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Network Operation Constraints on the Path to Net Zero

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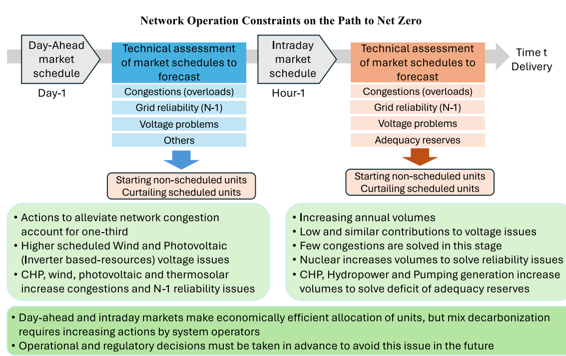
HIGHLIGHTS

- In 2023, redispatching in Spain cost 2 b€ - curtailed 3 TWh wind, 0.9 TWh solar
- Drivers of redispatching energy: Voltage (49 %), congestions (16 %) and N-1 (19 %)
- Inverter-based resources aggravate voltage problems.
- CHP, Wind and Photovoltaics aggravate congestion issues
- Thermosolar increase volumes by reliability (N-1).

GRAPHICAL ABSTRACT



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ABSTRACT

Operating a reliable electricity system requires strict safety and security criteria such as avoiding grid congestion, minimum levels of inertia, maintaining voltage levels, and minimum adequacy reserves. However, large scale integration of intermittent renewables, namely inverter-based resources (IBR), is creating operational challenges. When operational security criteria are not met, system operators use ancillary services (redispatching) to activate or curtail scheduled units to manage the flows. In Spain, the volumes and costs of redispatching have multiplied by two and nine times between 2019 and 2023, respectively. In 2023, the total costs amounted to 2 b€, for curtailing 3 TWh wind and 0.9 TWh photovoltaics. A similar picture is emerging in other countries. This is the first study to examine the determinants of network constraints associated with redispatched volumes at country level. We use the seasonal autoregressive ARIMA time-series estimators with hourly operational and market data (2019–2023). Results show that actions to alleviate grid bottlenecks amount to one-third of the volumes, and increasing every year with addition of wind, photovoltaics and thermosolar generation. Volumes for solving voltage issues (reactive energy needs) represent one-half. Scheduled MWh from IBR (wind and photovoltaics) increases volumes for voltage problems (+0.05 MWh) and congestion issues (+0.01 MWh). Scheduled MWh from CHP contributes to congestion issues (+0.18 MWh), while thermosolar to grid reliability (N-1) problems (+0.25 MWh). The day-ahead and intraday markets can make economically efficient allocation of units, but massive

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connection of renewables requires increasing actions by system operators. Operational and regulatory decisions must be taken in advance to avoid the issue in the future.

1. Introduction

Renewable energy sources (RES) are essential for decarbonizing power systems and achieving Net Zero greenhouse gas (GHG) emission target by 2050 [1]. Transmission and distribution grids are the backbone of the electricity system and transport the renewable energy from production to consumption areas. IEA [2] states that countries need to pay more attention to grids to support large scale integration of RES to connect the anticipated large amount of them. They estimate that achieving current environmental targets it is essential to add or refurbish over 80 million kilometers of grids until 2040. In many countries, the lack of hosting capacity is constraining the connection of new RES and estimates 3TW of RES are waiting in grid connection queues. IEA emphasizes the need to improve grid operation to accommodate the intermittent generation sources. Grid investments needed to achieve the clean energy transition targets in Europe amount to 584 billion of € [3]).

Efficient integration of RES requires enough grid hosting capacity to avoid congestion and bottlenecks while respecting other operational constraints such as minimum grid reserves, voltage constraints, or minimum adequacy reserves. Decarbonizing the mix is very relevant since RES production is intermittent, variable and dependent on weather conditions [4,5]. Moreover, they are inverter-based resources (IBR) made of power electronics converters, whose operational and dynamic response to control frequency or voltage differs from synchronous fossil fuel, i.e. spinning electromechanical machineries [6]. After the publication of day-ahead and intraday-market schedules, system operators assess whether for the next hours they would respect the operational constraints. If not, they activate non-scheduled units and curtail other scheduled units through ancillary services paid by customers, referred to as redispatching in Europe.[1] This is essential for a reliable and safe grid operation that minimizes the risk of blackouts and their economic impact [7]. O'Shaughnessy et al. [8] state that in 2018, relevant scheduled volumes of PV were curtailed in several key markets: 6 % in Chile, 3 % in China, 1.5 % in California, 8.4 % in Texas, and 2.9 % in Hawaii. In Europe, redispatched volumes in 2022 reached 50 TWh. Some studies forecast up to 240 or 800 TWh in 2040, depending on the grid investments and locations of RES [9].

However, to our knowledge, the impact of technologies and IBR (RES) on different network operational constraints at a highly decarbonized power system national level has not been empirically assessed. A similar analysis is Davi-Arderius and Schittekatte [10], where the CO2 emissions from the redispatching actions made after the day-ahead markets in Spain during the covid lockdown are assessed. They find that these actions produced 11 % of the total CO2 emissions in the power system. Moreover, these volumes amounted to curtailment of up to 8 % of all the wind scheduled production. Moreover, Davi-Arderius et al. [11] forecast volumes of redispatching actions based on several scenarios and find that installing 10 GW of small consumption behind the meter would require activating +1 TWh of energy from Combined Cycles, with an annual cost of 133 M€. However, both studies do not consider actions after the intraday markets and the disaggregated root source behind volumes either. The present analysis has general relevance and sheds light on future operational constraints in other countries with high levels of RES. Solving operational constraints requires a combination of inter-related long-term solutions to be taken in advance. These include requesting additional technical capabilities for new RES, limiting excessive concentration of RES in some grid areas, defining an optimal combination of different RES technologies across the system, setting specific tariffs to incentivize demand in certain hours or regions, implementing ancillary services, or boosting investments in grid digitalization to anticipate network constraints and set the most optimal solution.

The aim of this paper is to analyse the determinants of network operational constraints in a highly decarbonized power system, namely Spain. This study covers 2019–2023 and combines market data from the Spanish Nominated Energy Market Operator (NEMO) with operational data from the Spanish Transmission System Operator (TSO) [12,13].[2] This includes the hourly scheduled energy by technology in the day-ahead and intraday markets in the Spanish bidding zone, as well as hourly volumes activated to solve operational constraints. These actions are known as 'redispatching' in Europe. The combination of market and operational data is another contribution of this analysis. Empirical approach has three steps. First, the calculation of short-term contribution of each technology on volumes from each operational constraint on the day-ahead and intraday markets. This analysis of time-series datasets is made with seasonal ARIMA time-series estimator (SARIMA) method, where lagged dependent variables of the previous hour (h-1) and previous day (h-24) are included to capture time dynamics. All variables are differentiated to ensure their stationarity [14]. Second, the calculation of the long-term contribution (average in each year) of each technology on volumes from each operational constraint on the day-ahead and intraday markets. Third, total contribution – i.e. contributions of the day-ahead and intraday in the previous step. In Spain, volumes activated by redispatching actions are significant. In 2023, they required curtailing 3 TWh from wind, 0.9 TWh from photovoltaics and 0.5 TWh from thermosolar, while activating 6.6 TWh from Combined Cycle, and 2.2 TWh from Coal plants. This study can be considered a first step in the analysis of determinants of volumes redispatched due to network constraints.[3]

The remainder of the paper is organized as follows. Section 2 reviews the literature about the integration of RES. Section 3 describes the Spanish case. Section 4 outlines the methodology and empirical strategy. Section 5 describes the data used. Section 6 presents the results. Finally, Section 7 is conclusions.

2. Integrating RES in the power system

2.1. Grid planning

The energy planning and potential impacts of RES on electricity flows, congestion and future grid investments have attracted the attention of many scholars. The decarbonization of the power system substantially changes the electricity flows. In many cases, the optimal locations for new RES -considering maximum annual production- do not match with the location of the replaced polluting plants or with the available grid capacity [15]. In recent years, the limited grid capacity to connect new installations is one of the main barriers to connect new RES as they also require additional grid investments.[4] In energy economics

[1] The use of the term system operator refers either to Transmission System Operator (TSO) or Distribution System Operator (DSO).

[2] The Nominated Electricity Market Operator (NEMO) corresponds to the entity designated by the competent authority to perform tasks related to single day-ahead or single intraday market coupling. Link: https://www.nemo-committee.eu/

[3] The methodology in this study does not consider the locational position of activated and curtailed units. This would require additional data and different methodology, which are out of the scope of this analysis.

[4] https://www.iea.org/reports/is-the-european-union-on-track-to-meet-its-repowereu-goals.

literature, there are mainly three types of models about the grid planning.

First, the techno-economic models are related to the energy system optimization models and provide results on economic variables. They complement the traditional optimal power flow models used in the assessment of the potential economic benefits from transition to nodal pricing or splitting bidding zones as work made by Kunz et al. [16], who find that nodal pricing in Germany would improve the economic efficiency of the system operation, but consumer surplus in some regions might be negatively affected. In transmission grids, techno-economic models use exogeneous assumptions on capacity expansion. Oei et al. [17] applies the same models to regional characteristics for high renewable configurations to China, India, South-Africa, Mexico, Europe, Germany, and Colombia. However, they conclude that results from these models largely depend on the assumptions and hypothesis made, some values are difficult to measure, and use several endogenous technology choices. Sarmiento et al. [18] apply GENeSYS-MOD, ReEDS 2.0, urbs-MX and NANGAM models to examine the impact of natural gas prices on the power systems of Mexico and the US and find that high gas prices increase the use of carbon and oil in the short-term, while low gas prices have heterogeneous effects across models and scenarios. Rahdan et al. [19] quantify the potential impacts of distributed generation on distribution costs and electricity losses at European level through the PyPSA-EurSec open model and find that incorporating distributed photovoltaics decreases the total system cost in all scenarios. Finally, Costa-Campi et al. [15,20] study the Spanish transmission grid with gravity models and quantify potential grid investments related to different location for new RES and find that concentrating RES only in its most optimal locations would end with higher grid investments to solve network bottlenecks.

The second type are economic models that analyse the inputs and outputs of the energy markets in the economy, and economic variables such as prices, elasticities, gross domestic product, employment, or CO2 emissions. Transmission network is considered as an input, and results are obtained for different assumptions and scenarios of grid capacity investment. For instance, Hancevic et al. [21] develop an economic framework to provide insights into the economic and environmental effects of promoting the RES industry in Mexico. They find that maintaining the status quo energy policy would only benefit the government-owned electricity company revenues. Gutiérrez-Meave et al. [22] analyse the potential economic effects of accelerated electrification and decarbonization in selected Latin American countries with an economic equilibrium model. They find that local employment is positively affected by wind projects, but not for solar ones.

In the third type of models, incentive-based regulatory models bi-level programming combine a power-flow model (lower-level) with an incentive-regulatory model (upper-level) that incentivize and efficiently expansion of the transmission grid. Hogan et al. [23] study the regulatory approaches to transmission expansion compatible with merchant investment in the context of price-taking generators and loads. Zenón and Rosellón [24] study transmission planning of the Mexican electricity market and analyse welfare-optimal network expansion with two modeling strategies: an incentive price-cap mechanism to promote the expansion of Mexican networks, and a centrally planned grid expansion by an independent system operator (ISO) within a power-flow model. They show that an incentive price-cap regulation converges to optimal welfare transmission expansion for the Mexican transmission grid. Hesamzadeh et al. [25] study electricity transmission pricing and investment with the HRGV approach, based on a bilevel optimization with the transmission company (Transco) at the top and the ISO at the bottom level. They find that this approach leads to optimal pricing/investment.

The outcomes of all the previous models are used to set regulatory framework for an optimal grid expansion [26,27]. In them, grid investments are associated with potential congestion or grid bottlenecks. However, there are other operational constraints that limit the full operation of RES (IBR) such as inertia or voltage control issues [8]. These are known as operational security criteria. This study is not based on any of the three previous models related to grid optimization. Instead, this is an (ex-post) empirical assessment of time-series dataset from a national power system, with hourly time granularity. These kinds of analysis provide insightful results and have been used before in economic studies. Its computation needs and complexity are not the same [10,11,28].

2.2. Operational security criteria

A reliable operation of the power systems requires compliance with specific grid operation security criteria such as respecting thermal limits, maintaining flows, voltage and frequency within predetermined levels, and ensuring minimum capacity reserves [29]. In the short-term, system operators must forecast energy flows and validate if these criteria are met for the next hours or days and, if needed, take corrective actions. In real-time, system operators must also validate these criteria with monitoring devices. The following are the main security criteria for a safe grid operation. Appendix A describes further details of these security criteria and potential mitigation measures that system operators might use.

- **Thermal limits**: Each element of the grid has a maximum capacity for energy flows, also known as thermal limit or maximum congestion level. Congestion in parts of the grid, are expected to be positively correlated with the total electricity demand or higher volumes of RES production [30].
- **Grid reliability**: Relates to the redundant grid to assume the disconnection of a line or transformer without disrupting the electricity supply. They are also known as N-1 or N-2 security criteria if it refers to the disconnection of one or two grid assets, respectively. Grid reliability issues are expected to follow similar patterns as congestion [30].
- **Voltage**: An electrical parameter that must be within predetermined levels to ensure the safety conditions of the network and quality of supply. Voltage problems are more likely to happen during low demand times because of the surge impedance loading (SIL) effect: the load level determines whether a line behaves as a capacitor that injects reactive energy (and increases voltage), or as an inductance that consumes reactive energy (and reduces voltage) [31].
- **Frequency**: Relates to the oscillation of voltage generated by rotating machines which corresponds to its nominal value (50 Hz in Europe and 60 Hz in the US) when generation and consumption are balanced. Thus, frequency stability issues are more likely to happen when volumes from synchronous generation decrease [6,32].
- **Adequacy reserves**: Relates to the volume of dispatchable (upward and downward) scheduled generation to cover the forecast demand and immediately solve unbalances between generation and consumption. They are essential to address short-term time-variability of RES.[5] Deficit of adequacy reserves are more likely to happen when volumes of dispatchable technologies are low [33].

There are many theoretical studies on the impact of high shares of IBR in the system. In the UK, Homan et al. [34] analyse historic frequency data and assess the future frequency response requirements in 2030. They find that the frequency response needs to be fast acting to address lower levels of inertia. ENTSOE [35] study the cases that might cause a Rate of Change of Frequency (RoCoF) higher than 1 Hz/s due to its high potential risk of leading to a blackout. Johnson et al. [36]

[5] Short-term time variability of RES includes changes of photovoltaic or wind production that last seconds or minutes. For instance, when clouds move.

analyse the ERCOT to assess safe inertia levels under different levels of RES. They find that addressing low inertia levels increases the system costs by about 2 % and CO2 emissions by 3.4 % above the baseline scenario in 2030. As a solution for low inertia levels, they propose complementary mechanisms such as price signals to procure inertia contributions, plants retirements or fast frequency response services.

There are also several empirical about the redispatching actions and RES curtailments (see Table 1). O'Shaughnessy et al. [8] state that in 2018, scheduled volumes of PV were curtailed in several key markets: 6 % in Chile, 3 % in China, 1.5 % in California, 8.4 % in Texas, and 2.9 % in Hawaii. These numbers represented more than 6.5 million MWh of PV production. Davi-Arderius and Schittekatte [10] find 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. This is a consequence of the need to replace IBR (wind and photovoltaics) by synchronous generators (combined cycle and coal) in the day-ahead scheduling. Davi-Arderius et al. [11] forecast volumes of redispatching based on several scenarios and find that installing 10 GW of small consumption behind the meter would require activating +1 TWh of energy from Combined Cycles, with an annual cost of 133 M€. However, empirical assessments of actions behind volumes of redispatching by system operators at national level has not been explored.

Table 1
Main literature related to the redispatching and curtailment actions.

Reference	Aim	Main findings
O'Shaughnessy et al. [8]	o Study the photovoltaic curtailment in four key countries: Chile, China, Germany, and the United States	• 6.5 million MWh of PV was curtailed in these countries (2018). This represented high volumes of scheduled PV: 6 % in Chile, 3 % in China, 1.5 % in California, 8.4 % in Texas, and 2.9 % in Hawaii • Some PV curtailment is attributable to limited transmission capacity connecting remote solar resources to load centers
Savelli et al. [37]	• Assessment of Contract for Differences on redispatching in the UK	• Connecting RES increase congestion management costs by £5.61/MWh and CO2 abatement is reduced by 9 % due to redispatching actions
Joos and Staffell [38]	• Assess operating costs (congestion management, balancing services) from integrating RES in the UK and Germany	• In 2016, scheduled wind curtailed was 5.6 and 4.46 % in the UK and Germany, respectively, with a cost of 426 M€ and + 2.1 Tn CO2 • Balancing costs in Germany decreased
Davi-Arderius and Schittekatte [10]	• CO2 emissions from redispatching actions in Spain after day-ahead (2019–2021), especially during covid lockdown	• Redispatching actions produced 11 % of the total CO2 emissions in the power system during covid lockdown. Moreover, these volumes amounted to curtailment of up to 8 % of all the wind scheduled production • Emissions from day-ahead markets are downward biased +0.00391 and + 0.0145 tn of CO2 for each additional MWh of renewable
Davi-Arderius et al. [11]	• Costs from redispatching actions after day-ahead (2019–2022). • Forecast volumes of redispatching actions based on several scenarios	• Each scheduled MWh of IBR (wind and photovoltaics) results in +6.24 € related to costs from redispatching actions after day-ahead (after intraday markets is not considered) • Installing 10 GW of small consumption behind the meter would require activating +1 TWh of energy from Combined Cycles (133 M€/year)
Novan and Wang [39]	• Assess the curtailed photovoltaic production in California	• Curtailments of solar production are around 9 %
Petersen et al. [40]	• Assess wind impacts on consumer welfare in Spain (2009–2018)	• Operational costs increased on +0.19 €/MWh compared to an average of 3.85 EUR/MWh

(Source: own elaboration)

2.3. Technical solutions

Table 2 summarizes the technical solutions to deal with operational problems: thermal limits, voltage control and frequency (inertia). The table also identifies which regulatory instruments can be used for each technical solution. Below they are described:

- **Operational rules**: refers to the criteria used to operate the transmission and distribution grids, which define situations under which grid should be reconfigured, i.e. transformers or lines should be switched [41].
- **Grid planning criteria**: means the criteria used by system operators to build new lines and transformers, or reinforce existing ones [42].
- **RES (IBR) requirements**: refers to the technical requirements that RES should fulfill when they connect, including IBR. In Europe, they are set in the Grid Connection Codes and their national implementation rules [43].
- **Ancillary or local services**: consist of services necessary for the operation of the power system, but not including congestion management. These services can or not be procured under market-based (Electricity Regulation (EU) 2019/943).
- **Hourly ToU tariffs**: include different hourly charges to incentivize consuming electricity on some periods over others. Tariffs might also be time-spatial dependent [44].

However, when the previous solutions are not sufficient, system operators should activate non-scheduled units in the market and curtailed other scheduled units. These is made by the redispatching processes explained in the next section.

