

Full-length article

The future role of thermal energy storage in 100% renewable electricity systems

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ABSTRACT

Modeling tools and technologies that will allow reaching decarbonization goals in the most cost-effective way are imperative for the transition to a climate-friendly energy system. This includes models which are able to optimize the design of energy systems with a large number of spatially distributed energy generation sources coupled with adequate short, medium, and long duration storage technologies. Solar photovoltaic and wind energy are likely to become the backbone in a future greenhouse gas neutral energy system and will require low-cost, geographically independent storage technologies in order to balance their intermittent availability. As an alternative to lithium-ion batteries and hydrogen systems, thermal energy storage coupled with a power block (e.g., Carnot batteries, pumped thermal storage, etc.) could be a promising option. Therefore, the current study aims to investigate the influence of renewable generation profiles coupled with alternate storage options (i.e., Li-ion and hydrogen cavern) on the installed capacity of electric-to-thermal-to-electric systems using a 100% renewable electricity system in Germany as a case study. The analyses reveal that Carnot batteries complement established and near-future storage technologies, as they could fill the gap between daily storage such as batteries and seasonal storage such as hydrogen salt caverns. Furthermore, Carnot Batteries could offer multiple options for heat integration further increasing their potential.

1. Introduction

Despite a strong uptake in renewable power [1–3], carbon dioxide (CO₂) emissions continue to reach new heights [4], most likely placing the 1.5 °C limit stipulated by the Paris Agreement [5] out of reach [6]. Germany, meanwhile, has legally committed themselves to reach greenhouse gas (GHG) neutrality by 2045 [7], for which, however, significant progress as compared to latest tendencies must be made [8, 9]. It is due to these ambitious, and necessary, targets that significant research and investment is needed to transition to a GHG neutral yet reliable energy system. This transition is especially complex due to location and time dependent generation from renewables and the variety of potential storage technologies. Therefore, to analyze and understand the transition, advanced models considering spatial and temporal

inputs and outputs are required.

Over the past decade, the cost of variable renewable energy (VRE) technologies such as solar photovoltaic (PV) and wind have reduced to such a level that they are now cost-competitive or even more economic than established fossil fuel alternatives such as coal and natural gas [10–14]. More recently, supporting technologies such as lithium-ion batteries and hydrogen electrolyzers have seen significant reductions in cost to levels where they are also being deployed at scale throughout the globe [15,16]. Other established technologies such as pumped hydro or concentrated solar power (CSP) are also likely to play their part, however, these technologies are more dependent on location and have a limited geospatial potential in Germany [17]. Due to the location dependency of renewable plants, and frequent remoteness from load centers, an increased level of transmission would be required to ensure

Abbreviations: CAPEX, Capital Expenditure; ECTES, Electrically Charged Thermal Energy Storage; EHEB, Electric-heat-electric batteries; EHR, Electrical Heater and Rankine Cycle; ETHOS.FINE, Framework for Integrated Energy System Assessment; OPEX, Operational Expenditure; PTES, Pumped Thermal Energy Storage, TAC, Total Annualized Cost; TES, Thermal Energy Storage.

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sufficient supply [18].

Outside of these technologies, research has also recently begun to highlight the potential role of Thermal Energy Storage (TES) for the energy system [19,20]. While TES has been significantly deployed in conjunction with CSP plants [21] and buildings [22,23], there is also a growing body of research into standalone TES systems charged by electricity, stored thermally, and then reconverted into electricity. These systems are known as thermal, Joule, or Carnot batteries, electric (electrically charged) thermal energy storage (ECTES) or pumped thermal energy storage (PTES) [24–26]. For the purposes of the current study, all of these options will be summarized as electric-heat-electric batteries (EHEBs). In these systems, electricity is converted to heat (either through resistive elements and/or through expansion/compression systems) and then stored in a thermal storage media. The stored heat can then be reconverted to electricity through traditional power block systems (e.g., Rankine, Brayton, etc.) (Fig. 1).

