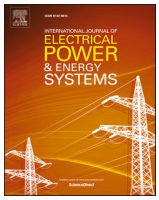
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Quantifying the full system value of distributed energy storage and demand response for a decarbonized Spanish power system

Miguel Martínez [a,*], Francisco Martín-Martínez [a], Andrés Ramos [a], Carlos Mateo [a], José Pablo Chaves-Ávila [a], Tomás Gómez San Román [a], David Ribó-Pérez [b], Pablo Frías [a]

[a] Instituto de Investigación Tecnológica (IIT), Universidad Pontificia Comillas, Madrid, Spain
[b] Universitat Politècnica de València, Institute for Energy Engineering, València, Spain

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ABSTRACT

Battery energy storage and demand response are critical technologies to provide flexibility in modern decarbonized electric power systems. This study presents a comprehensive techno-economic assessment of their combined value for the Spanish bulk power system and electricity distribution networks by 2030. The study integrates generation expansion planning, detailed hourly operational system dispatch, and distribution network planning modeling. The case study analyzes multiple deployment scenarios of batteries and demand response to quantify their benefits. For instance, the central scenario assumes 20 % residential and commercial participation in demand response and the installation of 6.4 GW of batteries. This deployment scenario of demand response and batteries results in bulk power system cost savings of approximately 1,447 M€/yr. In relative terms, this results in a reduction of 69 % in investments in additional peak conventional generation (i.e., open-cycle gas turbines), 28 % in variable generation costs, 26 % in emission costs, 55 % in average electricity market prices, and 7 % in renewable energy curtailment. Furthermore, of the total battery capacity installed in the central scenario, 1.4 GW is deployed as distributed batteries, which, together with demand response, defer 77 % of the grid reinforcements required to accommodate new demand and generation in medium and low voltage distribution networks, resulting in additional savings of 375 M€/yr. These results could be used to design policies to accelerate the deployment of these technologies while ensuring system reliability and economic efficiency.

1. Introduction

1.1. Motivation

As countries pursue ambitious decarbonization goals, the ability to flexibly manage electricity generation and demand becomes essential for power systems [1]. For instance, the National Energy and Climate Plan (NECP) of Spain [2] outlines a transformative pathway for the electricity sector by 2030. The NECP calls for the increased use of renewable energy sources, and the electrification of end uses, particularly in industry, transportation, and heating and cooling. Consequently, power systems will require significant investments in generation capacity and electricity networks to enable this transition.

Demand response (DR) and battery energy storage systems (BESSs) are widely recognized as key enablers for this transition, as they can provide flexibility across multiple power system applications. When effectively deployed, these resources can mitigate renewable energy curtailment, reduce peak demand, and defer or avoid costly investments in generation and network infrastructure. However, quantifying their full system value requires a comprehensive assessment that jointly considers generation expansion, hourly power system operation, and network planning, which involve very different temporal and spatial granularities. This creates a strong motivation for integrated analytical frameworks capable of capturing the techno-economic impacts of DR and BESSs across both the bulk power system and electricity distribution networks by soft-linking specialized models, which is the focus of this study.

1.2. Literature review

In the context of the energy transition, several authors have shown that the flexibility provided by BESSs [3] and DR [4] can contribute to reducing the total power system cost. The benefits of the deployment of these flexible technologies range from the reduction of wholesale

* Corresponding author.
E-mail address: Miguel.Martinez@comillas.edu (M. Martínez).

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Table 1
Literature review summary.

References	*Flexible DERs:* BESS	DR	*Scope of flexible DERs benefits quantified:* Bulk Power System	Distribution Grid Reinforcement
[3,6,7]	✓		✓	
[4,5,10]		✓	✓	
[8]	✓	✓	✓	
[20,22,23]	✓			✓
[11,13,26,27,31–33]		✓		✓
[12]		✓	✓	✓
This paper	✓	✓	✓	✓

electricity prices and emissions [5,6] to enhance resource adequacy, reduce investments in peaking units, and promote renewable energy integration [7–10].

Nevertheless, these studies do not consider the benefits of deploying DR and distributed BESSs for electricity distribution networks when evaluating the total power system cost. These additional benefits, which primarily stem from the deferral of investments in distribution networks necessary to accommodate new consumption and distributed generation [11], are important in determining the allocation of flexible energy resources, particularly distributed energy resources (DERs), such as distributed BESSs. A study conducted back in 2016 [12] examined the benefits of DR for the electricity generation system and distribution networks in Spain. Since then, new and more ambitious targets for electrification and renewable energy integration have changed the power system paradigm, increasing the need for flexibility. Investments in distribution grids are expected to increase significantly as they are adapted to meet the demands of the energy transition [13]. In Spain, they could double between 2024 and 2030, driven primarily by the need to reinforce distribution grids to accommodate growing demand [14,15].

Several studies have shown that distributed BESSs can reduce local demand peaks. In an Australian case study [16], community BESSs reduced peak demand by 28–45 %, depending on the share of customers involved. Similarly, a 22 % reduction in peak demand at distribution transformers could be achieved by optimally placing BESSs in Dutch low-voltage (LV) networks [17]. Residential BESSs can also increase self-consumption [18] and prevent overvoltage and congestion in LV networks [19]. Nevertheless, few authors have quantified these positive effects regarding reduced grid reinforcement costs. Installing BESSs at distribution transformers could reduce grid reinforcements by 10–25 %, if their investment cost drops to 60–80 €/kWh [20]. However, installing a single battery at a transformer is less efficient than installing several batteries throughout the LV network [21]. Additionally, utility-owned distributed BESSs in EU member states are not allowed to participate in electricity markets, which should be combined with other ancillary services at the distribution level [22]. Alternatively, distribution system operators (DSOs) could implement implicit or explicit flexibility mechanisms to leverage third-party-owned distributed BESSs for network planning purposes. For example, the co-deployment of distributed batteries and solar photovoltaic (PV) systems reduces incremental costs in German LV grids between 39 % and 51 %, depending on the grid type (rural, urban, or suburban) and the level of electric vehicle (EV) penetration [23].

Analogously, previous research has studied the potential benefits of DR for distribution grids, reporting reductions in peak load, voltage deviations, energy losses, and PV curtailment [24,25]. Despite these technical benefits for distribution grid operation, few authors quantify the resulting reductions in grid reinforcement costs attributable to DR. In [26], DR from residential, commercial, and office buildings lowers peak demand by 22–37 % and reduces grid investments by an equivalent amount (21–36 %). Similarly, [27] finds that, with 40 % customer participation, DR could reduce grid reinforcement investments by 15 % in urban networks and 23 % in rural networks, assuming a 3 % annual growth in demand. However, high participation levels of DR under time of use (ToU) tariffs can lead to synchronization of controllable loads, especially electric vehicles (EVs) [28,29], which could result in undesirable effects such as increased grid costs [13]. The assessment in [30], shows that capacity-based and mixed (capacity + volumetric TOU) tariffs are better because they charge users in proportion to their contribution to network peaks, which are the main drivers of congestion and grid reinforcements. Additionally, the integration of DR explicit flexibility services has also been shown to improve distribution network planning [31], even considering their procurement costs through market-based mechanisms [32,33].

1.3. Research gaps

This section identifies the main research gaps addressed by this study. While distributed BESSs and DR have been considered emerging solutions for optimizing distribution network plans, none of the reviewed literature analyzes their combined adoption. This paper addresses this gap by assessing how these technologies can jointly contribute to reducing the necessary reinforcements in LV and medium voltage (MV) grids to accommodate the demand and generation growth required for the energy transition at a national level. In addition, most studies rely on volumetric TOU tariffs, which are known to induce demand synchronization during off-peak periods. This paper incorporates the Spanish tariff structure, which includes both capacity and volumetric network charges, providing consumers an incentive to reduce their peak demand.

As shown in Table 1, the academic literature also lacks integrated evaluations of total system costs that account for the value of both DR and BESSs in reducing bulk power system costs (e.g., investments in peak generation units, fuel costs, emission costs, etc.) and deferring distribution network reinforcements. This paper addresses this gap by quantifying the system-level contribution of implicit flexibility across multiple deployment scenarios of distributed BESSs and DR, with a particular focus on their potential to also reduce distribution grid reinforcement needs.

