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Renewable Integration: The Role of Market Conditions

Daniel Davi-Arderius | Tooraj Jamasb | Juan Rosellon

Abstract

The 2022 energy crisis highlighted the dependence of Europe electricity sector on imported gas and the need to accelerate the connection of renewables to the power system. However, the allocation of generation and demand in electricity markets is not always technically viable and, where needed, system operators must activate or curtail specific generators not cleared in the day-ahead markets to ensure system reliability. This is a well-known operational, but under-researched, issue related to high integration of renewables. In Spain, most activated units are combined cycle or coal, while an equivalent volume of scheduled renewables (wind) must be curtailed to balance generation and consumption. Most of these actions are not used to alleviate congestion or grid bottlenecks, but to ensure system stability which highlights new challenges, but little empirically analyzed, in efficient integration of renewables. These actions impact on social welfare since all customers bear the costs of these actions, resulting in additional gas imports and CO2 emissions. We estimate how these actions could evolve under different scenarios. We find that additional renewables have increased the costs and CO2 emissions related to network operational needs. Moreover, the installation of small generation behind the meter might become a regressive policy since all customers will bear the additional operational costs. Finally, higher electricity consumption decreases the costs of solving operational needs, which highlights another social welfare benefit associated with the electrification of demand. Until the renewable or storage technologies evolve further, conventional generators (coal, combined cycle or nuclear) are needed for safe operation of systems with high rate of renewables, and countries need to assess when they disconnect them from the network.

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Renewable Integration: The Role of Market Conditions

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1. Introduction

The European Green Deal is the EU's long-term growth plan to make Europe climate neutral by 2050. This target is enshrined in the European Climate Law, as well as the legally binding commitment to reduce net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels (European Commission, 2019b; Borghesi et al 2022). In July 2021, the Commission presented its ‘Fit for 55' package of legislation to achieve these targets. these proposals would lower gas consumption by 30% by 2030, with more than a third of the savings coming from meeting the EU energy efficiency target (European Commission, 2019b). In May 2022, the Commission presented the REPowerEU Plan, in response to the hardships and global energy market disruption caused by Russia-Ukraine war (European Commission, 2022a). The European Commission also adopted the European Gas Reduction Plan to reduce natural gas consumption for the winter. This plan included three pillars of action: fuel switching from gas to alternative energy sources such as RES, incentivizing energy consumption reduction, and reducing heat and cooling consumption temperature thresholds for district heating in the household sector (European Commission, 2022b).

These plans coincide with the desire to replace polluting generation technologies, i.e. coal or gas power, with RES. In many cases, grids capacity constrains the connection of new RES. This has attracted the attention of scholars to optimal grid investments to connect RES given the existing grid capacity (Schermeyer et al., 2018; Liu et al., 2021). However, wind and photovoltaics generators are made of power electronics instead of rotating synchronous generators used in the replaced conventional generators (Hirth et al., 2018a). Power electronics have particular and limited operational behavior and operating higher rates of RES might affect the system stability and security. In these cases, system operators should activate or curtail specific generation units to minimize the risk of blackouts (Andresen et al., 2023). In Europe, these actions are managed through the redispatching processes, which were initially aimed to solve grid bottlenecks, but now they are mostly used for solving these non-grid issues. In Spain, more than two-thirds of redispatching volumes in the day-ahead are used to solve voltage or power system stability needs (ACER and CEER, 2021, 2022). This picture highlights a new scenario in highly decarbonized power systems where non-grid capacity issues become increasingly relevant and further technological developments in RES and storage are needed (Davi-Arderius et al., 2024).

In countries with high shares of RES, volumes of activated energy in redispatching peaked in 2020: 21.1 TWh in Germany, 11.1 TWh in Spain and 9.3 TWh in Italy. Its annual costs range from 1.47b€ for Italy, 0.43b€ for Spain and 0.25b€ for Germany in the same year. In 2022, volumes of activated energy were: 27.2 TWh in Germany, 11.0 TWh in Polland and 8.2TWh in Spain. During the covid lockdown, all these actions produced more than 11% of all the CO2 emissions of the Spanish power sector as most of them were related to activations of coal and combined cycles (ACER and CEER, 2021, 2022; ACER, 2023; Davi-Arderius et al., 2024).

This scenario highlights that the allocation of generation and consumption made in the electricity markets might be economically efficient, but are not always technically viable. In these cases, system operators must adjust market schedules with increasingly redispatching costly actions. With the greater connection of RES, this phenomenon is increasingly relevant.

The literature about redispatching is divided into main groups. On the one hand, theoretical studies, e.g. Hirth et al. (2018b) develops a zonal wholesale market with a locational redispatch market to identify optimal bidding strategies and determine Nash-equilibrium prices. Poplavskaya et al., (2020) develop a methodology for congestion management and increase cross-border exchanges through a preventive redispatch of units. Schermeyer et al. (2018) develop a congestion management scheme on distribution grid level considering the flexibility options to avoid curtailing Distributed Generation. Grimm et al. (2022) compare the cost and market based redispatching procurement to assess its cost efficiency and overall welfare. Ambrosius et al. (2022) use a stochastic multi-level equilibrium model that includes investment in grids, investments in generation capacity and redispatching costs to compare the effects of risk aversion in a system with zonal and nodal pricing. Staudt et al. (2021) develops a market mechanism for the expansion of transmission grid capacity using a cost-based redispatch. Potential gaming concerns related to the redispatching process has been analyzed: Hirth et al. (2020) identify potential gaming concerns related to market based redispatching process, and Palovic et al. (2022) study the potential strategic behavior of generators and consumers between the electricity markets and redispatching processes.

On the other side, empirical studies. Joos and Staffell (2022) find that congestion costs in the UK and Germany peaked since 2010, which resulted in curtailment rates of 5% for wind farms in both countries. Petersen et al (2023) assess the welfare impact of intermittent wind power in Spain (2009-2018) and find that an additional GWh of wind increases the operational costs up to 0,19 Euro/MWh, which includes redispatching costs. Davi-Arderius and Schittekatte (2023) find that redispatching in Spain lead to a reduction of between 0.93 and 6.2% of the maximum potential CO2 savings from RES. Finally, Davi-Arderius, et al (2024) identify that these activations of fossil fuels on day-ahead are mostly explained by voltage control issues.

This paper aims to analyze the costs and patterns related to the activation of conventional generators on the day-ahead market schedule with redispatching and identify how these could evolve with the implementation of programs now proposed in the European Gas Reduction Plan. All these programs affect the generation mix or change the hourly consumption profile, i.e., installation of RES, peak shaving, energy efficiency programs, and charging of electric vehicles (EVs). Activation of generators for operational security has relevant welfare implications: they represent an extra cost for consumers and produce CO2 emissions. Moreover, the activated plants need an equivalent curtailment of other scheduled generators (RES) to maintain the system balance, which ends with another relevant inefficient allocation of resources.

We aim to answer the following research questions:

- How does the electricity demand and renewables affect the redispatching volumes and costs?
- How could these redispatching volumes and costs in the future?

The methodology consists of two stages. First, we empirically assess how the total electricity demand and the rate of RES in the mix have set the redispatching volumes and costs in the day-ahead (2019-2022). Second, using empirical estimates from the first stage we quantify how the volumes, costs and CO2 emissions from redispatching processes could evolve in the future under different programs (scenarios), most of them related to the implementation of the European Gas Demand Reduction Plan. Precisely, this plan aimed to reduce gas consumption -reducing the electricity consumption and increasing the share of RES.

Our results are essential to implement efficient network tariff-schemes, charges, or locational incentives for future RES for an efficient integration of RES (European Commission, 2023b). In other words, we investigate potential inefficiencies and trade-offs related to power system needs and beyond the grid hosting capacity needs and the variability of RES production. The Spanish case anticipates similar challenges in other countries that are making heavy investments in RES. The magnitude of the challenge aggregated across the EU is much larger and regulatory frameworks should provide the right incentives to minimize future inefficiencies. To our knowledge, this question has not been addressed in literature so far.

Spain has a high share of RES in gross electricity consumption (42.9% in 2021) and grid operators should deny the connection of new RES if they identify future grid congestions or bottlenecks.[1] Moreover, the Iberian Peninsula is an "energy island" because the cross-border capacity with France and Morocco is limited (IEA, 2021). This interconnection is far from the 15% requirement by the European Commission (2018). The case of Spain is relevant for other systems that implement these policies. In 2021, the (net) redispatching of combined cycles in Spain amounted to 5.7TWh and increased 30% its gas consumption. We use hourly data from the Spanish Nominated Electricity Market Operator (NEMO) and the Spanish Transmission System Operator (TSO), namely OMIE and REE, between 2019 and 2021. Our empirical approach is a Seasonal Autoregressive Integrated Moving Average time-series estimator (SARIMA), where variables are differentiated to ensure their stationarity and lagged endogenous variables capture the time dynamics (Dickey and Fuller, 1979; Kwiatkowski et al., 1992).

This paper is organized as follows. Section 2 describes network operation and RES. Section 3 presents the empirical approach, Section 4 describes the data and descriptive statistics, while Section 5 presents the results. Finally, Section 6 is conclusions and policy recommendations.