As standalone TES has traditionally low storage capacity-specific costs [27] (i.e., 10–30 €/kWh_D), EHEBs are also found to be potentially competitive with other forms of electrical storage such as lithium-ion batteries, compressed air storage, and pumped hydro, especially for longer duration scenarios [24,28–31]. This is largely due to economies of scale, with an increase in thermal storage capacity merely requiring more low-cost storage material and nearly constant costs for the periphery (heaters, heat pumps, heat engines) as opposed to battery storage which scales linearly. It is these low costs which have led some researchers to investigate the potential of EHEBs to be deployed in certain areas of the energy system. For example, Steinmann et al. [32] investigated the potential of PTES to be used as a smart sector-coupling technology for heat and electricity. In their study, a thermal storage technology based on latent and sensible storage was combined with various charging options and a Rankine cycle. Under various operational conditions, they showed how the system would be mainly used for electrical storage during summer, while in winter, the system would be used to deliver heat and power. During the transitional months, the system would also supply heat and power as required in order to allow a heat pump to recharge the seasonal storage system. Lin et al. [33] explored how EHEBs could be used to assist in the cross-border delivery of steam and power for industrial parks. Under the assumptions of their analysis, it was found that the energy system employing a steam Carnot battery would reduce the operating cost by 28.6%, reduces carbon emissions by 43.5%, and reduces the consumption of grid electricity by 16.5% when compared to a system without the option for a Carnot battery. Frate et al. [34] also investigated using EHEBs to supply energy to three different residential systems. The results of the analysis were compared to a case without storage or with a lithium-ion battery. From their analysis they concluded that EHEBs could reduce the system operating cost by up to 15% when compared to the no storage case. Similar results were found for reductions in CO₂ emissions, with the EHEB saving up to 20% of emissions. However, despite these savings, the total annualized system cost was estimated to be twice that of lithium-ion batteries, and it was concluded for the investigated cases that the EHEB configurations were not financially viable. Therefore, while these studies highlight that EHEBs could be beneficial to the

energy system, their exact role still needs to be further explored, especially for the larger electricity system.

To this end, to assist in determining the most cost-effective transition to a highly renewable and stable grid, complex temporal and spatial models are required [35]. These models have previously been used to highlight the technologies required as well as their capacity to manage this transition [36]. For example, Bussar et al. [37] used the energy planning tool GENESYS to determine the capacity of solar and wind required in Europe by 2050 to meet a high percentage of renewable electricity integration. Alternate models such as the PyPSA-Eur-Sec-30 [38], also for Europe, and the Macro Energy Model (MEM) [39], Storage Deployment Optimization Model (SDOM) [40], or the Regional Energy Deployment System (ReEDS) [41], for America, have also been used to identify and quantify the costs of transitioning to 100% renewable electricity systems. These studies highlight the need for adequate temporal and spatial model resolution to accurately determine technology capacities and opportunities.

As future electricity grids are likely to have large shares of variable renewable electricity (VRE), novel storage technologies could provide firming capabilities to complement VRE as well as potentially lower system costs. To the best of our knowledge, TES as an option to store excess electricity has not yet been considered in a larger-scale (national or international) energy system optimization and therefore its role in the electricity sector transition is currently unknown. In particular, it is an open research question whether TES is likely to serve as an intra-daily, intra-weekly or seasonal storage. While relatively low storage specific costs and high power-specific costs for the periphery such as heat pumps, EHEBs are in favor of the operation on longer time scales at moderate power in- and output, the self-discharge due to heat losses would be decreased for a daily operation pattern.

Therefore, the purpose of the work is twofold; the first is to provide further information on the feasibility of using electric-to-thermal-to-electric technologies for electrical supply while the second is to specifically assess what, if any, the likely role of electric-heat-electric batteries (EHEBs) could be in future electricity systems and the influence of generation patterns and alternate technologies on its deployment. This information can help plan the transition in the most cost-effective way, and to highlight the type and cost of EHEBs that would be most economically beneficial.

