Applied Energy 336 (2023) 120828

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Opportunities for low-carbon generation and storage technologies to decarbonise the future power system

K. Guerra [a], R. Gutiérrez-Alvarez [b], Omar J. Guerra [c], P. Haro [a,*]

[a] *Chemical and Environmental Engineering Department. Escuela Técnica Superior de Ingeniería, Universidad de Sevilla, Camino de los Descubrimientos s/n, 41092 Seville, Spain*
[b] *Postgraduate Faculty, Universidad de las Américas Quito, Avenida de los Granados E12-41 y Colimes Quito, Ecuador*
[c] *National Renewable Energy Laboratory, 15013 Denver West Parkway, Golden, CO 80401, USA*

HIGHLIGHTS

- Flexibility and inertia are limiting factors in a high-VRE future power system.
- The proposed model integrates new technologies for different climate conditions.
- H_2 generation technologies meet up to 16% of electricity demand.
- In the long term, H_2 storage equivalent to 14.4 TWh is required.

ARTICLE INFO

Keywords:
Power system
Energy storage
Hydrogen
Hydrogen storage
Power Generation Technologies
Hydrogen turbines

ABSTRACT

Alternatives to cope with the challenges of high shares of renewable electricity in power systems have been addressed from different approaches, such as energy storage and low-carbon technologies. However, no model has previously considered integrating these technologies under stability requirements and different climate conditions. In this study, we include this approach to analyse the role of new technologies to decarbonise the power system. The Spanish power system is modelled to provide insights for future applications in other regions. After including storage and low-carbon technologies (currently available and under development), batteries and hydrogen fuel cells have low penetration, and the derived emission reduction is negligible in all scenarios. Compressed air storage would have a limited role in the short term, but its performance improves in the long term. Flexible generation technologies based on hydrogen turbines and long-duration storage would allow the greatest decarbonisation, providing stability and covering up to 11–14 % of demand in the short and long term. The hydrogen storage requirement is equivalent to 18 days of average demand (well below the theoretical storage potential in the region). When these solutions are considered, decarbonising the electricity system (achieving Paris targets) is possible without a significant increase in system costs (< € 114/MWh).

Abbreviations: A-CAES, Adiabatic Compressed Air Energy Storage; BESS, Battery Energy Storage Systems; CAES, Compressed Air Energy Storage; CC, Combined cycle; CCS, Carbon Capture and Sequestration; CHP, Combined Heat and Power; CIL, Critical Inertia Level; CR, Cogeneration and Non-Renewable Waste; CSP, Concentrated Solar Power; EU, European Union; FEPPS, Future Renewable Energy Performance into the Power System Model; H_2-CC, Combined cycle gas turbines (configured or upgraded for hydrogen); HDV, Heavy-Duty Vehicle; HDV-PEM, Heavy-duty vehicle Polymer Electrolyte Membrane fuel cells; LCA, Life-Cycle Analysis; LCOE, Levelized Cost of Energy; LDES, Long-Duration Energy Storage; Li-ion, Lithium-ion Batteries; N, Nuclear; NGCC, Natural Gas Combined Cycle; NTs, New generation technologies considered in this study; O&M, Operation and Maintenance Costs; P2G, Power to Gas; P2G2P, Power to Gas to Power; PEM, Polymer Electrolyte Membrane; PHS, Pumped Hydro Storage; PPA, Power Purchase Agreement; PV, Solar Photovoltaic; RES, Renewable Energies; ROCOF, Rate of Change of Frequency; SI, Supplemental Information; SOFC, Solid Oxide Fuel Cells; ST, Solar Thermal; Stat-PEM, Power generation through stationary PEM fuel cell; TES, Thermal Energy Storage; TR, Renewable Thermal; TRL, Technological Readiness Level; VRE, Variable Renewable Energy; W, Wind.

* Corresponding author.
E-mail address: pedrogh@us.es (P. Haro).

https://doi.org/10.1016/j.apenergy.2023.120828
Received 9 November 2022; Received in revised form 2 January 2023; Accepted 7 February 2023
Available online 16 February 2023

1. Introduction

The deployment of renewable energies is increasing worldwide to meet decarbonisation targets. In recent years, this growth has accelerated sharply to support economic recovery in the wake of different crisis. Renewable energies are seen as the backbone of the shift from fossil fuels to clean energy systems. However, their variability challenges the stable and reliable operation of power systems, which needs to be addressed on the path to net zero emissions [1,2]. Wind and solar photovoltaic (PV) are intermittent resources requiring generation that adapts to their variability. The unpredictability of Variable Renewable Energy (VRE) is another issue that is gradually decreasing through computer techniques that allow for improved forecasting. Nevertheless, the increasing share of VRE is bringing new and greater challenges that grid operators must face [3].

For 100 % renewable systems, improvements in transmission, long-duration and seasonal storage, and low-emission and flexible generation technologies are considered the most affordable ways to meet electricity demand [4]. Generally, the most flexible technologies that can vary their power output or be brought online when needed are hydroelectric and natural gas-fired power plants [3]. Alternatively, electricity storage systems are seen as a potential option to support the intermittency and unpredictability of VRE, and have been addressed in several studies [3,5,6]. The most outstanding feature of storage systems is that they can absorb surplus electricity from the grid and then return it, in contrast to power plants that only provide electricity [3].

Energy storage technologies can be electrochemical, electromechanical, electrical, thermal, and thermochemical [7]. The best-established storage technology at the utility level is pumped hydro storage (PHS). Compressed air energy storage (CAES) and PHS are mature technologies; however, it is unlikely to improve their efficiency in the near future [8]. In addition, developing new PHS power plants is limited in some regions due to the scarcity of environmentally and socially acceptable and cost-effective sites [9]. According to the European Commission, energy storage is critical in the energy transition [10]. Energy storage would help improve energy efficiency and security, helping to balance electricity grids by storing surplus and supporting further integration of VRE. PHS is currently the main storage system in the European Union (EU). However, due to its environmental limitations and storage times of less than a week, further development of PHS in the EU is limited.

Long-duration storage is crucial to reduce system costs to achieve more than 80 % VRE [5]. Moreover, flexibility options (including curtailment, short-duration, long-duration and seasonal storage) are necessary to achieve systems with high and super-high renewable generation (75 %–90 % and >90 %) [6]. Lithium-ion batteries account for most electrochemical storage demonstration projects and could become cost-competitive with continued cost reductions [10,11]. Overall, energy storage has not yet achieved sustained growth and is at an early commercialisation stage; specifically, long-duration energy storage in the power system is still in its infancy. Therefore, new regulations, policy support and investments are needed to deploy these technologies [3,12]. In recent years, power to gas (P2G) has emerged as an alternative to large-scale storage. P2G consists of converting electricity into hydrogen through electrolysis and then using it, for example, to produce methane (combined with CO_2). P2G is in an early stage of development; however, it is considered a necessary technology for 100 % renewable systems. It should be noted that the diversity of technologies is also seen as a source of flexibility in dealing with renewable penetration and grid challenges [5].

Several models have analysed the integration of storage and new power generation technologies into the grid. These models include dynamics and trade-offs between flexibility options, optimisations based on the least cost, residual curve analysis, and simulations between different sizes of storage and renewable integration [5]. Some models consider electrolysis to produce hydrogen, independent of curtailment, using a constant capacity factor for electrolysis. Other models increase this capacity factor according to VRE curtailment [11] or include coefficients or degrees of flexibility to the different generation technologies, where storage is assigned total flexibility [13]. Several models generally consider storage without specifying technologies or constraints [5,13] or including only one technology as a representative form of any storage [14]. Some optimisation studies differentiate storage technologies and consider, for example, batteries, PHS, CAES, and underground hydrogen storage (P2G), among others [5].

Batteries and PHS have been studied to reduce the costs of surplus wind and solar generation in the power system through an optimisation problem [15]. Other optimisation studies also include batteries as an hourly balancing mechanism to reduce curtailment [7] and costs required to achieve 100 % renewable power systems [16]. A dispatch strategy is applied for Europe, where the balancing energy requirements are minimised for a given storage size [17]. P2G systems have been explored in several optimisation studies [5,18,19], and some consider the power-to-gas-to-power approach (P2G2P) [19] to achieve 95–100 % renewable energy (RES) scenarios [20]. CAES has generally been included in models at the single power plant level (e.g., wind farm) rather than at the system level [21 22]. The role of hydrogen turbines in the electricity system has been assessed through an optimisation problem when an emission cap was set to ensure decarbonisation [23].

As seen above, many studies analysed the role of only one type of storage or low-carbon generation technology in the electricity system. Some consider more technologies through optimisation problems but without flexibility and technology constraints. In other studies, storage is a flexible option to deal with the VRE surplus and not to explore subsequent energy utilisation in the electricity system (like the P2G2P approach). Several studies impose the storage size and VRE share, assuming up to 100 % renewable systems but without considering feasibility aspects (stability) at the power grid level. Accordingly, to the best of our knowledge, no previous studies integrate different storage and power generation technologies into a model of the future electricity system, considering different climate conditions and limiting their generation by flexibility and stability requirements. Although the TYNDP (Ten-Year Network Development Plan) projections are based on different hydro-climate conditions, only P2G and batteries are analysed, and it does not include an hourly stability analysis to find the power generation and storage requirement for future scenarios [24,25].

Our study aims to fill these gaps by including low-carbon generation and storage technologies into a power system model developed from real data (hourly resolution), limiting their generation by flexibility and stability constraints. The novelty of our study is to determine the challenges for the penetration of these technologies in future power grids to replace fossil generation (natural gas combined cycle: NGCC) considering different climate conditions (DRY, NORMAL, and WET years) without compromising system inertia. In addition, the model allows us to determine the size of hydrogen storage needed in future scenarios. In other words, the storage size and the VRE share are not imposed to get decarbonisation (as usually done by optimisation studies) but are a result of the model.

A techno-economic analysis of 14 different technologies for long-duration energy storage and flexible power generation to support high-VRE grids (85 %) has been performed [4]. This techno-economic analysis was considered as it is based on the levelized cost of energy (LCOE) that enables the comparison across all technologies regardless of the type of energy stored [4]. The best-performing technologies have been selected as the new technologies (NTs) analysed in our study. A detailed discussion supporting the selection or exclusion of the new technologies is described in Note S1 (Supplemental Information: SI). The new technologies were included in the Future Renewable Energy Performance into the Power System Model (FEPPS), a rule-based model developed by the authors with a merit order approach [26]. The selected Member State to test our model and provide future scenarios is Spain since it has reduced and well-defined international interconnections

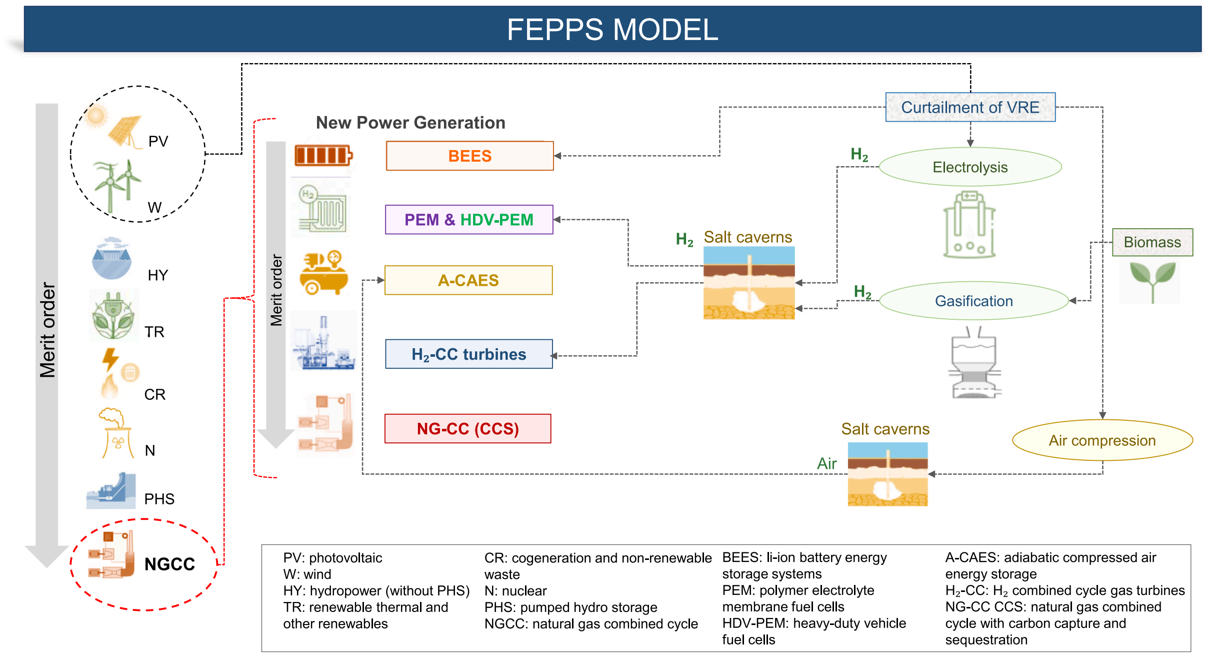

Fig. 1. FEPPS model structure with conventional and new technologies.

(sometimes Spain is considered an "electrical island"). In addition, Spain has well-defined decarbonisation scenarios established by national and European organisations. In this study, FEPPS provides the VRE potential curtailment and its use, the power generation and the capacity factor of current and new technologies (hourly resolution), the storage size and hydrogen needed for electricity, and the emissions reduction and system costs. Finally, the model makes it possible to analyse compliance with climate targets in decarbonisation scenarios.

2. FEPPS model with new technologies (NTs)

2.1. Selection of new technologies

In general, the storage technologies considered in the literature or real grid applications are PHS, CAES, flywheels, supercapacitors, batteries, concentrated solar power (CSP) with thermal energy storage (TES) systems, pumped-heat energy storage, and hydrogen [4]. Batteries and PHS have been studied for short-duration storage and P2G for long-duration energy storage to enable increased VRE penetration [11,18,27,28]. The technologies considered in this study are selected based on the least-cost options with future scenario costs obtained in a techno-economic analysis [4] and those that could play a significant role in the flexibility and stability of the future power system (Note S1). A detailed discussion supporting the selection or exclusion of the new technologies in this study are described in Note S1 of the SI.

FEPPS includes conventional technologies in the selected power system (Spain). Therefore, PHS is a well-developed and mature technology modelled before the new technologies. According to a historical function, the model also projects CSP generation, and its projection includes power generation from storage [29]. Therefore, it is not considered a storage technology by itself [30]. The least-cost technologies (future costs) for 12-h storage include lithium-ion batteries (Li-ion), PHS, A-CAES (adiabatic compressed air energy storage in a salt cavern that depends on thermal energy storage to reheat the air), and vanadium flow batteries [4]. Li-ion and A-CAES are considered for this study. PHS is already included in the model. Vanadium flow battery technology is excluded because, although for 12 h, it is one of the least expensive options, for longer storage duration, its costs increase significantly, and for more than 48 h, it becomes the most expensive technology.

For storage duration longer than 48-h to support high-VRE grids, the least-cost technologies are HDV-PEM/Salt (H_2 production through polymer electrolyte membrane-PEM electrolysis, H_2 storage in a salt cavern, and power generation through heavy-duty vehicle fuel cells), NG-CC/CCS (natural gas combined cycle with 90 % carbon capture and sequestration) and Stat-PEM/Salt (H_2 production through PEM electrolysis, H_2 storage in a salt cavern, and power generation through stationary PEM fuel cell) [4]. Therefore, these technologies are considered for this study. Although H_2-CC/Salt (H_2 production through PEM electrolysis, H_2 storage in a salt cavern, and power generation through a combined cycle) becomes the fourth-least costly technology after 72-h, this technology is also considered in the study because it can provide stability to the grid (synchronous generation), as well as A-CAES. It is worth noting that NG-CC/CCS and hydrogen systems with geologic storage are the lowest-cost and low-carbon technologies for 120-h storage [4]. Fig. 1 shows the structure of the FEPPS model (developed in Visual Basic for Applications: VBA) with conventional and new technologies (including storage) analysed in this study.