2. Network operation and RES

2.1 Synchronous generators

Generation devices are divided into two main types. First, synchronous generators made of rotatory machines that convert mechanical power into Altern Current (AC) electricity through electromagnetic induction processes. They were developed many decades ago and are used in nuclear power, hydropower, combined cycle, coal, biomass, or combined heat and power (CHP). Traditionally, synchronous generators have provided stability and reliability to the power system, which includes voltage and frequency control.

Second, power electronics made of converters that transform Direct Current (DC) into AC, or vice versa. They are used in photovoltaics, wind power, or storage devices such as batteries. Power electronics do not have the same operational response as synchronous generators related

[1] In Spain, RES can only be connected under firm connection agreements, while alternative 'non-firm connection agreements' or 'flexible connection agreements' are not allowed. Under firm connection agreements, RES can only be connected when there is available grid capacity during the year. On the contrary, on non-firm connection agreements, RES can be connected when there is no available grid capacity during some hours (CEER, 2023). This might explain the strong investments made by the Spanish TSO between 2010 and 2022, in many cases to connect RES: the length of 400kV lines has increased +17.1% (from 18,799 km to 22,013 km) and the length of 220kV lines +13.7% (from 17,755 km to 20,189 km) (REE, 2024).

to voltage control or inertia.[2] In consequence, a higher production of RES displaces synchronous generators, limit the generation resources available to the grid operators to control voltage or frequency, and might jeopardize these operational parameters if there is a deficit of synchronous generators in some areas. In the future, grid forming power electronics in combination with storage devices such as batteries, capacitors, or flywheels is expected to provide more response similar to those of synchronous generators (ENTSOE, 2021).

2.2 Network operation constraints

Power systems are made of networks that connect generators with end-consumers. Its operation is particularly complex and system operators must ensure that specific network operational criteria are always met across the network. This includes energy flows (congestions) in each cable and line must be below a maximum, while voltage and frequency must be within predetermined thresholds. If a criterion is not respected, the protection device of a cable or transformer might trigger for security reasons, affecting the quality of supply, and ultimately, increasing the likelihood of a blackout with corresponding welfare impacts (Andresen et al., 2023) if the balance between generation and consumption cannot be recovered immediately. When the system is operating under low levels of inertia, this balance might not be recovered immediately.

Three main network operational parameters might be affected by the decarbonization of the generation mix.

Congestions: They are related to the flow through each asset or the N-1 security criteria implying that the final dispatch should be robust against the failure of a network element. With an increasing penetration of RES, energy flow patterns through networks change and become more variable, often leading to dangerous congestion. In many cases, RES are located far from the replaced technologies or networks are not necessarily built as rapidly as RES are deployed (Janda et al., 2017).

Frequency: Frequency is related to the imbalances between generation and consumption. This is controlled through inertia, which is the power system capacity to immediately recover the nominal frequency when there is a disturbance related to an unbalance between generation and consumption. Combined Cycles or Coal plants are synchronous generators, whose stored kinetic energy provides inertia and keeps the frequency. However, wind or photovoltaic are made of power electronics whose inertial response is very different and much limited. Consequently, the massive connection of RES might decrease the inertia of the power system in some areas. (Denholm et al., 2020; Makolo et al., 2021). Lower inertia increases frequency oscillations, which in turn increases the risk to disconnect generators, further aggravating the unbalance between generation and consumption and endangering the system security (ENTSOE, 2020).

[2] Providing the same operational response as synchronous generators give with RES requires costly technologies or is restricted to innovation projects that are not commercial. For instance, providing voltage control with power electronics (RES) is constrained by the availability of the primary resource (sun or wind). In other cases, RES should install additional power electronic converters or costly dedicated devices such as capacitors, reactances or static synchronous compensators (STATCOM). Moreover, keeping frequency with power electronics is limited to virtual or synthetic inertial response, which also requires additional dedicated storage devices as RES do not store energy in rotating machines. This RES inertial response is less than large synchronous generators (Xing et al., 2021; Davi-Arderius et al., 2024).

Voltage: This is an electrical parameter that must be always respected to ensure network security conditions and quality of supply.[3] In high voltage grids, voltage is controlled with the reactive energy flows consumed or injected from generators and consumers. Traditionally, synchronous generators controlled reactive flows. However, power electronics used in RES require specific technologies to control reactive power flows as synchronous generators do. In the control of reactive energy flows, operational costs for RES might be relevant (Anaya et al., 2020).

Transmission grids with low demand inject reactive energy into the power system and increase the power system voltage, while grids with high demands consumes reactive energy and decrease the power system voltage.[4] This effect is aggravated by the increasing underground high voltage lines. Thus, operating a power system with many lines at low demand levels during many hours might create dangerous overvoltage in the system (National Grid ESO, 2021). This effect seems to be behind the peak CO2 emissions associated with redispatching actions during the low electricity demand due to the covid lockdown in Spain (Davi-Arderius and Schittekatte, 2023).

In late 2023, EU Action Plan for Grids defines several priorities to achieve 1,000 GW of solar and up to 317 GWh of wind offshore until 2030. Some of its actions include the need of distribution grids to turn into smart grids, becoming digital, monitored in real-time, and remotely controllable, or the improvement of the transmission and distribution long-term grid planning processes, which includes the installation of specific assets such as static synchronous condensers (STATCOM). They are useful to address frequency or voltage problems (European Commission, 2023b).

2.3 Redispatching processes

As part of the tasks assigned in the regulation, system operators must ensure that all the previous operational constraints in their whole network are respected. To do so, they forecast the flows in their grids -for the next days and hours- and, if needed, they must change flows by reconfiguring their network, i.e., opening and closing switches or lines. When these measures are not sufficient, they activate congestion management solutions to change the scheduled generation or consumption from specific units. These actions are known as redispatching and include the curtailment or activation of specific units.[5]

In Spain, grid operators assess the security of the power system considering the voltage, frequency and flows at each node of the grid. Moreover, TSO should consider contingencies such as the disconnection of a grid element (N-1 criteria), simultaneous disconnection of some High Voltage grids and stability problems related to a higher concentration of RES production (MICT, 2016). If needed, redispatching is applied to large generators and consumption made by pumping generators (MITECO, 2019).

[3] Each electrical equipment has its own nominal voltage.

[4] The load level used to determine whether a line behaves as a capacitor that injects reactive energy, or as an inductance that consumes reactive energy is the surge impedance loading or SIL, which depends on the physical characteristics of the line, as well as on their voltage. An unloaded underground line injects more reactive energy to the system than the same length of overhead line due to its higher impedance.

[5] Art. 2 (26) of the Electricity Regulation (EU) 2019/943 defines redispatching as '*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security'* (European Commission, 2019a).

3. Empirical approach

In this section we describe the empirical approach used in our analysis and the simulations based on the previous results.

3.1. Analysis

First, we analyze the energy activated from all synchronous generators in the dispatch model. Endogenous variable is the hourly (net) activated energy of synchronous generation ($r_{SYNCH,t}$) and corresponds to energy activated from Nuclear, Combined Cycle, Coal, Hydropower, Pumping Generation, CHP, Biomass and Thermosolar. This variable is positive if the sum of activated energy is higher than the curtailed energy and is negative in the opposite case. Explanatory variables include hourly total demand ($TDEM_t$) and percentage of power electronics ($sRES_t$) in total demand. Seasonality is controlled by several dummy variables: m_t, a dummy variable for each month, while $holiday_t$ equals to 1 in weekends and national holidays. See Equation 1:

$$r_{SYNCH,t} = \hat{\beta}_0 + \hat{\beta}_1 \cdot r_{SYNCH,t-1} + \hat{\beta}_2 \cdot TDEM_t + \hat{\beta}_3 \cdot sRES_t + \hat{\beta}_4 \cdot m_t + \hat{\beta}_5 \cdot holiday_t + \\ + \emptyset \cdot r_{SYNCH,t-24} + \varepsilon_t \quad (1)$$

$r_{SYNCH,t}$ is the sum of the (net) hourly redispatched energy from each synchronous technology in the day-ahead and is calculated in Equation 2:

$$r_{SYNCH,t} = \sum_{i=N,CC,CO,H,PG,CHP,B,TS} r_{i,t} \quad (2)$$

Where N corresponds to Nuclear, CC for Combined Cycle, C for Coal, H for Hydropower, PG for Pumping Generation, CHP for CHP, B for Biomass and TS for Thermosolar.