3. Redispatching in Spain

The Electricity Directive (UE) 2019/944 mandates system operators to ensure secure operation of the grid and if some network operational constraint is not respected, they should take action. First, they should use (non-costly) solutions such as changing network configuration with the operation of lines. When these actions are not sufficient, they should reschedule production (or consumption) from specific generators (or consumers), namely redispatching actions in Europe.[6]

In 2020, the costs of remedial actions in the European countries amounted to 3.6 billion Euros, and redispatching 2.3 billion Euros. At the EU level, Germany, Poland, and Spain have the highest volumes of energy redispatching, while Italy, Spain and Germany have the highest

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

Table 2
Technical solutions and their potential impact on three operational constraints. For details see Appendix A.

	Does the technical solution solve the operational constraint?				Regulatory instrument				
Technical solution	**Congestions and grid reliability** (need to curtail units)	**Voltage control** (need to replace RES by synchronous)	**Frequency (inertia)** (need to replace RES by synchronous)	**Adequacy reserves** (need to start thermal units)	*Operating rules*	*Grid planning criteria*	*RES requirements*	*Ancillary or Local Services*	*Hourly ToU tariffs*
Higher cross-border capacity	Yes	Yes, in the case of HVDC connections	Yes	Yes		X			
New lines and transformers	Yes	Yes, if loads in HV lines are above SIL	Yes, if interconnect different areas	No		X			
Switching lines and transformers	Yes	Yes, if loads in HV lines are above SIL	Yes, if interconnect different areas	No	X				
Dynamic Line Rating (DLR)	Yes	No	No	No	X	X			
Higher consumption in the affected nodes	Yes, if reduces need to transmit energy over long distances	Yes, if loads in HV lines are above SIL	Not clear (consumption reduces inertia)	No	X				X
New capacitors and reactances	No	Yes	No	No		X			
Storage in the RES curtailed plants	Yes	Yes, for storage in GFM	Yes, for storage in GFM	No			X	X	X
Virtual inertia in IBR+ battery	No	No	Yes	No			X	X	
Grid forming in IBR	No	Yes	Yes	No			X	X	
Flywheels in IBR	No	No	Yes	No		X	X	X	
Synchronous condensers	No	Yes	Yes	No		X	X	X	
Advanced IBR in RES to control reactive energy	No	Yes	No	No			X	X	
Higher withstand capability of RES IBR (RoCoF>1 Hz/s)	No	No	Yes	Might reduce needs of reserves			X	X	
Static synchronous compensators (STATCOM), flexible AC transmission system (FACTS)	Yes, they can control flows in meshed grids	Yes, for STATCOM with batteries	Yes	No		X	X	X	

Source: Pérez-Arriaga [30], Mishra et al. [41], ENTSOE [33,35], *Gu and Green [6], Ahmed et al. [32],* Davi-Arderius et al. [45] *and own elaboration.*
Note: Dispatchable energy reserves are not included in this table as they can only be solved through activating generators and consumers.

costs. This highlights the impact of these actions in the costs for customers [46].

As shown in Fig. 1, redispatching processes in Spain are divided in three Stages. Table 3 details the processes followed by system operators in each Stage. In all cases, solutions implemented by system operators are always the same. First, changing the network topology, changing the substation configuration, or switching reactances or capacitors. If these actions are not enough, TSO and DSO should curtail (or start) a scheduled unit (non-scheduled unit) in the market.

Redispatching actions are economically compensated considering the criteria in Table 4. Precisely, non-compensating the curtailed generators in the Stage 1 is behind many complaints by RES owners.[7]

In Spain, the annual costs for volumes between 2019 and 2023 have multiplied by nine and amount to 2.15 b€ in 2023. In 2022 the annual volumes of activated energy in the day-ahead decreased from 8042 GWh to 5856 GWh (−27 %), which coincides with the implementation of the new *Sistema Automático de Reducción de Potencia* (SARP).[8] According to ACER and CEER [46], 71 % (300 M€) of the redispatched costs in the day-ahead in 2020 were used to solve voltage issues. This highlights that overloads were not the main problem in the day-ahead, which might be explained by the relevant investments made in the transmission grid during the last decade and its criterion of prudence in connection of new RES [52].[9] See Table 5.

[7] https://www.elmundo.es/economia/empresas/2023/07/21/64ba9be9e9cf4a5e368b45a3.html

[8] Under this mechanism, generators -that voluntarily participate- must be tripped (in seconds) by the system operator when some security criteria are not respected. In consequence, system operators do not need to fulfill the N-1 security criteria and generators are not preventively curtailed. However, volumes in 2023 increase again. In the same period, volumes in day-ahead and real-time increased by 56 and 1797 %, respectively. https://www.cnmc.es/prensa/procedimiento-congestiones-20220125

[9] Between 2010 and 2020, the length of 400 kV lines increased from 18,799 km to 21,764 km (+15.6 %), and the length of 220 kV lines increased from 17,755 km to 19,939 km (+12.3 %). Source REE [13]. In Spain, the assessment to connect RES includes avoiding grid congestions.

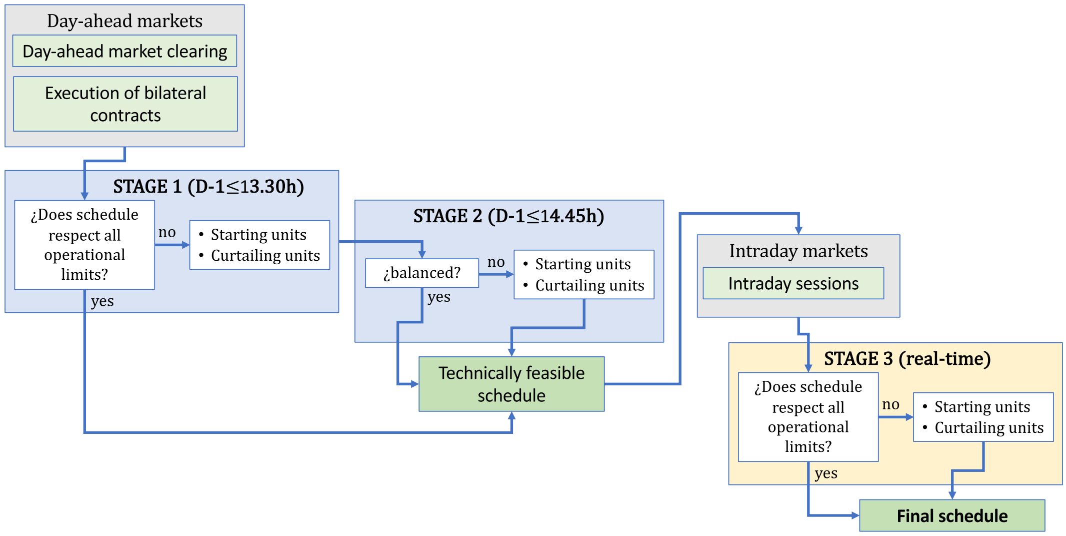

Fig. 1. Flowchart describing the processes for remedial actions in the day-ahead (redispatching in Stages 1 and 2) and in real-time (Stage 3). Source: own elaboration based on MICT [47].

Table 3
Processes made by system operators in each Stage.

Stage	Processes followed by system operators
1	System operators carry out a security analysis of the day-ahead market schedule assess potential problems related to congestions, voltage, grid reliability (N-1), frequency stability, inertia, reactive energy flows and adequacy reserve of upwards/downwards dispatchable units
2	TSO must restore the system balance, i.e. the sum of the of generation (and imports) must equal to the sum of consumption (and exports)
3	The process of the Stage 1 is repeated, but on the intraday-market schedules instead

Source: Own elaboration based on MICT [47,48] and CEER [49]

Table 4
Economic compensation scheme to the redispatched units in the Spanish Regulatory Framework Source: MITECO [50] and CNMC [51]

		Upward actions	Downward actions (curtailment)
Day-ahead	**Stage 1**	Compensated at bid prices	Not compensated
	Stage 2	Compensated at bid prices	Compensated at bid prices
Real-time	**Stage 3**	Compensated at bid prices	Compensated at bid prices

4. Empirical approach

This section describes the empirical approach followed to analyse the determinants of the network operational constraints in Spain (2019–2023). As shown in Fig. 2, this process is divided into 3 steps. First, estimations of the (short-term) contributions of each technology on volumes by operational constraint in the day-ahead and real-time with the day-ahead models and intraday models. In both cases, dependent variables correspond to the volumes associated to each operational constraints, while explicative variables to the scheduled generation in the day-ahead and intraday-markets. Second, the calculations of long-term contributions, i.e. average contribution each year. Third, the total contribution of each technology to each operational constraint summing the volumes on the day-ahead and real-time. Below, the three steps are defined.

4.1. Step 1: Short-term contributions

The short-term contribution of each technology on the operational constraints are calculated using the scheduled energy at each stage (day-ahead and intraday) and the volumes of energy by operational constraint in the same stage. Short-term corresponds to the impact of the scheduled generation on the volumes for the next hour.

4.1.1. Day-ahead models

The Day-ahead Technology Model estimates how the volumes activated after the spot market gate closure are determined by the scheduled generation for each technology ($daTECHN_{i,t}$). The dependent variable is the activated energy associated with the following network constraints: voltage issues (*daVoltage*), congestions (*daCongestions*), grid reliability (*daReliability*), or others (*daOthers*). The scheduled technologies are nuclear (*N*), combined cycle (*CC*), coal (*CO*), hydropower (*H*), pumping generation (*PG*), combined heat and power (*CHP*), thermosolar (*TS*), photovoltaic (*PV*), wind (*W*), and cross-border flows (*I*). Eq. (1):

Table 5
Annual volumes and costs.
Source: REE [13].

		Units	2019	2020	2021	2022	2023
Day-ahead (Stages 1 + 2)	Annual demand	GWh	249,900	237,205	243,862	235,437	229,282
	Volumes	GWh	7058	9979	8042	5856	11,030
	Economic cost	M€	239	423	443	473	912
Real-time (Stage 3)	Volumes	GWh	290	1091	2345	2429	5502
	Economic cost	M€	7.2	103	421	796	1233
Total	**Volumes**	GWh	**7248**	**11,070**	**10,387**	**8285**	**16,532**
		(% annual demand)	2.90 %	4.67 %	4.26 %	3.52 %	7.21 %
	Economic cost	M€	**246**	**526**	**864**	**1269**	**2145**

Note: Redispatched energy corresponds to the sum of the upward and downward energy redispatched.

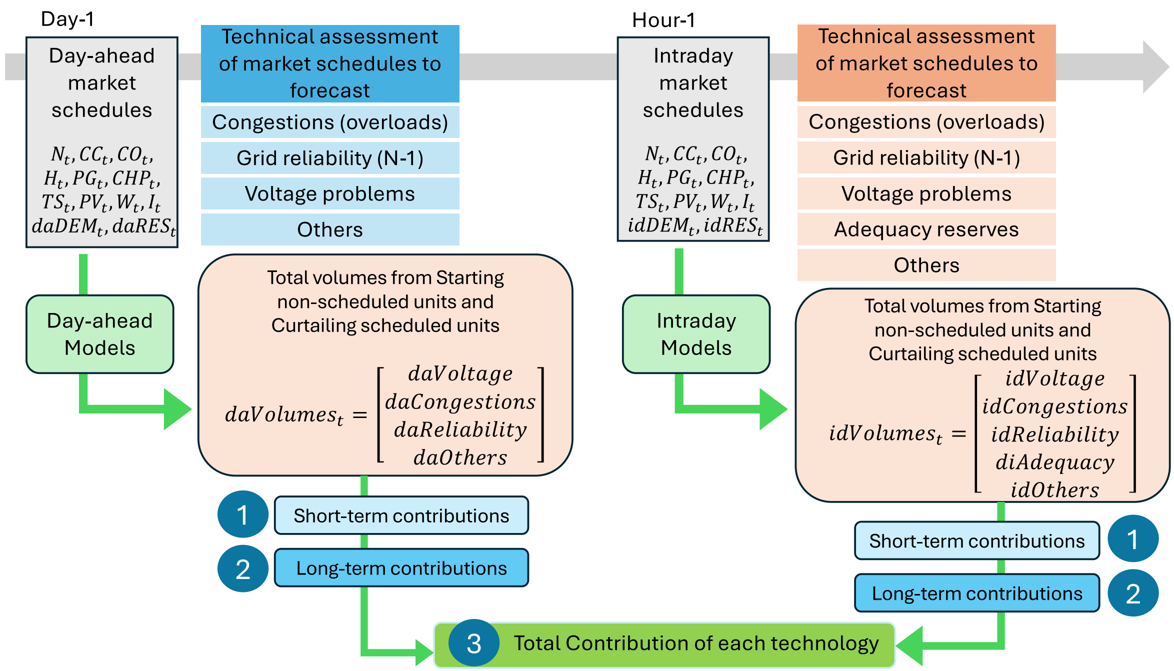

Fig. 2. Flowchart with the methodology followed in this analysis. Numbers identify outputs of each step.

$$daVolumes_t = \widehat{\beta}_0 + \widehat{\beta}_1 \cdot daVolumes_{t-1} + \widehat{\beta}_2 \cdot daTECHN_t + \widehat{\beta}_3 \cdot holiday_t + + \sum_{m=1}^{11} \widehat{\delta}_m \cdot M_t^m + \widehat{\varnothing} \cdot \Delta daVolumes_{t-24} + \varepsilon_t \quad (1)$$

$$daTECHN = \begin{bmatrix} N, CC, CO, H, PG, CHP, TS, PV, W, I \\ daDEM, daRES \end{bmatrix}$$

$$daVolumes_t = \begin{bmatrix} daVoltage \\ daCongestions \\ daReliability \\ daOthers \end{bmatrix}$$

The Day-ahead Demand Model analyses how the volumes activated are determined by the total demand after the day-ahead markets (*daDEM*) and the percentage of IBR in the scheduled generation (*daRES*). As before, the dependent variable is the activated energy associated with each network constraint. Eq. 2:

$$daVolumes_t = \widehat{\beta}_0 + \widehat{\beta}_1 \cdot daVolumes_{t-1} + \widehat{\beta}_2 \cdot daDEM_t + \widehat{\beta}_3 \cdot daRES_t + \widehat{\beta}_4 \cdot holiday_t + \sum_{m=1}^{11} \widehat{\delta}_m \cdot M_t^m + \widehat{\varnothing} \cdot \Delta daVolumes_{t-24} + \varepsilon_t \quad (2)$$

$$daVolumes_t = \begin{bmatrix} daVoltage \\ daCongestions \\ daReliability \\ daOthers \end{bmatrix}$$

In this case, the total scheduled demand after the day-ahead market (*daDEM*) and the rate of IBR (non-synchronous) in the total demand (*daRES*) is calculated as shown in Eqs. 3 and 4.

$$daDEM_t = N_t + CC_t + CO_t + H_t + PG_t + CHP_t + TS_t + PV_t + W_t + I_t \quad (3)$$

$$daRES_t = \frac{PV_t + W_t}{daDEM_t} \quad (4)$$

4.1.2. Intraday models

The Intraday Technology Model analyses how the volumes activated after the intraday gate closure are determined by the scheduled generation for each technology ($idTECHN_{i,t}$). The dependent variable is the activated energy associated with the same network constraints as in Eq. 1 but adding adequacy reserves. Eq. 5:

$$idVolumes_t = \widehat{\beta}_0 + \widehat{\beta}_1 \cdot idVolumes_{t-1} + \widehat{\beta}_2 \cdot daTECHN_t + \widehat{\beta}_3 \cdot holiday_t + + \sum_{m=1}^{11} \widehat{\delta}_m \cdot M_t^m + \widehat{\varnothing} \cdot \Delta idVolumes_{t-24} + \varepsilon_t \quad (5)$$

$$idTECHN = \begin{bmatrix} N, CC, CO, H, PG, CHP, TS, PV, W, I \\ idDEM, idRES \end{bmatrix}$$

$$idVolumes_t = \begin{bmatrix} idVoltage \\ idCongestions \\ idReliability \\ diAdequacy \\ idOthers \end{bmatrix}$$

In this model, network constraints are related to voltage issues (*idVoltage*), congestions (*idCongestions*), grid reliability issues (*idReliability*), insufficient adequacy reserves (*idAdequacy*), or others (*idOthers*). Scheduled technologies correspond to nuclear (*N*), combined cycle (*CC*), coal (*CO*), hydropower (*H*), pumping generation (*PG*), combined heat and power (*CHP*), thermosolar (*TS*), photovoltaic (*PV*), wind (*W*), and cross-border flows (*I*).

The Intraday Demand Model analyses how the volumes activated after the intraday gate closure are determined by total demand after the day-ahead markets (*idDEM*) and the percentage of IBR in the scheduled generation (*idRES*). The dependent variable is the activated energy associated with each network constraint. Eq. 6:

$$idVolumes_t = \widehat{\beta}_0 + \widehat{\beta}_1 \cdot idVolumes_{t-1} + \widehat{\beta}_2 \cdot idDEM_t + \widehat{\beta}_3 \cdot idRES_t + \widehat{\beta}_4 \cdot holiday_t + \sum_{m=1}^{11} \widehat{\delta}_m \cdot M_t^m + \widehat{\varnothing} \cdot \Delta idVolumes_{t-24} + \varepsilon_t \quad (6)$$

$$idVolumes_t = \begin{bmatrix} idVoltage \\ idCongestions \\ idReliability \\ diAdequacy \\ idOthers \end{bmatrix}$$

In this case, the total scheduled demand after the intraday market (*idDEM*) and the rate of IBR in the total demand (*idRES*) is calculated as shown in Eqs. 7 and 8.

$$idDEM_t = N_t + CC_t + CO_t + H_t + PG_t + CHP_t + TS_t + PV_t + W_t + I_t \quad (7)$$

$$idRES_t = \frac{PV_t + W_t}{idDEM_t} \quad (8)$$

In all models, seasonality is controlled by several dummy variables: M_t^m equals to 1 for all observations belonging to each m month and zero for all the rest, and $holiday_t$ equals to 1 for observation belonging to weekends and national holidays and zero for all the rest. ε_t corresponds to the error term.[10]

Ordinary least square estimations cannot be used because the inclusion of the lagged endogenous variable could lead to biases problems related to potential autocorrelation of residuals [53]. Instead, maximum likelihood estimators are used. Estimations include a SARIMA time-series estimator, including the first lagged endogenous variable as an independent variable to capture its dynamics. Moreover, lags of 24 endogenous variables are included as another independent variable to capture the daily seasonal patterns. Finally, all estimates are differentiated to ensure their stationarity. The coefficients are estimated for the activated or curtailed volumes associated with each network operational problem in the day-ahead. Similar methodology has been used previously in the literature [10].

In all cases, five different estimations are performed (one per year, 2019, 2020, 2021, 2022 and 2023) as there are notable differences during this period. First, the generation mix significantly changed between 2019 and the end of 2023: photovoltaics capacity increases up to 26.951 MW (+144 %), wind capacity increases up to 30,718 MW (+20 %), and coal capacity decreases until 3.464 MW (−64 %) [13]. Second, 2020 includes the covid lockdown and a major paralysis of the economic activity: in Spain the interannual GDP decreased −11.3 % (INE , 2023), with a clear impact on the total electricity demand [54]. Third, the average wholesale price differs from one year to another (47,78€/MWh in 2019, 33,95€/MWh in 2020, 111,93€/MWh in 2021, 167,53€/MWh in 2022, and 87,69€/MWh in 2023 which might significantly affect the technologies operating in each year [12]. Finally, there is an ongoing process to commission new lines, cables, substations, and reactive compensation equipment by the TSO and DSO.