2. Methodology

The following section outlines the main inputs and assumptions of the energy system optimization model implemented using the Framework for Integrated Energy System Assessment (ETHOS.FINE) [42], which is part of the Energy Transformation Pathway Optimization Suite (ETHOS). In particular, the approach to model EHEBs as well as techno-economic parameter assumptions are presented in the following. A rough schematic of the considered system is given in Fig. 2, while more information on the model and the assessed technologies are given in the following sections.

As this study is meant to identify niches for EHEBs, rather than to truly outline a real future German energy system, the basic model is a

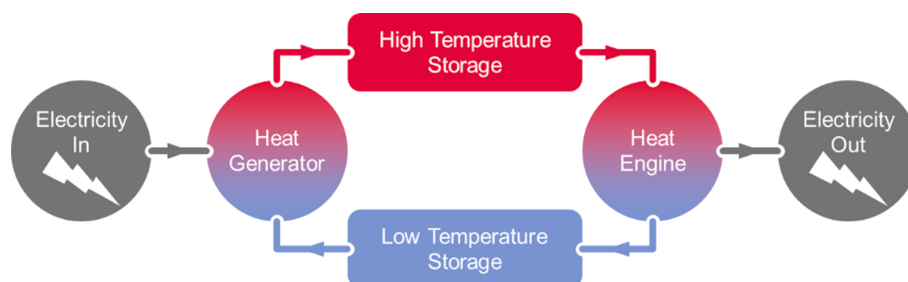


Fig. 1. Basic Schematic of a Carnot Battery System.

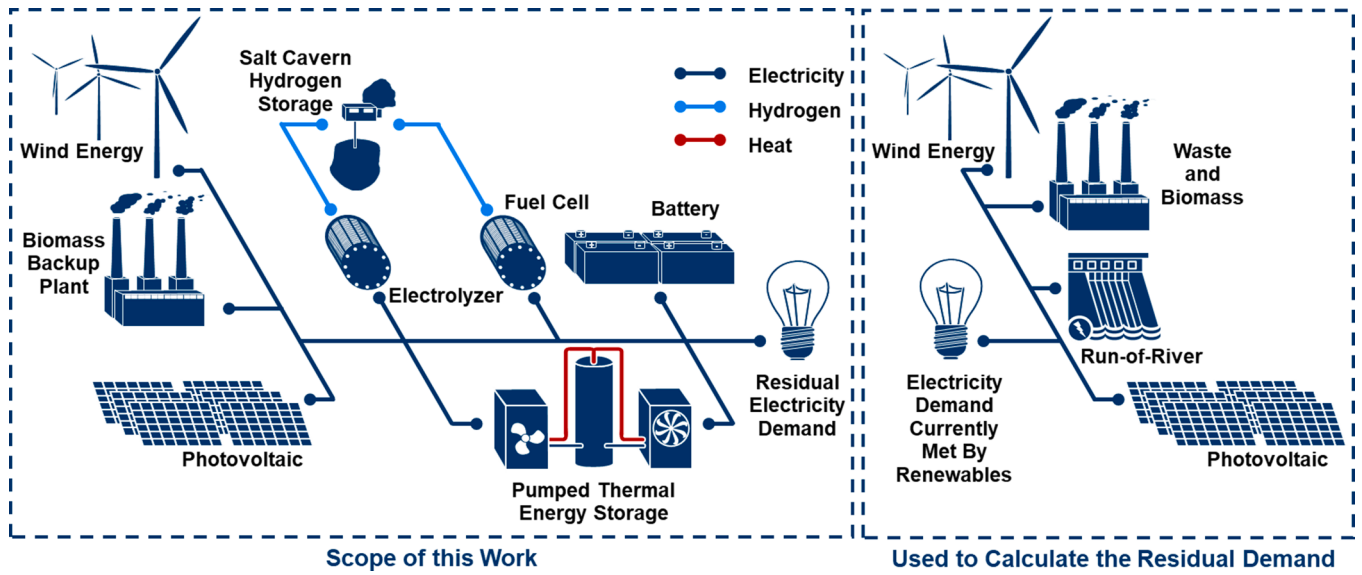


Fig. 2. Basic System Layout for Assessed Technologies.