The hourly share of RES ($sRES_t$) corresponds to the share of scheduled generation in the day ahead and made of power electronics. This is calculated as the sum of wind (W_t) and photovoltaics (PV_t) over the total demand as in Equation 3.

$$sRES_t = \frac{W_t + PV_t}{TDEM_t} \cdot 100 \quad (3)$$

Second, we study the activated energy only from combined cycle, coal, and CHP in the technology model. In this case, endogenous variable corresponds to the hourly (net) activated energy for combined cycle ($\Delta r_{CC,t}$), coal ($\Delta r_{CO,t}$) and CHP ($\Delta r_{CHP,t}$). As in the dispatch model, these variables are positive if the sum of activated energy is higher than the curtailed energy, while the negative is the opposite. See Equations 4 to 6.

$$\Delta r_{CC,t} = \beta_0 + \beta_1 \cdot \Delta r_{CC,t-1} + \beta_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot sRES_t + \beta_4 \cdot m_t + \beta_5 \cdot holiday_t + \\ + \emptyset \cdot \Delta r_{CC,t-24} + \varepsilon_t \quad (4)$$

$$\Delta r_{CO,t} = \beta_0 + \beta_1 \Delta r_{CO,t-1} + \beta_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot sRES_t + \beta_4 \cdot m_t + \beta_5 \cdot holiday_t + \\ + \emptyset \cdot \Delta r_{CO,t-24} + \varepsilon_t \quad (5)$$

$$\Delta r_{CHP,t} = \beta_0 + \beta_1 \Delta r_{CHP,t-1} + \beta_2 \cdot \Delta TED_t + \hat{\beta}_3 \cdot sRES_t + \beta_4 \cdot m_t + \beta_5 \cdot holiday_t +$$

$$+ \emptyset \cdot \Delta r_{CHP,t-24} + \varepsilon_t \tag{6}$$

Third, we analyze the hourly costs of the activated energy in the cost model. These costs are paid by all the customers through a specific charge on energy consumed. Endogenous variable is the hourly cost ($r_{COST,t}$). Explanatory variables include the hourly total demand ($TDEM_t$) and percentage of power electronics ($sRES_t$) in total demand. See Equation 7:

$$r_{COST,t} = \hat{\beta}_0 + \hat{\beta}_1 \cdot r_{COST,t-1} + \hat{\beta}_2 \cdot TDEM_t + \hat{\beta}_3 \cdot sRES_t + \hat{\beta}_4 \cdot m_t + \hat{\beta}_5 \cdot holiday_t + \\ + \emptyset \cdot r_{COST,t-24} + \varepsilon_t \tag{7}$$

Regarding the empirical approach, the ordinary least square estimations could lead to biases problems as we include the lagged endogenous variable (Keele and Kelly, 2006). As a solution, we use maximum likelihood estimators, which have been used in similar analyses (Davi-Arderius and Schittekatte, 2023).

In all cases, we perform four estimations, one per year (2019, 2020, 2021 and 2022) as there are notable differences between the years. First, the renewable capacity increases between 2019 and 2022: photovoltaics increases by 335% to 19.644MW, wind increases by 29% to 29.643MW. Moreover, coal capacity decreases by 66,3% to 3.223MW (REE, 2024). Second, demand decreased in 2020 due to the covid lockdown (Santiago et al., 2021). The interannual GDP decreased by 11.3% (INE, 2024). Third, the average wholesale price notably differs in this period (47,8€/MWh in 2019, 33,9€/MWh in 2020, 111,9€/MWh in 2021 and 167,5€/MWh). This might affect the technologies operating in each period (OMIE, 2024). Four, the annual price of CO2 on the EU ETS increases from 24.7€/tn in 2019 to 80.2€/tn in 2022 (EEX, 2024). Lastly, TSOs and Distribution System Operators (DSOs) are always commissioning new lines, cables, substations, and reactive compensation equipment.

3.2. Simulations

In this section, we simulate how annual volumes and costs of activated energy could evolve in the future under different scenarios related with changes on the total energy consumption and share of RES:

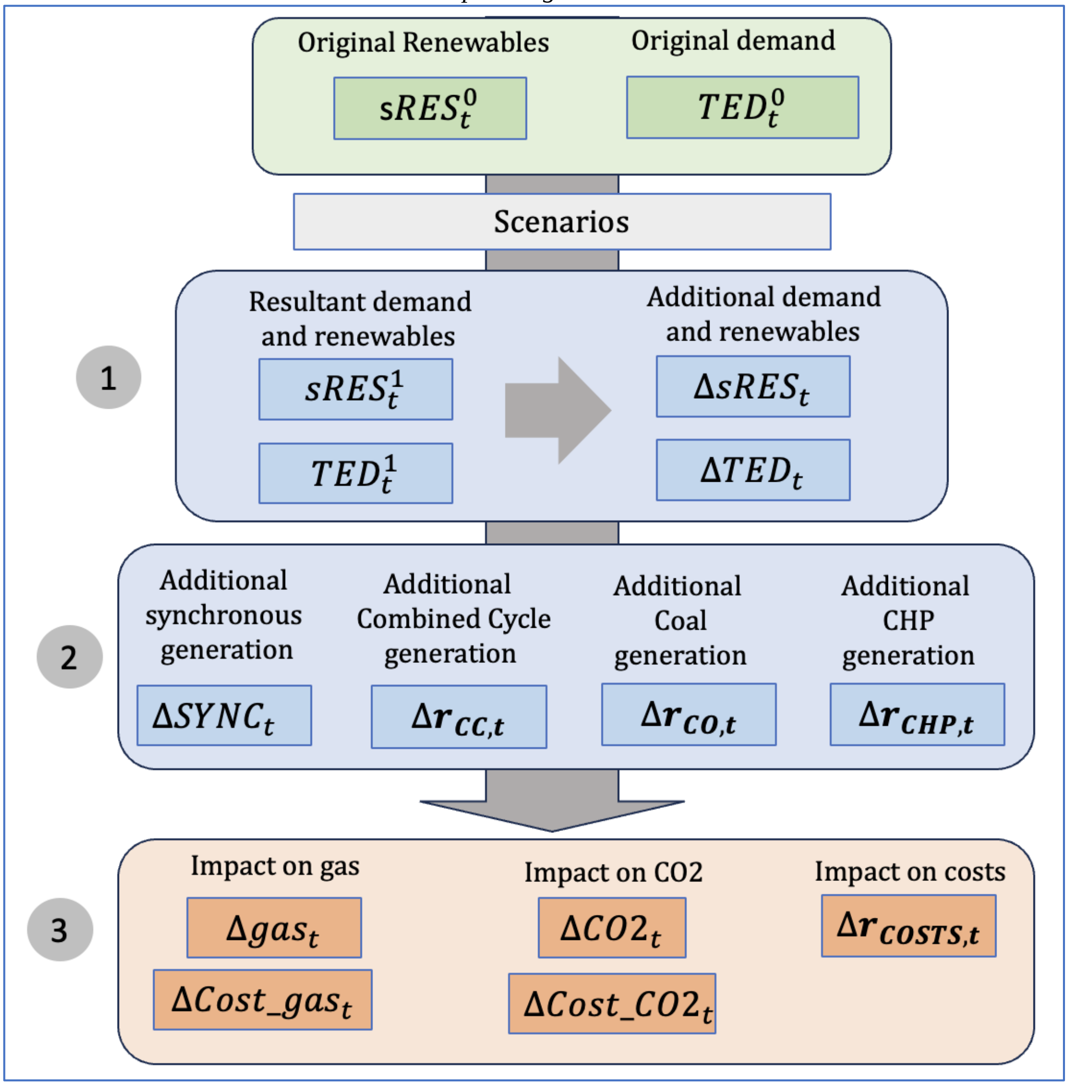
a) **Photovoltaic:** Connection of +10GW of photovoltaics (RES) to the grid.
b) **Wind:** Connection of +10GW of wind (RES) to the grid.
c) **Generation behind the meter:** Installation of +10GW of photovoltaics generation behind the meter, namely self-consumption. This generation reduces electricity consumption in the hours of photovoltaic production.
d) **Electric Vehicle at peak hours:** Charging EV during the peak hours (19h to 0h), which means higher electricity consumption during these hours. We consider different additional electricity consumption of +10GWh/year.
e) **Electric Vehicle at off-peak hours:** Charging EV during the off-peak hours (0h to 5h), which means higher electricity consumption during these hours. We consider different additional electricity consumption of +10GWh/year.
f) **Energy Efficiency:** Implementation of energy efficiency programs to reduce electricity consumption for each hour of the day. We consider lower electricity consumption of -10GWh/year.

g) **Higher Consumption:** Other electrification programs that would result in higher electricity consumption for each hour of the day. We consider different additional electricity consumption of +10GWh/year.
h) **Peak shaving products:** Implementation of peak shaving services to reduce 5% of national consumption during the four hours with the highest electricity consumption in the year.[6]

In all the cases, we consider 10 GW or 10 GWh in order to make results easily comparable. Simulations are made of three steps, and we use the original dataset for 2022 as a starting point. First, we recalculate the new hourly dataset made of the resultant total electricity demand (TED_t^1) and share of RES ($sRES_t^1$) from each scenario. Second, we use the hourly changes on the total electricity demand (ΔTED_t) and the share of RES ($\Delta sRES_t$) for each scenario and calculate the resultant changes on the activated synchronous generation ($\Delta SYNC_t$), activated energy for combined cycle ($r_{CC,t}$), coal ($r_{CO,t}$) and CHP ($r_{CHP,t}$). Finally, we calculate how all this activated energy impacts on the annual gas consumption (Δgas_t) and its costs ($\Delta Cost\_gas_t$), on the annual CO2 emissions ($\Delta CO2_t$) and its costs ($\Delta Cost\_CO2_t$), and on the annual costs paid by customers ($\Delta \boldsymbol{r}_{\boldsymbol{COSTS},\boldsymbol{t}}$). See Figure 1. It is noteworthy that all these impacts are calculated using the empirical estimates and dataset from 2022.[7] Detailed calculations are described in the Appendix A.