4.2. Step 2: Long-term contributions

In both the day-ahead and intraday models, the estimated $\widehat{\beta}_2$ represents the short-run effect of technologies or demand, i.e. the effect on the next hour.[11] In order to compare the contribution of each technology in different network constraints, the long-run effect are calculated, i.e. the average impact of each coefficient in each year. Eq. 9:

$$Long\ run\ effect = \frac{\widehat{\beta}_2}{(1 - \widehat{\beta}_1 - \widehat{\varnothing})} \quad (9)$$

[10] This study only considers eleven dummies for months as one (when all dummies are equal) corresponds to the base month.

[11] These models include the AR1 and AR24 estimates. Thus, a change in one hour "has some memory" and affect the next hours and days. This effect is solved when calculating the long-term effect that considers both AR1 and AR24 coefficients (Equation 9).

4.3. Step 3: Total contributions

Finally, total contributions are calculated summing the long-term coefficients from each technology on the day-ahead and intraday stages.

5. Data

Data includes hourly data from the Spanish bidding zone between 2019 and 2023. The dataset used combines the operating data published by the Spanish TSO and market data published by the Spanish NEMO [12,13].

5.1. Scheduled energy from day-ahead and intraday markets

Data includes the day-ahead and intraday market schedule made after the day-ahead markets and after the intraday markets published by the Spanish NEMO. Tables 6 and 7.[12] Figs. B1 to B5 (Appendix B) show the hourly scheduled energy by technology in the day-ahead.

5.2. Network constraints

Data from the network constraints in the day-ahead and real-time is published by the Spanish TSO. Table 7 provides the summary statistics. The following are the type of network constraints analysed (see Appendix A for details):

- **Voltage problems**: situations where voltage in the grid is out of the nominal parameters and system operators should activate and curtail generation units to control reactive power flows.
- **Congestion**: situations with grid bottlenecks (N security) at transmission and distribution grid level.
- **Reliability**: situations where the grid reliability criteria (N-1) at transmission grid level is not respected.
- **Adequacy reserve**: situations where volumes of very fast dispatchable generation in both directions (upwards and downwards) is below the security level.
- **Others**: refers to other situations.

In the day-ahead processes, voltage problems cause most of the redispatched volumes, while congestion and reliability problems

Table 6
Summary statistics the scheduled energy for each technology in the day-ahead ($daTECHN_t$) (N = 43,795).

Variable	Technology	Units	Mean	St. Dev.	Min	Max
CC_t	Combined cycle	MWh	3291	3435	0	15,666
CO_t	Coal	MWh	450	733	0	6530
H_t	Hydropower	MWh	3013	1802	456	10,264
N_t	Nuclear	MWh	6341	855	2683	7151
PG_t	Pumping Generation	MWh	270	459	0	2649
PV_t	Photovoltaic	MWh	2570	3690	0	16,359
TS_t	Thermosolar	MWh	595	681	0	2186
CHP_t	Combined Heat and Power	MWh	3671	741	1034	4865
W_t	Wind	MWh	7258	3889	392	21,620
I_t	Cross-border flows	MWh	−516	2457	−8371	6525
$daDEM_t$	Total demand	MWh	26,944	4322	14,013	40,491
$daRES_t$	Generation from IBR (PV + wind)	%	36.31	16.67	3.49	89.16

[12] Intraday schedule includes the energy scheduled after closing the last intraday session in each hour.

Table 7
Summary statistics the scheduled energy for each technology after the intraday markets ($idTECHN_t$) (N = 43,795).

Variable	Technology	Units	Mean	St. Dev.	Min	Max
CC_t	Combined cycle	MWh	4891	3219	165	16,111
CO_t	Coal	MWh	733	713	0	6677
H_t	Hydropower	MWh	2901	1794	367	9909
N_t	Nuclear	MWh	6309	874	3242	7129
PG_t	Pumping Generation	MWh	266	464	0	2656
PV_t	Photovoltaic	MWh	2499	3626	0	16,071
TS_t	Thermosolar	MWh	565	679	0	2186
CHP_t	Combined Heat and Power	MWh	3499	778	1028	4727
W_t	Wind	MWh	6678	3888	353	20,803
$idDEM_t$	Total demand	MWh	27,826	4206	16,870	40,763
$idRES_t$	Generation from IBR (PV + wind)	%	32.70	16.36	2.67	89.29

account for less than one-third of the volumes. In real-time processes, the need to solve adequacy reserves represents the highest volumes. See Table 8.

Figs. 3 and 4 show the annual volumes related to each of the above network constraints. In day-ahead, volumes in 2020 and 2023 peaked to 10TWh of energy and voltage problems were the main network constraints, while congestions and reliability problems hardly accounted for a third of volumes. In real-time processes, volumes increased exponentially between 2019 and 2023: from 43 TWh (2019) to 3391 TWh (2023). Moreover, ensuring adequacy reserves is the reason behind most of the actions.

Figs. C1, C2, C3:, C4 and C5 (Appendix C) show the hourly volumes in Stage 1. The figures show some interesting results. First, total volumes peaked at the off-peak hours (night), while the opposite after the intraday markets and voltage constraints were the highest at this time. Second, congestion and grid reliability problems are higher during the peak demand period. Third, volumes of curtailed generation due to grid reliability problems are at a maximum in 2023.

Figs C6, C7, C8, C9 and C10 show the hourly volumes in Stage 3. As before, the figures show some noteworthy results. First, total activated volumes are at maximum at peak time, and most were related to insufficient adequacy reserves. Second, volumes related to grid reliability were at maximum at peak time, almost all corresponded to curtailment of units. Third, very few volumes were used to solve congestion problems.

Finally, Figs. D1 to D10 show the hourly activated and curtailed technologies after the day-ahead and intraday-markets by year. Table 9 shows the total activated and curtailed energy after the day-ahead by technology and year. It is noteworthy that in 2023, activations for Combined Cycle and Coals amounted to +6614 GWh and + 2173 GWh, respectively. Moreover, curtailments for Wind, Photovoltaics and Thermosolar amounted to −2993 GWh, −919 GWh and − 529 GWh, respectively. This means a high waste of clean resources. This pattern is aggravating year after year.

Table 8
Volumes of energy activated and classified by network constraint (N = 43,804).

Network Constraint	Variable	Units	Mean	St. Dev.	Min	Max
Voltage	$daVoltage_t$	MWh	550	512	0	3615
Congestions	$daCongestion_t$	MWh	189	174	0	891
Reliability	$daReliability_t$	MWh	183	366	0	3625
Others	$daOther_t$	MWh	35	114	0	1988
Voltage	$idVoltage_t$	MWh	44	129	0	1766
Congestions	$idCongestion_t$	MWh	2	19	0	898
Reliability	$idReliability_t$	MWh	53	185	0	4161
Reserves	$idReserves_t$	MWh	161	413	0	3376
Others	$idOther_t$	MWh	5	65	0	1852

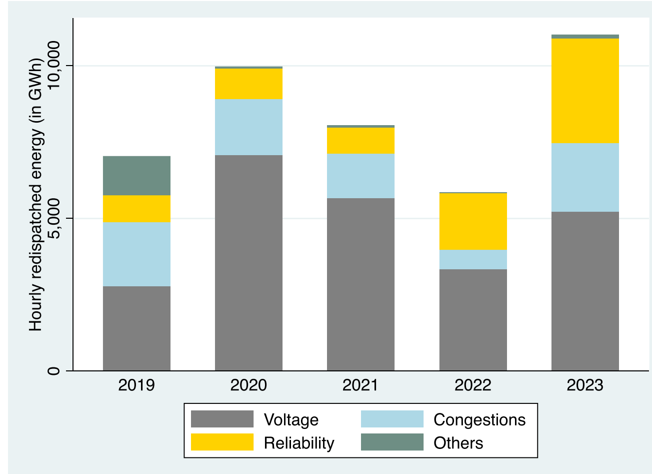

Fig. 3. Annual volumes in Stage 1 by network constraint (2019–2023).

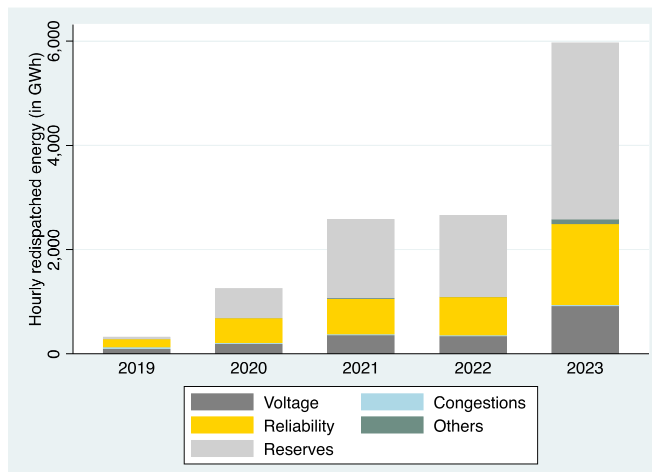

Fig. 4. Annual volumes in Stage 3 by network constraint (2019–2023).

6. Results

This section describes the main from long-term contributions (step 2) and total contributions (step 3). Detailed results from short-term contributions (step 1) are shown in Appendix E and F, but they are not analysed since they cannot be compared between years as their AR1 and AR24 coefficients are different. Detailed results from long-term contributions (step 2) are shown in Appendix G.

All the tables show the total contributions in each year, i.e. how each scheduled technology (MWh) contributes to the redispatched volumes (MWh) used to solve each type of network operational constraint after the day-ahead and intraday markets. The same applies for total Demand and RES (IBR). Positive values are in red, while the negative values are in black.

6.1. Long-term contributions (step 2)

First, the long-term contributions on voltage problems are shown in Table G.1 (Appendix G). After the day-ahead markets, almost all technologies show reduced voltage issues, except for nuclear in some years, while few technologies after the intraday-markets, which means that all these problems were mostly solved in the after the day-ahead markets.

Second, the long-term contributions on congestion problems and

Table 9
Total activated (positive values) and curtailed energy (negative values) after the day-ahead by technology and year (in GWh).

	Combined Cycle	Coal	CHP	Nuclear	Hydro	Pumping	Photovolt.	Thermos	Wind
2019	+3182.8	+2321.6	−841.7	−10.3	−995.7	−572.6	−0.8	−0.7	−2479.1
2020	+5508.4	+2899.8	−939.8	−52.4	−982.5	−458.2	−0.7	−2.8	−4952.3
2021	+5788.7	+1560.6	−900.6	−95.3	−1579.6	−372.3	−7.8	−29.4	−3450.8
2022	+3644.0	+607.4	−607.7	−30.4	−384.9	−160.6	−405.5	−353.6	−1352.5
2023	+6614.4	+2173.3	−1355.9	−318.3	−765.4	−648.1	−919.0	−529.1	−2999.3

reliability are shown in Tables G.2 and G.3, respectively (Appendix G). Almost all the actions are made after the day-ahead markets, while very few coefficients are significant after the intraday markets, which shows that system operators solve almost all these problems as soon as they identify them.

Third, the long-term contributions on solving a deficit of resource adequacy reserves are shown in Table G.3 (Appendix G). In this case, all the actions are only made after the intraday markets, which shows that system operators wait until being close of real-time to solve these problems.

6.2. Total contributions (step 3)

First, determinants of voltage problems are included in Table 10 and graphically shown in Fig. 5. Almost all technologies show reduced voltage issues, except for coal in two years. It is noteworthy the positive effect of CHP and combined cycle, whose additional scheduled MWh of both technologies reduce on −0.924 and − 0.297 MWh (2023), respectively, the need for volumes to solve voltage issues. These negatives effects are because coefficients for total demand are negative and decrease from −0.086 (2019) until −0.164 (2023), meaning that needed volumes to solve voltage increase on 0.164 MWh for each less scheduled MWh of demand. This might be explained by the Surge impedance loading or SIL effect: the load level determines whether a line behaves as a capacitor that injects reactive energy, or as an inductance that consumes reactive energy (see Section 2.2). However, coefficients associated with each scheduled IBR in the mix (RES) are positive and increase from 0.019 MWh (2019) until 0.045 MWh (2023) mix. The demand and IBR trends show that voltage problems are increasingly concerning in the Spanish power system.[13]

A combination of the two effects (on total demand and rate of IBR) cause the coefficients associated to individual technologies: coefficients for some synchronous generators (combined cycle, coal and CHP) are much smaller than generators made of IBR (photovoltaic and wind). These results highlight the added value of synchronous generation associated to system voltage.

The results for network voltage constraints shed light on a challenge related to the decarbonization of the power systems; increasing production from IBR requires solving new operational needs. As shown in Figs. C1, C2, C3, C4 and C5, volumes for voltage issues after the day-ahead are only related to starting new units. As shown in Figs. D1, D2, D3, D4 and D5, all activations after the day-ahead are coal and combined cycles. Thus, voltage problems are solved by the replacement of generators made of IBR by combined cycle or coal plants.

Second, determinants of congestion are shown in Table 10 and graphically shown in Fig. 6. Almost all technologies increase congestion, except for coal (−0.684 in 2023). This is confirmed by the coefficients associated to total demand, all positive, which explains that overload problems are associated with higher demand and production from each technology, as is obvious. However, the table depicts another pattern: volumes associated to CHP are the highest and each additional scheduled MWh contributes between 0.064 and 0.181 MWh to volumes due to congestion problems. Contribution from thermosolar (0.028) and photovoltaics (0.035) are also higher during this period, which show that an efficient integration of RES needs carefully assessing grid investments to minimize grid bottlenecks. Finally, scheduled IBR increase its impact on congestions until 0.011 MWh (2023) for each scheduled MWh of RES, which highlights a concerning problem related to congestions from photovoltaics and wind.

Third, determinants of grid reliability are shown in Table 11 and graphically shown in Fig. 7. They show that needs from thermosolar and CHP are substantially higher than the rest of technologies, which highlights the lack of grid capacity when scheduled. An additional scheduled MWh of thermosolar and CHP increases these needs on 0.253 MWh (2022) and 0.202 MWh (2023), respectively. In Figs. D4 and D5, the curtailment of photovoltaics and thermosolar scheduled production after the day-ahead market is noteworthy. After the intraday markets, photovoltaics, wind and thermosolar positively contributes to these problems. These results complement the determinants of congestion and confirm that decarbonizing the power system creates congestion problems. In this case, coefficients associated from IBR are significant, but very small.

Fourth, determinants of solving deficits of adequacy reserves are shown in Table 11 and graphically shown in Fig. 8. The table shows interesting patterns: the need to activate volumes and solve adequacy reserves decrease with the scheduled combined cycle until 0.176 MWh (2020) for each additional scheduled energy from this technology. In Spain, many solutions include starting thermal units at its technical minimum production to have room to increase its production. A similar pattern is seen for each scheduled MWh of photovoltaics, which decrease until 0.027 MWh (2022) for each scheduled MWh of this technology. On the contrary, volumes increase with the rest of technologies with extreme contribution from Hydro (0.363), Pumping Generation (0.390), Thermosolar (0.330) and CHP plants (0.883).

As shown in Figs. D6, D7, D8, D9 and D10, important volumes from combined cycle units are activated after the intraday markets. In conclusion, the power system needs always minimum volumes of combined cycle and coal to provide adequacy reserves, and when sufficient volumes of these are not scheduled in the market, they should be activated through redispatching processes. Finally, coefficients related to IBR are negative, which means that each scheduled MWh of IBR decreases these volumes until −0.174 MWh (2023).

6.3. Discussion of results

As shown in Figs. 3 and 4, volumes associated with grid bottlenecks – congestion and grid reliability – are not behind most of the redispatched volumes. On the contrary, they are explained with voltage problems after the day-ahead and a deficit of adequacy reserves after intraday-markets. Thus, the statement that grid bottlenecks are the main problem in the operation of power system with high shares of RES does not seem to hold, at least in Spain. These results might be explained because system operators only connect a new unit if there is sufficient grid hosting capacity and non-firm connection agreements are not implemented in Spain, yet. In these cases, there is a firm capacity for 24/365 and a non-firm capacity during some hours a year when the grid hosting capacity is limited [55]. Thus, non-firm connections or alleviating the

[13] The estimated coefficients show the contribution of each scheduled technology to redispatching volumes associated with each network constraint. They should not be understood as curtailments of each specific technology.

Table 10
Total contributions of each technology, demand and RES on the volumes by voltage and congestion issues.

	Voltage					Congestions				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
C.Cyle	−0.138	−0.218	−0.243	−0.170	−0.297	0.036	0.029	0.011	0.002	0.007
Coal	−0.027	0.917	−0.254	−0.248	1.112	−0.051	−0.510	−0.379	−0.152	−0.684
Hydro	−0.084	−0.087	−0.094	−0.107	−0.145	0.021	0.016	0.011	0.006	0.014
Nuclear		−0.122	−0.054		−0.027	0.080				
Pumping	−0.063	−0.074	−0.097	−0.126	−0.190	0.036	0.002	0.011	0.006	0.020
Photovolt.	−0.094	−0.082	−0.111	−0.095	−0.141	0.032	0.035	0.027	0.010	0.021
Thermosol.	−0.078	−0.105	−0.130	−0.093	−0.024	0.041		0.021	0.028	
CHP	−0.214	−0.575	−0.377	−0.562	−0.924	0.113	0.181	0.101	0.099	0.064
Wind	−0.069	−0.081	−0.084	−0.075	−0.099	0.020	0.009	0.001		
Imports	−0.050	−0.054	−0.098	−0.075	−0.109	0.013	0.008	0.008	0.005	0.005
Demand	−0.086	−0.108	−0.124	−0.107	−0.164	0.024	0.023	0.012	0.006	0.010
RES	0.019	0.011	0.030	0.042	0.045	−0.001	0.005	0.006	0.005	0.011

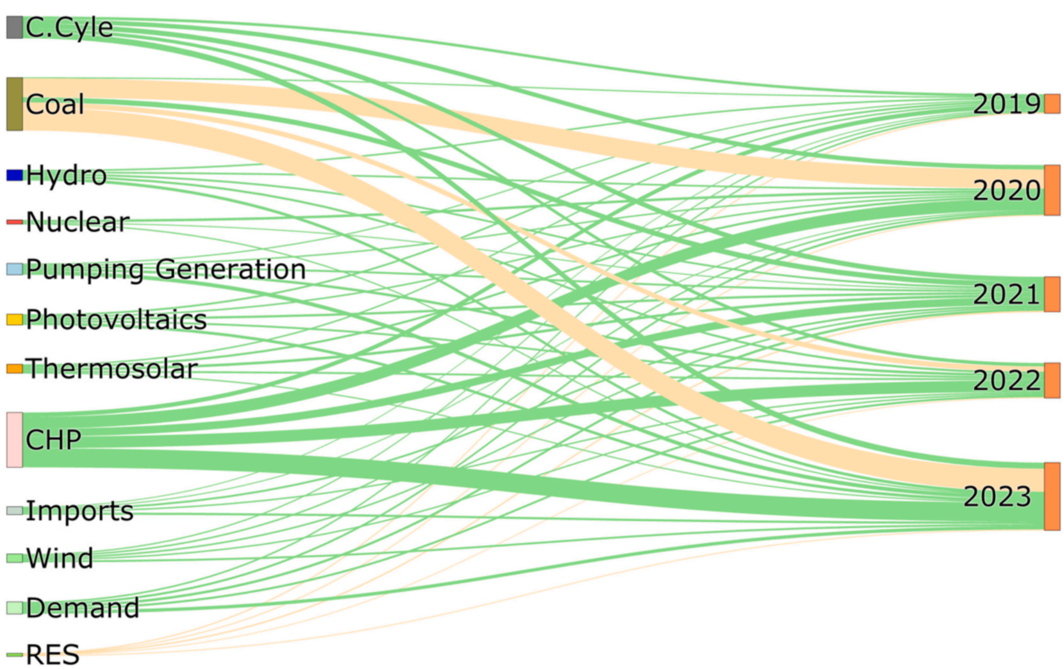

Fig. 5. Total contribution of each technology on the voltage issues represented in a Sankey plot. Flow width represents the coefficient from Table 10, while colors its sign: orange for negative and green for positive.

current criteria to connect new RES could result in higher volumes associated with congestions, which must be assessed prior to its implementation to identify all costs and benefits and avoid concerns about additional volumes.

