We used the word-count tool of Microsoft Word: the number of words in the paper (from the introduction to the conclusion, including figures and tables) is 6,943.

A sensitivity analysis on large-scale electrical energy storage requirements in Europe under consideration of innovative storage technologies

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ABSTRACT

As the share of variable renewable energies in the power system increases, so does the need for flexibility options. These include, inter alia, energy storage, network optimization and expansion, and demand side management. In this paper, a broad sensitivity analysis is carried out to assess the potential role of innovative electrical energy storage technologies in comparison to well-established ones. The innovative technologies considered include compressed heat energy storage, adiabatic compressed air energy storage, power-to-heat-to-power storage, and reversible solid oxide fuel cells storage. To this aim, the cost-optimizing energy system model REMix has been applied to analyze the impact of main techno-economic parameters of electrical energy storages on their role in the future European power supply system. Two main studies have been calculated. The first one deals with a cost sensitivity analysis on a generic storage technology. Among the main findings is that – beside cost – the ratio between photovoltaics and wind power potentials in a particular region have a relevant impact on the capacity as well as on the energy to power ratio of the installed storages. In addition, a strong competition has been observed between energy storages and gas turbines. The second scenario evaluates the competition between well-established and innovative energy storage technologies. The results show that while some of the regions – namely southern Europe, alpine regions and Scandinavia – mainly rely on pumped hydro storage, in most of Central European regions and United Kingdom the cost optimal solution consists of a mix of pumped hydro storage (totaling 64.2 TWh/y of discharged energy in Europe), hydrogen underground storage (45.1 TWh/y) and batteries (27.1 TWh/y), with an additional small share of power-to-heat-to-power storages (0.1 TWh/y). In line with earlier studies, hydrogen storage is found mostly in regions with high wind power supply, while the distribution of batteries is more spread overall in Europe. The model results underline the high sensitivity of the economic efficiency of storage facilities to the investment costs and their components.

KEYWORDS

Electrical energy storage, innovative storage technology, power-to-heat-to-power, renewable energy, energy system optimization, REMix

NOMENCLATURE

1. AC — Alternating Current
2. A-CAES — Adiabatic Compressed Air Energy Storage

3. CAES Compressed Air Energy Storage
4. CAPEX Capital Expenditures
5. CHEST Compressed Heat Energy Storage
6. CPLEX IBM ILOG CPLEX Optimization Studio
7. CSP Concentrating Solar Power
8. DLR German Aerospace Center (*Deutsches Zentrum für Luft- und Raumfahrt*)
9. DSM Demand Side Management
10. EES Electrical Energy Storage
11. ENTSO-E Network of Transmission System Operators for Electricity
12. GAMS General Algebraic Modeling System
13. HVDC High Voltage Direct Current
14. O&M Operation and Maintenance
15. OPEX Operational Expenditures
16. P2H2P Power-to-Heat-to-Power
17. PHS Pumped Hydro Storage
18. PV Photovoltaics
19. RE Renewable Energy
20. REMix Renewable Energy Mix Model
21. RSOFC Reversible Solid Oxide Fuel Cell
22. VRE Variable Renewable Energy

1. INTRODUCTION

Renewable energies (RE) are crucial for the achievement of climate neutrality goals. In particular, variable renewable energies (VRE) such as photovoltaics (PV) and wind power are expected to play a dominant role in future energy systems (Ram et al. 2018). However, their integration into power systems is challenging. The power generation patterns of PV and wind power are intermittent and very location-dependent, while the power production forecast is uncertain. Accordingly, balancing power has to be provided by different sources of flexibility. Flexibility measures include grid reinforcement and expansion, demand side management (DSM) in the industry sector as well as with regard to new loads (e.g. battery electric mobility, heat pumps and electrolyzers for hydrogen production). In addition, supply side management such as RE curtailment, flexible thermal power plants and usage of electrical energy storage (EES) represent further flexibility options. This works focuses on EES in power systems with very high VRE supply share.

1.1. State of research

Over the last decades, extensive amount of research studies on EES has been produced. In particular, energy storage requirements in systems with high shares of renewables have been tackled with model-based analyses in many studies and with different approaches. An overview on power system planning studies with focus on the role of variable renewable energy including flexibility and energy storage needs is provided by Deng and Lv (Deng and Lv 2019). The authors highlight the importance of adequate representation of variable renewables integration in planning models, with special regards to the constraints of flexible generation, interregional transmission as well as energy storage.

Cebulla et al. 2018 focuses on a least-cost optimization on EES needs for Europe in 2050. Applying a wide sensitivity analysis the aim is to assess the capacity expansion of different storage technologies such as adiabatic compressed air energy storages (A-CAES), H_2 underground storage, pumped hydro storage (PHS), Lithium-Ion (Li-Ion) batteries and Vanadium redox flow batteries. As main outputs, storage capacity expansion presents a high correlation with the VRE share (Figure 1), while the expansion of different storage technologies is characterized by a strong dependency on the region-specific renewable mixes. High correlation between wind and H_2 storage as well as between PV and Li-Ion batteries are part of the outcomes.

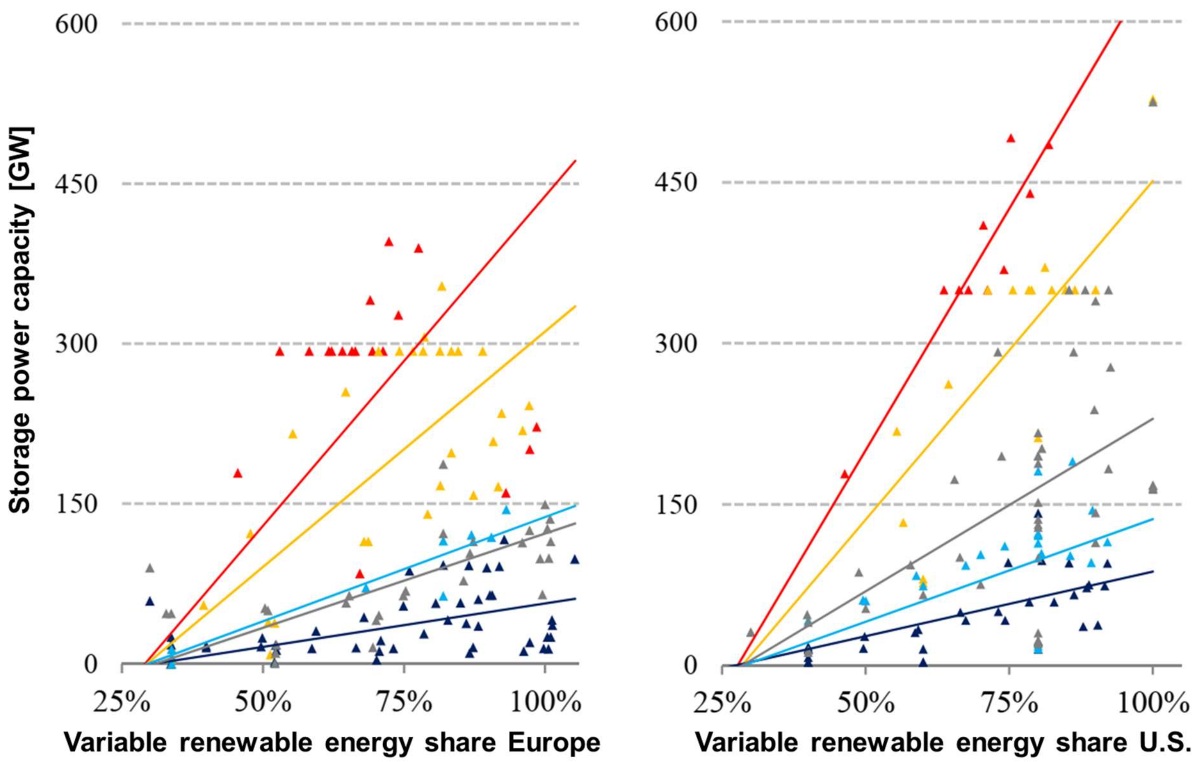

Figure 1: Storage capacity expansion and VRE (production) share correlation, according to (Cebulla et al. 2018)

Bussar et al. (Bussar et al. 2016), assume a system configuration based on a 100 % PV and wind supply considering PHS, Li-Ion batteries and H_2 storage as storage technologies. The option of grid expansion between the modelled countries in Europe, North Africa and the Middle East (EUMENA) is considered as well. However, the study is limited to the most mature energy storage technologies.

Child et al. 2018 highlight the role of battery prosumage within a 100 % renewable energy system in Europe. According to this analysis, energy discharge from both system and prosumers batteries covers up to 15 % of the European electricity demand.

Babrowski et al. 2016 evaluate an optimized electricity storage system for Germany until 2040 including grid restrictions. The authors emphasize the benefits of locating energy storages in strategic regions – i.e. close to large wind parks as well as near congested grid lines – and suggest the commissioning of 3.2 GW of battery storage. In the case EES cannot be installed, their role within the energy system would be taken over by gas turbines.

With regards to the alternatives to energy storages, in the last years a scientific debate has taken place about the complementarity or the substitutionality of energy storages and electricity transmission. A summary of this debate can be found in (Neetzow et al. 2018). While some studies argue that storages contribute to reduce network congestion – and other authors on the contrary claim that investments in storages are facilitated by the availability of additional transmission lines – recent works underline that several factors contribute to certain interdependence between energy storages and electricity transmission (e.g. spatial distribution of supply, demand and storage) besides other modeling specificities such as temporal and geographical resolution.

