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Carbon emissions impacts of operational network constraints: The case of Spain during the Covid-19 crisis

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ABSTRACT

Operating a highly decarbonized power system is technically complex and introduces novel challenges for system operators. To this effect, the hourly day-ahead market schedule must be compliant with all the network security criteria. If required, specific generators should be curtailed or started up after the market clearing via so-called redispatching actions. In this paper, we analyze the bias in emissions intensity of electricity generation that result from not internalizing grid operational limitations in the day-ahead market clearing. In other words, we investigate the incremental emissions resulting from actions by system operators to make the day-ahead market schedule physically feasible. We use hourly data from the Spanish power system between 2019 and 2021. We estimate that while redispatching actions accounts for 2–4% of total annual electricity demand, they represent 6–11% of the annual power sector's CO2 emissions. We find that volumes of fossil generators started up for network security reasons by system operators increase in hours during which the share of renewables in the supply mix is relatively high but, additionally, show that volumes also significantly increase during hours with low energy demand, as during the Covid-19 crisis. These latter actions are not triggered to alleviate grid bottlenecks, but to solve location-specific operational constraints requiring a minimum volume of synchronous generators always running. Because of these actions, we estimate that the emissions from the day-ahead market schedule are downward biased between +0.00391 and + 0.0145 tn of CO2 for each additional MWh of scheduled wind or photovoltaics. We offer several recommendations to better align the day-ahead schedule with the grid operation needs leading to a reduced need for redispatching actions.

1. Introduction

In many places around the globe the share of power generated by intermittent renewable energy sources (RES) is increasing. Merely connecting RES to the power grid does not always imply that all the generated clean electricity will finally be delivered to end consumers. The power grid, acting as an interface between generation and demand, is a complex system constrained by physical laws. A common feature of many power systems is that the replacement of conventional technologies by RES entails significant changes in the patterns of electricity flows through the grid (Costa-Campi et al., 2021). RES are often located relatively far away from load centers, have different production profiles than thermal generators, and displace the production from synchronous generation traditionally used to support the voltage system or to provide inertia (National Grid ESO, 2021; Capitanescu, 2021; Makolo et al., 2021). As often network development lags behind the deployment of RES, RES generation increasingly needs to be curtailed to avoid the violation of network elements and endanger the operation of the power grid (ACER and CEER, 2022).

There exist several power market design options that determine to what extent the scheduled electricity production and demand after the day-ahead market clearing will respect the physical limits of the power grid. In the European Union (EU) a zonal pricing model is applied to wholesale electricity markets. Zonal pricing implies that when trading

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electricity, the network within a bidding zone is considered a copper plate; only thermal network congestions between bidding zones are considered when clearing the pan-European markets at the day-ahead stage.[1] Bidding zones often coincide with the territory of a country. As the simplified representation of the network in the market clearing becomes harder to respect, transmission system operators (TSO) and the distribution system operators (DSO) (hereafter, system operators) increasingly require alterations of the dispatch after the day-ahead market clearing to avoid any network security violation. This is especially true in the case of large bidding zones. These measures are known as redispatching, and their costs are socialized over the consumers within each bidding zone. An alternative to zonal pricing is a nodal pricing model, in which the network elements at the transmission level are internalized in the day-ahead (and real-time) market clearing and, no, or at least a lot less, corrections of the dispatch after the market clearing are required to resolve thermal network congestions. The consideration of all thermal network limits in the market clearing might not suffice to always obtain a feasible dispatch after the market clearing. Power quality can still be impacted by local voltage issues or a lack of system inertia, unless the relevant constraints are also explicitly considered in the market clearing.

In the academic literature, several theoretical and empirical analyses study how uncoordinated RES deployment might result in the creation of grid bottlenecks, i.e., thermal limits of the networks (Schermeyer et al., 2018; Costa-Campi et al., 2020; Davi-Arderius et al., 2023b). Other studies explore how the deployment of RES impacts the volumes of redispatched energy (Staudt et al., 2018), redispatch costs (Joos and Staffell, 2018; Schermeyer et al., 2018; Petersen et al., 2022), voltage issues (Meegahapola et al., 2020), and system rotational inertia (Mehigan et al., 2020). In this paper, we empirically assess the determinants of the redispatching actions and the corresponding CO2 emissions associated to these processes for a case study of Spain between 2019 and 2021, including the Covid-19 lockdown period. Savelli et al. (2022) published a recent work that is related to our paper. They show for a case study in Great Britain using data between August 2020 and January 2021 how the location of newly installed RES impacts marginal redispatch costs and replaced emissions. They use a simulation model and focus on a proposal concerning improved long-term contracts for RES that better internalize redispatch and balancing costs. In contrast to that paper, we focus exclusively on redispatch-related emissions and study these in greater detail.

Concretely, the research questions we explore in this paper are:

(i) What is the bias in terms of CO2 emissions from actions by system operators to make the day-ahead market schedule physically feasible, i.e., how much emissions would have been avoided in case the Spanish network would have been able to always accommodate all day-ahead scheduled generation?
(ii) What are the drivers of incremental emissions compared to the day-ahead schedule introduced through the actions taken by system operators?
(iii) How much does the bias in emissions increases per MWh of additional RES production in the day-ahead schedule?

We do not want to imply that completely avoiding any RES curtailment is the most cost-efficient solution from a system perspective, but our analysis is relevant as it gives an idea of how the current day-ahead market design ignores physical realities that have an important emission impact.[2] Also, emission estimates from these actions can inform studies analyzing the benefits of investments aiming at mitigating grids constraints. Up to our knowledge, the potential bias on the emissions of the day-ahead market clearing have not been analyzed yet.

The zonal setup of the power market in the EU allows us to answer our research questions without the need for any additional information other than the hourly day-ahead schedule of the Spanish bidding zone, the final physical schedule of the same bidding zone per market time unit, and the amount of CO2 emitted per MWh per power plant active in Spain. We obtain this data from the Spanish market operator, namely OMIE, and the Spanish TSO, namely Red Eléctrica de España (REE), for the period between 2019 and 2021. To provide answers to the second and third research question our empirical approach is a seasonal ARIMA time-series estimator (SARIMA), where variables are differentiated to ensure their stationarity. A lagged endogenous variable and a seasonal component are included to capture the time dynamics.

Spain is an interesting case study for four reasons. First, due to its high share of RES in the gross annual electricity consumption (48.4% in 2021) (REE, 2022). Second, due to the fact that the Iberian peninsula is an "energy island"; the commercial exchange capacity with France and Morocco is limited and the interconnections between Spain and Portugal are rarely fully utilized (IEA, 2021).[3] As the whole territory of Spain is covered by one large bidding zone, the limited interconnection of the bidding zone across the Pyrenees makes it possible to isolate the impact of changes in the national generation mix on internal grid bottlenecks and subsequent redispatch actions, which are not aggravated by the need for redispatch to preserve cross-zonal exchanges. Third, annual volumes of redispatched energy peaked during the Covid-19 lockdown in 2020 which requires further investigation (REE, 2020, 2021a). Fourth, up to our knowledge, redispatching processes in Spain have been little explored in the literature (Petersen et al., 2022). The results for Spain can be of interest for other power systems that are being decarbonized but at a slower pace.

The paper is divided into five sections. In Section 2, we provide more technical background to redispatch processes and discuss the current regulatory framework that is in place in the EU around redispatch. In Section 3, we introduce the dataset, provide descriptive statistics, and lay out the empirical approach. In Section 4, we provide the results and present a discussion. We end with a conclusion.

2. Redispatching: technical and regulatory background

This section is split in two parts. First, we provide a technical description of the remedial actions taken on the day-ahead market schedule by the system operators, namely redispatching. After, we describe the current regulatory framework that is in place in the EU and in Spain specifically.

[1] In case flow-based market coupling is implemented, as in the CORE region in the EU, also internal network elements which have a significant impact on cross-zonal trade (so-called critical network elements) are explicitly considered in the market clearing. The CORE region comprises 13 countries: Austria, Belgium, Czechia, Croatia, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

[2] We do not analyze the emission impacts of an inefficient dispatch resulting from a zonal clearing followed by redispatch actions. Such exercise would require the simulation of a first-best nodal dispatch which goes beyond the scope of this paper but is an interesting avenue for future research.

[3] The commercial capacity between Spain and France is 2800 MW, the capacity between Spain and Morocco is 900 MW in the Spain-Morocco direction and 600 MW in the Morocco-Spain direction. The interconnections with Portugal are rarely congested (5% estimated by IEA (2021)). This is not necessarily because of the size (2300 MW in 2019) but rather because of the coincidence of generation and demand patterns. As such, we expect that few redispatch actions were needed to preserve cross-zonal exchanges.

2.1. Technical background

Electricity systems are made of networks that connect generators with end consumers. Operating this system is particularly complex because several technical security constraints must be always met: (i) the sum of the generated energy and imports should be equal to the sum of the consumed energy, exports and electricity losses at each time,[4] while storage is (at least today) limited to few hydro storage plants; (ii) each network asset (cable, transformer, substation…) should be operated under their thermal and voltage limits,[5] while alternating current (AC) flows are hard to control, and; (iii) operational security criteria should be fulfilled. Operational security criteria include the reservation of a minimum of generators able to provide near real-time ancillary services such as balancing, having a dispatch in place robust against the failure of a network element (N-1), and always having minimum level of inertia present in the system.[6]

With an increasing penetration of RES, active energy flow patterns through networks change and become more variable within a day and between seasons, often leading to thermal congestions as networks are not necessarily as rapidly expanded as RES is deployed (Janda et al., 2017). In operating terms, RES displace the production from synchronous generators, which historically provided the locational voltage support and inertia to the power system (Mehigan et al., 2020; National Grid ESO, 2021; Davi-Arderius et al., 2023a). In Annex I we provide more technical background about both issues. Accounting for carbon reductions when replacing conventional plants with RES is non-straightforward due to two not entirely mutually exclusive reasons: (i) the timing, i.e., one MWh of RES might replace one MWh of thermal generation during one moment but during another moment there might be abundant generation and excess of RES production, and (ii) the location, i.e., optimal locations for RES (e.g., windy or sunny areas) are not necessarily the same as conventional plants (close to a mine coal or river) and typically not close to load centers. As such, RES generation might lead to a violation of grid security limits and not all its production can be delivered to consumption centers. In this paper, we focus on the second point. The first point is internalized in the market clearing in a zonal system, i.e., as long as there is more demand within the bidding zone than zero marginal cost RES generation in the same market time unit, no RES will be curtailed in the day-ahead market clearing for that market time unit.[7]

Fig. 1 provides an overview of the day-ahead scheduling process in Spain, in which redispatch plays an important role as in most of the European countries. This process is divided into three main stages. The exact timing of the different steps might slightly differ from one Member State to another. The aim of Stage 1 is the provision of an economically efficient market schedule (EEMS) per bidding zone for each hour of the next day before 13 h30. This schedule includes the electricity generation and imports cleared in the day-ahead market, a pan-European auction held at noon the day before delivery organized by the nominated electricity market operator (NEMO) (for more detail see Schittekatte et al., 2021), and the data regarding the execution of bilateral contracts with physical dispatch of energy. In the EEMS, the sum of energy generated equals to the sum of energy consumed.[8]

In Stage 2.1, the system operators validate whether the EEMS is also technically feasible, which means verifying whether all the technical security constraints are respected. If not, the system operators must change their grid topology (so-called non-costly remedial actions), i.e., switch lines or transformers, and if that is not enough, then specific generators, consumers, or hydropower storage are redispatched. Art. 2 (26) of the Electricity Regulation (EU) 2019/943 formally 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). In Spain, the redispatching needs by DSO should be notified to the TSO who is entitled to perform the redispatching actions. As the schedule of several grid users is altered in Stage 2.1 and the sum of supply and demand always needs to match, the energy gap, i.e., a deficit or surplus of generation, is addressed in Stage 2.2.

Finally, in Stage 3 the economically and technically feasible schedule (EFTS) is obtained before 14 h45. As intraday trading is allowed after the EFTS, unvoluntary deviations from the day-ahead positions are possible (which are solved via near real-time balancing markets), or unforeseen failures of lines can occur, there might be the need for additional redispatch after Stage 3. However, the volumes of additional redispatch are typically significantly lower than in Stage 3. REE reports that the redispatched energy in the real time accounted about 3.9%, 9.9% and 22.6% of the total redispatched energy in 2019, 2020 and 2021, respectively (REE, 2020, 2021a, 2022).[9]

In Spain, the technical security constraints are defined in a specific national regulation (MICT, 2016). Table 1 shows the main data relevant to the redispatched energy from Stages 2.1 and 2.2 between 2019 and 2021. It is important to note that redispatched volumes of energy reached the highest observed levels during the corona lock down in 2020, although the annual electricity demand substantially decreased in this period. Precisely, ACER and CEER (2022) report that in 2020 Spain had the third highest volume of redispatched energy in the EU after Germany and Poland. In terms of redispatching costs, as defined by ACER and CEER, Spain ranks second after Italy.[10]

2.2. Regulatory framework

Electricity Regulation (EU) 2019/943 mandates in Article 13 that the redispatching of generation or demand response should be based on objective, transparent and non-discriminatory criteria. Moreover, downward redispatch of RES or high-efficiency cogeneration should be as minimum as possible to limit costs and emissions. Importantly, in the same Article 13 it is also stated that the provision of redispatch shall be organized using market-based mechanisms, shall be financially compensated, and shall be open to all technologies, storage devices or

[4] Electricity losses include: (i) technical losses are defined as the energy lost in the own electricity infrastructure due to a physical phenomenon, and (ii) commercial losses are defined as the unmetered consumption or fraud (Costa-Campi et al., 2018).