Electricity markets can make an efficient assignment of resources -generators and consumers- to minimize spot prices, but they do not necessarily provide technically feasible schedules. At this point, should we change the current European market design to also include these network constraints? A bold solution could be to implement nodal prices in Europe, but they are useful for network constraints related to grid bottlenecks (congestions). In this study, most volumes are activated for other operational constraints, i.e. voltage or capacity reserves. Moreover, it has been widely demonstrated that marginal prices and the current market design provides efficient outcomes and guarantees the demand coverage even under extreme shocks scenarios [56]. Thus, it seems reasonable that solutions to minimize these volumes do not consider changes in the fundamentals of the current European market design.

When considering solutions to decrease these volumes, there are several recommendations. First grid planning models made in advance and used for identifying efficient grid expansion related to new RES should go beyond the assessment of only grid bottlenecks as they don't explain the full picture. Results from this study show that complex operational constraints are limiting a higher integration of IBR in the power systems. They should also forecast operational issues such as voltage, inertia or adequacy reserves. However, this requires performing advanced dynamic simulations, which need more advanced software, grid structural data such as the resistances and impedances of the grid elements, and the dynamic models of the generators and consumers. In many cases, this information is not public. Related to the dynamic models of generators, some manufacturers are reluctant to make them public arguing for copyright issues [57,58].[14] In this context, "digital

[14] Some manufacturers are reluctant to show the issues from their units to other manufacturers. Dynamic models show all detailed operation characteristics and technical capabilities of IBR. In many cases, solutions implemented by them require costly research+development+innovation (R + D + I) processes and are part of property patents. In some Member States, dynamic models of generators are directly provided by manufacturers to the TSO and generators do not have access to them [92].

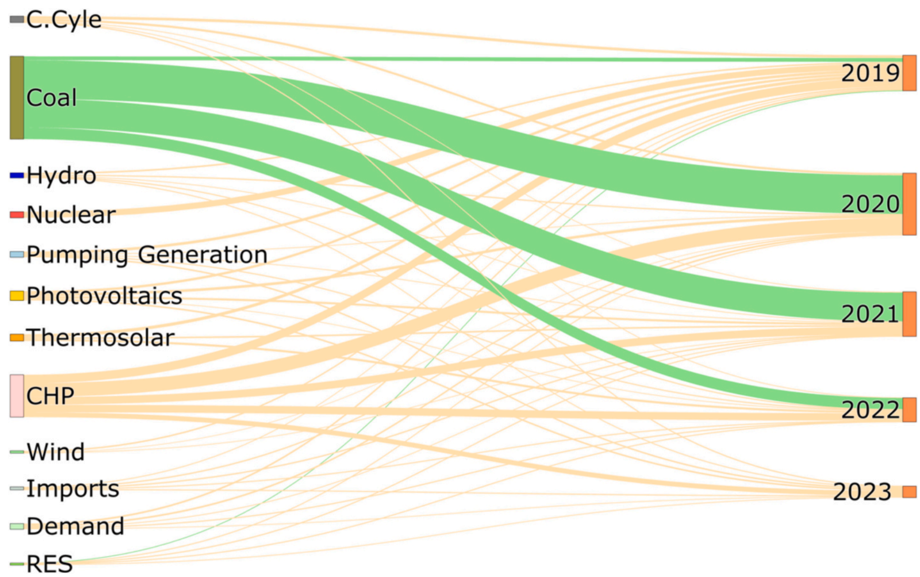

Fig. 6. Total contribution of each technology on the congestion issues represented in a Sankey plot. Flow width represents the coefficient from Table 10, while colors its sign: orange for negative and green for positive.

Table 11
Total contributions of each technology, demand and RES on the volumes by reliability and adequacy reserves.

	Reliability					Adequacy reserves				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
C.Cyle	0.015	0.010	0.001	0.000	−0.034	−0.003	−0.176	−0.145	−0.088	−0.158
Coal	0.011	−0.039	−0.060	−0.034	−0.310	−0.019			0.122	−0.499
Hydro	0.019	0.020	0.016	0.034	0.047	0.012	0.131	0.197	0.184	0.390
Nuclear	0.000	0.000	0.064	−0.160	0.043			0.082		
Pumping	0.014	0.036	0.000	0.000	0.056	0.049	0.349	0.316	0.313	0.363
Photovolt.	0.016	0.016	0.000	0.071	0.072			−0.014	−0.027	−0.016
Thermosol.	0.000	0.109	0.000	0.253	0.212			0.068	0.127	0.322
CHP	0.187	0.181	0.140	0.000	0.202		0.150	0.161	0.330	0.883
Wind	0.023	0.027	0.046	0.070	0.048		0.039	0.047	0.019	0.062
Imports	0.008	0.000	0.000	0.062	0.000	−0.003	0.028	0.056	0.044	0.088
Demand	0.015	0.021	0.008	0.048	0.050	0.002	0.051	0.078	0.069	0.182
RES	−0.000	0.000	0.000	0.000	0.000	−0.003	−0.028	−0.077	−0.086	−0.174

twins" of real processes emerge as a feasible alternative solution and study like this, based on the past data, seems a good starting point.[15] Results from grid planning models should provide sufficient data to identify regulatory recommendations, some of which are described below.

Second, implementing locational incentives in the long-term grid planning to limit the concentration of new RES, which includes moving from the unique (postal) tariff scheme to different regional tariffs [59], implementing regional auctions for new RES [60], publishing grid capacity maps, defining conditions under which specific anticipatory grid investments for RES shall be granted, or accelerating permitting and administrative processes related to new grids [3]. However, defining quotas for RES at regional level might become a controversial political issue between central, regional, and local administrations.

Third, the decision to phase out technologies in the climate change plans should go beyond the simple replacement of a MWh produced by combined cycles or coal by IBR (RES). Synchronous generators, specially combined cycles, cause most of the solutions for the network constraints, especially to solve voltage problems and insufficient adequacy reserves. Davi-Arderius et al. [10,11] highlight this problem for volumes of after day-ahead, but in this study, results show that this effect is aggravated with volumes of after intraday-markets. Moreover, the costs for activating combined cycles could be procured through a capacity market and their economic conditions could be set in advance. This could reduce potential in-dec gaming from owners of combined cycle if they know in advance that they will be regularly activated [61].

Fourth, implementing an efficient incentive to the system operators to optimize the volumes activated. Spanish TSO has an economic incentive to annually reduce the volumes of activated energy and their costs [62]. Currently, this incentive is capped to ±5 % the base remuneration.[16] However, incentivizing system operators to reduce curtailment could however internalize the problem. Under this incentive, how could we be sure that 'network benefits' don't over-shadow the 'whole-system benefits'? Another possibility is to assess whether the current criteria used by system operators to activate synchronous generators are not overly conservative. The Spanish National Regulator approved a mechanism to not fulfill several security criteria such as N-1 in exchange of tripping the generator in seconds or minutes after an unforeseen event. This is known as Sistema de Reducción Automática de Potencia

[15] Digital twin is a virtual model used to accurately reflect physical objects. This is a technology used to monitor, simulate, predict and optimize [58].

[16] According to CNMC [62], the "base remuneration" includes incomes for CAPEX and OPEX for the operating activities. In the proposed remuneration published by the Spanish Regulation for 2042, "base remuneration" accounts 77 M€ and incentives +1.5 M€ [91].

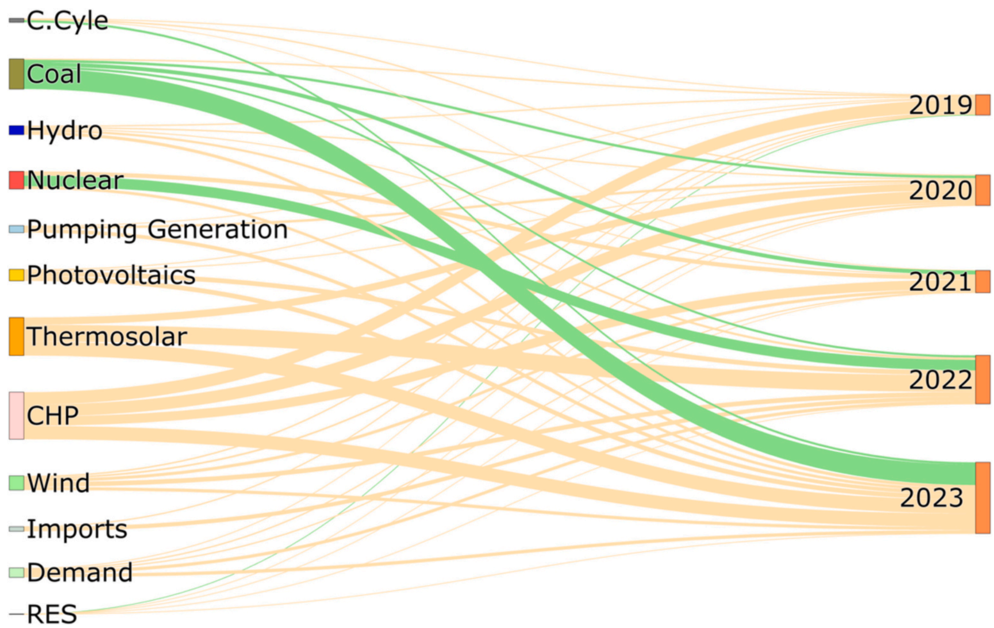

Fig. 7. Total contribution of each technology on the grid reliability issues represented in a Sankey plot. Flow width represents the coefficient from Table 11, while colors its sign: orange for negative and green for positive.

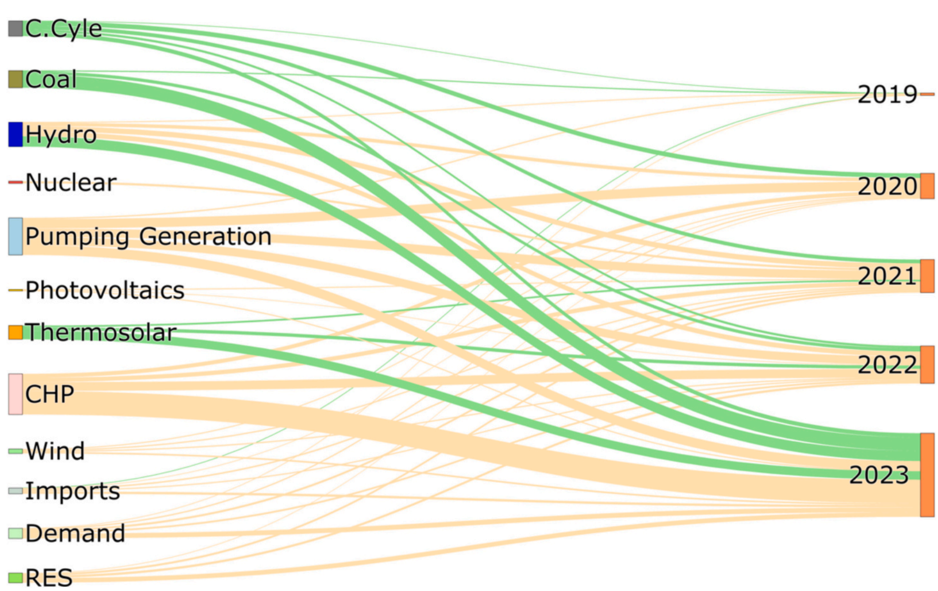

Fig. 8. Total contribution of each technology on the adequacy reserves represented in a Sankey plot. Flow width represent the coefficient from Table 11, while colors its sign: orange for negative and green for positive.

[51] and the participation of units to this service is not mandatory. However, this mechanism might not be useful for situations where a high concentration of scheduled RES might affect dynamics or produce network stability problems.

In the same context, National Regulators must overview if the hourly adequacy reserves used by TSO are optimal or excessively conservative. These reserves are calculated by the TSO considering its forecasts (Appendix A.5). Thus, more biased estimates from TSO can result in higher volumes of reserves with corresponding higher costs for customers. In the Spanish Regulatory framework, TSO have another economic incentive and penalty if their forecasts are biased, but they are capped to ± 5 % of base remuneration. Reducing these reserves could increase the risk of ending with important grid stability problems due to imbalances between demand and generation, but these trade-offs should be regularly analysed as scenarios might change.

Fifth, promoting smart grids and specific digitalization investments to increase grid capacity through mechanisms such as DLR. National Regulators have several instruments to promote them: approving these investments over others or incentivizing digitalization investments [63]. Traditional solution to deal with these volumes of energy is investing in new lines, cables, transformers, STATCOM, FACTS, etc. However, these investments incur costs for customers and the social resistance to building new lines or substations in increasing. Therefore, alternative solutions should be found and implementation of grid innovative technologies or local flexibility services might be a solution [3,56].

Sixth, implementing long-term local flexibility services to deal with structural or repetitive operational limits during peak RES production, also known as Demand Response (DR). O'Shaughnessy et al. [64]

highlight that DR can provide around 30 % of all the resources for deep decarbonization systems. These services might be procured one or two years in advance and would reduce the need for redispatching volumes after the day-ahead or intraday markets [65]. They might include a capacity compensation for being available and another compensation for the energy curtailed or activated. This mechanism would also provide efficient economic incentives to install storage devices in RES to store the curtailed production, or behind the meter. An alternative might be promoting large scale new storage solutions such as pumping, but its subsequent impact on operational constraints must be deeply assessed [66].

Another recommendation is to use utility scale combined solar-storage and some countries are making this a requirement for solar auctions [67]. However, this entails challenges if the stored production is later exported to the grid with the same generation technology as RES, i.e. IBR. This is the case with traditional storage batteries. Alternatively, storage should be performed through pumping consumption whose output is from pumping generators, which are synchronous generators with all their benefit capabilities compared to RES.

Seventh, implementing more demanding capabilities for IBR in new RES such as grid forming (GFM) technologies introduced in Section 2. However, there are some implications related to the implementation of GFM to RES: (i) this is not mature and commercial technology; (ii) this would increase the Levelized Cost of Energy (LCOE) associated to new RES with the corresponding negative impact on the wholesale prices; (iii) this might be discriminatory if it is required RES sited to specific areas. Moreover, there are not deep experiences with the implementation of GFM to all RES regardless of size and capacity and, especially at the distribution grid level with highly resistive lines. An additional solution, implementing specific ancillary or local services to incentivize specific RES units to have more robust dynamic capabilities related to the voltage or inertia services. This mechanism would avoid the discriminatory effect related with the establishment of mandatory requirements for new RES. Moreover, the economic compensation to providers would be defined efficiently through the ancillary service markets. However, the procurement of these services should be done in the long term, for instance a year-ahead, to provide efficient incentives to retrofit specific RES.

Related to the growing concern of the curtailment of RES made in 2022 and 2023, this study does not identify specific locations of all curtailed photovoltaics plants, but many thermosolar productions were curtailed at the same time. Precisely, 99 % of all thermosolar capacity is concentrated and sited in the mid-south of the Iberian Continental as is shown in the Fig. 9.[17] Thus, it is very likely that many of these photovoltaics plants could be in the mid-South area of Spain.

Eighth, implement regulatory instruments to foster consumption on specific regions during the peak solar production. For instance, defining a specific bidding zone for the mid-South area in Spain. However, splitting bidding zones would require deep analysis of the structural congestion to identify if grid bottlenecks are associated to the transmission lines that connect the North to the South or are more related to local transmission lines. In this last case, defining a new bidding zone won't be an efficient solution.

Nineth, enabling the possibility that the demand and consumption participates in the redispatching process and in the provision of adequacy reserves. The possibility of demand participation instead of using pollutant combined cycles should be explored. Moreover, this would ensure technological neutrality as the participation of demand in balancing services should be made on equal footing than generation. However, this would require the implementation of incentives to avoid unforeseen additional consumption later (rebound effects) that would create new operational constraints.

Fig. 9. Map of the thermosolar plants in Spain.
Source: Prothermosolar [68].

Finally, accelerating the implementation of projects of common interest to increase the cross-border capacity and improve the power system dynamics and share potential adequacy reserves between different countries. A more interconnected power system can host higher volumes of RES made of IBR. However, sharing adequacy reserves between different countries would require closer operation coordination between TSO from different countries. This recommendation is included in the EU Grid Action Plan [3].

In summary, these results show that the transmission grid planning should consider the potential redispatching needs within a bidding zone in an integrated way in line with Kemfert et al., [69]. Redispatching needs are relevant enough and clearly constraint the operation of a high share of RES.

7. Conclusions

This analysis highlight some of the relevant operational challenges related with the decarbonization of the power system, which trade-off some of the expected benefits of the replacement of traditional pollutant plants -made of synchronous generators- by RES -made of IBR. When redispatching services should be activated after day-ahead and intraday markets means that there are relevant inefficiencies and room for improvement. Only in 2023, very high volumes of scheduled RES in the day-ahead were curtailed: 3 TWh of wind, 0.9 TWh of photovoltaics and 0.5 TWh of thermosolar. All these actions result in additional costs for customers and trade-offs some of the potential benefits from RES, when their scheduled should be replaced by other pollutant technologies. If no decisions are taken, this pattern is aggravating year after year. The increasing costs related to these actions also highlight that revenues from future ancillary services might become relevant and be an additional revenue alternative for customers and generators, especially for those who are optimally located and can provide flexibility to the power system.

Up to now, grid planning models have been focused to identify future grid bottlenecks and quantify grid investments needed to connect new RES. These models should evolve and study potential network operational constraints beyond grid congestions. However, requirements on grid data models are relevant and some information barriers should still be addressed.