simplified single-nodal island system model of the German power system focusing on the residual electricity demand. Here, the residual demand should be covered by wind and solar energy as well as biomass as the only remaining dispatchable renewable energy source, which is considered to contribute to up to 10% of the overall electricity demand keeping storage requirements moderate in our study. In case that the 10% would stem from dispatchable fossil plants, this would equal a share of 90% renewable electricity according to the renewable portfolio standard (RPS) [43].

The hourly residual electricity demand of Germany in 2021 is given as the total national demand minus generation from renewable sources over the same timeframe (i.e., hourly 2021 electricity from wind, photovoltaic, hydroelectricity, waste and biomass, as indicated in the right half of Fig. 2). The optimization model depicted in the left half of Fig. 2 needs to meet the resulting residual electricity demand via capacity expansion by means of renewable energy sources while

minimizing the total annualized costs, i.e., the demand is assumed to be perfectly inelastic and effects such as demand response are neglected. Further detail on this assumption is given in Section 4. The portfolio of technology options comprises onshore and offshore wind turbines, photovoltaics and auxiliary dispatchable biomass plants as sources as well as lithium-ion batteries, salt caverns for hydrogen, and thermal energy storage as options for storing electricity. The hydrogen subsystem is linked to the electricity system via electrolyzers and fuel cells, whereas the thermal energy storage is connected by heat pumps or resistance heaters and power cycles (Fig. 3).

In Fig. 3, a basic schematic of a PTES and EHR system is shown. In a PTES system, a heat pump (or similar) machine is used to increase the temperature of the incoming fluid. Assuming the storage media is not the working fluid, the heat can be exchanged with the higher temperature TES system to ‘charge’ the tank. During discharging, the stored energy can be retrieved and used to run a heat engine. In some scenarios