[5] The thermal limit corresponds to the maximum temperature that any electrical asset -cable or transformer- can operate under normal conditions. This operating temperature depends on the electricity flows through it, which heats the asset due to electricity losses, and the local weather conditions. A voltage limit corresponds to the maximum operating voltage for any electrical asset.

[6] Inertia corresponds to the energy stored in large rotating generators that gives them the tendency to remain rotating. When a large power plant is disconnected, this stored energy delays the subsequent frequency drop which allows for other resources to respond and avoid a blackout (Denholm et al., 2020).

[7] An exception can be when rather inflexible generation, e.g., nuclear, bids negative prices to remain dispatched ahead of zero marginal cost renewables. See also the discussion in Section 3.2.

[8] Scheduled exports are considered as consumption, while the scheduled imports as generation.

[9] The Spanish TSO does not provide any explanation about this increasing redispatched energy in real time. However, the quality of supply worsened significantly in 2021 compared to 2020: the non-supplied energy in the transmission grid increased from 95 to 188 MWh, and the average time of interruption increased from 0.21 min to 0.41 min per year.

[10] In terms of total costs for remedial actions Germany surpasses Spain. A significant amount of costs for remedial actions in Germany are classified as 'other costs' described as costs for network reserves (including both availability and activation payments) and RES curtailment compensations.

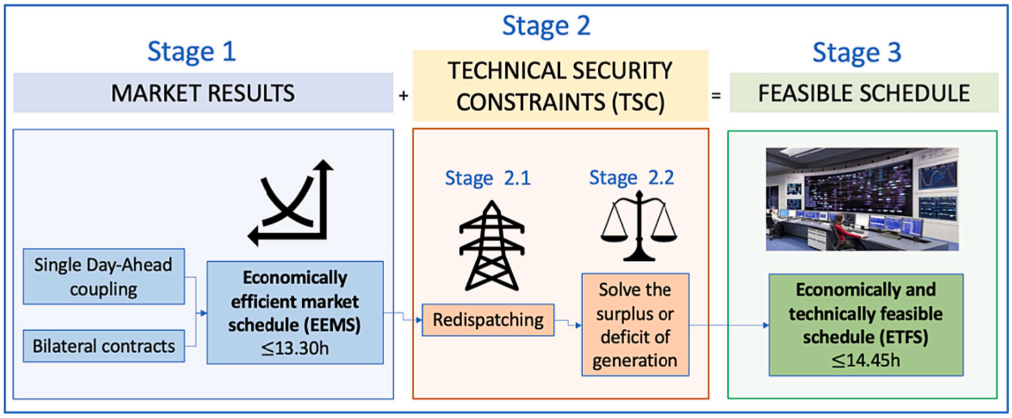

Fig. 1. Sequential processes in the day-ahead market to have an economically and technically feasible schedule (ETFS) made of generation, consumption, and hydro storage plants. Source: own elaboration.

Table 1
Redispatched energy and costs from the Stage 2 (Fig. 1) in the Spanish electricity system. Source: Own calculations, based on our dataset and REE (2020, 2021a, 2022).

	Units	2019	2020	2021
Annual electricity demand	GWh	249,257	236,755	242,492
Redispatched Energy	GWh	7058	9979	8042
	(% total)	(2.83%)	(4.21%)	(3.32%)
Costs from the redispatched energy	M€	239	423	443
	€/MWh	1.00	1.79	1.83

Note: Redispatched energy corresponds to the sum of the upward and downward energy redispatched in Stage 2.1, while the costs include both the Stage 2.1 and 2.2. Redispatched energy in real time is not included.

demand response. Non-market-based redispatching is only allowed if not enough competition can be guaranteed.

Even though mandated by Electricity Regulation (EU) 2019/943, as far as the authors are aware, market-based redispatching is still not to the same extent applied in all EU Member States (European Commission, 2019a). A relevant paper is the work by Poplavskaya et al. (2020). In that paper the redispatching regimes of TSOs in three countries are compared: Germany, France, and the Netherlands. Poplavskaya et al. (2020) explain that there is no universally established procurement mechanism for redispatch energy. Germany applies cost-based redispatch, France procures redispatch energy jointly with mFRR/RR balancing services, and in the Netherlands a separate redispatch market was created. Cost-based redispatch can avoid gaming but hinders the provision of system services from most small market participants, such as flexible demand and storage, whose variable costs are difficult to determine administratively. In Spain, the procurement of redispatched energy is a hybrid mechanism (MICT, 2015; CNMC, 2022c)[11]:

- Downward redispatched energy in Stage 2.1: Generators are not financially compensated.
- Downward redispatched energy in Stage 2.2: At any given hour generators must bid a volume of downward redispatch energy based on their scheduled energy in the EEMS. Downward redispatch bids can be split between 10 different energy blocks with each a different price.
- Upward redispatched energy in Stages 2.1 and 2.2: At any given hour generators must bid a volume of upward redispatch energy that is equal the difference between their scheduled energy in the EEMS (Stage 1) and their maximum production. In the case of RES, the maximum productions should consider the maximum primary resource availability, i.e., sun or wind. Upward redispatch bids can be split between 10 different energy blocks with each a different price.

Recently the rise of "bottom-up" flexibility markets is witnessed in the EU. Flexibility markets are often referred to as markets set up at distribution-level to procure local system services from distributed energy resources (DERs). Flexibility markets are fostered due to provisions in the Electricity Directive (EU) 2019/944 stating in Article 32 that distribution system operators shall procure services in a market-based manner from resources such as distributed generation, demand response, or storage when such services are cheaper than grid expansion (European Commission, 2019b). Valarezo et al. (2021), providing an overview of newly emerging system service markets, explain that several pilot projects are currently in place in Spain. As the volumes redispatched in these pilots is very limited for the time being, they do not interfere with our analysis. Importantly, as discussed in Schittekatte and Meeus (2020), in the future for several flexibility markets the idea is that they are jointly (or at least planned to) operated by DSOs and TSOs. As such, resources connected at the distribution-level can more easily provide services to resolve congestion issues at transmission-level, or vice-versa. Such evolution is expected to be important to decarbonize redispatching.

3. Dataset, descriptive statistics, and empirical approach

We start this section by explaining our dataset variables, after we provide relevant descriptive statistics, finally, we describe the chosen empirical approach.

The answer to our first research question, i.e., the CO2 emissions that would have avoided if the Spanish network could accommodate all the scheduled generation, can directly be calculated from the constructed dataset. Answers to our second and third research questions, i.e., the drivers behind the CO2 emissions and the quantification of the bias of the emissions in the day-ahead market clearing when more RES generation is scheduled, requires a deeper analysis. We conduct this deeper analysis using descriptive statistics and the estimation of models based on the dataset.

[11] Pumping generators are treated differently. If pumping consumption is curtailed to provide upward redispatch, the non-consumed energy is not remunerated. To provide downwards redispatch, pumping generators must bid the difference between their scheduled (in the EEMS) and maximum consumption. MICT (2015) was amended by CNMC (2022b), where the new SRAP mechanism (Sistema Reducción Automática de Potencia) for generators is introduced. Under this mechanism of voluntary participation for generators, they are not curtailed by the TSO/DSO in the day-ahead when the N-1 criteria is not fulfilled. In exchange, generators should be disconnected in seconds (or minutes) when requested by TSO/DSO.

Table 2
Summary statistics of the EEMS by technology for 2019–2021(N = 26,280).

Variable	Technology	Units	Mean	St. Dev.	Min	Max
CC_t	Combined cycle	MWh	3103.9	3141.6	0	14,990.2
CO_t	Coal	MWh	376.7	726.2	0	5295
H_t	Hydropower	MWh	3209.4	1743.0	531.5	10,161.1
N_t	Nuclear	MWh	6336.0	898.9	3410.2	7151.9
PG_t	Pumping	MWh	216.1	386.9	0	2648.9
PV_t	Photovoltaic	MWh	1546.8	2107.0	0	8638.7
TS_t	Thermosolar	MWh	553.8	653.5	0	2184
CHP_t	Combined Heat and Power	MWh	3230.3	259.1	2278.6	3878.1
B_t	Biomass and others	MWh	1014.1	97.5	604.2	1410.9
W_t	Wind	MWh	7093.7	3663.1	770.6	20,715.6
I_t	Imports	MWh	1699.1	1202.9	0	6592.1

3.1. Summary statistics

All data is hourly and refers to the Spanish bidding zone. The necessary data is provided by Spanish nominated electricity market operator (NEMO), namely OMIE, and the Spanish TSO, being REE. The considered period covers from 2019 to 2021. Building this dataset requires merging several datasets from both the NEMO and the TSO, and all the calculations are detailed in Annex II. Table 2 shows the summary statistics of the EEMS by technology. This data is used as exogeneous variables in the empirical analysis. Note that we use the empirical day-ahead schedule as the "benchmark" in our analysis but that this dispatch is not necessarily the welfare maximizing outcome, even under the assumption of a copper plate. For example, Ito and Reguant (2016) or Fabra (2022) have documented strategic behavior from RES producers bidding in the Spanish day-ahead market. However, simulating a perfectly competitive day-ahead dispatch is beyond the scope of this paper.

Table 3 shows the summary statistics of the net redispatched energy and -in brackets- the upwards redispatched energy (Stage 2.1) per technology. Combined cycle is the technology most often upward redispatched, while wind is the technology that is by far most downwards redispatched (curtailed).[12] When comparing Tables 2 and 3 note that the share of coal-fired generation in terms of redispatch energy is significantly higher than in terms of scheduled energy in the EEMS. When disaggregating this energy, we find that almost all the redispatched energy in Stage 2.1 corresponds to upward redispatched energy.[13] This means that most of these locational operational constraints are addressed by starting up synchronous generation rather than curtailing RES to alleviate (thermal) congestion issues. In other words, rather than an excess of RES generation, a deficit of synchronous generation often triggers redispatch, which we discuss in more depth later. This finding is in line with ACER and CEER (2022) reporting that in 2020 71% of total redispatched energy in Spain was related with voltage support issues. Moreover, it is interesting to highlight that an average of 414 MWh of wind production was curtailed each hour to accommodate the additional coal and combined cycle production, representing about 5.8% of all the scheduled wind generation.[14]

[12] Note that the average downward redispatched photovoltaics is almost null. This is because wind generators, at least in the considered period, are frequently relatively large plants connected to the transmission grid, while photovoltaics are smaller plants connected to the distribution grids.

[13] In Stage 2.1, the rate of upward redispatched energy over all the redispatched energy in the same Stage is 96.3% (2019), 94.5% (2020) and 96.8% (2021) (REE, 2023). Unfortunately, the Spanish TSO does not publish the detailed data about the root cause of each redispatch activations.

[14] This share is calculated by dividing the hourly redispatched wind production from Table 3 (−414.1 MWh) overt the hourly scheduled wind generation from Table 2 (7093.7 MWh).

Table 3
Summary statistics of the net redispatched energy by technology for 2019–2021. Data for the upwards redispatched energy is provided in brackets.