1.4. Contributions

This study presents a comprehensive techno-economic assessment of the value of deploying DR and BESSs in the bulk power system and distribution networks in the context of energy transition. We propose a new integrated modeling framework that combines generation expansion planning, detailed hourly power system operation, and distribution network planning models to capture impacts across multiple layers of the power system. The methodology optimizes generation and storage investments, considering the participation of residential and commercial loads in DR. Then, the operational performance at hourly resolution of the resulting generation and storage mix is evaluated to compute variable generation costs and emissions. Moreover, distribution grid reinforcement needs are assessed using representative synthetic networks with high spatial and consumer-level detail. The results are consistently scaled to the national level, allowing a unified quantification of bulk power system and distribution network benefits of DR and BESSs. The main contributions are:

- Developing an integrated framework that soft-links three complementary modeling tools— generation expansion planning, detailed hourly operational system dispatch, and distribution network planning—allowing the evaluation of DR and BESS impacts across different aspects of the power system with diverse time horizons and varying levels of granularity.
- Quantifying the benefits for the bulk power system of the co-deployment of DR and BESSs for the energy transition. These benefits include reducing variable generation costs, emissions, wholesale

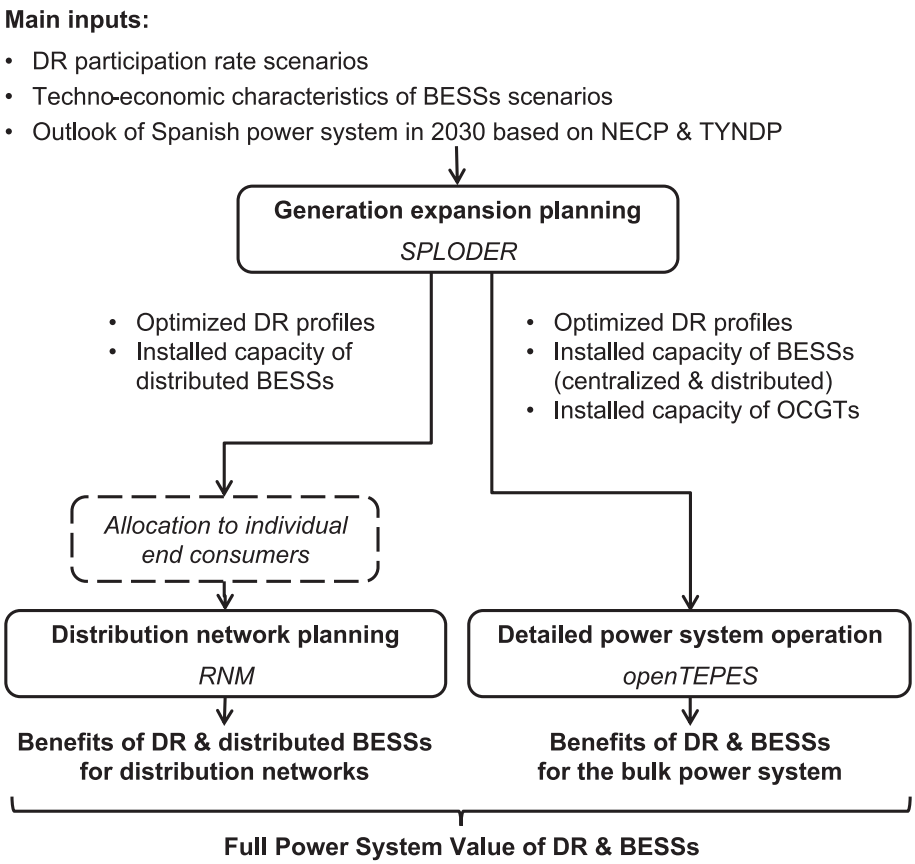


Fig. 1. Proposed integrated framework combining generation expansion planning, hourly system operation, and distribution network planning models.

market electricity prices, and renewable energy curtailment, while shelving investments in conventional peaking generation.

- Quantifying the benefits of adopting DR and distributed BESSs on distribution network reinforcements at a national level. To this end, we built three distribution grid models (urban, semi-urban, and rural) that represent all the national distribution grids. Then, we performed a detailed distribution network planning analysis on these three representative grids and scaled up the results to the national level.
- Quantifying the benefits of flexible technologies for the Spanish power system through a realistic case study grounded in a detailed review of publicly available reports and datasets (including the Spanish NECP, ENTSO-E's Ten-Year Network Development Plan, open data from Spanish transmission and distribution system operators, sectoral reports on DR and BESS, and regulated reference costs for electricity distribution investments), enabling a thorough characterization of the current power system and its projected evolution up to 2030.

The proposed integrated framework is described in Section 2. Section 3 outlines the case study and the scenarios for deploying BESSs and DR. The subsequent sections are dedicated to analyzing their impact on the bulk power system and distribution networks (Section 4) and discussing their potential benefits and limitations (Section 5). Finally, Section 6 concludes with a summary of key findings and their implications.

2. Methodology

This study aims to assess the value of DR and BESSs in different aspects of the power system. Therefore, a new integrated framework has been developed, combining three complementary power system modeling tools: generation expansion planning (SPLODER) [34], hourly system operation (openTEPES) [35], and distribution network planning (RNM) [36]. Fig. 1 illustrates how these three models are combined to quantify the benefits of DR and BESSs. The main inputs of the framework are scenarios for DR participation and BESS techno-economic characteristics, along with long-term power system projections.

First, the SPLODER generation expansion planning model is used to optimize investments in generation and storage technologies, including BESS. The model explicitly represents the participation of residential and commercial loads in DR. SPLODER computes the optimal generation and storage mix, investment costs in additional peak generation, optimal DR profiles, and electricity market prices [37]. These results are then used as inputs to the openTEPES model, which simulates power system operation with hourly resolution over a full year, verifying the feasibility of the generation mix by ensuring that electricity demand is met in all hours. OpenTEPES computes variable generation costs, emission costs, and renewable energy curtailment [7].

In parallel, the impacts of DR and distributed BESS on distribution networks are assessed using RNM. RNM estimates the required distribution grid reinforcements in each future scenario, given the installed capacity of distributed BESS and optimized DR profiles obtained with SPLODER. Representative synthetic distribution networks are used to capture impacts at high spatial and consumer-level resolution [13]. Finally, the results are scaled up to the national level.

This allows the quantification of bulk power system benefits, such as reduced peak generation investments, fuel costs, and emissions, as well as distribution network investment deferral benefits from DR and BESS across different time and spatial scales.

2.1. Modeling of the bulk power system

The first stage of the proposed framework in Fig. 1 uses a generation expansion planning model to optimize DR profiles and the installed