In the analysed period (2019–2023), the contribution of each additional MWh of scheduled IBR (wind and photovoltaic) on the mix increases every year. In 2023, this peaks for voltage problems (+0.045 MWh), congestion issues (+0.011 MWh), which highlights that

[17] The installed capacity of thermosolar plants was 2300 MW in 2023, of which only 25 MW were in the North-West of Spain (Catalonia), representing only 1 % of the capacity.

decarbonizing the power system requires addressing increasing operational challenges and implementing additional markets for procuring specific ancillary services. If not, RES curtailment increases every year. Moreover, an additional MWh of electricity demand reduces volumes for voltage problems (−0.16 MWh), as well as the scheduled combined cycle production (−0.30 MWh). Therefore, policies aimed to increase electricity demand might have positive effects on the volumes of redispatching related to alleviate voltage problems. Main contribution to congestions problems come from each scheduled MWh of CHP (+0.18 MWh), which shows that the relatively flat production profile from this technology might not be fully efficient in terms of operational constraints. Volumes to solve grid reliability issues (N-1 problems) are maximum for each scheduled MWh of Thermosolar (+0.25 MWh). After intraday-markets, two thirds of the redispatched volumes were related to insufficient adequacy reserves, which are maximum for each scheduled MWh of CHP (+0.88 MWh), pumping generation (+0.36 MWh) or hydropower (+0.39 MWh).

Related to the curtailment of RES in these processes, some technological advances are still necessary to make IBR capabilities much more robust and closer to those from replaced synchronous generators. However, this also requires its fast adoption in the current regulatory framework and TSO and DSO should be incentivized to exploit their new IBR capabilities. This might imply reducing some of the actual security of supply levels used by TSO, but this should be deeply assessed, and different operational solutions should be considered. Otherwise, new capabilities won't be never fully exploited.

Future research directions from this analysis are related with a further exploration with the locational patters with a power-flow model the trade-off among redispatch, transmission-capacity expansion and voltage control when renewable generation is integrated. However, this requires additional data and different methodologies. Moreover, this would imply adding in the TSO's objective function terms for transmission-capacity costs and for voltage control costs that the TSO is going to minimize. Under a change of demand, or an increase in renewable output, the TSO would choose either to redispatch in favor of fossil fuels, increase network capacity, increase voltage controls, or a combination of the three. Additional analysis can focus on the costs of these volumes considering the activated and curtailed technologies in each case. Moreover, the empirical trade-off between transmission capacity expansion and redispatching, due to voltage control issues, would be interesting and important to explore also at regional level.

CRediT authorship contribution statement

Daniel Davi-Arderius: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Tooraj Jamasb:** Writing – review & editing, Writing – original draft, Methodology, Conceptualization. **Juan Rosellon:** Writing – review & editing, Validation, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Juan Rosellon and Tooraj Jamasb declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. Daniel Davi-Arderius works at e-Distribucion Redes Digitales, SLU and is part of the EU DSO Entity. 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.

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Appendix A – Technical appendix.

A.1. Thermal limits

When energy flows through the grid elements e.g. transformers, overhead lines, etc., power losses turn into heat and electricity losses [28]. The higher these flows, the higher the heat dissipated in each element. Therefore, each element of the grid has a maximum capacity for energy flows, also known as thermal limit or maximum congestion. This leads system operators to forecast congestion and identify potential grid investments several years ahead. The same procedure is followed when system operators assess the connection of a new consumer or generator: they simulate flows under the operation of this new unit. These grid investments are part of the network development planning processes [70].

In the long-run, congestion is forecasted in scenarios that consider the most likely future situations. However, these scenarios do not consider all the possible futures mainly due to the variability of RES production. Therefore, system operators need to forecast energy flows for the next days and hours to anticipate potential grid bottlenecks, i.e. congestion above the maximum capacity of grid elements. In these forecasts, system operators use reliable information such as historical data on flows in the past hours, or the scheduled generation or consumption from the day-ahead markets.[18] In real-time, system operators monitor flows in its network through digital devices installed on the lines and transformers.

The first and easiest solution for congestion management is to change the grid topology, i.e. switching lines or transformers. However, the potential for these measures is limited. Complementary solutions are Dynamic Line Rating (DLR) or setting maximum allowable current-carrying capacity on the lines depending on the weather conditions along the lines. For instance, setting a higher maximum capacity of lines on winter than in summer. However, DLR requires advanced monitoring and digitalized tools [71,72]. Another solution to grid congestion is grid reinforcements or new electrical infrastructure such as transmission lines, substations, transformers, etc. In the future, procurement of flexibility services by system operators will be a complementary measure to alleviate congestions by changing the consumption or generation profiles [56].

A.2. Grid reliability

Grid reliability refers to the redundant grid assuming the disconnection of a line or transformer without creating any losses in the electricity supply.

[18] Schedules from day-ahead market are commitment with an associated financial compensation.

They are also known as N-1 or N-2 security criteria if it refers to the disconnection of one or two grid assets, respectively.[19] This security criteria provides grid reliability as an unforeseen disconnection of any element can be solved by system operators. The higher the grid voltage, the higher is the need for grid reliability. It requires complex iterative calculation processes of resultant flows when a grid element is disconnected, either for scheduled maintenance works or protection tripping in case of faults, lighting strikes or overloads. Grid reliability is considered in the same calculation process as congestion: in the grid planning process (long-term) and in the grid operation (short or real-time). Moreover, the solutions useful for congestion can also be applied to grid reliability needs.

A.3. Voltage

Voltage is an electrical parameter that must be always within predetermined levels to ensure the safety conditions of the network and the quality of supply.[20] Operating a power system outside these levels is risky: electrical equipment -transformers or lines- can be damaged, and some loads or generators could not remain coupled to the grid. Ultimately, lines, transformers or generators might be disconnected by protection devices.

In High Voltage grids, voltage is managed through the control of the reactive energy flows, traditionally by synchronous generators.[21] The replacement of synchronous generators by RES entails that IBR should provide a similar response to voltage control as the replaced synchronous generators. However, this is not straightforward for several reasons. First, reactive energy from IBR is constrained to the primary resource availability, i.e. sun or wind. Second, IBR should include specific and expensive devices. Third, the provision of voltage control services by RES needs cooling converters, which means additional electricity consumption in ancillary services, thus affecting their economic feasibility of the plant. Fourth, large RES plants might have many kilometers of underground cables between the point of connection to the grid and the furthest windmills or photovoltaic panels scattered across the service area, which behaves like a large capacitor and injects reactive power flows. Fifth, the decarbonization of the system has coincided with the burying of many overhead High Voltage lines that behave as natural capacitors, aggravating the need for voltage control. Finally, some equipment might also be useful for controlling reactive flows: Static synchronous compensators (STATCOM), flexible AC transmission system (FACTS), synchronous condensers, capacitors or reactances [45,73].[22]

In the UK, the transmission system operator (TSO) has identified important regional overvoltages under two complementary situations: (i) long or underground High Voltage lines whose load is below its surge impedance loading (SIL), which is very common when the demand is low[23]; (ii) absence of synchronous generators in the area to consume reactive energy. In these cases, system operators must make actions such as starting specific synchronous generators or disconnecting some underground cables [74]. At present, there are few experiences with the procurement of voltage services through market based ancillary services [75].

The Spanish National Regulator launched two regulatory sandboxes to trial a new ancillary service for provision of voltage control services by RES and consumers [76,77]. To take advantage of the voltage control capacities already required in the national implementation of the Regulation (EU) 2016/631 [78]. The National Regulator justifies the sandbox with the increasing need to start specific synchronous generators for redispatching or to disconnect HV lines to control reactive flows.

A.4. Frequency

In Altern Current, frequency relates to the oscillation of voltage generated by rotating machines. Nominal frequency in Europe is 50 Hz, or 60 Hz in The United States and other countries. Frequency is controlled through inertia. This is the stored kinetic energy in rotating synchronous generators that gives the tendency to remain rotating and set the immediate frequency response when there is a power generation and demand unbalance. They are usually a consequence of tripping of a large generator, a large consumer or a disconnection of electrical areas [79].[24] Under low levels of inertia, frequency disturbances become more abrupt and frequency changes increase.[25] In these disturbances, some generators or loads might disconnect, further aggravating the initial frequency oscillation. In other words, this is a looping process that might put at risk the overall stability of the power system stability and with a blackout [80–82].

The connection of RES might affect power system stability since inertia and short-circuit current might decrease because the dynamic response of IBR used in wind or photovoltaics differs from synchronous generators used in nuclear, hydropower, combined cycle, or coal plants [83–87]. In synchronous plants, rotating generators are directly coupled to the grid providing their rotational energy when there is a disturbance. In RES, IBR are coupled with the grid, and they may provide virtual or synthetic inertial response through the activation of its IBR.[26] However, implementing virtual inertia requires installing some battery or storage device in the generator [88]. Moreover, the provision of inertia might suffer from some delay since the power control system needs to identify the need and react.[27] This might pose a problem when the share of RES based on IBR in the grid is very high.

[19] N-1 security criteria means that the power system operates in normal conditions when there is the disconnection of a grid element such as line or transformer.
[20] Each electrical equipment has its own nominal voltage.
[21] High Voltage lines have a lower R/X ratio, where R is the resistance and X the impedance [45].
[22] Most of these points might also apply to synchronous generators. In RES, these reasons are relevant since the connection of many RES is made under auctions that aim to minimize their LCOE costs [60].
[23] Surge impedance loading or SIL corresponds to the load to determine whether a line behaves as a capacitor that injects reactive energy, or as an inductance that consumes reactive energy. SIL depends on the physical characteristics of the line, as well as on their voltage.
[24] The disconnection of electrical areas might be related, for instance, to tripping a High Voltage cross-border line. If a country is importing energy, the impact of this disconnection equals to tripping a large generator and equals to the disconnection of a large consumer if the country is exporting energy.
[25] Rate of Change of Frequency (RoCoF) is measured as the time derivative of the frequency in Hz/s [93].
[26] Some wind turbines might have some kinetic energy stored in their blades, gearbox or generators, which is not possible in photovoltaics where there are no rotating parts.
[27] Full activation times to provide inertia for technologies vary: 4 ms for flywheel inverters, 100–200 ms for photovoltaics, 0.5 to 5 s for wind turbines [94].

There are other technical solutions to provide inertia. First, inertial response from IBR might evolve with a combination of grid forming (GFM) IBR and storage devices such as batteries, capacitors, or flywheels [35].[28] However, GFM are not fully commercial solutions. Third, flywheels storage devices provide fast dynamic response and inertia to the system. They are made of a synchronous generator, a bidirectional power converter, a flywheel, and a bearing system [89]. Similarly, synchronous condensers are synchronous generators coupled to the grid to maintain a spinning mass that provide the same inertial response as a synchronous generator during a disturbance.[29] Fourth, fast frequency response services include the response from generators for fast increase/decrease of net supply of energy. For instance, the Electric Reliability Council of Texas (ERCOT) implemented this service in non-critical loads to respond to changes in the frequency [83]. Fifth, building new lines to increase the interconnection capacity between different areas or countries might reduce impedance and increase the inertia of the system.

A.5. Adequacy reserves

A TSO calculates the daily minimum volume of dispatchable (upward and downward) scheduled generation in the day-ahead markets and after the intraday markets, namely dispatchable reserve capacity.[30] These reserves are in addition to the procurement of balancing services. In Spain, the upward and downward dispatchable capacity reserves are calculated considering the following parameters: (i) the difference between the scheduled demand forecasted by TSO and the final demand in the day-ahead and intraday markets; (ii) the difference between the scheduled wind and photovoltaic production made by TSO and the final scheduled wind production; (iii) situations with a risk of coupling delay or load increasing combined cycles [90]. In the Spanish regulatory framework, a TSO has economic incentives to improve the accuracy of demand and renewable forecasts and if the forecasts are biased, the incentive becomes a penalty [62,91].

Appendix B – Hourly scheduled generation in the day-ahead markets.

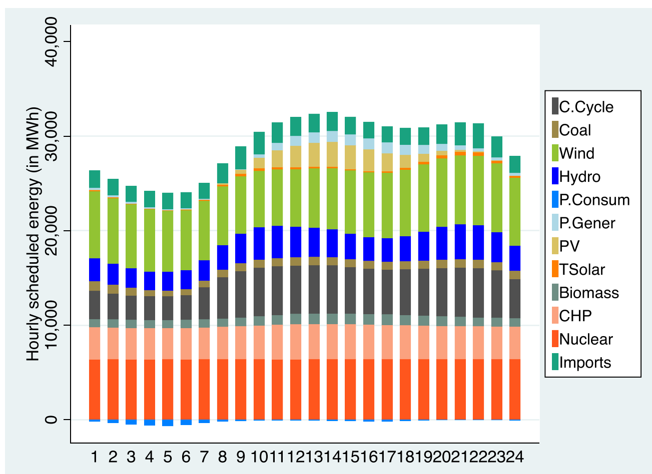

Fig. B1. Average hourly scheduled energy in 2019. Source: own calculations.

[28] There are two main IBR technologies for RES: grid following (GFL) and grid forming (GFM). GFL is the most used technology, while GFM is in a nascent stage. GFL behave as a controlled current source with a high parallel impedance, while GFM is represented as a voltage source with low series impedance. Hence, GFL regulates its voltage or current by controlling the injected current, while GFM regulates the power by controlling the voltage. Under no-load conditions, GFM provides a reference voltage, while GFL requires an external voltage for current injection. Accordingly, dynamics and response of GFM are closer to a synchronous generator than GFL [84,95].

[29] There are some studies related to the retrofit of synchronous generators from phased-out pollutant plants and transform them into synchronous condensers. However, this is not straightforward and requires an exhaustive analysis case by case (Deecke et al., 2015).

[30] "Enough upward reserve capacity" means there are enough dispatchable generators not operating at their nominal load, and with the capability to increase production quickly. For each unit, these reserves are calculated as the difference between scheduled production and nominal capacity. On the contrary, "Enough downward reserve capacity" means enough dispatchable generators able to reduce production quickly.

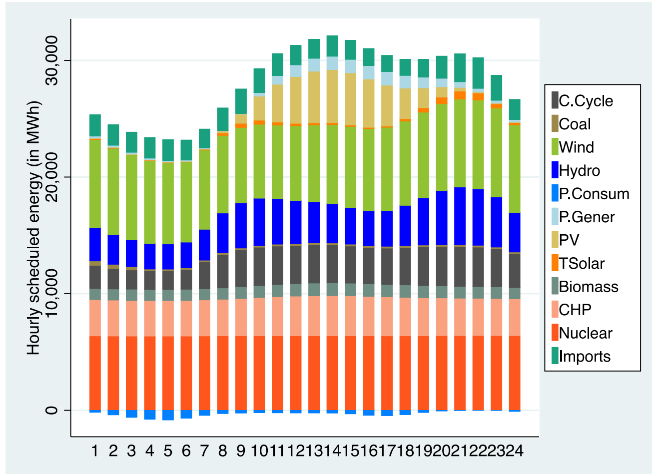

Fig. B2. Average hourly scheduled energy in 2020. Source: own calculations.

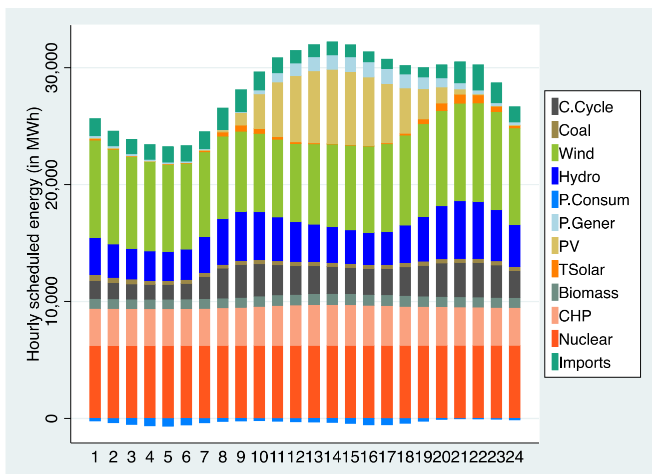

Fig. B3. Average hourly scheduled energy in 2021. Source: own calculations.

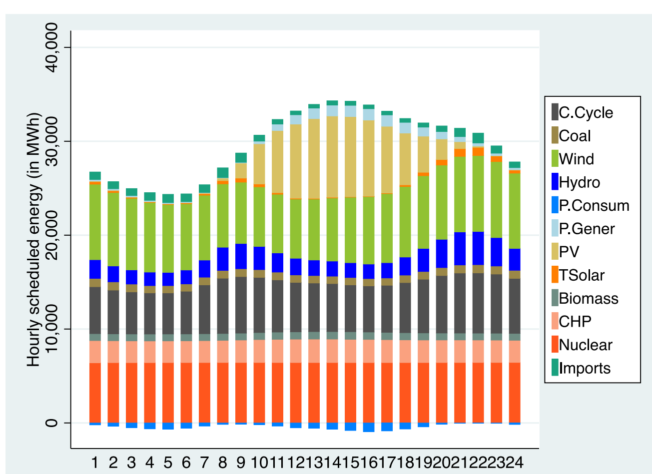

Fig. B4. Average hourly scheduled energy in 2022. Source: own calculations.

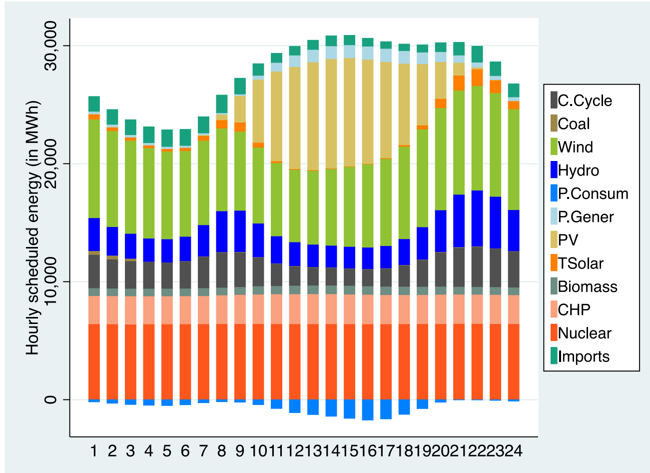

Fig. B5. Average hourly scheduled energy in 2023. Source: own calculations.

Appendix C – Hourly redispatching volumes by network constraint.

In all the graphs, positive values in vertical axis correspond to upward redispatched energy, while negative values show downward redispatch energy.

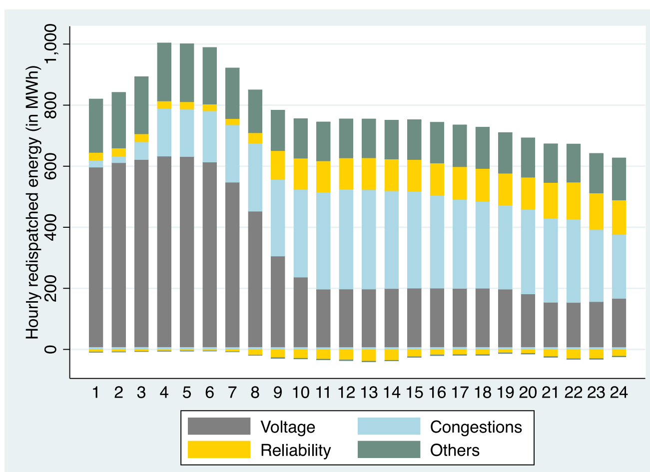

Fig. C1. Average hourly redispatched energy (Stage 1) by operational constraints in 2019.