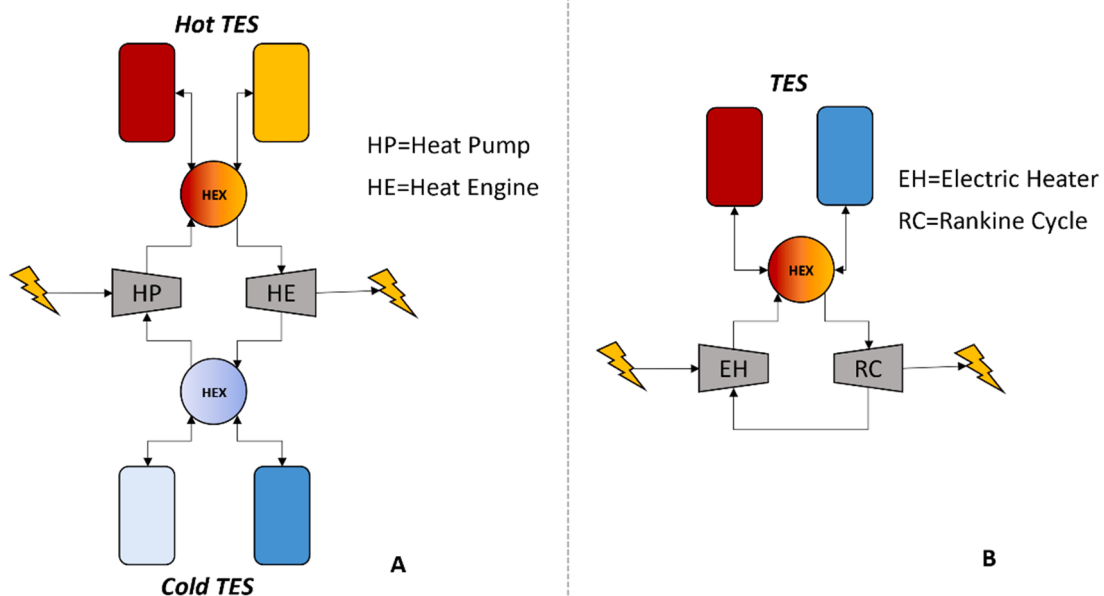


Fig. 3. Schematic of A) Pumped Thermal Energy Storage (PTES) and B) Electrically Heated Rankine (EHR) System.

a cold temperature TES system can be utilized to increase efficiency. In the EHR system, an electric heater is used to generate heat instead of a heat pump. This has the potential to generate higher temperatures, however, it can be less efficient. Similar to the PTES system, the generated heat can be stored in the TES system for later use. Upon retrieval, this heat can be used to generate steam in a typical Rankine cycle. Further information on these systems can be found in [24,25].

2.1. ETHOS.FINE model for techno-economic optimizations

The open-source ETHOS.FINE framework is a mixed integer linear program that can be used for the design and operation optimization of energy systems. Previous information on the model can be found in Welder et al. [42].

To aid in reducing the computational time of the analyzed cases, the data was aggregated [44] into typical periods (as suggested by Hoffmann et al. [45]) which could be further reduced to fewer time steps with irregular length referred to as segments [46,47]. A comparison of how the results compare for fully resolved vs. clustered time-series data indicates that optimizations with 136 clusters and 12 periods involve adequate accuracy (with deviations <4% of total annualized costs for every technology class, i.e., sources, sinks, conversion and storage components) and computing time. Therefore, all following optimizations were run using this clustering type. Further discussion on the impact of clustering results is given in the 'Results and Discussion' section

The techno-economic impact of each design was estimated by annualizing the capital with a suitable discount rate (4%) for the economic lifetime of the system. Note that discount rates, which are commonly used for calculating the net present value of investment appraisals in the energy sector [48] vary greatly in the literature (between 3 and 10% according to Alpizar et al. [49]). Due to the mid-term investment and the fact that Germany is an industrial country with a slow-growing GDP, we assumed this value being at the lower end of the scale. Using this information, the model would then determine the least-cost combination of the studied technologies to meet the stated demand for each time step. It should be noted that in the current study, the total annualized cost (TAC) has the units of €/yr.

2.2. Demand, generation and assessed technologies

The demand and generation for the base case was determined using the published actual load and generation by production type for Germany in 2021 [50]. The unmet demand (for which new capacity would need to be installed) was then determined as the residual demand when all fossil-fuel generation was removed. For the purposes of the current study existing wind and solar, biomass, all forms of hydro, and electricity generated from waste were considered to contribute to meeting the total demand but were kept at 2021 capacity levels to calculate the residual demand, which would need to be met by additional renewable capacities (i.e., the system in the left half of Fig. 2). Furthermore, the impact of imports and exports was not considered. The total demand, residual demand, and generation capacity for the current study is therefore summarized in Table 1.

Table 1
Load and Existing Generation for Current Study.¹

Parameter	Value	Parameter	Value
Total Demand	507 TWh _e	Biomass Generation	39 TWh _e
Hydro Generation	34 TWh _e	Waste Generation	7 TWh _e
Existing Solar	47 TWh _e	Existing Wind	114 TWh _e
Residual Demand	267 TWh _e		

¹ Rounding errors may mean these values do not add up

Using the capacity factors determined by the methodology presented by Pfenninger, Staffell et al. [51,52], the expected generation outputs of the assessed technologies for Germany in 2019 could be determined using the data base Renewables.ninja [53] yielding the profiles depicted in Fig. 4.