Variable	Technology	Units	Mean	St.Dev.	Min	Max
CC_t	Combined cycle	MWh	538.4 (647.3)	505.9 (461.0)	−2436.5 (0)	3022.3 (3022.3)
CO_t	Coal	MWh	248.2 (264.9)	204.2 (208.2)	−399 (0)	1215 (1215)
H_t	Hydropower	MWh	−133.2 (3.1)	151.0 (16.5)	−1450.7 (0)	559.6 (559.6)
N_t	Nuclear	MWh	−6.0 (0.0)	56.4 (0.8)	−1113.2 (0)	90.1 (90.1)
PG_t	Pumping	MWh	−53.4 (1.6)	102.0 (25.3)	−949.7 (0)	865 (865)
PV_t	Photovoltaic	MWh	−0.4 (0.0)	3.0 (0.3)	−58.6 (0)	15.1 (15.1)
TS_t	Thermosolar	MWh	−1.3 (0.0)	7.35 (0.5)	−184 (0)	24.5 (24.5)
CHP_t	Combined Heat and Power	MWh	−79.2 (0.2)	96.0 (2.5)	−868.9 (0)	58.3 (58.3)
B_t	Biomass and others	MWh	−12.1 (0.1)	17.5 (1.7)	−170.8 (0)	21.5 (43.4)
W_t	Wind	MWh	−414.1 (1.6)	312.7 (21.1)	−2207.8 (0)	658.1 (668.2)

Moreover, the highest volumes of redispatch hours during the night. During these hours demand is typically low and wind production is high. Such combination typically leads to potential voltage issues. This is shown in Fig. 2 in which the average hourly upward and downward energy per technology is displayed. Note that in the same hour a combined cycle unit can provide upward redispatch in one part of the grid, while in another part of the grid another combined cycle unit can provide downward redispatch. A remarkable observation is that relative to its scheduled generation in the day-ahead, the amount of upwards redispatch provided by hydropower is several orders of magnitudes lower than for gas-fired generation and, especially, coal.[15] This is surprising as, typically, hydropower is flexible, often even more flexible than gas-fired or coal generation. A potential explanation is that hydropower plants are not located at the specific locations where grid support is required (e.g., inertia or voltage support). Another explanation can be that it is financially more attractive to sell hydropower in balancing and reserve markets rather than redispatch markets. Delving deeper into this finding is beyond the scope of this paper but recommended for future research. On the other hand, pumping is often used to provide downward redispatch relative to its total consumption, more or less in similar proportion as for gas-fired power generation and upward redispatch.

Considering the technologies that are upwards and downwards redispatched (Fig. 2), it is no surprise that the hourly change in CO2 emissions due to redispatch is in almost all hours positive. We estimate that on average an additional 401.9 ton of CO2 per hour was emitted due to redispatch needs for 2019–2021 (standard deviation: 214.1, minimum: −376.2, maximum: 1634.34). Table 4 provides an answer to our first research question: the CO2 emissions associated to the redispatching energy. As we see, the upward redispatched energy, mostly from combined cycles and coal, represents between 6.3 and 11.4% of the total power system emissions, while the redispatched energy only represents 2.8%- 4.2% of the total power (see Table 1). In other words, redispatched energy is a lot more polluting than the average non-redispatched power production. It is important to note that we utilize

[15] We thank an anonymous reviewer for bringing up this point. While the ratio of generation in the EEMS (Table 2) over upwards redispatched energy (Table 3) is 4.8 and 1.4 for, respectively gas-fired and coal generation, this ratio is as big as 1035.3 for hydropower. The ratio of consumption in the EEMS over downwards redispatched energy is about 4.0, which is in line with gas-fired power generation.

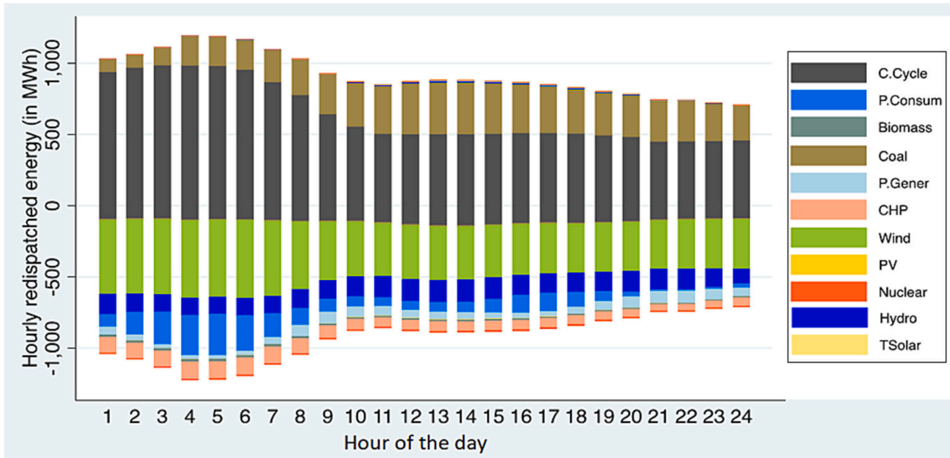

Fig. 2. Average hourly redispatched energy in Stage 2 (Fig. 1) by technology (2019–2021). Source: own calculations. Positive values in vertical axis corresponds to upward redispatched energy, while negative to downward redispatch energy. The negative coefficient for pumping consumption means a higher consumption of electricity.

Table 4
CO_2 emissions from the redispatched energy. Source: Own calculations and based on our dataset and REE (2020, 2021a, 2022). Note: Redispatched energy in real time is not included.

	Units	2019	2020	2021
CO2 emissions from the redispatched energy	ktn of CO2 (% total)	3142.68 (6.29%)	4121.55 (11.41%)	3297.37 (9.18%)
Total power sector CO2 emissions	ktn of CO2	50,000.0	36,130.9	35,906.6

a weighted average CO2 emission factor per technology as provided by REE (2021b). Using a weighted average CO2 emission factor per technology rather than individual emission factors per power plant, which we do not possess, might lead to conservative estimates of CO2 emissions from redispatch processes.[16] The reason being that redispatched plants are likely to be less efficient and thus more polluting than the average plant of the same technology group. Also, the efficiency of a thermal power plant varies with output. As the output of a power plants get further away from nominal conditions, which might again be the case in redispatch processes, the heat rate reduces and thus emissions per MWh generation increase.

3.2. Analysis of the constructed dataset

To provide an intuition behind the answers to our second and third research question, we first analyze the dataset in more depth before introducing the empirical approach.

An important finding from Table 4 is that during the Covid-19 confinement (Spring-early summer 2020) the redispatched energy and accordingly the CO2 emission from redispatch actions were the highest, while there was an overall lower electricity demand compared to the other considered years. This might be counterintuitive on first sight but can be explained by the fact that in the Spanish power system, during low demand periods surpluses of reactive energy flows are more frequent and, at least currently, the only way to absorb these (local) surpluses is by having the TSO starting up some synchronous generators (combined cycle or coal) (Anaya and Pollitt, 2022).[17] From the data, we identified this dynamic by noting the high volumes of upwards redispatch by thermal generators in Stage 2.1. ("the first redispatch action is the start-up of these units"). As these generating units require to run at minimum load levels that are higher than zero, other (scheduled) often non-synchronous generation (RES) needs to be redispatched downwards ("a second action" in Stage 2.2) to rebalance the system. Concretely, in 2020, a record of 8% of the scheduled wind production was downward curtailed in the redispatching process (Stage 2.2).[18] Fig. 3 provides more insight in this phenomena by showing the CO2 emissions from all the hourly redispatched actions in Spain for 2019–2021. The y-axis corresponds to the hourly day-ahead scheduled energy (EEMS) and x-axis the share of intermittent RES (solar PV and wind) in the EEMS. Blue coloured dots represent lower CO2 emissions from redispatch, while red dots indicate high emissions.

We discuss two observations from Fig. 3. First, the hours with the highest hourly emissions due to redispatch actions occur when the share of RES as the total scheduled energy (% RES divided by EEMS) is relatively average (between 20 and 40% of the total supply), while at the same time the absolute hourly total scheduled energy (=demand) is low. For the same shares of RES in the day-ahead schedule, the emissions from redispatch are significantly higher with lower overall scheduled energy. When overall scheduled energy is relatively high, only under a significant share of RES production the CO2 emissions from redispatch increase. In Section 4, we investigate these relationships in more depth based on the empirical approach introduced in the next subsection. In Annex III, we provide additional figures, including visualisations per year. It can be seen that especially in 2020 during the Covid-19 confinement the highest emissions associated with redispatch were observed during the hours with the lowest total scheduled energy. Second, the hours with very high shares of RES day-ahead scheduled production (>60%) occur only exclusively when the system demand is also relatively high. Under very high shares of RES, the CO2 originating from redispatching actions is relatively low. This can be explained by

[16] We thank an anonymous reviewer for bringing up this point.

[17] As discussed in Section 4, wind and photovoltaics interface the grid via power electronics, which implies that the participation in voltage control services required different procedures than the synchronous generators, i.e., combined cycle, coal, hydropower or nuclear.

[18] The average hourly wind scheduled production W_t was 6691 MWh (2019), 7035 MWh (2020), 7554 MWh (2021) and the average hourly wind curtailed was 284 MWh (2019), 564 MWh (2020), 394 MWh (2021), which represents a share of 4.2%, 8.0% and 5.2% respectively.

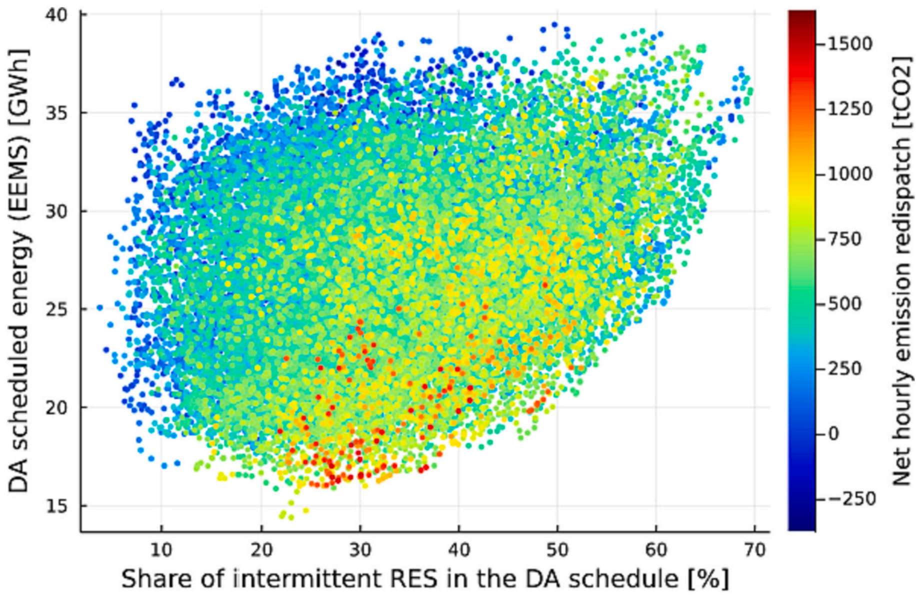

Fig. 3. Day-ahead scheduled energy (EEMS) vs share of renewables (wind and sun) in the EEMS for Spain from 2019 to 2021. Colours show the additional CO2.

two reasons that would require deeper analysis beyond this paper. First, the correlation of high demand periods and high intermittent RES production. Second, at times with very high intermittent RES production, not necessarily all RES production is cleared in the day-ahead market even though the total hourly production of intermittent RES is <100% of the hourly demand. This happens for example because it is very costly to shut down some generators for a brief period (e.g., nuclear is the prime example but this can also happen for coal). An "indicator" of this happening are day-ahead power prices being near or lower than zero.

Fig. 4 shows two panels with data from Spain for 2019–2021 that further explain the dynamics displayed in Fig. 3. In both graphs, similar as in Fig. 3, the y-axis corresponds to the hourly day-ahead scheduled energy (EEMS) and x-axis to share of intermittent RES supply in EEMS. In the left panel, the colours of the dots represent the sum of the upward redispatched energy from combined cycle, coal, CHP and biomass, while in the right panel, the colours of the dots represent the average CO2 emissions per MWh upwards redispatched energy from combined cycle, coal, CHP and biomass. In both cases, blue indicates lower and red indicate higher values.

We observe contrasting patterns when comparing these panels. The left panel shows that the highest hourly upwards redispatch energy from polluting power plants occurs when demand is low and the share of intermittent RES is average. This pattern is rather similar as the pattern in Fig. 4. In other words, the amount of hourly CO2 emissions due to redispatched energy seem to be mostly driven by the volume of upwards redispatch energy from polluting power plants in the same hour. A very different pattern appears on the right panel. Highest average CO2 emissions per MWh from the upwards redispatch energy occurs when the share of RES in the day-ahead schedule is relatively low and the overall schedule day-ahead energy is high. The main reason for this finding is that during those hours coal is providing most redispatch energy as typically many gas-fired generators have already been started up and are running near their maximum capacity. Gas is running near their maximum capacity to fullfill the high energy demand that can be only to a limited extent be fullfilled by RES generation (i.e., low share of RES in the EEMS). The least average CO2 emitted per MWh of redispatch energy occur when the highest volume of redispatch occurs, when the share of RES is average and the overal day-ahead scheduled is low. In Section 4, we investigate these relationships in more depth based on the empirical approach introduced in the next subsection. In Annex III, we provide the same figures per year. It can be seen that the year 2021, the year in which the European energy crisis started, shows a different pattern for the average CO2 emissions per upwards redispatch energy. We explain this finding in more depth in Section 4.