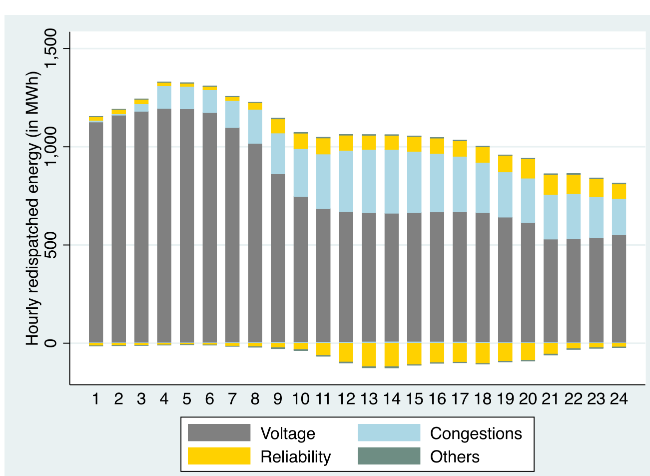

Fig. C2. Average hourly redispatched energy (Stage 1) by operational constraints in 2020.

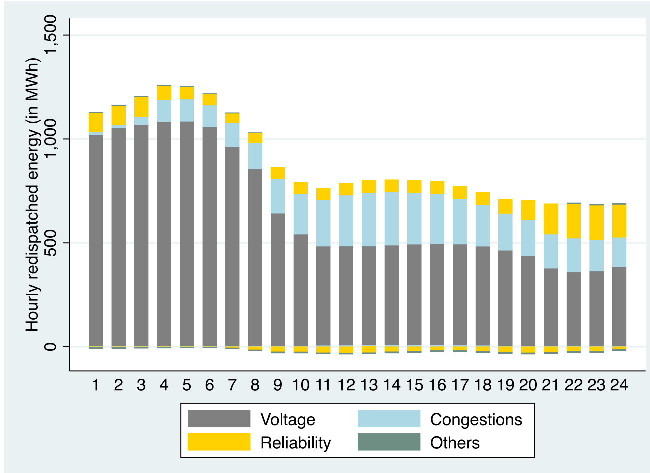

Fig. C3. Average hourly redispatched energy (Stage 1) by operational constraints in 2021.

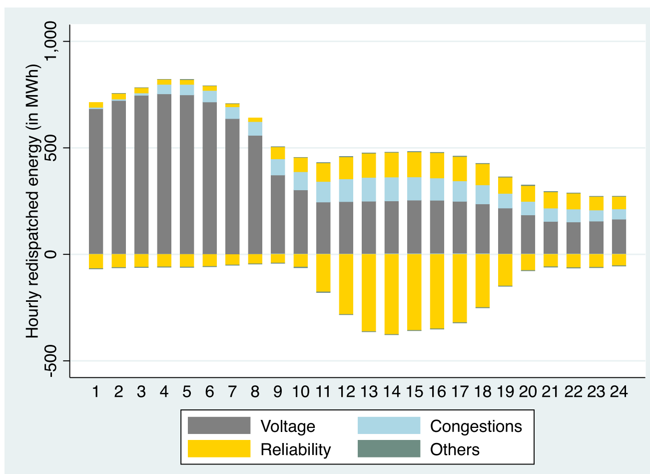

Fig. C4. Average hourly redispatched energy (Stage 1) by operational constraints in 2022.

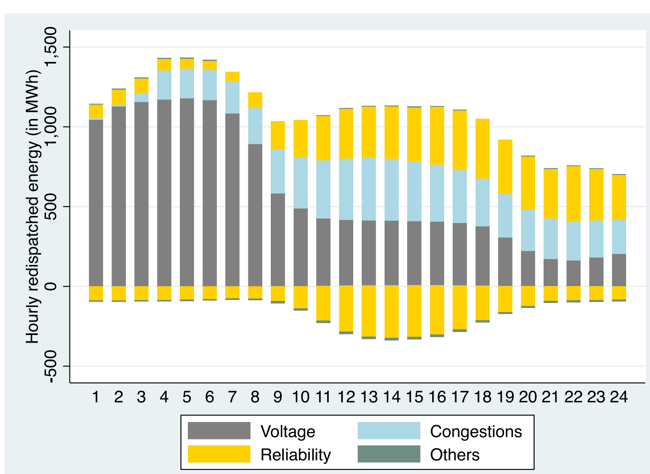

Fig. C5. Average hourly redispatched energy (Stage 1) by operational constraints in 2023.

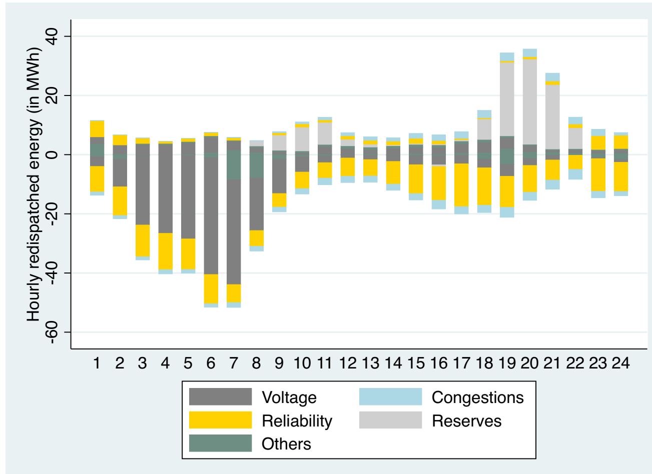

Fig. C6. Average hourly redispatched energy (Stage 3) by operational constraints in 2019.

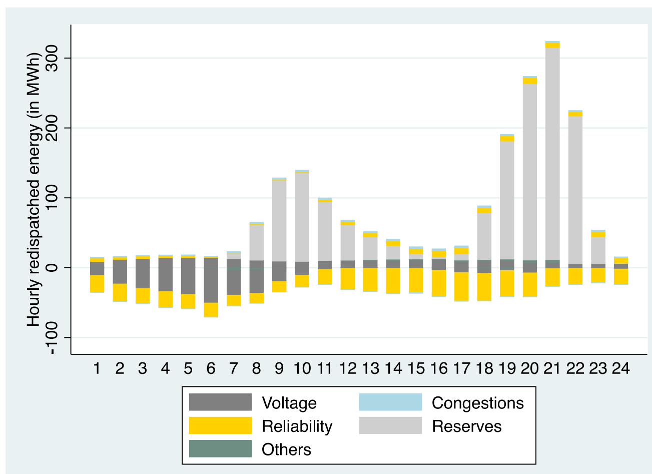

Fig. C7. Average hourly redispatched energy (Stage 3) by operational constraints in 2020.

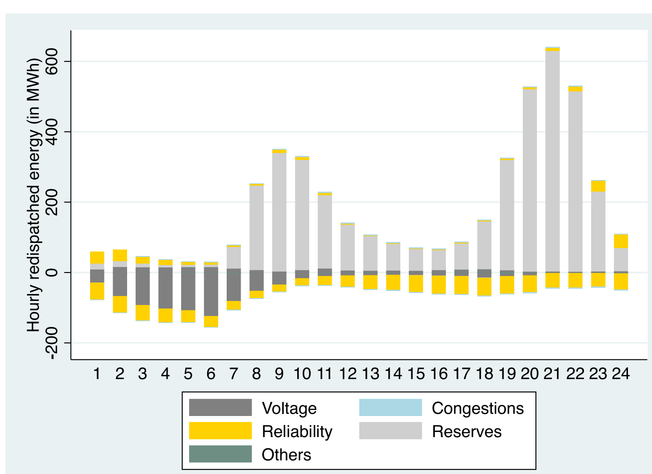

Fig. C8. Average hourly redispatched energy (Stage 3) by operational constraints in 2021.

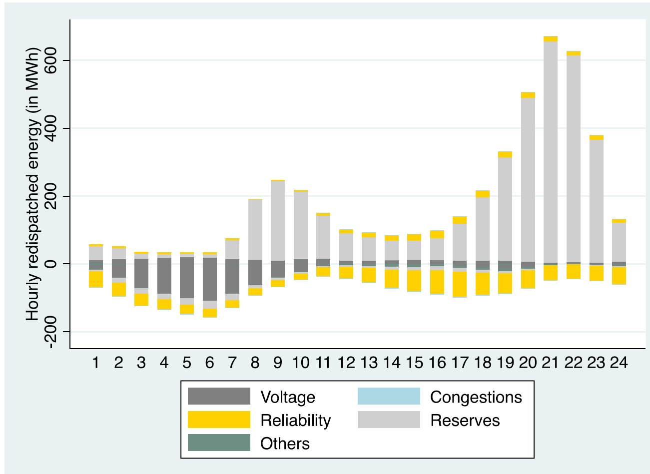

Fig. C9. Average hourly redispatched energy (Stage 3) by operational constraints in 2022.

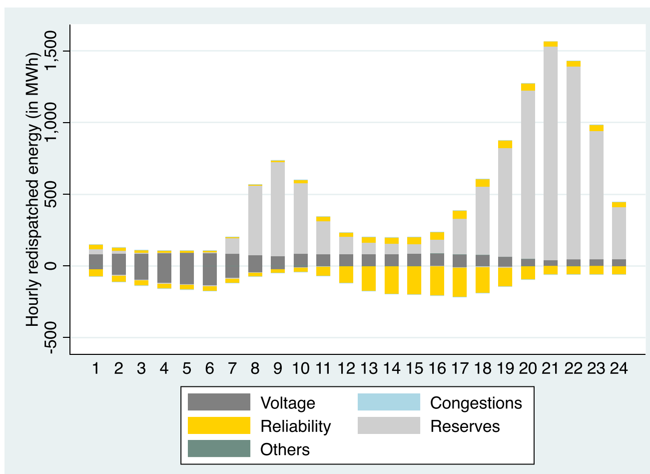

Fig. C10. Average hourly redispatched energy (Stage 3) by operational constraints in 2023.

Appendix D – Hourly volumes by activated technology.

In all the graphs, positive values in vertical axis correspond to upward redispatched energy, while negative values show downward redispatch energy.

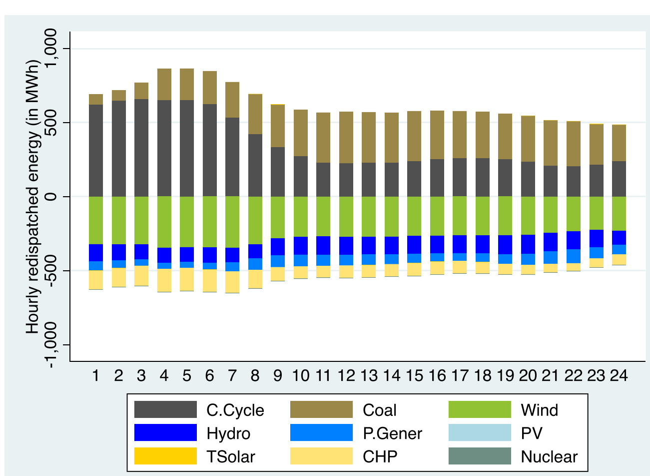

Fig. D1. Average hourly redispatched energy (Stages 1 and 2) by technology in 2019.

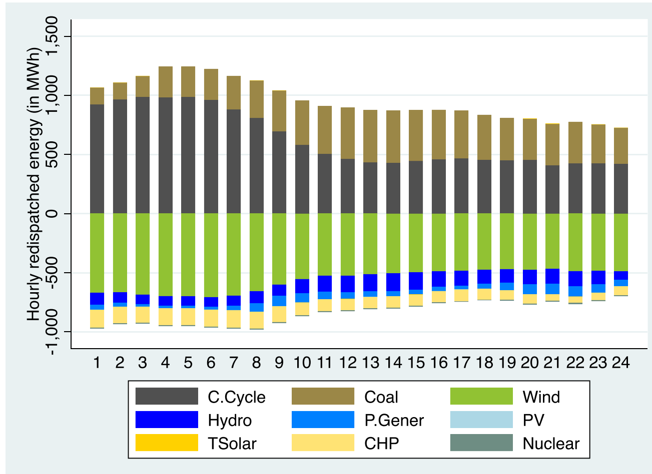

Fig. D2. Average hourly redispatched energy (Stages 1 and 2) by technology in 2020.

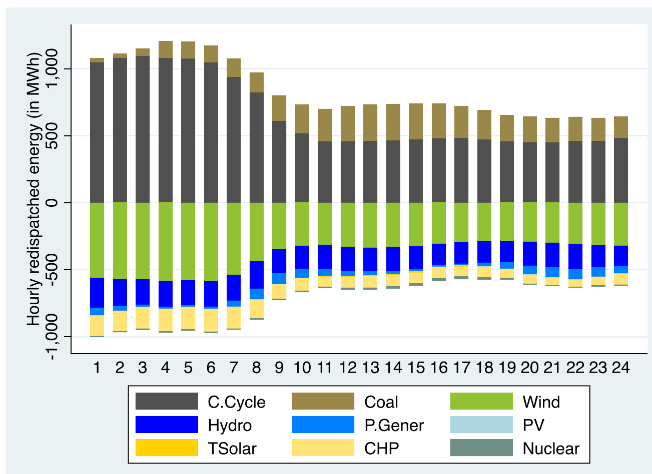

Fig. D3. Average hourly redispatched energy (Stages 1 and 2) by technology in 2021.

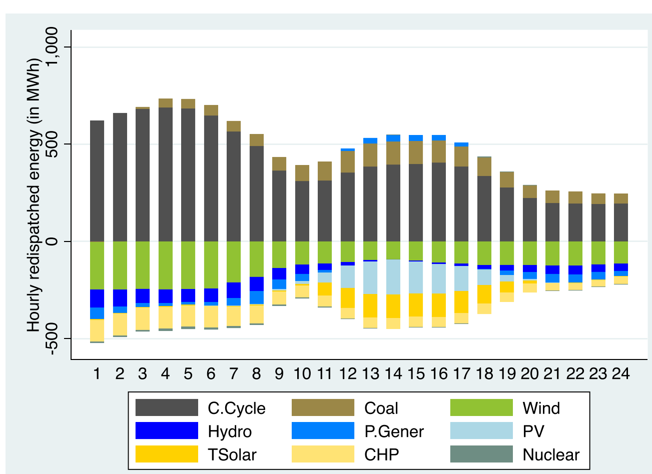

Fig. D4. Average hourly redispatched energy (Stages 1 and 2) by technology in 2022.

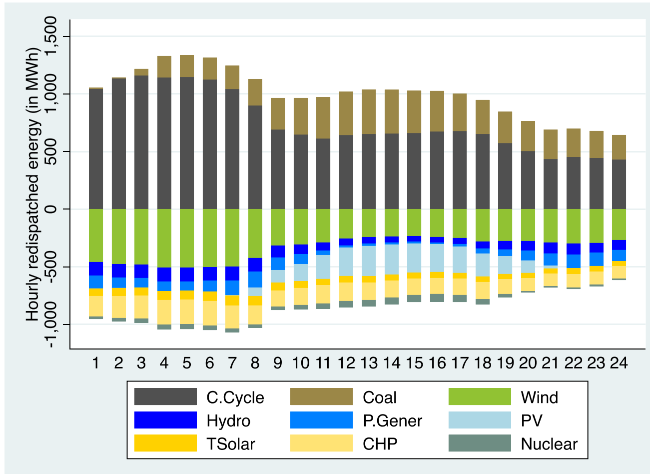

Fig. D5. Average hourly redispatched energy (Stages 1 and 2) by technology in 2023.

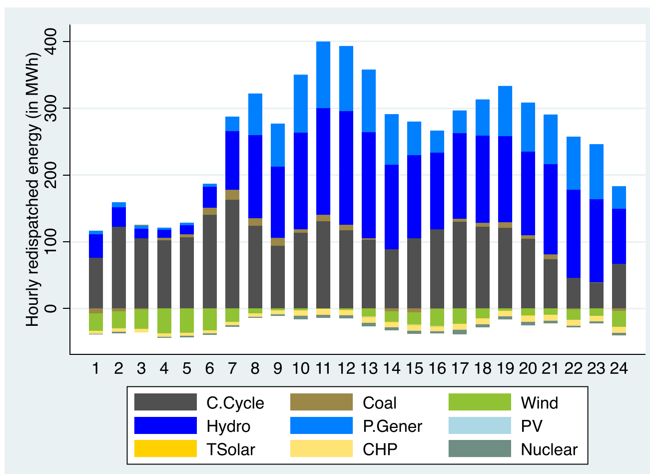

Fig. D6. Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2019.

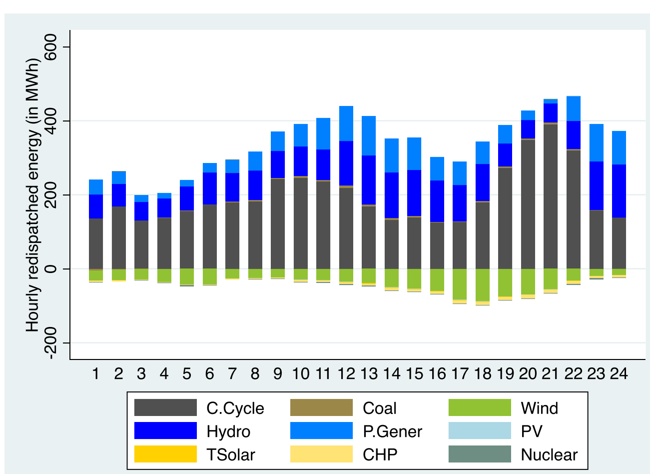

Fig. D7. Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2020.

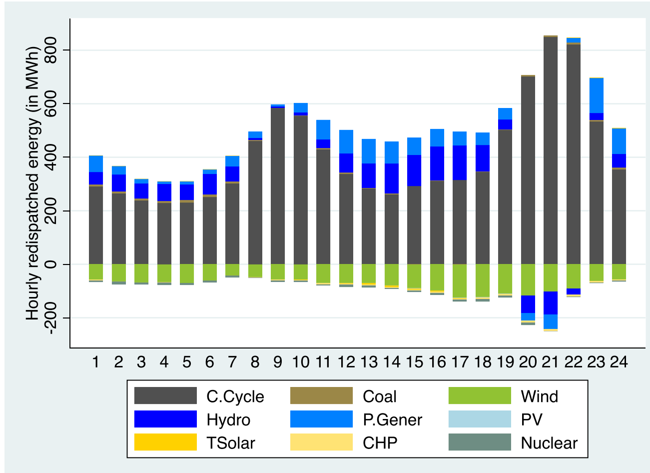

Fig. D8. Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2021.