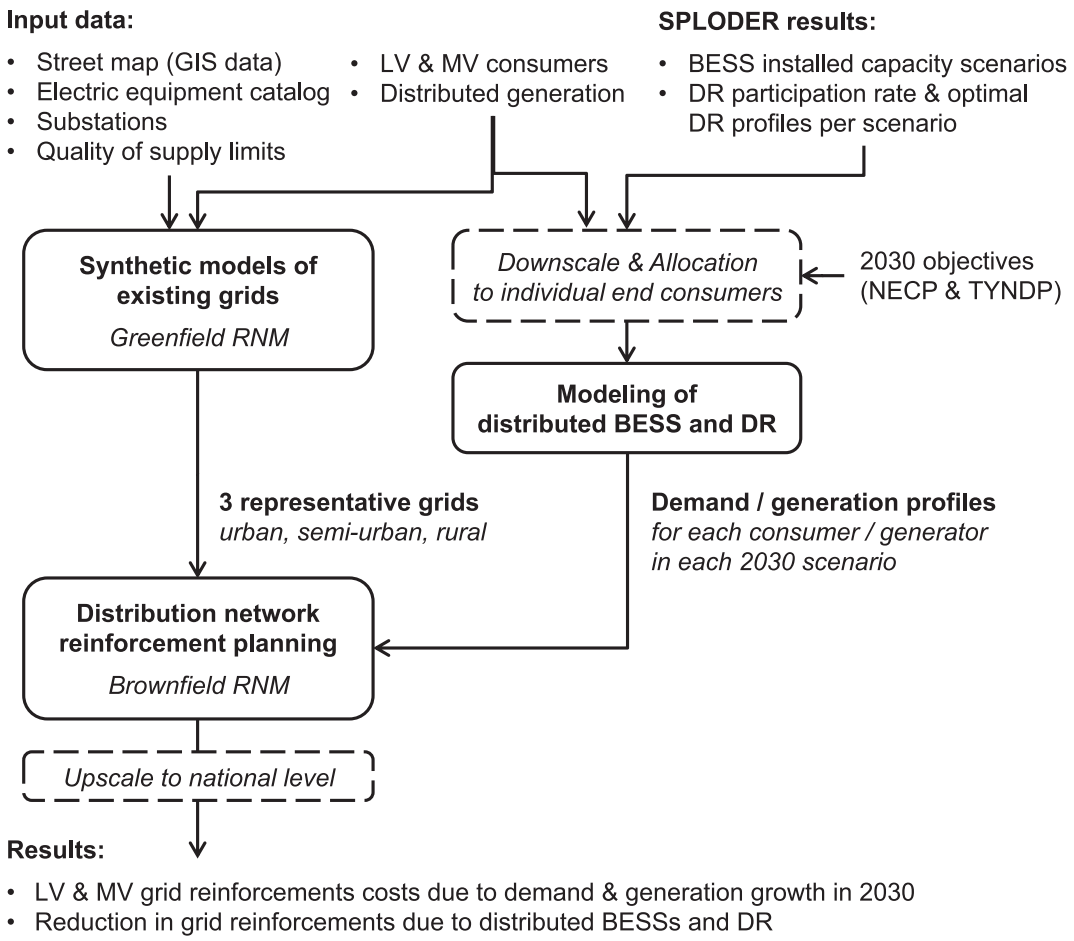


Fig. 2. Flowchart for the assessment of DR and distributed BESS benefits in distribution network planning.

capacity of BESS. The SPLODER model [34]is a generation expansion planning model incorporating economic and technical constraints to study the efficient adoption and real-time operation of centralized and distributed energy resources. The initial version of the SPLODER model was fully described in [33]. Some upgrades performed and their new formulation with respect to this initial version are presented in [8,37,38] to include policy constraints, to consider new storage technologies that can compete with flexible demand resources. It was developed to support regulatory analysis and strategic decision-making in the electricity sector. SPLODER optimizes investments in generation and storage through a comprehensive approach that considers various technologies: nuclear, combined cycle gas turbines (CCGT), wind, concentrated solar, solar PV, hydropower, BESS, cogeneration, etc. The objective function of SPLODER minimizes investment costs in new generation and storage capacity, fixed costs for maintaining new and existing generation and storage units, and operational expenditures of generation (e.g., fuel and emission costs) [37].

Moreover, in both the residential and commercial sectors, the SPLODER model divides demand into non-controllable and controllable categories, enabling the modeling of DR from controllable loads. The modeling of non-controllable and controllable demand follows the methodology described in [37]. Non-controllable demand is assigned a fixed hourly consumption profile. In contrast, a fraction of controllable demand, characterized by the DR participation rate parameter, responds to time-varying electricity prices by shifting consumption to minimize electricity costs, subject to technical and comfort constraints. Controllable loads include EVs and electricity demand for thermal applications, such as climatization and domestic hot water (DHW). DR profiles are computed considering the constraints inherent to each type of load (e.g., comfort levels or EV connection times).

In this study, the SPLODER model is used to optimize the installed BESS capacity and DR profiles in the different scenarios analyzed for the Spanish power system. The results indicate not only the optimal installed capacity for each generation and storage technology, but also the necessary investment costs in each scenario. Furthermore, SPLODER offers insights into the impact of BESSs and DR on electricity market prices. As a result, SPLODER computes the benefits of DR and BESS for the bulk power system in terms of reduced investments in peak generation capacity, as well as savings in demand payments driven by lower average wholesale electricity prices and price volatility. Additionally, the optimal installed capacity of distributed BESS and the associated DR profiles obtained from SPLODER are passed as inputs to the distribution network planning model presented in Section 2.2.

SPLODER models the operation of the power system using representative periods for generation expansion planning. Therefore, a more detailed operational model for the power system operation, the openTEPES model [35]is used to validate the results of SPLODER and to measure more accurately the impact of DR and BESSs on operational power system costs. The openTEPES model assesses the operation of the electrical power system over a whole year with hourly granularity, using as inputs the additional installed generation and storage capacities and the DR profiles derived from SPLODER.

The openTEPES model is an open-source generation, storage, and transmission expansion planning model, described and publicly available in [35]. The Ministry for Ecological Transition and the Demographic Challenge has used this model to update the latest Spanish

NECP [2]. In this study, however, it is only used to analyze the operation of the power system with additional details (e.g., annual variable generation costs, system operating reserves, etc.). The transmission network is represented as a single node (copper-plate assumption), and the additionally installed generation and storage capacities for each technology are taken from the SPLODER results, as done in [7] to assess the centralized operation of the future 2030 electrical power system over a whole year with hourly granularity. The objective function openTEPES minimizes operational expenditures of generation, including fuel, start-up/shutdown, operation and maintenance (O&M), and emission costs [7].

The openTEPES model receives as input the installed generation and storage capacities obtained with SPLODER, which has a more detailed modeling of the effects of DR on generation expansion planning. Then, openTEPES ensures that the optimal generation mix obtained with SPLODER meets hourly electricity demand without any episodes of unsupplied energy. In openTEPES, each CCGT, nuclear, and closed-loop pumping unit is modeled individually, and non-dispatchable renewable generation, pumped storage hydropower, and open-loop pumped hydro are aggregated. Necessary restrictions are imposed so that the system's operation is realistic.

The results of openTEPES consist of emission costs associated with electricity generation and variable generation costs, which include fuel, start-up/shutdown, and O&M costs. Moreover, it estimates renewable energy curtailment and potential revenues for BESS from the day-ahead market, operating reserve markets, and capacity payments. Therefore, openTEPES is used to evaluate the benefits of DR and BESS in terms of reductions in variable generation costs and renewable energy curtailment.

2.2. Modeling of distribution networks

DR and BESSs are flexible DERs that can reduce the peak aggregated demand in the distribution network by actively responding to price signals. For instance, network charges in Spanish electricity tariffs promote self-consumption and shifting grid consumption from peak hours to off-peak hours. Their impact on MV and LV grids is assessed with the Reference Network Model (RNM) as shown in Fig. 2. RNM is a distribution network planning model, presented in [36]. The objective of RNM is to minimize the total cost of the distribution network (investment, operation and maintenance, and energy losses costs) while complying with grid limits (voltage drop and thermal ratings), reliability criteria, and geographical constraints (e.g., street layouts). RNM can be applied both to the design of distribution grids from scratch for a given region, referred to as *greenfield* planning, and to the reinforcement and expansion of existing networks within a distribution network development plan, known as *brownfield* planning. As shown in Fig. 2, in this paper Greenfield RNM is used to generate synthetic, representative grids for the initial year, which are subsequently reinforced using the Brownfield RNM to accommodate additional demand and distributed generation under each future scenario.

First, three representative synthetic networks (urban, semi-urban, and rural) are obtained using Greenfield RNM [39] for the initial year (2024). Greenfield RNM designs the network infrastructure to supply consumers and distributed generation, complying with network, geographic, and supply quality constraints, as described in [36]. It follows a bottom-up, sequential planning process from lower to higher voltages. It first determines the location and optimal sizing of supply points at each voltage level (e.g., MV/LV transformers and HV/MV substations) and subsequently designs the layout and capacity of the power lines. Line layouts are initially based on a minimum-spanning-tree linking consumers to supply points and are then iteratively adjusted to satisfy geographical constraints, grid limits, and reliability criteria. National statistics on consumers (by sector and tariff type), self-consumption, and distributed generation connected at MV are given as input data. To make these distribution networks representative of Spain, they are based on national statistics, applying scaling factors considering the number of consumers. The details of the modeling of the initial networks are explained in Appendix A.

Brownfield RNM is then used to plan the required grid reinforcements. These reinforcements are necessary to accommodate new demand and distributed generation in future scenarios, following the methodology described in [13]. Brownfield RNM proceeds similarly to the Greenfield RNM. However, an initial network is already provided to Brownfield RNM as an input, and it is improved using branch exchange to make it technically feasible to connect new demand and distributed generation at the minimum cost. Finally, the results of the Brownfield RNM for the three representative grids are transformed into national figures using the scaling factors.

Consumers participating in DR are assigned an optimal consumption profile, which the SPLODER model determines. For consumers who install distributed batteries, their individual consumption profile (and generation profile, since most also have PV panels for self-consumption) is optimized to minimize the cost of both the energy and power terms in their electricity bill. On Spanish electricity bills, there is a power term—the contracted power—which is the maximum amount of electricity that you are allowed to consume at once. It is charged as a fixed monthly fee, regardless of how much energy you consume. Consequently, this tariff design incentivizes the reduction of peak demand, resulting in potential savings by deferring distribution network reinforcements. By comparing scenarios with varying levels of DR and distributed BESS deployment, the associated benefits in terms of deferred or avoided grid reinforcement investments are evaluated.