The existing literature on the investigation of the future role of electricity storage in the European electricity system is limited to a few, quite established technologies. Innovative technologies such as A-CAES, compressed heat energy storage (CHEST), power-to-heat-to-power (P2H2P) and reversible solid oxide fuel cells (RSOFC) are not considered. One possible reason is that some of the technologies present a relatively low technology readiness level (TRL).

A-CAES systems use electricity to compress air into a storage unit, which can be for instance an underground salt cavern. The compressed and heated-up air releases heat into a separate thermal energy storage. The process is reverted when electricity is needed and air is expanded through a turbine after exchanging heat with the included thermal energy storage (Budt et al. 2016).

The CHEST concept consists into a particular design of pumped thermal energy storage, where a high-temperature heat pump is used to reverse a conventional Rankine cycle. The energy is stored e.g. in a two-tank molten salt storage system. During storage discharge, the heat is used to operate the Rankine cycle when electricity is needed (Steinmann 2017). In addition, CHEST systems may be utilized as a sector-coupling technology for heat and electricity through low temperature heat integration (Steinmann et al. 2019).

P2H2P storages mainly consist into heating up the storage unit exploiting the Joule effect. During storage discharge, the thermal energy storage provides the high-temperature heat to drive a conventional Rankine cycle (Bauer 2019).

RSOFC systems can produce hydrogen and oxygen from electricity in charging mode (electrolysis mode). Both hydrogen and oxygen are stored in pressurized tanks. When needed, electricity is produced reversing the process in the fuel cell mode (Nguyen and Blum 2016).

Another novel energy storage concept in very early stage of development is liquid carbon dioxide (Xu et al. 2019). The authors developed a detailed thermodynamic model and compared key performance indicators of carbon dioxide energy storage and liquid air energy storage, concluding that carbon dioxide storage has a superior performance with regard to round-trip efficiency (45.4 % vs. 37.8 %).

Finally, economic evaluation of gravity energy storage has been provided by Berrada et al. 2017. The authors implemented a techno-economic model for gravity energy storage and compared levelized cost of energy of different storage options. According to the analysis, gravity energy storage may be able to provide low levelized cost of energy (123 €/MWh). Such cost are assumed to be in the same range as PHS (120 €/MWh).

1.2. Scope of this work

Despite the high number of existing publications on the role of electricity storage in Europe's future energy system, the analysis of innovative storage technologies is not sufficiently covered by the existing literature. Our work closes this gap by focusing specifically on the necessary cost reductions and the potential system benefits of innovative electricity storage technologies. For this purpose, different technologies are integrated into an optimizing energy system model and evaluated among each other and in competition with established storage technologies, power grid expansion and flexible power plants. As some of such innovative technologies present a low TRL, and consequently future investment cost as well as round-trip efficiency are rather difficult to assess and are mostly uncertain, a two-step methodology is applied:

1. The aim of the first part of the study is to identify the investment costs at which innovative storage technologies could become part of a cost-optimized power supply system. Therefore, a wide sensitivity analysis in terms of investment costs for both power unit (referred in the following as "converter") and energy unit (referred in the following as "storage") of EES is carried out. The analysis is performed for a **"generic" storage** (4.1), whereas generic means that no specific technology is meant for this analysis. The storage is simply characterized by capacity-specific capital expenditure (CAPEX), distinguished for power and energy unit, operational expenditure (OPEX) as well as round-trip efficiency. Within this case, only generic storages and no technology-specific storages are considered. This analysis provides insights about economic storage potentials of innovative storages (installed converter and storage capacities), their preferred region of installation within a European power system scenario for the year 2050 as well as their optimized dispatch within one year. The sensitivities on generic storages are performed taking into account a 95 % reduction of CO_2 emissions in comparison to 1990. The analysis is subdivided in three sections:
    - The first one assumes varying specific capital expenditures for the converter by keeping the storage specific CAPEX constant (***Converter CAPEX Sensitivity***, 4.1.1).
    - Within a second section, the storage CAPEX has been varied while keeping fixed the converter CAPEX (***Storage CAPEX Sensitivity**,* 4.1.2).
    - In a third section the impact of renewable energy potential on the geographical distribution of the installed storage capacities is highlighted ***(Geographical Storage Distribution***, 4.1.3).
2. The obtained results are expected to be useful for orientation in further research on EES development. The aim of the second part of the analysis is to assess to what extent the innovative storage technologies could compete with alternative storage technologies and alternative flexibility options under the cost projections available today. Therefore, the technologies are explicitly modelled and parameterized using **technology-specific storage**

cost assumptions (4.2). This analysis includes the well-established storage technologies, PHS, Li-Ion batteries, and H_2 underground storage as well as the innovative storage technologies A-CAES, P2H2P, RSOFC, and CHEST. In this case the CO_2 limit has been set to – 98 % in comparison to 1990 levels. The choice is due to the fact that the group of considered innovative technologies is assumed to have higher capital expenditures than conventional storage technologies, so that they probably become relevant only in systems characterized by very high VRE shares and energy storage demand. In this case, a sensitivity analysis is performed which consists into different constraints with regard to the transmission network expansion. In particular, three different cases are investigated:

- ***Unlimited grid expansion*** (4.2.1),
- ***No Grid Expansion*** (4.2.2), i.e. considering input TYNDP-based grid values for 2030)
- ***Grid Expansion Sensitivity*** (4.2.3), i.e. the number of maximally installable interconnections lines has been varied

2. MATERIALS AND METHODS

In this section the REMix model applied in this study is introduced, with a focus on the representation of EES in the model.

2.1. REMix

REMix is a high resolution energy system optimization model aiming to the determination of least-cost design and hourly operation of power supply systems (Scholz et al. 2017). The model relies on a linear programming approach, is realized in GAMS, and typically solved with CPLEX. The objective function to be minimized is the total systems cost, composed of the annuities C_{invest} and fixed operation and maintenance (O&M) costs $C_{o\&m,fixed}$ of endogenously added capacities, variable O&M costs $C_{o\&m,var}$ of all assets, fuel costs C_{fuel}, and optional emission costs $C_{emission}$.

$$(1) \qquad min\{\, C_{o\&m,fixed} + C_{o\&m,var} + C_{fuel} + C_{emission} + C_{unsupplLoad} + C_{invest}\}$$

The electricity storage technologies in the focus of the analysis presented here contribute to the annuitized investment costs as well as the fixed and variable O&M costs according to the cost assumptions made (see Section 3) and model-based investment and operating decisions. The objective function is subject to numerous physical (e.g. sites for hydro power plants) and technical constraints. The main model constraint is represented by the power balance, which ensures the match of power provision and demand for every considered model region at each time step. REMix is a multi-node model. Model regions can be flexibly defined, and interconnected by power lines. Distances between model nodes are given as input and refer to the direct linear connection between the geographic centers of regions. Within each region, all assets of one technology are grouped and treated as one unit, corresponding to the implicit assumption of unlimited power transmission within the regions. REMix is organized in a modular structure, where each module, referring to a specific technology or set of technologies, is set up with all the needed parameters, variables, equations and inequalities to model its technical and economic characteristics. Power generation, storage and transmission technologies are described in the modules according to their efficiency, technical constraints (power and energy specific), and costs. To account for daily, weekly and seasonal fluctuations, for each model region the electricity demand is calculated from an annual demand and a normalized hourly demand profile of a statistically meaningful historic year. Figure 2 shows the fundamental REMix structure, while an in depth description of the model and the considered equations and inequalities can be found in (Gils et al. 2017).

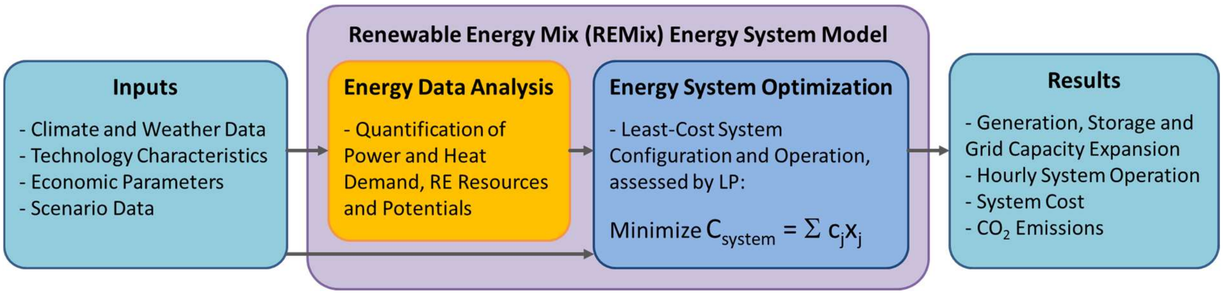

Figure 2: REMix model overview (Gils et al. 2017)

2.2. Energy storage modeling

REMix includes two different modules for EES. Both modules are generic, which means that they can be used to model different technologies with the same set of equations. The storage modules always consist of two subsystems, i.e. the power unit (or converter) and the energy unit (or storage). The main difference between the EES modules is the consideration of charging and discharging units (Figure 3), which are either considered together (single converter) or separate (separate converters). The latter choice mainly allows for an individual dimensioning of each of both converter units, and gives the storage design and operation a higher degree of flexibility. For both representations the main equation is the storage energy balance, which ensures that the stored energy in the actual time step $E_{stor}(t)$ [MWh] is equal to the energy level in the preceding time step $E_{stor}(t-1)$ plus the charged energy $P_{conv\_ch}(t)$ [MWh/h] minus the output energy $P_{conv\_dis}(t)$ and the self-discharge losses, under consideration of the relative efficiencies.

$$E_{stor}(t) - E_{stor}(t-1) = \\ = \left(\eta_{ch} P_{conv\_ch}(t) - \frac{P_{conv\_dis}(t)}{\eta_{dis}}\right)\Delta t - \frac{\eta_{self}}{2}\left(E_{stor}(t) + E_{stor}(t-1)\right) \tag{2}$$

An additional equation sets the storage level at the first and last time step of the simulation to the same value in order to avoid net energy production or destruction from the storage itself. The sum of installed and optimized charge and discharge capacity as well as the storage capacity are constrained according to a maximum installable value. Optimization of power and energy units of EES can be carried out in two different approaches, either considering a fixed or an optimized energy to power ratio. In the model application presented here, the second modelling approach is used. The analysis of a generic storage is performed assuming single converters (Section 4.1), whereas the technology-specific scenarios are evaluated using separate converters wherever applicable (Section 4.2).