[6] https://www.consilium.europa.eu/en/press/press-releases/2022/09/30/council-agrees-on-emergency-measures-to-reduce-energy-prices/#:~:text=Electricity%20demand%20reduction&text=Member%20states%20will%20identify%2010,both%20targets%20in%20this%20period.
[7] In our simulations we are considering only dataset for 2022 as this year best reflects the reality of the current situation. For instance, the dataset from the previous years does not consider the installed new RES made in 2022, or the new commissioned networks in 2022.

Figure 1: Flowchart with the process followed to calculate the potential impacts of each scenario in the redispatching actions.



4. Data

The data used in this study is made of a combination of operating data published by the Spanish TSO and market data published by the Spanish NEMO (REE, 2024; OMIE, 2024). They include hourly data between 2019 and 2022 and corresponds to the Spanish bidding zone. Figure 2 shows the hourly electricity generated by technology between 2019 and 2022. The Spanish hourly electricity demand follows two peaks, one at 12-13h and another at 20-21h. It is interesting to see how wind production is relatively constant throughout the hours of the day, while photovoltaic is producing during between 8h and 21h.

Table 1 shows the summary statistics of the remedial actions by technology. They can be classified in two groups: those whose volumes activated are higher than curtailed during this (combined cycle, coal, and pumping consumption), and those whose volumes activated are lower than curtailed during this (wind, photovoltaics, thermosolar, CHP, hydropower, and pumping generation). Table 2 shows the summary statistics of total electricity demand, and share of RES.

Figure 2. Total Electricity demand by technology. Source: Own elaboration based on OMIE (2024)

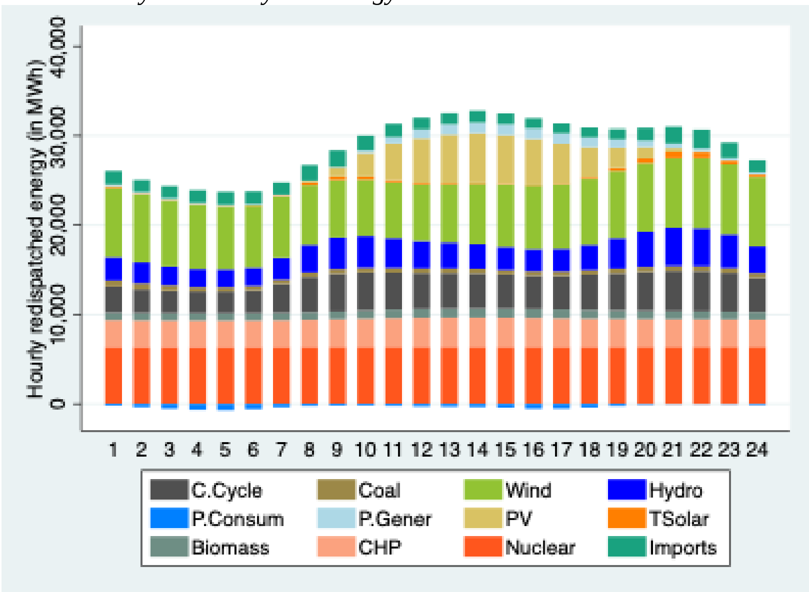


Table 1. Summary statistics of the net redispatched energy by technology in the day-ahead. Positive values mean starting units (higher generation), negative means curtailing units (lower production) (N=38,663)

Variable	**Definition**	**Units**	**Mean**	**St. Dev.**	**Min**	**Max**
$r_{CC,t}$	(Net) redispatched energy from Combined Cycle	MWh	507.64	495.10	-2436.50	3022.30
$r_{CO,t}$	(Net) redispatched energy from Coal	MWh	210.89	213.40	-567.00	1215.00
$r_{W,t}$	(Net) redispatched energy from Wind	MWh	-349.21	312.27	-2207.80	658.10
$r_{PV,t}$	(Net) redispatched energy from PV	MWh	-11.83	93.51	-2375.00	34.90
$r_{TS,t}$	(Net) redispatched energy from thermosolar	MWh	-11.03	64.96	-940.80	24.50
$r_{CHP,t}$	(Net) redispatched energy from CHP	MWh	-74.32	90.70	-868.90	81.60
$r_{H,t}$	(Net) redispatched energy from Hydro	MWh	-110.85	146.33	-1,504.00	1,160.40
$r_{PG,t}$	(Net) redispatched energy from Pumping Generation	MWh	-44.63	106.78	-1,360.00	1,198.20
$r_{PC,t}$	(Net) redispatched energy from Pumping Consumption	MWh	-103.62	226.37	-2,456.10	800.00
$r_{SYNCH,t}$	(Net) redispatched energy from synchronous generators	MWh	472.15	398.53	-658.1	3,176.2
$r_{COST,t}$	Hourly costs	€	40,817.24	47,035.08	-47,409.59	738,436.1

$Auction_{gas,t}$	Gas price	Eur/MWh	43.25	43.54	4.17	246.25
$Price\_CO2_t$	CO2 auction price	Eur/tn	45.71	24.35	14.6	97.51

Note: The (net) redispatched synchronous generation ($r_{SYNCH,t}$) is calculated using Equation 2. In generation technologies, positive values mean starting units during redispatching, negative values mean curtailing in the day-ahead. In pumping consumption, positive values mean curtailing consumption during the redispatching process, negative values mean starting consumption in the day-ahead. In costs, negative costs mean savings for customers, which might be explained when volumes of activated energy are mostly related with pumping consumption.

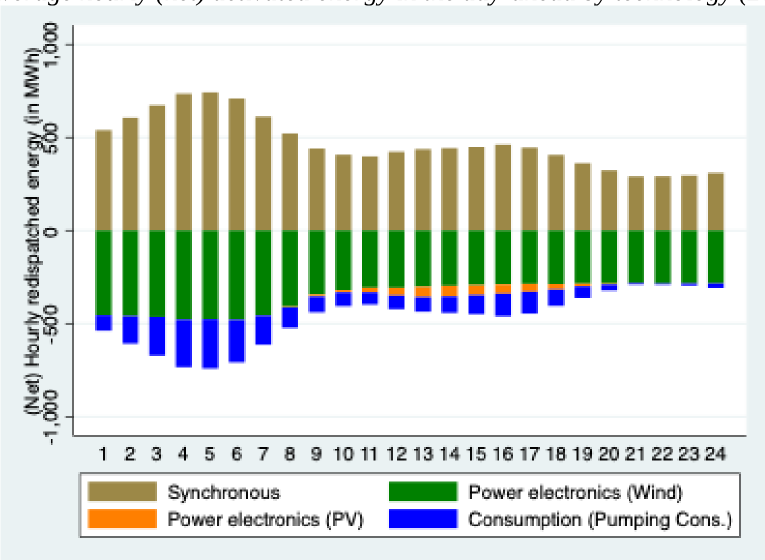
Table 2. Summary statistics of the total electricity demand and the share of wind and photovoltaics in Total Electricity Demand (TED). (N=38,663)

Variable	Definition	Units	Mean	St. Dev.	Min	Max
TED_t	Total (scheduled) demand in the day-ahead	MWh	28,820.93	4473.20	17,161.73	42,064.50
PV_t	Scheduled photovoltaic in the day-ahead	MWh	2132.24	3066.89	0	15053.80
W_t	Scheduled wind in the day-ahead	MWh	7306.32	3794.45	477.60	21545.00
$sRES_t$	Share of wind and photovoltaics in TED	%	31.12	12.72	3.48	72.73

Note: The share of power electronics ($sRES_t$) is calculated using Equation 4.

Figure 3 shows the hourly (net) activated energy in redispatching in the day-ahead and differentiating between synchronous generation (Equation 2), generation made of power electronics (Wind and Photovoltaics) and Pumping Consumption.

Figure 3: Average hourly (net) activated energy in the day-ahead by technology (2019-2022).



Note: Positive values mean activated energy, while negative means curtailment. Pumping in negative values means higher activated. Source: own calculations.

Table 3 shows the annual volumes of activated and curtailed energy in the day-ahead by technology, as well as the annual costs paid by customers. Annual volumes of curtailed wind and photovoltaic production peak at 4953 and 405 GWh, respectively. In the case of wind, this equals to 8% of the annual scheduled production in the day-ahead. In synchronous generation, combined cycle and coal are mostly activated, while hydropower, CHP and pumping generators are curtailed. This shows that network operational constraints are time and spatial issues, and locations of combined cycle and coal plants fit better with the location of grid network constraints than other synchronous sources.

Table 3. Annual volumes of redispatched energy in the day-ahead and costs for customers. Source: REE (2024) and own calculations.