3.3. Empirical approach

To investigate in more depth the patterns that are observed and discussed in the previous subsection, we employ a SARIMA (1,1,0)x (1,1,0,24) time-series estimator, where variables are differentiated to ensure their stationarity, the lagged endogenous variable is included to capture the time dynamics, and a seasonal component is included for each hour (24).[19] We introduce four models. The first three models correspond with the panels shown in Figs. 3 and 4 and relate to our second research question. The fourth model provides an answer to our third research question.

In our first model, our endogenous variable is the hourly CO2 emissions associated to the sum of the upward and downward redispatched energy ($\Delta CO2$), while the explicative variables correspond to day-ahead energy schedule before redispatching ($\Delta EEMS$), and the share of wind and photovoltaics (ΔRES_t) in the EEMS.

$$\Delta CO2_t = \beta_0 + \beta_1 \bullet \Delta CO2_{t-1} + \beta_2 \bullet \Delta EEMS_t + \beta_3 \bullet \Delta RES_t + \beta_4 \bullet m_t + \beta_5 \bullet holiday_t + $$

$$+ \varnothing \bullet \Delta CO2_{t-24} + \varepsilon_t \tag{1}$$

$$EEMS_t = \sum_{i=CC,CO,H,N,PG,PV,TS,CHP,B,W,I} EEMS_{i,t} \tag{2}$$

$$RES_t = \frac{\sum_{i=PV,W} EEMS_{i,t}}{EEMS_t} \bullet 100 \tag{3}$$

[19] In the partial autocorrelation analysis, we find the first lag to be significant as in other studies related with hourly scheduled generation or consumption (Costa-Campi et al., 2018). We provide the stationary tests for the variables in the Annex IV. Under the ADF test, we reject the null hypothesis that there is a unit root in both levels and differences. However, under the KPSS test, we only reject the null hypothesis that the series is stationary in levels, but not in differences. Therefore, in the empirical analysis we use all our endogenous and explicative variables in differences to ensure they are stationary. Finally, we include a seasonal component to consider the autocorrelation with the same hour of the previous day.

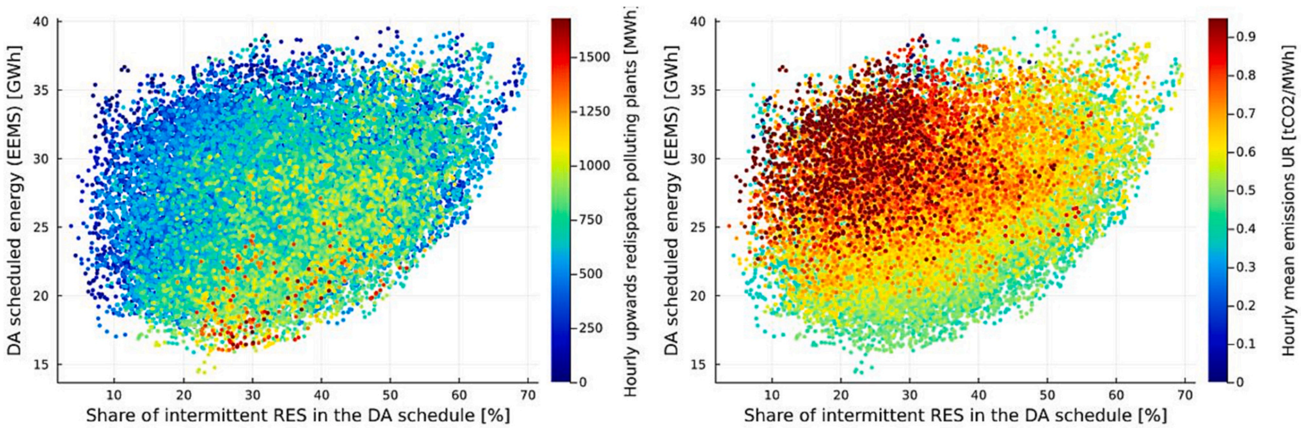

Fig. 4. Day-ahead scheduled energy (EEMS) vs share of renewables in the EEMS. The left graph shows the sum of the upward redispatched energy from combined cycle, coal, biomass and CHP, while the right graph the average CO2 emissions from the same upwards redispatched energy.

In our second model, our endogenous variable is the hourly upward redispatched energy associated to the pollutant technologies (Δur_t) -combined cycle, coal, biomass, and CHP, while the explicative variables correspond to daily energy schedule before redispatching ($\Delta EEMS$), and the share of wind and photovoltaics production in EEMS (ΔRES_t).

$$\Delta ur_t = \beta_0 + \beta_1 \bullet \Delta ur_{t-1} + \beta_2 \bullet \Delta EEMS_t + \beta_3 \bullet \Delta RES_t + \beta_4 \bullet m_t + \beta_5 \bullet holiday_t + \\ + \varnothing \bullet \Delta ur_{t-24} + \varepsilon_t \tag{4}$$

$$ur_t = \sum_{i=CC,CO,B,CHP} ur_{i,t} \tag{5}$$

In our third model, our endogenous variable is the average CO2 emissions (in Kg CO2/MWh) associated to the upward redispatched energy from coal, combined cycle, biomass and CHP ($\Delta avCO2_t$) and the explicative variables correspond to day-ahead energy schedule before redispatching ($\Delta EEMS$), and the share of wind and photovoltaics in EEMS (ΔRES_t).

$$\Delta avCO2_t = \beta_0 + \beta_1 \bullet \Delta avCO2_{t-1} + \beta_2 \bullet \Delta EEMS_t + \beta_3 \bullet \Delta RES_t + \beta_4 \bullet m_t + \\ + \beta_5 \bullet holiday_t + \varnothing \bullet \Delta avCO2_{t-24} + \varepsilon_t \tag{6}$$

$$avCO2_t = \frac{0.34 \bullet ur_{CC,t} + 0.95 \bullet ur_{CO,t} + 0.38 \bullet ur_{CHP,t} + 0.24 \bullet ur_{B,t}}{ur_{CC,t} + ur_{CO,t} + ur_{CHP,t} + ur_{B,t}} \bullet 1000 \tag{7}$$

In our fourth model, our endogenous variable is the hourly CO2 emissions associated to the sum of the upward and downward redispatched energy ($\Delta CO2$) and the explicative variables correspond to daily energy schedule per technology in the EEMS.

$$\Delta CO2_t = \beta_0 + \beta_1 \bullet \Delta CO2_{t-1} + \beta_2 \bullet \Delta CC_t + \beta_3 \bullet \Delta CO_t + \beta_4 \bullet \Delta H_t + \beta_5 \bullet \Delta N_t + \\ + \beta_6 \bullet \Delta PG_t + \beta_7 \bullet \Delta PV_t + \beta_8 \bullet \Delta TS_t + \beta_9 \bullet \Delta CHP_t + \beta_{10} \bullet \Delta B_t + \\ + \beta_{11} \bullet \Delta W_t + \beta_{12} \bullet I_t + \beta_{13} \bullet m_t + \beta_{14} \bullet holiday_t + \varnothing \bullet \Delta CO2_{t-24} + \varepsilon_t \tag{8}$$

Where the explicative variables correspond to scheduled energy in the EEMS per technology.[20] In all the equations, seasonality is controlled by m_t, a dummy variable for each month, while $holiday_t$ equals to 1 in weekends and national holidays.

In our estimations we include the lagged endogenous variable to capture the dynamics. Using ordinary least square estimations could lead to biases problems also related with a potential residual autocorrelation (Keele and Kelly, 2006). Therefore, we use maximum likelihood estimators that have been used in similar studies (Costa-Campi et al., 2018). Further, we perform three different estimations, one per year (2019, 2020 and 2021) as there are relevant differences during this period (see also the figures in Annex III). We enumerate five developments over the considered years. First, the generation mix changes between 2019 and 2021: photovoltaics capacity increases +212% up to 15.048 MW, wind capacity increases +20% up to 28.175 MW, and coal capacity decreases −62,5% up to 3.764 MW (REE, 2022). Second, 2020 includes the pandemic containment and severe restrictions on movement during some months, which clearly affected the national electricity demand (Santiago et al., 2021). Third, the average wholesale price is quite different from one year to another (47,78€/MWh in 2019, 33,95€/MWh in 2020 and 111,97€/MWh in 2021), which might constraint the technologies operating in the particular year (OMIE, 2022). Four, the annual average price of CO2 on the EU ETS has substantially increased in this period (24,67€/tn in 2019 to 53,45€/tn in 2021) (EEX, 2023). Five and last, the TSO and DSOs are ongoing commissioning new lines and cables, substations, and reactive compensation equipment, precisely aimed at reducing redispatching.

Table 5
ML estimations for Eq. (1) year.

	2019	2020	2021
	$\Delta CO2_t$	$\Delta CO2_t$	$\Delta CO2_t$
Scheduled Energy ($\Delta EEMS_t$)	0.00210****	0.00262****	−0.00564****
	(0.000611)	(0.000733)	(0.000565)
Renewables (ΔRES_t)	2.441****	1.402****	3.732****
	(0.425)	(0.422)	(0.302)
Holiday ($holiday_t$)	0.996	−0.160	1.373
	(1.400)	(1.603)	(1.459)
Lagged ($\Delta CO2_{t-1}$)	−0.0641****	−0.0974****	−0.0851****
	(0.00930)	(0.00914)	(0.00899)
Seasonality ($\Delta CO2_{t-24}$)	0.387****	0.420****	0.372****
	(0.00557)	(0.00547)	(0.00570)
Constant ($\widehat{\beta_0}$)	63.14****	74.58****	66.40****
	(0.229)	(0.259)	(0.244)
N	8735	8783	8759
Seasonality			
Month	Yes	Yes	Yes
Weekends & Nat. holidays	Yes	Yes	Yes

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

[20] In EEMS we are not considering the exported energy as we are considering only all the inflows (generation + imports). Moreover, using the imported and exported energy variables in the same equation could result in a multicollinearity problem.

4. Results and discussion

We first present results based on the dataset and models presented in the previous section. After, we discuss in more depth these results and provide regulatory recommendations.

4.1. Results

Table 5 displays the results for Eq. (1). Note that in all our estimations, both the endogenous and explicative variables are in differences.

Regarding the potential bias on the CO2 emissions in the day-ahead market schedule, we can do two observations. First, there is no consistent relationship between the additional amount of CO2 emitted due to the redispatch process and a change in scheduled energy across years. For 2019 and 2020, an increase in the hourly demand leads to more CO2 emitted via redispatching, while the opposite is true for 2021. These results can be explained by the different roles of the upward redispatched of combined cycle and coal, driven by relative prices between gas and coal and the CO2 price. In Annex V, we show that when the scheduled energy increases, redispatch energy from combined cycle decreases, while redispatched energy from coal increases.[21] In 2019 and 2020, coal-fired generation was more expensive than gas-fired generation, combined cycles were less operated in the low demand periods and more available to provide upward redispatch (MITECO, 2019b).[22] However, in the high demand periods, generation from combined cycle generators are operating closer to their maximum capacity (as a fleet) and the TSO must opt for coal to provide upward redispatch.[23] Due to the rising gas prices from the summer of ‘21 onwards, gas and coal switched in the merit order which explains the change in sign for the relationship between CO2 emitted via redispatch and the scheduled energy for the year 2021.

The second observation is that higher shares of wind and photovoltaics in the EEMS results in higher CO2 emissions related to the redispatching processes. This coefficient should be understood as the additional emissions from redispatching processes as consequence of an additional percentage point of RES in the EEMS.[24] The impact of the share of intermittent RES grows when comparing 2019 with 2021, which could be to some extent explained by the higher wind and solar capacity connected. The sudden increase in 2021 can also explained by the fact that the higher shares of RES in the day-ahead schedule, the higher the probability that coal is the marginal technology in the day-ahead market in the second part of 2021 and thus can provide a significant volume of the upwards redispatch energy.

In the next estimations we disentangle the previously described dynamics. Table 6 shows results from estimations based on Eqs. (4 and 6) for the considered years. Overall, when comparing the results from Table 5 and 6, it can be said that when discussing the hourly net emissions due to redispatch (Eq. (1)), the “volume effect”, i.e., the MWh’s redispatched in an hour by polluting technologies (Eq. (4)), is significantly more important than the “supply mix effect”, i.e., what polluting technologies are providing redispatch (Eq. (6)). Note again that this statement is to some extent conditional upon our used emissions factors, which are rather conservative.