3. Case study

The proposed methodology is applied to a case study focusing on the Spanish power system in 2030, considering incremental investments beginning in 2024. It evaluates the benefits of deploying DR and BESSs across generation expansion, power system operation, and distribution grids. The case study is limited to mainland Spain, excluding the islands and international interconnections. This section details the DR and BESS deployment scenarios and the projections that characterize the generation mix, distributed generation, and end-use electricity demand in 2030.

3.1. Demand response and battery deployment scenarios

To assess the benefits of DR and BESS, this study considers several scenarios with varying levels of deployment of these technologies. The participation rate in DR programs and the future evolution of BESS techno-economic parameters are two major sources of uncertainty affecting planning decisions and the robustness of the estimated benefits of DR and BESS deployment. The SPLODER model uses the participation rate of residential and commercial consumers in DR and the techno-economic parameters of BESSs, especially their investment cost, as inputs to optimize DR profiles and installed battery capacity. By combining DR and BESS scenarios, the proposed framework enables a systematic sensitivity analysis of their individual and combined benefits for both the bulk power system and the distribution network.

Regarding the definition of DR scenarios, the associations ENTRA [40] and SmartEn [41] estimate that, by 2030, DR will be capable of reducing the system peak demand by 10 % and 20 %, respectively. Given that the present study is concerned exclusively with residential and commercial loads for DR, two levels of participation in DR have been considered:

- **DR00**: baseline scenario without DR.
- **DR20**: central scenario with 20 % participation from residential and commercial consumers, resulting in a potential peak demand reduction in 2030 of 4.3 GW (8.0 %).

Table 2
Scenarios analyzed in the case study.

	BAT0	BAT1	BAT2	BAT3*
DR00	**DR00-BAT0 baseline scenario** no DR no BESSs	DR00-BAT1 scenario no DR central BESSs (22 % distributed BESSs)	DR00-BAT2 scenario no DR optimistic BESSs (22 % distributed BESSs)	DR00-BAT3 scenario* no DR optimistic BESSs (44 % distributed BESSs)
DR20	DR20-BAT0 scenario central DR no BESSs	**DR20-BAT1 central scenario** central DR central BESSs (22 % distributed BESSs)	DR20-BAT2 scenario central DR optimistic BESSs (22 % distributed BESSs)	DR20-BAT3 scenario* central DR optimistic BESSs (44 % distributed BESSs)
DR40	DR40-BAT0 scenario optimistic DR no BESSs	DR40-BAT1 scenario optimistic DR central BESSs (22 % distributed BESSs)	DR40-BAT2 scenario optimistic DR optimistic BESSs (22 % distributed BESSs)	DR40-BAT3 scenario* optimistic DR optimistic BESSs (44 % distributed BESSs)

*DR00-BAT3, DR20-BAT3, and DR40-BAT3 scenarios are only used in the distribution network analysis.

Table 3
Characterization of the electricity generation mix for mainland Spain in 2030.

Generation Technology	Capacity [MW]	Firmness coefficient
Nuclear	5,105	0.95
CCGT	24,499	0.95
Cogeneration	4,205	0.55
Biomass	1,964	0.55
Solar thermal	4,804	0.12
Conventional hydro	11,414	0.44
Run-of-the-river hydro	3,424	0.17
Pumped storage hydro	5,591	0.90
Solar PV	72,130	0.00
Wind	60,537	0.07

Table 4
Characterization of Spanish electricity demand in 2030.

Demand [TWh]	**Residential**	**Commercial**	**Industrial**	**Total**
Non-controllable loads	32.07	36.06	108.00	176.13
Climatization	39.54	23.26	–	62.80
DHW	16.70	3.97	–	20.67
EVs	13.73	–	–	13.73
H_2	–	–	16.41	16.41
Total	102.04	63.29	124.41	289.74

- **DR40**: optimistic scenario with 40 % participation from residential and commercial consumers, resulting in a potential peak demand reduction in 2030 of 9.1 GW (16.9 %).

Regarding the definition of BESS scenarios, the NECP establishes a target of 22.5 GW of installed storage capacity by 2030, primarily through a combination of pumped storage hydropower, batteries, and solar thermal. Lithium-ion battery investment costs are currently around 160–282 $/kWh in 2024, according to Lazard [42]. In Spain's interim resolution on grants for innovative energy storage projects published in 2025, the costs of BESS projects ranged from 80 €/kWh to 300 €/kWh, with a mean cost of 181 €/kWh [43]. Nevertheless, up to a 57 % decrease in battery costs is expected by 2030 compared to 2024 prices, according to Goldman Sachs [44]. Based on these projections, the following techno-economic scenarios for BESS deployment are defined:

- **BAT0**: baseline scenario without BESS installation.
- **BAT1**: central scenario for BESS deployment, assuming an average battery cost in 2030 of 120 €/kWh. We estimate that 22 % of the total installed battery capacity corresponds to behind-the-meter distributed BESSs, based on ENTSO-e's Ten-Year Network Development Plan (TYNDP) [45].
- **BAT2**: optimistic scenario for BESS deployment, assuming an average battery cost in 2030 of 87.5 €/kWh and that 22 % of the total battery capacity corresponds to distributed BESSs.
- **BAT3**: optimistic scenario for BESS deployment, assuming an average battery cost in 2030 of 87.5 €/kWh and that 44 % of the total battery capacity corresponds to distributed BESSs. This scenario is only used in the distribution network analysis. From the point of view of the bulk power system, the results would be the same as in the BAT2 scenario.

To calculate the equivalent annual cost of batteries in all scenarios, we assume a 20-year lifespan [42] and a discount rate of 6.5 % for utility-scale, centralized BESSs and 9 % for behind-the-meter, distributed BESSs. Battery installation results for each scenario obtained with the SPLODER model are presented later in Section 4.1.

The combination of DR and BESS deployment results in 9 scenarios for the bulk power system analysis, while the distribution network planning analysis comprises 12 scenarios, since it includes 3 additional scenarios (DR00-BAT3, DR20-BAT3, and DR40-BAT3) that consider a higher share of distributed BESSs. These scenarios are presented in Table 2. The central scenario, the most likely scenario combination (DR20–BAT1), which aligns with Spain's NECP 2030 targets, results in 6.4 GW of batteries in mainland Spain in 2030. Scenarios DR00 and BAT0 serve as the baseline to quantify the incremental benefits of deploying BESS and DR, respectively.

3.2. *Spanish bulk power system in 2030*

The projections for 2030 regarding the Spanish electricity generation mix, derived from Spain's NECP [2] and ENTSO-e's TYNDP [45], have been employed to determine the installed capacity of each technology, as illustrated in Table 3. The values of the firmness coefficients for the diverse generation technologies in Table 3 have been retrieved from Red Eléctrica de España (REE) [46], National Grid [47], and ENTSO-e [45]. Efficiencies, fuel costs, and CO_2 emission costs for generation technologies projected by the NECP are also considered. An efficiency of 33 % and a fuel cost of 7.4 €/MWh are assumed for nuclear power, while CCGTs are projected to operate at 57 % efficiency and 49.72 €/MWh fuel costs. The estimated cost of CO_2 emissions is 113 €/tonCO_2. The main technologies responsible for CO_2 emissions are CCGTs (0.36 tonCO_2/MWh) and cogeneration (0.262 tonCO_2/MWh). Regarding battery energy storage, a firmness coefficient of 0.4 is assumed, a round-trip efficiency of 90 %, and an average C-rate of 0.33 (i.e., 3 equivalent hours). A round-trip efficiency of 75 % is assumed for pumped storage hydropower.

The hourly generation and demand profiles are derived from [48], which provides demand profiles for the following sectors: residential, commercial, and industrial. Residential demand is divided into three climate zones (i.e., North, Continental, and Mediterranean). Moreover, demand is divided into controllable and non-controllable loads in the residential and commercial sectors. Controllable loads include EVs and electricity demand for thermal applications, such as climatization and DHW. The breakdown of electricity demand is presented in Table 4. Additionally, based on TYNDP estimates, it is assumed that there will be 4 GW of hydrogen electrolyzers in Spain by 2030. According to [49], the electricity demand for hydrogen electrolysis in 2030 will be 16.41 TWh.

Table 5
Share of EV charging profile types considered in each scenario.