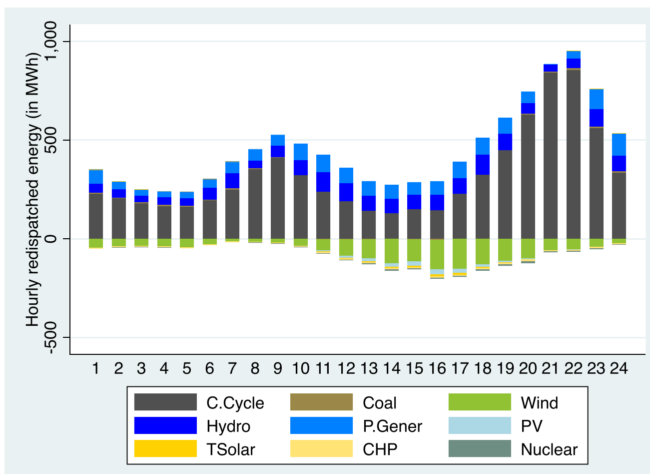

Fig. D9. Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2022.

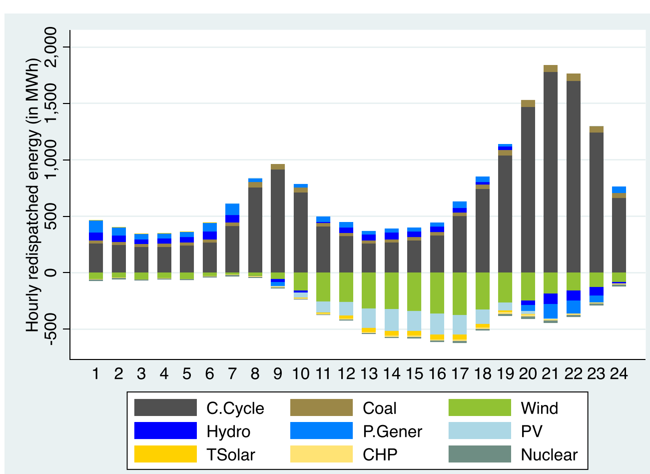

Fig. D10. Average hourly redispatched energy (Stages 3 + balancing actions) by technology in 2023.

Appendix E – Short-term contributions of technologies (Step 1).

Table E1
ML estimations for voltage constraints after the day-ahead markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daVoltage_t$
Comb. Cycle (ΔCC_t)	−0.0580****	−0.0869****	−0.101****	−0.0700****	−0.120****
	(0.00144)	(0.00253)	(0.00169)	(0.00159)	(0.00259)
Coal (ΔCO_t)	−0.0117****	0.383****	−0.124****	−0.115****	0.528****
	(0.00318)	(0.0186)	(0.00850)	(0.00847)	(0.0225)
Hydropower (ΔH_t)	−0.0352****	−0.0336****	−0.0370****	−0.0444****	−0.0547****
	(0.00198)	(0.00227)	(0.00266)	(0.00272)	(0.00240)
Nuclear (ΔN_t)	−0.00771	−0.0508****	−0.0433****	0.0160	−0.0156
	(0.00613)	(0.0104)	(0.0120)	(0.0148)	(0.0123)
Pumping gen. (ΔPG_t)	−0.0275****	−0.0309****	−0.0471****	−0.0502****	−0.0742****
	(0.00442)	(0.00437)	(0.00403)	(0.00347)	(0.00403)
Photovoltaics (ΔPV_t)	−0.0389****	−0.0318****	−0.0474****	−0.0382****	−0.0572****
	(0.00691)	(0.00538)	(0.00393)	(0.00265)	(0.00243)
Thermosolar (ΔTS_t)	−0.0341****	−0.0437***	−0.0559****	−0.0432****	−0.0224
	(0.00934)	(0.0137)	(0.0133)	(0.0126)	(0.0146)
CHP (ΔCHP_t)	−0.0934****	−0.240****	−0.184****	−0.261****	−0.391****
	(0.0138)	(0.0195)	(0.0206)	(0.0197)	(0.0208)
Wind (ΔW_t)	−0.0272****	−0.0310****	−0.0312****	−0.0265****	−0.0379****
	(0.00220)	(0.00270)	(0.00255)	(0.00294)	(0.00308)
Imports (ΔI_t)	−0.0191****	−0.0216****	−0.0408****	−0.0292****	−0.0453****
	(0.00146)	(0.00182)	(0.00185)	(0.00171)	(0.00224)
AR1	−0.0818****	−0.0687****	−0.134****	−0.0885****	−0.0882****
	(0.00815)	(0.00764)	(0.00709)	(0.00755)	(0.00802)
AR24	0.646****	0.651****	0.646****	0.624****	0.640****
	(0.00322)	(0.00312)	(0.00373)	(0.00330)	(0.00395)
Constant ($\widehat{\beta_0}$)	88.21****	119.3****	124.2****	123.4****	157.0****
	(0.268)	(0.338)	(0.429)	(0.384)	(0.528)
N	8732	8780	8756	8756	8757

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

Table E2
ML estimations for congestion issues after the day-ahead markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$
Comb. Cycle (ΔCC_t)	0.0177****	0.0210****	0.00628****	0.000963*	0.00495****
	(0.00101)	(0.00142)	(0.00119)	(0.000512)	(0.000970)
Coal (ΔCO_t)	−0.0252****	−0.385****	−0.222****	−0.0691****	−0.464****
	(0.00233)	(0.00755)	(0.00395)	(0.00211)	(0.00436)
Hydropower (ΔH_t)	0.0104****	0.0120****	0.00631****	0.00273***	0.00928****
	(0.00146)	(0.00120)	(0.00102)	(0.000878)	(0.000870)
Nuclear (ΔN_t)	0.0398****	0.00287	−0.00562	0.00866	0.00165
	(0.0104)	(0.00568)	(0.00454)	(0.00649)	(0.00475)
Pumping gen. (ΔPG_t)	0.0181****	0.00143	0.00616****	0.00271***	0.0136****
	(0.00331)	(0.00289)	(0.00166)	(0.000901)	(0.00145)
Photovoltaics (ΔPV_t)	0.0158****	0.0260****	0.0154****	0.00444****	0.0144****
	(0.00402)	(0.00168)	(0.00133)	(0.000684)	(0.000621)
Thermosolar (ΔTS_t)	0.0203***	0.00784	0.0120**	0.0128****	−0.00149
	(0.00632)	(0.00556)	(0.00521)	(0.00315)	(0.00414)
CHP (ΔCHP_t)	0.0564****	0.136****	0.0539****	0.0428****	0.0437****
	(0.0105)	(0.0112)	(0.00740)	(0.00701)	(0.00760)
Wind (ΔW_t)	0.00976****	0.00701****	0.000212	0.000750	0.000232
	(0.00157)	(0.00147)	(0.00107)	(0.000739)	(0.00101)
Imports (ΔI_t)	0.00650****	0.00573****	0.00430****	0.00214****	0.00330****
	(0.00103)	(0.000972)	(0.000781)	(0.000564)	(0.000771)
AR1	−0.107****	−0.154****	−0.105****	−0.0399****	−0.0658****
	(0.00843)	(0.00969)	(0.00782)	(0.00722)	(0.00949)
AR24	0.609****	0.402****	0.524****	0.589****	0.387****
	(0.00484)	(0.00609)	(0.00465)	(0.00298)	(0.00582)
Constant ($\widehat{\beta_0}$)	54.93****	58.23****	48.79****	30.78****	45.91****
	(0.193)	(0.255)	(0.161)	(0.0777)	(0.180)
N	8732	8780	8756	8756	8757

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

Table E3
ML estimations for grid reliability issues after the day-ahead markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daReiability_t$	$\Delta daReiability_t$	$\Delta daReiability_t$	$\Delta daReiability_t$	$\Delta daReiability_t$
Comb. Cycle (ΔCC_t)	0.0111****	0.00770***	0.00365*	−0.00316	−0.0109***
	(0.00131)	(0.00287)	(0.00191)	(0.00278)	(0.00346)
Coal (ΔCO_t)	0.00832***	−0.0594**	−0.0447****	−0.0153	−0.193****
	(0.00291)	(0.0235)	(0.00917)	(0.0134)	(0.0272)
Hydropower (ΔH_t)	0.0147****	0.0147****	0.0120****	0.0168****	0.0294****
	(0.00197)	(0.00261)	(0.00250)	(0.00496)	(0.00332)
Nuclear (ΔN_t)	−0.0235	−0.0186	0.0475****	−0.0712**	0.0144
	(0.0145)	(0.0194)	(0.0140)	(0.0312)	(0.0252)
Pumping gen. (ΔPG_t)	0.0160***	0.0268****	0.00161	0.00939	0.0348****
	(0.00541)	(0.00509)	(0.00409)	(0.00667)	(0.00503)
Photovoltaics (ΔPV_t)	0.0119***	0.0122****	0.00260	0.0296****	0.0337****
	(0.00456)	(0.00334)	(0.00198)	(0.00237)	(0.00215)
Thermosolar (ΔTS_t)	0.00317	0.0625****	−0.00826	0.105****	0.113****
	(0.00768)	(0.00923)	(0.00744)	(0.0111)	(0.0117)
CHP (ΔCHP_t)	0.142****	0.135****	0.0815****	−0.00499	0.126****
	(0.0130)	(0.0272)	(0.0247)	(0.0333)	(0.0274)
Wind (ΔW_t)	0.00880****	0.0101***	0.0185****	0.0177****	0.0298****
	(0.00227)	(0.00319)	(0.00258)	(0.00426)	(0.00408)
Imports (ΔI_t)	0.00462***	0.00275	0.00151	0.0229****	0.00188
	(0.00151)	(0.00168)	(0.00164)	(0.00270)	(0.00246)
AR1	−0.0172**	0.0179****	−0.0235****	0.213****	0.0543****
	(0.00697)	(0.00471)	(0.00617)	(0.00506)	(0.00750)
AR24	0.256****	0.235****	0.284****	0.343****	0.323****
	(0.00404)	(0.00376)	(0.00393)	(0.00409)	(0.00443)
Constant ($\widehat{\beta_0}$)	76.21****	108.1****	97.13****	129.2****	171.0****
	(0.169)	(0.150)	(0.197)	(0.300)	(0.429)
N	8732	8780	8756	8756	8757

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

Table E4
ML estimations for other issues after the day-ahead markets. Note: Estimations for 2023 are not converging.

	(2019)	(2020)	(2021)	(2022)
	$\Delta daOthers_t$	$\Delta daOthers_t$	$\Delta daOthers_t$	$\Delta daOthers_t$
Comb. Cycle (ΔCC_t)	−0.0196****	0.000270	0.000786*	−0.000208
	(0.000485)	(0.000821)	(0.000415)	(0.000609)
Coal (ΔCO_t)	−0.0462****	−0.0102**	−0.00610***	−0.00142
	(0.000870)	(0.00450)	(0.00226)	(0.00191)
Hydropower (ΔH_t)	0.00417****	0.00123	−0.000233	0.000467
	(0.000833)	(0.000935)	(0.000424)	(0.000694)
Nuclear (ΔN_t)	−0.0331****	−0.00174	−0.00547***	−0.00202
	(0.00454)	(0.0232)	(0.00181)	(0.00963)
Pumping gen. (ΔPG_t)	−0.000779	0.00123	0.000714	0.000380
	(0.00220)	(0.00195)	(0.000838)	(0.00155)
Photovoltaics (ΔPV_t)	0.000282	0.00113	−0.0000789	0.000296
	(0.00182)	(0.000712)	(0.000369)	(0.000288)
Thermosolar (ΔTS_t)	−0.000543	−0.00241	−0.00136	−0.0000566
	(0.00327)	(0.00226)	(0.00152)	(0.00162)
CHP (ΔCHP_t)	−0.00198	−0.00419	−0.0000383	−0.00381
	(0.00581)	(0.0139)	(0.00550)	(0.00565)
Wind (ΔW_t)	0.00285***	0.000141	0.00113	0.000731
	(0.000978)	(0.00119)	(0.000711)	(0.000566)
Imports (ΔI_t)	0.000860	0.000318	0.000401	0.000301
	(0.000675)	(0.000768)	(0.000389)	(0.000334)
AR1	−0.0163**	−0.0218****	0.0449****	0.133****
	(0.00718)	(0.00297)	(0.00276)	(0.00282)
AR24	0.152****	0.0231****	0.376****	−0.0226****
	(0.00422)	(0.00456)	(0.00112)	(0.00563)
Constant ($\widehat{\beta_0}$)	34.81****	22.76****	13.49****	10.83****
	(0.0839)	(0.0204)	(0.0130)	(0.00793)
N	8732	8780	8756	8756

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

Table E5
ML estimations for voltage constraints after the intraday markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idVoltage_t$
Comb. Cycle (ΔCC_t)	−0.00488****	−0.0101****	−0.0314****	−0.0183****	−0.0268****
	(0.00108)	(0.00159)	(0.00147)	(0.00191)	(0.00189)
Coal (ΔCO_t)	−0.00388	−0.0125	−0.0235	−0.0197	−0.0612****
	(0.00382)	(0.0215)	(0.0196)	(0.0164)	(0.0159)
Hydropower (ΔH_t)	−0.00341**	−0.00731****	−0.0159****	−0.0112****	−0.0212****
	(0.00173)	(0.00134)	(0.00187)	(0.00235)	(0.00149)
Nuclear (ΔN_t)	−0.00496	−0.00646	0.0307***	−0.0368	−0.0247***
	(0.0162)	(0.0387)	(0.0107)	(0.0264)	(0.00950)
Pumping gen. (ΔPG_t)	−0.00498	−0.00234	−0.00660	−0.0169****	−0.0221****
	(0.00386)	(0.00338)	(0.00465)	(0.00402)	(0.00260)
Photovoltaics (ΔPV_t)	−0.00465**	−0.00653****	−0.0126****	−0.0125****	−0.0123****
	(0.00198)	(0.00150)	(0.00169)	(0.00132)	(0.00100)
Thermosolar (ΔTS_t)	−0.00328	0.00289	−0.0139*	−0.0120	−0.0220****
	(0.00451)	(0.00651)	(0.00816)	(0.00733)	(0.00590)
CHP (ΔCHP_t)	0.0227	0.0108	0.00783	−0.00364	−0.0472***
	(0.0162)	(0.0184)	(0.0175)	(0.0187)	(0.0164)
Wind (ΔW_t)	−0.00740****	−0.00725***	−0.0179****	−0.0168****	−0.0129****
	(0.00183)	(0.00265)	(0.00261)	(0.00288)	(0.00262)
Imports (ΔI_t)	−0.00633****	−0.00277**	−0.0124****	−0.0118****	−0.00763****
	(0.000962)	(0.00113)	(0.00126)	(0.00159)	(0.00148)
AR1	−0.0868****	−0.112****	−0.0252****	0.0108**	−0.0530****
	(0.00311)	(0.00294)	(0.00368)	(0.00445)	(0.00468)
AR24	0.0316****	0.0477****	0.144****	0.0315****	0.132****
	(0.00470)	(0.00592)	(0.00394)	(0.00586)	(0.00616)
Constant ($\widehat{\beta_0}$)	44.39****	57.21****	78.14****	82.58****	81.82****
	(0.0637)	(0.0842)	(0.183)	(0.167)	(0.222)
N	8732	8780	8756	8756	8757

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

Table E6
ML estimations for congestion issues after the intraday markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$
Comb. Cycle (ΔCC_t)	0.000169	0.000631*	0.000314	−0.0000836	−0.0000797
	(0.000603)	(0.000348)	(0.000329)	(0.000402)	(0.000221)
Coal (ΔCO_t)	−0.00158	−0.0145****	−0.0222****	−0.00525****	0.0000101
	(0.00217)	(0.00196)	(0.00169)	(0.00108)	(0.00137)
Hydropower (ΔH_t)	0.00101**	−0.00000868	0.0000982	−0.0000306	0.0000796
	(0.000404)	(0.000336)	(0.000242)	(0.000349)	(0.000170)
Nuclear (ΔN_t)	−0.00240	0.000167	0.00167	0.00749****	−0.000588
	(0.00935)	(0.0395)	(0.00247)	(0.00115)	(0.00290)
Pumping gen. (ΔPG_t)	−0.000133	−0.000445	0.000301	0.0000707	−0.0000695
	(0.000844)	(0.000493)	(0.000470)	(0.000511)	(0.000373)
Photovoltaics (ΔPV_t)	−0.000367	0.000495	0.000732****	0.0000295	0.000184
	(0.000585)	(0.000312)	(0.000159)	(0.000155)	(0.000123)
Thermosolar (ΔTS_t)	0.00167	−0.000981	−0.000573	0.00123	−0.000758
	(0.00117)	(0.000903)	(0.000762)	(0.000903)	(0.000915)
CHP (ΔCHP_t)	0.00141	0.00443	0.00788****	0.00428**	−0.000993
	(0.00616)	(0.00420)	(0.00175)	(0.00188)	(0.00210)
Wind (ΔW_t)	0.0000763	−0.000115	0.000582**	0.000443	0.000401*
	(0.000377)	(0.000697)	(0.000256)	(0.000328)	(0.000209)
Imports (ΔI_t)	0.000178	0.000168	0.000361*	−0.0000434	0.000146
	(0.000234)	(0.000250)	(0.000189)	(0.000231)	(0.000223)
AR1	0.212****	−0.00248	−0.0985****	−0.0442****	−0.158****
	(0.00144)	(0.00237)	(0.00304)	(0.00230)	(0.00158)
AR24	0.0159*	−0.00000937	−0.0432****	−0.0248****	0.178****
	(0.00883)	(0.105)	(0.00342)	(0.00348)	(0.00150)
Constant ($\widehat{\beta_0}$)	9.728****	9.390****	8.610****	7.473****	7.457****
	(0.00939)	(0.00826)	(0.0138)	(0.00731)	(0.00529)
N	8732	8780	8756	8756	8757

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

Table E7
ML estimations for grid reliability issues after intraday markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idReiability_t$	$\Delta idReiability_t$	$\Delta idReiability_t$	$\Delta idReiability_t$	$\Delta idReiability_t$
Comb. Cycle (ΔCC_t)	−0.00337***	−0.0992****	−0.101****	−0.0533****	−0.101****
	(0.00105)	(0.00291)	(0.00295)	(0.00323)	(0.00429)
Coal (ΔCO_t)	−0.0185****	0.000839	0.0572	0.0737***	−0.319****
	(0.00340)	(0.0241)	(0.0371)	(0.0263)	(0.0341)
Hydropower (ΔH_t)	0.0112****	0.0737****	0.137****	0.111****	0.249****
	(0.000974)	(0.00247)	(0.00282)	(0.00361)	(0.00361)
Nuclear (ΔN_t)	−0.0112	−0.0141	0.0575*	0.0536	0.0308
	(0.0102)	(0.0480)	(0.0338)	(0.0366)	(0.0376)
Pumping gen. (ΔPG_t)	0.0472****	0.197****	0.220****	0.189****	0.232****
	(0.00135)	(0.00323)	(0.00419)	(0.00487)	(0.00601)
Photovoltaics (ΔPV_t)	−0.00188	−0.00712	−0.00995***	−0.0162****	−0.0103****
	(0.00157)	(0.00448)	(0.00317)	(0.00281)	(0.00284)
Thermosolar (ΔTS_t)	0.00292	0.00887	0.0474****	0.0767****	0.206****
	(0.00364)	(0.0128)	(0.0134)	(0.0166)	(0.0192)
CHP (ΔCHP_t)	0.00144	0.0843**	0.112****	0.199****	0.564****
	(0.0217)	(0.0362)	(0.0321)	(0.0382)	(0.0326)
Wind (ΔW_t)	0.000653	0.0219****	0.0326****	0.0114**	0.0397****
	(0.00155)	(0.00432)	(0.00456)	(0.00480)	(0.00541)
Imports (ΔI_t)	−0.00265****	0.0159****	0.0389****	0.0268****	0.0563****
	(0.000759)	(0.00205)	(0.00229)	(0.00303)	(0.00352)
AR1	−0.0329****	0.0532****	0.0308****	0.0278****	−0.0230***
	(0.00732)	(0.00708)	(0.00812)	(0.00718)	(0.00830)
AR24	0.0622****	0.383****	0.272****	0.369****	0.384****
	(0.00360)	(0.00472)	(0.00688)	(0.00558)	(0.00682)
Constant ($\widehat{\beta_0}$)	37.58****	121.2****	152.9****	164.7****	227.0****
	(0.0729)	(0.410)	(0.668)	(0.627)	(1.039)
N	8732	8780	8756	8756	8757