2.2. Merit order of new technologies

Models are classified into optimisation and rule-based. Optimisation models generally include the effects of investment decisions in VRE more simply; however, they are more computationally constrained than rule-based models. The latter tend to incorporate more technologies and more complicated functional forms to represent the effects of VRE on the power system [11]. These models have different strengths and limitations; however, a rule-based model allows us to incorporate several technologies with more flexibility and stability constraints [11]. FEPPS is a rule-based and linear power model based on the merit order effect. This merit order approach was followed because it is the natural way prices arise in a free market-based system, such as the electricity system [31]. These approaches were considered as the model aims to obtain the power generation of renewable technologies from historical data and system constraints and not to impose a specific generation of VRE (%) as cost-optimised production models usually do. The unit commitment scheduling is complex to predict because of, for example, other commitments of power plants (heat), power purchase agreements (PPA) [32] or security constraints [33]. Therefore, the merit order is a guide to

Table 1
Merit order of new power generation technologies included in the model (operating and maintenance costs and TRL).

Technology	Place in the merit order for power generation	Fixed O&M (USD/kW-yr)[a]	Variable O&M (USD/MWh)[a]	TRL (SI- Table S2)
Li-ion	1	8.3	3.1	9[b]
PEM fuel cells	2	12.8	1.3	8[c]
HDV-PEM fuel cells	3	12.8	1.3	6–7-8[d]
A-CAES	4	13.5	3.3	5-6[e]
H_2-CC	5	13.6	2.5	R&D needed to raise to the demonstration level[f]
NG-CC (CCS)	6	27.2	5.8	6–9 [g]

[a] [4]. Fixed operating costs will become more relevant for future systems with high shares of VRE since, unlike conventional technologies compensated by their variable operating costs, renewable and storage systems are almost entirely capital and other fixed costs and near-zero variable operating costs. Thus, fixed operating costs are the basis for selecting the merit order of new technologies.
[b] [36].
[c] TRL of fuel cells in industrial and other large-scale stationary use cases [37].
[d] Fuel cells for heavy-duty transport applications include trains, buses, and heavy-duty trucks. The technological Readiness Level (TRL) of fuel cell electric trains is 7, for buses is 8, and for heavy-duty trucks is 6 [38].
[e] [39,40].
[f] Pure H_2 turbines need to be raised to the demonstration level. However, all General Electric (GE) gas turbines can burn hydrogen to some degree (higher TRL ~ 7) up to 50 % H_2. GE is continually developing turbines that allow for greater content [41].
[g] The CCS technology considered is post-combustion chemical absorption (aqueous amine, TRL 6–9) [42].

scheduling power generation technologies based on the marginal operating costs (ranked from lowest to highest cost) and has been used in several studies [11,32].

Power markets based on marginal cost are designed to compensate conventional power plants for their variable operating costs (fuel and variable O&M). However, there is some criticism of the merit order because some factors are not correctly reflected in the long term with high shares of VRE [34]. Fixed operating costs are especially relevant since no power plant operator will build more plants if electricity sales only cover marginal costs. It should be noted that renewable energy is almost entirely capital and other fixed costs and near-zero variable operating costs [35]. Besides, storage technologies are also capital intensive. Therefore, fixed operating costs of the new generation technologies are considered to order electricity dispatch, as shown in Table 1. The merit order to use the curtailment of VRE also matches the order of Table 1, i.e., (1) Li-ion batteries charging, (2) electricity to produce hydrogen through PEM electrolysers and (3) electricity to compress the air in A-CAES.

3. Methodology

FEPPS is a rule-based power system model used to analyse the role of the new storage and generation technologies [26]. FEPPS has a new approach where the residual load is modelled after demand, variable renewable energy, solar thermal and hydropower projections. These projections are based on historical data. The model is tested for Spain, and the technologies generate according to the merit order. The conventional technologies in the model are wind (W), solar photovoltaic (PV), solar thermal (TS), hydropower (HY), renewable thermal (TR), cogeneration and non-renewable waste (CR), nuclear (N), pumped hydro storage (PHS) and natural gas combined cycle (NGCC). The new technologies included are Li-ion batteries, PEM and HDV-PEM fuel cells, A-CAES, H_2-CC turbines, and the final load is met by NGCC with CCS (listed according to the merit order). The model has an hourly resolution and provides the power exchanged with international interconnections (France, Portugal, Morocco) and the Balearic link and PHS consumption. Power generation is constrained according to flexibility parameters for TR, CR, and N (minimum and maximum power outputs, adjustments to the number of plants operating each day to set the minimum load, ramp-up and ramp-down rates). NGCC is the latest technology that meets demand in the system due to its high flexibility. Flexibility constraints were obtained from theoretical and historical parameters so that the power variations in the system challenging to predict (scheduled shutdowns, real-time services or exceptional events) could be captured to a certain extent. Fig. 2 shows the flowchart of the model. The extended flowchart is presented in Figure S5, and further details of flexibility constraints, considered in our previous study, can be found elsewhere [26,29].

According to the following methodology, the new technologies replace the power generation from combined cycle power plants. However, it is important to analyse the variation of the installed capacity of conventional technologies to explore the best alternatives to reduce emissions and find the best scenarios to incorporate new technologies. The substitution of the combined cycle by new technologies depends on the curtailment and the load that can be replaced without affecting inertia.

This study analyses the role of NTs in the future power system and obtains the storage required for different climate conditions. This storage depends on (i) the power generation from NGCC that can be replaced, (ii) the calculation of the hydrogen/air required for this generation, and (iii) the hydrogen/air produced from the curtailment and the estimation of the hydrogen needed from other sources. The curtailment of VRE is obtained (as a result of the model) after the flexibility and stability restrictions are applied, i.e., unlike other studies, no assumptions (ranges) are made. VRE generation is based on real data (historical) that allow capturing their variability in the future power system. Therefore, to maintain and capture this variability, storage is modelled according to the hydrogen produced from VRE curtailment (via electrolysis) and other sources, and the hydrogen consumed according to the system's needs.

3.1. Hydro climate conditions (DRY, NORMAL, and WET years)

TYNDP (Ten Year Network Development Plan) projections, developed by the European Network of Transmission System Operators (ENTSO-E), are based on different hydro-climate conditions. These are DRY, NORMAL, and WET obtained from climate variations of 1982, 1984 and 2007, respectively [24]. The power system was modelled in a previous study based on data from a DRY year (2017) [26,29]. In this study, we also modelled 2030 and 2040 scenarios based on WET and NORMAL years from the Spanish historical data of 2018 and 2019, respectively. It should be noted that coal-fired power plants were previously considered, but they have been excluded in this study due to the expected total closure by 2030 [43]. In addition, the entire combined cycle (flexible and inflexible) was modelled only as the flexible combined cycle for this study.

It should be noted that FEPPS considers the same or approximate total demand and installed capacities for conventional generation technologies as TYNDP. The demand for the different scenarios by 2030 and 2040 is described in Table 2. The installed capacities of the generation technologies and interconnections are the same for the three climate years (Table 3). The historical demand and generation (hourly resolution data) of wind, solar photovoltaic, solar thermal, hydro, international interconnections and Balearic link needed for the modelling as inputs were obtained from real-time data provided by the power system operator (*Red Eléctrica de España*: *REE*) [44].

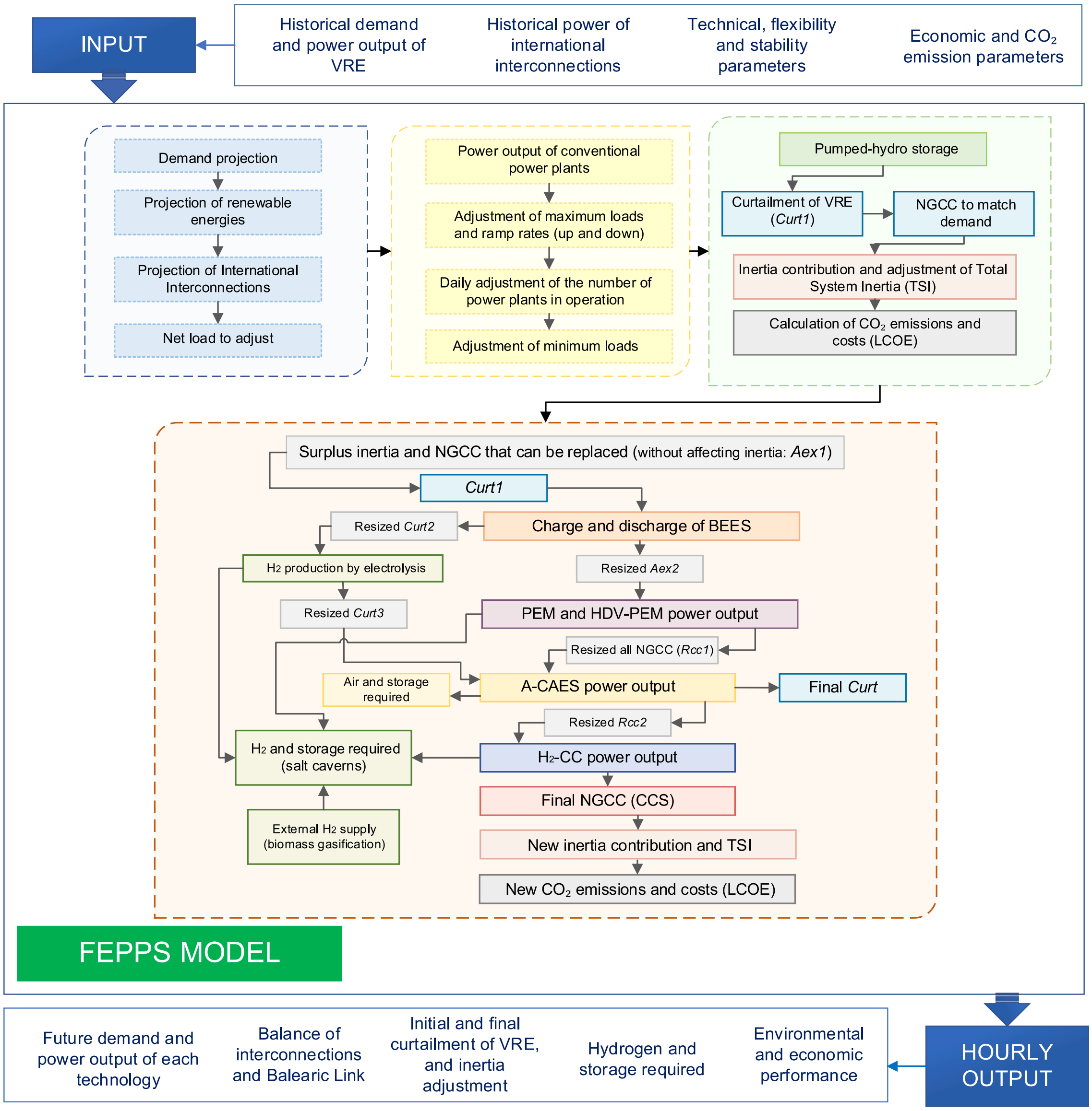

Fig. 2. Flowchart of the FEPPS model (modified from [26]). The section in the orange box corresponds to the present study, including the new technologies. The extended flowchart of this study is provided in Figure S5.

Table 2
Demand for 2030 and 2040 according to hydro-climate conditions.

	DRY-2030	NORMAL-2030	WET-2030	DRY-2040	NORMAL-2040	WET-2040
Annual demand (GWh)	281 765	283 846	281 935	290 331	292 424	290 503

3.2. Variations in installed capacity of conventional technologies

Before including new storage and generation technologies in FEPPS, the installed capacities of conventional technologies were varied to assess the effect on emissions and LCOE (sensitivity analysis). As the aim is to reduce emissions, the variations for increasing or decreasing installed capacity will depend on this reduction. For instance, the increase in installed capacity of wind, solar photovoltaic and solar thermal and the reduction of nuclear and cogeneration and non-renewable waste were considered. We also considered the reduction of CR emissions by assuming the use of renewable energy sources (-20 % and −30 %). NTs

Table 3
Installed capacities of conventional technologies for 2030 and 2040 [26].

Technology (MW)	2030	2040
Wind	31 000	51 000
Solar PV	40 000	77 000
Solar Thermal	2304	3363
Nuclear	7117	3050
NGCC	38 241	46 440
Hydro	23 050	24 920
PHS	8280	10 150
CR	8500	8500
TR	2550	2550
Interconnection with France (import)	8000	9000
Interconnection with France (export)	8000	9000
Interconnection with Portugal (import)	3500	4000
Interconnection with Portugal (export)	4200	4700
Interconnection with Morocco (import)	700	1500
Interconnection with Morocco (export)	900	1500
Balearic link (export)	400	400

Table 4
Parameters of BESS (Li-ion).

Parameter	Symbol	Value
Total installed capacity (MW)	*Bic*	2500[a]
Installed capacity of each BESS (MW)	*Bc*	500[b]
Number of systems (No.)	*Nbs*	5[c]
System round trip efficiency (%)	*Bef*	90[d]
System storage duration (hours)	*Stb*	4[e]
System energy capacity (MWh)	*Cb*	2000[f]

[a] Input (section 4.2).
[b] Assumed according to Note S2 of the SI.
[c] Calculated according to the total installed capacity.
[d] [46].
[e] Assumed.
[f] Calculated based on storage duration and the installed capacity of each system.

were included in the scenarios with the installed capacities that allowed for the greatest emission reductions.

3.3. Initial installed capacity of new storage and low-carbon technologies

One of the model inputs is the installed capacity of each new technology. To determine these values, a sensitivity analysis was performed in a long-term scenario (NORMAL year 2040). The initial installed capacity for each NT is detailed in Note S2 of the SI. Sensitivity considers the effect of increased capacity on system emissions. The installed capacity selected for all scenarios is that from which emissions are not significantly reduced, and the LCOE does not rise considerably.

3.4. New generation and storage technologies

The methodology for modelling the power generation of the new technologies is described below. Table S1 of the SI details all the parameters and variables used in FEPPS. Figure S5 of the SI includes the FEPPS code flowchart with new technologies. We use index *j* as the hour counter and *hoursc* denoting the hours in a year (Table S1).

3.4.1. Battery energy storage systems

Lithium-ion battery energy storage systems have priority for the use of VRE curtailment and priority for electricity dispatch. The model identifies the first hour of the year when curtailment (*Curt1*) occurs and starts charging the BESS. We assumed that each system is charged (*Bat*) for 4 h up to its energy capacity (Eqs. (1) and (2)). Therefore, each system has a storage duration of 4 h (the amount of time the system can discharge at its power capacity). However, after charging, we assume a discharge for the next 12 h (more flexibility), considering that this technology has to adapt to the needs of the grid (generation after conventional technologies), and each BESS is composed of a set of batteries. This discharge (*Batd*) occurs up to the system energy capacity and according to the combined cycle load that can be replaced without affecting the system inertia (*Aex1*) (Eqs. (3) and (4)). Accordingly, it should be noted that the battery charge and discharge depend on the curtailment and *Aex1*, respectively; thus, the system is not always fully charged or fully discharged. After the discharge, the model again identifies curtailment to charge the system until all the year's hours are covered. The equations to obtain *Aex1* and *Curt1* from the inertia variation and the critical inertia level (CIL) are described in Note S3 of the SI.

$$Curt1_{(j)}(MWh) \geq Bat_{(j)}(MWh) \leq Bc(MW) \quad \forall j \in hoursc \tag{1}$$

$$\sum_{i=1}^{4} Bat(MWh) \leq Cb(MWh) \tag{2}$$

$$Aex1_{(j)}(MWh) \geq Batd_{(j)}(MWh) \leq Bc(MW) \quad \forall j \in hoursc \tag{3}$$

$$\sum_{i=1}^{12} Batd \leq \left(\sum_{i=1}^{4} Bat\right) \cdot Bef(\%) \tag{4}$$

Table 5
Parameters of PEM and HDV-PEM fuel cells.

Parameter	PEM	Symbol	HDV-PEM	Symbol
Total installed capacity (MW)[a]	2000	*Fc*	2000	*Fs*
Installed capacity of each system (MW)[b]	500	*Pcp*	100	*Pcv*
Number of systems (No.)[c]	4	*Npm*	20	*Nvpm*
Electrical efficiency (LHV basis) (%)[d]	60	*Hre*	60	*Hre*
Hydrogen low heating value (MWh/t)[e]	33.3	LHV_{H2}	33.3	LHV_{H2}

[a] Input (section 4.2).
[b] Assumed according to Note S2 of the SI.
[c] Calculated according to the total installed capacity.
[d] [48].
[e] [49].

