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Research paper

Storage and demand response contribution to firm capacity: Analysis of the Spanish electricity system

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ABSTRACT

Provision of firm capacity will become a challenge in power systems dominated by renewable generation. This paper analyzes the competitiveness and role of battery storage, six types of pumped-hydro storage, open cycle gas turbine (OCGT), and demand response (DR) technologies in providing the firm capacity required to guarantee the security of supply in a real-size power system such as the Spanish one in horizon 2030. The paper contributes with detailed and realistic modeling of the DR capabilities. Demand is disaggregated by sector and activities and projected towards 2030, applying a growth rate by activity. The load flexibility constraints are considered to ensure the validity of the results. A generation operation planning and expansion model, SPLODER, is conveniently upgraded to properly represent the different storage alternatives addressed in the paper. The results highlight the importance of considering demand response for evaluating long-term firm capacity requirements, showing a non-negligible impact on the investment decisions on the amount of firm capacity required in the system and the optimal shares of wind and solar PV renewable generation. Results also show the dominance of cost-competitiveness of pumped hydro and OCGTs over batteries. Additionally, capacity payments are required to support firm capacity providers' investments.

1. Introduction

Ensuring the security of supply in the Spanish electricity system is a task that faces multiple challenges in the near future. The Spanish national energy strategy commits to achieving at least 74% of renewable electricity generation by 2030 (PNIEC, 2020). Spurred by their increasingly competitive investment costs, there is no doubt the system will mainly rely on wind farms and solar photovoltaic (PV) power plants to meet this target. The production of such renewable generation is fully weather dependent, severely jeopardizing the security of supply, that is, the system's availability to count on enough available generation to meet the demand at any time. These renewable sources are substituting thermal generation, which has traditionally provided the system security of supply and flexibility. Therefore, it will be necessary to resort to additional resources to fill the gap left by phased-out thermal generators as firm capacity[1] providers. Moreover, to be aligned with European goals (Meeus and Nouicer, 2020), these new resources should also have low emissions.

Storage facilities are one of the most suitable technologies to provide firm capacity. A large-scale battery is one of the options. (Mallapragada et al., 2020) assess its potential as the primary resource of firm capacity, concluding that further cost reduction is necessary for batteries to become a cost-effective alternative. Although available in scarce locations, pumped-hydro storage is another option to be considered due to their maturity, large storage capacity, relatively low capital costs, mainly when they take

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[1] Firm capacity technologies refer to energy sources whose capacity is available at the most critical periods of generation as it is controllable and able to supply energy as needed independently of weather or external conditions (Zachary et al., 2019) safeguarding system adequacy.

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advantage of some already installed hydro reservoirs, and fast response capability when needed (Amirante et al., 2017). Many other innovative storage kinds of resources have also been assessed in Korkmaz (2019), such as compressed air energy storage, hydrogen storage, and other developing technologies such as flow batteries and liquid air energy storage. However, none of these more innovative resources is yet close to being cost-competitive.

Other options to provide security of supply beyond storage technologies have also been considered in some publications addressing the future of electricity systems. For instance, the use of power plants with carbon capture and storage combined with high interconnectors capacity (Brouwer et al., 2014), or the geographical diversification of wind farms in Germany, show the reduction of firm capacity needed (Bucksteeg, 2019).

There are other papers similar to this one, where the high penetration of renewables is the issue that result in the pursuit of generation alternatives to guarantee the security of supply of the electricity system. Gaete-Morales et al. (2019) provides the analysis of the Chilean system in horizon 2050. Ruhnau and Qvist (2022) compare different storage types (hydrogen storage, pumped-hydro storage & batteries) to guarantee the security of supply in the German electricity system. Arion (2020) analyze Moldova's pumped-hydro storage needs and Lu et al. (2021) assess China's options to achieve a carbon-neutral electricity system where DR is mentioned qualitatively. However, it is not assessed its impact on the electricity system.

As presented, in the literature, firm capacity requirements are primarily addressed, in addition to generation units, with pumped-hydro storage and lithium-ion batteries. The main contribution of this paper is the analysis of an additional competitor in the provision of firmness, neglected in those studies, which is the impact of demand-side management in a high renewables penetration electricity system. Besides, the paper contributes with the upgrades performed in the model to enable it to be used for the first time for this purpose. DR is expected to rapidly increase to comply with European Commission directives (European Parliament, 2019), although regulatory, technological, and social barriers (Freire-Barceló et al., 2022) need to be addressed. New automation technologies and increasing customer engagement (Gómez-Barredo et al., 2021) may have a non-negligible impact in many aspects, also regarding the firmness requisites and generation investment planning.

Moreover, the information available in the literature about the origin of electricity demand and the corresponding flexibility, was completely outdated (Red Eléctrica de España, 1998; Instituto para la Diversificación y Ahorro de la Energía, 2016a). Therefore, a disaggregated representation of the demand differentiates demand growth rates towards 2030 by demand use and to accurately and realistically represent the demand response capabilities of each consumption category. Thus, this valuable and useful information can be used for developing different types of studies.

Overall, the work presented in this paper is a natural follow-up of the one presented in Huclin et al. (2022), where firm coefficients are determined for the different storage technologies. Using those coefficients and the ones that can be found in the literature, the paper analyzes and discusses the need for new firm resources to maintain the security of supply of the Spanish electricity system in horizon 2030 and to consider the generation volatility in a scenario 2030 with a high share of renewables. The SPLODER model, a generation expansion planning model, is the tool used for the analysis. The first version of the model has been presented in Martínez et al. (2017) where the core equations were introduced with the novelty of a disaggregated representation of the demand by usage types such as heating and cooling, domestic hot water or electric vehicles. This fact limits the capability to shift demand freely since each consumption type have specific constraints. The model has already been applied in previous studies such as Martín-Martínez et al. (2017), in which the analysis and scenario definition was focused on comparing centralized vs. distributed generation alternatives considering flexible loads. The model formulation has also been upgraded and used in Gerres et al. (2019), including new remuneration mechanisms required to achieve the renewable penetration targets together with enough firm capacity provision. In addition, the model is already prepared to manage flexible demand and to develop this study, it has been upgraded to properly represent in detail different firm capacity providers, namely different kinds of pumped-hydro storages, large-scale batteries, and OCGT, as well as the consideration of the demand-side response. Thus, the model is used for the first time to analyze the resources required to provide firm capacity and the competitiveness among them, and how the full potential of DR may impact these results as well as the optimal investments in renewable generation. The Spanish electricity system is weakly interconnected, and it can be considered as an energy island (THE LOCAL, 2022; Wilson and Muñoz, 2022). Therefore, neglecting interconnections allows obtaining insights into the possible evolution of power systems with high penetration of variable renewable energy resources.

The main contributions of this paper are threefold. Firstly, the paper contributes by providing a detailed Spanish demand growth disaggregated analysis, obtaining two extreme cases. This allows the consideration of a detailed and realistic representation of DR, previously modeled, in a real-sized electricity system and assessing its role and relevance when planning the future firm capacity provision, as it considerably diminishes the required investments. Secondly, the paper contributes to analyzing the competitiveness among different firm capacity technology providers under different scenarios. Thirdly, the methodology applied resorts to an optimization tool, the SPLODER model. SPLODER mathematical formulation presented in Martínez et al. (2017) and Gerres et al. (2019) has been upgraded with the inclusion of storage technologies to enable the analysis of the contribution of DR and other technologies to firm capacity requirements. These changes are thoroughly explained in Section 3, thus contributing with a more complete model in the literature.

The rest of the paper presents the following structure. Section 2 presents a demand growth analysis necessary for characterizing the Spanish electricity system until 2030 and identifies demand management capabilities as another firm capacity resource. Section 3 describes the new formulation added to SPLODER, differentiating multiple different types of centralized storage resources, and the description of the associated required input data. Section 4 presents the scenarios assessed in the paper based on the national policy targets and extended to cover different sensitivities aligned with this study's main aim. Results are discussed in Section 5. Finally, Section 6 assesses the findings and identifies additional future research needs.

2. Demand growth analysis

In the next future, electricity systems will experience a deep change in the demand side towards more efficient energy consumption. Besides, decarbonization targets will boost higher levels of electrification so that significant growth of demand flexibility is expected to be available. The more electric loads, the easier it becomes to profit from their adaptability to consume at different times without compromising the electricity end usage and the consumers' comfort. To take advantage of controllable loads, it is necessary to compute the load flexibility potential and the limits that consumption can be managed. To this end, four categories of electricity consumption within the residential

Table 1
2015 electricity demand in Spain.