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

Table E8
ML estimations for insufficient adequacy reserves after the intraday markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$
Comb. Cycle (ΔCC_t)	−0.00337***	−0.0992****	−0.101****	−0.0533****	−0.101****
	(0.00105)	(0.00291)	(0.00295)	(0.00323)	(0.00429)
Coal (ΔCO_t)	−0.0185****	0.000839	0.0572	0.0737***	−0.319****
	(0.00340)	(0.0241)	(0.0371)	(0.0263)	(0.0341)
Hydropower (ΔH_t)	0.0112****	0.0737****	0.137****	0.111****	0.249****
	(0.000974)	(0.00247)	(0.00282)	(0.00361)	(0.00361)
Nuclear (ΔN_t)	−0.0112	−0.0141	0.0575*	0.0536	0.0308
	(0.0102)	(0.0480)	(0.0338)	(0.0366)	(0.0376)
Pumping gen. (ΔPG_t)	0.0472****	0.197****	0.220****	0.189****	0.232****
	(0.00135)	(0.00323)	(0.00419)	(0.00487)	(0.00601)
Photovoltaics (ΔPV_t)	−0.00188	−0.00712	−0.00995***	−0.0162****	−0.0103****
	(0.00157)	(0.00448)	(0.00317)	(0.00281)	(0.00284)
Thermosolar (ΔTS_t)	0.00292	0.00887	0.0474****	0.0767****	0.206****
	(0.00364)	(0.0128)	(0.0134)	(0.0166)	(0.0192)
CHP (ΔCHP_t)	0.00144	0.0843**	0.112****	0.199****	0.564****
	(0.0217)	(0.0362)	(0.0321)	(0.0382)	(0.0326)
Wind (ΔW_t)	0.000653	0.0219****	0.0326****	0.0114**	0.0397****
	(0.00155)	(0.00432)	(0.00456)	(0.00480)	(0.00541)
Imports (ΔI_t)	−0.00265****	0.0159****	0.0389****	0.0268****	0.0563****
	(0.000759)	(0.00205)	(0.00229)	(0.00303)	(0.00352)
AR1	−0.0329****	0.0532****	0.0308****	0.0278****	−0.0230***
	(0.00732)	(0.00708)	(0.00812)	(0.00718)	(0.00830)
AR24	0.0622****	0.383****	0.272****	0.369****	0.384****
	(0.00360)	(0.00472)	(0.00688)	(0.00558)	(0.00682)
Constant ($\widehat{\beta_0}$)	37.58****	121.2****	152.9****	164.7****	227.0****
	(0.0729)	(0.410)	(0.668)	(0.627)	(1.039)
N	8732	8780	8756	8756	8757

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

Table E9
ML estimations for other issues after the intraday markets.

	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idOthers_t$	$\Delta idOthers_t$	$\Delta idOthers_t$	$\Delta idOthers_t$	$\Delta idOthers_t$
Comb. Cycle (ΔCC_t)	0.000597	0.000112	0.000698	−0.000158	0.00488***
	(0.000987)	(0.000820)	(0.000618)	(0.000718)	(0.00153)
Coal (ΔCO_t)	−0.000999	−0.00660	−0.000272	0.00812	−0.0478****
	(0.00247)	(0.00817)	(0.00899)	(0.00688)	(0.0106)
Hydropower (ΔH_t)	−0.00119	−0.00144*	−0.000382	−0.000159	0.00138
	(0.00126)	(0.000770)	(0.000672)	(0.00120)	(0.00142)
Nuclear (ΔN_t)	0.00146	−0.00126	−0.00396	−0.00266	0.322****
	(0.0190)	(0.0277)	(0.00392)	(0.0262)	(0.00206)
Pumping gen. (ΔPG_t)	−0.00133	0.00512****	−0.00233**	0.000330	0.00100
	(0.00187)	(0.00151)	(0.00113)	(0.00162)	(0.00220)
Photovoltaics (ΔPV_t)	−0.00207*	−0.000283	−0.000749*	0.000392	0.00147**
	(0.00110)	(0.000830)	(0.000419)	(0.000608)	(0.000630)
Thermosolar (ΔTS_t)	0.00223	0.00154	0.00239	0.00231	0.00617*
	(0.00296)	(0.00392)	(0.00246)	(0.00270)	(0.00362)
CHP (ΔCHP_t)	−0.0136	−0.00223	0.00200	0.00148	−0.0148
	(0.00832)	(0.00675)	(0.00599)	(0.00704)	(0.0112)
Wind (ΔW_t)	−0.000818*	0.000373	0.0000782	0.000730	0.00185
	(0.000433)	(0.00112)	(0.000468)	(0.00102)	(0.00158)
Imports (ΔI_t)	−0.000175	−0.0000256	−0.000284	−0.000984	0.000451
	(0.000475)	(0.000551)	(0.000451)	(0.000730)	(0.00109)
AR1	−0.428****	−0.219****	−0.318****	−0.156****	−0.223****
	(0.000717)	(0.00161)	(0.00146)	(0.00181)	(0.00164)
AR24	0.0565****	0.00145	0.0306****	0.0494****	0.0151****
	(0.00565)	(0.0105)	(0.00803)	(0.00513)	(0.00334)
Constant ($\widehat{\beta_0}$)	27.65****	25.21****	26.80****	35.45****	53.11****
	(0.0203)	(0.0351)	(0.0185)	(0.0442)	(0.0558)
N	8732	8780	8756	8756	8757

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

Appendix F – Short-term contributions of demand and RES (Step 1).

Table F1
ML estimations for actions made after day-ahead.

	(2019)	(2020)	(2021)	(2022)	(2023)	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daVoltage_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$	$\Delta daCongestion_t$
Demand (ΔTED_t)	−0.0343****	−0.0376****	−0.0503****	−0.0418****	−0.0531****	0.0111****	0.0135****	0.00565****	0.00262****	0.00340****
	(0.00100)	(0.00147)	(0.00131)	(0.00138)	(0.00143)	(0.000656)	(0.000697)	(0.000549)	(0.000389)	(0.000530)
RES ($\Delta sRES_t$)	2.339****	1.097**	3.997****	5.518****	4.374****	−0.0932	0.819***	0.840****	0.553****	1.035****
	(0.499)	(0.536)	(0.517)	(0.402)	(0.434)	(0.358)	(0.301)	(0.238)	(0.112)	(0.154)
AR1	−0.0860****	−0.0697****	−0.129****	−0.0853****	−0.0837****	−0.106****	−0.157****	−0.101****	−0.0381****	−0.0397****
	(0.00791)	(0.00751)	(0.00719)	(0.00758)	(0.00763)	(0.00835)	(0.00927)	(0.00739)	(0.00702)	(0.00865)
AR24	0.666****	0.705****	0.657****	0.638****	0.720****	0.637****	0.565****	0.629****	0.618****	0.706****
	(0.00306)	(0.00277)	(0.00368)	(0.00321)	(0.00328)	(0.00456)	(0.00536)	(0.00374)	(0.00274)	(0.00428)
Constant ($\widehat{\beta_0}$)	89.24****	122.1****	126.8****	125.0****	161.9****	55.39****	60.85****	50.49****	31.33****	50.12****
	(0.265)	(0.339)	(0.430)	(0.388)	(0.513)	(0.184)	(0.246)	(0.140)	(0.0658)	(0.168)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

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

Table F2
ML estimations for actions made after day-ahead.

	(2019)	(2020)	(2021)	(2022)	(2023)	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta daReliability_t$	$\Delta daReliability_t$	$\Delta daReliability_t$	$\Delta daReliability_t$	$\Delta daReliability_t$	$\Delta daOthers_t$	$\Delta daOthers_t$	$\Delta daOthers_t$	$\Delta daOthers_t$	$\Delta daOthers_t$
Demand (ΔTED_t)	0.0118****	0.0142****	0.00528****	0.0196****	0.0232****	−0.00474****	0.000649**	0.000240	0.000225	
	(0.000753)	(0.00122)	(0.00105)	(0.00178)	(0.00160)	(0.000297)	(0.000277)	(0.000208)	(0.000164)	
RES ($\Delta sRES_t$)	−0.653	2.215****	−0.512	4.768****	6.605****	2.232****	−0.0131	−0.0584	0.0330	
	(0.487)	(0.487)	(0.338)	(0.517)	(0.379)	(0.215)	(0.0932)	(0.0690)	(0.0602)	
AR1	−0.0183***	0.0180****	−0.0187***	0.227****	0.0604****	−0.0131*	−0.0219****	0.0456****	0.134****	
	(0.00695)	(0.00465)	(0.00606)	(0.00495)	(0.00731)	(0.00713)	(0.00290)	(0.00268)	(0.00169)	
AR24	0.266****	0.248****	0.294****	0.359****	0.352****	0.162****	0.0239****	0.379****	−0.0231****	
	(0.00393)	(0.00353)	(0.00373)	(0.00391)	(0.00416)	(0.00376)	(0.00304)	(0.000978)	(0.00318)	
Constant ($\widehat{\beta_0}$)	76.49****	108.8****	97.59****	130.5****	173.5****	36.17****	22.78****	13.51****	10.84****	
	(0.167)	(0.149)	(0.177)	(0.277)	(0.431)	(0.0827)	(0.0149)	(0.00858)	(0.00664)	
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	

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

Table F3
ML estimations for actions made after day-ahead.

	(2019)	(2020)	(2021)	(2022)	(2023)	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idVoltage_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$	$\Delta idCongestion_t$
Demand (ΔTED_t)	−0.00456****	−0.00566****	−0.0151****	−0.0131****	−0.0159****	0.000244*	0.0000997	0.000313***	0.0000286	0.0000932
	(0.000457)	(0.000553)	(0.000786)	(0.000964)	(0.000833)	(0.000128)	(0.000109)	(0.0000967)	(0.000111)	(0.0000809)
RES ($\Delta sRES_t$)	−0.432	−0.393	0.305	−0.0270	0.902****	−0.0755	−0.00539	0.0396	0.0380*	0.0207
	(0.307)	(0.251)	(0.343)	(0.182)	(0.163)	(0.0881)	(0.0499)	(0.0373)	(0.0229)	(0.0169)
AR1	−0.0864****	−0.111****	−0.0184****	0.0123***	−0.0471****	0.213****	−0.00136	−0.0995****	−0.0434****	−0.158****
	(0.00292)	(0.00273)	(0.00354)	(0.00436)	(0.00467)	(0.00104)	(0.00205)	(0.00287)	(0.00204)	(0.00126)
AR24	0.0307****	0.0491****	0.160****	0.0335****	0.147****	0.0170**	−0.00181	−0.0425****	−0.0262****	0.178****
	(0.00456)	(0.00577)	(0.00375)	(0.00573)	(0.00599)	(0.00826)	(0.121)	(0.00312)	(0.00300)	(0.00144)
Constant ($\widehat{\beta_0}$)	44.41****	57.30****	78.62****	82.66****	82.50****	9.735****	9.412****	8.666****	7.489****	7.460****
	(0.0594)	(0.0806)	(0.179)	(0.157)	(0.224)	(0.00768)	(0.00500)	(0.00884)	(0.00508)	(0.00467)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

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

Table F4
ML estimations for actions made after day-ahead.

	(2019)	(2020)	(2021)	(2022)	(2023)	(2019)	(2020)	(2021)	(2022)	(2023)
	$\Delta idReliability_t$	$\Delta idReliability_t$	$\Delta idReliability_t$	$\Delta idReliability_t$	$\Delta idReliability_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$	$\Delta idAdequacy_t$
Demand (ΔTED_t)	−0.000558	0.00101*	0.000312	0.000794	0.00776****	0.00152***	0.0247****	0.0490****	0.0382****	0.0970****
	(0.000397)	(0.000522)	(0.000785)	(0.000811)	(0.00136)	(0.000521)	(0.00207)	(0.00192)	(0.00208)	(0.00286)
RES ($\Delta sRES_t$)	0.315	1.532****	1.287****	1.661****	3.248****	−82.08**	−392.3****	−1429.8****	−1452.8****	
	(0.257)	(0.206)	(0.289)	(0.191)	(0.282)	(33.40)	(88.25)	(80.38)	(60.12)	−2775.3****
AR1	0.0519****	0.128****	0.110****	0.146****	0.157****	−0.00889	0.0696****	0.0256***	0.0472****	0.000928
	(0.00202)	(0.00350)	(0.00278)	(0.00360)	(0.00452)	(0.00650)	(0.00620)	(0.00827)	(0.00701)	(0.00811)
AR24	0.0594****	0.0544****	0.0614****	0.0440****	0.136****	0.0957****	0.446****	0.343****	0.396****	0.467****
	(0.00496)	(0.00660)	(0.00355)	(0.00655)	(0.00579)	(0.00347)	(0.00411)	(0.00647)	(0.00535)	(0.00645)
Constant ($\widehat{\beta_0}$)	36.28****	45.07****	69.35****	65.18****	124.4****	38.64****	139.4****	180.0****	179.6****	271.2****
	(0.0394)	(0.0631)	(0.0833)	(0.112)	(0.299)	(0.0388)	(0.345)	(0.719)	(0.622)	(1.227)
N	8732	8780	8756	8756	8757	8732	8780	8756	8756	8757

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

Appendix G –Long-term contributions (Step 2).

The colors of the cells compare the values: the highest numbers are in red, while the lowest ones are in green and the intermediate ones in yellow. Cells for values corresponding to RES do not have colour as these coefficients are in different units.

Table G1
Annual determinants of volumes activated by voltage issues by the scheduled technologies.

	After Day-ahead					**After Intraday**				
Voltage	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
CC	−0.133	−0.208	−0.207	−0.151	−0.268	−0.005	−0.009	−0.036	−0.019	−0.029
Coal	−0.027	0.917	−0.254	−0.248	1.178					−0.066
Hydro	−0.081	−0.080	−0.076	−0.096	−0.122	−0.003	−0.007	−0.018	−0.012	−0.023
Nuclear		−0.122	−0.089					0.035		−0.027
Pumping	−0.063	−0.074	−0.097	−0.108	−0.166				−0.018	−0.024
Photovoltaics	−0.089	−0.076	−0.097	−0.082	−0.128	−0.004	−0.006	−0.014	−0.013	−0.013

(continued on next page)

Table G1 (*continued*)

Voltage	After Day-ahead 2019	2020	2021	2022	2023	After Intraday 2019	2020	2021	2022	2023
Thermosolar	−0.078	−0.105	−0.115	−0.093				−0.016		−0.024
CHP	−0.214	−0.575	−0.377	−0.562	−0.872					−0.051
Wind	−0.062	−0.074	−0.064	−0.057	−0.085	−0.007	−0.007	−0.020	−0.018	−0.014
Imports	−0.044	−0.052	−0.084	−0.063	−0.101	−0.006	−0.003	−0.014	−0.012	−0.008
Demand	−0.082	−0.103	−0.107	−0.093	−0.146	−0.004	−0.005	−0.018	−0.014	−0.018
RES	0.019	0.011	0.030	0.042	0.041					0.003

Note: Missing values corresponds to non-significant coefficients in estimations from Appendix B and C.

Table G2
Annual determinants of volumes activated by congestion issues by the scheduled technologies.

RTD	After Day-ahead 2019	2020	2021	2022	2023	After Intraday 2019	2020	2021	2022	2023
CC	0.036	0.028	0.011	0.002	0.007		0.001			
Coal	−0.051	−0.512	−0.382	−0.153	−0.684		0.002	0.003	0.001	
Hydro	0.021	0.016	0.011	0.006	0.014	−0.000				
Nuclear	0.080									
Pumping	0.036	0.002	0.011	0.006	0.020					
Photovoltaics	0.032	0.035	0.027	0.010	0.021			0.001		
Thermosolar	0.041		0.021	0.028						
CHP	0.113	0.181	0.093	0.095	0.064			0.008	0.004	
Wind	0.020	0.009						0.001		0.000
Imports	0.013	0.008	0.007	0.005	0.005			0.000		
Demand	0.024	0.023	0.012	0.006	0.010	0.000		0.000		
RES	−0.001	0.005	0.006	0.004	0.011				0.000	

Note: Missing values corresponds to non-significant coefficients in estimations from Appendix B and C.

Table G3
Determinants of volumes activated by grid reliability issues by the scheduled technologies.

SC	After Day-ahead 2019	2020	2021	2022	2023	After Intraday 2019	2020	2021	2022	2023
CC	0.015	0.010	0.005		−0.018			−0.004		−0.017
Coal	0.011	−0.080	−0.060	−0.034	−0.310		0.041			
Hydro	0.019	0.020	0.016	0.038	0.047				−0.004	
Nuclear			0.064	−0.160						0.043
Pumping	0.021	0.036			0.056	−0.007				
Photovoltaics	0.016	0.016		0.067	0.054				0.004	0.018
Thermosolar		0.084		0.236	0.181		0.025		0.016	0.030
CHP	0.187	0.181	0.110		0.202			0.030		
Wind	0.012	0.014	0.025	0.040	0.048	0.011	0.014	0.021	0.030	
Imports	0.006			0.052		0.002			0.011	
Demand	0.016	0.019	0.007	0.047	0.039	−0.001	0.001	0.000	0.001	0.011
RES	−0.000	0.000	−0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Table G4
Determinants of volumes activated by insufficient adequacy reserves by scheduled technologies.

RS	After Intraday 2019	2020	2021	2022	2023
CC	−0.003	−0.176	−0.145	−0.088	−0.158
Coal	−0.019			0.122	−0.499
Hydro	0.012	0.131	0.197	0.184	0.390
Nuclear			0.082		
Pumping	0.049	0.349	0.316	0.313	0.363
Photovoltaics			−0.014	−0.027	−0.016
Thermosolar			0.068	0.127	0.322
CHP		0.150	0.161	0.330	0.883
Wind		0.039	0.047	0.019	0.062
Imports	−0.003	0.028	0.056	0.044	0.088
Demand	0.002	0.051	0.078	0.069	0.182
RES	−0.003	−0.028	−0.077	−0.086	−0.174

Data availability

Data will be made available on request.

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