	Units	**2019**	**2020**	**2021**	**2022**
Annual electricity demand	GWh	249.900	237.205	243.862	235.437
Scheduled wind production in the day-ahead	GWh	58,454.3	61,797.6	66,170.4	63,667.5
Scheduled photovoltaic production in the day-ahead	GWh	7583.6	13,667.3	19,399.2	27,211.1
Scheduled combined cycle production in the day-ahead	GWh	37,505.7	24,591.8	19,472.3	46,950.8
Scheduled Coal production in the day-ahead	GWh	7330.1	1568.5	3106.9	7188.5
(Net) redispatched energy from combined cycle	GWh	+3019.5	+5361.2	+5767.8	+3639.0
(Net) redispatched energy from Coal	GWh	+2321.6	+2899.8	+1560.9	+607.4
(Net) redispatched energy from CHP	GWh	-622.1	-695.6	-775.9	-510.8
(Net) redispatched energy from Hydropower	GWh	-947.5	-972.1	-1579.8	-384.8
(Net) redispatched energy from Pumping Generation	GWh	-572.6	-458.2	-372.3	-160.6
(Net) redispatched energy from thermosolar	GWh	-0.7	-2.8	-29.4	-353.6
(Net) redispatched energy from synchronous generators	GWh	+3083.9	+5973.0	+4373.1	+2715.1
(Net) redispatched energy from Wind	GWh	-2,479.2	-4,952.7	-3,451.4	-1,352.8
(Net) redispatched energy from Photovoltaics generators	GWh	-0.7	-0.7	-405.1	-219.3
Economic cost	**M€**	**239**	**423**	**443**	**473**

Note: In (net) redispatched energy, positive values mean higher activated than curtailed energy, while negative the opposite.

Table 4 summarizes the annual scheduled production from Combined Cycle in the day ahead, as well as the redispatched energy with the corresponding gas consumption. It should be noted that the activated energy in this technology due to remedial actions exceeds 22% of the scheduled energy in 2020 and 2021.

Table 4. Main data associated to the Combined Cycle plants in Spain in the day-ahead (2019-2022). Source: own elaboration based on REE (2024) and OMIE (2024)

		Units	**2019**	**2020**	**2021**	**2022**
Scheduled generation	Energy	GWh	37.51	24.59	19.47	46.95
	Gas	Mm3 gas	4567.65	2994.93	2371.44	5717.94
Remedial actions	Energy	GWh	3.02	5.36	5.77	3.64
	Gas	Mm3 gas	367.74	652.92	702.44	443.18
Remedial actions vs scheduled		**%**	**8%**	**22%**	**30%**	**8%**

Note: Gas consumption is calculated using Equation 7. Mm3 means Million of m3.

Figure 4 plots how the (net) volumes of synchronous generation evolve with the total demand (TED_t) for each year. We find a negative correlation between the two variables, showing that volumes of redispatched energy at nights are higher when the load levels of lines are lower due to the surge impedance loading (SIL) effect described in Section 2.2. Figure 5 shows how the (net) volumes of energy activated from synchronous generators evolve with the RES ($sRES_t$) for each year.

Figure 4: Annual (net) volumes of energy activated from Synchronous generation ($r_{SYNCH,t}$) in vertical axis vs. total demand (TED_t) in horizontal axis for each year (2019-2022). Red line shows the fitted trend line.

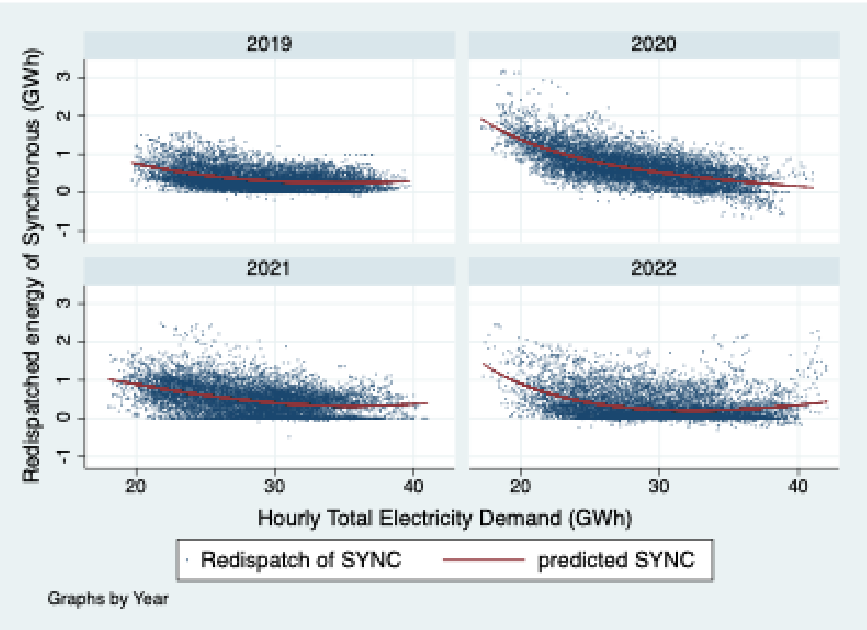
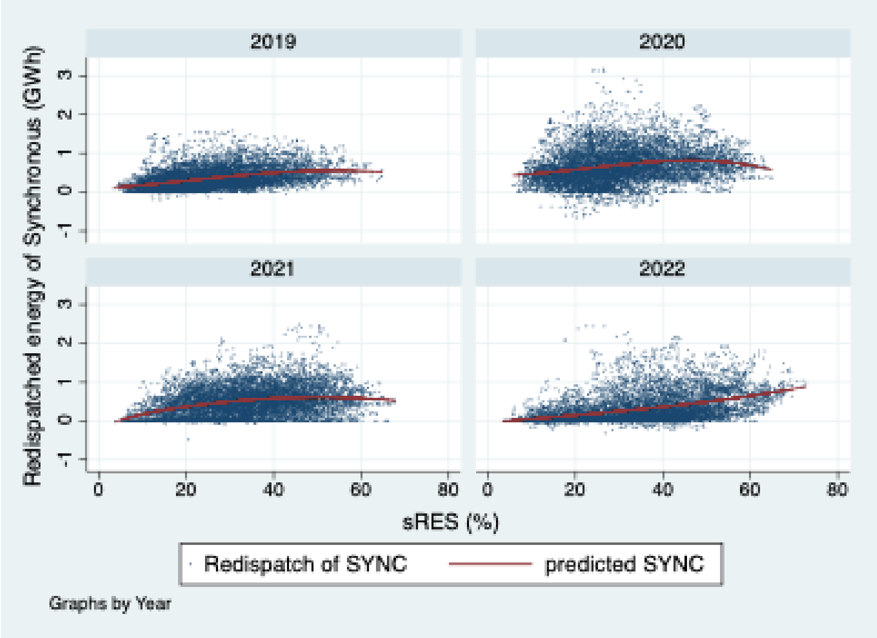


Figure 5: Annual (net) volumes of energy activated from synchronous generators ($r_{SYNCH,t}$) in vertical axis vs. RES ($sRES_t$) in horizontal axis for each year (2019-2022). Red line shows the fitted trend line.



5. Results

5.1. Costs of redispatching

In the Cost Model, we analyze the hourly costs of the energy activated and curtailed in the day-ahead to answer our first research question, relating to the costs of volumes activated. Endogenous variables are the hourly costs paid by customers and compensate the activated and curtailed generation units (Table 5). Hourly costs related to volumes activated in the day-ahead processes increase when the total demand decreases or the scheduled RES increase. Each additional scheduled MWh in the total demand (TED_t) reduces the costs of redispatching between 0.67€ and 2.63€. Moreover, one additional percentage point in the share of RES ($sRES_t$) increases the costs between 459.8€ and 1854.2€. In terms of energy, each scheduled MWh of RES increases the costs between 1.63€/MWh and 6.24€/MWh in average (Table 6). These costs include the activation of synchronous generators, and the curtailment of other generators keeps the system balanced (Figure 3). Note that the costs peaked during the 2022 gas crisis and were at their lowest during the covid pandemic, likely because of the minimum gas prices during this period.

In the Spanish regulatory framework, hourly redispatching costs are added to the hourly wholesale price paid by all suppliers. Consequently, redispatching costs increase the final price when the scheduled RES in the day-ahead increase, which might desincentivize consuming during the hours of maximum RES production.[8] Thus, it is essential to deep dive into their determinants to minimize potential welfare impacts.

[8] The wholesale price use to be minimum or close to zero when the RES production is maximum (Jamasb et al., 2024).

Table 5. Maximum Likelihood estimations each year

	2019	2020	2021	2022
	$\Delta r_{COST,t}$ **(Eq.1)**	$\Delta r_{COST,t}$ **(Eq.1)**	$\Delta r_{COST,t}$ **(Eq.1)**	$\Delta r_{COST,t}$ **(Eq.1)**
Total Demand (ΔTED_t)	-0.671****	-0.722****	-2.316****	-2.629****
	(0.137)	(0.0906)	(0.145)	(0.195)
Renewables $(\Delta sRES_t)$	635.8****	459.8****	1256.5****	1854.2****
	(101.6)	(51.06)	(70.62)	(76.55)
Holiday $(holiday_t)$	-86.71	-27.59	191.7	110.0
	(328.6)	(188.2)	(329.3)	(508.2)
Lagged $(\Delta r_{COST,t-1})$	0.0138	-0.0662****	0.0607****	0.107****
	(0.0122)	(0.00757)	(0.00604)	(0.00619)
Seasonality $(\Delta r_{COST,t-24})$	0.175****	0.470****	0.423****	0.400****
	(0.00166)	(0.00377)	(0.00452)	(0.00319)
Constant $(\widehat{\beta_0})$	9965.7****	9235.1****	14,280.8****	20,857.0****
	(4.118)	(24.66)	(34.20)	(40.55)
N	8734	8783	8759	8759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table 6. Average redispatching costs associated with scheduled volumes of RES.