Once one system generates electricity, the other begins until all systems dispatch. The characteristics of the BESS used in the model are detailed in Table 4. Other parameters did not constrain batteries due to the time resolution of the model and the fact that they are highly flexible (they do not have a minimum stable level and provide a high ramp up and down in seconds either for charge or discharge) [45].

3.4.2. PEM and HDV-PEM fuel cells

The model identifies the remaining load (*Aex2*) to be covered by other technologies without affecting inertia after BESS power generation. PEM and HDV-PEM fuel cells dispatch (*Pem* and *Vpem*) according to *Aex2 and Aex3, respectively,* and the total installed capacity for each system (*Fc* and *Fs*) (Eqs. (5) and (6)). Since PEM systems are flexible (minimum load of 5 % by 2017 and 0 % expected by 2025 and high ramp rates) [38,47] and each system comprises a set of fuel cells, we have considered complete flexibility for the model's hourly resolution.

The differences between these two technologies are the costs, as the capital costs of HDV-PEM systems would be lower (as mentioned in Note S1), and the priority dispatch of PEM, as described in Table 1. After fuel cells generation, the model identifies the hydrogen need for power generation according to Eqs. (7) and (8).

$$Aex2_{(j)}(MWh) \geq Pem_{(j)}(MWh) \leq Fc(MW) \quad \forall j \in hoursc \tag{5}$$

$$Aex3_{(j)}(MWh) \geq Vpem_{(j)}(MWh) \leq Fs(MW) \quad \forall j \in hoursc \tag{6}$$

$$Hpem_{(j)}(t) = \frac{Pem_{(j)}(MWh)}{Hre(\%)\cdot LHV_{H_2}\left(\frac{MWh}{t}\right)} \quad \forall j \in hoursc \tag{7}$$

$$Hvpe_{(j)}(t) = \frac{Vpem_{(j)}(MWh)}{Hre(\%)\cdot LHV_{H_2}\left(\frac{MWh}{t}\right)} \quad \forall j \in hoursc \tag{8}$$

The parameters of these technologies are described in Table 5.

3.4.3. Hydrogen production from curtailment

The curtailment is recalculated after charging the BESS. It should be noted that curtailment is recalculated throughout the study. It is then used for hydrogen production by electrolysis (*Hpe*), according to Eq. (9). This hydrogen is consumed by PEM, HDV-PEM fuel cells and H_2-CC turbines. Using PEM electrolysers, the electricity consumption for hydrogen production is 50MWh/t (*Hel*) [50]. An installed capacity of 4000 MW (*Cel*) is expected in Spain by 2030 [51], and we assume 8000 MW by 2040 (500 MW systems). PEM electrolysers are highly flexible (start time of 1 s – 5 min, ramp up/down 100 %/second and shut down in seconds) [47]; therefore, no further constraints were included here.

$$Curt2_{(j)}(MWh) \geq Hpe_{(j)}(t) = \frac{Curt2_{(j)}(MWh)}{Hel\left(\frac{MWh}{t}\right)} \leq Cel(MW) \quad \forall j \in hoursc \tag{9}$$

Table 6
Parameters of A-CAES.

Parameter	Symbol	Value
Total installed capacity (MW)	*Cae*	6900 [a]
Installed capacity of each system (MW)	*Cas*	300 [b]
Number of systems (No.)	*Ncs*	23 [c]
System round trip efficiency (%)	*Cef*	65 [d]
Energy per ton of air (MWh/t)	*Ecae*	0.11 [e]
Air density (kg/m^3)	ρ_{air}	55.7 [f]
Standard volume of the cavern (m^3)	*Vstc*	300 000 [g]
Inertia constant (s)	*ac*	4.97 [h]

[a] Input (section 4.2).
[b] Assumed according to Note S2 of the SI.
[c] Calculated according to the total installed capacity.
[d] [4].
[e] A simulation of an A-CAES system producing 700 MWh and consuming 6464 tons was used as a reference [52]. *Ecae* is obtained by dividing these values.
[f] The density was calculated at 50 bar cavern pressure and 40C [52].
[g] [52].
[h] The inertia constant of the combined cycle is assumed for this system [26].

3.4.4. Adiabatic compressed air energy storage (A-CAES)

A-CAES is the third technology that uses the remaining curtailment in the system. The power output of this technology (*Pcae*) is conditioned by the curtailment and the total combined cycle that can be replaced (*Rcc1)*. Here, the total CC is considered, and not only the CC load committed to inertia (Eq. (10) and Eq. (11)). It is assumed that ambient air is compressed and stored under pressure in underground salt caverns. When electricity is needed (*Rcc1*) the air is heated and expanded in turbines. Therefore, this system provides inertia to the grid. Once the power generation is obtained, the air required is calculated according to Eq. (12). The parameters used in this technology are detailed in Table 6. A-CAES is a flexible technology that operates with regular cycling. Its operation with salt caverns is considered well-suited to provide higher flexibility due to its high injection and withdrawal rates; therefore, no further constraints were considered [21].

$$Curt3_{(j)}(MWh) \geq Pcae_{(j)}(MWh) = Curt3_{(j)}(MWh)\cdot Cef(\%) \leq Cae(MW) \quad \forall j \in hoursc \tag{10}$$

$$Pcae_{(j)}(MWh) \leq Rcc1_{(j)}(MWh) \quad \forall j \in hoursc \tag{11}$$

$$Acae_{(j)}(t) = \frac{Pcae_{(j)}(MWh)}{Ecae\left(\frac{MWh}{t}\right)} \quad \forall j \in hoursc \tag{12}$$

The maximum amount of air required in one hour ($Acae_{max}$) of the year and the energy per ton of air (*Ecae*) allow to obtain the maximum storage needed (*Pac*) (Eq. (13)). The geometric volume for storage is obtained from $Acae_{max}$ and the storage density (ρ *air*) (Eq. (14)). Finally, the number of caverns (*Nsc*) is calculated from a standard volume (*Vstc*) (Eq. (15)).

$$Pac(GWh) = \frac{Acae_{max}(t)\cdot Ecae\left(\frac{MWh}{t}\right)}{1000} \tag{13}$$

$$Vc\left(m^3\right) = \frac{Acae_{max}(t)\cdot 1000}{\rho_{air}\left(\frac{kg}{m^3}\right)} \tag{14}$$

$$Nsc = \frac{Vc(m^3)}{Vstc(m^3)} \tag{15}$$

3.4.5. Hydrogen combined cycle turbines (H_2-CC)

Hydrogen turbines generate electricity (*Tur*) according to the total combined cycle load that can be replaced (*Rcc2-recalculated*) (Eq. (16)). The same inertia constant of natural gas combined cycle power plants is assumed. According to H_2-CC generation, the amount of hydrogen required is calculated (Eq. (17)). Since there is still room for improvement in using pure hydrogen in the turbines, we assume mixing with nitrogen as diluent. The parameters used in this technology are in Table 7. Gas turbines provide dispatchable and flexible power generation, and future gas turbines using H_2 will also need this flexibility to deal with grid fluctuations.

Table 7
Parameters of H_2-CC turbines.

Parameter	Symbol	Value
Total installed capacity (MW)	*Cht*	9000 [a]
Installed capacity of each system (MW)	*Cat*	500 [b]
Number of systems (No.)	*Ntu*	18 [c]
Electrical efficiency (LHV basis) (%)	*Hrt*	0.57 [d]
Hydrogen low heating value (MWh/t)	LHV_{H2}	33.3 [e]

[a] Input (section 4.2).
[b] Assumed according to Note S2 of the SI.
[c] Calculated according to the total installed capacity.
[d] [53].
[e] [49].

Table 8
Parameters of salt cavern storage.

Parameter	Symbol	Value
Standard cavern volume (m^3)	*Vsth*	500 000 [a]
Hydrogen density (kg/ m^3)	ρH_2	10 [a]
Operating pressure (bar)	–	150 [b]
Average depth (m)	–	1200 [c]
Cushion gas (%)	–	30 [d]
Hydrogen losses (% per year)	*Hlo*	8.33 [e]

[a] [57].
[b] The pressure is 130 bar for a density of 10 kg/m^3 and 25C (thermodynamic method: Peng Robinson). However, if we assume a pressure drop of 20 bar during injection, the pressure should be 150 bar to keep the density.
[c] [58].
[d] [22].
[e] The annual volume loss rate is in the order of 0.03 % per year (30 m^3 per year in a 100 000 m^3 opened cavern (1000 m depth)) [59,60]. For our standard volume, this loss would be 150 m^3. We add compression losses as a fraction of the LHV_{H2} (%) for underground storage of 8.3 % [50]. From the total annual hydrogen required for PEM, HDV-PEM and turbines, we calculate the tons equivalent of 8.33 % losses. These 8.33 % equivalent tons are divided by the year's hours and the result is the value used in Eq. (18).

$$Cht(MW) \geq Tur_{(j)}(MWh) \leq Rcc2_{(j)}(MWh)\forall j \in hoursc \tag{16}$$

$$Htur_{(j)}(t) = \left(\frac{Tur_{(j)}(MWh)}{Hrt(\%)\cdot LHV_{H_2}\left(\frac{MWh}{t}\right)}\right) \quad \forall j \in hoursc \tag{17}$$

3.4.6. Hydrogen total needed and hydrogen storage

The total hydrogen required (*Htn*) for electricity generation is assumed to come from storage in underground salt caverns. The annual volume loss rate in a salt cavern and compression losses are added to this requirement (*Hlo*) (Eq. (18)); see the details in Table 8. The annual difference (*Hd*) between *Htn* and the hydrogen produced by electrolysis (*Hpe*) (Section 3.4.3) is divided by the total hours of the year to obtain the estimated external hydrogen supply. For this study, we assumed biomass gasification (*Hga*) to produce this external hydrogen according to Eqs. (19) and (20). A hydrogen yield of 0.08 t H_2/t biomass (steam gasification of sawdust wood) was assumed to calculate the biomass requirement [54]. The total installed capacity of biomass gasification for hydrogen production is calculated assuming a LHV_b of 18.338 GJ/t (pine sawdust) [55], i.e., 5.094 MWh/t, and 400 MW_{th} plants. The hydrogen produced by electrolysis and biomass obtained in the last hour of the year is assumed to be that of the first hour.

$$Htn_{(j)}(t) = Hpem_{(j)}(t) + Hvpe_{(j)}(t) + Htur_{(j)}(t) + Hlo(\%) \quad \forall j \in hoursc \tag{18}$$

$$Hd_{(j)}(t) = Htn_{(j)}(t) - Hpe_{(j)}(t) \quad \forall j \in hoursc \tag{19}$$

$$Hga_{(j)}(t) = \frac{\sum_{i=1}^{hoursc} Hd}{hoursc} \quad \forall j \in hoursc \tag{20}$$

The model allows for simulating the hydrogen flow in storage (*Hst*). This flow is calculated for each hour as the charges (*Hpe* and *Hga* denoted as $\dot{Hst}_{in}$) and discharges (*Htn* denoted as $\dot{Hst}_{out}$) are performed according to Eq. (21).

$$Hst_{(j)}(t) = \dot{Hst}_{in}(t) - \dot{Hst}_{out}(t) \quad \forall j \in hoursc \tag{21}$$

It is worth mentioning that gaseous hydrogen can be stored in pressurised steel tanks and underground reservoirs such as salt caverns and pipelines [50]. When dealing with significant amounts of hydrogen, pressurised tanks or liquid vessels are not enough due to their capacity; therefore, large-scale storage in underground storage facilities such as salt caverns, depleted natural gas reservoirs, and aquifers have been addressed [56]. Nevertheless, salt caverns are considered the most suitable solution due to the low investment costs, high thickness and low need for cushion gas [50].

The methodology developed by Fichtner [57], which assesses technologies that show potential for grid-scale energy storage in Lower Saxony (Germany), is used to calculate the storage and the number of caverns required in future scenarios. We also apply this methodology to calculate the required caverns for A-CAES (Section 3.4.4). A geometric volume and a storage density need to be assigned to determine the storage required (TWh) [57]. Depending on the depth, the storage density varies between 8 and 11 kg of working gas per m^3 of the cavity. However, an average storage density of 10 kg/m^3 and an average standard volume of 500 000 m^3 were considered. In our study, the same density (ρH_2) and average standard volume (*Vsth*) were assumed (see Table 8).

$$Nsi_{(j)}(MWs) = inertia\ contribution\ of\ existing\ technologies - previous\ NGCC\ inertia + ci_{cae} + ci_{ht} + nci_{cc} \quad \forall j \in hoursc \tag{28}$$

The maximum storage needed (*Pah*) can be obtained from the working gas (*Gt*) and the hydrogen lower heating value LHV_{H2}. In our study, the working gas is equivalent to the maximum amount of hydrogen remaining in storage in one hour of the year (Hst_{max}) (Eq. (22)). The working gas and the storage density (ρH_2) are needed to calculate the geometric volume (*Vh*). Finally, to calculate the number of caverns (Nhc), both the standard volume and the one calculated are needed (Eq. (23) and Eq. (24)).

$$Pah(GWh) = Hst_{max}(t) \cdot LHV_{H_2}\left(\frac{MWh}{t}\right) \tag{22}$$

$$Vh(m^3) = \frac{Hst_{max}(t) \cdot 1000}{\rho_{H_2}\left(\frac{kg}{m^3}\right)} \tag{23}$$

$$Nhc = \frac{Vh(m^3)}{Vsth(m^3)} \tag{24}$$

3.4.7. Natural gas combined cycle NG-CC (CCS) and new system inertia

NGCC power generation is recalculated (*Rcc3*) by subtracting from the initial combined cycle the NTs power generation. The new technologies that contribute inertia to the system are A-CAES (ci_{cae}), hydrogen turbines (ci_{ht}), and combined cycle gas turbines (nci_{cc}). The inertia constant for these technologies (*aci, tci and cci*) is equivalent to that of the combined cycle (4.97 s). The inertia contribution is calculated according to Eqs. (25), (26) and (27). The new system inertia is calculated according to Eq. (28).

$$ci_{cae(j)}(MWs) = Pcae_{(j)}(MWh) \cdot aci \quad \forall j \in hoursc \tag{25}$$

$$ci_{ht(j)}(MWs) = Tur_{(j)}(MWh) \cdot tci \quad \forall j \in hoursc \tag{26}$$

$$nci_{cc(j)}(MWs) = Rcc3_{(j)}(MWh) \cdot cci \quad \forall j \in hoursc \tag{27}$$

Table 9
CO_2 equivalent emissions of new generation technologies.

Technologies	Emission factor (kg CO_2/MWh)
Li-ion	33[a]
PEM fuel cells	38[a]
HDV-PEM fuel cells	38[a]
A-CAES	52.8[b]
H_2-CC	5.96[c]
NG-CC / NG-CC (CCS)	(-)[d]

[a] [62].
[b] [63].
[c] CO_2 equivalent emissions corresponding to nitrous oxide (1 kg N_2O = 298 kg CO_2 equivalent; 0.02 kg N_2O/MWh) [64,65].
[d] The methodology used in [26] for flexible CC mode of operation is considered. In addition, we assume 90% carbon capture and sequestration [4] for NGCC and 85% for cogeneration and non-renewable waste plants.

3.5. CO_2 equivalent emissions

Emissions are calculated by multiplying the power output by the emission factor of each technology. The life cycle emission factors of the new technologies are given in Table 9. The details on the conventional technologies' emission factor, is at reference [26] as the same methodology is used here. Hydrogen-related emissions have not been included in this study. However, it is worth mentioning that analysing the global warming impact of hydrogen emissions for a future developed hydrogen economy is raising attention (i.e., hydrogen leaks to the atmosphere), as recently discussed in [61].

3.6. Levelized cost of energy (LCOE)

The system costs are calculated according to [26]. The power generation is multiplied by the LCOE (obtained according to the capacity factor of the generation technologies). The LCOE of the new technologies is obtained according to the values presented in [4] for different capacity factors (future costs for 120 h of storage). Since three values are given for three capacity factors according to their sensitivity analysis, we assume ranges and an LCOE for each range, as shown in Table 10. The LCOE used in that study is in 2018 USD/MWh, so the Euro foreign exchange average for 2018 (USD 1 = € 0.8476) was used [66]. The final annual LCOE is calculated as a weighted average.