	DR00	DR20	DR40
Fixed charging profile	100 %	80 %	60 %
Smart charging at night	0 %	13 %	25 %
Smart charging at daytime	0 %	3 %	7 %
Smart charging optimized over 24 h	0 %	4 %	8 %

Table 6
Net and gross demand increase by sector in 2030 relative to 2024.

	Net demand	Gross demand
Residential	3.9 %	9.0 %
Industrial	27.2 %	35.4 %
Commercial	−0.8 %	2.7 %

Table 7
Scaling factors used to adjust national statistics to representative distribution networks.

	Number of residential consumers		Scaling factor
	Mainland Spain	*Representative Grid*	
Rural	2,679,419	1,769	0.06602 %
Semiurban	7,458,968	5,909	0.07922 %
Urban	13,653,820	90,317	0.66148 %

Table 4 shows no commercial EV demand, as we have modeled only private residential EV charging in this study.

Table 5 details the classification utilized in the SPLODER model to represent demand from EVs. The SPLODER model differentiates between EVs with a fixed charging profile and those that perform smart charging at night, during the day, or throughout the day. This study does not consider bidirectional vehicle-to-grid (V2G) charging, as the implementation of this technology in Spanish homes by 2030 remains uncertain. This is a conservative assumption, as a significant V2G rollout would likely increase the benefits of DR on the power system.

3.3. Spanish distribution networks in 2030

To construct distribution network scenarios, projections on final electricity demand, PV self-consumption, and DER adoption in 2030 are used. First, according to the NECP targets, it is estimated that the final net electricity demand will increase by 16.4 % between 2024 and 2030.[1] However, the increase in gross electricity demand from end consumers will be even higher due to the expansion of self-consumption. In fact, following NECP estimates, PV self-consumption installations in mainland Spain are expected to reach 18 GW by 2030. As shown in Table 6, the growth rate of end consumers' electricity demand will vary by sector of activity, with higher growth among industrial consumers. This increase is mainly attributed to the electrification of heating and cooling demand. Heat pumps are the key technology for their electrification.

It is important to note that the growth rates presented in Table 6 do not account for the increase in electricity demand resulting from the electrification of transportation. This case study employs the methodology proposed in [13] to generate a population of residential EVs and characterize their individual charging demand. It has been assumed that, of the 5.5 million EVs targeted in the NECP for 2030, there will be 4.9 million light-duty EVs in mainland Spain. This estimation is derived from the ratio of light-duty to heavy-duty EVs projected in the TYNDP.

In the BAT1 and BAT2 scenarios, 22 % of the total installed capacity is assumed to correspond to distributed BESSs. In the BAT3 scenario, it is assumed that the adoption of BESSs will be more distributed, with 44 % of the total installed capacity in the BAT2 scenario corresponding to distributed BESSs. For each battery scenario, we consider two options to allocate distributed BESSs: a) they can be installed by consumers of residential, industrial, and commercial sectors, and b) they are only installed by residential consumers.

Finally, scaling factors were estimated based on the number of customers. This allowed us to adjust the national figures to each of the representative networks. The scaling factors used are shown in Table 7 and correspond to the percentage of the national total assigned to each type of representative network.

[1] This increase in final electricity demand does not include exports, electricity used for storage applications, and consumption in the energy transformation (e.g., transmission losses). Additionally, since energy demand dropped in 2020, the final electricity demand in 2024, the first year of this study, is comparable to the demand in 2019. Therefore, we assume that the percentage increase in demand that the NECP forecasts for 2030 compared to 2019 will be approximately the same as the percentage increase between 2030 and 2024.

Table 8
Additional installed capacity (GW) of BESSs in Spain by 2030.

[GW]	BAT0	BAT1	BAT2
DR00	0	12.18	15.31
DR20	0	6.36	9.95
DR40	0	1.17	1.17

Table 9
Additional installed capacity (GW) of peak conventional generation (e.g., OCGTs) in Spain by 2030.

[GW]	BAT0	BAT1	BAT2
DR00	10.99	5.86	4.54
DR20	6.08	3.40	1.89
DR40	4.94	0	0

4. Results

This section presents the main findings of the case study, quantifying the benefits of DR and BESSs in the Spanish power system by 2030. First, the installed capacity of BESSs across different scenarios is analyzed. Next, the value of DR and BESSs for the bulk power system is assessed, including reductions in investment, operation, and emission costs. Finally, the potential of DR and distributed BESSs to defer grid reinforcements in distribution networks is quantified. Results reported in tables in this section should be interpreted as the outcome of a scenario-based sensitivity analysis, reflecting the uncertainty associated with DR participation levels and BESS techno-economic assumptions.

4.1. Deployment of batteries and demand response

This section presents the results of the SPLODER generation expansion model for the Spanish power system under various 2030 scenarios involving BESSs and DR. Table 8 shows the new capacity investments in BESSs. Both DR and BESSs are viable options for the system to shift consumption to other times of day. The scenario-based sensitivity analysis in Table 8, shows that greater available capacity in one technology diminishes the necessity for the other.

Security of supply is a primary driver for installing BESSs. Where permitted by the regulatory framework, BESSs can provide a wide range of ancillary services, including frequency regulation, reserve provision, and peak shaving. Table 9 shows that deploying BESSs and DR into power systems can reduce the installed capacity of open-cycle gas turbines (OCGTs), which would otherwise be necessary to ensure system security and resilience.

Table 10 shows the additional installed capacity of distributed BESSs in 2030 that has been considered in the distribution network planning

Table 10
Additional installed capacity (GW) of distributed BESSs in Spain by 2030.

[GW]	BAT0	BAT1	BAT2	BAT3
DR00	0	2.7	3.4	6.8
DR20	0	1.4	2.2	4.4
DR40	0	0.3	0.3	0.6

Table 11
Percentage of residential consumers that install a behind-the-meter BESS in each scenario.

	a) BESSs in residential, industrial, and commercial			*b) BESSs only in residential*		
	BAT1	**BAT2**	**BAT3**	**BAT1**	**BAT2**	**BAT3**
DR00	1.16 %	1.59 %	3.07 %	3.67 %	5.10 %	15.20 %
DR20	0.54 %	0.96 %	2.06 %	1.95 %	3.18 %	7.60 %
DR40	0.11 %	0.11 %	0.25 %	0.35 %	0.35 %	0.74 %

Table 12
Scenario-based sensitivity to DR and BESS deployment of total bulk power system costs (M.€/yr), including investment costs in peaking OCGT units, variable generation costs, and CO_2 emission costs.

	Investment costs in peaking generation(OCGTs) [M€/yr.]			**Variable costs** (fuel, start-up/shutdown,O&M) [M€/yr.]			**Emission costs** [M€/yr.]			**Total costs** [M€/yr.]		
	BAT0	**BAT1**	**BAT2**	**BAT0**	**BAT1**	**BAT2**	**BAT0**	**BAT1**	**BAT2**	**BAT0**	**BAT1**	**BAT2**
DR00	514	274	213	2,240	1,610	1,595	1,811	1,345	1,334	4,565	3,229	3,141
DR20	285	159	88	1,778	1,613	1,602	1,467	1,345	1,338	3,259	3,118	3,028
DR40	23	0	0	1,618	1,617	1,617	1,344	1,342	1,342	2,985	2,959	2,959

Table 13
Scenario-based sensitivity to DR and BESS deployment of MV and LV distribution network reinforcement annuities (M€/yr.).

		a) BESSs in residential, industrial, and commercial			*b) BESSs only in residential*		
[M€/yr.]	**BAT0**	**BAT1**	**BAT2**	**BAT3**	**BAT1**	**BAT2**	**BAT3**
DR00	487.50	450.98	435.85	300.18	303.41	291.81	263.41
DR20	124.06	112.06	111.96	93.31	103.25	96.09	78.15
DR40	67.94	64.37	64.37	64.57	63.93	63.93	64.26

Table 14
Expected revenues (M€/yr.) for BESSs from the day-ahead market, reserve markets, and capacity payments.

