]	[0.00]
2020	33.96	2.79	1.96	0.30	0.42	0.10
	[0.91]	[0.09]	[0.07]	[0.01]	[0.01]	[0.00]
2021	111.94	4.72	2.02	1.08	1.13	0.49
	[0.93]	[0.07]	[0.04]	[0.01]	[0.02]	[0.00]
2022	167.53	7.85	2.08	2.29	2.24	1.24
	[0.94]	[0.06]	[0.02]	[0.01]	[0.02]	[0.01]
2023	87.11	10.59	4.34	3.25	2.21	0.80
	[0.83]	[0.17]	[0.09]	[0.03]	[0.04]	[0.01]
2024	63.04	11.80	5.63	3.38	2.29	0.50
	[0.69]	[0.31]	[0.21]	[0.05]	[0.05]	[0.00]

Notes. The reported numbers represent the average hourly cost for each market segment in €/MWh. Values in brackets are the average percentage of total hourly cost of each market segment. Energy costs reflect the day-ahead market price and Total AS are the total costs across all AS markets. AS market costs are split into four segments including the day-ahead (DA) and real-time (RT) restrictions, secondary market costs, and all other AS costs that include both tertiary and deviation market costs.

the AS market is an increasingly important driver of the total costs of delivering energy.

The restrictions market makes up the majority of AS market costs, followed by the costs associated with the secondary market. This is consistent with the restrictions market representing the largest quantities across all AS markets (as shown in Figure 3). The pattern of elevated restrictions costs in Spain is consistent with rising redispatch costs in other European markets that have been attributed in part to the growth in renewable generation (Davi-Arderius and Graf, 2025).[20]

Taken together, the results above demonstrate that wind and solar generation make up an increasing share of total output. Despite the documented pressures associated with managing both the intermittency and location-specific features of wind and solar output, we cannot quantify the impacts of this growth on operating costs using descriptive statistics alone. In the next section, we will present our empirical approach to more rigorously quantify the impacts of wind and solar output on wholesale energy, ancillary services, and subsequently, total costs of delivering energy.

[20]The majority of restrictions-related costs arise in the day-ahead restrictions market. However, over our sample, there is an increasing trend of shifting towards real-time restrictions. For a detailed discussion on this point, see (Davi-Arderius and Graf, 2025).

5 Empirical Methodology

We empirically analyze the impact of wind and solar output on wholesale DAM energy prices, AS market operating cost, and final prices representing the summation of the two. We use an empirical framework that leverages variation in solar and wind output across multiple years (i.e., as wind and solar capacity expanded). We begin with daily-level regressions to quantify the net effect of solar and wind output throughout the day. We then consider the impact of daily wind and solar generation on hourly outcomes to take into account the spillover effects of renewable generation on hours in which output is low. Although this difference is small in the case of wind (Petersen et al., 2024), it can make a big difference for the case of solar, as solar production is absent during the evening and overnight hours (Bushnell and Novan, 2021).

First, we estimate the following equation at the daily (d) level:

$$P_d \;=\; \beta\,\text{Wind}_d + \gamma\,\text{Solar}_d + \theta\,\mathbf{X}_d + \tau_d + \varepsilon_d, \tag{1}$$

where P_d in €/MWh represents one of three dependent variables: DAM wholesale energy price, total AS operating costs, and the final price per unit representing the summation of the two. For each day, we construct a demand-weighted DAM price and AS operating costs to better represent a measure of the cost paid by consumers. Wind_d and Solar_d are the total daily wind and solar generation (in GWh) in the DAM, respectively. The coefficients β and γ capture the average change in our daily price and operating cost dependent variables due to a 1 GWh increase in daily wind and solar generation in the DAM, respectively.[21]

To control for other factors that shift supply and demand, $\mathbf{X}_d$ includes the total daily hydro production in the DAM (in GWh), natural gas marginal cost (in €/MWh), and total daily DAM market demand (in GWh). The natural gas marginal cost measure captures the fact that gas generation is a key resource on the margin setting prices over our sample period. This measure represents the marginal cost of a combined-cycle gas turbine (CCGT) using natural gas prices (MIBGAS index) and the price of emissions permits in the EU Emissions Trading System, which have been found to be passed through to the final costs (Fabra and Reguant, 2014).[22] In τ_d, we include fixed effects at the monthly level to control for seasonal factors. ε_d denotes our error term. We report standard errors clustered at the year-month level.

The regression identifies the effects of wind and solar generation on prices and operating costs by exploiting the random variation in the availability of wind and solar. For wind power, generation

[21] Using DAM output allows us to better capture curtailment effects for solar, as later in the period, final solar output is significantly smaller than its offered output in the DAM. We present results using final daily wind, solar, and hydro generation in the Appendix and find our conclusions are robust.

[22] We use engineering estimates of efficiency and emissions factors to construct the marginal cost variable as $MC = 2\,p_{Gas} + 0.35\,p_{CO_2}$, where p_{Gas} and p_{CO_2} are the natural gas price and carbon price, respectively. In 2022, due to the "Iberian Solution" policy that was deployed to mitigate the energy price impacts of the broader European energy crisis, the input costs paid by fossil fuel power plants in Spain were effectively capped for one year (Fabra et al., 2025). We cap p_{Gas} according to the schedule outlined in the policy. We also explored specifications that included each of these input price variables separately in the regressions instead of MC and it yielded similar results.

is quite random and varies within a calendar month. Furthermore, while wind capacity has grown, it has done so to a more limited extent over our sample. Therefore, the identification comes mostly from the "cross-sectional" variation within a month. For solar power, the trends have been very different. Solar capacity was much smaller in 2016 and has grown exponentially in recent years (see Figure A.1). Therefore, our identification also relies on the fact that, early in our sample, installed solar capacity is limited, while later in the sample, solar capacity is much larger.

This approach allows us to not just estimate the impact of short-run variation in wind and solar, but to understand how wholesale prices and AS market costs would differ on days with a low level of renewable capacity relative to one with a high level of installed renewable capacity, holding all else constant. This is achieved by not removing long-run variation by using annual fixed effects or other time trends. However, this means that it is key for us to control for variables that capture broader long-run changes in market conditions. To address this, we include key anticipated drivers of wholesale prices and costs in Spain (i.e., demand, natural gas prices, hydro production).

Despite wind and solar being driven by exogenous weather and climatic conditions, daily wind and solar generation in the wholesale market can be endogenous, especially in the presence of curtailment. Therefore, we instrument these two variables with measures that capture wind and solar *potential*. For wind generation, we use a measure of wind speed constructed from zonal and meridional wind at 10 meters.[23] For solar generation, we use hourly solar radiation (downward shortwave flux). Because solar and wind potential depend on both climatic conditions and installed capacity, we interact these variables with monthly installed capacity of each respective technology to capture the scale of potential generation.[24] These instruments are aggregated at the daily level to instrument for the daily renewable potential. Similarly, hydroelectric supply in the DAM can be endogenous because it is determined in part by bidding behavior of firms and the interaction between renewables and hydro scheduling. We use a daily hydroelectric potential index constructed by REE as an instrument for the total daily hydro supply in the DAM. Finally, demand in the wholesale market can be endogenous as it reflects bidding decisions. We instrument demand with temperature controls, including heating degrees (HDD) and cooling degrees (CDD), and a day-of-week categorical variable to capture systematic patterns in demand.[25]

We extend our baseline daily specification to consider a saturated version of our analysis that includes fixed effects at the year-month level. This specification identifies the impacts of solar and wind based on short-run variation within each year-month, absorbing long-run variation in the fixed effects. In these specifications, identification relies exclusively on the meteorological component of renewable potential, while installed capacity serves only to scale the instrument but does not contribute time-series variation.

[23]More concretely, wind speed (ws) can be approximated as the square root of the sum of squared zonal ($u10m$) and meridional ($v10m$) wind, i.e., $ws = \sqrt{u10m^2 + v10m^2}$, which we obtain from MERRA-2.

[24]One may be concerned with the fact that renewable capacity can change in the long-run in response to shifts in wholesale prices. We mitigate these concerns by directly controlling for factors that drive long-run variation in wholesale prices (i.e., natural gas prices, demand, hydroelectric supply).

[25]Heating and cooling degrees are defined as the average temperature below 65 degrees Fahrenheit for heating and above 65 degrees Celsius for cooling. We construct both an hourly and a daily measure of HDD and CDD.