4. Results and discussion

The initial installed capacities of conventional power plants and interconnections are equal or approximate to the TYNDP (reports

Table 10
LCOE of new generation technologies.

Technologies	Capacity factor (%)	LCOE (€/MWh)[4]	Capacity factor (%)	LCOE (€/MWh)[4]	Capacity factor (%)	LCOE (€/MWh)[4]
Li-ion	>39	362	39–29	411	<29	477
PEM fuel cells/salt system[ab]	>14	150	14–4	175	<4	265
HDV-PEM fuel cells/salt system[ac]	>14	135	14–4	152	<4	212
A-CAES/salt system[d]	>24	258	24–14	312	<14	405
H_2-CC /salt system[ae]	>14	175	14–4	214	<4	348
NG-CC / NG-CC (CCS)[f]	–	–	–	–	–	–

[a] LCOE was taken as a function of the capacity factor of electricity generation for the entire system (in this case, H_2 production, storage and power generation) according to [4]. The price of hydrogen produced by electrolysis is USD 2.41/kg (break-even price) [4]; while a techno-economic analysis in [68] shows similar hydrogen selling prices of down to € 2.7/kg for hydrogen from biomass gasification. Therefore, the same LCOE was assumed for both production pathways in this study. [4].

[b] Hydrogen production through PEM electrolysis or gasification, power generation through a stationary PEM fuel cell, and hydrogen storage in a salt cavern.

[c] Hydrogen production through PEM electrolysis or gasification, power generation through heavy-duty vehicle fuel cells, and hydrogen storage in a salt cavern.

[d] Adiabatic compressed air energy storage in a salt cavern and power generation.

[e] Hydrogen production through PEM electrolysis or gasification, power generation through the combined cycle, and hydrogen storage in a salt cavern.

[f] The methodology used in [26] according its Fig. 5 (LCOE vs capacity factor) is considered for conventional technologies. For NG-CC (CCS), we add 50% to the previous value (CCS technologies increase the cost of electricity by about 50%) [67].

approved at a European level) [24]. The historical hourly data were obtained from *REE* [44]. A sensitivity analysis was performed by varying the Rate of Change of Frequency (ROCOF) levels from 3 Hz/s to 0.5 Hz/s (0.1 Hz/s steps) to identify the ROCOF level at which there are no power grid failures. As described in Tables S4 and S5, the results were 1 Hz/s for all scenarios but 1.1 Hz/s for the WET-2030 scenarios. The CIL level to be met depends on ROCOF, as shown in Figure S1. Finally, the base scenarios were obtained from these data, along with the power system flexibility and stability constraints.

A sensitivity analysis was performed on these base scenarios (before incorporating the new technologies) to determine the increase or reduction in the capacity of existing technologies that would allow a greater reduction in emissions without a significant cost increase. These sensitivities were carried out for each year and climate condition (see the main results in Fig. 3). In this way, the most optimal scenarios to integrate and analyse the role of new technologies were selected. Accordingly, considering the most optimal scenarios (four in total: base and three most optimal) for each climate condition per year, 2030 and 2040, i.e., 24 scenarios were obtained to include the new technologies. These variations allow analysing differences for each climate condition regarding renewable share, capacity factors, use of curtailment, hydrogen produced and required, biomass demanded, the storage required (number of salt caverns), and emissions and costs, as explained below.

4.1. Lowest emission scenarios

The variation in installed capacity of conventional technologies (Table 11) allows for obtaining the lowest-emission scenarios before the incorporation of NTs (bold scenarios in Fig. 3). An additional 20 % increase in wind and solar PV installed capacities caused a slight increase in emissions due to the rise of the NGCC power generation to adapt to their variability and meet demand. Only in the NORMAL-2030 and DRY-2040 scenarios did emissions decrease by −0.6 % and −0.3 %, respectively, and the LCOE increased in all scenarios (3–5 %). Therefore, no further installed capacities of these technologies were considered.

Conversely, when considering greater solar thermal capacity, emissions decreased in all scenarios due to the reduction of NGCC generation. Because of this effect, 3xST and 4xST scenarios were considered. In 4xST scenarios, up to 8 % emissions reduction by 2030 and 11 % by 2040 were obtained, with a maximum LCOE increase of 7 %. In the case of nuclear, a capacity reduction from 7117 to 3050 MW by 2030 and 0 by 2040 was considered. However, in all scenarios, a substantial emissions increase occurs (35 % by 2030 and 19 % by 2040 – because of higher NGCC generation), and LCOE increases by 5 %. Therefore, no additional nuclear reductions were considered.

On the other hand, a reduction in emissions is achieved in all scenarios when considering half of the cogeneration and non-renewable waste (CR) capacity since variable renewable (W: wind and solar PV) and nuclear generation increases even though NGCC generation also increases. The maximum reduction was 8 % and 5 % by 2030 and 2040, respectively. Here, the LCOE increases by a maximum of 2 % and decreases in other scenarios (up to −1%). Based on these results, combined scenarios such as (-CR 3xST), (-CR 3xST + W), and (-CR + W) were also modelled. In these combinations, an increase in wind is considered because combining it with lower CR and higher solar thermal allows for further emission reductions.

For cogeneration, a reduction in emissions of 20 % and 30 % was assumed due to the use of renewable energy sources. The two most optimal scenarios per climate condition were selected (considering the 30 % reduction). Since they generally coincide, if there is an additional low-emission scenario for the same year, it is also modelled (see Table 12). Initial scenarios for each climate condition (no variations) were also considered; therefore, 12 scenarios for each year (4 per climate condition) were modelled, including the NTs. The selected scenarios will be abbreviated as follows:

1. Initial scenarios: SC1.
2. 4xST: SC2.
3. -CR 3xST + W: SC3.
4. -CR 3xST: SC4.

Table 13 shows the overall results for each year (see also Note S4 of the SI). The detailed results by scenario can be found in Table S4 and Table S5 of the SI.

Several studies have analysed the flexibility required to achieve a high share of VRE in the power system. Flexibility requirements have been addressed for shares greater than 30 % of variable renewable energy [27,69]. Also, highly flexible systems have been considered with shares between 50 % and 80 % of variable renewable generation (curtailment of<10 %) [70] or even up to 100 % [70,71]. These studies are generally based on optimisations that analyse how different flexibility mechanisms allow achieving the expected VRE shares, decarbonisation targets and cost optimisation. On the other hand, as our model ensures stability and flexibility, the resulting VRE share is much lower than that considered in other studies or predicted by national and international organisations. Emissions and costs in our model are also a result. For example, Spain is predicted to have a VRE share of more than 50 % by 2030 [43,72] and over 65 % by 2040 [72], which would enable climate targets to be met. However, these VRE penetrations are far from the shares achieved in our study, as shown in Table 13.

In our study, no scenario in 2030 meets the Paris target of 75–80 $kgCO_2/MWh$ (even considering 20 % and 30 % reduction in CR emissions due to the use of renewable sources). In 2040, emissions are higher

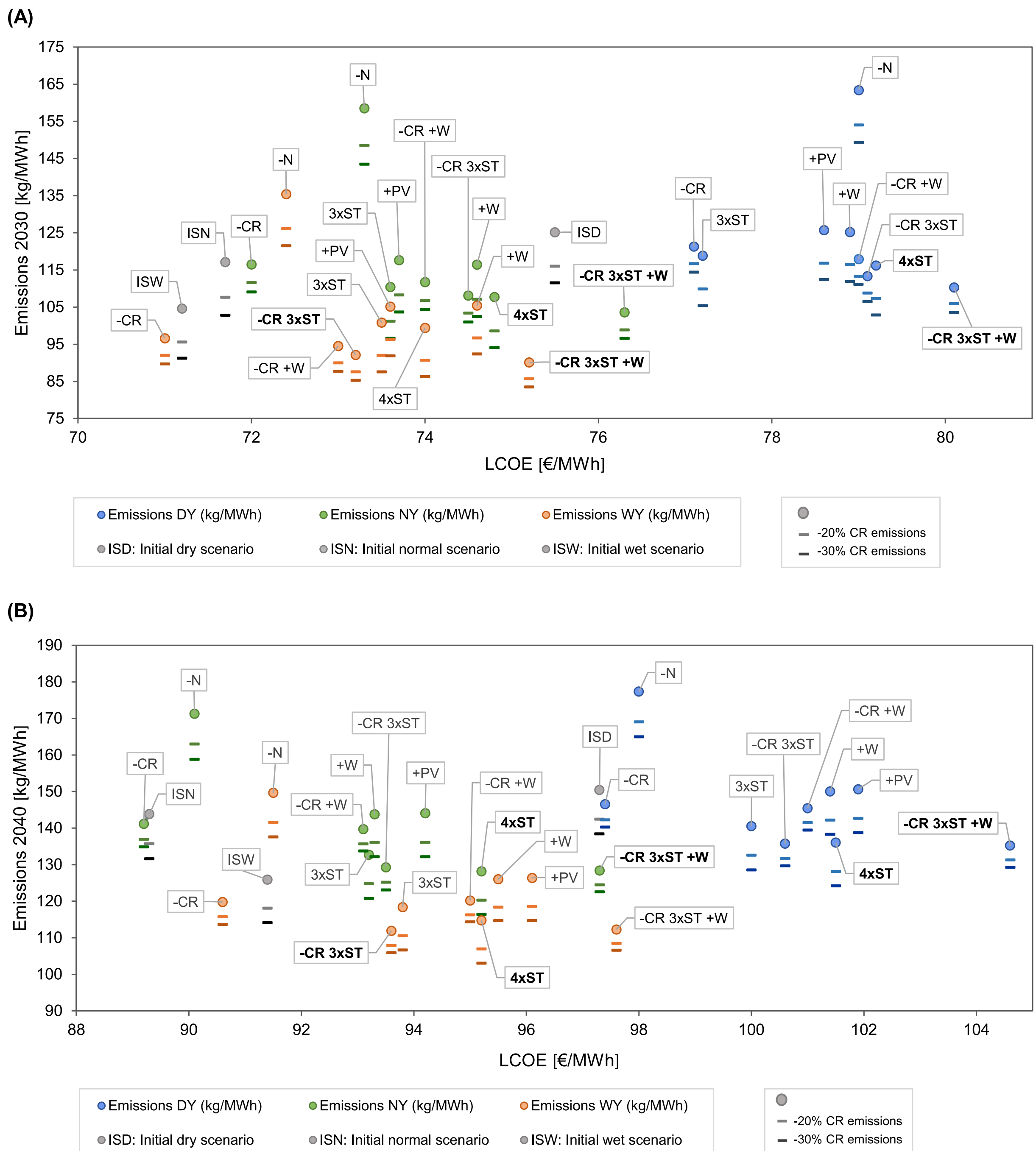

Fig. 3. Emissions for different variations of installed capacity for (A) 2030 and (B) 2040. The bold scenarios show the lowest emissions scenarios achievable without the incorporation of new technologies (storage and low-carbon).

than in 2030 and significantly farther from the Paris target (which is between 0 and 5 $kgCO_2$/MWh). The LCOE also increases in 2040 due to increased curtailment (lower overall capacity factor for VRE, solar thermal, and nuclear, which increases system costs). The highest LCOE occurs in the DRY years, consistent with the highest levels of curtailment and emissions, and the lowest LCOE is in the WET year for 2030 and NORMAL for 2040. Despite the increase in the LCOE, in 2030, no scenario exceeds € 80/MWh, which is below the reference value (€ 85/MWh) that allows remaining on track to decarbonisation towards 2030 for new builds [73]. The LCOE in 2040 is between € 89–105/MWh; therefore, it is around the reference value obtained in our previous study, € 102/MWh [26]. As can be seen in Fig. 1 and Table 12, all the scenarios that allow for the most significant emission reductions involve an increase in solar thermal capacity. Therefore, it would be interesting to first consider increasing solar thermal capacity, then reducing CR and increasing wind capacity (jointly) before incorporating new technologies.

4.2. Installed capacity of new technologies

The increase in the installed capacity of the new technologies leads to a reduction in emissions, as shown in Fig. 4. A NORMAL scenario for the long term was considered for the sensitivity analysis, and the initial installed capacity for each NT is detailed in Note S2 of the SI. A-CAES and H_2-CC show the most significant reduction. Therefore, the change in LCOE for these technologies was further analysed. The reduction of

Table 11
Initial installed capacity and variation for DRY, NORMAL, and WET years for 2030 and 2040.

Technology	Initial capacity 2030 (MW)	Variation of initial capacity 2030 (MW)	Initial capacity 2040 (MW)	Variation of initial capacity 2040 (MW)
Wind	31 000	(+20 %) 37 200	51 000	(+20 %) 61 200
Solar PV	40 000	(+20 %) 48 000	77 000	(+20 %) 92 400
Solar Thermal	2034	(3xST) 6912	3363	(3xST) 10 089
Solar Thermal	2034	(4xST) 9216	3363	(4xST) 13 452
Nuclear	7117	(-43 %) 3050	3050	0
CR	8500	(-50 %) 4250	8500	(-50 %) 4250

Table 12
Selected scenarios to include new technologies.

Initial Scenarios	Most optimal scenarios		Additional scenarios
	1st	2nd	
DRY 2030	4xST	-CR 3xST + W	-CR 3xST
NORMAL 2030	4xST	-CR 3xST + W	-CR 3xST
WET 2030	-CR 3xST + W	-CR 3xST	4xST
DRY 2040	4xST	-CR 3xST + W[a]	-CR 3xST
NORMAL 2040	4xST	-CR 3xST + W[a]	-CR 3xST
WET 2040	4xST	-CR 3xST	-CR 3xST + W

[a] The second scenario with the lowest emissions is 3xST; however, since it is the same technology as the first scenario 4xST, the following is considered.

Table 13
Overall results for 2030 and 2040 before including new technologies.

Results	2030[a]	2040[a]
Total curtailment of VRE (%)	15–35	40–57
Share of RES (%)	46–57	52–62
Share of VRE (%)	30–35	36–40
Capacity of NGCC (MW)	41 855	49 023
CO_2 equivalent emissions ($kgCO_2$/MWh)	90–125	112–150
CO_2 equivalent emissions (-20 % CR emissions)[b] ($kgCO_2$/MWh)	86–116	107–142
CO_2 equivalent emissions (-30 % CR emissions)[c] ($kgCO_2$/MWh)	84–112	103–138
LCOE (€/MWh)	71–80	89–105

[a] Ranges show the lowest and highest values obtained in the scenarios. Results for each scenario are presented in Table S4 and Table S5 of the SI.
[b] 20% reduction in CR emissions assuming the use of renewable energy sources.
[c] 30% reduction in CR emissions assuming the use of renewable energy sources.

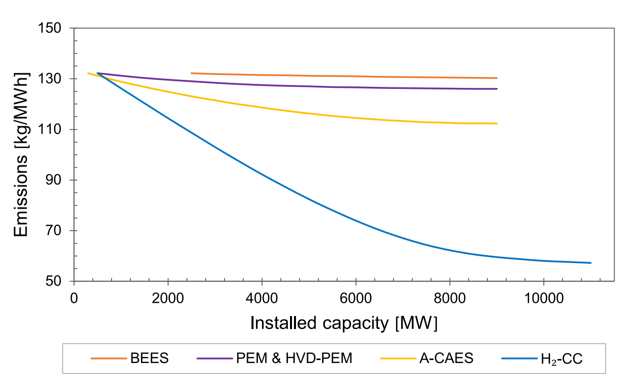

Fig. 4. Emission reductions vs increased installed capacity of new technologies in the power system. The NORMAL Scenario 2040 was selected as a representative case.

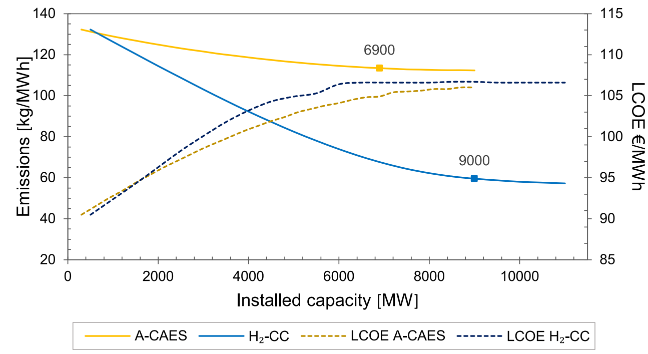

Fig. 5. Emission reductions and LCOE vs increased installed capacity of A-CAES and H_2-CC in the power system. The NORMAL Scenario 2040 was selected as a representative case.

emissions due to the increased battery capacity is negligible; therefore, the installed capacity for the 2030 and 2040 scenarios is the same as the expected value for 2030 (2500 MW) [43]. For PEM and HDV-PEM, the additional emissions reduction is negligible from 2000 MW onwards (initial capacity); therefore, this is the capacity selected for all scenarios.