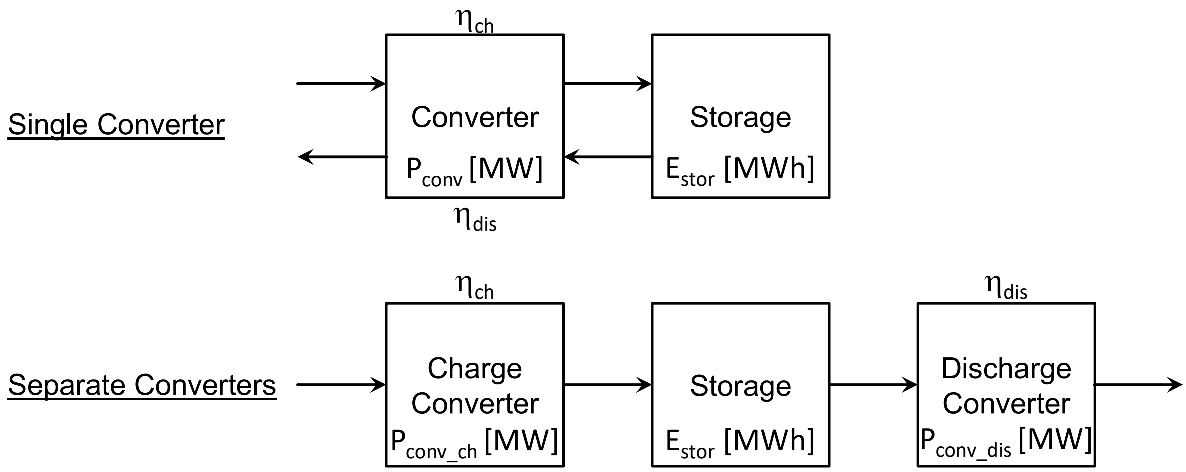

Figure 3: Schematic overview of the two energy storage modeling approaches in REMix

2.3. Model set-up in this work

In the configuration used here, REMix includes power generation by conventional fossil and nuclear power plants, reservoir and run-of-river hydro power, concentrating solar power (CSP), wind onshore and offshore, and solar photovoltaic. Excess power generation from all hydro, wind and solar power sources can be curtailed without any limitation. This curtailment is not related to any variable costs. However, it lowers the load factor and thus specific power generation costs, which makes the investment in the corresponding technology less attractive. According to earlier analyses, biomass and geothermal are not expected to contribute substantially to the future European power supply given the limited potential and comparably high costs (International Energy Agency 2011). For this reason, to limit the computational complexity, and to focus on the effects related to EES, biomass and geothermal power plants are neglected. Also CHP is not explicitly modelled. Earlier REMix studies have shown that high VRE shares require a power-controlled CHP operation (Gils 2015 and Gils et al. 2019). This means that – enabled by the integration of thermal energy storage as well as other heat sources – CHP systems are operated according to the power system needs and thus similar to the condensation power plants considered here. The model considers spatial balancing through power transmission via alternating current (AC) as well as direct current (DC) power lines and temporal balancing through EES.

The model is run in a partial green field approach, which implies that capacities are optimized for some but not all technologies. Exogenously defined capacities include all existing hydro power stations (run-of-river, reservoir and pumped storage hydro). Furthermore, existing alternating current (AC) and direct current (DC) power lines are considered. In contrast, today's existing capacities of all other technologies are not considered, implicitly assuming that these are not replaced at the end of their lifetime.

For most technologies, REMix not only evaluates the hourly operation, but also the optimal capacity. These include all generation – except hydro power where potentials are assumed to be mostly exhausted – DC power transmission lines between all regions and EES. Capacity installation of pumped hydro storage, A-CAES, hydrogen storage, wind and solar power generation is limited considering available potentials, whereas there is no limit to the installation of all other technologies optimized in capacity including generic storage.

In the configuration used here, the main results of a REMix model run are:

- installed capacity of conventional (cycle gas turbines (CCGT), natural gas driven gas turbines (GT), hard coal, lignite and nuclear power plants) as well as renewable energy plants (PV, CSP, wind onshore, wind offshore) per each or node
- installed capacity of energy storages (converter [GW] and storage [GWh_{el}]) per each node
- the hourly dispatch of the power fleet per each node
- the additionally installed DC transmission grid capacity between interconnected nodes
- the system cost (average annual power supply cost taking into account operation and maintenance (O&M) cost of the existing power plant fleet plus the complete cost –i.e. CAPEX and operational expenditures (OPEX)- of the newly installed power plants)

3. INPUT DATA AND CALCULATION

In this section the main assumptions and the input data needed for the optimization are described. The parametrization of the model relies on previous studies based on REMix application (Cebulla 2017)(Gils et al. 2017). In line with the targets of the European Union, total annual emissions are limited to a budget that corresponds to almost climate-neutral power generation (Section 3.4). The resulting high share in VRE power generation is the main driver for energy storage demand.

3.1. Spatial resolution, power demand and transmission

The European assessment area consists of a total 20 countries, which are aggregated to 11 model regions as reported in Table 1.

Table 1: list of considered model regions

	Model Region	Nodes
1	Germany	Germany
2	France	France
3	Benelux	Belgium, Luxemburg, Netherlands
4	SwitzLi	Switzerland, Lichtenstein
5	Austria	Austria
6	PolCzeSlk	Poland, Czech Republic, Slovakia
7	Italy	Italy
8	Iberia	Spain, Portugal
9	UK+IE	UK, Ireland
10	Denmark W	Denmark West (Jutland, Funen)
11	NordEl	Denmark East (Zealand, Lolland-Falster), Finland, Norway, Sweden

Hourly load data are taken from the European Network of Transmission System Operators for Electricity (ENTSO-E) (European Transmission System Operators 2019) and scaled according to the development of the total electricity demand assessment for the investigation year 2050, according to (Cebulla 2017).

The power grid is modeled in the system both as AC and HVDC connections and lines expansion is limited to HVDC connections between neighboring regions (Figure 4).

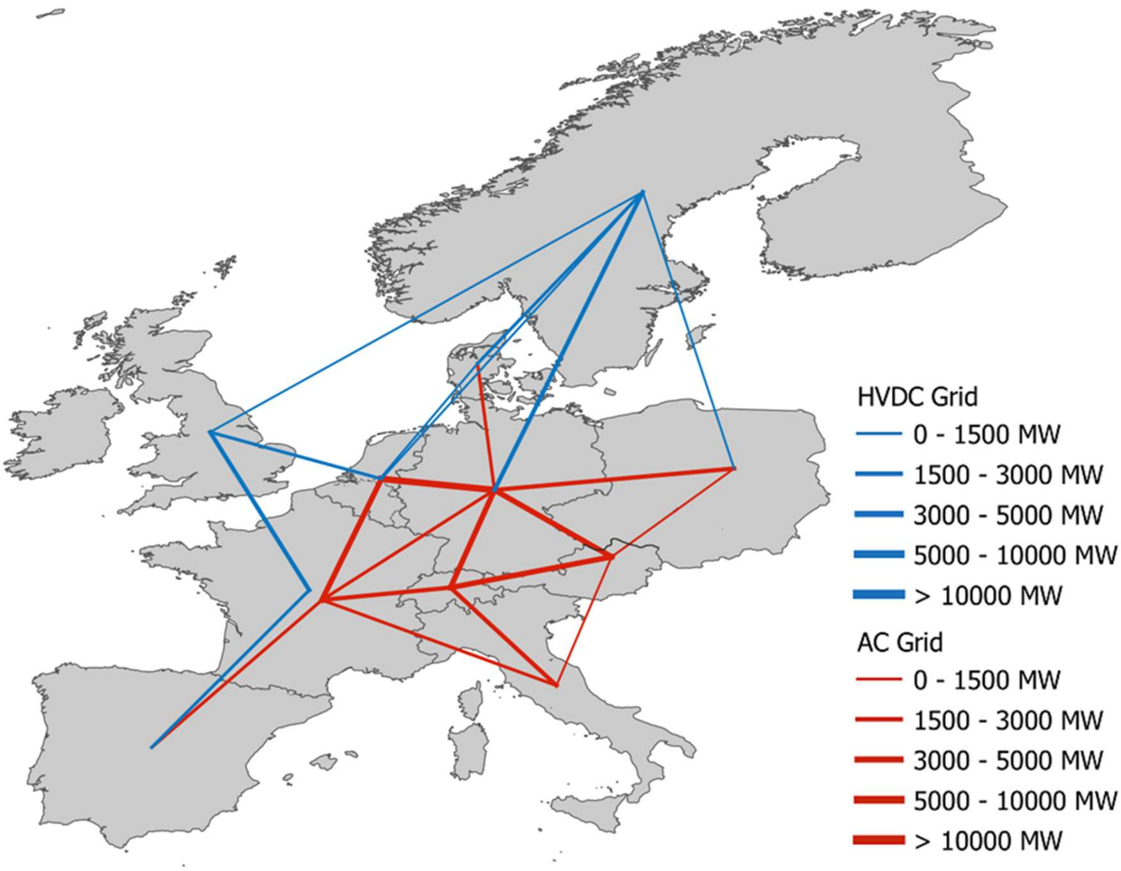

Figure 4: assumed grid network in REMix (AC and DC lines)

Assumptions regarding the main HVDC lines techno-economic parameters are reported in Table 2.