In addition, we consider a specification that allows the impacts of wind and solar generation to differ by quintiles. That is, we include separate daily wind and solar output variables for each quintile. Finally, to facilitate a clearer economic interpretation of our results, we consider a version of our analysis where we multiply the hourly wholesale price, AS market operating costs, and total final price (all in €/MWh) by hourly market demand (in MWh), yielding a measure of the procurement costs by market in millions of Euros. We take the sum of these total cost measures over the day and use these as our dependent variables. We then use the specification in equation (1) to quantify the marginal impacts of an increase in daily wind and solar output on these procurement cost measures.

As our second set of analyses, we extend this regression framework to the hourly level. More specifically, we estimate the following equation at the hour (h) and day (d) level, which are run separately for each hour to be as flexible as possible:

$$P_{h,d} \;=\; \beta_h \,\mathrm{Wind}_d + \gamma_h \,\mathrm{Solar}_d + \theta_h \,\mathbf{X}_{h,d} + \tau_{h,d} + \varepsilon_{h,d}, \tag{2}$$

where $P_{h,d}$ in €/MWh represents hourly versions of our three primary dependent variables: DAM wholesale energy price, total AS operating costs, and the final price per unit representing the summation of the two. Wind_d and Solar_d continue to represent the total daily wind and solar generation (in GWh) in the DAM, respectively. This allows us to capture noncontemporaneous impacts of solar and wind on prices and costs (e.g., if on days with high solar, this changes the dynamics of supply decisions in the overnight hours). The coefficients β_h and γ_h capture the average change in our dependent variables in hour h due to a 1 GWh increase in daily wind and solar generation, respectively.

Our supply and demand control variables in $\mathbf{X}_{h,d}$ include hourly market demand, daily market demand (to account for dynamic effects across hours), and hydroelectric daily supply in the DAM, and our daily measure of the marginal cost of a CCGT natural gas unit.[26] $\tau_{h,d}$ represents fixed effects at the month-level to absorb seasonal trends. For the same reasons noted above, we instrument daily wind and solar output using our daily aggregated measures of wind and solar potential, we instrument hydroelectric supply with the daily hydroelectric potential index, and market demand with HDD and CDD (hourly and daily) and day of the week dummies. We continue to report standard errors clustered at the year-month level.

This specification continues to identify the marginal effects of an increase in daily wind and solar generation using both short-run and long-run variation. In the Appendix B, we present robustness checks that include fixed effects at the year-by-month level. This saturated specification will identify the impacts of wind and solar only using short-run variation within the year-month-hour-of-day.

[26] Different combinations of demand and hydro production (e.g., including daily, hourly, or both) produce very similar results.

6 Empirical Results

6.1 Daily Effects

Table 2 presents the daily regressions with two specifications. In the first specification (columns (1)-(3)), as outlined above in equation (1), we control for daily demand, hydroelectric production, and the cost of natural gas, as well as month fixed effects. In the second specification (columns (4)-(6)), we present results for the saturated regression with month-of-sample fixed effects.

Column (1) shows that a one GWh increase in daily solar and wind output has a significant impact of reducing average daily day-ahead energy prices by 16 and 19 cents per MWh, respectively. The magnitude of these effects are within the same range of a one GWh decrease in daily demand, which reduces energy prices by approximately 17 cents per MWh. This same general scale of these average effects is intuitive given an increase in wind and solar supply can be viewed as a reduction in net demand. The coefficient on the marginal costs of combined cycle units is close to one, consistent with a full pass-through in the market (Fabra and Reguant, 2014).

In contrast, column (2) demonstrates that the average daily operating costs of ancillary services increased by 5 and 1.8 cents per MWh with each additional GWh of daily solar and wind generation, respectively. To provide a sense of scale for the AS market costs of integrating wind and solar, it is useful to note that a GWh increase in average daily demand results in an approximate 2.3 cent per MWh increase in AS market costs, comparable to the additional marginal AS costs of wind generation. In contrast, the average marginal impact of a GWh increase in daily solar on average daily AS market costs is approximately 2 - 3 times the impact of a GWh increase in market demand and wind supply. This elevated effect likely reflects unique factors related to the AS market costs of managing solar ramps in the early morning and evening hours as the sun rises and sets, as well as the geographical location of solar resources. We will leverage hour-specific estimates to disentangle these effects in more detail.

Column (3) demonstrates that the overall impact of a GWh increase in average daily solar and wind supply reduces the final prices by 11 and 17 cents per MWh, respectively. This implies that solar and wind continue to significantly reduce the overall cost of electricity in the market, even after accounting for the increase in operational costs of managing their increased output. However, the higher average solar wholesale price effects are partially eroded by the larger AS market costs of integration. In fact, the impact of wind on average final prices is statistically significantly different (i.e., more negative) than effect of a 1 GWh increase in daily solar generation.

What are the economic implications of these estimates? To put the scale of the wind and solar estimates into context, and because we are identifying off of long-run variation in renewable supply, the average daily solar (wind) output increased from 35.33 GWh (131.18 GWh) in 2016 to 147.96 GWh (185.87 GWh) in 2024. The coefficient estimates imply that the growth in average daily solar generation over this time period reduced average DAM energy prices by 18.02 €/MWh and increased AS market prices by 5.86 €/MWh, resulting in a net reduction in final prices of 12.16 €/MWh. The implied effects of wind generation over this time period were also economically

Table 2: Marginal Daily Impacts on Prices by Market Segment

	(1) DA price	(2) AS costs	(3) Final price	(4) DA price	(5) AS costs	(6) Final price
Daily Solar	-0.160	0.052	-0.108	-0.182	0.023	-0.159
	(0.029)	(0.004)	(0.028)	(0.042)	(0.005)	(0.041)
Daily Wind	-0.189	0.018	-0.171	-0.186	0.013	-0.173
	(0.017)	(0.002)	(0.016)	(0.026)	(0.002)	(0.025)
Daily Hydro	-0.160	0.030	-0.129	-0.104	0.020	-0.084
	(0.032)	(0.006)	(0.028)	(0.083)	(0.008)	(0.079)
Daily Demand	0.168	-0.023	0.145	0.149	-0.019	0.130
	(0.016)	(0.002)	(0.014)	(0.026)	(0.003)	(0.025)
MC CCGT	1.040	0.019	1.060	1.012	0.019	1.031
	(0.016)	(0.004)	(0.016)	(0.032)	(0.009)	(0.033)
Observations	3,256	3,256	3,256	3,256	3,256	3,256
R-squared	0.905	0.676	0.917	0.609	0.215	0.617
FE	Month	Month	Month	Year-Month	Year-Month	Year-Month

Notes. The Table provides the impact of an additional daily GWh of wind and solar (in GWh) on wholesale energy prices, AS operating costs, and final prices in €/MWh using equation (1). Prices are weighted by hourly demand to be a better measure of total costs paid by consumers. Renewable generation for wind, solar, and hydro is instrumented with radiation capacity, wind speed capacity, and hydro producible. Demand is instrumented by average daily HDD and CDD, and day-of-week dummies. Fixed Effects (FE) are either at the monthly or year-month level. Standard errors are clustered at the year-month level.

significant with reductions in average DAM energy prices by 10.34 €/MWh, increased AS market prices by 0.98 €/MWh, and resulted in a reduction in final prices of 9.35 €/MWh.[27] These effects are economically important when compared to the 2024 average demand-weighted DAM wholesale energy price, AS market price, and final prices which were 61.67, 11.71, and 73.38 €/MWh.

Including month-of-sample fixed effects reduces the residual variation in our data and our ability to explain it, as seen in the R-squared in columns (4) - (6). However, the results are overall consistent with the previous findings. As expected, given the increase in curtailment and ancillary services over time, looking at short-run effects reduces the negative impacts of renewable power on ancillary services, although the overall effect on the final price remains largely consistent with our main specification. The consistency of our results across baseline and saturated specifications provides reassurance that our findings are not driven by omitted long-run trends or by the mechanical correlation between renewable capacity expansion and other structural changes in the Spanish electricity system.[28]

To provide further economic intuition on the scale of the cost impacts, we also performed a regression based on the total procurement costs to the system (in daily millions of Euros) in each market, so that we can interpret the average marginal impacts in terms of the EUR saved for each

[27] These calculations reflect the coefficient estimates for solar and wind for each dependent variable in columns (1) - (3) in Table 2, multiplied by the increase in average daily GWh of generation from each resource; (147.96 - 35.33) for solar and (185.87 - 131.18) for wind.

[28] Table B.1 presents results for the daily regression using final outcomes instead of DAM variables for wind, solar, hydro, and market demand. Our results are highly robust to this alternative specification.