Electricity demand	2015	
Sector	TWh	%
Residential	72.73	29%
Services	76.24	31%
Transport	6.40	3%
Industry	91.86	37%
Total	247.22	100%

Table 2
2015 electricity demand of the residential sector in Spain.

Electricity demand	2015	
Residential sector	TWh	%
Heating	4.42	6%
Cooling	3.40	5%
DHW	4.48	6%
Lighting and others	60.43	83%
Total residential	72.73	100%

and services sectors have been considered to be controllable in different ways: heating & cooling (climatization), domestic hot water (DHW), refrigeration (cold chain, freezers, and fridges) and electric vehicles (EV). It is relevant to come up with an estimation of the amount of demand associated with each of these categories and which proportion of each one will be ready to be controllable.

To estimate the amount of demand in the Spanish sector, classified according to the above-mentioned categories, the following methodology has been applied:

- First, load hourly data of the Spanish electricity system for the year 2015 are considered for each sector (residential, services, transport, industry) as the base profiles. This year has been selected because the information available is very detailed by different usage types. In addition, the pandemic does not influence consumption and clearly serves as a reference year for estimating growth rates (Instituto para la Diversificación y Ahorro de la Energía, 2011).
- Second, residential and commercial sectors' data are further disaggregated using a set of complementarity reports to reach the granularity required to identify the potential controllable, that is, climatization, DHW, refrigeration, and estimation of EVs loads. This disaggregation was deeply studied during the years 2014–2018.
- Third, a literature review has been performed to set a range of annual demand growth for each category.
- Fourth, the two extreme values found in the literature for the 2030 demand growth will define the range in which it is located and the potentially controllable load that the model will consider. Furthermore, to validate the estimated growth, it has been checked that there are no inconsistencies with the information available up to 2022.

Table 1 shows the 2015 electricity demand breakdown in the four main consumption sectors, obtained as the average value from reports (PNIEC, 2020; International Energy Agency, 2015; Linares and Declercq, 2018; Deloitte, 2018b; Government of Spain, 2018).

As shown in Tables 2 & 3, the "Residential" and "Services" consumption sectors have then been further broken down into different categories based on Instituto para la Diversificación y Ahorro de la Energía (2016a), Persson and Werner (2015) and Consultores (2005), using the "Lighting and others" category to gather the rest of demand, considered as inflexible.

The transport sector electricity consumption for 2015 has been calculated as the sum of EV and electric trains consumption.

Table 3
2015 electricity demand of the services sector in Spain.

Electricity demand	2015	
Services sector	TWh	%
Heating	13.89	18%
Cooling	11.11	15%
DHW	0.80	1%
Lighting and others	47.91	63%
Refrigeration	2.52	3%
Total services	76.24	100%

Table 4
2015 EV fleet in Spain.

EV	2015
EV fleet [N° of vehicles]	5848

Table 5
2015 total transport sector electricity consumption in Spain.

Transport	2015
EV consumption [TWh]	0.017
Trains [TWh]	6.39
Total [TWh]	6.40

Table 6
2030 min. and max. demand for the residential sector [TWh].

Residential demand	2030 min	2030 max
Heating	36.87	48.29
Cooling	5.65	13.48
DHW	14.79	22.77
Lighting and others	39.68	45.46
Total residential	97	130

The following calculation has been applied to estimate the part of it corresponding to EV. The EV fleet published in European Commission (2015) and presented in Table 4 has been used as the starting point. Then, an average EV consumption of 0.2 kWh/km has been assumed based on the average electric car consumption in Oak Ridge (2022), and considering the inefficiency due to the charging and discharging cycle as assessed in Iclodean et al. (2017). Finally, Spain's average daily car uses is assumed to be 40 km/day, as shown in European Environment Agency (2019). These assumptions led to an estimation of 17 GWh for the total EV electricity demand in 2015, as presented in Table 5. The remaining transport sector electricity consumption in Table 1 has been associated with the railway sector.

Once the 2015 demand breakdown has been set, minimum and maximum demand growth values for 2030 have been estimated for the different sectors and consumption categories.

For residential and service sectors, forecasts published in Linares and Declercq (2018), Instituto para la Diversificación y Ahorro de la Energía (2011), Jakubcionis and Carlsson (2018) and Instituto para la Diversificación y Ahorro de la Energía (2016b) have been contrasted to determine the demand growth rate for the different consumption categories. The most optimistic and pessimistic predictions published across the reviewed publications have been selected to define a range with the minimum and the maximum demand growth for 2030. The residential and services sector's minimum and maximum consumption are presented in Tables 6 and 7, respectively.

Transport sector demand growth assumed in the study and presented in Table 8 is based on the most extreme values concerning the expected EV fleet growth stated by PNIEC (2020) and International Energy Agency (2015) .

Table 7
2030 min. and max. demand for the services sector [TWh].

Services demand	2030 min	2030 max
Heating	14.71	22.47
Cooling	12.03	17.08
DHW	0.89	1.78
Lighting and others	56.92	43.49
Refrigeration	2.80	2.81
Trains	6.60	8.77
Total including trains	93.94	96.39

Table 8
2030 min. and max. demand for the transport sector.

Transport demand	2030 min	2030 max
EV fleet [N° of vehicles]	300,000	5,000,000
EV consumption [TWh]	0.876	14.6

Table 9
2030 min. and max. demand for the industrial sector [TWh].

Industrial demand	2030 min	2030 max
Industry	103.6	124.9

Table 10
2030 total min. max. and average demand [TWh].

Total demand	2030 min	2030 max	Average
Residential	97	130	114
Services	94	96	95
Industry	104	125	114
Transport	1	15	8
Total	295	366	331

Industrial demand growth for 2030 is expected to be in the range described in Linares and Declercq (2018) and presented in Table 9.

In the scenarios presented below, intermediate growths in-between the range presented (2030Min and 2030Max) are considered individually for each sector and consumption category. Table 10 presents the minimum, the maximum and the average of the total electricity demand by sector.

As a final step in the demand characterization, different degrees of penetration of demand response are considered in the study. It is assumed that only a fraction of all the potentially controllable loads will be ready to participate in demand response programs by 2030.

Finally, it is important to properly model the actual capabilities of demand response of such manageable loads. Demand management corresponds to a demand shift among hours. But demand cannot be shifted in any way. Each of these loads obeys to a process that limits its response capabilities. For instance, the heating and cooling demand cannot be freely shifted over time as it should ensure that the temperature of the building does not go out of a preset comfort band.

The SPLODER model enables a very detailed representation of the demand. The way different consumption categories that can provide DR are modeled is detailed in Martín-Martínez et al. (2017), but overall is as follows:

- EVs: a given portion of the EV demand if considered fully flexible and manageable during the 24 h. The rest of EV demand is considered a non-flexible one and follows a pre-determined charging profile, split up between base and peak hours, as presented in Gerres et al. (2019).
- Heating and cooling: a reference and comfort band temperature is set according to predefined temperature bands. The building thermal inertia is considered to simulate the temperature evolution. Buildings are clustered according to their geographical area with different external temperatures according to the month and their level of thermal isolation.
- DHW: the portion assumed to be flexible can be managed freely during a whole day as it is associated with the stored hot water inertia.
- Refrigeration: is flexible if the average temperature follows a reference temperature. The temperature could be two degrees upper or lower this reference, whereas the average is respected at the end of the day. The energy to keep the temperature in reference during a day can be considered constant in an adiabatic system, and it can be freely allocated throughout the day.

3. Characterizing storage resources in SPLODER

The SPLODER model performs an optimal generation expansion plan minimizing investment, production, and O&M costs for a given time horizon. Years are represented by a set of clustered representative weeks with hourly time granularity. These four weeks represent the seasons' winter, spring/fall, summer, and vacations, each of them with different weights along the year. The four-week demand and renewables generation profiles are obtained by applying the k-means clustering algorithm (Hartigan and Wong, 1979).

Several renewable production profiles are considered in the optimization framework (three renewable scenarios are used in this study); although there is stochasticity, another model with the 8760 h of the year could validate SPLODERs operation decisions; however, this proof is out of the scope of the paper. The main inputs and outputs of the model are summarized in Fig. 1. As further explained in Gerres et al. (2019), the resulting optimal generation and storage mix should comply with two main constraints. First, generation and demand should meet hourly. Hourly energy prices (€/MWh) are obtained as the dual variable of such generation–demand balance constraint. Second, the model guarantees that enough firm capacity is provided to the system (a 10% reserve margin over the peak demand is used in this study). Each generation technology contributes differently to the system firm capacity. A specific firm capacity coefficient is assigned to each generation technology. An annual based capacity price (€/MW) is obtained as the dual variable of firm capacity requirement constraint and thus used to model a new capacity market for the Spanish electricity system. Hence, generation units are remunerated both for providing energy and firm capacity to the system, and both incomes are considered to ensure the full cost recovery of all newly installed units. Balancing services provision is out of the scope of this paper. The full description of the SPLODER optimization model, including a detailed explanation and formulation of the objective function and constraints, can be found in Martínez et al. (2017) and Gerres et al. (2019).