	Revenues from day-ahead market [M€/yr.]		**Revenues from reserve markets** [M€/yr.]		**Revenues from capacity payments** [M€/yr.]		**Total revenues** [M€/yr.]	
	BAT1	**BAT2**	**BAT1**	**BAT2**	**BAT1**	**BAT2**	**BAT1**	**BAT2**
DR00	109	120	0.7	0.6	327	411	436.7	531.6
DR20	68	93	0.8	0.5	171	267	239.8	360.5
DR40	17	17	1.6	1.6	27	16	45.6	34.6

Table 15
Percentage of distributed BESS equivalent annual cost that could be recovered from savings in distribution network reinforcements.

	a) BESSs in residential, industrial, and commercial			*b) BESSs only in residential*		
	BAT1	**BAT2**	**BAT3**	**BAT1**	**BAT2**	**BAT3**
DR00	13.29 %	18.66 %	33.83 %	46.10 %	48.65 %	27.85 %
DR20	8.42 %	6.76 %	8.58 %	10.05 %	10.75 %	8.82 %
DR40	11.72 %	14.65 %	6.90 %	9.04 %	11.30 %	5.19 %

analysis. Recall that, in the BAT1 and BAT2 scenarios, we assume that 22 % of the total BESS installed capacity in Table 8 correspond to distributed BESSs. Consequently, this leads to 1.4 GW of distributed BESSs in the central scenario (DR20-BAT1). This result of distributed battery installations is consistent with the NECP targets [2], which aim to achieve 1.6 GW of distributed BESS capacity in Spain by 2030. The BAT3 scenario assumes a more distributed BESS deployment, with 44 % of the BAT2 total installed capacity in Table 8 attributed to distributed BESSs.

Table 11 shows that the share of residential consumers who install a distributed BESS in this case study is lower than the percentage of residential consumers who participate in DR. Controllable loads, such as

Table 16
Number of consumers by sector of activity in 2024 in Spain and in each representative network.

	LV &MV consumers in mainland Spain				*LV &MV consumers in representative networks*			
	Residential	**Industrial**	**Commercial**	**Total**	**Residential**	**Industrial**	**Commercial**	**Total**
Rural	2,679,419	73,586	393,220	3,148,964	1,769	49	260	2,078
Semiurban	7,458,968	188,978	1,058,917	8,716,167	5,909	150	839	6,898
Urban	13,653,820	171,926	1,588,954	15,419,690	90,317	1,137	10,511	101,965

Table 17
Installed capacity of PV for self-consumption by sector of activity in 2024 in Spain and each representative network.

	PV self-consumption in mainland Spain [MW]				*PV self-consumption in representative networks [kW]*			
	Residential	**Industrial**	**Commercial**	**Total**	**Residential**	**Industrial**	**Commercial**	**Total**
Rural	117	289	95	501	147	363	119	629
Semiurban	325	743	255	1,323	490	1,118	384	1,992
Urban	1,633	2,383	1,116	5,132	7,483	8,491	4,812	20,786

EVs and heat pumps, that enable DR are expected to have a more widespread adoption than distributed BESSs.

4.2. Bulk power system benefits

This section discusses the technical and economic benefits of co-deploying DR and BESSs for the bulk power system. In the previous section, the results of the SPLODER model already showed that increasing the capacity of DR and BESSs allows for reducing the installed capacity of conventional peaking generation, mainly OCGTs. The equivalent annual investment costs in OCGTs in each scenario are shown in Table 12. In the central scenario (BAT1-DR20), there is a 69 % reduction in investments in OCGTs. Moreover, in the scenarios with 40 % DR, there is no or very little investment in OCGTs.

Additionally, the findings of the SPLODER model indicate a reduction in the average wholesale electricity market prices. The average electricity market price in the central scenario (BAT1-DR20) is 17.41 €/MWh, 55 % lower than the baseline scenario (BAT0-DR00).[2] Moreover, the standard deviation in the central scenario (35.7 €/MWh) is lower than in the baseline scenario (47.1 €/MWh). Consequently, deploying DR and BESSs in the central scenario reduces demand payments by 55 %, resulting in annual savings of 6,868 M€/yr. in demand payments compared to the baseline scenario.

Moreover, the benefits of DR and BESSs in the operation of the power system have been assessed with the openTEPES model. These benefits are also shown in Table 12 in terms of variable system costs (i.e., fuel costs, start-up/shutdown costs, and O&M costs) and emissions. In the central scenario (DR20-BAT1), variable and emission costs decrease with respect to the baseline scenario by 27.9 % and 25.7 %, respectively. Although it is not straightforward to compare due to the changes in the generation mix in each scenario, it can be seen how the deployment of DR and BESSs also reduces the generation from gas turbines. In the baseline scenario, OCGTs and CCGTs generate 3,059 GWh and 20,485 GWh, respectively. This is reduced to 69 GWh and 11,877 GWh in the central scenario. Furthermore, deploying DR and BESSs in the central scenario reduces renewable energy curtailment to 85,985 GWh, which is 6.9 % lower than the 92,361 GWh of curtailed renewable energy in the baseline scenario.

Analyzing scenarios with just DR shows how the flexibility provided by DR results in savings for the bulk power system. If 20 % of residential and commercial demand is manageable (BAT0-DR20 scenario), a total annual cost reduction of 22.7 % is achieved. These savings rise to 34.6 % with 40 % DR (BAT0-DR40 scenario), but the marginal benefit per flexible capacity unit added is lower. The most significant component of these savings is the reduction of system variable costs. However, moving from the BAT0-DR20 scenario to the BAT0-DR40 scenario, the principal reduction is seen in the investment costs in OCGTs.

Similar conclusions can be reached by analyzing those scenarios where only BESSs are deployed. With 12 GW of BESSs (DR00-BAT1 scenario), total savings of 29.3 % are achieved, while in the case of 15 GW (DR00-BAT1 scenario), total savings are 31.2 %. However, in these scenarios with only BESSs, the percentage of savings due to reduced investments in OCGTs is lower, while the reduction in variable and emission costs is more relevant.

From the system's perspective, incorporating flexible resources results in a decrease of total costs, derived from the investment costs of the generation expansion planning model and the operational costs of the detailed operational system dispatch model. Even if operating costs increase slightly in specific scenarios, there are greater savings in investment costs. As the system becomes more flexible with more DR and BESSs, generation start-up and shutdown costs become more significant in coping with the availability of flexible resources. Overall, results from the central scenario (assuming 20 % participation in DR and the deployment of 6.4 GW of batteries) show a 69 % reduction in investments in additional peak OCGT units, a 28 % decrease in variable generation costs, and a 26 % reduction in CO_2 emission costs. Together, these effects yield savings of 1,447 M€/yr. in bulk power system costs. Moreover, average wholesale electricity market prices decrease by 55 %, translating into additional annual savings of 6,868 M€/yr. in demand payments for consumers. Furthermore, renewable energy integration is improved with DR and BESS deployment, reducing renewable energy curtailment by 7 %.

4.3. Distribution network planning benefits

An increase of 16.4 % in final electricity consumption is projected by the NECP for Spain in 2030, mainly in the industrial and transport sectors. Besides, solar PV installed capacity for self-consumption is projected to triple by 2030. Self-consumption will reduce net electricity demand during the middle of the day, but without distributed BESSs or DR, it cannot mitigate evening peaks. In the baseline scenario (DR00-BAT0), the evening peak aggregate demand increases 18.5 % on average in the three reference distribution grids. This results from incrementing the load profiles for each type of consumer by an increase in gross final demand (see Table 6) and adding them by applying the corresponding simultaneity coefficients. Therefore, peak load growth will be the key driver for investments in distribution networks. Additionally, some grid

[2] The results of market prices in the baseline scenario align with Spain's NECP, which indicates average marginal electricity prices ranging from 28 €/MWh to 34 €/MWh in 2030. The main inputs that influence electricity prices are the fuel cost of CCGTs (49 €/MWh) and OCGTs (75.2 €/MWh) and the cost of CO_2 emissions (113 €/tonCO_2).