MWh of wind and solar introduced in the system. The results are reported in Table B.2. To fix ideas, it is easiest to compare the estimates to those from a 1 MWh increase in daily market demand. In column (1), we can see that increasing demand by 1 MWh increases the costs of the day-ahead market by 100 EUR.[29] Compared to this, similar calculations reveal that a 1 MWh increase in daily solar and wind generation impacts the system in a similar albeit negative scale with a 95 and 119 EUR reduction in the total wholesale procurement costs, respectively. When it comes to AS market costs, column (2) shows that a 1 MWh increase in daily solar and wind generation increases costs by an average 32 and 12 EUR, respectively. Combining these effects, when looking at the marginal effects on the final all-in procurement costs, the overall cost savings from 1 MWh of daily solar and wind are 63 and 108 EUR, respectively. These results indicate that in addition to having a lower estimated marginal effect on wholesale procurement costs, the higher marginal impact on AS costs leads to a sizably smaller net effect on final procurement costs from a 1 GWh increase in daily solar.[30]

Finally, we examine the heterogeneous effects of having increasing amounts of solar and wind power by also running a daily regression separately for each quintile of a given source. We define the quintiles based on our instrumental variables (radiation times monthly capacity and wind speed times monthly capacity). To start, it is useful to gain some intuition by examining binscatter plots by technology, which are reported in Figure 4, panels (a) and (c).[31] The patterns are very different for wind and solar. Wind has a sustained impact on the reduction of wholesale prices, which becomes even greater in the presence of high levels of wind. On the contrary, solar appears to have limited and noisy impacts for low levels of generation, and it is only on the high generation days that negative impacts on prices are significant. Figure 4, panels (b) and (d), report the marginal effects for wind and solar, respectively. Consistent with the binscatters, the impacts of wind are relatively stable and significantly negative. The marginal effects of solar generation are noisily estimated and we cannot reject a zero marginal effect for several quintiles. The effect becomes only significantly negative for large amounts of solar generation.

6.2 Hourly Effects

The results above aggregated the analysis to the daily level to quantify the net impacts of wind and solar generation across wholesale energy and AS markets. However, these daily effects can mask within-day differential impacts of renewable output on market outcomes. This can be particularly relevant for solar generation that has more substantial and systematic within-day changes in output (i.e., as the sun rises and sets).

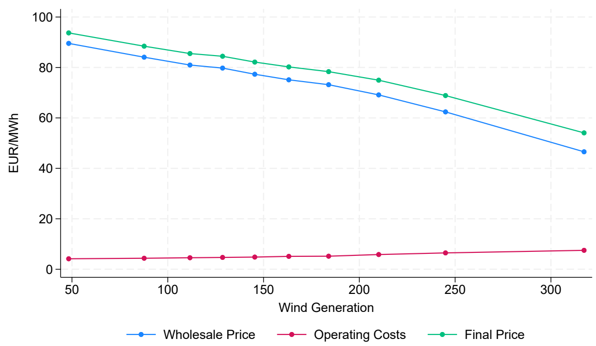
Figure 5 presents the hour-specific marginal impact of a GWh increase in daily wind and solar

[29] This effect reflects the coefficient on daily demand (in GWh) of 0.100 multiplied by an increase of 0.001 GWh (1 MWh) in demand, scaled up by $1 million EUR to account for the scale of the dependent variable.

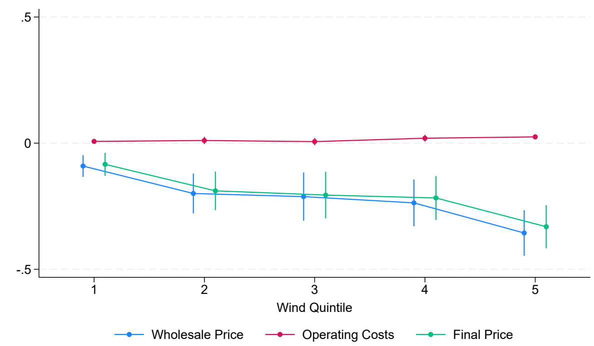
[30] Columns (4) - (6) in Table B.2 include year-month fixed effects. Similar to the results in columns (4) - (6) in Table 2, we observe larger solar wholesale price effects and smaller AS price effects in the saturated specification. Despite these quantitative differences, our key conclusions are consistent across both specifications.

[31] The binscatter plots each price/quantity metric as it varies with renewable output quintile, controlling for marginal cost of a CCGT gas unit and month fixed effects to absorb potentially confounding factors.

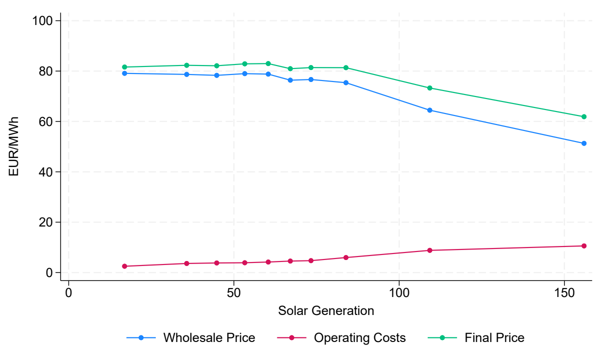
Figure 4: Non-linear effects of daily solar and wind generation



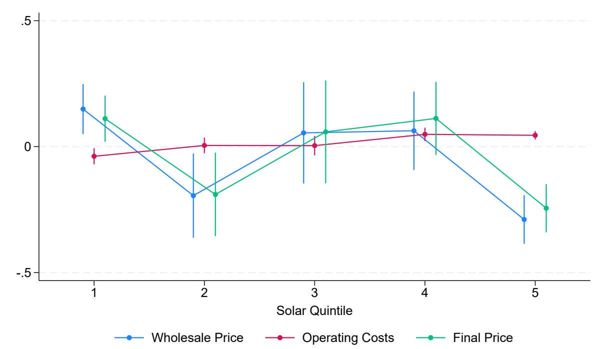
(a) Wind Binscatter



(b) Wind Marginal Effects



(c) Solar Binscatter



(d) Solar Marginal Effects

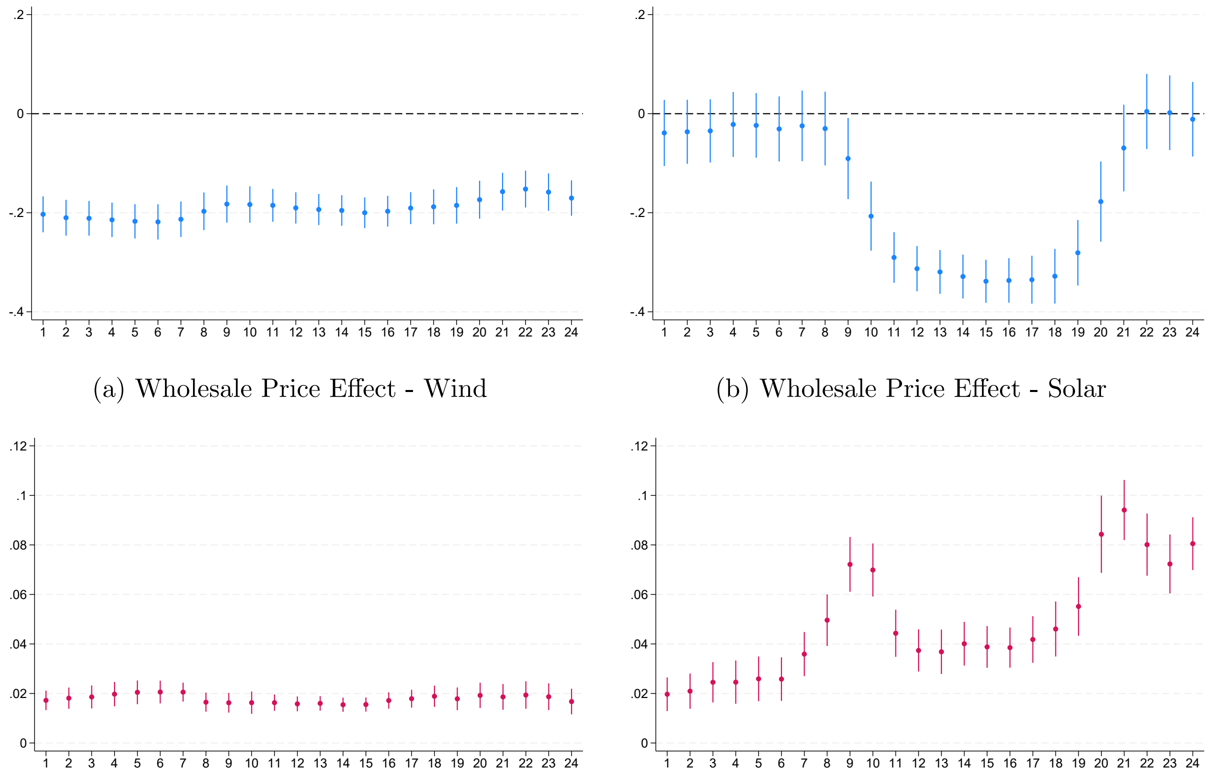
Notes. The figure shows binscatter plots in subfigures (a) and (c) that control for controlling for marginal cost of a CCGT gas unit and month fixed effects. Subfigures (b) and (d) present results from an alternative specification to Equation (1), run independently for each quintile. The quintiles are defined in terms of wind and solar potential multiplied by capacity, i.e., our main instrument.