A description of the assessed technologies is given in Fig. 2, while more details on the technology efficiencies and costs are summarized in the following section and Table 2, below. It should be noted that the technologies chosen in the current study are not exhaustive and are more selected to show the difference in technology operation and how this would benefit and be representative of the overall system. For example, it is expected that the future electrical grid will be mainly fed by solar PV with lower capacity-specific costs as well as less full load hours and, capacity-specifically, more expensive wind turbines with higher average capacity factors and a less predictive temporal availability pattern. The variable renewable electricity will need to be stored to meet generation shortfalls on the intra-daily, and -seasonal scale. Therefore, higher storage cost but fast responding lithium-ion batteries, lower storage cost but higher power cost thermal storage, and very low storage cost but higher power specific cost hydrogen storage, respectively, was considered as potential storage options to properly cover all potential storage cycle lengths.

2.3. New capacity generation, conversion and storage sources

For the current study it was assumed that all new generation would be by ways of solar PV, wind, and a dispatchable backup capacity for peak demands. Excess solar and wind could be stored or converted to hydrogen and then electricity to also fill in generational gaps. The peak-load plant (i.e., a plant which is only designed to run for short amounts of time each year) is designed so that it cannot meet more than 10% of demand and is assumed to be fed by biomethane in a gas turbine. The cost of the biomethane was estimated to be €14.2/GJ (€0.05/kWh), based on estimates from the IEA [58].

The present study only considers the conversion of electricity to hydrogen and vice-versa in the future German electricity grid. Inputs for the model are based on Hunter et al. [59] for the fuel cell (Table 2), while inputs for the alkaline or PEM electrolyzers are based on assumptions presented in the Lazard report on hydrogen production costs [55]. As a range of electrolyzer sizes will be required, the base-case assumptions are an average of the 20 MW_e and 100 MW_e capacities for the 'average' case presented in Lazard [55] (Table 2), i.e. a linearized cost curve was assumed for the sake of simplicity.

The cost and efficiency parameters for the *Electrical Heater and Rankine Cycle* (EHR) system (Table 2) were estimated based on a previous technology review by Dumont et al. [25]. In this study, the cost and efficiency of the Electrical Heater and Rankine Cycle system was based on a Siemens Gamesa system [60]. In the current study, the self-discharge parameter was determined by considering the stated self-discharge of the *Pumped Thermal Energy Storage* (PTES) system. In the current study, the EHR system operates at a lower temperature and therefore suffers from less self-discharge (as noted by Dumont et al. [25]). Additionally, similar to the PTES system, the design and operation of the Electrical Heater and Rankine Cycle system will affect its final cost, efficiency and, as such, a sensitivity analysis was performed on the cost and technical efficiencies to understand these impacts (c.f. Section 3.2.2). The cost and efficiency parameters for the PTES system (Table 2) were based on previous studies performed by Smallbone et al. [28], Benato and Stoppato [24], and Dumont et al. [25]. As each study differs in the assumptions and system setup, input values were determined using an average of the stated values in the aforementioned studies. However, due to the range of values given, a sensitivity analysis using more conservative or optimistic estimates for costs and efficiencies is included in Section 3.2.2

The cost and efficiency of lithium-ion storage was based on estimates from Lazard [15] and Cole et al. [57] using the average cost and