For this paper, SPLODER has been upgraded to improve the modeling of firm capacity resources, enabling the characterization of different pumped-hydro storage types and adding centralized battery storage as candidate technologies to be considered in the future generation and storage mix. This section focuses specifically on describing the storage technologies considered in this study and the detailed formulation of equations added to the existing SPLODER model to represent their behavior properly.

According to the Spanish context, six different categories of pumped-hydro storage have been modeled as candidates for expanding the system. They have different storage capacity sizes and investment costs representing basically two options: build an artificial upper reservoir associated with an existing storage hydro power plant or build a new penstock with a reversible turbine in an already existing pumped-hydro storage power plant (CEEPR, 2020). Table 11 summarizes the set of new pumped hydro storage

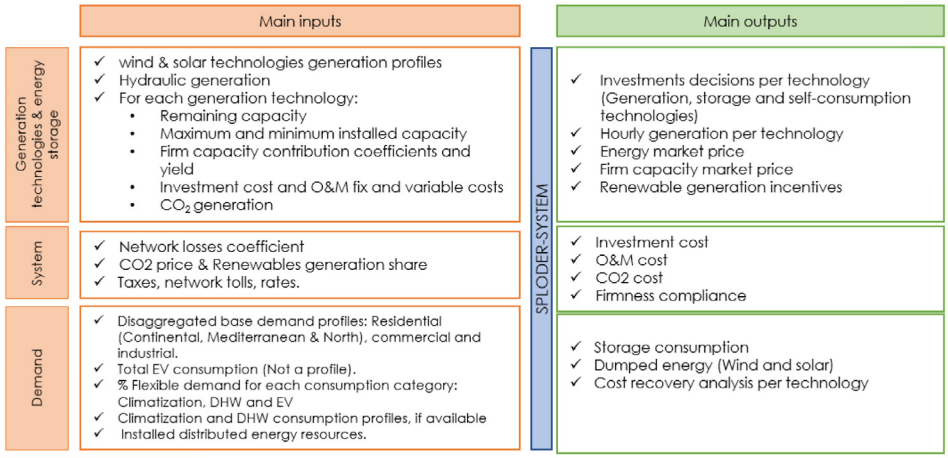

Fig. 1. Main inputs and outputs of SPLODER (Gerres et al., 2019).

Table 11
Storage data.

Agent	Max. install. [MW]	Min. install. [MW]	Annualized install. cost [€/MW]	Fix annual O&M [€/MW]	Var annual O&M [€/MWh]	Firm Coeff.	Round-trip eff.	Charge hours	Discharge hours
Batt_cent	0	0	133,799	5550	0.00025	0.69	0.9	4	4
Sto_8h_1	1000	400	39,255	9000	3	0.96	0.75	8	8
Sto_20h_1	2000	400	52,340	12,000	3	0.96	0.75	20	20
Sto_20h_2	5800	400	65,424	15,000	3	0.96	0.75	20	20
Sto_40h_1	800	400	35,983	8250	3	0.96	0.75	40	40
Sto_40h_2	600	400	62,153	14,250	3	0.96	0.75	40	40
Sto_60h_1	1500	400	55,611	12,750	3	0.96	0.75	60	60

types included in SPLODER. Table 11 also shows the centralized large-scale Li-Ion batteries that have been modeled and considered in the study. The economy of scale of centralized storage makes distributed batteries unprofitable, thus discouraging their deployment from a centralized point of view. The same thing happens with distributed solar generation, although in this case, a fixed amount has been set as input in the model (Red Eléctrica de España, 2019), considering their natural deployment due to individual motivations or local tariffs incentives. However, profits from solving local distributed system congestion problems are not considered.

Installation, fix, and variable O&M costs for batteries are based on Mongird et al. (2019). Pumped-storage hydro data, including maximum available installation capacities for the different options and the associated firm capacity coefficients, are estimated based on CEEPR (2020) and PNIEC (2020). Additionally, the annualized installation costs for the different storage options have been estimated with public pumped-storage hydro projects with different storage capacities (Repsol, 2021; European Commission, 2019; Roca, 2019, 2020). These storage facilities are modeled within an upgraded version of SPLODER. The detailed formulation of equations is provided, preceded by the used nomenclature (Table 12):

All new storage types, both pumping hydro and batteries, have been modeled similarly. Constraints (1), (2), (3), (4) & (5), control the state of charge (SOC) of all storage types, forcing it not to exceed the maximum storage capacity according to investment decisions.

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m,h} \tag{1}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m,h-1} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m, h > 1 \tag{2}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w,m-1,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m, h = 1 \tag{3}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,w-1,7,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w, m = 1, h1 \tag{4}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \geq soc_{ist,p,4,7,24} + charge_{i,p,w,m,h} \times YIELD_{ist} \forall\ ist, p, w = 1, m = 1, h1 \tag{5}$$

Constraints (6), (7), (8) & (9), are the boundary conditions for the maximum energy that can be discharged at each time of the year. The $YIELD_{ist}$ considered in the model gathers the round-trip efficiency. Hence, it is not necessary to multiply the $discharge_{i,p,w,m,h}$ variable again.

$$soc_{ist,p,w,m,h-1} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w, m, h > 1 \tag{6}$$

$$soc_{ist,p,w,m-1,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w, m, h = 1 \tag{7}$$

$$soc_{ist,p,w-1,7,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w - 1, m = 1, h = 1 \tag{8}$$

$$soc_{ist,p,4,7,24} \geq discharge_{i,p,w,m,h} \forall\ ist, p, w = 1, m = 1, h = 1 \tag{9}$$

Constraints (10), (11), (12) & (13) calculate the SOC at every hour for each storage type. The SOC at each hour equals to the SOC at the previous hour, plus the charged energy, minus the discharged energy. The four equations differ only in reference to the previous hour SOC, in which, due to the temporal granularity of the model, the sets to be referred to slightly change with time (depending on the week, the day and the hour).

$$soc_{ist,p,w,m,h} = soc_{ist,p,w,m,h-1} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\ ist, p, w, m, h > 1 \tag{10}$$

Table 12
Sets, parameters, and variables added.

Sets	
i	Technology type {1–27}
ist ϵ i	New storage types {1–7}
p	Renewable scenario {1–3}
w	Week {1–4}
m	Day of the week {1–7}
h	Hour {1–24}
Parameters	
$INSTALLED_i$	Existing power previously installed for each technology i [MW]
$CHARHOURS_i$	Charging hours for each type of storage [h]
$DISCHARHOURS_i$	Discharging hours for each type of storage [h]
$YIELD_i$	Storage round-trip efficiency by technology i [%]
$MAXINSTALL_i$	Maximum capacity to be installed of each technology i [MW]
Variables	
$finalinstalled_i$	Total capacity in place for each technology i [MW]
$newInstall_i$	New installed capacity for each technology i [MW]
$soc_{i,p,w,m,h}$	State of charge of hydro plant at each hour [MWh]
$charge_{i,p,w,m,h}$	Pumped hydro storage charge at each hour [MW]
$discharge_{i,p,w,m,h}$	Pumped hydro storage discharge at each hour [MW]
$energySell_{i,p,w,m,h}$	Hourly energy sold by each technology i [MWh]
$energyBought_{i,p,w,m,h}$	Hourly energy bought by each technology i [MWh]

$$soc_{ist,p,w,m,h} = soc_{ist,p,w,m-1,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\, ist, p, w, m > 1, \mathrm{h} = 1 \tag{11}$$

$$soc_{ist,p,w,m,h} = soc_{ist,p,w-1,7,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\, ist, p, w > 1, m = 1, \mathrm{h} = 1 \tag{12}$$

$$soc_{ist,p,w,m,h} = soc_{ist,p,4,7,24} + \left(charge_{i,p,w,m,h} \times YIELD_{ist}\right) - discharge_{i,p,w,m,h} \forall\, ist, p, w = 1, m = 1, \mathrm{h} = 1 \tag{13}$$

Constraint (14) sets the SOC to be the same at the beginning and end of the year (first hour of the first representative week and last hour of the last representative week) for all storage types in order to better represent the storage potential throughout the year.

$$soc_{ist,p,1,1,0} = soc_{ist,p,4,7,24} \tag{14}$$

Constraints (15) & (16) set the charging and discharging speed rate depending on the storage hours' capacity.