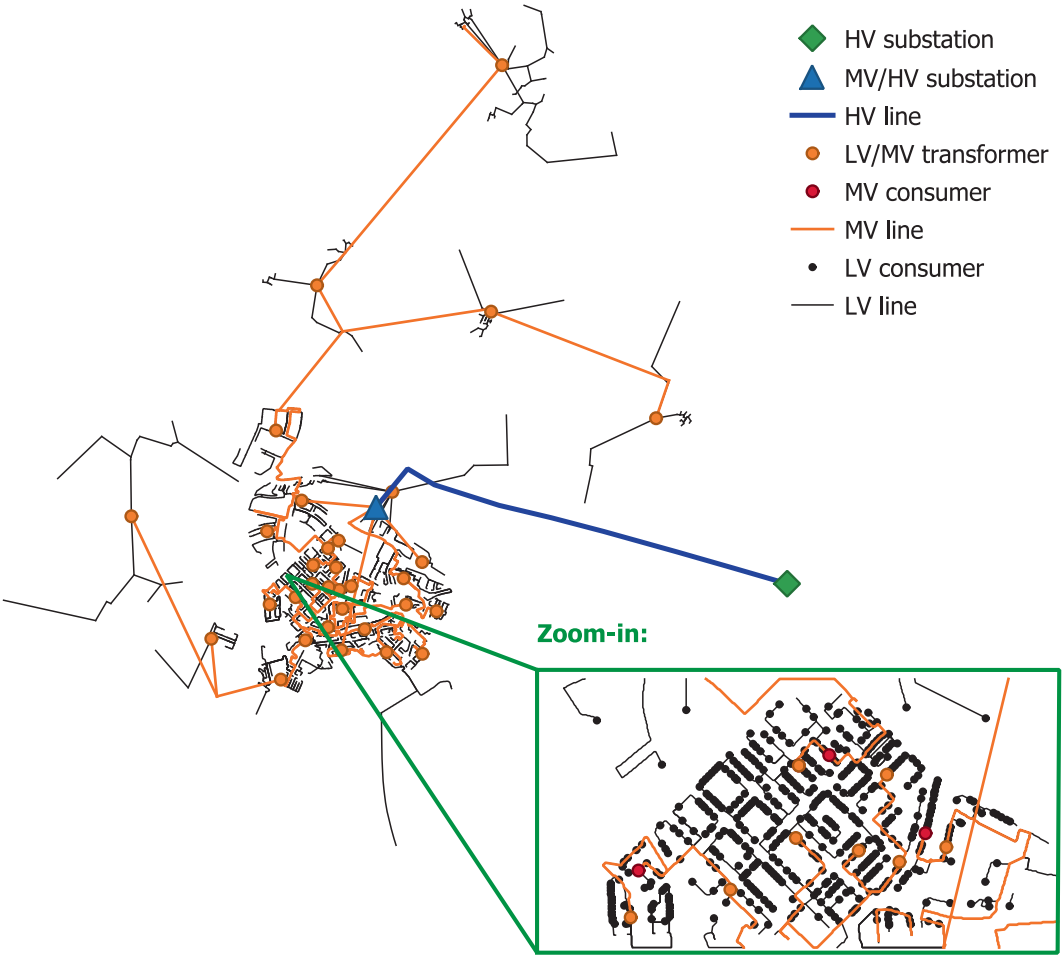


Fig. 3. Semiurban reference distribution network layout.

investments will be required to connect new solar and wind generation facilities to MV grids.

In the baseline scenario, the annuity of the incremental costs in MV and LV distribution networks in mainland Spain due to load and generation growth would amount to 487.5 M€/yr.[3] in 2030. If these investments are spread evenly over the period from 2025 to 2030, the average annual investment cost would be 1,059 M€/yr..[4] These results for the baseline scenario are aligned with major sector reports, which have estimated investment levels in European distribution grids based on DSO proprietary data. These reports estimate annual investments in distribution network reinforcements to meet increased demand and distributed generation in Spain of 880 M€/yr. between 2020 and 2030 [50], and 2,053 M€/yr. between 2025 and 2040 [15]. Therefore, the proposed methodology, which uses three representative grids to estimate national distribution grid reinforcements, yields reliable results and has the advantage of using only public data sources.

Flexible DERs can contribute to reducing these distribution grid investments by reducing load peaks and increasing self-consumption. Distributed BESSs allow storing excess energy during periods of low demand, which can be consumed later at more valuable periods with higher demand and electricity prices. On the other hand, DR involves adjusting consumption in response to variable electricity prices. For instance, network charges in Spain are higher at peak demand hours, incentivizing consumers to shift their demand to off-peak hours.

In the central scenario (DR20-BAT1), evening peak demand increases on average 4.15 %. This is 77 % lower than in the baseline scenario. This reduction in peak demand achieved in the central scenario also leads to a decrease of 77 % in MV and LV grid reinforcements. This results in savings of 375.44 M€/yr. in mainland Spain. Note that the reduction in incremental distribution grid costs is highly proportional to the decrease in the aggregate peak demand, as observed in [26]. Table 13 shows the savings in MV & LV grid reinforcements achieved by the combined adoption of DR and distributed BESSs.

The first column of Table 13 shows a substantial reduction in grid reinforcements due to DR. Similarly, the positive effect of distributed BESSs can be seen in the first row of Table 13. The reduction achieved with distributed BESSs is lower than that obtained with DR, not because batteries are a less efficient technology for reducing peak demand, but because, in the scenarios analyzed, there are fewer customers with

[3] Annuities of distribution installations have been calculated using a discount rate of 5.58 % and a useful life of 40 years. During the course of this study, the values in question were in line with the regulations in force in Spain at the time. Annuities represent the equivalent annual cost of investments in network infrastructure, accounting for both capital recovery and the time value of money over the asset's lifetime. This metric differs from the annual investment levels commonly used in sectoral reports, which typically refer to the average annual capital expenditures over a period and do not reflect the discounted lifetime cost of the assets.

[4] Assuming that mainland Spain accounts for 95 % of distribution networks and that the cost of MV and LV voltage networks accounts for 79 % of the total, the average annual investment in distribution networks due to demand and generation growth for the period 2024–2030 would amount to 1,413 M€/year. This figure could be even higher, especially in high-voltage distribution networks, if new demand growth vectors were considered, such as biogas or fast EV charging points, which have not been modeled in this study. Additionally, DSOs will also have to invest in asset replacement, grid digitalization, etc.

distributed BESSs compared to those with DR (see Table 11).

In Table 13, diminishing returns are observed for both DR and distributed BESSs. Although both can provide the flexibility needed to defer grid reinforcements, they exhibit a synergistic effect, except in the most optimistic scenario (DR40-BAT3). In the DR40-BAT3 scenario, the tariffs could be revised to achieve a more grid-friendly operation of DR and distributed BESSs. However, we do not expect significant improvements because the 2030 peak demand in the DR40-BAT3 scenario is very close to that in the initial year. Therefore, deploying additional DR and distributed BESSs can be effective in deferring distribution network reinforcements if it remains effective in lowering the rising demand that justifies such reinforcements.

Table 13 also compares two options to allocate distributed BESSs: a) installed in residential, industrial, and commercial consumers, and b) installed only in residential consumers. Savings in distribution network reinforcements are more significant when distributed BESSs are located at consumers whose peak demand coincides with the aggregate peak demand of the distribution network. This is particularly true for residential consumers. Furthermore, BESSs in urban consumers can yield greater savings in distribution network reinforcements, as urban grids typically feature more underground cables and distribution transformers, which are more expensive.

Overall, results for the central scenario indicate that deploying 1.4 GW of distributed BESSs in combination with 20 % DR participation enables the deferral of 77 % of the required grid reinforcements in MV and LV grids. This represents 375 M€/yr. in additional savings, highlighting the value of distributed flexibility for distribution networks. Besides, distribution reinforcement savings are higher when distributed BESSs are installed at consumers whose peak demand coincides with the aggregate network peak.

5. Discussion

5.1. Discussion of results and practical implications

The findings of this study demonstrate the substantial benefits of DR and BESSs for both the bulk power system and distribution networks. However, realizing these outcomes in practice will necessitate overcoming several technical, economic, and regulatory barriers. While the deployment of 6.4 GW of BESSs, of which 1.4 GW would be distributed BESSs, and 20 % participation in DR are assumed in the central scenario, which is aligned with NECP targets, future costs of BESSs and DR have not been incorporated in our analysis. Achieving this level of DR adoption heavily depends on consumer engagement, the adoption of enabling technologies, and the implementation of appropriate incentive mechanisms. Moreover, the costs associated with DR remain uncertain due to variability in consumer behavior and technology adoption.

One of the barriers to their deployment is the lack of some economic signals that reflect their actual value for the power system. For instance, there were no capacity payments when this study was conducted in Spain. However, a proposal to implement a capacity market in Spain is being considered. In the generation expansion planning model, considering its firmness coefficient, we have estimated a theoretical capacity payment as the installed BESS power multiplied by the dual variable associated with the reserve margin. Table 14 shows the expected revenues for BESSs from the day-ahead market, reserve markets, and the theoretical capacity payments. These results highlight that capacity payments could be key for BESSs' profitability. The equivalent annual cost of a utility-scale centralized BESS would need to decrease to 12.57 €/kWh-yr[5] in the central scenario, considering the theoretical revenues from capacity payments and assuming the absence of other revenue streams or incentives.