Further we want to highlight two important observations from the results in Table 6. First, the results confirm that the sum of the upward redispatched energy from pollutant technologies is consistently inversely related with the hourly scheduled energy, and positively related with the share of RES. As the gap between RES and the total demand is to an important extent filled up by combined cycle and coal plants, this implies that in case the scheduled energy provided by combined cycle and coal plants is low, the volume of upward redispatched energy from these technologies increase. This can be explained by the fact that the power system always needs a minimum level of these synchronous generators online. Second, the mean intensity of CO2/MWh associated with the previous upward redispatched energy from pollutant technologies in 2019 and 2020 is positively correlated with the hourly scheduled energy, and negatively related with the share of RES. This finding confirms that coal, the most pollutant technology, is more probably to be upward redispatched when the scheduled energy increases, but less probably when the participation of RES increases. In 2021, estimations are not significant, meaning that we do not see this effect on the intensity of CO2/MWh. We speculate that the reasons are the lingering demand due to the corona post-lock down in the first half of the year and the coal-gas merit order switch around the middle of the year due to rising natural gas prices.

Table 7 shows the estimations based on Eq. (8) for the three years. In all cases, we control for seasonality by the inclusion of a dummy per month, and another dummy per weekend or national holiday days occurring during the working week. For our third research question, what we are mostly interested in from these results are the estimated changes in emissions due to changes in wind and solar photovoltaics generation. As expected, when considering the previous results, we can see that higher production volumes of intermittent RES in the EEMS induce higher CO2 emissions from redispatched energy necessary for the ETFS. More specifically, we find that each additional MWh of wind in the day-ahead schedule downward biases its emissions between +0.00435 and + 0.00622tn of CO2, and each additional MWh of photovoltaics between +0.00391 and + 0.0145tn of CO2. This is an important finding from our paper as it shows that the emission assessment based on the day-ahead schedule are biased due to the omission of operational needs. In other words, the day-ahead market often does not result in a fully operational viable programs, which results in additional emissions and costs for consumers (Tables 1 and 4). The positive correlations highlight that integrating RES might require addressing some operating challenges that should be solved to avoid the need for pollutant technologies.

Finally, in Table 8 we calculate the potential net saved CO2 emissions related to wind and photovoltaics, considering two different replaced technologies: coal and combined cycle. It is important to note that current redispatching processes reduce the potential CO2 savings between −2.2% and 6.2% for photovoltaics, and between 0.9% and 2.6% for wind.[25] To our knowledge, such “emission reduction day-ahead correction factors” due to locational operational issues in the integration

[21] In Annex V, an additional MWh in the scheduled energy (ΔSE_t) entails the following redispatch of combined cycle: -0.0481MWh (2019), −0.0504MWh (2020) and − 0.0618MWh (2021). Moreover, an additional MWh in the scheduled energy entails the following redispatch of coal: +0.0182MWh (2019), +0.0188MWh (2020) and + 0.0113MWh (2021). In Table 6, the positive CO2 emissions in columns 1, 3 and 5 are due to the higher emissions from coal (0.95tn/MWh) compared to combined cycle (0.37tn/MWh).

[22] In the Spanish regulation, the criteria defined by the NRA to choose technologies to upward redispatch are the following: (i) the cheapest bid to redispatch, (ii) RES technologies, (iii) high efficiency thermal installations, (iv) the remainder.

[23] In Figure 2, the upward redispatch energy in coal is higher at day. Moreover, the average EEMS for combined cycle in *holiday* = *1* is 2829MWh (2019), 1517MWh (2020), 1022MWh (2021), in *holiday* = *0* is 4927MWh (2019), 3350MWh (2020) and 2741MWh (2021). The average EEMS for coal in *holiday* = *1* is 376MWh (2019), 129MWh (2020), 277MWh (2021), in *holiday* = *0* is 730MWh (2019), 163MWh (2020) and 388MWh (2021).

[24] The percentage of RES(RES_t) should not be understood as volumes of energy produced by RES, but to the participation rate of RES in the system. From the electrical engineering point of view, this directly relates to the share of power electronics converters in the system.

[25] A more detailed calculation of the net abated CO2 emissions in Table 8 would require individual information about the CO2 emissions from each combined cycle and coal plant, as well as their technical characteristics to consider different levels of operation. However, this deeper detailed analysis is out of the scope of this paper.

Table 6
ML estimations for Eqs. (4 and 6) per year. Note: estimations for Eq. (6) in 2021 are not shown as all the coefficients are not significant.

	2019	2020	2021	2019	2020
	(Eq. 4)	(Eq. 4)	(Eq. 4)	(Eq. 6)	(Eq. 6)
	Δur_t	Δur_t	Δur_t	$\Delta avCO2_t$	$\Delta avCO2_t$
Scheduled Energy ($\Delta EEMS_t$)	−0.0120****	−0.00590****	−0.0244****	0.0136****	0.00743****
	(0.000910)	(0.00128)	(0.00119)	(0.000789)	(0.000562)
Renewables (ΔRES_t)	5.737****	5.759****	8.039****	−2.63****	−2.04****
	(0.637)	(0.703)	(0.594)	(0.552)	(0.350)
Holiday ($holiday_t$)	1.860	0.535	2.608	−0.809	−1.92
	(2.164)	(2.600)	(2.838)	(1.79)	(1.46)
Lagged (Δur_{t-1})	−0.0390****	−0.0748****	−0.118****		
	(0.00902)	(0.00869)	(0.00935)		
Seasonality (Δur_{t-24})	0.397****	0.541****	0.466****		
	(0.00529)	(0.00423)	(0.00570)		
Lagged ($\Delta avCO2_{t-1}$)				0.161****	−0.188****
				(0.00592)	(0.00349)
Seasonality ($\Delta avCO2_{t-24}$)				0.455****	0.358****
				(0.00376)	(0.00453)
Constant ($\widehat{\beta_0}$)	100.5****	126.4****	134.4****	0.0805****	0.0676****
	(0.366)	(0.402)	(0.545)	(0.000205)	(0.000143)
N	8735	8783	8759	8735	8783
Seasonality					
Month	Yes	Yes	Yes	Yes	Yes
Weekends & Nat. Holidays	Yes	Yes	Yes	Yes	Yes

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

Table 7
ML estimations for Eq. (8) per year.

	2019	2020	2021
	$\Delta CO2_t$	$\Delta CO2_t$	$\Delta CO2_t$
Combined Cycle (ΔCC_t)	−0.00575****	−0.0153****	−0.0331****
	(0.00105)	(0.00175)	(0.00112)
Coal (ΔCO_t)	−0.105****	−0.179****	−0.291****
	(0.00204)	(0.0116)	(0.00500)
Hydropower (ΔH_t)	0.0155****	0.00951****	−0.00152
	(0.00157)	(0.00151)	(0.00128)
Nuclear (ΔN_t)	0.0213***	−0.0175**	−0.0255***
	(0.00815)	(0.00716)	(0.00813)
Pumping generation (ΔPG_t)	0.0342****	0.00681**	0.00373
	(0.00380)	(0.00335)	(0.00247)
Photovoltaics (ΔPV_t)	0.00476	0.0145****	0.00391***
	(0.00401)	(0.00278)	(0.00151)
Thermosolar (ΔTS_t)	0.0237****	−0.0116	−0.00946*
	(0.00699)	(0.00755)	(0.00523)
Biomass (ΔB_t)	−0.00790	−0.0470*	0.0761**
	(0.0174)	(0.0262)	(0.0356)
CHP (ΔCHP_t)	−0.0305**	−0.0287	−0.0489****
	(0.0128)	(0.0175)	(0.0132)
Wind (ΔW_t)	0.00622****	0.00435**	0.00488***
	(0.00162)	(0.00193)	(0.00149)
Imports (ΔI_t)	0.00212	0.00216	0.000922
	(0.00147)	(0.00143)	(0.00125)
Holiday ($holiday_t$)	−1.174	−1.394	−1.094
	(1.367)	(1.590)	(1.369)
Lagged ($\Delta CO2_{t-1}$)	−0.0660****	−0.104****	−0.113****
	(0.00923)	(0.00909)	(0.00905)
Seasonality ($\Delta CO2_{t-24}$)	0.360****	0.418****	0.344****
	(0.00591)	(0.00539)	(0.00654)
Constant ($\widehat{\beta_0}$)	60.69****	73.91****	62.72****
	(0.239)	(0.256)	(0.261)
N	8735	8783	8759
Seasonality			
Month	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes

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

of RES are not considered in emission-related assessments of RES technologies, which we consider to be an important contribution of this paper.

4.2. Discussion and regulatory recommendations

We divide this section into two parts. First, a discussion of the results and their implications. Second, a discussion of broader recommendations to reduce bias in emissions between the day-ahead market clearing and real-time dispatch, i.e., a reduction in (polluting) redispatch actions. The latter discussion goes beyond our quantitative results.

4.3. The results and their implications

Our analysis confirms, at least for the considered case study, that volumes of coal and combined cycles activated by system operators for network security reasons increase when the scheduled production from both technologies decrease, due to higher RES production and/or lower electricity demand. The latter highlights that these redispatching actions are very frequently triggered by location-specific operational needs other than the alleviation of thermal network limits. We estimate for the case of Spain, considering the period between 2019 and 2021, emissions from the day-ahead market schedule to be biased between +0.00262 and − 0.00564 tn of CO2 for each additional scheduled MWh in the day-ahead markets. Moreover, the scheduled RES production also affects the need to start pollutant technologies, and the hourly emissions from the day-ahead market clearing should be downward biased between +0.00391 and + 0.00622 tn of CO2 for each additional scheduled MWh of wind or photovoltaics. This highlights that actions taken by system operators to ensure the technical security constraints have a relevant environmental cost. From all these results, we estimate that expected savings in CO2 emissions related to the connection of RES need to be downward corrected between 1% and 6%. Importantly, these estimates represent a lower bound due to the assumption of static weighted average emission factors per technology rather than plant specific emission factors that also vary depending on operational conditions. Moreover, the volumes of redispatch actions peaked when the electricity demand is minimum during the covid-19 lockdown, emphasizing that especially operating a power system with very low residual electricity

Table 8
Net abated CO2 emissions from photovoltaics and wind, considering two replaced technologies.

Renewable technology generating	Replaced technology	Savings on CO2 emissions: Day-ahead schedule (tCO2/MWh)	Redispatching (tCO2/MWh)	Net CO2 emissions (tCO2/MWh)	Emission correction %
Photovoltaics	Coal	−0.95	+0.0211	−0.9274	**2.22%**
	Combined Cycle	−0.34	+0.0211	−0.3174	**6.22%**
Wind	Coal	−0.95	+0.0088	−0.9409	**0.93%**
	Combined Cycle	−0.34	+0.0088	−0.3309	**2.59%**

Note: Redispatching emissions come from the maximum long-term CO2 emissions shown in Annex VI.

demand (demand minus RES production) creates challenges. It is expected that power systems will evolve in that direction. In other words, the operational challenges faced during the Covid-19 crisis gave us a glimpse of what the future could look like.

What our analysis has also shown is that the common idea that increasing volumes of redispatch, and hence increased emissions from redispatched energy, are solely driven by higher shares of RES production is an incomplete statement. The exact drivers of emissions from upward redispatch, in most cases replacing curtailed RES, and the most efficient solutions to reduce emissions from redispatch are a lot more complex and case dependent. On top, it is hard to make any general statement about redispatch processes, and their associated additional emissions, as they are heavily impacted by "shocks" to the power system. Examples that have been illustrated in our analysis are the Covid-19 confinement, leading to a decrease in overall demand, and the ongoing EU energy crisis, leading to a switch between gas and coal-fired generation in the merit order underlying the day-ahead dispatch.

When thinking about solutions to reduce redispatching needs and their associated emissions, it is important to consider whether the redispatch needs are related with thermal grid congestions or other operational issues such as inertia needs or power quality. As we have explained, solving congestion issues entails curtailing generation in Stage 2.1, while solving other operational issues entails starting some synchronous generators due their technical benefits for the power system in the same stage.

In the case of thermal grid congestions, reinforcing the grid and/or implementing smaller bidding zones or nodal pricing would indeed result in a more efficient schedule of generation and consumption and lead to a significant reduction of redispatched energy. The remaining redispatch needs could be reduced in costs and emissions by allowing for other resources than conventional thermal generators to provide redispatch. For example, Xiong et al. (2021) introduce Power-to-Gas as a redispatch option and apply their model to the German electricity system. They find that instead of curtailing RES, increased synthetic natural gas can be produced and injected into the gas grid for later usage. Their results show a reduction on curtailment of renewables by 12% through installing Power-to-Gas at a small set of nodes frequently facing curtailment. In that respect, via the Clean Energy Package, published in 2019, the European Commission has introduced regulations to promote the participation of RES, demand, and storage in the provision of redispatch. So far, at least for the considered case study, very little progress seems to have been made in this respect. Integrating small storage and demand response in redispatching processes would require fully fledged market-based redispatch systems. On the other hand, it is also well known that market-based redispatch can lead to serious gaming concerns (see e.g., Hirth and Schlecht, 2020).