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist}/CHARHOURS_{ist} \geq charge_{ist,p,w,m,h} \tag{15}$$

$$(INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist}/CHARHOURS_{ist} \geq discharge_{ist,p,w,m,h} \tag{16}$$

For each pumping storage type, the new installed capacity cannot exceed the total available capacity to be built, as stated in (17).

$$MAXINSTALL_{ist} \geq newInstall_{ist} \tag{17}$$

In (18), the three different renewable scenarios considered in the study are forced to start at the same state of charge for each storage type, which is set to be 60% of their total installed capacity.

$$soc_{ist,p,1,1,0} = 0.6 \times (INSTALLED_{ist} + newInstall_{ist}) \times DISCHARHOURS_{ist} \forall p \tag{18}$$

Additionally, (19) guarantees that each technology considers its given yield when buying electricity.

$$energySell_{i,p,w,m,h} = energyBought_{i,p,w,m,h} \times YIELD_{ist} \forall\, ist, p, w, m, \mathrm{h} \tag{19}$$

4. Case study and scenario definition

This section describes the scenarios considered in the study. Since the study focuses on the cost competitiveness of the different firm capacity providers and how DR may impact the overall firm capacity needs and that competitiveness, four sets of scenarios have been built. These four blocks are characterized by the parameter which sensitivity is analyzed. These sets of scenarios and sensitivities addressed are presented in Table 13:

A base case scenario is used as a reference for each scenario set. All base cases evolve from the baseline scenario. The baseline scenario assumes there are no DR capabilities in the system and looks for an optimal, minimum cost, mix of generation and storage technologies for the 2030 Spanish electricity system, assuming the following set of technical and cost parameters. As explained in Section 2, demand growth from 2015 data is set using an intermediate value between the minimum and maximum growth rates for each disaggregated category of demand.

Table 14 summarizes the firm capacity coefficients assumed for each technology. These values are obtained from Red Eléctrica (2020), except for batteries with four hours of discharging rate (NationalgridESO, 2020) and pumped hydro storage (National Grid, 2017). The values corresponding to the candidate pumped storage hydro facilities are presented in Table 11.

Table 15 summarizes the 2019 existing generation capacity expected to be still available by 2030. Values are extracted from PNIEC (2020).

Table 16 presents the values assumed for the investment costs and the fix and variable O&M costs for both conventional and renewable technologies, updated from previous studies (Gerres et al., 2019) and based on additional Refs. International Renewable Energy Agency (2017), European Commision (2018), Allen (2017), Larsen and Rønnov (2018), The National Renewable Energy Laboratory (NREL) (2018) and PNIEC (2020). The values corresponding to storage facilities (including hydropower) are presented in Table 11.

Table 17 summarizes the assumptions adopted for fuel prices, CO_2 emission costs, and taxes for pollutant technologies. Prices for CO_2 and gas are based on International Energy Agency (2019):

4.1. Baseline_NewFC scenario: Firm coefficient sensitivities

The SPLODER model results may be pretty sensitive to the firm capacity coefficient (FC) parameter adopted for each technology.

Table 13
Scenarios sets definition.

Set	Main feature analyzed	Base case	Sensitivities built upon base case scenario	
A	Firm coefficient	Baseline	Baseline_NewFC	
B	Percentage of DR deployment	Baseline_NewFC(0%DR)	25%DR	50%DR
C	Reduction of battery price	25%DR	PriceBatt_L	PriceBatt_LL
D	CO_2 and gas prices	Baseline	EVC_XHigh EVC_High	EVC_Low

Table 14
Firmness coefficients.

Technology	Firm capacity coefficient
Nuclear	0.97
OCGT	0.96
CCGT	0.96
Cogeneration	0.55
Biomass/Biogas	0.55
Solar thermal	0.14
Hydro (reservoir)	0.44
Hydro (run-of-river)	0.25
Existing pumped hydro storage	0.77
Solar photovoltaics	0
Wind power	0.07
Li-Ion batteries	0.69

Table 15
2019 existing generation capacity expected to be still available by 2030.

Technology	Installed capacity (MW)
Nuclear power plants	3050
OCGT	0
CCGT	24,560
Cogeneration	3745
Biomass/Biogas	2146
Solar thermal	2299
Hydro (reservoir)	15,614
Hydro (run-of-river)	636
Existing pumped hydro storage	3329
Solar photovoltaics	8372
Wind Power	25,553
Li-Ion batteries	0

Table 16
2030 generation technologies' costs.

	Investment costs (€/kW)	Annual fixed O&M cost (€/kW-year)	Variable O&M cost (€/MWh)
Nuclear	–	108.3	–
OCGT	544.1	18.4	11.0
CCGT	845.1	19.3	2.0
Hydropower (All)	–	68.8	3.0
Solar PV (utility)	500	10	–
Solar thermal	4396.6	49.6	0.46
Wind	950	29	–

Table 17
2030 fuel costs, CO2 emissions costs and individual taxes.

	Fuel cost (€/MWh)	CO_2 cost (84 €/tonCO_2)	Taxes (€/MWh)
Nuclear	8.72	–	15.02
OCGT	48.88	42.42	4.68
CCGT	32.58	28	4.68
Cogeneration	–	48.78	–

Table 18
Firmness coefficients sensitivities.

Scenario	Batt_cent	Sto_8h_1
Baseline	0.69	0.96
Baseline_newFC	0.294	0.567

Table 19
Scenarios with distributed PV panels under different DR percentages.

Scenario	DR Climate	DR DHW	DR EV	DR REF
0DR	0	0	0	0
25DR	25%	25%	25%	25%
50DR	50%	50%	50%	50%

In a system dominated by renewable generation, it is quite often that scarcity periods last longer than 4 h (which is the charging and discharging cycle of batteries) and sometimes last even longer than 8 h (which is the charging and discharging cycle of 8 h pumped hydro storage) (Huclin et al., 2022). To be conservative, the security of supply of an electricity system should not fall upon storage with less than 10 h of storage capacity. For this reason, authors evaluated in Huclin et al. (2022) the firm coefficient of the different storages, coming up with lower FCs for batteries and 8 h cycle pumped hydro storage, and with these new FCs has been built another scenario, referred to as Baseline_newFC, being these values more accurate for future scenarios. Considering (Huclin et al., 2022; NationalGrid, 2018), the new values adopted for these two technologies are shown in Table 18 and are used for all the rest of the scenarios.

4.2. DR scenarios: Percentage of DR sensitivities

Three additional scenarios built upon the Baseline_NewFC scenario are considered to analyze the impact of DR on the firm capacity requirements of the system. The three scenarios include a fixed amount of solar distributed generation as explained below. Baseline_NewFC scenario neglected any DR capability in the system as the 0DR scenario does. Two additional scenarios (25DR and 50DR scenarios) are built for which, respectively, 25% and 50% of the total load identified as controllable (see Section 2) is considered ready to actively participate in demand response programs. These segments of load correspond to heating and cooling (climate), domestic hot water (DHW), electric vehicles (EV) and refrigeration (REF) as shown in Table 19.

An amount of distributed small-size self-consumption solar PV generation is assumed to be already installed by 2030 for these three scenarios (0DR, 25DR and 50DR). A conservative fixed preset amount, shown in Table 20, has been considered. This amount has been estimated assuming that there will be a 25% of new installation capacity between the two extreme values found in the literature, a minimum growth by 2030 of 0.6 GW (Deloitte Advisory, 2017) and a maximum one of 6.5 GW (Deloitte, 2018a), upon the currently 1 GW installed capacity (Red Eléctrica de España, 2019). This amount is geographically allocated by climate zones around Spain according to Red Eléctrica de España (2019) and associated with the three demand sectors (residential, services and industry) according to NationalgridESO (2020). Nevertheless, these distributed solar PV panels have a very marginal impact on the results of this study. They substitute utility-scale solar PV installation needs (actually at a slightly larger ratio than 1:1 as some network losses are avoided) but do not contribute to firm capacity.

4.3. Battery low price scenarios: Battery price sensitivities

As results will show later, batteries are far from being competitive, provided the installation costs assumed in scenarios so

Table 20
Assumed installed PV distributed capacity in 2030.

Technology	Installed capacity (MW)
Solar distributed	2467

Table 21
Batteries installation costs.

Scenario	Batt_cent install cost [€/kW]
25DR	133.8
PriceBatt_L	30
PriceBatt_LL	20

Table 22
CO_2 and gas prices scenarios.