generation on the DAM wholesale energy price and AS operating cost (€/MWh). Figure 5a and 5c demonstrate that the marginal effect of a GWh increase in daily wind on both the average hourly wholesale price and AS operating costs is relatively stable throughout the day. This is consistent with the fact that wind output is fairly random in its timing throughout the day, fluctuating at different levels throughout the day and night, and across days. As a result, the scale of the hourly marginal effects estimates are in line with the average daily estimates reported in Table 2 above.

In contrast, Figure 5b and 5d show that the hourly marginal effects for a 1 GWh increase in daily solar output is considerably more variable throughout the day. For the average wholesale price effect, we see no effects in the morning and overnight hours, but a large effect of a 1 GWh increase in daily solar output in the mid-day hours. The marginal effect reaches its peak in magnitude from 1 - 6 PM with a reduction in hourly wholesale prices of 32 - 34 cents per MWh for each GWh increase in daily solar generation.

For AS operating costs, we see considerably larger marginal effects for solar generation compared

Figure 5: Marginal Hourly Impacts of Daily Wind and Solar Output on Mean Wholesale Price and AS Operating Cost (€/MWh)



(a) Wholesale Price Effect - Wind

(b) Wholesale Price Effect - Solar

(c) AS Operating Cost - Wind

(d) AS Operating Cost - Solar

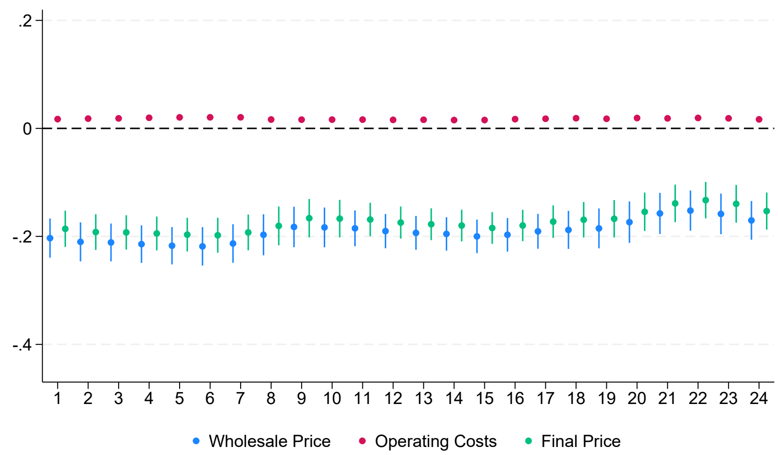
Notes. This figure presents the hourly marginal effects of an increase in daily wind and solar output on the DAM wholesale price and AS operating costs, using the specification in equation (2). Reported standard errors are clustered at the year-month level.

to those that arise from an increase in daily wind output. The solar marginal effects are largest in the early morning and evening hours as the sun rises and sets, reaching a peak marginal effect point estimate of increasing AS operating costs by approximately 9.6 cents per MWh at 9 PM. These results are consistent with the use of AS markets to manage systematic daily solar ramps.

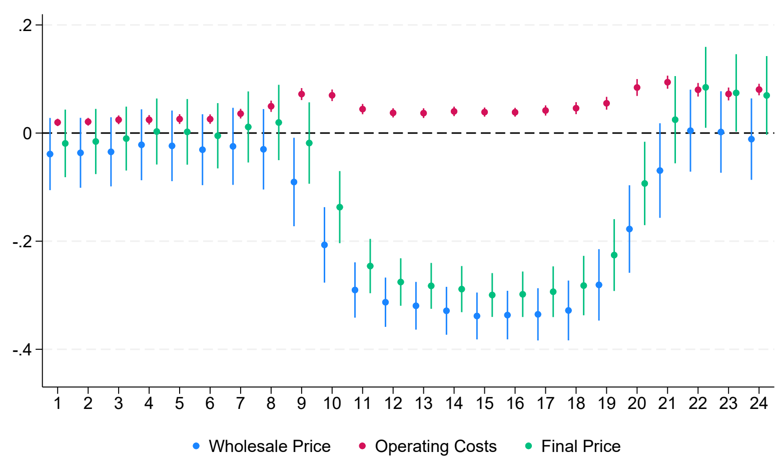
Figure 6 brings these countervailing effects together by presenting the hourly marginal effects of a GWh increase in daily wind and solar on the wholesale price, AS operating costs, and the combined final price. For both wind and solar, the marginal effects on the final price closely track the wholesale price effects, but are shifted upward due to the marginal increase in AS operating costs. The largest difference arises in the early morning and evening hours for a 1 GWh increase in daily solar generation, reflecting the additional AS market costs of managing the solar ramps.

Figure B.1 in the Appendix presents the marginal hourly impacts of daily wind and solar output that identifies only off of short run variation in wind and solar output. That is, we adjust our hourly specification to include year-by-month fixed effects for each hourly regression. The effects are noisier

Figure 6: Marginal Hourly Impacts of Daily Wind and Solar Output by Market Segment



(a) Wind



(b) Solar

Notes. This figure presents the hourly marginal effects of an increase in daily wind and solar output on the DAM wholesale price, AS operating costs, and the combined final price, using the specification in equation (2). Reported standard errors are clustered at the year-month level.

and somewhat more negative for solar generation. However, the overall conclusions of the hourly marginal effects on final prices remain unchanged.

To provide further intuition on these hourly effects, we consider a regression analysis that builds on equation (2), but replaces the dependent variables based on market prices with hourly generation in the DAM by generation technologies gas, hydro, nuclear, coal, other, and imports. We estimate the marginal effects of an increase in daily wind and solar generation on hourly output across these various technologies. We continue to control for CCGT marginal cost, market demand (instrumented using HDD, CDD, and day-of-week dummies), hydroelectric potential, and monthly fixed effects.[32]

Figure B.2 in the Appendix presents the marginal hourly impacts of a 1 GWh increase in daily wind and solar output on generation from a wide range of technologies. Consistent with the price effects, wind has a relatively stable impact on generation technologies throughout the day, with more displacement of gas generation in the middle of the day, consistent with the merit-order curve. We also observe displacement from hydro, coal supply, and increased exports (negative imports). The dynamic implications of solar are much more interesting. We observe increases in hydro supply overnight, but reductions mid-day corresponding with the timing of solar output, natural gas supply follows the same pattern but is more muted, and we observe increased exports during the day (negative imports). As would be expected, taking the summation of the estimated effects under these curves over all hours of the day yields estimates approximately equal to -1.

7 Market Structure Analysis

The results above show that at the daily level (i.e., looking across all hours), the expansion of wind and solar output had a net price-reducing effect on wholesale energy and final prices, despite the upward pressure both technologies had on AS market costs. For solar generation at the hourly level, while the net price effect was systematically negative (or zero), the increase in solar generation had a non-trivial impact on AS procurement costs during periods where solar is ramping up or downward. Underneath these empirical relationships are market-based mechanisms. It is informative to understand the market structure in each market segment, and document if the nature of market competition has changed as renewable capacity has expanded. We begin with the wholesale market, followed by descriptive statistics of each AS market segment.

7.1 Evolution of Market Concentration

Figure 7 summarizes several measures of market concentration in the wholesale energy market.[33] Figure 7a presents the average annual 3-firm concentration ratio across all output (total), and

[32] We directly control for hydroelectric potential instead of controlling for hydroelectric supply in the DAM (instrumented by the hydro potential index) as this is now a dependent variable of interest.