Table 2: techno-economic HVDC lines characterization in REMix

Techs	Rated Power	Cost Land	Cost Sea	Losses Land	Losses Sea	Cost Conv	Loss Conv	Amor. Time	O&M Fix
	[MW]	[k€/km]	[k€/km]	[1/100km]	[1/100km]	[k€]	[-]	[y]	[% Cost]
HVDC 1,500UC[1]	1,500	1,661	1,953	0.0034	0.0026	162,000	0.007	40	0.006
HVDC 3,200	3,200	384	2,640	0.0045	0.0027	240,000	0.007	40	0.01

[1] Underground Cable

3.2. Power generation from renewable energy

All VRE potentials are expressed as hourly time series and maximum installable capacities computed with respect to a reference year, in the case 2006, with the sub-model REMix-EnDAT. The model is able to assess global VRE resources in high spatial and temporal resolution (Scholz 2012). The year 2006 has been chosen because it represents a year with medium availability of wind and solar power generation for the considered countries.

The obtained hourly profile is used to calculate the maximum hourly power output from specific VRE technologies. Furthermore, curtailments of the latter can be enabled and the model consequently considers hourly power generation equal to the sum of grid feed-in and curtailment. The main considered techno-economic parameter as reported in Table 3.

Table 3 : main techno-economic characterization of VRE technologies in REMix for 2050 (Cebulla 2017

Technologies	CAPEX	Amortization Time	O&M Fix
	[€/kW]	[y]	[%CAPEX]
Hydro – Run-of-river	5,030	60	5
Photovoltaics	593	20	1
Wind Onshore	1,160	18	4
Wind Offshore	2,050	18	5.5

3.3. Energy storage technologies

Main input techno-economic parameters used in the technology-specific scenarios (4.2) are reported in Table 4. In the case that no source is reported, data have been collected from an internal DLR database.

For hydrogen storage and A-CAES, a technical potential has been set on the maximum installable storage volumes. Values are derived from (Gillhaus 2010) based on (Bünger et al. 2016) considering underground salt deposits and cavern fields in Europe (for details see Supplementary Material). The salt cavern volumes estimated for each model node were used as a limit for the sum of A-CAES and hydrogen storage to consider possible competition between the two technologies.

Table 4: main techno-economic characterization of energy storage technologies in REMix for 2050

Technologies	Storage CAPEX	Charger CAPEX	Discharger CAPEX	η_{charge}	$\eta_{discharge}$	η_{self}	O&M Fix
	[€/kWh]	[€/kW]	[€/kW]	[-]	[-]	[-]	[% CAPEX]
A-CAES	60	350	350	0.86	0.86	0.0157	1.0
RSOFC	130	500	500	0.87	0.87	0.0075	1.0
CHEST	105	750	750	0.84	0.84	0.0833	1.0
P2H2P[1]	50	300	0	1.00	0.42	0.0833	2.0
H_2 Storage	0.7	300	800	0.75	0.62	0	2.0
Li-Ion	150	25	25	0.97	0.97	0.0011	1.0
PHS	10	200	250	0.91	0.91	0.0005	1.0

[1] Following the assumption that costs don't consider the installation of a new turbine but existing turbines are used in the discharge phase. Sources: A-CAES (Cebulla 2017), (Fuchs et al. 2012); RSOFC (German Aerospace Center 2019); CHEST (German Aerospace Center 2019); P2H2P (German Aerospace Center 2019); H_2 Storage (Bünger et al. 2016), (Bertuccioli et al. 2014), (Schmidt et al. 2017), (Steward 2010), Li-Ion (Doetsch et al. 2014), (Giuliano et al. 2017), PHS (Cebulla 2017), (Fuchs et al. 2012),

3.4. CO_2 emissions and conventional power plants

The considered conventional technologies are combined cycle gas turbines (CCGT), natural gas driven gas turbines, hard coal, lignite and nuclear power plants. The CO_2 emission budget is defined for the overall European assessment area, its allocation to the regions is endogenously calculated by REMix. Compared to the emissions in 1990, the budget chosen for the scenario year 2050 corresponds to a reduction of 95% in the case of the model runs for the evaluation of generic storage technologies, and even 98% for the technology-specific model runs. This is equivalent to total values of 200 Mt and 80 Mt, respectively. Specific CO_2 emissions are fuel dependent and its value has been set accordingly. Natural gas produces 0.20 tCO_2/MWh_{chem}, coal 0.34 tCO_2/MWh_{chem} and lignite 0.40 tCO_2/MWh_{chem}. The study only considers direct emissions, so all other generation and storage technologies have zero emissions.

4. RESULTS AND DISCUSSION

In this section the main results of the REMix calculations are presented and discussed. The generic storage sensitivity analysis is described in 4.1. The technology-specific cases are discussed in 4.2.

4.1. Generic storage technology

In this section the results of the generic storage are presented and discussed. The sensitivities on generic storages are performed taking into account a 95 % reduction of CO_2-emissions in comparison to 1990.

4.1.1.Converter CAPEX sensitivity

The first study (Figure 5) concerns the sensitivity analysis of a generic storage as a function of the converter CAPEX in the range between 50 €/kW_{el} and 1,000 €/kW_{el}, while the CAPEX of the storage unit are kept to a fixed value of 50 €/kWh_{el}. The results are reported for the whole assessment area. As one could expect, the more expensive is the converter, the less is the storage installed capacity. With regard to the reduction of the storage installed capacity for different converter cost, the slope of the curve becomes steeper in the middle of the considered cost region (approx. between 500 €/kW and 600 €/kW). In the same region the international grid expansion slightly reduces, while the installed capacity of gas turbines counterbalances the storage reduction.

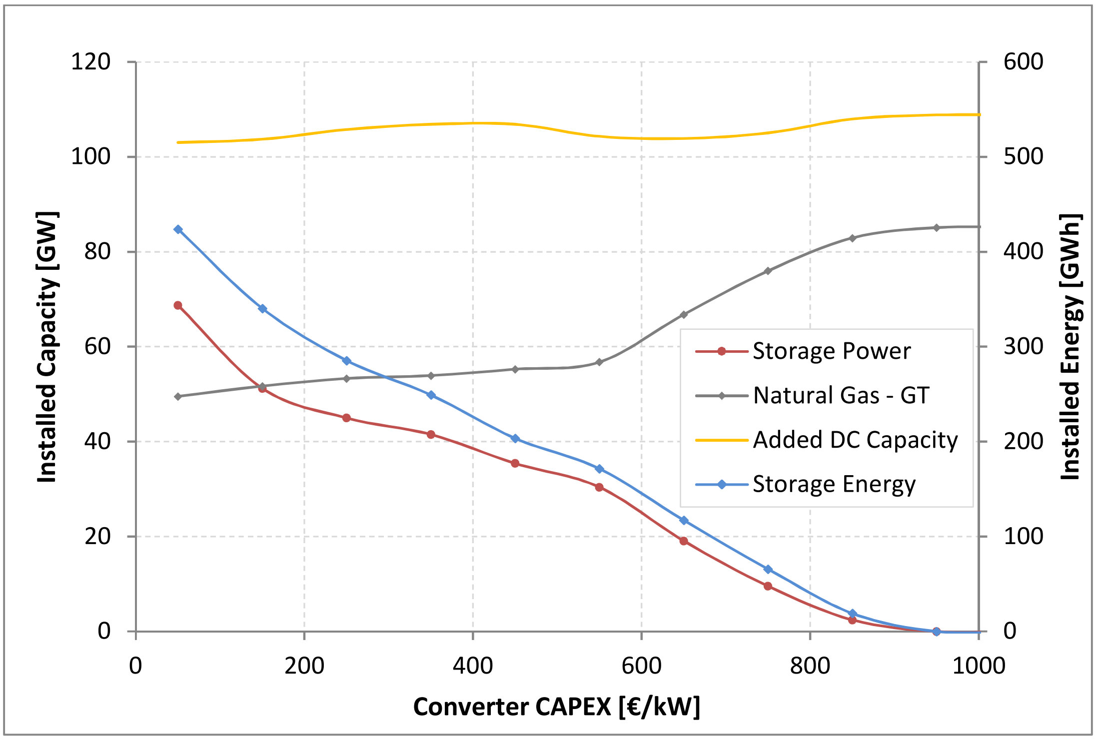

Figure 5: storage converter cost sensitivity on storage installed capacity, grid expansion and installed GT capacity (storage cost 50 €/kWh$_{el}$)

In the high converter cost range, both grid and gas turbines capacities increase – even if to different extents – before leveling off when the installed storage capacity tends to zero. In addition, the capacities of CSP and CCGT increase over the complete cost range when moving toward more expensive storage converters. However, such increases are relatively small (3.3 GW of CSP and 8.0 GW of CCGT added in the analyzed cost range). Given the fixed CO_2 emissions limit for all considered cases, the increase in GT operation corresponds to a reduction of the power provided by coal power plants. Over the considered cost range, the annual renewable energy supply share in the system slightly decreases from 81.3 % to 80.0 %.