Scenario	CO_2 [€/tonCO_2]	Natural gas [€/MMBTU]
EVC_XHigh	83	27
EVC_High	62	18
Baseline	84	6
EVC_Low	90	4

far. Two additional scenarios (PriceBatt_L and PriceBat_LL) have been considered lowering the installation cost of batteries, as presented in Table 21. Both are built upon the 25DR scenario. The main purpose of the first scenario, PriceBatt_L, is to identify the battery installation cost threshold below which batteries begin to be competitive enough to be competitive. For that purpose, batteries installation costs have been reduced in steps of 1€/kW until results show some battery installation, substituting OCGT. This happens for an installation cost decrease of 77%, as shown in Table 21. The second scenario, PriceBatt_LL, allows a larger penetration of batteries to understand the impact of the technological mix of renewables and the competitiveness of other firm capacity providers. This is achieved with a further reduction in batteries installation costs (85% of reduction), as shown in Table 21.

4.4. Equivalent variable cost scenarios: CO_2 and gas prices sensitivities

CO_2 and gas prices have a substantial impact on electricity wholesale market prices. Therefore, a set of scenarios has been built to specifically assess their incidence on generation investment priorities. The Baseline of this set of scenarios assumes the same prices for gas and CO_2 in 2030 than all previously described sets of scenarios. They follow the values stated in the WEO2019 (International Energy Agency, 2019) for 2030. Then, three sensitivities to these prices are performed. The EVC_XHigh scenario is built upon the first semester of 2022 average CO_2 (SENDECO, 2022) and natural gas (MIBGAS, 2022) prices, which have historically influenced the market in the Iberian Peninsula. EVC_High scenario assumes extremely high prices for gas and moderately high prices for CO_2, similar to those the world faced in the summer, autumn, and winter of 2021, taken respectively from MIBGAS (2021) and SENDECO (2021). It assumes those prices will remain similar in 2030. Finally, the EVC_Low scenario considers the more recent forecasts up to a day for CO_2 (Simon, 2021) and natural gas (Sönnichsen, 2022) price evolution. These three scenarios provide a sensitive sensibility analysis of the gas and CO_2 emission prices. These values are presented in Table 22. Unit conversion types considered in these cases are: 1$ →0.84€ and 1 MWh→3.41MMBTU

The price tendency of each of the three scenarios has been clarified by calculating the equivalent variable cost (EVC) in €/MWh for the two-generation technologies affected by CO_2 and gas prices: OCGT and CCGT. EVC integrates into a single production cost per technology the actual impact of both the gas and

Table 23
Equivalent variable cost for OCGT and CCGT.

Scenario	OCGT [€/MWh]	CCGT [€/MWh]
EVC_XHigh	258	167
EVC_High	180	115
Baseline	102	63
EVC_Low	90	54

CO_2 emission allowance prices. Table 23 summarizes the resulting EVC for both technologies. It provides sensible information on the assumption made in each scenario. The production cost of both technologies respectively increases and decreases in the EVC_High and EVC_Low sensitivity scenarios compared to the Baseline one.

5. Results

This section presents and discusses the results provided by the SPLODER model. Results are organized following the sequence of the blocks of scenarios described previously.

5.1. Firm coefficients analysis

Figs. 2 and 3 show the generation and storage optimal investment decisions for the period 2019–2030 as provided by SPLODER for these scenarios. Namely, Fig. 2 displays the investments in renewable technologies (wind and solar PV) for both scenarios, while Fig. 3 shows the investments in the rest of the technologies, mainly oriented to provide firm capacity to the system (storage and thermal backup capacity).

Fig. 2 shows that the new installed renewable capacity is very large (almost 73 GW) compared to the peak demand value for 2030, which is assumed to be 51.39 GW and given the initially existent installed capacity (see Table 15). This is because storage technologies are helping to decrease renewables' spillage. Although installation costs are significantly lower for solar PV than for wind, investments in both technologies are balanced. This is partly because solar PV production is concentrated in fewer hours than wind production. Therefore, solar contribution to the system firm capacity is much lower (indeed, it is zero in this study, as the more stressful periods for the system happen during hours without sun). Besides, the concentration of the solar PV in the hours of sunshine ends up cannibalizing the energy income of solar PV. This effect is more significant than for wind since the latter has more variability at different hours.

On the other hand, as shown in Fig. 3, batteries are fully discarded, not being competitive compared to other options. On the contrary, 5 out of 7 available pumped-hydro storage options are selected. The mix is completed with thermal OCGT backup generation to meet the system firm capacity requirements.[2]

By comparing in Figs. 2 and 3, the impact of considering stricter (lower) firm capacity coefficients for shorter-term storage technologies, that is, batteries and 8 h pumping storage, no very relevant changes are shown (Baseline_NewFC results compared to Baseline ones). Renewable investments almost do not change, although wind generation comes out slightly favored at the expense of solar PV. This is because 8 h pumping storage loses some competitiveness due to its reduced firm capacity coefficient,

[2] If investments in gas generation technologies are to be avoided to meet decarbonization commitments, the OCGTs investment would be replaced by the rest of available hydro pumping options and batteries if also needed. Nevertheless, OCGTs would almost not produce, being their role mainly to provide firm capacity.

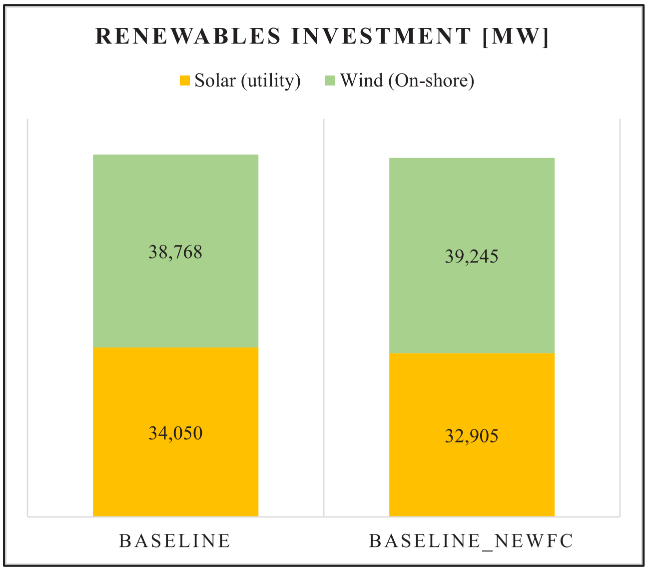

Fig. 2. New renewable investments (2019–2030) in baseline scenarios.

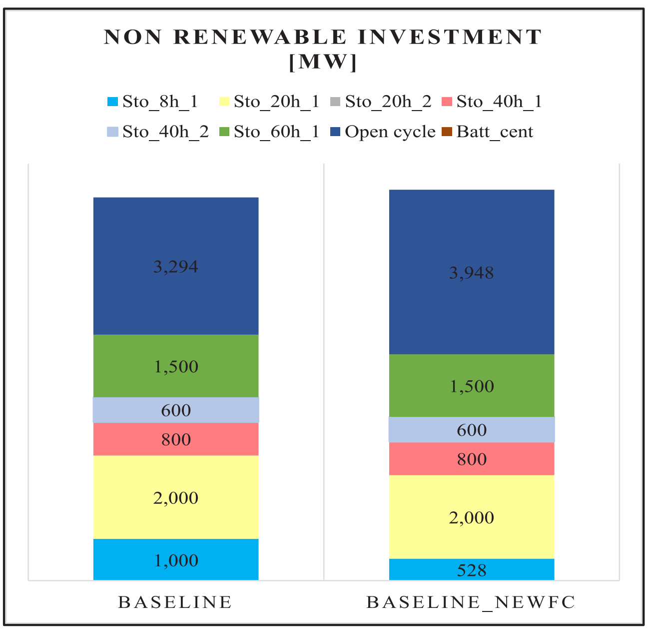

Fig. 3. New firm capacity investments (2019–2030) in baseline scenarios.