Fig. 5 shows the impact of the installed capacities of CAES and H_2-CC in both emissions and LCOE of the power system. For CAES, 6900 MW were selected since, above this value, emissions do not decrease significantly, and the LCOE continues to rise. For H_2-CC, 9000 MW were selected as there is a steep emissions reduction until this value, and the LCOE does not rise (Fig. 5).

4.3. Results for 2030 and 2040 scenarios with new technologies (NTs)

The results of the capacity factor of each technology are shown in Fig. 6. The capacity factors and generation for each technology and scenario can be found in Table S6 and Table S7 of the SI. The capacity factor obtained for BESS is only 8–10 % for the 2030 scenarios, as it relies on VRE curtailment and BESS generation does not provide stability. Self-discharge is between 34 and 50 % (annual). By 2040, although NGCC generation (to be replaced) and curtailment are higher than in 2030, BESS generation is even lower, with a capacity factor of 5–8 %. That is because the load to be replaced without affecting inertia is lower in 2040 (due to higher VRE penetration). This year experiences a higher self-discharge between 62 % and 75 % (annual).

Increasing BESS capacity in the system would not significantly impact power generation and, therefore, emissions reduction (Fig. 4) neither in the short nor in the long term. On the other hand, the additional capacity of hybrid photovoltaic and BESS (Li-ion) has been considered to replace up to the total generation of CO_2 emitting technologies in the Spanish electricity system [74]. Nevertheless, as demonstrated in this study, the increase in solar PV (in addition to increasing the LCOE) causes a slight growth in emissions due to the higher curtailment and NGCC generation to ensure system stability (Fig. 3). Furthermore, although BESS is the first new technology in the merit order to use VRE curtailment, they do not exceed the 10 % capacity factor in any scenario due to the restrictions they would face in their operation.

PEM has a higher capacity factor than batteries, between 29 and 39 % by 2030 and 12–20 % by 2040. The capacity factor of HDV-PEM is between 18 and 26 % and 8–13 %, respectively. Although these technologies also rely on the load to be replaced without affecting inertia, they have greater flexibility than batteries in the system. It should be noted that PEM and HDV-PEM depend on hydrogen, which we assumed always to be available (from storage). Although these technologies perform better in 2030, they decrease their average generation, as batteries do, in 2040. In addition, an increase in capacity does not lead to a reduction in emissions (Fig. 4). Some studies have determined the

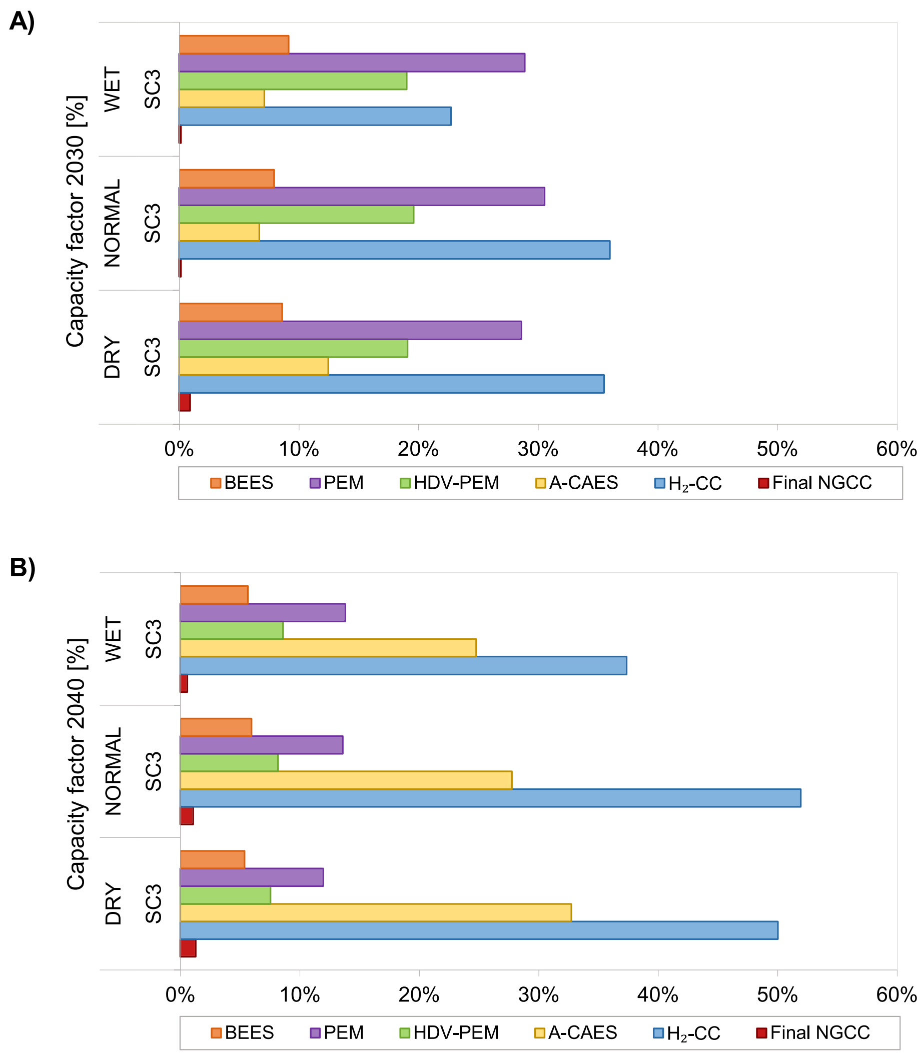

Fig. 6. Capacity factors of the proposed new technologies for (A) 2030 and (B) 2040. The scenario shown is SC3, the results of all scenarios are shown in Figure S2.

potential for installing P2G2P capacity focused on the electric system for up to 95–100 % renewable energy (RES) scenarios [20]. Reversible fuel cells are found to be cost competitive in the electricity market for current hydrogen prices and even considering a substantial price reduction due to their flexibility [75]. Nevertheless, these studies have not considered the stability or their participation with other storage technologies, which limits their operation, especially by 2040 (Fig. 6). Therefore, PEM and HDV-PEM could be considered transition technologies but will not play a significant role in the long term.

A-CAES has a capacity factor of 4–13 % by 2030 and 14–33 % by 2040. This technology also depends on curtailment, and its generation in 2030 is low, even though it provides inertia to the power system. In 2040, its generation significantly increases due to stability contribution, reaching up to 7 % of total demand. In addition, the increase in initial capacity allows a greater reduction in emissions compared to BESS, PEM and HDV-PEM. Therefore, A-CAES could play an important role in the decarbonisation of the power system in the long term.

H_2-CC has a capacity factor of 15–38 % by 2030 and 31–54 % by 2040. The generation of this technology provides stability, and as mentioned above, an increase in capacity allows a significant reduction in emissions compared to the other technologies (Fig. 4). It should be noted that hydrogen is assumed to be always available for electricity generation for this technology, as well as for PEM and HDV-PEM (due to storage). This technology allows the highest substitution of NGCC power generation, replacing it between 46 % and 66 % by 2030 and 57–67 % by 2040. Therefore, H_2-CC is the major source of system flexibility, contributes most to decarbonisation in the short and long term, and covers up to 11 % and 14 % of demand in 2030 and 2040. Considering all hydrogen generation technologies (PEM, HDV-PEM and H_2-CC), this share is 15 % and 16 %. The role of hydrogen turbines in the electricity system has been assessed and found to be competitive only with a strict cap on CO_2 emissions, i.e., in 2040 and 2050, with little or no role to play in 2030 [23]. However, in our study, in which emissions are a result (not a limit), turbines would play an essential role as early as 2030 due to the stability they bring to the grid and their high-power generation share.

The NGCC capacity factor is a maximum of 2 % for both years, which suggests that its generation is negligible and that in all scenarios, a large degree of substitution of this technology would be feasible. Therefore, the potential retrofitting of combined cycle turbines for hydrogen operation is of particular interest.

4.3.1. Results of curtailment with NTs

Fig. 7 shows the curtailment used by new technologies and the corresponding VRE curtailment (% of VRE availability) after NTs integration (see also Table S8 of the SI). Curtailment would increase significantly by 2040, being lower in NORMAL years. By 2030, 10 % of the curtailment (on average) and 4 % by 2040 is used to charge batteries, for electrolysis 36/35 %, and A-CAES 18/19 %. Electrolysis (hydrogen production) is the technology that most reduces curtailment. Comparing the final curtailment for each climate condition, the initial scenario SC1,

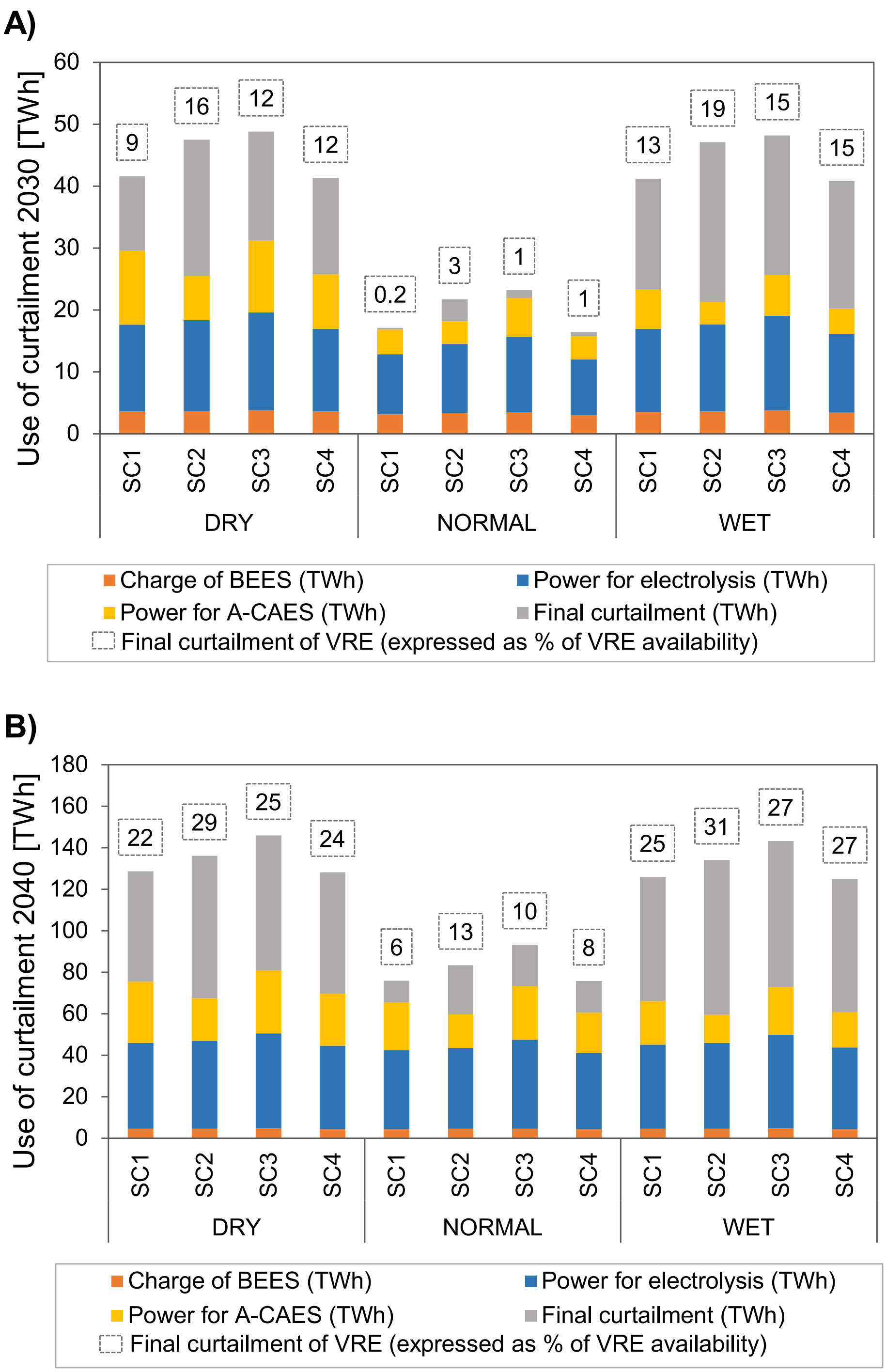

Fig. 7. Use of the curtailment of VRE for different scenarios by (A) 2030 and (B) 2040.

where no capacity variations were considered, has the lowest value. In contrast, SC2 (4xST) has the highest final curtailment.

Curtailment levels depend mainly on the share of VRE in the electricity mix and can vary considerably across regions. For several countries, historical wind curtailment levels of<5 % have been determined, while others have already exceeded 10 % [76]. Several models of the future electricity system have determined or established curtailment levels between 9 and 20 % for high shares (up to 100 %) of renewable energy when flexibility options such as energy storage are incorporated into the system [14,46,70]. In our study, before the incorporation of the new technologies, curtailment levels reached very high levels due to the constraints of our model (see Table 13). After NTs, we have found that the final curtailment also depends on the climate condition of the year. For instance, despite the curtailment reduction, there is still up to 19 % and 31 % final curtailment in 2030 and 2040, respectively (scenario WET-SC2). Nonetheless, in NORMAL years, almost all curtailment is used, with a final value of 0.2 % by 2030 and 5.6 % by 2040 (NORMAL-SC1).

4.3.2. *Maximum storage needed for H_2*

The maximum storage needed allows for determining the size of the storage (i.e., the number of salt caverns). Up to 93 caverns (DRY-SC4) and a minimum of 45 (WET-SC1, WET-SC2) are needed in 2030. In 2040, between 86 and 44 are needed (DRY-SC4 and NORMAL-SC1,

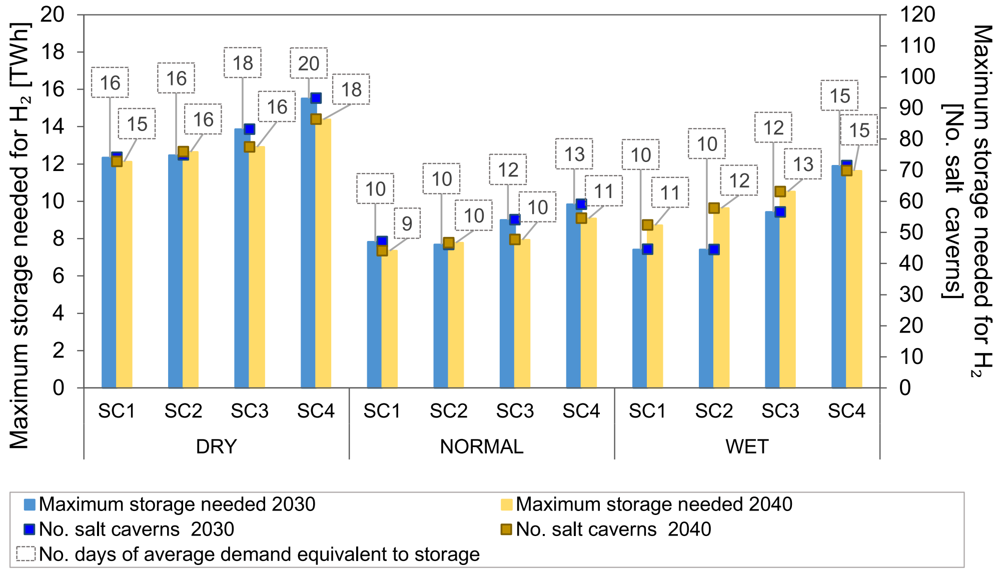

Fig. 8. Maximum H_2 storage and No. of salt caverns for each scenario by 2030 and 2040.