All in all, the results indicate that, at least at this geographical aggregation level, the strongest competitors for the expansion of energy storage are gas turbines, while the impact on grid expansion is less intuitive. The seemingly small impact of the sensitivities on the grid expansion is also due to the model setting, i.e. the 95 % CO_2-emissions reduction limit in comparison to 1990. Accordingly, the main cost drivers beside the converter cost are the natural gas price (assumed to be: 47.5 €/MWh$_{th}$) and the load change cost of GT. The details of installed capacity and generated power per technology and model region are reported in the Supplementary Material.

Figure 6 reports a comparison of the installed capacity of storages and of gas turbines for the two different storage cost, i.e. 1 €/kWh and 50 €/kWh, respectively. As one could expect, an increase in the storage investment cost shifts the curves towards lower storage installed capacities. In the case of very low storage cost, as it is the case for hydrogen underground storage, storage systems completely substitute natural gas-fed GT, if specific converter cost below 400 €/kW are reached. The diagram also shows that when the installed storage capacity tends to zero, the GT capacity totals to approximately 85 GW.

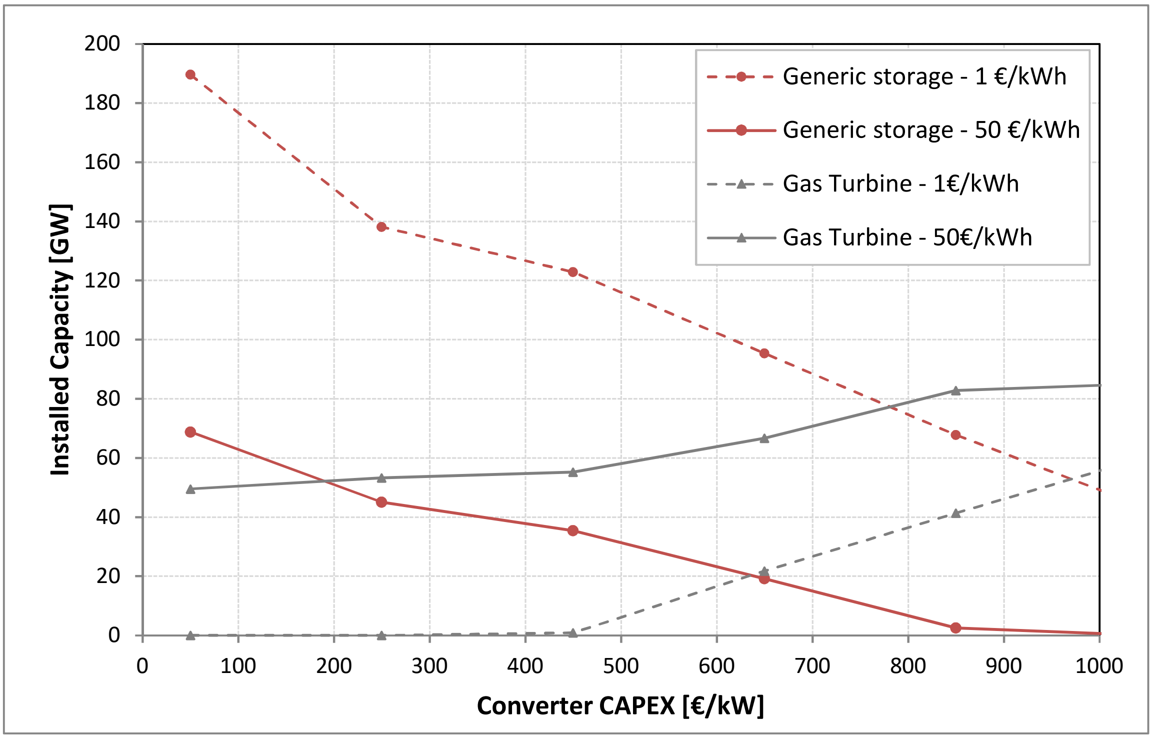

Figure 6: storage installed capacity and GT capacity for different storage and converter costs (storage cost 50 €/kWh$_{el}$)

4.1.2.Storage CAPEX sensitivity

The second study (Figure 7) investigates the impact of specific storage CAPEX on installed storage capacity, grid expansion and GT. Analogous to the previous case the results are reported for the whole assessment area.

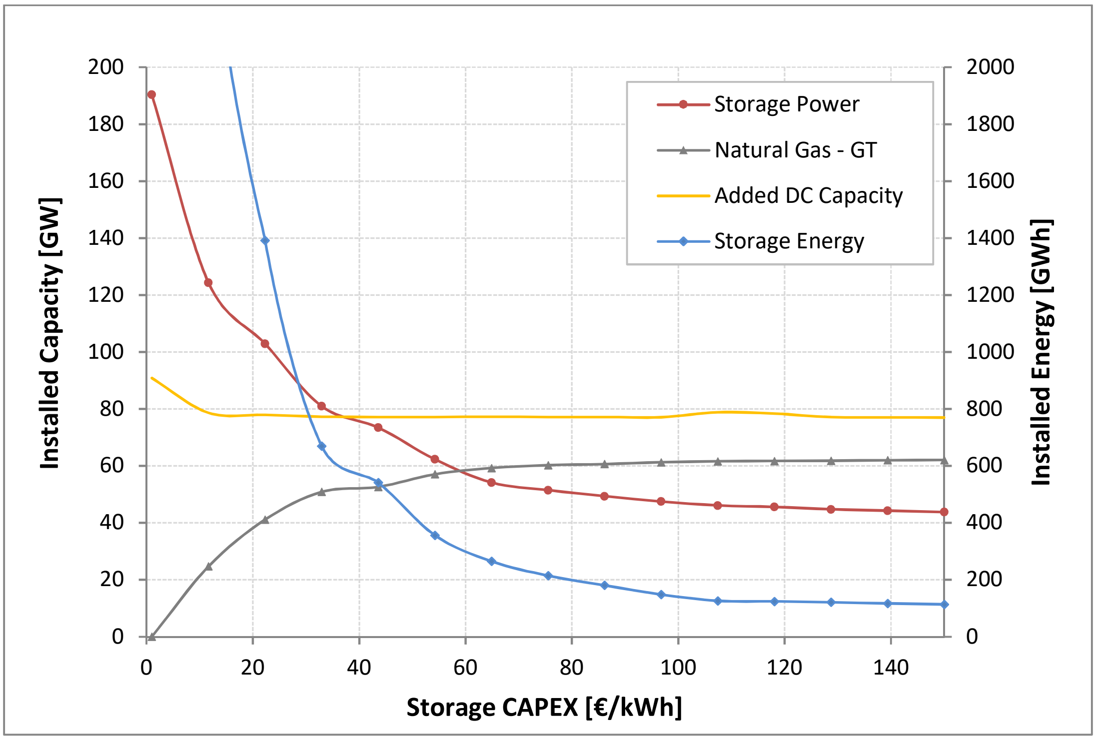

Figure 7: storage cost sensitivity on installed capacity, grid expansion and installed GT capacity (converter cost 500 €/kW)

Also in this case a substitution effect between generic EES and GT occurs. However, the sensitivity on the storage investment leads to different trends in comparison to the previous case. According to the results, a storage expansion up to approx. 190 GW is expected in the case of very low storage cost. In the range between 1 €/kWh and 50 €/kWh a steep decrease of storage installed capacity takes place, while the capacity of mainly GT and other thermal power plants increases (39.7 GW CCGT, 7.5 GW CSP). After that, the storage capacity slightly decreases.

In addition, important information can be deduced, with particular regard to future research for thermal energy storages. Currently thermal storages have a specific storage cost around 20 €/kWh$_{th}$ (Steinmann 2017), which – depending of the efficiency of the conversion to electrical power – can be around 50 €/kWh$_{el}$. This means in turn that a relatively small reduction of storage cost may potentially lead to a relevant extension of the installed thermal storage capacity in future energy systems.

4.1.3. Geographical storage distribution

The geographical distribution of renewable energy potentials plays a key role not only in the type and amount of installed PV and wind power plants, but also in the storage expansion and dispatch. Figure 8 shows the hourly dispatch of power for an exemplary summer week in the model region Iberia, consisting of Spain and Portugal. The black line represents the demand, which is characterized by a typical day/night profile, higher during working days and lower at the weekend.