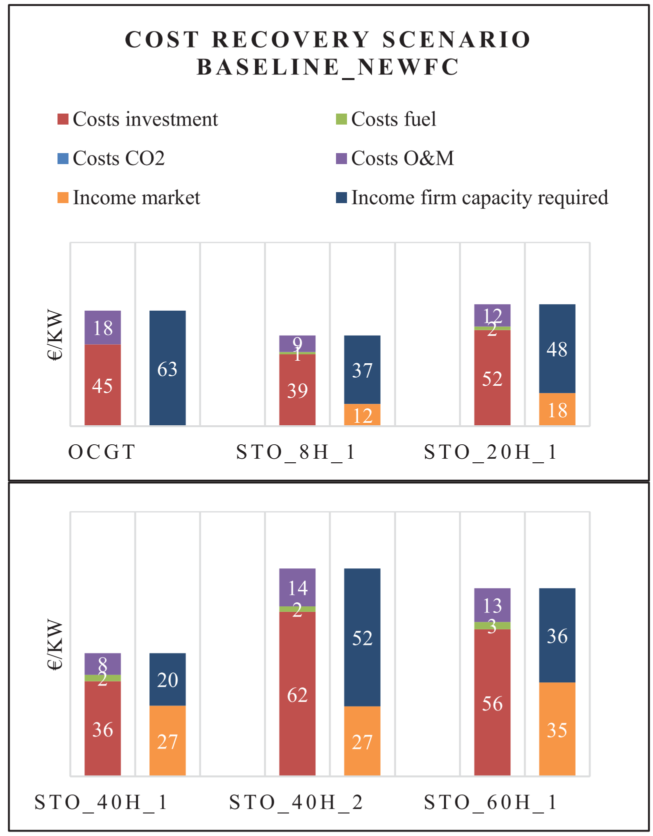

Fig. 4. Cost recovery for new firm capacity investments (2019–2030) in Baseline_NewFC scenario.

being thus replaced by OCGT. This reduces the system's total storage capacity, which disfavors solar PV more than wind. Also, the lower the storage capacity, the higher the total firm capacity required in the system since storage supply peak demand. In this case, around 200 MW of additional firm capacity is needed. Wind power provides some firm capacity while PV solar does not.

To complete the analysis of the competitiveness of firm capacity providers, a cost recovery analysis for new investments for the baseline_newFC is presented in Fig. 4. This figure shows, on the left-hand bar, the total annualized costs faced by the technology, disaggregated into investment, fuel, O&M and CO2 emissions costs, and on the right-hand bar the total incomes received by the technology, disaggregated into the incomes from the hourly energy production valued at the hourly energy price and the required income from the firm capacity provision to balance costs and incomes.

It could be observed first that all selected technologies do recover their total costs considering an income due to firm capacity provision equal to the missing money for each technology. Indeed, the capacity payment mechanism would follow a marginal price approach for the provision of firm capacity. The incomes from capacity payments would equal or exceed these values for the selected technologies, as OCGTs and the 8 h pumped-hydro storage are the marginal technologies providing firm capacity.

OCGT incomes fully come from the provision of firm capacity showing that its role in producing energy will be very marginal.[3] On the contrary, although they are also providing firm capacity, pumped-hydro storage technologies do have some income by operating in the energy market.[4] The energy market-related incomes may recover up to 60% of their total costs for some of these technologies (for instance, the Sto_40h_1), but only 22% for others. The more hours the pumped-hydro storage can store, the more it would operate and more income from the energy market.

The results show the relevance of capacity payments to ensure investments cover the system firm capacity requirements.

5.2. DR analysis

Fig. 5 shows the investment decisions in renewable technologies, and Fig. 6 those in firm capacity providers' technologies

[3] The production of such peaking units is however somehow underestimated in models such as SPLODER since a fully stochastic approach will reveal more situations where these back-up technologies will produce some energy.

[4] These figures are slightly underestimated due to the same reason as for OCGTs. See previous footnote.

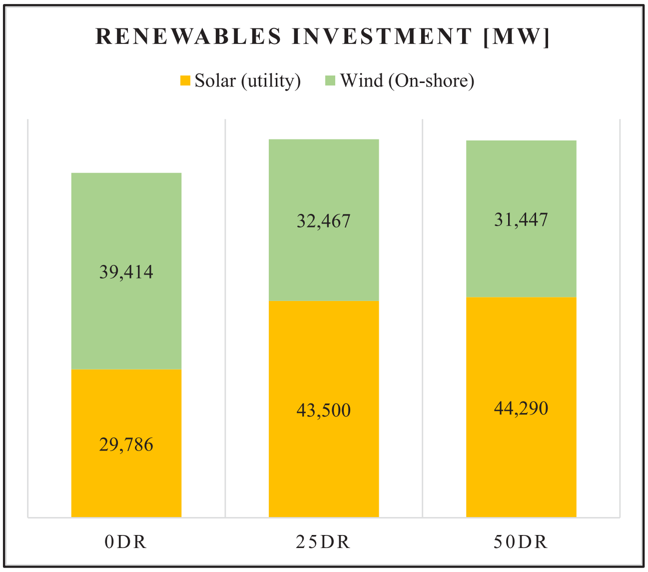

Fig. 5. New renewable investments (2019–2030) in DR scenarios.[5]

for the three DR capability scenarios for the period 2019–2030. Firstly, it is noticeable how DR increases the overall optimal renewable investments by more than 7%. This impact seems to saturate once 25% of DR is reached. Secondly, there is a clear switch between the two renewable generation technologies. Comparing 0% DR and 25% DR scenarios, results in a 46% increase in solar generation investment and an 18% decrease in wind generation. This is because DR maximizes the value of solar generation since part of the load can be switched to hours with solar PV production. This effect also seems to saturate above a 25% rate of DR. Results point out the relevance of considering DR in long-term system requirements.

Fig. 6 shows that firm capacity requirements in the system significantly reduce when considering DR capabilities. Indeed, peak demand in the system could be reduced, hence, reducing firm capacity investments. As could be expected, the marginal firm capacity technologies reduce their investments or even disappear, as is the case for the 8 h pumped-hydro storage. The rest of the hydro pumping options remain competitive and are needed to meet the firm capacity requirements while also providing energy to satisfy demand.

To better illustrate the impact of DR on firm capacity requirements, Fig. 7 represents the evolution of the equivalent firm capacity (EFC) with respect to the level of DR penetration. EFC measures the total firm capacity required to be met by newly installed technologies, that is, once discounted for the firm capacity already provided by the initially existing technologies.

Roughly, it could be concluded that each point of a percentage of DR reduces around 30 MW of firm capacity requirement in the system. This percentage corresponds to the load considered to be controllable, not to the whole demand. Moreover, it is important to highlight also that the management of this demand is not free but subject to specific behavioral constraints. These considerations enhance the relevance of these results.

5.3. Battery low price assessment

As presented in Table 21, battery installation costs are lowered in these scenarios to identify their threshold installation costs to

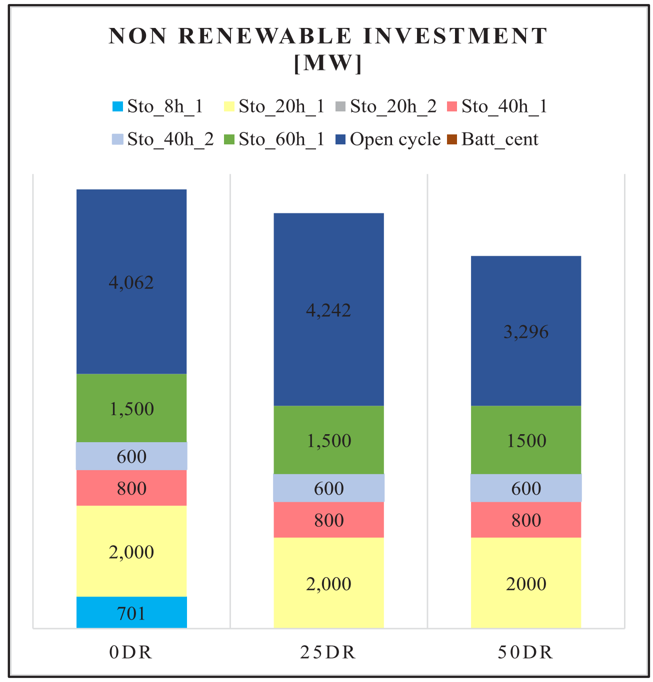

Fig. 6. New firm capacity investments (2019–2030) in DR scenarios.

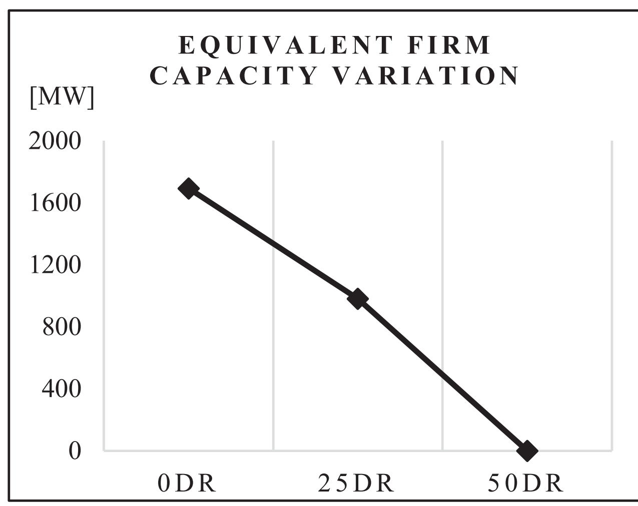

Fig. 7. Equivalent firm capacity variation for DR scenarios.

become competitive (PriceBatt_L scenario) and, in that case, to understand how they may impact other firm capacity technology options (PriceBatt_LL scenario).