[33] We acknowledge that while standard market concentration measures have their limitations in the electricity sector (Borenstein et al., 1999), our goal is to capture broad characteristics of the market structure and understand how these measures vary both over time and across markets.

separately by non-renewable and renewable output. We define renewable generation to include wind, solar, and hydro supply. The market is fairly concentrated with three firms (Endesa, Iberdola, and Naturgy) having a total market share of approximately 55% in 2016. This market share has declined to 47% by 2024. Non-renewable generation is considerably more concentrated among the big 3 firms than renewable generation. Consequently, looking at total output, the reduction in the 3-firm concentration ratio is driven by the increasing proportion of market supply coming from the lower concentrated renewable generation.

Figure 7b demonstrates that these market dynamics translate into a reduction in the average annual Herfindahl–Hirschman Index (HHI), representing the summation of squared market shares across all firms, when looking across all total output. Renewable generation has a lower and declining HHI than non-renewable supply. Despite the relatively high market share among the big 3 firms, the HHI in the wholesale market is relatively low and below common thresholds that define a market as being moderately or highly concentrated (i.e., above 1,500 and 2,500, respectively).

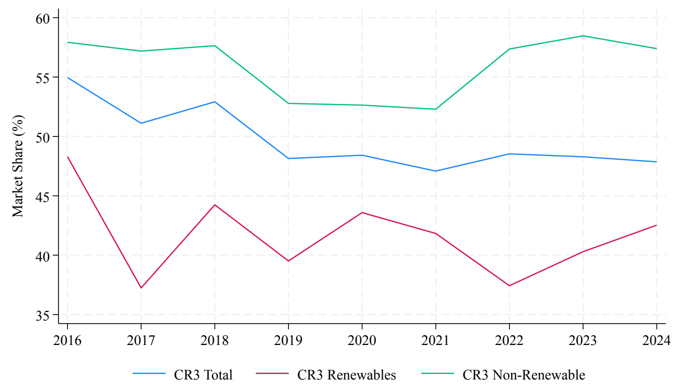
These figures mask hour-specific market dynamics. Figure 7c presents the average annual HHI by year and hour-of-day. We can see a distinct pattern of declining mid-day HHIs corresponding with the growth in solar capacity that is often owned by smaller firms. There is some indication of higher market concentration in the early morning and evening hours when the sun rises and sets. However, we see an overall reduction in wholesale market concentration as renewable capacity has expanded over our sample period.

Next, we consider the market structure across the various AS markets. Figure 8 presents the average annual HHI for upward and downward products by market segment.[34] The wholesale market HHI is provided as a point of reference. We can see that for both directions, the AS markets are considerably more concentrated than the wholesale market. Further, while the annualized average HHI metric is relatively volatile for certain market segments, we see either a flat or general increase in the HHI value across the various markets. This is despite efforts to increase participation in these markets (e.g., via the participation of wind and solar resources).

The market concentration values across the AS markets tell a different story by market segment given the nature of each product. As shown in Table 1 and Figure 3, the restrictions market makes up the majority of the AS market operating costs and has the highest quantities procured. The downward product has a lower market concentration than the upward restrictions product. This is consistent with the fact that the downward product is often supplied by renewable generators (via curtailment). In contrast, the upward product is largely supplied by natural gas generators that are more concentrated within the big 3 firms. Unlike the other AS products, the location of resources plays a key role in the procurement in restrictions market. Consequently, as will be explored in more detail below, the results in Figure 8 indicate that the units that can alleviate the constraints on the grid are concentrated among a handful of firms.

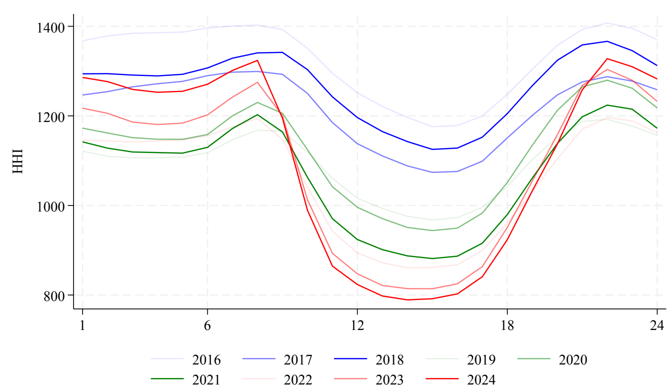
[34] We only present the day-ahead restrictions market. Until 2023, the real-time restrictions market had low procurement quantities. Over this period, only a few firms provided this product leading to high HHI values. We focus on the day-ahead restrictions market where the majority of quantities were procured to avoid misrepresenting the importance of this market concentration.

Figure 7: Wholesale Market Concentration Metrics by Year



(a) Average 3-Firm Concentration Ratio by Technology

(b) Average HHI by Technology

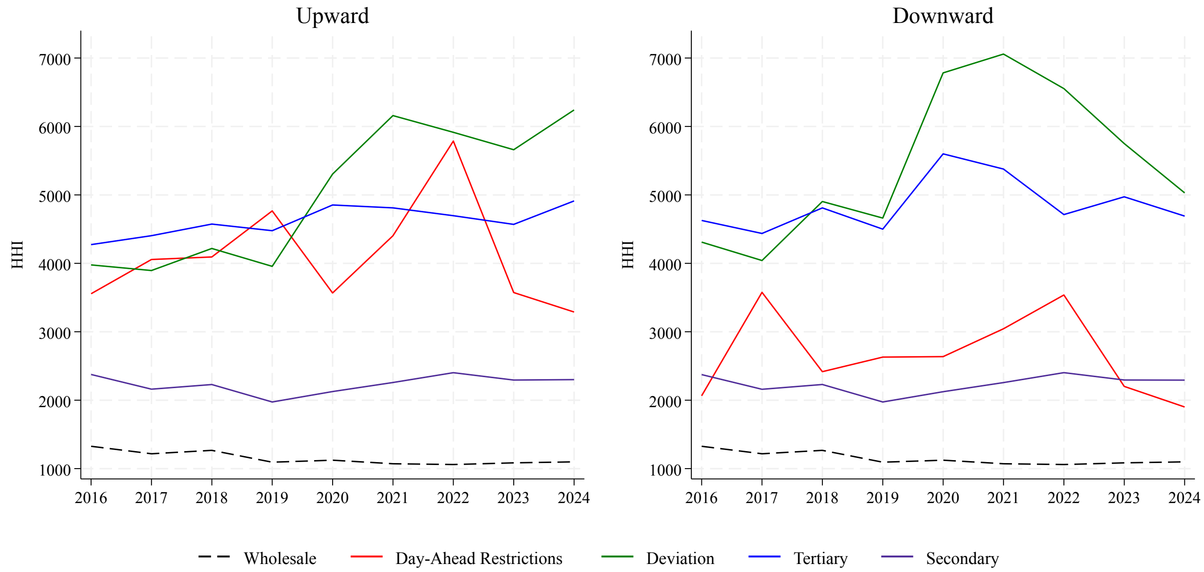


(c) Average HHI by Year and Hour

Notes. This figure displays the evolution of average concentration metrics in the day-ahead market using hourly data for the period 2016-2024.

Interestingly, despite having relatively high participation requirements (i.e., requiring automatic and rapid responses to restore frequency), the secondary market has the lowest HHI values among the AS products. This capacity-based market takes place day-ahead and often represents only a

Figure 8: Average Annual HHI by AS Market and Year



Notes. This figure plots average annual HHI for each AS market segment by upward and downward product types. The wholesale market HHI values are provided across both product types as a point of reference.

portion of a firm's generation asset that is supplying other products. Despite the average HHI values being below the other AS markets, the secondary market would be deemed as being moderately-to-highly concentrated using standard HHI thresholds.

Finally, Figure 8 shows that the tertiary and deviation markets typically have the highest degree of market concentration in both upward and downward directions. These markets are unique in that they are procured in real-time to satisfy system imbalances. These results indicate that there are relatively few firms that are providing these real-time services.[35]

7.2 Auction Participation

Another way to understand the prevailing market structure is to analyze the number of firms competing to supply each AS product and the number of firms with accepted bids. The HHI may still be high if there are only a few firms with the majority of the market share with the remainder supplied by a fringe of many small competitors (i.e., it may not capture the presence of a crowded field of small competitors) or if there are only a handful of winning bids (e.g., due to the market being relatively small and the presence of indivisibilities).