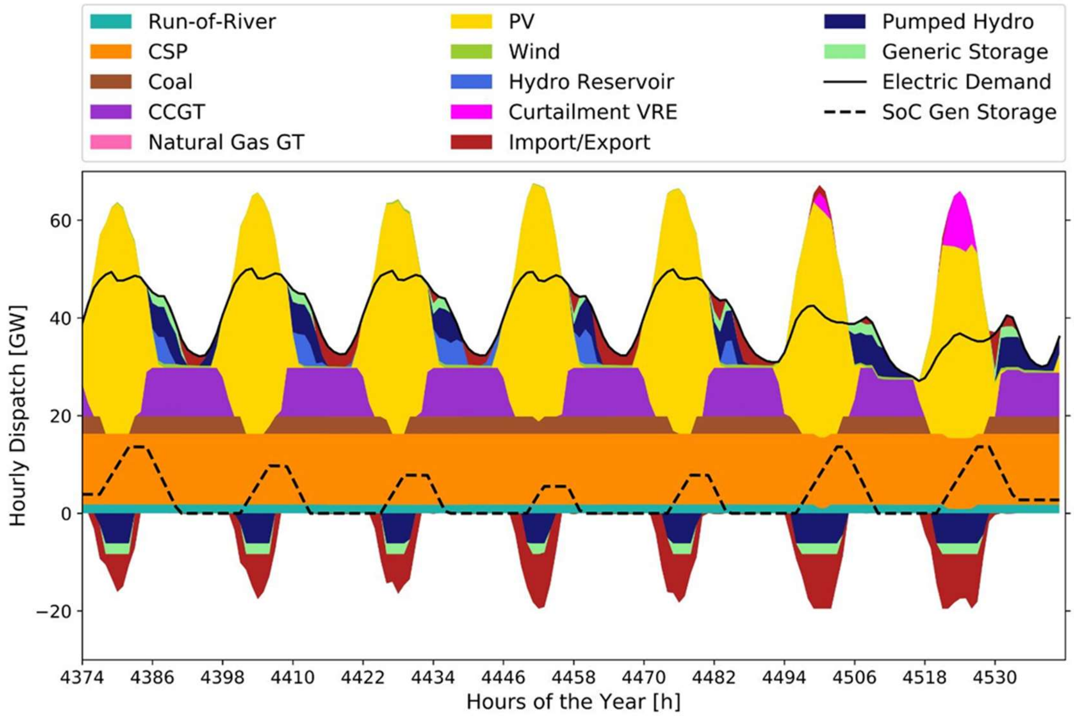

Figure 8: exemplary hourly dispatch for the model region Iberia (CAPEX: 50 €/kWh – 450 €/kW)

The load is covered by an energy mix mainly consisting of PV, CSP, wind power and conventional thermal power plant (coal, CCGT). While CSP provides nearly base load due to the integrated thermal energy storage and potentially the option of hybrid operation with fossil fuels, PV basically covers the noon demand peaks. Wind power generation typically is larger during night hours, when also coal and CCGT plants are operated. Storage charge (existing pumped hydro power and generic storage) takes place at noon while the discharge occurs in the early evening hours. Power generation which is not absorbed by the energy storages are either exported or – as a last option – curtailed. Curtailment is higher during weekends due to the lower power demand.

The model results show that in PV-dominated regions such as Iberia, energy storages experience a full or partial charge-discharge cycle every day (also see the dashed black line in the chart, which represents the state of charge (SoC) of the storage). This does not apply in wind power-dominated regions such as UK (Figure 9). Wind resources and power generation are prone to non-cyclic patterns, which make daily charge-discharge operation of storages less convenient. Similar to Iberia, storage discharge takes place mainly in the early evening hours, while storage charge follows the wind power generation peaks and does not present pronounced regularities.

The power supply in the UK is guaranteed by a mix of mainly wind power, CCGT and a lower share of PV than Iberia. Power imports and exports are more important than for Iberia, which reflects the fact that for non-regular power surplus patterns grid expansion is more convenient than storage installation. On the contrary, for regularly occurring surplus patterns as it is the case for Iberia, storage expansion is more favorable and grid expansion can be at least partially avoided.

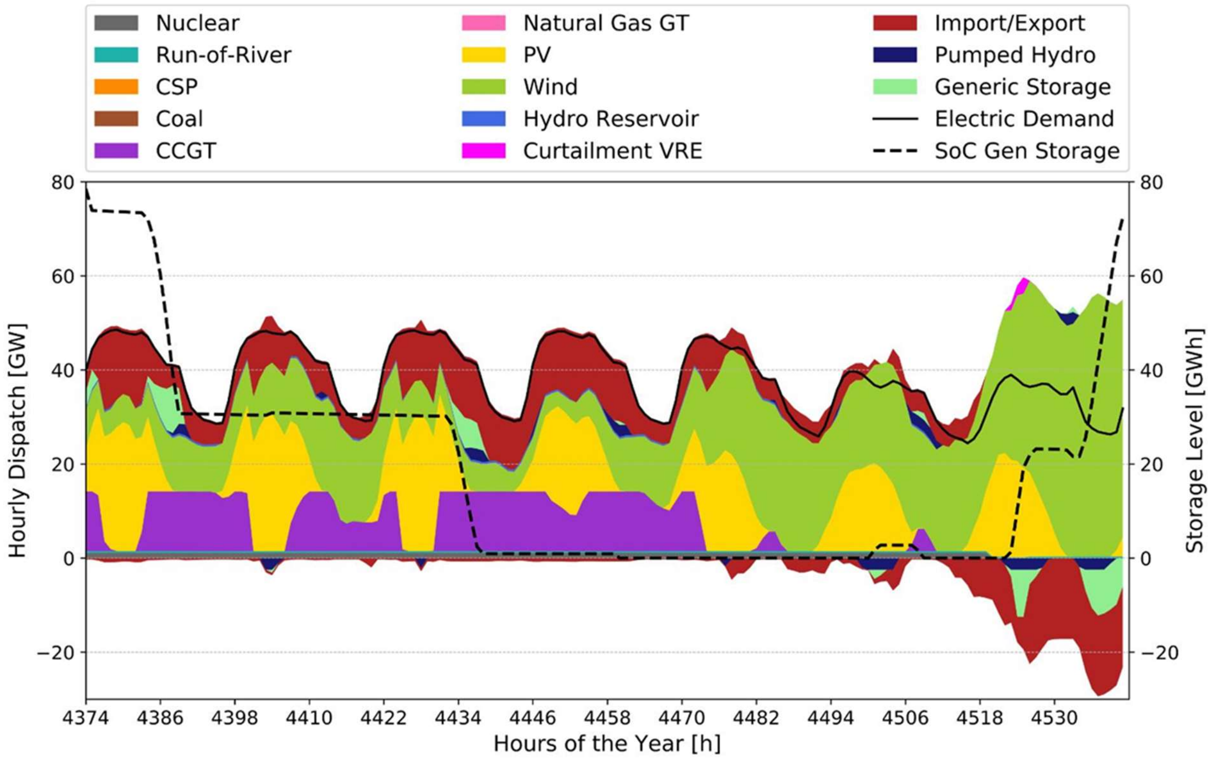

Figure 9: exemplary hourly dispatch for the model region UK (CAPEX: 50 €/kWh – 450 €/kW)

Another interesting model result is that specific storage cost values results in different storage capacity distributions, i.e. the reduction of installed storage capacity is more accentuated in some region than others. This strongly relates to the geographical distribution of renewable power generation and to the resulting optimal storage operation patterns. Figure 10 shows the results of the installed storage capacity as well as the annual discharged energy for each model region and for two specific storage investment cost, i.e. 1 €/kWh$_{el}$ and 50 €/kWh$_{el}$.

From the comparison of the two figures it becomes evident that the storage cost increase results in a strong capacity reduction in UK and BeNeLux (72 % and 87 % respectively), while in Iberia the reduction is much less pronounced (48 %). In other words, the storage reduction is related to the share of wind power of the respective regions.. This appears reasonable, as only low-CAPEX storages can be economically be operated with few, non-regular charging patterns, while relatively expensive storages remain economically advantageous if the number of total equivalent full cycles during a year is sufficiently high (s. also Supplementary Material).