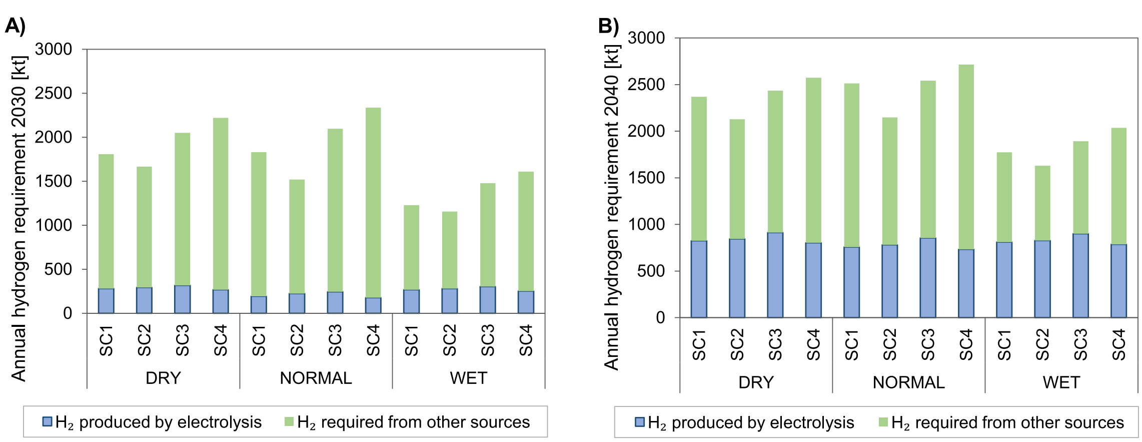

Fig. 9. H_2 produced by electrolysis and required from other sources (gasification in this study) for each scenario by (A) 2030 and (B) 2040. Hydrogen from electrolysis does not include potential dedicated off-grid renewable facilities.

respectively) (Fig. 8). Therefore, a large number of caverns would be required in the long term (around 86) to supply the power system's needs, corresponding to a storage capacity of 14 400 GWh (equivalent to 18 days of average demand in 2040). In the NORMAL year, less storage is required due to the better distribution of renewable resources, contrary to the DRY year.

The CAES storage needed for all scenarios is 6.9 GWh, corresponding to 4 salt caverns. The salt cavern storage potential for Europe was analysed, and Spain is estimated to have an onshore storage potential of 1.26 PWhH_2. Therefore, it has the third largest onshore potential in Europe, after Germany and Poland [77]. Considering the highest potential reached in our scenarios for hydrogen in the long term (86 caverns) and for A-CAES (4 caverns), only 1.1 % of the total potential would theoretically be used. However, an in-depth study of the locations and feasibility of using the caverns would be necessary as these characteristics have not been considered here.

The hydrogen storage needed was determined considering the electricity sector as the only consumer. An average requirement (in all scenarios) of around 2000 kt tonnes to meet the electricity system's needs was calculated in this study. In Spain, there is a consumption of 500 kt/year of grey Hydrogen; 70 % is used in refineries, 25 % in the manufacture of chemical products and the remainder in the metallurgical sector [51]. Hydrogen is mainly produced in the same plant for these uses, which does not have relevant hydrogen storage facilities. However, it would be interesting to address shared storage with these sectors and the change in loading and unloading behaviour. In general, considering other sectors would allow for identifying the role and the storage size for decarbonising the entire energy system.

In both years, 2030 and 2040, the hydrogen required by other sources is higher than the hydrogen obtained from electrolysis, but in 2030 it is significantly higher (Fig. 9). Hydrogen produced by electrolysis is higher in 2040 due to the higher curtailment, which is approx. 3.2 times that of 2030. The capacity factor of electrolysers is 26–45 % by 2030 and 52–65 % by 2040. The installed capacity for electrolysis for 2030 is the one expected by national scenarios (4 GW), and we assume 8 GW by 2040. However, despite the higher curtailment (over three times) and increase of the installed capacity of electrolysers (double) by 2040, the capacity factor does not exceed 65 %, and there are final curtailment levels of up to 31 % (Fig. 7) due to power system constraints. Therefore, an increase in the capacity of this technology was not further analysed.

The NORMAL-SC4 year has the highest hydrogen requirement (2338 kt and 2717 kt by 2030 and 2040). On average, the NORMAL year also has the highest requirement, matching the lowest storage needed. The WET year requires less hydrogen (minimum of 1158 kt and 1630 kt for SC2) due to less NGCC power generation to replace and less NTs generation, mainly from turbines (Fig. 6). We assumed that the hydrogen

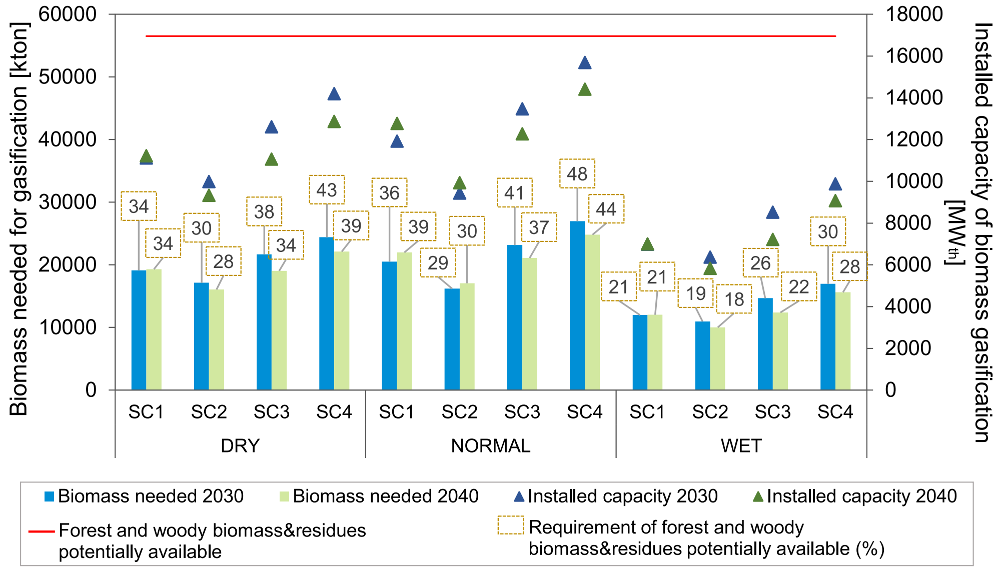

Fig. 10. Biomass needed for gasification and installed capacity of biomass gasification plants for each scenario by 2030 and 2040. The maximum amount of biomass is in the NORMAL-2030 SC4 scenario (26 982 kt), with a requirement of 39 biomass plants (400 MW_{th}).

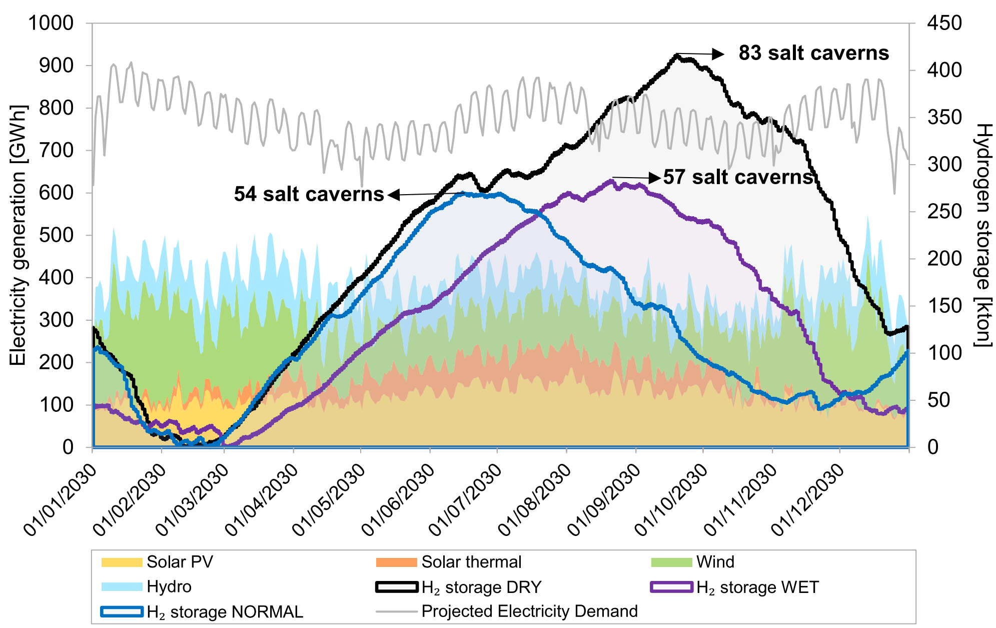

Fig. 11. Storage behaviour of H_2 throughout the year for different climate conditions for SC4-2030. Here an average of renewable generation for the three years is shown in a daily resolution (see renewable generation in an hourly resolution for each year in Figure S3).

needed from other sources comes from biomass gasification. It should be noted that dedicated off-grid renewable facilities may be deployed, and solar and biomass are considered the most direct resources for hydrogen production in the long term [78]. Off-grid facilities can provide low-cost hydrogen in locations with high solar and wind resources. However, the capacity factor of the electrolysers will be lower due to resource variability, which can increase the cost of hydrogen [47].

Some studies suggest similar prices for off-grid and grid-connected hydrogen; others suggest that the latter is cheaper than standalone solar PV [79]. A techno-economic study of hydrogen produced by standalone solar PV provides several cost ranges. However, with a combination of factors, the cost can be as low as USD 2.7/kg, close to the USD 2.5/kg that IRENA estimates to be cost-competitive with fossil hydrogen. These prices are close to those considered for hydrogen from grid-connected electrolysis and gasification (see Table 10) [79]. For example, in our study, the estimated external hydrogen supply in the scenario with the highest demand in 2030, NORMAL-SC4, is covered by an installed biomass gasification capacity of 15 690 MW (see Table S9). However, considering off-grid renewable facilities to supply this external hydrogen (2159 kt), the installed off-grid wind capacity would be 52 GW and solar PV 101 GW (calculated based on our VRE projections, not including inertia constraints).

Overall, the amount of biomass and installed gasification capacity is higher in the NORMAL year, as seen in Fig. 10. According to the potential biomass available in Spain (see Figure S4), between 19 and 48 % of the forest and woody biomass (suitable for planting on forest and agricultural land) and woody residues would be required in 2030. Considering all the potential biomass available, it would be 12–30 %. By 2040 18–44 % of the forest, woody biomass and woody residues, and 11–28 % of all the potential would be required. The installed capacity

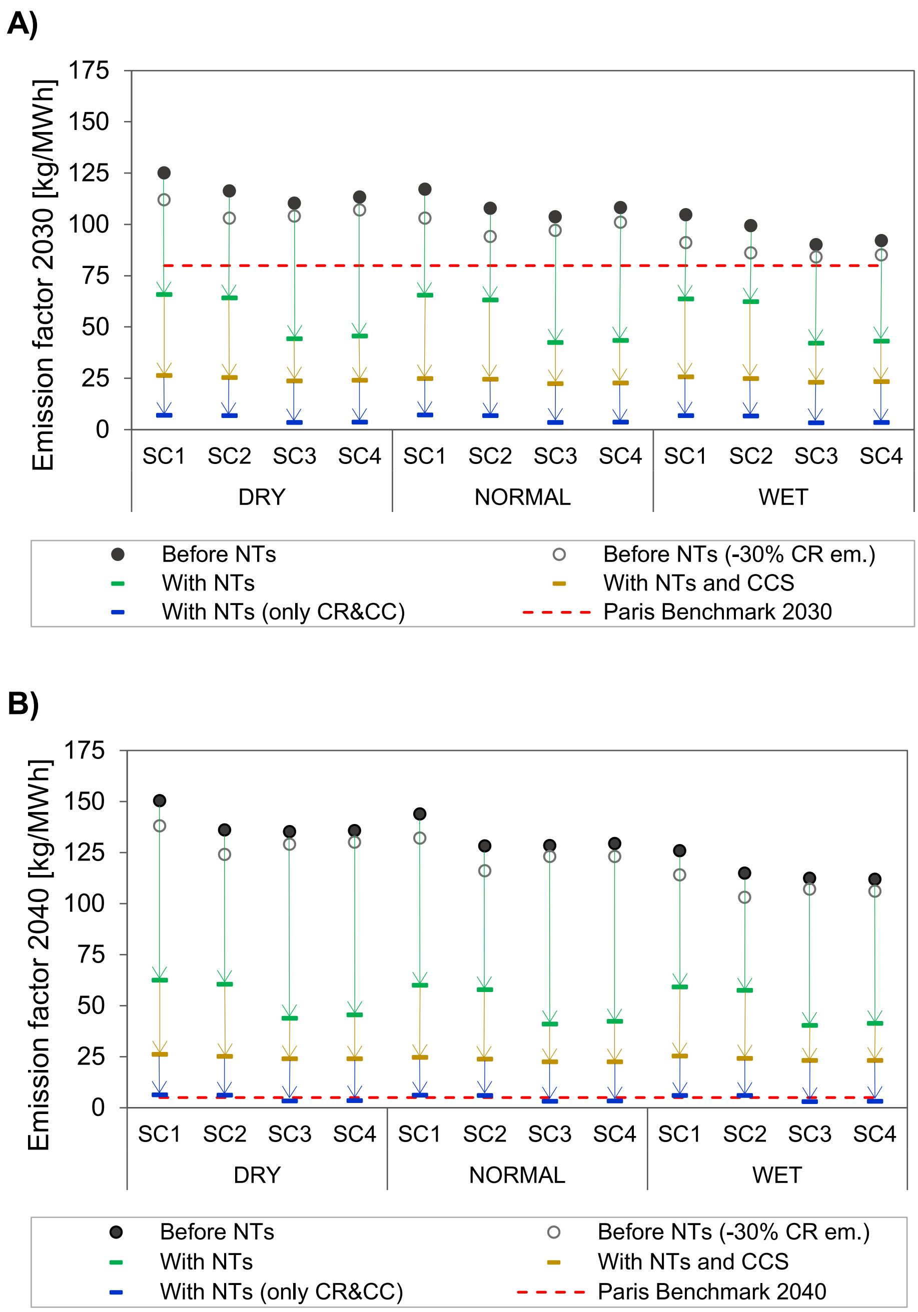

Fig. 12. CO_2 emission factors for different climate conditions and scenarios before and after NTs by (A) 2030 and (B) 2040. See also Table S10.

for 2030 would be 15 690 MW and 14 419 MW for 2040 (highest values).

The behaviour of hydrogen storage for different climate conditions is shown in Fig. 11. An average of the renewable generation for the three types of weather conditions (three years) is presented here. However, renewable generation by each climate condition is shown in Figure S3. Solar PV generation is higher in the DRY year than in NORMAL and WET years (higher resource utilisation). Solar PV generation is higher from summer onwards, partly contributing to the storage in these months. In addition, demand decreases in autumn, leading to greater storage accumulation. Hydroelectric and wind generation are lower than in the other two scenarios. In the DRY year, NGCC generation to be replaced and initial inertia are higher than in the other two scenarios. Nevertheless, the load to be replaced has a less uniform distribution throughout the year, not well coupled with NTs generation, which contributes to a higher hydrogen accumulation in storage.

Compared to the DRY year, less storage is needed in the NORMAL year due to the better distribution of the load to replace and the renewable generation. In a normal year, wind generation is higher than in DRY and WET years. NORMAL year electricity generation allows more efficient storage utilisation, with only one month of storage accumulation and higher loading and unloading behaviour. Therefore, less storage is needed than in the other scenarios (more uniform hydrogen requirement and higher NGCC replacement). In addition, solar PV penetration is the lowest but more uniform, allowing better utilisation of hydrogen from storage. Hydro generation is significantly higher in the WET year than in the DRY and NORMAL years. Hydro is higher in spring and, together with renewable generation, allows to start accumulating energy in storage. More storage is required in a WET year than in a NORMAL year. Storage utilisation is also uniform; however, the cavern filling time is longer than in the NORMAL year.