Figure 9 presents the distribution of the number of bidders and number of firms with accepted bids in each market for upward and downward products. In the day-ahead restrictions market, there is a large number of firms bidding to provide adjustments in their day-ahead schedule. The

[35] We also decomposed market concentration metrics by year and hour-of-day for each AS product. Unlike the wholesale market, there are no distinct hour-specific patterns in the market concentration metrics.

median hourly count is 73 for upward and 102 for downward. However, the large number of bidders is driven by the fact that firms are required to submit bids to reflect their willingness to make adjustments from the day-ahead schedule.[36] Yet, only a small number of firms have accepted bids, with a median of 4 for upward restrictions and 16 for downward restrictions. The restrictions market is used to solve local grid constraints or security requirements (e.g., voltage stability) that only a small of units with certain capabilities can resolve, and it is, thus, segmented by both location and technical characteristics. This problem is more acute for upward than downward redispatch, which is used to resolve excess generation (e.g., from wind and solar) in an export pocket. While renewables have the ability to curtail their energy, they are subject to stricter rules for increasing output. For this reason, they cannot compete in upward redispatches, as seen in Figure 3, leading to increased concentration.

Figure 9 illustrates that bidding participation among the other AS markets (deviations, tertiary, and secondary) is relatively similar, with a median number of bidders ranging from 8 to 14 across market segments and directions. The deviation market has the fewest median number of accepted bidders (4), followed by the tertiary market (5), and then the secondary market (9). For the tertiary and deviations markets, the upward product had fewer bidders, despite having the same median number of accepted bidders. Because these markets are not differentiated, and follow a uniform price auction, the degree of competition can be larger than in the restrictions market, in which operational constraints can give a few firms substantial market power.

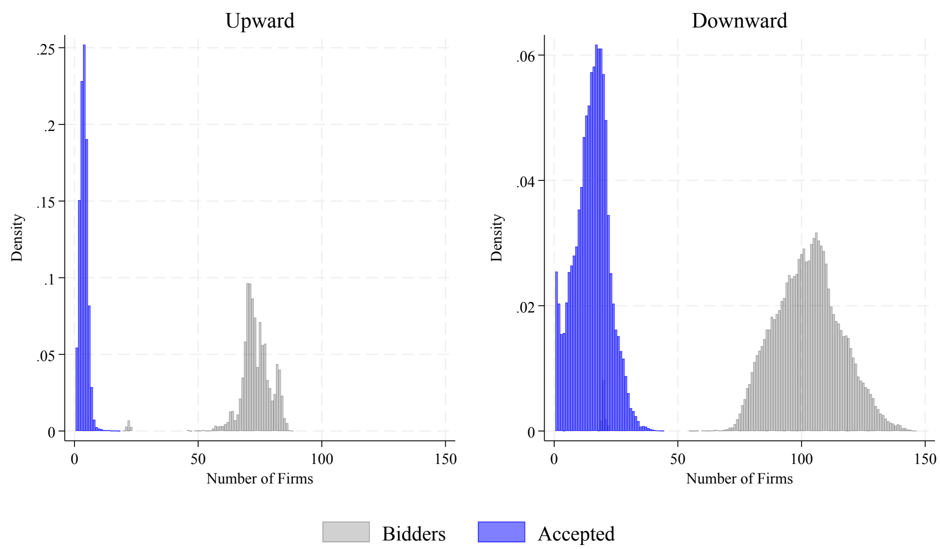
8 Conclusions

Using Spain's electricity market transition between 2016 and 2024, we provide empirical evidence on how the rapid expansion of renewable generation reshapes both price formation and market structure. We leverage detailed unit-level data and exogenous variation in renewable resource availability and find that increased wind and solar output delivers substantial reductions in wholesale electricity prices, with particularly pronounced effects during hours of high solar generation. However, these savings are partially offset by rising ancillary service (AS) operating costs, with solar generation driving higher AS operating costs in the early morning and evening ramp periods. Despite these operational frictions, the net effect of renewable generation yields large overall final price reductions.

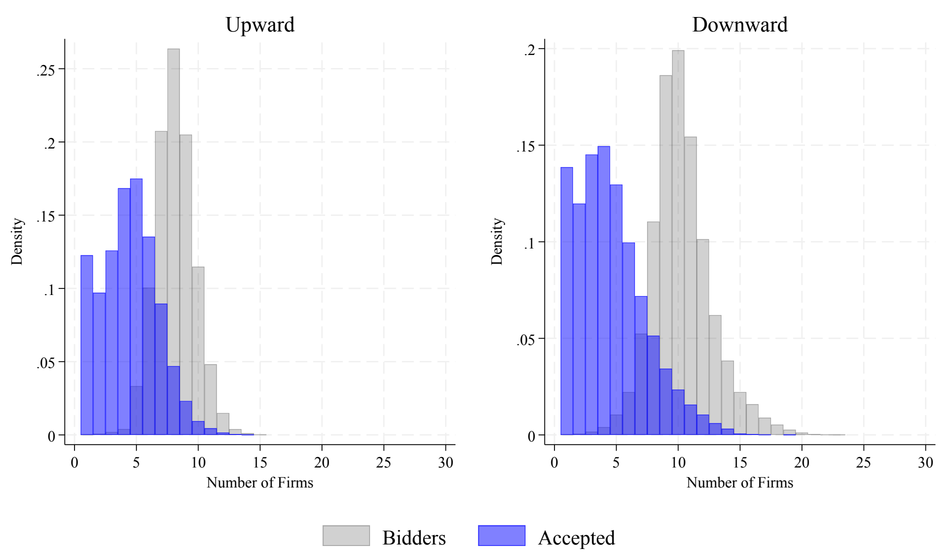
Beyond price impacts, our analysis documents important features of the prevailing market structure in both wholesale and AS markets. We find that renewable entry reduced concentration in the wholesale market, especially during midday hours when solar output is at its peak. In contrast, AS markets remain highly concentrated, reflecting technological and locational constraints that restrict the set of participating generation assets. In Spain's redispatch restrictions market, which accounts for the majority of AS costs, only a small number of firms routinely provide upward services

[36] Participation is mandatory for all generation units and all their capacity, even if they have bilateral agreements for their generation (see rule P.O. 3.2, REE).

Figure 9: Number of Firms - Bidding and Accepted



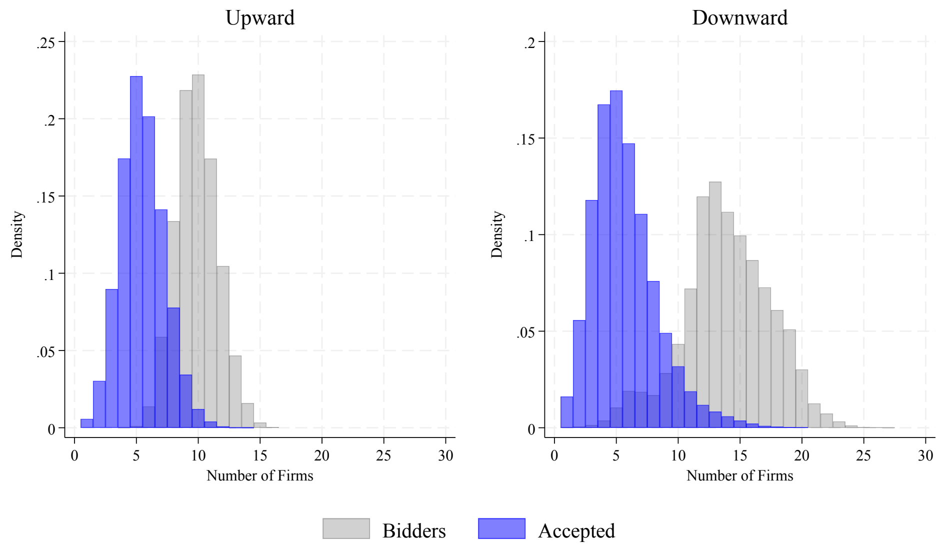
(a) Day-Ahead Restrictions



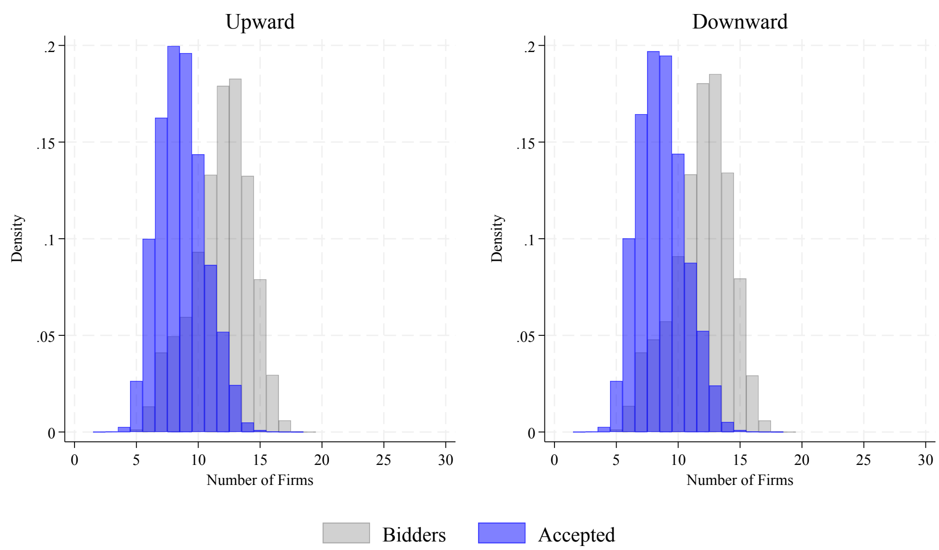
(b) Deviation

Notes. This figure plots the number of firms that actively participate in the restrictions and the deviations markets at the hourly level.