	(1)	(2)	(3)	(4)
Year	$\overline{TED}_t$ (in MWh)	**1% of** $\overline{sRES}_t$ (in MWh)	$\Delta sRES_t$ **coefficients from Table 5** (in Eur/% RES)	**Cost** (in Eur/MWh of RES)
2019	29,045.35	290.5	635.8	**+2.19**
2020	28,173.42	281.7	459.8	**+1.63**
2021	28,341.88	283.4	1256.5	**+4.43**
2022	29,725.44	297.3	1854.2	**+6.24**

Note: Costs from column (4) represent the average costs for each year. They are calculated by dividing the coefficients from column (3) and column (2).

5.2. Activation of synchronous generation

In the Dispatch Model, we analyze the volumes of synchronous generation technologies activated in the day-ahead processes (see Table 7). The activated energy from synchronous generators follows the same pattern for each year: they increase when total demand decreases or the share of RES increases. Each additional scheduled MWh in the total demand (TED_t) reduces the activated energy in synchronous generation between 0.018 and 0.034 MWh. Moreover, one additional percentage point in the share of RES ($sRES_t$) increases the activated energy in all synchronous generators between 9.82 and 13.36 MWh. These results are very relevant because, as shown in Figure 3, additional activated synchronous generation implies additional pumping consumption and curtailment of RES to keep balanced the power system, i.e. total demand equals total generation. In other words, the activated energy in synchronous generators show the potential curtailment of RES.

Table 7. Maximum Likelihood estimations each year

	2019	2020	2021	2022
	$\Delta r_{SYNCH,t\ t}$	$\Delta r_{SYNCH,t\ t}$	$\Delta r_{SYNCH,t\ t}$	$\Delta r_{SYNCH,t\ t}$
	(Eq.2)	**(Eq.2)**	**(Eq.2)**	**(Eq.2)**
Total Demand (ΔTED_t)	-0.0181****	-0.0264****	-0.0335****	-0.0217****
	(0.000902)	(0.00131)	(0.00122)	(0.00129)
Renewables ($\Delta sRES_t$)	9.824****	9.821****	13.36****	12.54****
	(0.641)	(0.757)	(0.604)	(0.536)
Holiday ($holiday_t$)	1.966	0.289	-0.150	0.530
	(2.031)	(3.061)	(3.134)	(3.404)
Lagged ($\Delta SYNC_{t-1}$)	-0.0643****	-0.0520****	-0.0915****	0.0385****
	(0.00764)	(0.00861)	(0.00831)	(0.00674)
Seasonality ($\Delta SYNC_{t-24}$)	0.302****	0.350****	0.301****	0.246****
	(0.00654)	(0.00628)	(0.00682)	(0.00650)
Constant ($\widehat{\beta_0}$)	94.30****	137.6****	143.2****	142.1****
	(0.374)	(0.519)	(0.583)	(0.473)
N	8734	8783	8759	8759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

In the Technology Model, we analyze the determinants of the activated energy for combined cycle, coal, and CHP, which are the synchronous technologies with the highest volumes of activated energy. In Table 8, the activated energy for combined cycle follows the same patterns as the other synchronous generations (Table 7). The need for activating combined cycle ranges between 0.026 and 0.044 MWh for each MWh less of scheduled energy in the day-ahead. Related to the scheduled RES, they increase between 4.240 MWh to 12.28 MWh for each additional percentage point of RES in the day-ahead mix.

Table 8 Maximum Likelihood estimations for each year.

	2019	2020	2021	2022
	(Eq. 5)	**(Eq. 5)**	**(Eq. 5)**	**(Eq. 5)**
	$\boldsymbol{\Delta r_{CC,t}}$	$\boldsymbol{\Delta r_{CC,t}}$	$\boldsymbol{\Delta r_{CC,t}}$	$\boldsymbol{\Delta r_{CC,t}}$
Total Demand (ΔTED_t)	-0.0294****	-0.0260****	-0.0443****	-0.0321****
	(0.00113)	(0.00149)	(0.00139)	(0.00134)
Renewables ($\Delta sRES_t$)	7.841****	4.240****	7.944****	12.28****
	(0.699)	(0.843)	(0.654)	(0.511)
Holiday)	3.136	4.615	3.319	2.128
	(2.368)	(3.239)	(3.085)	(3.001)
Lagged ($\Delta r_{CC,t-1}$)	-0.0872****	-0.0542****	-0.0995****	-0.0204**
	(0.00918)	(0.00760)	(0.00922)	(0.00932)
Seasonality ($\Delta r_{CC,t-24}$)	0.480****	0.563****	0.562****	0.511****
	(0.00470)	(0.00357)	(0.00449)	(0.00428)
Constant ($\widehat{\beta_0}$)	112.8****	143.1****	144.8****	139.2****
	(0.393)	(0.343)	(0.506)	(0.477)
N	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

In Table 9, activated energy for coal follows different patterns than other synchronous generations (Table 7) and combined cycle (Table 8). Coal plants are only activated when the total electricity demand increases. This might be explained because in the peak hours many combined cycles are already scheduled, and TSO opts for this technology as the second-best option. The coefficient of the share of RES is only significant in 2021 and 2022, coinciding with the higher RES connected to the grid.

In Table 10, activated energy from CHP increases with the total electricity demand, but decreases with the share of RES in the generation mix. This explains that this technology is mostly curtailed to allocate volumes of activated combined cycle and coal, which might be explained by CHP locations are not optimal from the point of view of network operational needs.

Table 9 Maximum Likelihood estimations for each year.

	2019 (Eq. 6) $\Delta r_{CO,t}$	**2020 (Eq. 6)** $\Delta r_{CO,t}$	**2021 (Eq. 6)** $\Delta r_{CO,t}$	**2022 (Eq. 6)** $\Delta r_{CO,t}$
Total Demand (ΔTED_t)	0.00910****	0.0101****	0.00488****	0.00301****
	(0.000750)	(0.000693)	(0.000587)	(0.000454)
Renewables $(\Delta sRES_t)$	0.480	-0.630	0.709**	0.974****
	(0.434)	(0.390)	(0.287)	(0.172)
Holiday)	0.0170	-1.751	0.412	1.249
	(1.411)	(1.318)	(1.117)	(0.975)
Lagged $(\Delta r_{CO,t-1})$	-0.0787****	-0.118****	-0.0671****	-0.0682****
	(0.00992)	(0.00975)	(0.00712)	(0.00674)
Seasonality $(\Delta r_{CO,t-24})$	0.516****	0.511****	0.570****	0.450****
	(0.00481)	(0.00532)	(0.00405)	(0.00336)
Constant $(\widehat{\beta_0})$	66.28****	67.39****	54.99****	46.04****
	(0.192)	(0.256)	(0.130)	(0.109)
N	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table 10 Maximum Likelihood estimations for each year.

	2019 (Eq. 7) $\Delta r_{CHP,t}$	2020 (Eq. 7) $\Delta r_{CHP,t}$	2021 (Eq. 7) $\Delta r_{CHP,t}$	2022 (Eq. 7) $\Delta r_{CHP,t}$
Total Demand (ΔTED_t)	0.00713****	0.00734****	0.0119****	0.00776****
	(0.000311)	(0.000397)	(0.000426)	(0.000335)
Renewables $(\Delta sRES_t)$	-1.101****	-0.750****	-1.051****	-1.635****
	(0.222)	(0.226)	(0.218)	(0.140)
Holiday)	-0.490	-0.0492	-0.549	-0.323
	(0.777)	(1.050)	(1.194)	(0.869)
Lagged $(\Delta r_{CHP,t-1})$	-0.125****	-0.210****	-0.187****	-0.191****
	(0.00629)	(0.00581)	(0.00723)	(0.00647)
Seasonality $(\Delta r_{CHP,t-24})$	0.140****	0.142****	0.0884****	0.141****
	(0.00529)	(0.00638)	(0.00717)	(0.00600)
Constant $(\widehat{\beta_0})$	37.62****	54.62****	60.83****	45.29****
	(0.113)	(0.176)	(0.242)	(0.153)
N	8,735	8,783	8,759	8,759
Seasonality				
Month	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

5.3. Simulations for different scenarios

This section provides the results from the simulations detailed in Section 3.1 to answer the second research question, i.e. how this activated energy and costs could evolve in the future. In all the simulations, calculations include future values: total demand in 2022 (TED^0), the share of renewables in 2022 (RES^0), additional renewable production (ΔRES), additional need of synchronous generation ($\Delta SYNC$), additional energy activated from combined cycle (ΔrCC), additional energy activated from coal (ΔrCO) and additional energy activated from CHP ($\Delta rCHP$). Positive values mean higher activated energy, while negative values mean less activated energy. Moreover, we calculate the resultant CO2 emissions associated with energy activated from combined cycle, coal and CHP, and the gas consumption associated to the activations of combined cycle and coal. Finally, we calculate the costs associated to these actions ($\Delta Cost$), but considering estimations from 2022.[9] These costs include both the costs of gas and the corresponding CO2 emissions because the owners of non-scheduled generators in the day ahead markets should bid in the redispatching processes (MITECO, 2019; CNMC, 2022).