In Spain, we find that >95% of all the redispatched energy in Stage 2.1 corresponds to upward redispatch energy, which is almost all delivered by coal and combined cycle (Table 3). The corresponding annual costs for consumers -in redispatching- range from 239 M€ to 443 M€ and lead to significant additional CO2 emissions. Despite the Spanish TSO not publishing the root cause of all the redispatching actions, from the data we can infer that most of the actions are very likely closely related with the need to start synchronous generators to deal with locational operational issues other than thermal limitations of lines, such as voltage or inertia issues. If redispatch is to an important extent driven by such operational issues, simply building more networks would not necessarily reduce these. In the case of voltage issues, more networks could even make them worse.[26] Also a bidding zone revision alone cannot be expected to significantly reduce redispatch volumes (at least not directly) if these problems are related with voltage problems or inertia needs.

4.4. Regulatory recommendations

Regulatory recommendations aimed to minimize the downward bias of the day-ahead market schedule emissions can be divided in three main groups: some related to the day-ahead market design, others related with the own operation of the power system and generators, and others related to set locational incentives for new RES.

In the first group, a theoretical solution to avoid the need to start up synchronous units after the market clearing due to voltage or inertia violations would be to not only consider thermal violations of network elements in the market clearing but also internalize other operational constraints such as voltage limitations and inertia limits. As far as the authors are aware, current zonal and nodal pricing systems do not, or at least not to a large extent, consider voltage limits in the market clearing. Nearly three decades ago, there has been a debate about the calculation and publication of reactive power prices, in addition to active power prices in nodal systems (Hogan, 1993). At that time the idea has finally been abandoned as the costs seemed higher than the benefits (Kahn and Baldick, 1994), but this debate might need to be revisited. There are important studies looking at the inclusion of inertia in the market clearing (Doherty et al., 2005; Liang et al., 2022) but, as far as the authors are aware, such approaches have not yet been introduced in practice.

In the second group, a more pragmatic solution is assessing if the operational security criteria applied by TSO and DSO in the day-ahead can be improved. In this way, the recent SRAP mechanism implemented in Spain seems an efficient alternative to the curtailment of RES when the N-1 security criteria is not respected in the day-ahead forecasts (CNMC, 2022b). Another solution is to have RES participate in voltage control services as synchronous generators are already doing, but such practice is limited to a few countries so far (ENTSOE, 2022). ACER and CEER (2022) states that voltage issue is the most important root cause to active redispatching actions in Spain. In Spain as in many other countries, RES constantly follow a fixed power factor setpoint (peak/offpeak hours, working/holidays days) following specific hourly tariffs related to reactive energy (Budhavarapu et al., 2022). Traditionally, these tariffs follow a static approach and are not adapted to temporal or spatial needs of the power system (Potter et al., 2023). An approach to mitigate voltage issues is to mandate voltage control provision by newly connecting RES. In that regard, European Commission (2016) mandates new wind plants and photovoltaics to provide variable reactive energy also according to a voltage setpoint, which would enable an active

[26] New grids behave as a capacitor if flows through them are low.

participation of RES in the power system voltage control. However, mandating voltage control capabilities might not always be the most efficient solution as reactive energy needs might differ across different regions within the same country. Also, RES providers of voltage control face additional operating costs (electricity losses and extra cooling to power inverters) and often would have to reduce their active energy production as these plants will not be operating within their optimal conditions (Davi-Arderius et al., 2023a). There are important questions around how to reimburse RES plants for those additional costs.

Currently, to avoid the need to start up synchronous generators to mitigate locational operational issues or voltage issues, there are two alternative instruments that are gaining attention: (i) a traditional solution based on installing new reactive compensation equipment and, (ii) more innovative market-based solutions aiming at better exploiting current and future RES, or also using synchronous condensers made of the generators device from the phased-out pollutant plants (see e.g., Power, 2020). The Spanish TSO has planned to follow the traditional approach, i.e., install new static synchronous compensators (STATCOMs) during the period 2021–2026 with an investment cost of >100 M€ and an annual operating cost of >2 M€, directly funded by electricity tariffs (MITECO, 2019a). However, such an approach would imply that voltage issues are entirely dealt with by TSO and costs are passed through to consumers.

Related to the compensation of these remedial actions in Spain, the curtailment of units in the day-ahead does not include any economic compensation. The efficiency of this procurement design should be evaluated and assess if this might be discriminatory for the curtailed units. In addition, other alternative approach would leverage the benefits of competitive pressure by introducing specific ancillary services. For instance, auctions can be organized to procure voltage control in the specific grid locations where they are needed. Anaya and Pollitt (2020), and Jay and Swarup (2021) do a review of current trends in the procurement of reactive power and confirm that currently market-based mechanisms are only to a very limited extent in place but have relevant potentials in the decarbonized power systems. In that respect, a social cost benefit analysis of the introduction of the market-based procurement of reactive power for the Power Potential project, a case study in the UK, indeed found significant savings for end consumers in the range from 8 to 21% of business-as-usual asset costs by 2050 (Anaya and Pollitt, 2022). It is important for regulators to make sure that the current regulatory framework of network operators provides the right incentives to explore such innovative solutions, e.g., rewarding reductions in redispatch volumes and the associated emissions. Relevant in that regard is that in May 2022, the Spanish Regulator opened a regulatory sandbox to trial an ancillary service for voltage control at the request of the Spanish TSO (CNMC, 2022a).

By having auctions, different emission-free resources that can solve local voltage issues could compete: STATCOMs (unbundled from the TSO), new RES plants, old RES plants (needing to be upgraded to implement this active participation in the voltage control), or synchronous condensers made of the generator devices from the phased-out pollutant plants. In that respect, Regulation 2019/943 enlists non-frequency ancillary services, such as voltage control, as one of the areas for new network codes (Art. 59.1) (European Commission, 2019a). Further, also the framework guidelines of the new network code for demand-side flexibility discuss the introducing of long-term market-based procurement of voltage control to drive potential investments, including at the distribution-level (ACER, 2022).

Other location-specific operational constraints than voltage issues related with the need to start synchronous generators are a lack of inertia, excessively deep fault ride throughs, or potential frequency oscillations. In this regard, the recent European Commission (2016) and MITECO (2020) already mandates new wind plants and photovoltaics to provide demanding capabilities to deal with both issues. In the case of inertia also tenders can be organized to allow inertia to be provided by third parties rather than the system operator. Such tenders procuring inertia ancillary services have recently been launched in Great Britain (see e.g., National Grid ESO, 2022). Note that voltage control services and inertia ancillary services are often short to medium term solutions to deal with the current operational needs.

In the long term, it is also necessary to assess whether potential locations for new RES would not aggravate the current location-specific operational needs. Setting locational incentives for new generators, considering the current grid conditions in each area, would provide long-term solutions. More precisely, when assessing future locations for RES deployment not only potential thermal limits shall be studied (addressed via smaller bidding zones or nodal pricing) but also wider impacts on operational needs in the relevant area. In the regulatory framework, there are two main mechanisms to provide such additional locational incentives for RES investors. First, implementing regionally differentiated charges, as for example currently done in the UK. Second, setting location incentives in auctions for new RES. This includes a variety of instruments such as site-specific auctions (Portugal, South Australia), locational signals in the merit order (Mexico), locational signals in remuneration (Germany), site volume specific (Germany), previous prequalification (South Africa), technology-specific auctions (many countries) (Davi-Arderius et al., 2023b).

5. Conclusions

Connecting RES to the grid does not necessarily imply that all its scheduled generation in the day-ahead markets will finally be delivered to end users. Day-ahead markets do not always lead to operational viable outcomes, especially when grid constraints are not reflected in the market design. The power grid is a complex system and system operators must avoid any security violation that could end with failures of electrical assets, electrical disturbances or, in extreme cases, in blackouts. As a remedy, system operators validate the day-ahead market schedule and, if needed, start, or disconnect specific generation, demand, or storage through the redispatching actions.

In this paper we study the bias in terms of CO emissions that result from not internalizing grid operational limitations in the day-ahead market clearing. In other words, we assess how much incremental emissions are introduced due to the actions taken by the system operators to avoid the violation of internal network security constraints. We do this for the case of Spain between 2019 and 2021. Concretely, we answered three research questions:

(i) What is the bias in terms of CO2 emissions from actions by system operators to make the day-ahead market schedule physically feasible, i.e., how much emissions would have been avoided in case the Spanish network would have been able to always accommodate all day-ahead scheduled generation?
(ii) What are the drivers of incremental emissions compared to the day-ahead schedule introduced through the actions taken by system operators?
(iii) How much does the bias in emissions increases per MWh of additional RES production in the day-ahead schedule?

Regarding the first question, for Spain, when looking at the years 2019–2021, to make the day-ahead market schedule operation viable, the system operators needed to activate relevant volumes of coal and combined cycle power plants for an amount between 2.8% to 4.2% of the total demand. This represents an annual economic cost of 443 M€ paid by customers, and represent 6–11% of the annual power sector's CO2 emissions.

Regarding the second question, we have shown that the hourly emissions from redispatching are rather driven by the volume of redispatch energy than the change in resources supplying redispatched energy in a given hour. Increasing hourly volumes of redispatch energy correlate not only with increasing shares of intermittent RES in the day-ahead schedule but also with decreasing hourly electricity demand, which was especially apparent during the period of the Covid-19 confinement. The operational challenges faced during the Covid-19 crisis gave us a glimpse of what the future with low residual demand (low demand and high-RES generation) could look like. A low electricity demand clearly affects the efficient integration of RES in the power system; currently, there is an identified need of having minimum coal and combined cycle plants running to ensure operational security criteria. Further, in case that the production costs of coal are higher than gas (as in the case of most of the considered periods), the largest average emissions per MWh of upwards redispatch energy typically occur when the share of intermittent RES is low, and overall demand is high. In case gas-fired generation is more expensive than coal-fired generation, as is the case since the onset of the European energy crisis in the summer of 2021, this statement does not hold.

Finally, regarding the third research question, we find that the emissions from the day-ahead market schedule are downward biased when the RES scheduled production increases. More in detail, there is a downward bias between +0.00391 and + 0.0145 tn of CO2 for each additional MWh of scheduled wind or photovoltaics. This result is relevant and shows that some of the expected environmental benefits from the decarbonization of the power mix might be traded-off when system operators must ensure compliance with operational security constraints.

Based on our findings, we ended the paper with regulatory recommendations to minimize this bias in terms of CO emissions that result from not internalizing grid operational limitations in the day-ahead market clearing. When thinking about solutions, it is important to differentiate between improvements on the own day-ahead market design, improvements on the power system operation through the implementation of new ancillary services, or the implementation of additional locational incentives for new RES.

Regarding the market design, the introduction of more spatially granular wholesale prices would be useful to internalize potential grid constraints in the day-ahead market schedules. Another possibility is publishing locational information about the units providing congestion management can also be a lever to attract investment in flexibility at the right location. However, information could also be used for potential providers of congestion management to bid higher prices if they are aware of their pivotal role in solving a specific local issue. Regarding the operational issues, we distinguish between voltage control issues and inertia. The latter might be addressed with a specific new ancillary service for voltage control, while the former with an inertia service. Overall, our analysis provides a basis for urging the implementation of a new ancillary services for the provision of voltage control and other operational needs via market-based mechanisms complementing the current rule-based mechanisms with the final aim to reduce the need for starting up polluting plants generating at minimum load. Total costs for consumers would reduce if the market procurement of new ancillary services turns out to be cheaper than the traditional alternative of installing additional reactive compensation equipments or simply mandating all RES to provide both services. Finally, the implementation of locational incentives for new RES would provide incentives to include the grid conditions in the decisions to locate a new generator. With all these recommendations, the necessary actions taken by system operators to ensure the technical security criteria would reduce, as well as the bias on the day-ahead market schedule emissions.

We cannot say at this point whether all our findings can be generalized for other countries. There is a general trend in increasing redispatch volumes over the last decade for all EU countries with increasing penetration of intermittent RES (see e.g., the annual wholesale market monitoring reports by ACER and CEER) and we assume that it is highly likely that the redispatched energy could be also more pollutant than the non-redispatched energy in most other countries (with the possible exception of hydro-dominated countries). However, more detailed country case studies are needed. Another important future research stream is to conduct a spatially more granular analysis. The present paper utilized aggregated data for the entire country. However, some issues can be concentrated in specific locations, which would further extend the current analysis. Finally, we highlight the need to assess the potential operational needs when studying locations for future RES deployment.

CRediT authorship contribution statement

Daniel Davi-Arderius: Conceptualization, Data curation, Methodology, Software, Validation, Formal analysis, Writing – original draft, Writing – review & editing. **Tim Schittekatte:** Conceptualization, Methodology, Formal analysis, Writing – original draft, Writing – review & editing.

Disclaimer

The opinions expressed within the contents are solely the authors' and do not reflect the opinions of the institutions or companies with which they are affiliated. Daniel Davi-Arderius works at e-Distribucion Redes Digitales, SLU (Endesa) and is part of the EU DSO Entity.