Similarly, no economic signal explicitly reflects the positive effects of distributed BESSs and DR on the reduction/deferral of distribution network reinforcements. Although in most cases these revenues would not justify installing distributed BESSs as an alternative to grid reinforcement, Table 15 shows that a significant percentage of their cost could be recovered thanks to the savings in distribution network reinforcements. For this calculation, annuities[6] of distributed BESSs were compared with the savings in network reinforcements from Table 15. Nevertheless, for these benefits to be accomplished in practice, owners of BESSs must optimize their profile to minimize their contracted power during periods of maximum demand. This shows that installing BESSs can provide significant savings in the distribution networks, but revenue stacking is needed to make them profitable.

5.2. Limitations and future research

This study demonstrates the potential value of DR and BESSs using an integrated modeling framework that quantifies the benefits across generation expansion, power system operation, and distribution network reinforcements. Building on these contributions, this section identifies modeling challenges and limitations that should be addressed in future research.

This study does not model high-voltage distribution grids or the transmission network, as uncertainty regarding the location and scale of emerging large loads(e.g., data centers and hydrogen) and new generation at these voltage levels would require dedicated forecasting tools. In addition, the demand associated with public EV charging infrastructure and heavy-duty electric transportation is not considered, nor is the DR potential of industrial low- and medium-temperature processes. The analysis also does not account for weekly-scale DR, particularly for EVs, such as users delaying charging to another day with lower electricity prices. Future research should extend the proposed framework to incorporate additional demand segments, voltage levels, and sources of distributed flexibility. Moreover, explicit flexibility mechanisms, such as flexible grid connections [51] and local flexibility markets [33], could be considered in future research to unlock even more value from flexible DERs.

Another limitation of this study is the limited availability of open data on the costs of real projects and open power system models. For instance, the unitary costs of investment in electricity distribution installations employed in this analysis are derived from Ministerial Order IET/2660/2015 [52], which remains in force but has not undergone substantial revision since its enactment in 2015. Consequently, current cost estimates for distribution grid assets may be higher, potentially resulting in greater absolute economic benefits, while the relative outcomes of the analysis would remain unaffected.

Although the benefits quantified in the previous sections do not account for the investment and operation costs of DR and BESSs, the findings of this study reveal the potential benefits of these flexible technologies on the power system. These results could be utilized to design policies that can accelerate their deployment while ensuring system reliability and economic efficiency. Future work should also further assess the cost-benefit analysis of investing in DR and BESSs in the energy transition.

6. Conclusions

This study illustrates the potential value of DR and BESSs for power systems in the context of the energy transition. An integrated modeling approach is proposed to quantify their techno-economic benefits in

[5] Assuming a useful life of 20 years and a 6.5 % rate of return, this would be the equivalent annual cost of a 3h utility-scale BESS with an investment cost of 138.5 €/kWh.

[6] For the BAT1 scenario, we assume an annuity of 49.30 €/kWh-yr. for residential BESSs and of 33.92 €/kWh-yr. for an average distributed BESSs. For the BAT2 and BAT3 scenarios, we assume that BESS costs drop by 20 % with respect to these values. To compute these annuities, we assumed a useful life of 20 years and a 9 % rate of return. Annuities are used because they allow us to compare investments with different useful lives.

various deployment scenarios. This methodology encompasses generation expansion planning, hourly power system operation, and distribution network planning models. Since no single model can adequately capture all aspects of the power system due to differences in time horizon, spatial resolution, and technical scope, this approach demonstrates comprehensively how to combine specialized models to evaluate the full system value of these flexible technologies.

Results from the central scenario of the case study, which assumes 20 % residential and commercial participation in DR and the deployment of 6.4 GW of BESSs, indicate a 69 % reduction in investments in additional peak conventional generation (i.e., open-cycle gas turbines), a 28 % decline in variable generation costs, and a 26 % reduction in emission costs. These positive effects translate into bulk power system cost savings of approximately 1,447 M€/yr. Moreover, the central scenario reveals a 7 % decline in renewable energy curtailment and a 55 % reduction in average electricity market prices, which results in additional annual savings of 6,868 M€/yr. in demand payments.

In the central scenario, 1.4 GW of the total battery capacity is deployed as distributed BESSs, which, alongside DR, defer 77 % of the required grid reinforcements in MV and LV networks, resulting in additional savings of 375 M€/yr. This result demonstrates the potential value of implicit flexibility provided by DERs when optimizing their consumption/generation profile in response to electricity tariffs, especially for reducing contracted power and peak network utilization.

These findings highlight the potential of these flexible technologies to enhance system reliability and economic efficiency, and they provide a robust foundation for designing policies that support their accelerated and strategic deployment. Nevertheless, in this study, we have not performed a cost-benefit analysis that accounts for the investment and operational costs of DR and BESSs, which should be addressed in future research.

CRediT authorship contribution statement

Miguel Martínez: Writing – original draft, Visualization, Software, Methodology, Investigation, Data curation, Conceptualization. **Francisco Martín-Martínez:** Writing – review & editing, Software, Methodology, Investigation, Data curation, Conceptualization. **Andrés Ramos:** Writing – review & editing, Software, Methodology, Investigation, Data curation, Conceptualization. **Carlos Mateo:** Writing – review & editing, Supervision, Software, Project administration, Methodology, Funding acquisition, Conceptualization. **José Pablo Chaves-Ávila:** Writing – review & editing, Supervision, Methodology, Conceptualization. **Tomás Gómez San Román:** Writing – review & editing, Supervision, Methodology, Conceptualization. **David Ribó-Pérez:** Writing – review & editing, Supervision, Project administration, Funding acquisition, Conceptualization. **Pablo Frías:** Writing – review & editing, Supervision, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: This paper is based on research conducted to quantify the value of distributed batteries and demand response for the Spanish power system as part of the EBAFLEX project, led by Samso EDS and funded by UNEF, AEPIBAL, Octopus Energy, PIMEC, Circutor, Riello, BeePlanet, Cegasa, Sonnen, TAB, and Ampere Energy.

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Appendix A:. Reference network models of current Spanish distribution grids

Due to the confidentiality of the actual network models and the complexity of modeling the entirety of the distribution network at the national level, Greenfield RNM is employed to obtain synthetic models that are representative of current distribution networks in Spain. Consequently, three representative networks have been modeled, corresponding to the following three types of distribution areas:

- **Urban**: municipalities with more than 20,000 consumers. Selected municipality: Albacete.
- **Semiurban**: municipalities with between 2,000 and 20,000 consumers. Selected municipality: Sant Sadurní d'Anoia.
- **Rural**: municipalities with fewer than 2,000 consumers. Selected group of municipalities: Chodes, Morata de Jalón, El Frasno, and Santa Cruz de Grío.

The inputs to Greenfield RNM are the power and location of consumers and distributed generation, street layouts, a catalog of standard electrical equipment, and configuration parameters (e.g., simultaneity factors, load-based reliability indices, etc.). The catalog of standard equipment is based on the Spanish Ministerial Order IET/2660/2015 [52], which establishes reference unitary investment and O&M costs for standard types of electricity distribution equipment.

The total number of consumers (by sector of activity and type of electricity tariff) can be found in the open data platform of Spanish distribution companies, Datadis [53]. The information used dates from June 30th, 2024. The number of customers in each representative network in Table 16 is calculated by applying the scaling factors (see Table 7).

Each consumer is assigned to a cadastral reference, based on their primary use reported in the URBAN3R open data platform [54]. In the case of residential buildings, the number of dwellings and the building footprint are considered. Then, each consumer is assigned a contracted power based on their tariff and sector of activity. Simultaneity coefficients are applied to aggregate the contracted power of LV and MV consumers, which are stipulated in the Spanish regulation, to determine the hosting capacity for new demand connections to distribution networks [55].

The installed capacity of PV for self-consumption in each representative network in Table 17 is calculated by applying the scaling factors (see Table 7) to the total capacity installed for self-consumption per sector of activity in Spain, as reported by UNEF [56] and APPA Renovables [57]. The self-consumption PV installed capacity is distributed among individual customers within each sector based on their contracted power and the building's footprint. Furthermore, as of May 2024, in mainland Spain, there are 2,221 MW of wind and 1,511 MW of PV connected to MV distribution grids [58]. Therefore, a 1.5 MW wind farm and a 1 MW photovoltaic plant have been added to the representative rural network to model the distributed generation connected at MV.

Finally, Fig. 3 illustrates the reference distribution network of the semiurban area used in the case study.

Data availability

Data will be made available on request.

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