Figure 9: Number of Firms - Bidding and Accepted (Continued)



(c) Tertiary



(d) Secondary

Notes. This figure plots the number of firms that actively participate in the tertiary and secondary regulation markets at the hourly level.

because of the location-specific needs of this product. These findings highlight the challenges created by variable renewable generation in currently highly concentrated AS markets.

Our results provide several policy implications. We show that the net effect of Spain's rapid wind and solar capacity growth is to reduce overall final (wholesale energy plus AS market) prices. However, the growth in renewables, solar in particular, yields a non-trivial increase in AS market operating costs. Reducing these cost pressures as renewable capacity continues to grow will be important to cost-effectively and reliably integrate high levels of renewable generation. While AS markets face natural limits to competition relative to wholesale markets (Pollitt and Anaya, 2021), continued efforts to expand participation—through emerging technologies (e.g., battery storage, wind, and solar) and greater integration with broader EU ancillary service markets—can help increase competition and lower the cost of providing ancillary services.[37]

Another broader reform would be to begin to integrate grid constraints within the clearing of the wholesale energy market. Like other European electricity markets, Spain does not consider intra-regional grid or technical constraints in day-ahead wholesale market clearing. This contrasts with integrated market designs in the United States, for example, that directly account for these constraints, while often co-optimizing across wholesale and ancillary service products. Integrated market designs have been found to yield sizable operational cost savings (Triolo and Wolak, 2022).[38]

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[37] In 2025, Spain launched a €700 million support mechanism to increase battery storage, with a target of 22.5 GWs of additional energy storage by 2030 (Murray, 2025). In addition, in June 2025, Spain integrated its automatic frequency market with the EU's broader market called PICASSO, representing continuing efforts to increase European-wide AS market integration (Backer et al., 2023).

[38] For a comprehensive discussion of electricity market design and a comparisons of European simplified versus United States-style integrated market designs, see Graf (2025).

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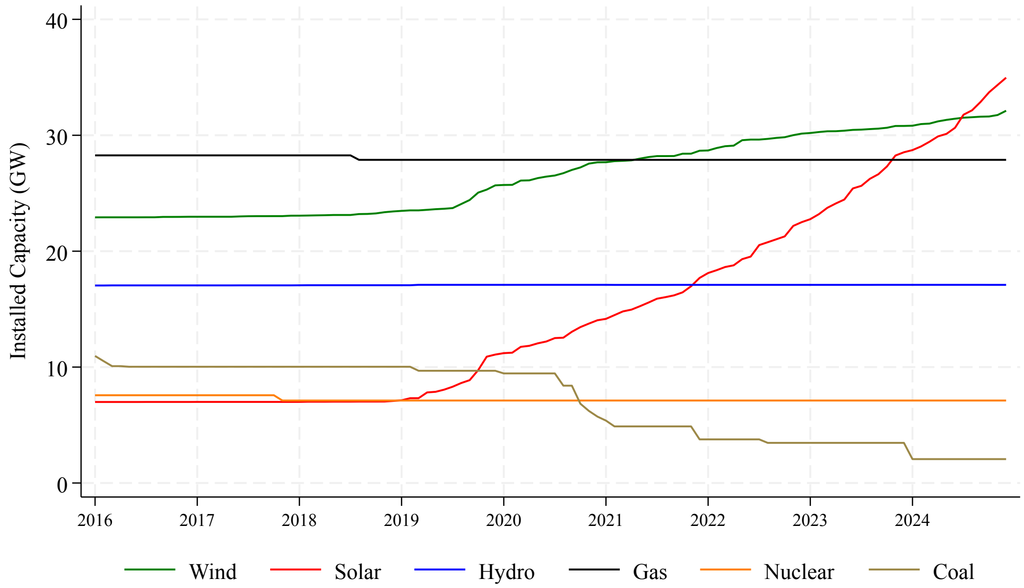
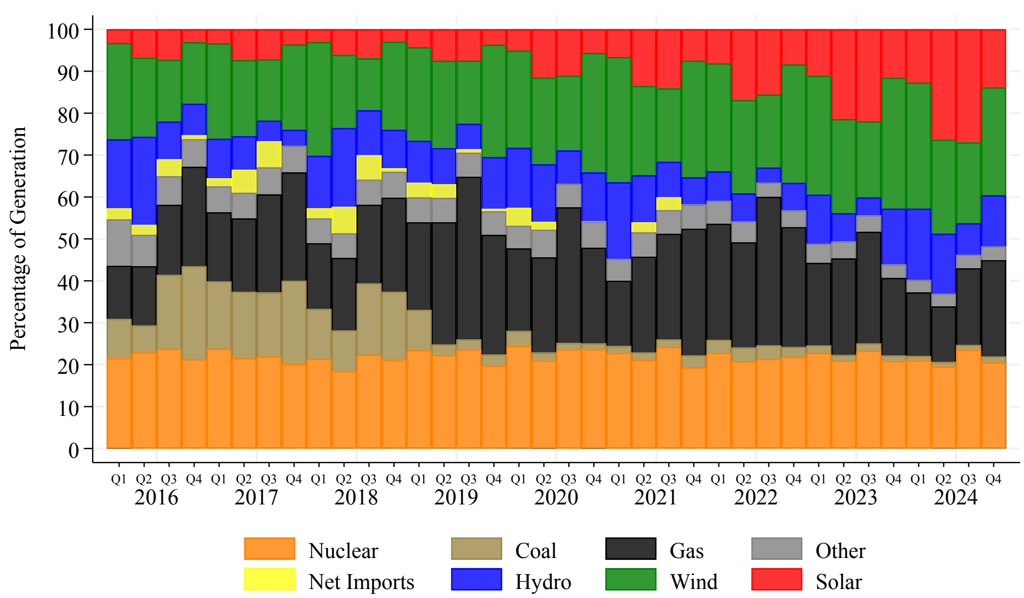
A Additional Tables and Figures

Figure A.1: Installed Generation Capacity (in GW) by Technology



Notes. This figure presents monthly generation capacity (in GW) separated by generation technology.

Figure A.2: Percentage of Total Generation by Technology and Quarter



Notes. This figure presents the percentage of generation supplied by generation technology and quarter. Net Imports are only reported if they are positive to capture net generation within Spain.

B Extensions and Robustness

Table B.1: Marginal Daily Impacts on Prices by Market Segment - Final Outcomes

	(1) DA price	(2) AS costs	(3) Final price	(4) DA price	(5) AS costs	(6) Final price
Daily Solar	-0.174	0.057	-0.117	-0.159	0.018	-0.141
	(0.035)	(0.005)	(0.033)	(0.043)	(0.005)	(0.042)
Daily Wind	-0.188	0.018	-0.170	-0.184	0.010	-0.174
	(0.017)	(0.002)	(0.016)	(0.026)	(0.002)	(0.025)
Daily Hydro	-0.184	0.034	-0.150	-0.124	0.015	-0.109
	(0.035)	(0.006)	(0.030)	(0.085)	(0.008)	(0.082)
Daily Demand	0.167	-0.024	0.143	0.146	-0.017	0.129
	(0.016)	(0.003)	(0.015)	(0.027)	(0.003)	(0.026)
MC CCGT	1.045	0.019	1.064	1.004	0.021	1.025
	(0.017)	(0.004)	(0.016)	(0.033)	(0.009)	(0.034)
Observations	3,256	3,256	3,256	3,256	3,256	3,256
R-squared	0.903	0.652	0.916	0.621	0.210	0.628
FE	Month	Month	Month	Year-Month	Year-Month	Year-Month