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Appendix A. Annex I: Technical Background

A.1. Inertia

In power systems, inertia is the energy stored in large rotating generators that gives the tendency to remain rotating. Inertia provides the temporary response when there is a disturbance in the power system, i.e., a large power suddenly disconnects or a high-voltage line is disconnected (NREL, 2023). Low inertia might affect the quality of supply (voltage drops), produce unpredictable frequency oscillations, or even increase the likelihood that a disturbance ends with a blackout (Makolo et al., 2021).

In power systems inertia has been traditionally provided by synchronous generators. Nowadays, the connection of RES interfacing the grid via power electronics might affect the inertia of the system since few large synchronous generators are replaced by a high number of RES plants. On top, those RES plants are often connected to the distribution grids far from the transmission grid. This evolution increases the rate of change of frequency (RoCoF) to values higher than 1 Hz/s. As a solution, the latest generation of power electronics with batteries, namely grid-forming, can provide inertia. However, this technology is quite expensive and not yet mature (ENTSOE, 2021). These inertia problems are locational issues, mostly related with the generation technologies instantaneously producing in a particular region.

A.2. Voltage control

In AC systems, the total energy that is transmitted through the grid is known as the apparent current (in MVA), which consists of active energy (in MWh) and reactive energy (in MVAr). The grid frequency is controlled by adjusting active power consumption or generation,[27] while voltage is controlled by the reactive power flows, which is especially important in the high voltage (HV) grids due to their high impedance.[28] Reactive power is local, cannot be transmitted over long distances, and can constraint grid capacity.

Besides issues with thermal limits due to changes in the transmission and distribution of flows, regional imbalances in reactive power can also lead to the need for redispatch to respect voltage limits. A surplus of reactive power in some point of the grid can increase the voltage above the nominal operating rate of the relevant assets, while a deficit decreases the voltage and might compromise the grid stability. Table 13 gives an overview of the grid parameters related to the sources of reactive energy flows and potential mechanisms to control them.

Table 13
Sources of reactive energy in the power systems and potential mechanisms to control reactive flows, i.e., voltage in the power system. Source: own elaboration based on National Grid ESO (2021), Potter et al. (2023) and Davi-Arderius et al. (2023a).

	Asset	Impact on the reactive energy flows
Sources of reactive energy	Grids	HV grids generate more reactive energy than the low voltage (LV) grids due to their higher impedance Long underground cables act as a capacitor and generates more reactive energy than the aerial cables. Lightly loaded grids generate more reactive energy than the highly loaded grids.
Mechanisms to control reactive energy	Grid solutions	Active control of the on-load tap changers installed in the substations.
	Reactive compensation equipment	Static synchronous compensator (STATCOM) can generate or consume reactive energy, while capacitors can inject reactive energy. Flexible AC transmission system (FACTS) can generate or consumer reactive energy. A synchronous condenser is an AC synchronous generator not attached to any driven equipment (ENTSO-E, 2023).
	Consumers	Generate or consume reactive energy depending on their consumption assets. Moreover, embedded generation decreases the minimum demand in the transmission grids. Recently, the connection of electric vehicles charging points increases the rate of power electronics connected to the grid, which could negatively affect the reactive flows if they are not performing according to the operational needs of the grid. In extreme cases, specific consumers might be disconnected to deal with extreme power quality problems.
	Synchronous generators	Traditionally, synchronous generators (combined cycle, fuel and coal plants) have had the most important role in actively controlling the reactive energy flows due to their efficient regulation of power factor setpoints.
	Generators made of power electronics	Traditionally, power electronics have not made an active control of reactive energy flows although their reactive power capacities. To be actively controlling the reactive energy flows, they should be operated in specific way and is expensive by them. In extreme cases, specific generators might be disconnected to deal with extreme power quality problems.

Traditionally, specific power factors (the ratio between the active energy and apparent energy) were fixed for consumers and generators, which ensured that some share of reactive energy is consumed or generated. Nowadays, power electronics implemented in RES and in some consumption, devices can provide an apparent energy (MWA) setpoint regardless the active energy (MWh) (European Commission, 2016). However, power electronics might need cooling, which might result in some additional operational costs or oversizing some power electronic devices. This evolution opens the possibility to create ancillary service markets for voltage control.

National Grid ESO (2021) identifies several situations with potential voltage issues in Great Britain. Among others: (i) lightly loaded long transmission lines with limited local voltage support generation (West Mindlands); (ii) additional reactive energy flows from (underground) cable circuits, particularly overnight when the demand is low, in combination with reliance on synchronous generator (London); large penetration of small generation offsetting demand and higher reliance on synchronous generator (Southwest Peninsula). All these voltage issues are locational operational needs related with the specific network and instantaneous generation schedule in a particular region.

Appendix B. Annex II: Building the Dataset

The construction of the dataset consists of two steps. First, the calculation of the hourly redispatched energy per technology. Second, the calculation of the hourly change in CO2 emissions due to the redispatched energy.

a) Step 1: the calculation of the hourly redispatched energy per technology.

In the first step of our data collection process, we need to obtain the economically efficient market schedule (EEMS) and the economically and technically feasible schedule (EFTS) per generation technology, i.e., the energy schedule after redispatch actions. Having obtained these two datasets, we can calculate the hourly redispatched energy per technology. The EEMS is the market schedule at the day-ahead stage, including the electricity generation and imports cleared in the day-ahead market, a pan-European auction held at noon the day before delivery, and the data regarding the execution of bilateral contracts with physical dispatch of energy. The raw data is provided by the Spanish NEMO, but to have a useful dataset to perform our estimations requires complex data processing.

As explained in the Section 2, based on the EEMS all the system operators evaluate whether the resultant electricity flows are also technically feasible, i.e., they do not violate congestion limits and fulfill the rest of security criteria. If not, system operators alter specific generation, load pattern, or both, to change the physical flows in the grid. In that regard, as we have access to the EFTS, i.e., the energy schedule after redispatch actions, we can calculate the redispatched energy for each i technology at each t hour using Eq. (9):

[27] If supply does not match demand within a synchronous area, the frequency starts deviating from its reference value. Large frequency deviations can lead to the disconnection of generation and/or load further worsening the frequency with potentially a black-out as the outcome. Electricity can only be stored through the transformation in other energy sources, such as chemical energy in batteries or kinetic energy in pumping plants.

[28] The impedance of the low voltage grids is very small. Consequently, reactive energy is poorly effective to control their voltage. Instead, voltage drops can be controlled by the active energy flows.

$$r_{i,t} = EEMS_{i,t} - EFTS_{i,t} \quad i = [CC, CO, H, N, PG, PV, TS, CHP, B, W] \tag{9}$$

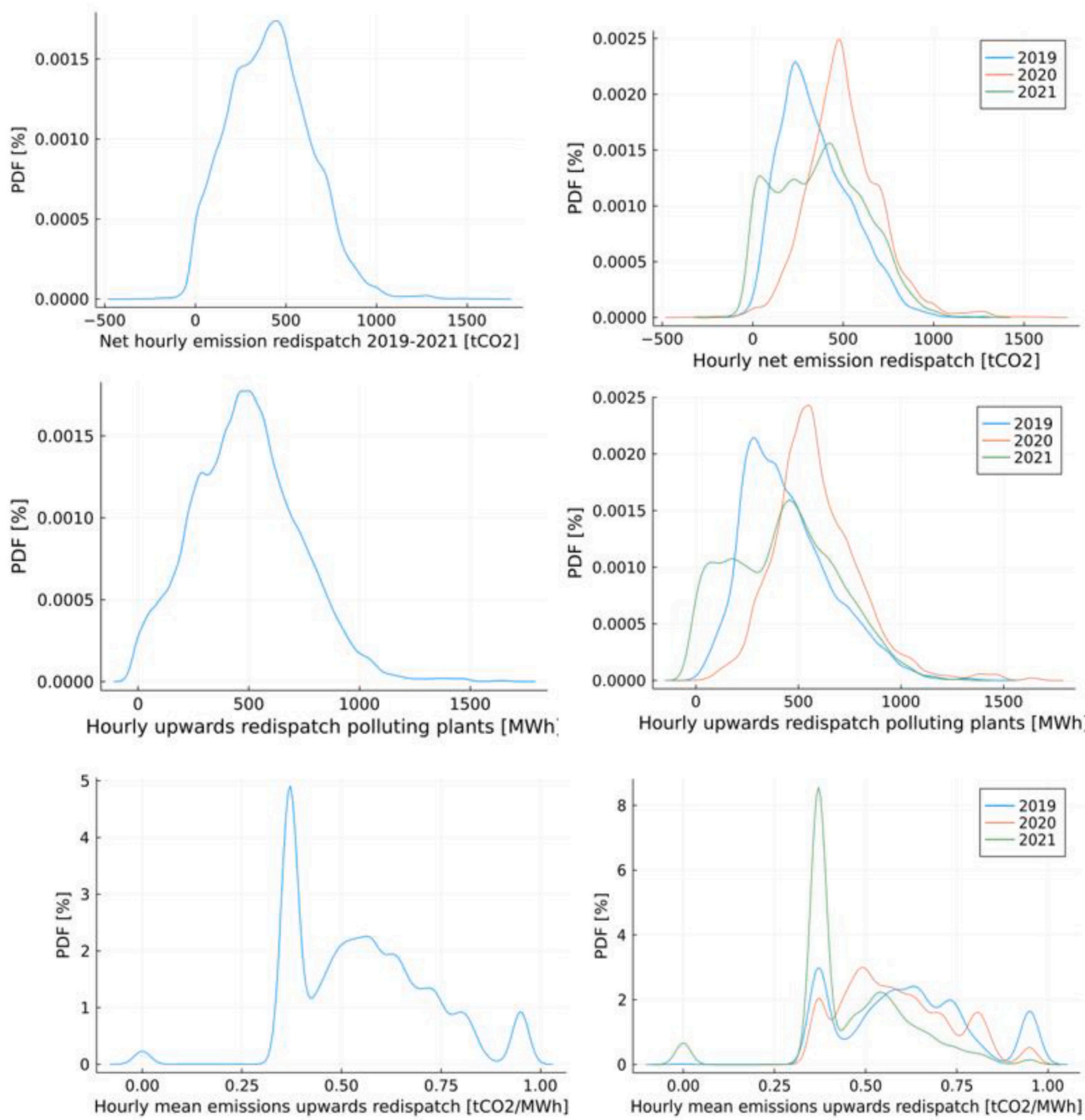
b) Step 2: calculation of the hourly impact of redispatch on CO2 emissions.

In the second step, we calculate for each hour the total CO2 emissions related to the redispatched energy ($CO2_t$) considering the specific emissions per each technology (Eq. (10)).[29] Obviously, $CO2_t$ can be either positive or negative, depending on the generation technologies that are upward and downward redispatched in the particular hour.