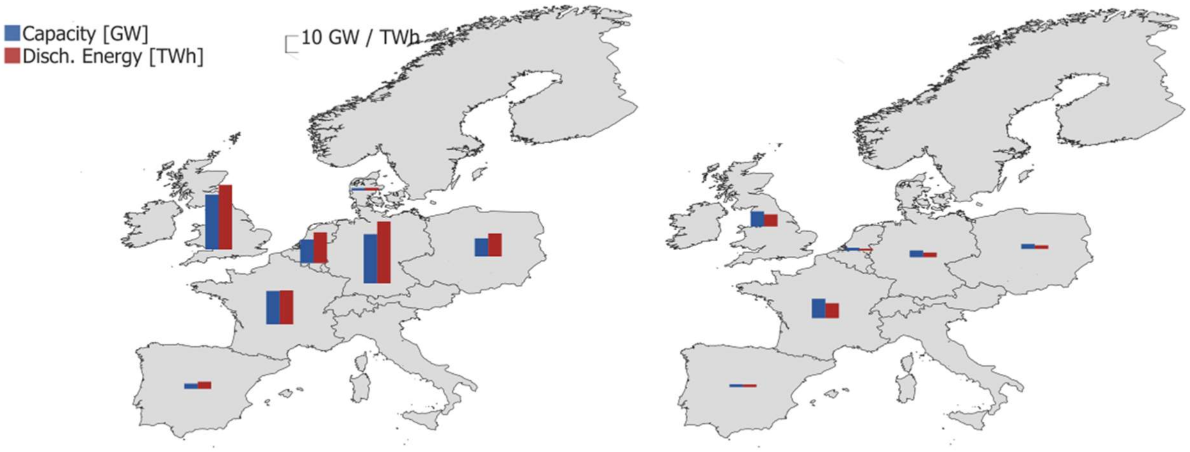

Figure 10 : Region-specific installed generic storage capacity [GW] and discharged energy [TWh]. Storage CAPEX: 1 €/kWh$_{el}$ (left) and 50 €/kWh$_{el}$ (right), converter cost: 500 €/kW

4.2. Technology-specific scenarios

The REMix model has been also applied to investigate the role of a group of innovative storage technologies, which includes A-CAES, CHEST, P2H2P and RSOFC. The main constraint is again represented by the European CO_2 limit, always considering 2050 as the reference year. In this case the CO_2 limit has been set to − 98 % in comparison to 1990 levels instead of − 95 %.

Results are mainly reported by means of maps representing the capacity expansion of both the storage and the grid.

4.2.1. Unlimited grid expansion

Figure 11 shows the results of the case without any limitation of grid expansion. The grey shadings on the countries indicate the different share of VRE to the total power generation. Accordingly, regions with highest variable renewable energy generation are UK and Denmark, due to the high wind potentials. Despite the high PV potentials, Iberia and Italy have relatively low VRE shares. This is because of the lower capacity factor of PV in comparison with wind power. Highest total RE shares are in Denmark, Switzerland and Scandinavia (100 %). Lowest RE shares are in Italy, Iberia, France and PolCzeSlk (61.1 %, 76.7 %, 73.9 % and 70.8 %, respectively). All other remaining regions present a RE share above 80 %.

Largest storage capacities are located in UK, Iberia, Germany, France and Poland. Scandinavia has a minor storage expansion only, which is due to limitations in the additional PHS potentials. PHS covers the majority of the storage demand in Italy, Switzerland, Austria, Iberia and Scandinavia. Total storage expansion amounts to 139.9 GW and 105.2 GW, respectively for charge and discharge converter capacity.

Most of the central European regions are characterized by a technology storage mix consisting of H_2-caverns, batteries and PHS. Highest shares of battery expansions are in France and Eastern Europe. Finally, hydrogen storage plays a dominant role in the UK. The resulting E2P ratios are typically low for batteries, i.e. 1 hour to 3 hours (1.9 hours as European average), depending on the PV potential. In all analyzed cases, the discharge E2P of PHS is in the range of 4 hours to 12 hours. For hydrogen, which is characterized by very low storage cost, the discharge E2P is much higher and is in the range between 550 hours and 800 hours (s. Supplementary Material). Under the given techno-economic assumptions and the model setup, the additionally considered innovative storage technologies only play a minor role. The most competitive of them, namely P2H2P finds some market niches (4.9 GW) as shown in the following sensitivity (Figure 13). In parallel, relevant grid expansion (14.1 GW) takes place to and from Scandinavia. Grid expansion in addition to the current TYNDP takes place for every available transmission line. Major grid expansions are between UK and France, Switzerland and France, Iberia and France, Scandinavia and Poland and are in the range of 7.5 to 9 GW per line.

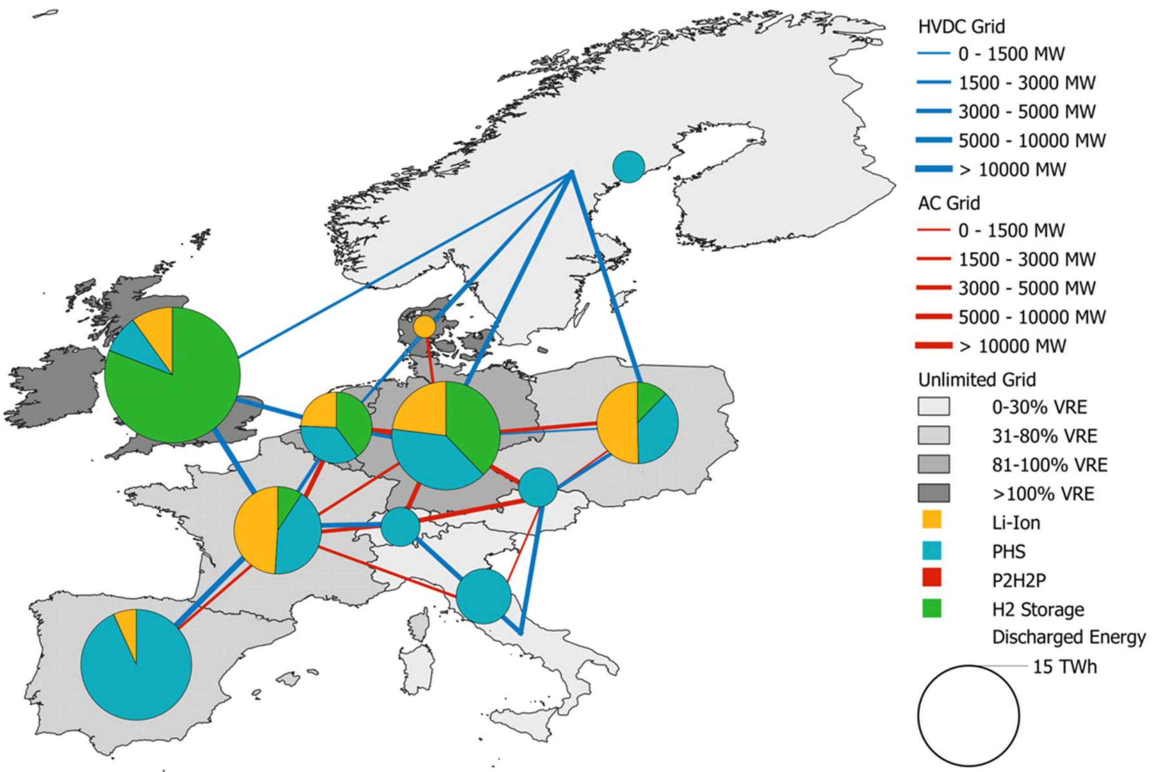

Figure 11: grid expansion and storage installation by technology and model region without grid expansion limitation

The results obtained are in line with the ranges provided by Cebulla et al. 2018 (approx. 200 GW for the "balanced" case and 90 % RE share). However, the range provided there is very broad (50 - 350

GW) as it summarizes in turn a large number of studies. With regards to the energy capacity, Cebulla et al. 2018 report for Europe a range between approx. 2 and 11 TWh. In this study the energy capacity totals to 10.06 TWh. In a previous study (Cebulla et al. 2017) the authors analyze a European electricity-only system with a RE supply share of 89 %, which is comparable to those obtained in this study. They provide a base scenario with a storage requirement of 126 GW and 16 TWh in the case of endogenous grid expansion, i.e. without grid expansion constraints. In (Cebulla et al. 2017) hydrogen underground storage provides 97.3 % of the total storage capacity. The remaining amounts are PHS, Li-Ion and A-CAES. Also in this work H_2-storage plays a dominant role (94.7 % of total storage capacity), while A-CAES does not appear in the results due to the higher CAPEX.

4.2.2. No grid expansion

In the case with no allowed grid expansion beyond the current TYNDP plans, the storage demand significantly increases, in particular considering H_2 storage (Table 5), whereas the capacity of Li-Ion batteries shows a slight decrease (Figure 12).

Table 5: H_2 storage installed capacities for selected model regions and different grid expansion scenarios

	H_2 Storage added capacity [GW]	
	Unlimited Grid	**No Grid Expansion**
Benelux	1.43	4.26
France	0.41	4.50
UK+IE	10.94	16.37
Germany North	2.77	3.67