Table 11 shows the results for all the scenarios. Related to the connection of wind and photovoltaics, the additional RES production (ΔRES) are similar as the annual wind and photovoltaic production is nearly the same. However, the need for synchronous generation ($\Delta SYNC$) differs between 792 TWh for photovoltaic vs. 928 TWh for wind. This is explained because photovoltaic production is made during the highest total electricity demand, while wind

[9] The spot prices in 2022 peaked and so could redispatching actions. However, we consider 2022 as the year reflects the last grid commissioned cables, generators, and consumers, which clearly constraints the need for redispatching actions. In Tables 11 to 18, total redispatching costs ($\Delta Cost$) are mostly lower than the sum of the cost of gas (Δgas) and CO2 emissions ($\Delta CO2$) in many cases. This is explained because since the Iberian exception was implemented during this period and the wholesale price was partially decoupled from gas prices in the international markets. The Iberian exception was a price cap mechanism to limit the impact of the gas on the electricity markets (Jamasb et al., 2024).

production is also important at night (off peak time) (see Figure 2). These results are relevant and highlight that some RES used to replace pollutant technologies (and decrease gas consumption) should be later curtailed and replaced by these pollutant technologies to address network operational constraints. For wind, this effect is even higher as their production profile is not well correlated with total demand peaks. This also affects the resultant CO2 emissions and gas consumption. In terms of gas consumption, installing 10GW of photovoltaics and wind results in extra gas consumption of 81.89 and 95.94 Mm3/year, respectively. In terms of costs for customers, they increase with 117M€/year for photovoltaic and 137M€/year for wind. Costs of gas consumption increase with 98M€/year for photovoltaic and 105M€/year for wind.

Table 11. Results for each scenario

Scenario	$\boldsymbol{TED^0}$ **(TWh)**	$\boldsymbol{RES^0}$ **(TWh)**	$\boldsymbol{\Delta RES}$ **(TWh)**	$\boldsymbol{\Delta SYNC}$ **(GWh)**	$\boldsymbol{\Delta rCC}$ **(GWh)**	$\boldsymbol{\Delta rCO}$ **(GWh)**	$\boldsymbol{\Delta rCHP}$ **(GWh)**	**ΔCO2 (kTn)**	**ΔGas (Mm3)**	**ΔCO2 (MEur)**	**ΔGas (MEur)**	**ΔCost (MEur)**
Photovoltaics (+10GW)	260.39	112.45	+21.57	**+792.12**	+775.69	+61.52	-103.28	**+282.93**	**+81.89**	+22.74	+97.80	**+117.12**
Wind (+10GW)	260.39	112.45	+21.57	**+928.04**	+908.80	+72.08	-121.00	**+331.48**	**+95.94**	+26.42	+105.45	**+137.22**
Gener behind the meter (+10GW)	260.39	236.91	-24.48	**+991.45**	+1225.66	-33.36	-245.04	**+291.91**	**+119.42**	+23.47	+142.23	**+132.99**
Electric Vehicle at peak hours (+10GWh/year)	260.39	282.28	+21.89	**-679.44**	-902.86	+50.12	+196.52	**-184.68**	**-86.02**	-14.77	-99.32	**-87.78**
Electric Vehicle at offpeak hours (+10GWh/year)	260.39	282.28	21.89	**-707.91**	-930.73	+47.91	+200.23	**-194.85**	**-88.96**	-15.58	-102.19	**-91.99**
Energy efficiency (-10GWh/year)	260.39	172.79	-87.60	**+3882.17**	+4752.13	-110.23	-938.10	**+1154.53**	**+464.49**	+92.19	+527.70	**+523.25**
Higher consumption (+10GWh/year)	260.39	347.99	87.60	**-2852.50**	-3743.81	+190.20	+803.85	**-786.74**	**-358.05**	-62.90	-412.27	**-371.0**
Peak shaving (-5%)	260.39	257.91	-2.489	**+97.43**	+122.43	-4.13	-24.98	+28.21	**+11.87**	**+2.26**	+13.78	**+12.96**

Related to the installation of generation capacity behind the meter also known as self-consumption, the total demand (TED^1) decreases, which implies a need for additional synchronous generation ($\Delta SYNC$) of 991 GWh/year. Moreover, most of the activated energy is combined cycle, while energy activated for coal and CHP decreases. This lower activated energy might be explained by less need for combined cycle in the day-ahead scheduled energy. In terms of CO2 emissions, installing RES generation behind the meter increases power system emissions of +292 kTn/year. In terms of gas consumption, there is a need for additional gas of 119 Mm3/year. In terms of costs to customers, they increase to 133 M€/year. In summary, a program aimed at reducing the CO2 emissions and gas imports also increases the issues related to network operational limits and their costs. These results are very relevant for the design of programs aimed at subsidizing the installation of small generation capacity behind the meter.

Related to charging the EV during the peak and off-peak hours, respectively. The positive impacts on synchronous generation, CO2 emissions and gas consumption are very similar. However, increasing the electricity demand in the peak time is less efficient than in the off-peak time: the need for synchronous generation decreases with 708 compared to 679 TWh/year. In terms of costs for customers, redispatching costs are reduced by 92M€/year compared to 88M€/year, which represents another positive externality. All these results show that the performance of the power system is more optimal when the electricity demand is made in the off-peak hours. These savings should be considered when countries design the time periods on Time-of-Use Tariffs (ToU) considering the operational needs.

Impacts associated to higher and lower demand during all hours of the day are not symmetric: the need of synchronous generation associated to a higher demand is -2,853 GWh/year, while +3,882 GWh/year for a lower demand. In terms of costs for customers, savings range up to -371M€/year, while costs go up to 523M€/year. These results complement the previous ones and highlight that decreasing the total electricity consumption is less efficient because of the need for more synchronous generation to solve network operational constraints. Indeed, the Spanish volumes of emissions related to redispatching peaked during the covid-19 lockdown (Davi-Arderius and Schittekatte, 2023).

Finally, the implementation of peak shaving products to reduce 5% of the total demand for four hours reduces the annual demand by 2,489 GWh, but also increases the need of synchronous generation by +97.43 GWh for the same period. In terms of costs for customers, they increase up to +13M€/year. All these results highlight that peak shaving products might not provide all the expected savings in gas consumption and these inefficiencies should be considered in their design. These additional costs are directly paid by customers and trade-off other expected potential savings.

6. Conclusions and regulatory recommendations

This paper shows that demand profiles and the participation of RES in the mix affect the system operational needs. Higher shares of RES require activating polluting synchronous generators to solve these operational needs, which implies relevant costs for customers and subsequent curtailment of RES to keep the system balanced. These volumes depend on hourly electricity demand and the share of RES scheduled in the day-ahead.

When these results are used to simulate how these volumes might evolve in the future, we find that changes in the hourly demand have a clear impact on them. In consequence, benefits from programs aimed at replacing pollutant technologies, reducing CO2 emissions, reducing gas imports might differ from those expected in advance. Moreover, the potential benefits associated with wind are higher than photovoltaic due to its lower correlation with the electricity demand. Our results show that network operational constraints must be considered in the design of these programs as an additional cost in the cost benefit analysis. We are not suggesting that RES should not be implemented, but that their expected welfare improvements should consider their impact on the network operational constraints.

Simulations provide important insights on how to reduce volumes of activated polluting plants in the future: (i) electricity demand should increase in the current off-peak hours over the peak hours, and (ii) the correlation between demand and RES should improve. Both issues can be incentivized through ToU with lower charges in off-peak hours, which would provide time incentives. However, efficiency of ToU might be neutralized if suppliers offer flat tariffs to customers, which means the same tariff regardless of time of consumption. This also neutralizes the hourly incentive from the day-ahead spot markets when prices decrease up to zero when there is a surplus of RES production, and peaks when there is a deficit. As an intermediate solution, it should be evaluated potential benefits from considering different tariffs for each period, i.e. peak/off-peak hours, or work/weekends. This is technically feasible with the current smart meter solutions. However, its social acceptance may be low, and decision-makers might be reluctant to implement it. There are additional complementary recommendations and solutions to minimize the volumes of activated energy.

First, system operators should devise efficient grid operation strategies to predict future network operation constraints. The best approach is an efficient coordination of diverse actions in the long-term: grid planning criteria, technical capabilities for new RES, setting optimal location of new RES, implementing specific ancillary services, designing ToU tariffs or setting economic incentives for reactive energy. In this context, system operators should perform ex-post studies to assess scenarios related to the decarbonization. This analysis shows that relevant results can be obtained from empirical analysis of the past grid operation data.