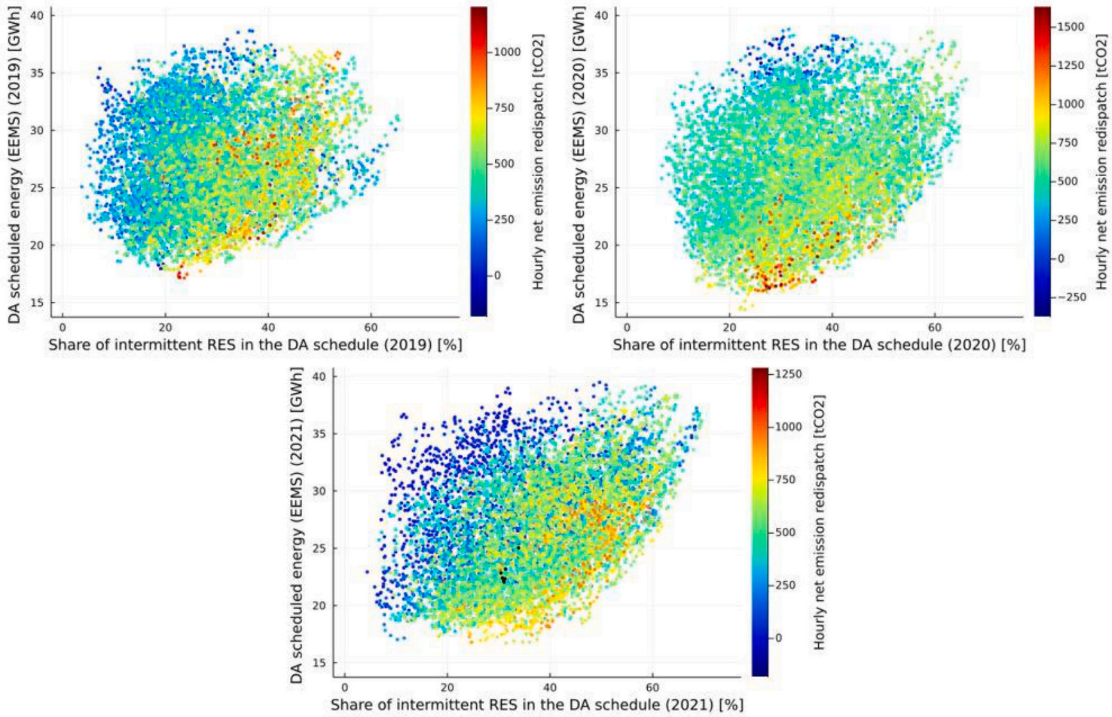
$$CO2_t = 0.34 \bullet r_{CC,t} + 0.95 \bullet r_{CO,t} + 0.38 \bullet r_{CHP,t} + 0.24 \bullet r_{B,t} \tag{10}$$

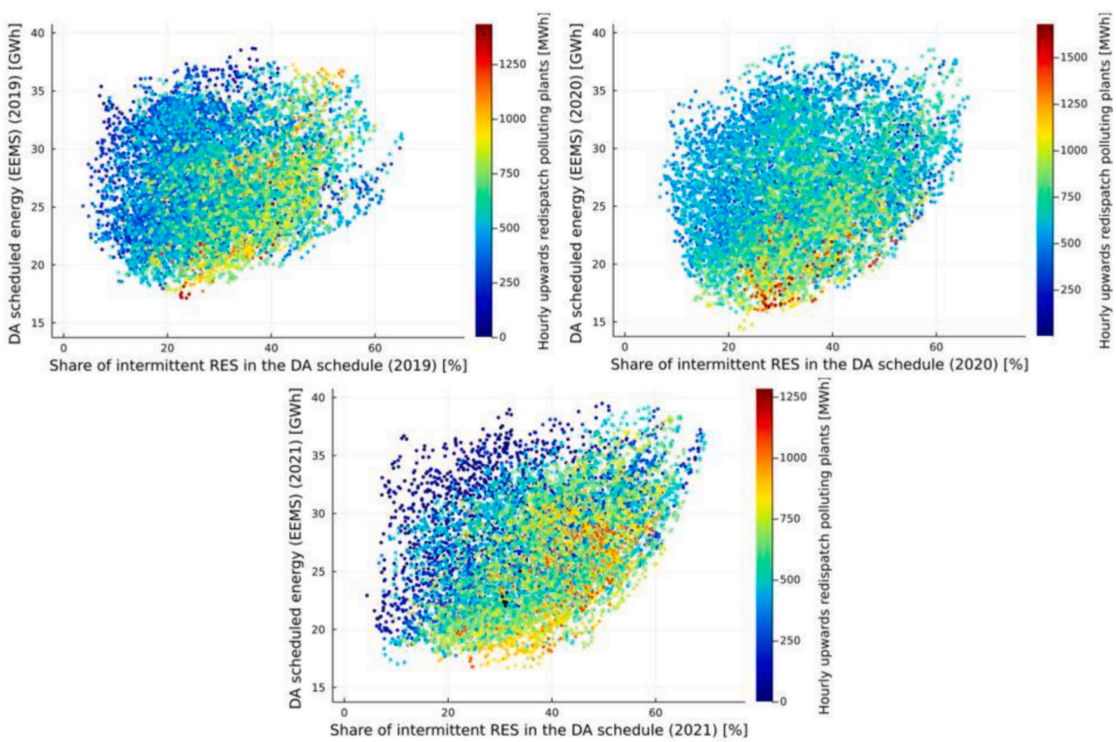
Appendix C. Annex III: Additional Descriptive Statistics of the

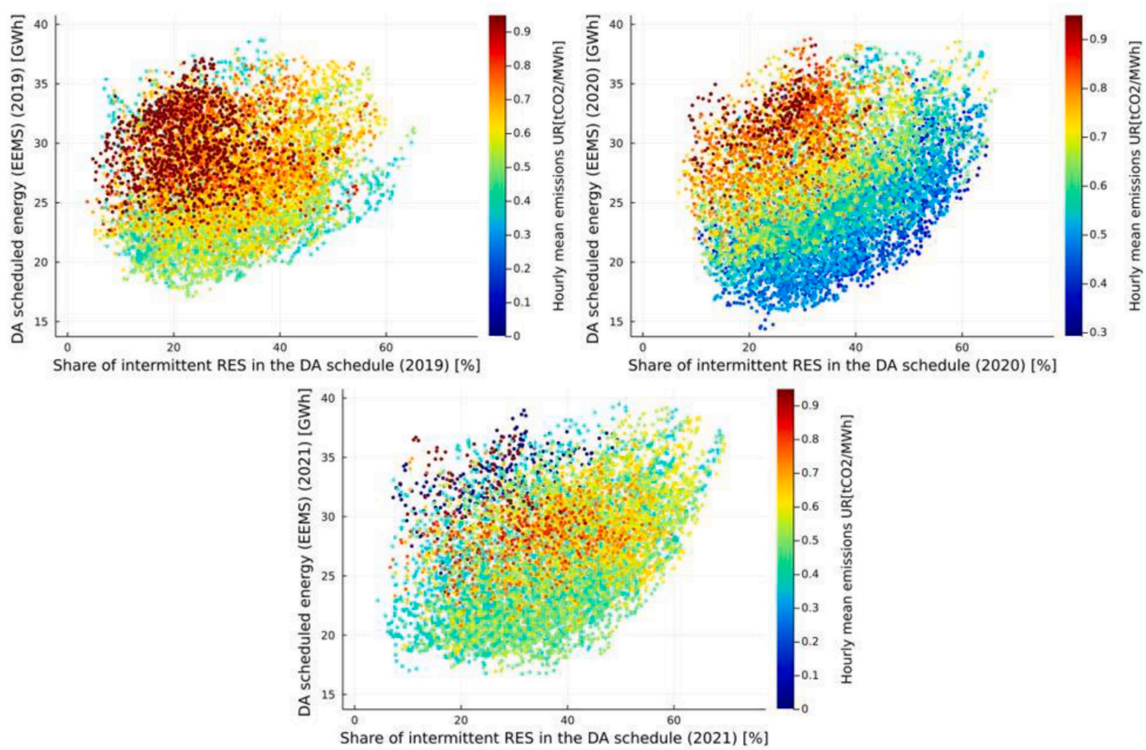
Entire Dataset and Yearly Series



[29] 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.


DA scheduled energy (EEMS) (2019) [GWh]
Share of intermittent RES in the DA schedule (2019) [%]
Hourly net emission redispatch [tCO2]
DA scheduled energy (EEMS) (2020) [GWh]
Share of intermittent RES in the DA schedule (2020) [%]
Hourly net emission redispatch [tCO2]
DA scheduled energy (EEMS) (2021) [GWh]
Share of intermittent RES in the DA schedule (2021) [%]
Hourly net emission redispatch [tCO2]


DA scheduled energy (EEMS) (2019) [GWh]
Share of intermittent RES in the DA schedule (2019) [%]
Hourly upwards redispatch polluting plants [MWh]
DA scheduled energy (EEMS) (2020) [GWh]
Share of intermittent RES in the DA schedule (2020) [%]
Hourly upwards redispatch polluting plants [MWh]
DA scheduled energy (EEMS) (2021) [GWh]
Share of intermittent RES in the DA schedule (2021) [%]
Hourly upwards redispatch polluting plants [MWh]



Appendix D. Annex IV: Stationarity Tests

As we are using hourly data, we perform two stationarity tests to our variables: the ADF test (Dickey and Fuller, 1979), and the KPSS tests (Kwiatkowski et al., 1992). Results are shown in Table 10.

Table 10
Stationarity tests of our variables.

Variable	ADF test		KPSS test	
	Levels	differences	Levels	differences
$CO2_t$	−27.093***	−163.997***	96.2***	0.000651
$EEMS_t$	−23.627***	-76.356***	10.8***	0.000911
RES_t	−14.203***	-69.543***	9.45***	0.001190
ur_t	−27.965***	−156.431***	82.4***	0.000925
$avCO2_t$	−155.700***	−265.878***	0.0112	0.000020
CC_t	−27.748***	−148.660***	31.4***	0.000794
CO_t	−29.698***	−156.520***	58.3***	0.000269
H_t	−51.439***	−193.990***	39.8***	0.000145
N_t	−40.455***	−167.111***	1.12***	0.000162
PG_t	−58.101***	−185.605***	10.5***	0.000249
PV_t	−35.362 ***	−147.155***	12.6***	0.000213
TS_t	−45.840***	−171.590***	8.93***	0.000130
CHP_t	−50.415***	−187.209***	10.6***	0.000195
B_t	−54.269***	−201.732***	8.4***	0.000151
W_t	−32.430***	-173.341***	97.7***	0.000373
I_t	−36.602***	−138.915***	22.0***	0.000202

Note: $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

Appendix E. Annex V: Redispatched Energy from Combined Cycle and Coal

In the Eqs. (11 and 12), we calculate how the redispatched energy by combined cycle ($\Delta r_{CC,t}$) and coal ($\Delta r_{CO,t}$) evolve with the day-ahead scheduled energy ($\Delta EEMS_t$).

$$\Delta r_{CC,t} = \beta_0 + \beta_1 \bullet \Delta r_{CC,t-1} + \beta_2 \bullet \Delta EEMS_t + \beta_3 \bullet m_t + \beta_4 \bullet holiday_t + \\ + \varnothing \cdot \Delta r_{CC,t-24} + \varepsilon_t \quad (11)$$

$$\Delta r_{CO,t} = \beta_0 + \beta_1 \bullet \Delta r_{CO,t-1} + \beta_2 \bullet \Delta EEMS_t + \beta_3 \bullet m_t + \beta_4 \bullet holiday_t + \\ + \varnothing \cdot \Delta r_{CO,t-24} + \varepsilon_t \tag{12}$$

Table 11
ML estimations for each year.

	2019	2019	2020	2020	2021	2021
	(Eq. 11)	(Eq. 11)	(Eq. 11)	(Eq. 12)	(Eq. 12)	(Eq. 12)
	$\Delta r_{CC,t}$	$\Delta r_{CO,t}$	$\Delta r_{CC,t}$	$\Delta r_{CO,t}$	$\Delta r_{CC,t}$	$\Delta r_{CO,t}$
Scheduled Energy ($\Delta EEMS_t$)	−0.0294****	0.00910****	−0.0260****	0.0101****	−0.0443****	0.00488****
	(0.00113)	(0.000750)	(0.00149)	(0.000693)	(0.00139)	(0.000587)
Renewables (ΔRES_t)	7.841****	0.480	4.240****	−0.630	7.944****	0.709**
	(0.699)	(0.434)	(0.843)	(0.390)	(0.654)	(0.287)
Holiday)	3.136	0.0170	4.615	−1.751	3.319	0.412
	(2.368)	(1.411)	(3.239)	(1.318)	(3.085)	(1.117)
Lagged ($\Delta r_{CC,t-1}$)	−0.0872****		−0.0542****		−0.0995****	
	(0.00918)		(0.00760)		(0.00922)	
Seasonality ($\Delta r_{CC,t-24}$)	0.480****		0.563****		0.562****	
	(0.00470)		(0.00357)		(0.00449)	
Lagged ($\Delta r_{CO,t-1}$)		−0.0787****		−0.118****		−0.0671****
		(0.00992)		(0.00975)		(0.00712)
Seasonality ($\Delta r_{CO,t-24}$)		0.516****		0.511****		0.570****
		(0.00481)		(0.00532)		(0.00405)
Constant ($\widehat{\beta_0}$)	112.8****	66.28****	143.1****	67.39****	144.8****	54.99****
	(0.393)	(0.192)	(0.343)	(0.256)	(0.506)	(0.130)
N	8735	8735	8783	8783	8759	8759
Seasonality						
Month	Yes	Yes	Yes	Yes	Yes	Yes
Weekends & National holidays	Yes	Yes	Yes	Yes	Yes	Yes

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

Appendix F. Annex VI: Long-Run CO2 Emissions

The long-term effects for photovoltaics $(CO2_{PV,LT})$ and wind $(CO2_{W,LT})$ are calculated with Eqs. (13 and 14), respectively.

$$CO2_{PV,LT=}\beta_7/[(1-\beta_1-\varnothing)] \tag{13}$$

$$CO2_{W,LT=}\beta_{11}/[(1-\beta_1-\varnothing)] \tag{14}$$

Table 12
Long-term CO2 emissions effects from each technology.

	2019	2020	2021	Maximum
Photovoltaics $(CO2_{PV,LT})$	0.00000	0.02114	0.00508	0.02114
Wind $(CO2_{W,LT})$	0.00881	0.00634	0.00635	0.00881

Appendix G. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2023.107164.

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