A 77% reduction of the batteries' installation costs upon the initially assumed values is necessary for the batteries to become competitive. Costs must go down from 133.8 €/kW to 30 €/kW. Batteries are still far from being competitive.

Figs. 8 and 9 show the optimized investment decision in renewables and firm capacity providers' technologies for the three scenarios related to the battery installation costs for the period 2019–2030. Fig. 8 clearly shows that batteries enhance the role of solar PV generation as compared to wind generation. Indeed, higher levels of storage favor solar generation deployment, substituting wind farms installation. It is equivalent to that observed for DR deployment but larger as batteries do not have the DR

5 In order to properly analyze these results it should be remembered that around 2.5 GW have already been expanded as small-size distributed PV solar.

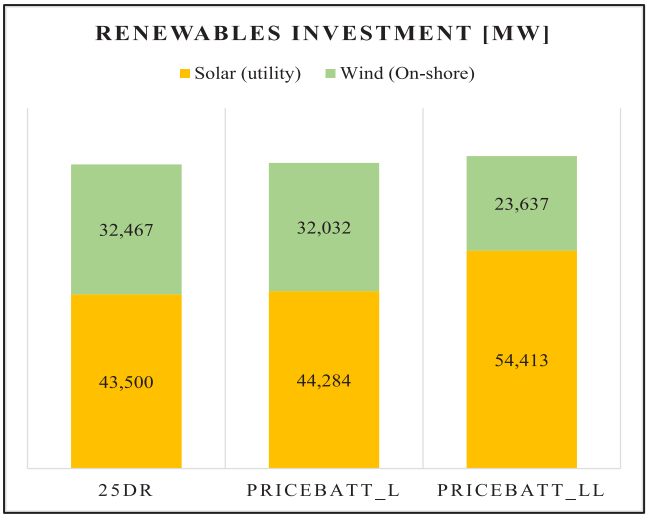

Fig. 8. New renewable investments (2019–2030) in the Battery low-cost scenarios (see footnote 5).

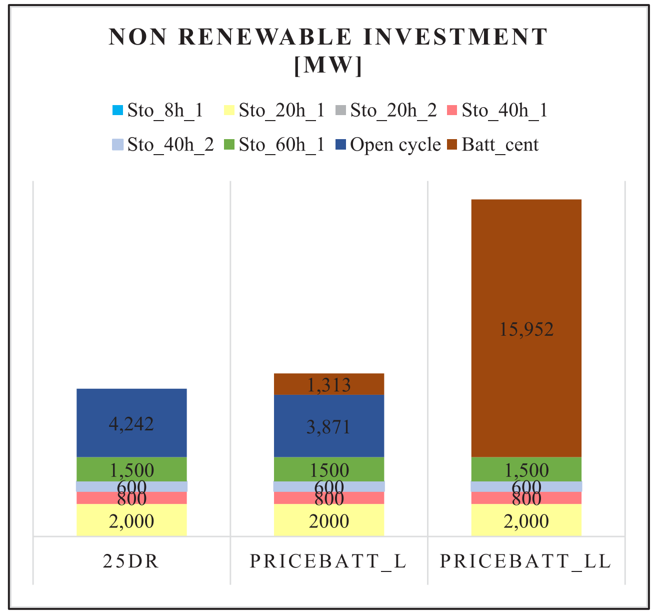

Fig. 9. New firm capacity investments (2019–2030) in Battery low-cost scenarios.

limitations associated with complying with temperature comfort constraints or EC availability.

Fig. 9 shows several interesting features. First, batteries compete with OCGTs, not with pumped-hydro storage, once 8 h pumped hydro storage has been already expelled by DR, as shown in the 25DR scenario. Even with a further reduction of its installation costs, batteries do not replace pumped-hydro storage with storage capabilities larger than 8 h. This is certainly because 4 h batteries contribution to firm capacity is quite low (its FC stands for 0.294). Four hours of storage is not enough to face longer episodes of renewable production scarcity in the system. Very large amounts of battery investments would be needed to substitute the firm capacity provided by pumped hydro storage with storage capabilities larger than 8 h.

Second, 4 h batteries need a substantial installation cost reduction to replace OCGT as a firm capacity provider. This is again a consequence of its low contribution to firm capacity. Roughly three times more capacity of 4 h batteries are needed to replace OCGT capacity. This is clearly shown in the PriceBat_LL scenario results. Batteries have entirely replaced OCGTs, but the investments required to meet firm capacity requirements skyrocket.

These three scenarios present the same EFC. The main difference between them is which technology is providing firm capacity. In the PriceBatt_LL scenario, solar generation installation increases and substitutes wind installation reducing their overall contribution to EFC, which is replaced by batteries' contribution to EFC. Anyhow, the huge investments in batteries in that scenario obey the replacement of OCGT as firm capacity provider, as explained previously.

5.4. CO_2 and gas prices sensitivity analysis

Optimal renewables investment capacity is presented in Fig. 10 for the four CO_2 and Natural Gas price sensitivity scenarios presented in Table 22. Besides, Fig. 11 presents the optimal investment in the rest of the technologies that provide firm capacity. Table 24 summarizes some of the main outcomes (market prices, CO_2 emissions and renewable quota energy production) for these scenarios.

Results show that for high OCGT and CCGT's EVCs (EVC_XHigh and EVC_High scenarios), hydro storage technologies, even the costlier ones (Sto_20h_2), replace OCGTs as providers of firm capacity to the system, together with a significant increase of both wind and solar generation capacity. So high gas and CO_2 emission prices expel generation gas-based technologies' investments. Only the current CCGTs, still in place in 2030, remain in the system. Market prices increase somewhat, allowing the cost recovery of the additional wind and solar investments. A relevant increase in renewable production quota is achieved together with a significant reduction of CO_2 emissions. The increase of EVC cost between EVC_High scenario and EVC_XHigh produce a lower change in renewable ratio than the variation obtained from the Baseline to the EVC_High scenario (Table 24). Results reveal a turning point at which increasing the EVC cost does not lead to a relevant increase in renewable production. As expected, high prices of gas and/or CO_2 (high prices of EVC for OCGTs and CCGTs), lead to a faster decarbonization process of the electricity system, resorting to more pumped-hydro storage capacity to provide firm capacity to the system. Also, it is noticeable that, as already identified in previous results, an increase in storage facilities favors solar over wind generation capacity since solar is a cheaper generation technology than wind. Indeed, in this scenario, both increase their installed capacity, but proportionally in larger amounts for solar.

The system behaves the other way around for lower OCGT and CCGT's EVCs (EVC_Low scenario). Being cheaper, OCGTs investments increase their share, disincentivizing renewable generation investments altogether, although solar significantly replaces wind technology. Higher amounts of firm capacity (driven by cheaper OCGTs), as it happens in this case, also favor solar over wind. Consequently, this scenario leads to larger expected CO_2 emissions and lower renewable production quotas. Market prices, instead, are slightly reduced.

6. Conclusions & future work

The provision of firm capacity becomes a challenge in power systems dominated by renewable generation. This paper demonstrates that DR has a non-negligible impact on the system firm capacity requirements and, therefore, in its generation investment decisions. This study analyzes the competitiveness of battery

Table 24
CO_2 and gas prices sensitivity scenarios results.

	EVC_XHigh	EVC_High	Baseline	EVC_Low
Average marginal market price (€/MWh)	48	42	39	38
Market price standard deviation (€/MWh)	70	52	34	30
CO2 emissions (Mton)	9	11	16	21
Renewable generation quota (%)	86%	85%	81%	77%

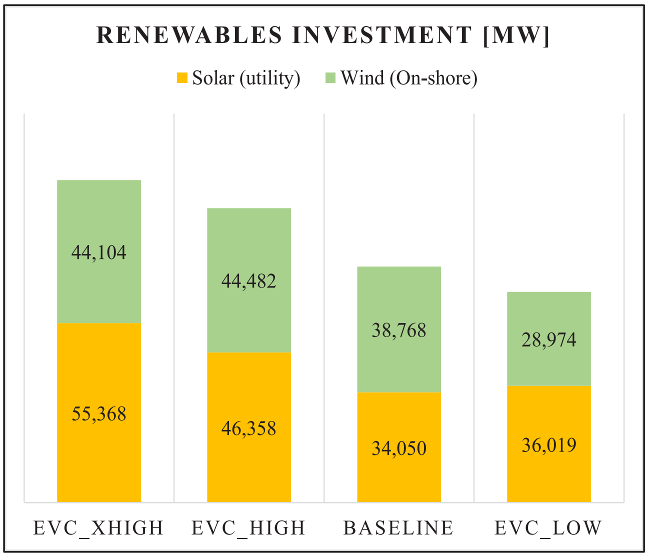

Fig. 10. New renewable investments (2019–2030) in CO_2 and gas prices scenarios.