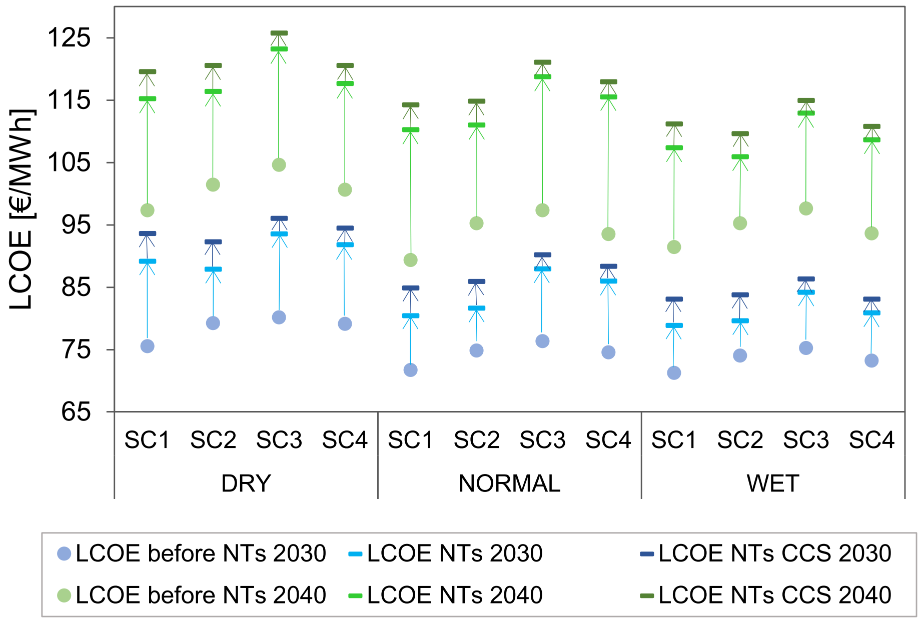

Fig. 13. Resulting LCOE in the power system for different climate conditions and scenarios by 2030 (a) and 2040 (b). See also Table S10.

4.3.3. Emissions and costs

Before introducing new technologies in 2030, the initial scenarios did not meet the emissions target, and the reduction of up to 30 % of CR emissions (assuming using RES sources) did not significantly impact the system. After including storage and power generation from the new technologies, the reduction is significant, and all scenarios surpass the target (Fig. 12). Besides, although 85 % and 90 % of CCS for CR and CC were considered, CCS does not play an important role in 2030. If we only consider emitting technologies without CCS (only CR and CC), emissions in all scenarios with NTs are close to 0. Therefore, only considering emitting technologies, the new technologies could almost decarbonise the electricity system by 2030 (emissions < 7 $kgCO_2$/MWh).

In 2040, the emissions of the initial scenarios are far from meeting the targets, and the 30 % emission reduction of CR did not contribute either. After including the new technologies, equivalent emissions were significantly reduced, although they are still far from the target. However, if we consider only the emitting technologies in scenarios with new technologies, it is possible to meet the benchmark by 2040 (emissions < 6 $kgCO_2$/MWh). Accordingly, CCS for electricity generation does not play a significant role in 2040 either. SC3 and SC4 achieve the lowest emissions in scenarios with NTs, as shown in Fig. 12, considering both equivalent emissions (with NTs) or only emitting technologies (with NTs – only CR&CC). In this study, we considered the equivalent emissions of clean energy technologies based on life cycle analysis (LCA) parameters. However, these equivalent emissions are not included in the emissions calculation to meet the Paris targets, i.e., only the emitting technologies are quantified.

Including NTs increases the LCOE for 2030 by 13 % compared to the initial scenarios (average for all scenarios). The final LCOE with NTs is € 85/MWh, which is in line with the reference value that allows for remaining on track to decarbonisation towards 2030 for new builds [73]. As seen in Fig. 13, the initial LCOE before including the new technologies is higher for SC3 (higher levels of curtailment). A previous study analysed the impact of VRE penetration in the LCOE for Europe. For example, for 20 % VRE, the LCOE was € 94/MWh; for 40 %, € 91/MWh; and for 60 %, € 88/MWh; i.e., the LCOE decreases with the increase of renewables [71]. In contrast, in our study, the LCOE increases for 2040 (€ 89–105/MWh) when the share of VRE is higher than in 2030 (Table 13 and Table S10). This increase is because the system has to deal with variability, and the capacity factor of VRE drops (higher curtailment) to meet constraints, which causes higher costs in the system. By 2040 the increase with NTs is 18 %, with a final LCOE of € 114/MWh (weighted average) equivalent to an LCOE of € 206/MWh for NTs. Our previous study found that the NTs would need a maximum LCOE of € 134/MWh (which allows reaching a reference value of € 102/MWh). Therefore, in this study, a reduction of 10 % would be needed to obtain € 102/MWh in 2040. Although the increase in LCOE with CCS is negligible (NGCC penetration is low in all scenarios, and CR is also low in SC3 and SC4 due to less installed capacity), its role in emissions reduction was minor.

5. Main findings

Before including the new technologies, the capacity variation of existing technologies (sensitivity analysis) showed that increasing ST and reducing CR allows for emissions reductions without significantly impacting system costs. On the other hand, increasing VRE capacity or reducing nuclear does not reduce emissions and costs, as the system has to increase NGCC generation to deal with variability and stability requirements. In terms of weather conditions, a WET year has the highest share of renewable energy due to high hydropower. VRE is higher in the DRY year (due to high solar PV penetration) for 2030 and in the WET year for 2040 (on average). Curtailment is the highest in the DRY years (due to the higher variability of renewables) and the lowest in the NORMAL years, as renewable generation is more evenly distributed throughout the year.

Fig. 14 shows a diagram of the use of curtailment and the role of new generation technologies and hydrogen requirement in the future electricity system. The new technology that generates the most electricity is H_2-CC, and the most extensive use of the curtailment is in hydrogen production by electrolysis. In the scenario depicted (WET), a high amount of final curtailment is still expected, especially in 2040 and hydrogen production from other sources is significantly higher in 2030 than in 2040.

Our findings are novel since no previous studies have obtained the power generation of new technologies and the storage size needed for future scenarios for different climate conditions based on flexibility and stability constraints. The sensitivity analysis of conventional technologies' varying installed capacities shows that it would be interesting to consider increasing ST capacity before incorporating new technologies (in the case of Spain). It should be noted that ST generation has a projection based on the historical generation profile in which only 24 of the

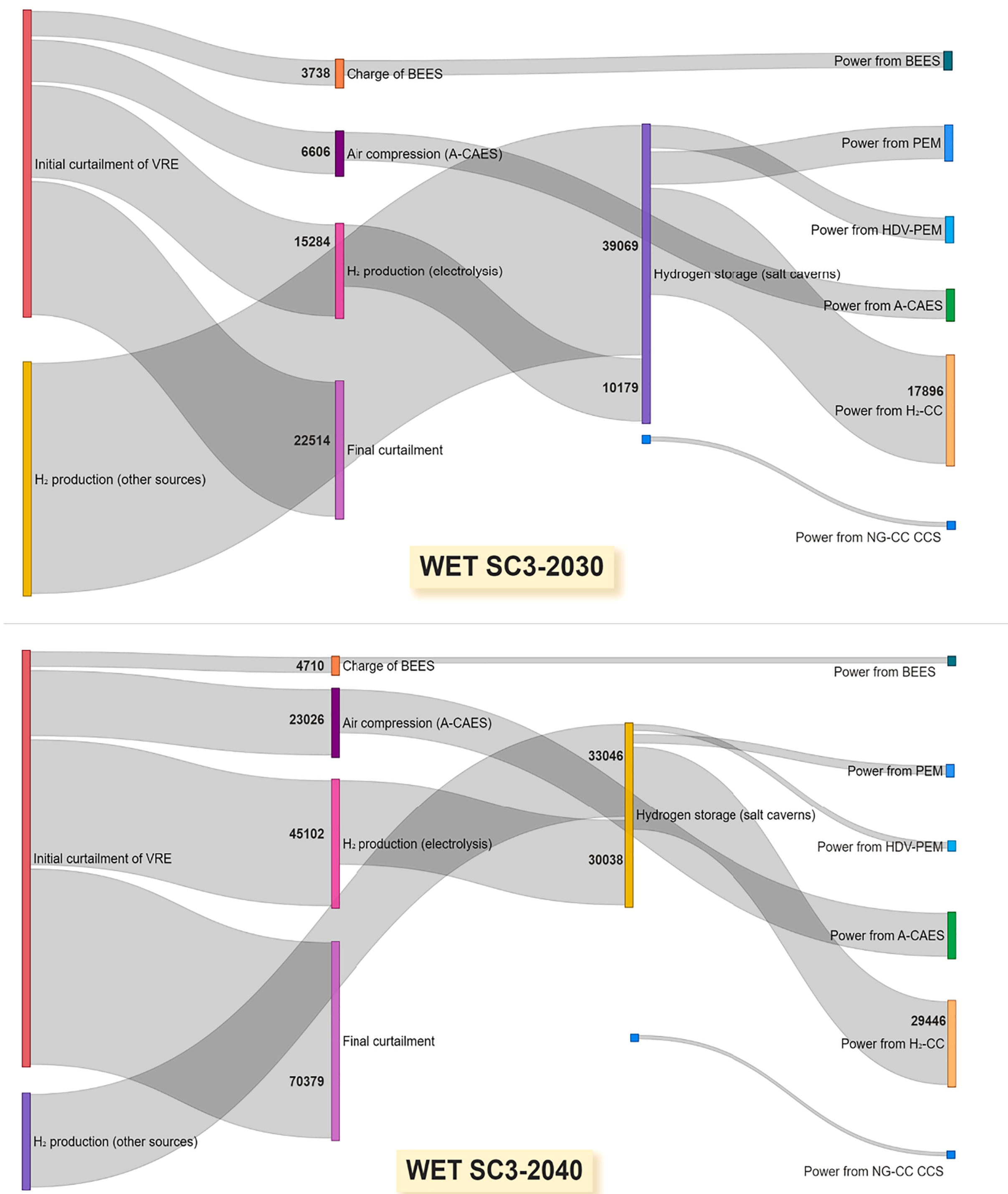

Fig. 14. Sankey diagram of the use of curtailment and electricity generation with new technologies (energy basis, GWh). The scenario depicted is the one that achieves the lowest emissions with NTs (WET-SC3).

50 CSP plants in Spain had storage systems. Therefore, it would be interesting to conduct a study to assess the effect of including storage in the rest of the plants.

Some of the findings regarding NTs contrast with other studies that point out that technologies like batteries and PEM can play an important role in future electricity generation. However, they have not addressed inertia or flexibility. For example, none of our results reached the generation from batteries proposed by the national scenario for 2030 (greater than 3TWh), as the maximum generation obtained here, for the same capacity, was 2.2 TWh [43]. On the contrary, in this study, the technologies that could provide more generation and stability in the long term are A-CAES, but especially H_2-CC. The latter depends not only on curtailment (for hydrogen production) but also on the supply that can come from other sources. Therefore, an in-depth analysis of hydrogen production from other sources would be crucial.

In addition, storage technologies may face supply chain, technical and scalability constraints. These constraints include, for example, the use of critical materials for batteries or the availability of geological formations for A-CAES and Hydrogen. This study estimates the storage required in the electricity system. However, each application will depend on different economic, legal, and social factors that would allow or hinder their deployment. In our study, hydrogen-related technologies have the largest share and allow the greatest decarbonisation of the Spanish system due to hydrogen's versatility in production, storage and power generation. It should be noted that Carbon Capture and Sequestration did not allow for significant emission reductions in any scenario. The lowest emissions are achieved in the SC3 and SC4 scenarios which have in common more ST and less CR capacity. Therefore, instead of CCS, including long-duration energy storage (salt caverns for hydrogen) and H_2-CC would provide greater benefits for further decarbonisation.

In this regard, our findings imply that new studies and policies should strengthen the incorporation of flexible technologies based on synchronous generation and long-duration storage technologies to meet the system's needs. These needs involve not only meeting demand or including flexibility constraints for power generation of each technology but also the provision of inertia, which is reduced in systems with high share of variable renewable electricity. Some studies have incorporated inverters connected to renewable generation to analyse the provision of grid stability. These studies recognise that a certain amount of synchronous generation would be needed to provide stability in the near to medium term as there is a delay in response and the technology is still under development [80].

6. Conclusions

Renewable energy will continue to be deployed globally to achieve decarbonisation targets and energy security. However, high shares of variable renewable energy (VRE) bring several challenges to the electricity system due to their intermittency and unpredictability. To the best of our knowledge, the requirements for system stability when including new low-carbon generation and storage systems for different climate conditions have not been addressed. Therefore, FEPPS, a rule-based power system model developed by the authors, was used to fill this gap. Before including new technologies, it was found that by increasing solar thermal capacity and capping cogeneration and non-renewable waste, emissions decreased in all scenarios. Conversely, increasing VRE or reducing nuclear capacity does not imply reducing emissions since the system has to increase the natural gas combined cycle to meet the power system's constraints. VRE penetration reaches up to 35 % and 40 %, and renewable energy 57 % and 62 % in 2030 and 2040, respectively, due to system constraints. By 2030 and 2040, no scenario meets the Paris targets.

Regarding the inclusion of new technologies, batteries will not impact the power system in the short or long term. Fuel cells perform better than batteries in 2030; however, they could be considered transition technologies that would not play an important role in the long term. Although Adiabatic Compressed Air Energy Storage (A-CAES) provides inertia, its capacity factor in 2030 is low (<13 %). However, in the long term, this technology plays an important role in power generation and reducing emissions, reaching up to a 33 % capacity factor. Combined cycle gas turbines for hydrogen (H_2-CC) reach a capacity factor of up to 38 % and 54 % by 2030 and 2040 and allow the most significant replacement of natural gas combined cycle (up to 67 %). H_2-CC could cover up to 11 % and 14 % of demand by 2030 and 2040, respectively. This technology is essential for decarbonising the power system in the short and long term. Therefore, efforts and policies should encourage long-duration energy storage and hydrogen turbines as they represent the major source of power system flexibility. H_2-CC relies on electrolysis, which enabled the most considerable curtailment reduction, as demonstrated in this study.

In the long term, a maximum of 14.4 TWh would be needed for hydrogen storage, equivalent to about 18 days of average demand. This requirement represents only 1.1 % (theoretically) of the total onshore salt cavern storage potential in Spain (the third largest onshore potential in Europe). However, an analysis of the technical feasibility of caverns would be necessary. Regarding biomass for hydrogen production, about 12–30 % of the total potential biomass available in Spain would be needed. Regarding emissions, in 2030, it is possible to surpass the Paris emission target (42–66 $kgCO_2/MWh$) after including new technologies. In 2040, although new technologies allow a significant reduction, they are still far from the target (40–62 $kgCO_2/MWh$). However, if only emitting technologies are considered in 2040, it is possible to meet the benchmark. Therefore, NTs could decarbonise the power system in the short and long term. It should be noted that Carbon Capture and Sequestration did not allow for significant emission reductions in any scenario. In addition, the average Levelized Cost of Electricity (LCOE) for the 2030 scenarios with new technologies is in line with the European Commission reference value that allows for remaining on track to decarbonisation for new builds. By 2040, a 10 % reduction of the LCOE is necessary to reach the reference value.

A limitation of our study is that hydrogen storage and use has only been analysed for the electricity sector. Therefore, it would be critical to analyse hydrogen integration with other sectors and other technologies for hydrogen production. Another area that could be explored is the provision of synthetic inertia, which could benefit the system by allowing a greater share of VRE. Network improvements can be analysed to enable higher levels of rate of change of frequency than those considered here, with lower critical inertia levels to be met. Additionally, applying FEPPS to other regions could provide insights into the role of the new technologies in decarbonising the future power system.

CRediT authorship contribution statement

K. Guerra: Methodology, Investigation, Formal analysis, Data curation, Software, Writing – original draft. **R. Gutiérrez-Alvarez:** Data curation, Visualization, Investigation, Writing – review & editing. **Omar J. Guerra:** Visualization, Writing – review & editing. **P. Haro:** Conceptualization, Funding acquisition, Methodology, Supervision, Validation, Visualization, Writing – review & editing.

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 dataset generated during this study is available at HARVARD Dataverse: https://doi.org/10.7910/DVN/DLO6TF. The code flowchart is available in the Supplemental Information. The FEPPS model was previously published and the code flowchart (before the inclusion of the new generation and storage technologies) is available at https://doi.org/10.1016/j.apenergy.2022.118561 and https://doi.org/10.1016/j.dib.2022.108095; and its dataset is available at HARVARD Dataverse: https://doi.org/10.7910/DVN/R2IVYN.