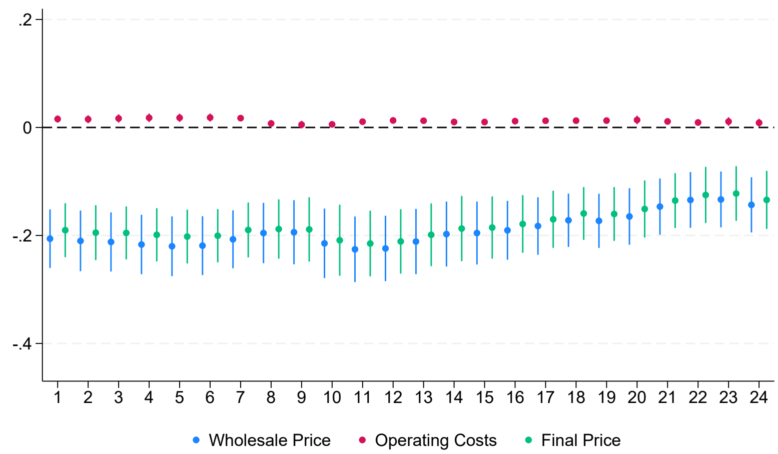
Notes. The Table provides the results from the regression outlined in equation (1) for the dependent variables wholesale energy prices, AS operating costs, and final prices, using final outcomes instead of day-ahead market outcomes. Renewable generation for wind, solar, and hydro is instrumented with radiation capacity, wind speed capacity, and hydro producible. Demand is instrumented by average daily HDD and CDD, and day-of-week dummies. Fixed Effects (FE) are either at the monthly or year-month level. Standard errors are clustered at the year-month level.

Table B.2: Marginal Daily Impacts on Procurement Costs by Market Segment

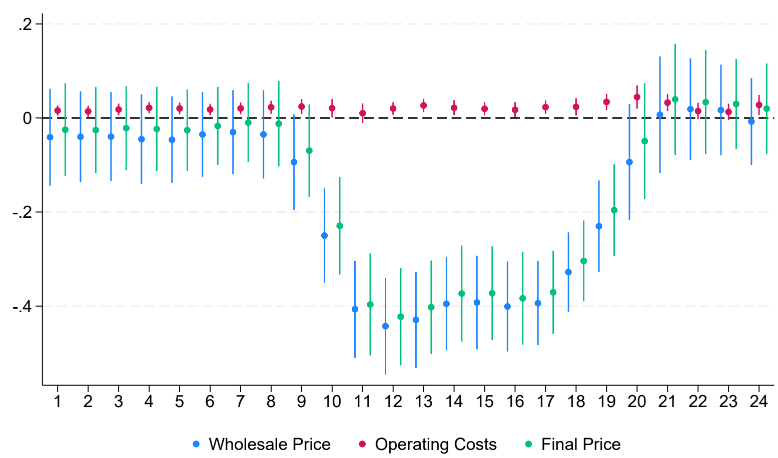
	(1) DA costs	(2) AS costs	(3) Final costs	(4) DA costs	(5) AS costs	(6) Final costs
Daily Solar	-0.095	0.032	-0.063	-0.121	0.015	-0.106
	(0.017)	(0.002)	(0.016)	(0.024)	(0.003)	(0.024)
Daily Wind	-0.119	0.012	-0.108	-0.120	0.009	-0.112
	(0.010)	(0.001)	(0.009)	(0.015)	(0.001)	(0.015)
Daily Hydro	-0.103	0.020	-0.083	-0.077	0.014	-0.063
	(0.018)	(0.003)	(0.016)	(0.047)	(0.005)	(0.046)
Daily Demand	0.100	-0.010	0.089	0.093	-0.008	0.085
	(0.009)	(0.001)	(0.008)	(0.015)	(0.002)	(0.015)
Total MC Cost	1.039	0.020	1.058	1.008	0.019	1.027
	(0.016)	(0.003)	(0.015)	(0.031)	(0.008)	(0.034)
Observations	3,256	3,256	3,256	3,256	3,256	3,256
R-squared	0.921	0.670	0.929	0.730	0.139	0.737
FE	Month	Month	Month	Year-Month	Year-Month	Year-Month

Notes. The Table provides the results from the regression outlined in equation (1), but replacing each dependent variable with the respective (non-weighted) hourly prices times hourly DAM demand summed to the daily level to reflect the total procurement costs in each market. Renewable generation for wind, solar, and hydro is instrumented with radiation capacity, wind speed capacity, and hydro producible. Renewable generation for wind, solar, and hydro is instrumented with radiation capacity, wind speed capacity, and hydro producible. Demand is instrumented by average daily HDD and CDD, and day-of-week dummies. Fixed Effects (FE) are either at the monthly or year-month level. Standard errors are clustered at the year-month level.

Figure B.1: Marginal Hourly Impacts of Daily Wind and Solar Output by Market Segment - Saturated Specification



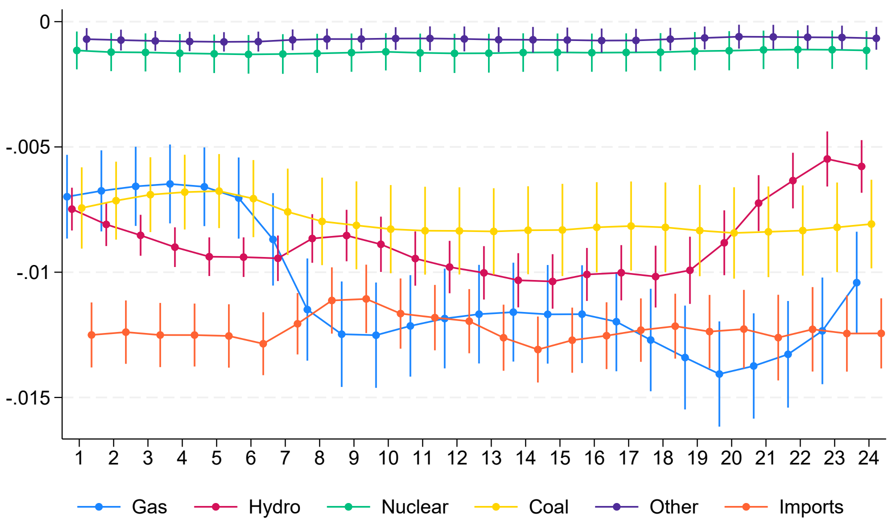
(a) Wind



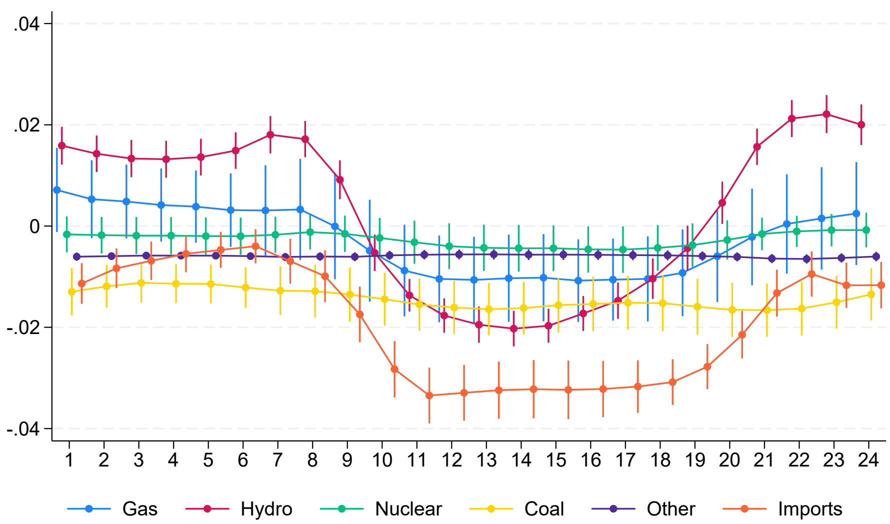
(b) Solar

Notes. This figure presents the hourly marginal effects of an increase in daily wind and solar output on the DAM wholesale price, AS operating costs, and the combined final price, using the specification in equation (2) with fixed effects at the year-month. Reported standard errors are clustered at the year-month level.

Figure B.2: Marginal Hourly Displacement Effects of Daily Wind and Solar Output Specification



(a) Wind



(b) Solar

Notes. This figure presents the hourly marginal effects of an increase in daily wind and solar output on generation outcomes for several technologies, controlling for demand (instrumented with HDD, CDD, and day-of-week), CCGT marginal costs, daily hydro producible, and month fixed effects. Reported standard errors are clustered at the year-month level.