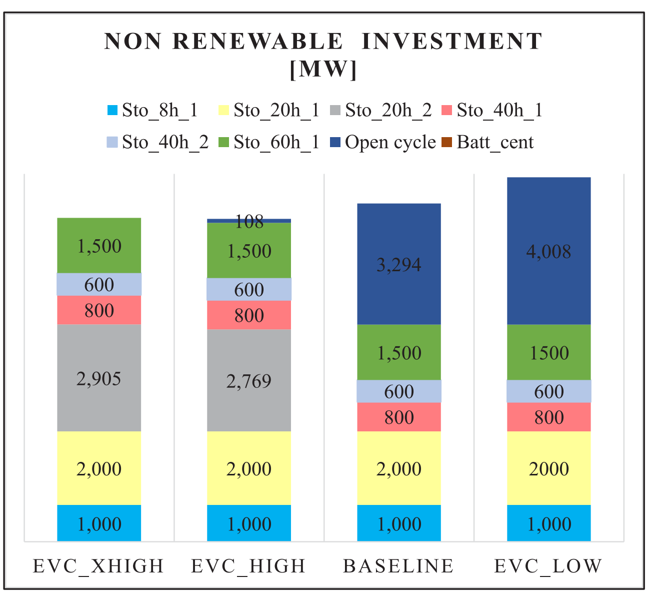

Fig. 11. New firm capacity investments (2019–2030) in CO_2 and gas prices scenarios.

storage, six types of pumped-hydro storage, OCGT, and demand-side response technology in providing the firm capacity required to ensure the security of supply of a real-size system such as the Spanish system in a 2030 horizon.

Furthermore, the mathematical formulation presented in Martínez et al. (2017) and Gerres et al. (2019) considers disaggregated demand suitable for limiting the amount that can be shifted and obtain a better estimation of DR capabilities. This formulation has been accordingly upgraded to enable SPLODER model to analyze the contribution of DR, storage and other technologies, to firm capacity requirements for the electricity system.

The third contribution of this paper is to provide a detailed study of the 2030 Spanish demand. The electricity demand is disaggregated by sector and consumption activities and projected towards 2030, applying the estimated growth rates by energy usage. This demand disaggregation identifies the controllable portion of the electricity consumption. Moreover, the controllability constraints of such flexible loads are considered to ensure the validity of the results.

The main findings driven by a Spanish-like system are:

- DR does have a non-negligible impact on the system firm capacity requirements. Neglecting DR in long-term analyzes could lead to biased decisions.
  - DR decreases firm capacity requirements in the system, roughly at a rate of 30 MW per 1% of the total potentially controllable demand participating in demand-response programs.
  - DR replaces (and therefore somehow competes with) eight-hours pumped hydro storage and OCGT. More than eight hours pumped hydro storage is not replaced by DR. However, DR implementation costs (new equipment, smart meters…) are not considered in this study. Hence, DR competitiveness results can be somehow overestimated.
  - DR fosters solar generation over wind generation.
- Pumped hydro with storage capacity larger than eight hours (except for one of the study's options) is very competitive choices to provide system firm capacity.
  - They are more competitive than OCGTs
  - They are more competitive than batteries even for extremely high reductions of batteries installation costs (85%).
  - DR does not replace them even with a high share (50%) of the potentially controllable load being participating in demand-response programs.
- Four-hour large-scale batteries are far from being competitive enough to provide firm capacity to the system
  - Pumped-hydro storage, OCGTS, and DR are far more competitive than batteries.
  - In the presence of DR, batteries installation costs should decrease up to at least 77% to become competitive against OCGT. A cost reduction of up to 85% leads to replace OCGT fully but is not enough to replace more significant than eight-hours pumped hydro storage alternatives.
  - Batteries are penalized because of their high installation costs and their low firm capacity contribution (its FC is 0.294). Four-hour storage is not enough to face longer episodes of renewable production scarcity in the system. But this effect may be very much system-dependent.

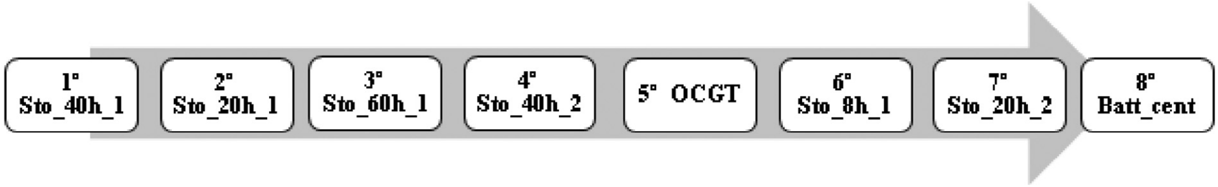

Fig. 12. Investment in firm capacity technologies priority order for baseline_newFC scenario.

- The competitiveness among different technological options to provide firm capacity to the system does depend mainly on the ratio (investment cost/FC). Fig. 12 below shows the resulting competitiveness rank for the firm capacity providers' technologies considered in the study in the Baseline_newFC scenario.
  - Pumped-hydro storages and OCGTs are the most promising firm capacity providers at this stage for the Spanish system, provided there are no restrictions on the installation of emitting capacity. If this were the case, OCGTs would be replaced by the rest of the available hydro pumping options and, if needed, also batteries if also needed. Nevertheless, OCGTs would almost not produce, being their role mainly to provide firm capacity.
  - The value of FC assigned to each technology depends on the specific power system analyzed. For thermal backup, FC is high (0.96 in this case) and non-system dependent.[6] The larger the storage capacity, the greater the FC since critical periods for supply may last several hours in a system dominated by renewable generation. Indeed, they could provide firm capacity in scarcity periods lasting less than their storage capacity (for instance storing PV production excesses in sunny hours and delivering that energy in non-sunny hours) but will not be able to do so for events with larger durations for instance a whole week with low wind. Nevertheless, the resulting values could be very much system-dependent.
- The technologies selected to provide firm capacity do also have an impact on the renewable generation mix. DR and storage-based technologies favor solar PV over wind since solar PV is cheaper but produces only in mid-day hours. On the contrary, OCGT favors wind over solar PV.
- CO_2 emission rights and natural gas prices have a combined impact when planning generation investment. This combined effect is related to the EVC of the technologies that require CO_2 emission rights or gas for their operation.
  - The higher the EVC, the better it is to invest in renewables, leading to a reduction of CO_2 emissions, although the higher the electricity price becomes. Therefore, there is a heavy dependence between electricity prices and CO_2 and natural gas prices.
  - There is a turning point in which the increase in EVC would lead to a rise in electricity prices not comparable to the renewable ratio growth.
- Results show the relevance of capacity payments to ensure the investments meet the system firm capacity requirements, that is, to ensure maintaining reasonable levels of security of supply
  - Incomes from the energy market, although underestimated in this study, do not allow for full recovery costs. OCGTs almost do not obtain payment from the energy market. On the contrary, one of the pumped hydro storage options recovers up to 60% in an extreme case.

Four main lines of future work would enhance the analysis performed in this paper. First, results have shown to be quite sensitive to the FC adopted for each technology. Although reports support values, FCs do depend on the final generation and storage mix adopted in each specific system. Further methodological and modeling work to better estimate them will enhance the accuracy of the results. Second, the deployment of DR does have a cost. Correctly estimating it for each kind of sector and activity and including it as an additional technological alternative for SPLODER, may provide interesting insights into the optimal level of deployment of DR in the system. Third, additional technologies should be considered in the basket of firm capacity providers' options, for instance, power-to-gas technologies (hydrogen, among others), to analyze their competitiveness, role, and impact on the rest of the technologies in the mix. Fourthly, the situation Europe is facing in 2022 with the gas crisis (Elliott, 2022), opens another research question, which is the effect of geopolitical issues on the electricity security of supply, that should not be underestimated, and how countries could protect themselves from a power outage.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data that has been used is confidential.

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[6] Provided there is no problems with the gas supply in the country.

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