Acknowledgements

This work was supported by grant PID2020-114725RA-I00 of the project GH2T funded by MCIN/AEI/ 10.13039/501100011033 and by the "European Union". The Ph.D. grant of K. Guerra from Universidad de Sevilla under VI PPIT-US is acknowledged.

Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2023.120828.

References

[1] International Energy Agency. Renewables 2021 - Analysis and forecast to 2026. 2021:167.

[2] International Energy Agency (IEA). Renewable electricity growth is accelerating faster than ever worldwide, supporting the emergence of the new global energy economy - News - IEA n.d. https://www.iea.org/news/renewable-electricity-growth-is-accelerating-faster-than-ever-worldwide-supporting-the-emergence-of-the-new-global-energy-economy (accessed March 9, 2022).

[3] Robert Socolow C, Arnold C, Davies G, Kreutz T, Powell W, Schwartz M, et al. Grid-scale electricity storage. implications for renewable energy. an energy technology distillate from the Andlinger Center for Energy and the Environment at Princeton University; 2014.

[4] Hunter CA, Penev MM, Reznicek EP, Eichman J, Rustagi N, Baldwin SF. Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule 2021;5: 2077–101. https://doi.org/10.1016/j.joule.2021.06.018.

[5] Blanco H, Faaij A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. Renew Sustain Energy Rev 2018;81:1049–86. https://doi.org/10.1016/j.rser.2017.07.062.

[6] Guerra OJ, Eichman J, Denholm P. Optimal energy storage portfolio for high and ultrahigh carbon-free and renewable power systems. Energy Environ Sci 2021;14: 5132–46. https://doi.org/10.1039/d1ee01835c.

[7] Dalala Z, Al-Omari M, Al-Addous M, Bdour M, Al-Khasawneh Y, Alkasrawi M. Increased renewable energy penetration in national electrical grids constraints and solutions. Energy 2022;246:123361. https://doi.org/10.1016/J.ENERGY.2022.123361.

[8] Denholm P, Kulcinski GL. Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems. Energy Convers Manag 2004;45: 2153–72. https://doi.org/10.1016/j.enconman.2003.10.014.

[9] Huggins RA. Energy storage: Fundamentals, materials and applications. second edition 2015. https://doi.org/10.1007/978-3-319-21239-5.

[10] European Commission. Energy storage. Energy storage can help increase the EU's security of supply and decarbonisation. n.d. https://energy.ec.europa.eu/topics/research-technology-and-innovation/energy-storage_en (accessed March 11, 2022).

[11] Pietzcker RC, Ueckerdt F, Carrara S, de Boer HS, Després J, Fujimori S, et al. System integration of wind and solar power in integrated assessment models: A cross-model evaluation of new approaches. Energy Econ 2017;64:583–99. https://doi.org/10.1016/j.eneco.2016.11.018.

[12] Energy Storage News. European Green Deal "needs to support long-duration energy storage" - Energy Storage News n.d. https://www.energy-storage.news/european-green-deal-needs-to-support-long-duration-energy-storage/ (accessed March 11, 2022).

[13] Carrara S, Marangoni G. Including system integration of variable renewable energies in a constant elasticity of substitution framework: The case of the WITCH model. Energy Econ 2017;64:612–26. https://doi.org/10.1016/j.eneco.2016.08.017.

[14] Reichenberg L, Hedenus F, Odenberger M, Johnsson F. The marginal system LCOE of variable renewables – Evaluating high penetration levels of wind and solar in Europe. Energy 2018;152:914–24. https://doi.org/10.1016/j.energy.2018.02.061.

[15] Hong YY, Apolinario GFD, Lu TK, Chu CC. Chance-constrained unit commitment with energy storage systems in electric power systems. Energy Rep 2022;8: 1067–90. https://doi.org/10.1016/J.EGYR.2021.12.035.

[16] Narayanan A, Mets K, Strobbe M, Develder C. Feasibility of 100% renewable energy-based electricity production for cities with storage and flexibility. Renew Energy 2019;134:698–709. https://doi.org/10.1016/J.RENENE.2018.11.049.

[17] Rasmussen MG, Andresen GB, Greiner M. Storage and balancing synergies in a fully or highly renewable pan-European power system. Energy Policy 2012;51:642–51. https://doi.org/10.1016/J.ENPOL.2012.09.009.

[18] He G, Mallapragada DS, Bose A, Heuberger-Austin CF, Gençer E. Sector coupling: Via hydrogen to lower the cost of energy system decarbonization. Energy Environ Sci 2021;14:4635–46. https://doi.org/10.1039/d1ee00627d.

[19] Zhang J, Guerra OJ, Eichman J, Pellow MA. Benefit Analysis of Long-Duration Energy Storage in Power Systems with High Renewable Energy Shares. Front Energy Res 2020;8:313. https://doi.org/10.3389/FENRG.2020.527910/BIBTEX.

[20] Wulf C, Linssen J, Zapp P. Power-to-gas-concepts, demonstration, and prospects. Hydrog. Supply Chain Des. Deploy. Oper., Elsevier; 2018, p. 309–45. 10.1016/B978-0-12-811197-0.00009-9.

[21] King M, Jain A, Bhakar R, Mathur J, Wang J. Overview of current compressed air energy storage projects and analysis of the potential underground storage capacity in India and the UK. Renew Sustain Energy Rev 2021;139:110705. https://doi.org/10.1016/j.rser.2021.110705.

[22] Maton JP, Zhao L, Brouwer J. Dynamic modeling of compressed gas energy storage to complement renewable wind power intermittency. Int J Hydrogen Energy 2013; 38:7867–80. https://doi.org/10.1016/J.IJHYDENE.2013.04.030.

[23] Öberg S, Odenberger M, Johnsson F. Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. Int J Hydrogen Energy 2022;47: 624–44. https://doi.org/10.1016/j.ijhydene.2021.10.035.

[24] Report 2018.

[25] Scenario Building Guidelines 2020.

[26] Guerra K, Haro P, Gutiérrez RE, Gómez-Barea A. Facing the high share of variable renewable energy in the power system: Flexibility and stability requirements. Appl Energy 2022;310:118561. https://doi.org/10.1016/J.APENERGY.2022.118561.

[27] Ueckerdt F, Brecha R, Luderer G, Sullivan P, Schmid E, Bauer N, et al. Representing power sector variability and the integration of variable renewables in long-term energy-economy models using residual load duration curves. Energy 2015;90: 1799–814. https://doi.org/10.1016/j.energy.2015.07.006.

[28] Pilpola S, Lund PD. Different flexibility options for better system integration of wind power. Energy Strateg Rev 2019;26:100368. https://doi.org/10.1016/j.esr.2019.100368.

[29] Guerra K, Haro P, Gutiérrez RE, Gómez-Barea A. Data for the modelling of the future power system with a high share of variable renewable energy. Data Br 2022; 42:108095. https://doi.org/10.1016/J.DIB.2022.108095.

[30] National Renewable Energy Laboratory (NREL). ES | Concentrating Solar Power Projects | NREL n.d. https://solarpaces.nrel.gov/by-country/ES (accessed August 20, 2021).

[31] Hirth L. The Merit Order Model and Marginal Pricing in Electricity Markets. 2022.

[32] Imperial College London. The Merit Order Stack. n.d.

[33] National Association of Clean Air Agencies. Chapter 21. Change the Dispatch Order of Power Plants. Implement. EPA's Clean Power Plan A Menu Options, 2015, p. 355–67.

[34] NEXT. Merit Order: How ancillary services get their price n.d. https://www.next-kraftwerke.com/knowledge/what-does-merit-order-mean (accessed November 29, 2021).

[35] Deane P. Rapid Response Energy Brief Quantifying the "merit-order" effect in European electricity markets 2015.

[36] The Power of Change. Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies. Washington, D.C.: National Academies Press; 2016. 10.17226/21712.

[37] ENTSO-E. ENTSO-E Technopedia n.d. https://www.entsoe.eu/Technopedia/ (accessed December 6, 2021).

[38] Ruf Y, Kaufmann M, Lange S, Pfister J, Heieck F, Endres Brussels A. Fuel Cells and Hydrogen Applications for Regions and Cities. vol. 1. 2017.

[39] Olympios AV, McTigue JD, Farres-Antunez P, Tafone A, Romagnoli A, Li Y, et al. Progress in Energy Progress and prospects of thermo-mechanical energy storage-a critical review 2021. https://doi.org/10.1088/2516-1083/abdbba.

[40] Groenenberg R, Koornneef J, Sijm J, Janssen G, Morales-Espana G, van Stralen J, et al. Large-Scale Energy Storage in Salt Caverns and Depleted Fields 2020:40.

[41] General Electric. Hydrogen as a fuel for gas turbines. A path to lower CO2. 2021.

[42] Cousins A, Feron P, Hayward J, Jiang K, Zhai R. Further assessment of emerging CO2 capture technologies for the power sector and their potential to reduce cost IEAGHG R&D Programme *Visiting scientist from North China Electric Power University 2019.

[43] Ministry for the Ecological Transition and the Demographic challenge (MITECO). Plan Nacional Integrado de Energía y Clima (PNIEC) (in Spanish). 2020.

[44] Sistema de Información del Operador del Sistema (ESIOS). Análisis | ESIOS electricidad · datos · transparencia (in Spanish). n.d. https://www.esios.ree.es/es/analisis (accessed June 21, 2022).

[45] Bowen T, Chernyakhovskiy I, Denholm P. Grid-Scale Battery Storage. Frequently Asked Questions 2019.

[46] Dowling JA, Rinaldi KZ, Ruggles TH, Davis SJ, Yuan M, Tong F, et al. Role of Long-Duration Energy Storage in Variable Renewable Electricity Systems. Joule 2020;4: 1907–28. https://doi.org/10.1016/j.joule.2020.07.007.

[47] IRENA. Hydrogen from renewable power: Technology outlook for the energy transition 2018.

[48] U.S. Department of Energy. Comparison of Fuel Cell Technologies | Department of Energy. n.d. https://www.energy.gov/eere/fuelcells/comparison-fuel-cell-technologies (accessed July 27, 2021).

[49] Zohuri B. Hydrogen Energy: Challenges and Solutions for a Cleaner Future. 2018.

[50] Irena. Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C. Climate Goal 2020.

[51] Ministerio para la Transición Ecológica y el Reto Demográfico (MITECO). Hoja de Ruta del hidrógeno. Una apuesta por el hidrógeno renovable (in Spanish). 2020.

[52] Huang Y, Chen H, Zhang X, Keatley P, Huang M, Vorushylo I, et al. ScienceDirect Techno-economic modelling of large scale compressed air energy storage systems Selection and/or peer-review under responsibility of ICAE 2017:1876–6102. https://doi.org/10.1016/j.egypro.2017.03.851.

[53] Chiesa P, Lozza G. Using Hydrogen as Gas Turbine Fuel. J Eng Gas Turbines Power 2005;127:73–80.

[54] Abuadala A, Dincer I, Naterer GF. Exergy analysis of hydrogen production from biomass gasification. Int J Hydrogen Energy 2010;35:4981–90. https://doi.org/10.1016/J.IJHYDENE.2009.08.025.

[55] Zhang Y, Li B, Li H, Liu H. Thermodynamic evaluation of biomass gasification with air in autothermal gasifiers. Thermochim Acta 2011;519:65–71. https://doi.org/10.1016/J.TCA.2011.03.005.

[56] Laban MP. Hydrogen storage in salt caverns. Chemical modelling and analysis of large-scale hydrogen storage in underground salt caverns. TU Delft 2020.

[57] Fichtner. Erstellung eines Entwicklungskonzeptes Energiespeicher in Niedersachsen - PDF Free Download n.d. https://docplayer.org/5174810-Erstellung-eines-entwicklungskonzeptes-energiespeicher-in-niedersachsen.html (accessed August 6, 2021).

[58] Letcher T, Law R, Reay D. Storing Energy: With Special Reference to Renewable Energy Sources. 2016.

[59] Bérest P, Brouard B, Durup JG. Tightness Tests in Salt-Cavern Wells NOTATIONS Latin Letters. Oil Gas Sci Technol IFP 2001;56:451–69.

[60] Bérest P, Brouard B. Safety of Salt Caverns Used for Underground Storage Blow Out; Mechanical Instability; Seepage; Cavern Abandonment. Oil Gas Sci Technol IFP 2003;58:361–84. https://doi.org/10.2516/ogst:2003023ï.

[61] Commission E. Hydrogen emissions from a hydrogen economy and their potential global warming impact. JCR technical report Luxembourg 2022. https://doi.org/10.2760/065589.

[62] National Renewable Energy Laboratory (NREL). Life Cycle Emissions Factors for Electricity Generation Technologies | NREL Data Catalog n.d. https://data.nrel.gov/submissions/171 (accessed February 18, 2022).
[63] United Nations Economic Commission for Europe (UNECE). Life Cycle Assessment of Electricity Generation Options n.d.
[64] CBS Statistics Netherlands. CO2 equivalents n.d. https://www.cbs.nl/en-gb/news/2019/37/greenhouse-gas-emissions-down/co2-equivalents (accessed March 3, 2022).
[65] Steen M. Greenhouse Gas Emissions from Fossil Fuel Fired Power Generation Systems. European Commission. n.d.
[66] European Central Bank. Euro foreign exchange reference rates n.d. https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-usd.en.html (accessed March 25, 2021).
[67] U.S. Department of Energy. Changing Role of Natural Gas in Energy Generation. 2016.
[68] International Energy Agency. Hydrogen from biomass gasification. 2018.
[69] Huber M, Dimkova D, Hamacher T. Integration of wind and solar power in Europe: Assessment of flexibility requirements. Energy 2014;69:236–46. https://doi.org/10.1016/j.energy.2014.02.109.
[70] Denholm P, Hand M. Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Policy 2011;39:1817–30. https://doi.org/10.1016/j.enpol.2011.01.019.
[71] Gils HC, Scholz Y, Pregger T, Luca de Tena D, Heide D. Integrated modelling of variable renewable energy-based power supply in Europe. Energy 2017;123:173–88. https://doi.org/10.1016/j.energy.2017.01.115.
[72] European Network of Transmission System Operators for Electricity (ENTSO-E). Maps & Data n.d. https://tyndp.entsoe.eu/maps-data/ (accessed February 8, 2021).
[73] European Commission. Power Perspectives 2030. On the road to a decarbonised power sector n.d.:1–11.
[74] Fraile J, Alvaro R, Castano S, Merino J. Carbon-Free Electricity Generation in Spain with PV–Storage Hybrid Systems. 2022:1–20.
[75] Glenk G, Reichelstein S. Reversible Power-to-Gas systems for energy conversion and storage. Nat Commun 2022;13:1–10. https://doi.org/10.1038/s41467-022-29520-0.
[76] Bird L, Lew D, Milligan M, Carlini EM, Estanqueiro A, Flynn D, et al. Wind and solar energy curtailment: A review of international experience. Renew Sustain Energy Rev 2016;65:577–86. https://doi.org/10.1016/j.rser.2016.06.082.
[77] Caglayan DG, Weber N, Heinrichs HU, Linßen J, Robinius M, Kukla PA, et al. Technical potential of salt caverns for hydrogen storage in Europe. Int J Hydrogen Energy 2020;45:6793–805. https://doi.org/10.1016/j.ijhydene.2019.12.161.
[78] U.S. Department of Energy. Hydrogen Resources. Hydrogen and Fuel Cell Technologies Office. n.d. https://www.energy.gov/eere/fuelcells/hydrogen-resources (accessed June 11, 2022).
[79] Yates J, Daiyan R, Patterson R, Egan R, Amal R, Ho-Baille A, et al. Techno-economic analysis of hydrogen electrolysis from off-grid stand-alone photovoltaics incorporating uncertainty analysis. Cell Reports Phys Sci 2020;1:100209. https://doi.org/10.1016/j.xcrp.2020.100209.
[80] Johnson SC, Papageorgiou DJ, Mallapragada DS, Deetjen TA, Rhodes JD, Webber ME. Evaluating rotational inertia as a component of grid reliability with high penetrations of variable renewable energy. Energy 2019;180:258–71. https://doi.org/10.1016/j.energy.2019.04.216.