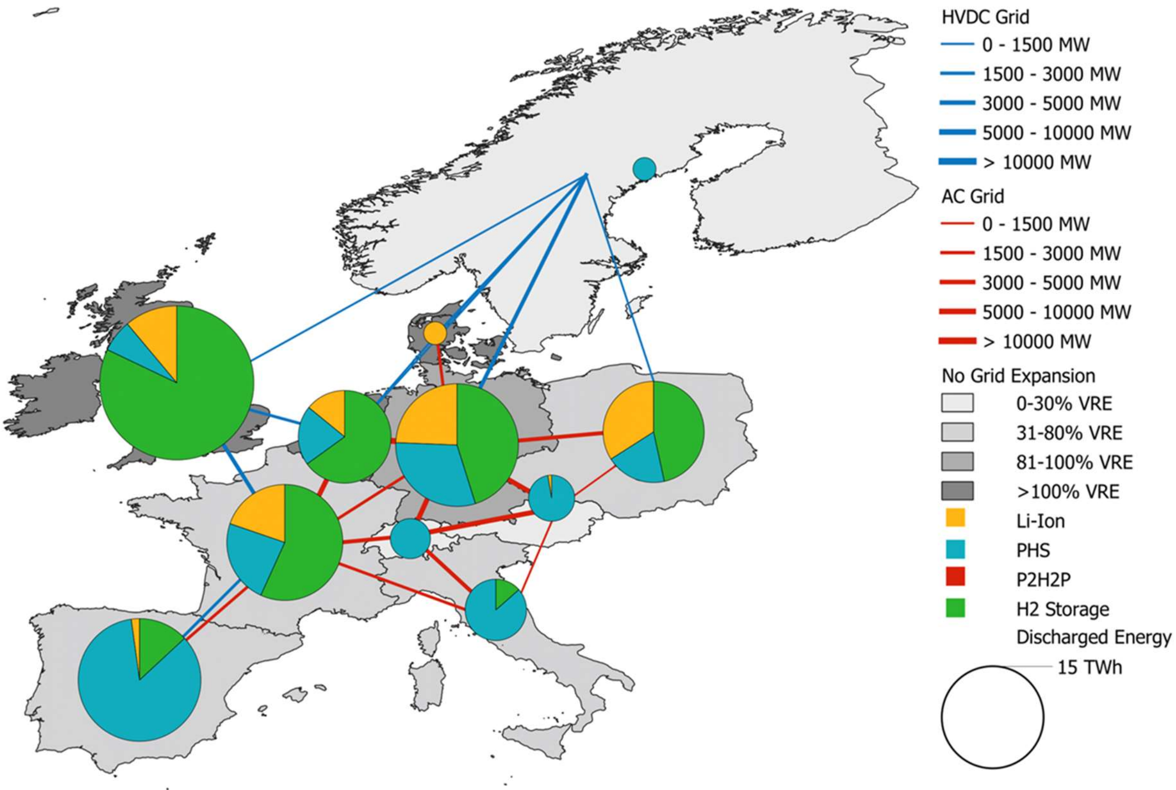

Figure 12: grid expansion and storage installation by technology and model region with grid expansion limitation (following TYNDP)

Total storage expansion amounts to 189 GW and 116 GW, respectively for charge and discharge converter capacity. The installed storage energy approximately doubles to 21.1 TWh. In addition, the relative share of storage technologies also changes. In particular, a shift takes place from batteries (−1.6 %) to hydrogen storage (+47.9 %).

4.2.3. Grid expansion sensitivity

The results of the grid expansion sensitivity are reported in Figure 13. If the added interconnecting transmission is low, the considered system cost mainly consist of hydrogen storage cost, which is less surprising in the light of the previous discussion about Figure 12. Despite providing an important share of the installed storage capacity, PHS cost is relatively low and approximately 0.65 Billion €/y. The reason behind is the fact that the majority of the installed PHS is assumed to be already paid off due to the green field assumptions, so that for PHS O&M cost only have to be considered. This is different to all other installed technologies, for which annualized capital expenditures as well as O&M cost are taken into account. In addition, the system cost consists of a minor share of battery cost, which is nearly independent of the allowed grid expansion. Moving toward higher added interconnecting transmission, hydrogen cost is reduced to approximately one third of the cost without grid expansion, while grid cost linearly increases. This reflects the fact that storage options operated with regular cycles are less prone to sensitivities such as grid expansion or – as it has been discussed previously – storage CAPEX increase. The reason mainly is the better amortization of storage devices at higher annually discharged power. Finally, cost for power-to-heat-to-power plants plays a minor role and presents a slight increase with increasing interconnections.

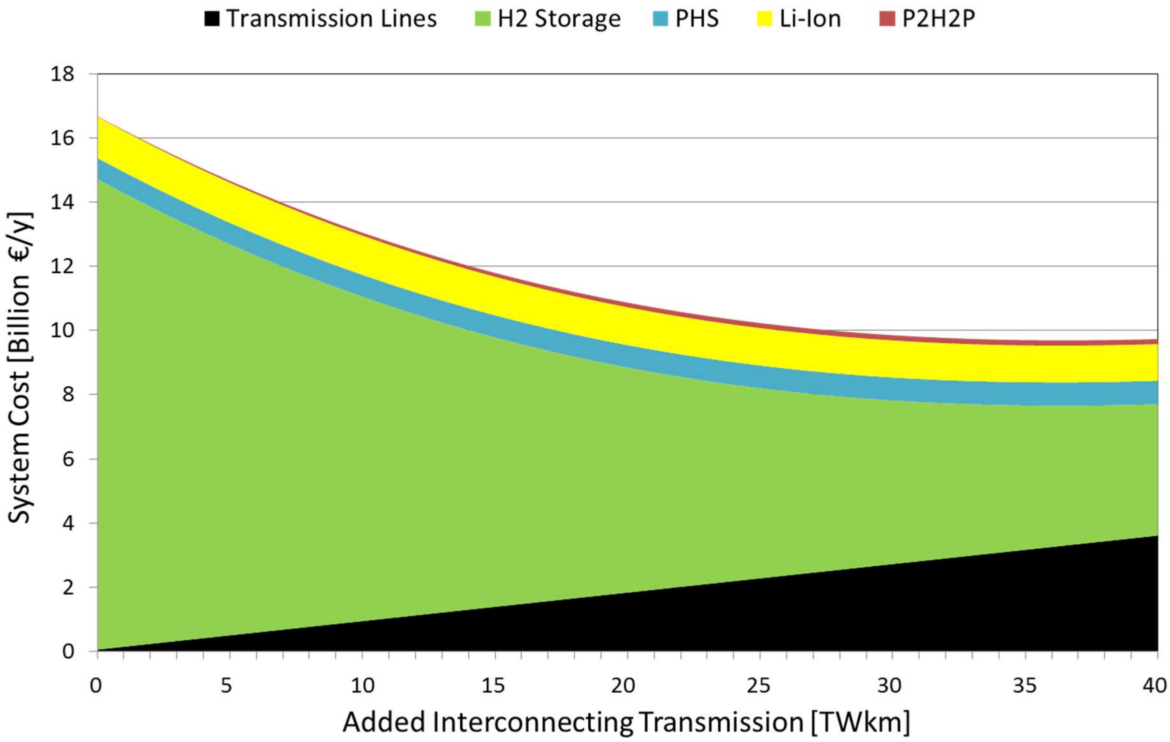

Figure 13: excerpt of system cost (grid expansion and storage cost only) for different grid expansion scenarios

5. CONCLUSIONS

This paper provides a wide sensitivity analysis on the requirement of electrical energy storages in Europe under the assumption of a CO_2 emission reduction of 95 % - 98 % in comparison to 1990. The main novelty of this work consists in the integration of a group of innovative energy storage technologies such as adiabatic compressed air energy storage, compressed heat energy storage, power-to-heat-to-power storage and reversible solid oxide fuel cells into energy system models. Furthermore, it systematically assesses the relation between investment costs and installed capacity of electrical energy storage in a least-cost power system for Europe. To this aim, the REMix model has been applied to optimize power fleet installation and dispatch as well as required grid expansion.

A wide sensitivity analysis in terms of investment costs for power and energy storage units is carried out for a generic storage. The sensitivity analysis on storage investment cost shows that in the range between 1 €/kWh and 30 €/kWh a steep decrease of storage installed capacity takes place, while the capacity of mainly gas turbines and other thermal power plants increases. At storage cost higher than 30 €/kWh, the relative reduction storage capacity flattens until a value of approximately 75 €/kWh is reached. Beyond this value, storage facilities will be replaced more quickly by gas-fired power plants as costs continue to rise. A similar pattern is found when varying converter costs: here, a comparatively low gradient is found in the range between 150 €/kW and 550 €/kW. These results indicate an attractive target range for the specific storage costs of new technologies.

With regard to the geographical distribution of storage installations, it has been found that in regions with high PV potentials such as Southern Europe, energy storages experience a full or partial charge-discharge cycle every day. Also, for regularly occurring storage charge and discharge patterns driven e.g. by PV power generation, storage expansion is less sensitive to storage investment cost. This implies a high robustness for the combination of PV and short-term storage.

Technology-specific scenarios for storages have been also considered. Total storage expansion amounts to 140 GW and 105 GW, for charge and discharge converter capacity respectively. This corresponds to 29 % and 22 % of the annual peak load, respectively. The energy capacity totals to 10 TWh, equivalent to about 0.3 % of the annual power demand. From this follows, that the storage is mostly used for closing capacity gaps, not for storing large amounts of energy. The results show that while some of the regions – namely Southern Europe, Alpine regions and Scandinavia – mainly rely on pumped hydro storage, in most of Central European regions and United Kingdom the cost optimal solution consists of a mix of pumped hydro storage (47.0 % of annual discharged energy in Europe), hydrogen underground storage (33.1 %) and batteries (19.9 %), with an additional small share of power-to-heat-to-power storages (0.04 %).

The model results show that the examined innovative technologies are not competitive under the considered scenario framework conditions and cost assumptions made. It follows that further cost reductions are necessary, or market niches other than large-scale intra-regional load balancing must be found. Restrictions in the availability of raw materials, or an overestimation of the development potential of battery storage and hydrogen underground cavern storage could also change this picture.

While the current work focuses on the power sector, future work will extend the analyses by inclusion of additional flexibility options such as sector coupling with heat as well as mobility sector. Other developments will include a higher time and spatial resolution as well as the consideration of marginal power generation cost in different model regions for strategic commitment of storage units.

ACKNOWLEGDMENTS

This research was funded by the Helmholtz Association within the framework of the Program-Oriented Funding (DLR institutional funding: “IsEn” Project – Isentrope Energiespeicher).

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