Second, grid planning analysis related to the location of RES should go beyond the forecast of future grid bottlenecks and consider its impacts on network operational constraints. As network constraints depend on specific grid locational characteristics (lines, transformers, consumers, generators), some locations for new RES might be more optimal than others. In consequence, locational regulatory incentives for RES might be considered such as locational RES auctions or defining additional grid capacity for hosting new RES in some areas over others.

Third, the need to incentivize innovative power electronics such as grid-forming whose capabilities are closer than replaced synchronous generators. However, this technology should be gradually implemented to identify potential unforeseen operational problems, especially when different power electronic technologies coexist in the same network.[10] Innovative projects could be devised to test these impacts at small scale.

[10] It is essential to study potential oscillation problems when old and new power electronic technologies are closely connected and are producing at the same time. As solution, grid operators should perform complex dynamic analysis in advance.

Fourth, maintaining the voltage system within predetermined thresholds requires that consumers and generators do not inject reactive energy to the system when there is a surplus of reactive energy, or inject when there is a deficit of reactive energy. The surplus of reactive energy produces over-voltages, while deficits produce under-voltages. As a solution, consumers and generators can be given time related economic incentives in their tariffs. However, the efficiency of this regulatory instrument is limited as to when customers or generators should make investments.

Fifth, the possibility to install grid devices to minimize the need to start specific synchronous generators such as synchronous compensators, reactances, capacitors or STATCOM. Its installation might be done under two different schemes: they can be built by the TSO/DSO and funded by tariff charges or built by private investors and funded through the procurement of specific ancillary services. If they are built by TSO/DSO, they should be included in the grid investment plans. However, if the assets are built by private investors, their building costs might be lower. The procurement of these ancillary services should be done under long-term procurement to provide efficient signals for long-term investments. Under short-term procurement, economic incentives to make these investments are lower. In any case, the decision to either install these assets or procure long-term flexibility services should be taken in advance to prevent delays in the connection of new RES.

Sixth , the assessment of additional needs on voltage control services when new grid infrastructure is built, i.e. high voltage underground line. It seems contradictory to connect new cables that increase the need for voltage control services and at the same time, replace synchronous generators that provide these services with RES. As an intermediate solution, some projects of new high voltage lines should also include the commissioning of specific devices to control voltage such as STATCOM or reactances. For the longer underground transmission lines, high voltage direct current (HVDC) is a good solution, but their costs might be a barrier.

Seventh, inertia can be increased with synchronous condensers, which might be made of the generator devices from phased-out polluting plants coupled to the grid. These generators do not produce active energy, but they take advantage of the inertia of their rotor. However, there is not enough experience in this field. As a solution, regulatory frameworks should set efficient economic incentives for pilot projects and analyse its technical feasibility. Economic compensation for this solution can be offered through specific ancillary services.

Eight, the massive development of generation behind the meter, namely self-consumption, might challenge the operation of the power system and create additional emissions and costs associated to these volumes. This might highlight that this policy might be regressive as the wealthiest consumers can afford this investment in their homes, but all the rest of the customers should pay additional costs related to the operational needs.

The Spanish case anticipates similar scenarios in countries that are making heavy efforts to decarbonize their mix. The magnitude of the challenge aggregated across the EU is much larger. Our main conclusion is that solving grid congestion is a necessary, but not sufficient condition for an efficient integration of RES. Further research is needed to analysis the remedial actions discussed also in real-time. A more detailed analysis of the activated units could provide useful locational information on potential network operational constraints.

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Appendix A

For each scenario, we calculate the activated synchronous generation ($SYNC_t$), and activated energy for combined cycle ($r_{CC,t}$), coal ($r_{CO,t}$) and CHP ($r_{CHP,t}$). Moreover, we calculate the corresponding gas consumption (gas_t) associated with the activated energy for Combined Cycle and CHP. Finally, we find the (net) additional CO2 emissions associated to these actions ($CO2_t$) and their economic costs. The process consists of the next steps:

- **Step 0:** The starting point consists of the hourly total electricity demand (TED_t^o) and share of renewables ($sRES_t^o$).[11]

- **Step 1:** For each hour, we calculate the new hourly total electricity demand (TED_t^1) and the change in the total electricity demand (ΔTED_t). This step is not followed in the Scenarios related with the connection of photovoltaic and wind using Equation A.1.

$$\Delta TED_t = TED_t^1 - TED_t^0 \tag{A.1}$$

- **Step 2:** For each hour, we calculate the change on the share of renewables ($\Delta sRES_t$) using the Equation A.2:

$$\Delta sRES_t = RES_t^1 - RES_t^0 = \frac{RES_t^1}{TED_t^1} - \frac{RES_t^0}{TED_t^0} \tag{A.2}$$

  where the new hourly share of renewables ($sRES_t^1$) is calculated as follows:[12]
  - For scenarios photovoltaic and wind, $sRES_t^1$ corresponds to the new share of renewables considering the additional capacity. Therefore, $\Delta sRES_t > 0$
  - For the other scenarios:
    - If $TED_t^1 > TED_t^0 \rightarrow$ additional demand is covered by synchronous generators, thus $s\Delta sRES_t < 0$.
    - If $TED_t^1 < TED_t^0 \rightarrow$ Lower total demand reduces production by synchronous generators, thus $\Delta sRES_t > 0$.
    - If $TED_t^1 = TED_t^0 \rightarrow \Delta sRES_t = 0$.

- **Step 3:** For each hour, we calculate the changes on the activated energy for synchronous generation ($\Delta SYNC_t$) using the estimates $\hat{\beta}_2$ and $\hat{\beta}_3$ from Equation 2 (2022) in Table 7. In other words, this additional synchronous generation means curtailing an equivalent production from power electronics (wind and photovoltaics) to keep the system balanced.

$$\Delta SYNC_t = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{A.3}$$

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[11] In the Scenario Photovoltaic and Wind, the assignment of additional RES production at each hour is made considering the hourly production profile and estimated annual production for each technology. For both technologies, we consider an annual production based on the average production for Spain: 2.08 GWh by each installed MW for photovoltaics, and 2.16 GWh by each installed MW for wind (Davi-Arderius and Schittekatte, 2023).

[12] This criterion is based on the principles that photovoltaics and wind bid at very low marginal price. Therefore, they are always included in market clearing. For each hour, the new hourly share of RES ($sRES_t^1$) is calculated using the existing hourly RES production ($sRES_t^o$) for 2022.

- **Step 4:** For each hour, we calculate the activated energy for combined cycle ($\boldsymbol{r_{CC,t}}$), coal ($\boldsymbol{r_{CO,t}}$) and CHP ($\boldsymbol{r_{CHP,t}}$) using the estimates $\hat{\beta}_2$ and $\hat{\beta}_3$ (2022) from Tables 8 to 10. See Equations A.4 to A.6.

$$\Delta \boldsymbol{r_{CC,t}} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{A.4}$$

$$\Delta \boldsymbol{r_{C0,t}} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{A.5}$$

$$\Delta \boldsymbol{r_{CHP,t}} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{A.6}$$

- **Step 5:** For each hour, we calculate the additional gas consumption (Δgas_t) associated to Combined Cycle and CHP redispatching processes and its cost. See Equations A.7 and A.8.

$$\Delta gas_t = \frac{\Delta \boldsymbol{rCC_t} + \Delta \boldsymbol{rCHP_t}}{0.7 \cdot 0.0117} \tag{A.7}$$

$$\Delta Cost\_gas_t = Auction_{gas,t} \cdot \Delta gas_t \cdot 0.0117 \tag{A.8}$$

where 0.7 is the efficiency rate of the Combined Cycle and CHP technologies, and 0.0117 is the ratio (MWh/m3 of gas) (DGPEM, 2022). $Auction_{gas,t}$ corresponds to the daily price of the Daily Product in the Spanish zone (Eur/MWh) (MIBGAS, 2023).

- **Step 6:** For each hour, we calculate for the (net) additional CO2 emissions ($CO2_t$) related to the activated and curtailed generation from combined cycle, coal, and CHP. Clearly, $CO2_t$ can be positive or negative, depending on the activated and curtailed generation technologies in the hour. [13] We also calculate the corresponding daily costs of the emission based on the CO2 auction ($Price\_CO2_t$) (in Eur/tn) (EEX, 2023). See Equations A.9 and A.10.

$$\Delta CO2_t = 0.34 \cdot \Delta r_{CC,t} + 0.95 \cdot \Delta r_{CO,t} + 0.38 \cdot \Delta r_{CHP,t} \tag{A.9}$$

$$\Delta Cost\_CO2_t = \Delta CO2_t \cdot Price\_CO2_t \tag{A.10}$$

- **Step 7:** For each hour, we calculate the costs from activated energy ($\boldsymbol{r_{COSTS,t}}$) using estimates from Equation Table 6. See Equation A.11.

$$\Delta \boldsymbol{r_{COSTS,t}} = \hat{\beta}_2 \cdot \Delta TDEM_t + \hat{\beta}_3 \cdot \Delta sRES_t \tag{A.11}$$

[13] The CO2 emission factors considered are 0.95 tn CO2/MWh for coal, 0.37 tn CO2/MWh for combined cycle, 0.38 tn CO2/MWh for CHP and 0.24 tn CO2/MWh for biomass plants. Source: REE (2021).