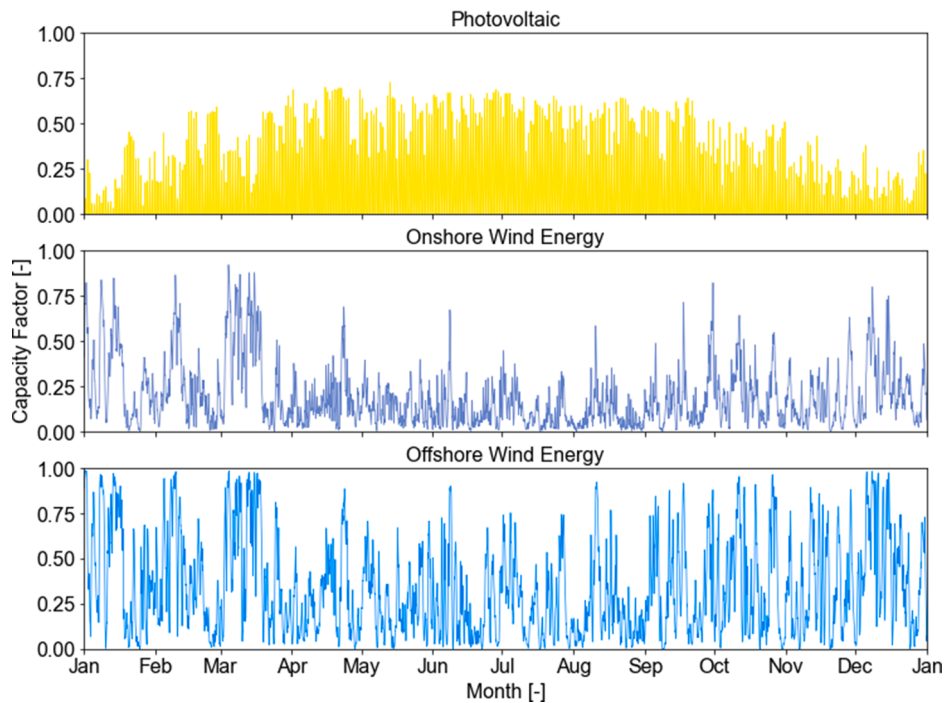


Fig. 4. Capacity Factors for Solar and Wind Output in Germany [51–53].

efficiencies of the standalone systems (Table 2) whereas the self-discharge value was determined by Shchurov et al. [56]. Furthermore, the cost and performance of hydrogen storage was based on parameters determined by Hunter et al. [59] for salt cavern storage (Table 2). As noted by Caglayan et al. [61], Germany has sufficient salt cavern storage for hydrogen, therefore this was the only method of hydrogen storage considered in the ‘Base’ case scenario for the sake of simplicity and given the fact that more expensive technologies such as hydrogen pressure vessels would not be part of a cost-optimal solution in a single-node model anyways.

2.4. Studied cases

In the current study, several different scenarios were considered to better understand the influence of technology choice and assumptions on both the energy system design and the capacity of electric-heat-electric batteries. In the ‘Base’ case scenario, the assumptions presented in Table 1 and Table 2 were applied. In addition to the ‘Base’ case, several other scenarios were studied including the influence of technology costs and constraints as well as whether the wind farms are on- or offshore. This is summarized in Table 3 and described below.

Impact of limited technology potentials. In the current study, the maximum installed capacities are based on the average theoretical limit from Risch et al. [54]. However, cases may arise in which it would be cost-effective to install more of a technology if the limit was raised or land use may not be as available as expected. Therefore, to study the impact of such restrictions, the calculated maximum and minimum allowable technology capacity limits from Risch et al. [54] were also analyzed (Table 4).

Impact of technology costs. As the price of PV is dependent on many factors such as location, supplier, etc., the impact of cost changes of the PV system on the overall system cost and design was studied. This involved varying the cost of the PV system from as low as €650/kW to €1000/kW. In both of these cases, the OPEX and other technology costs remained the same as the ‘base’ case. Analogous to the cost changes that could be experienced by PV, a similar study was undertaken on the cost of on- and offshore wind farms. The cost of the systems was varied from €1200/kW to €3000/kW, and €800/kW to €1300/kW, for offshore and

onshore farms, respectively.

The CAPEX of the alkaline electrolyzer was also varied from €550/kW_e to €800/kW_e, and the impact of using PEM electrolyzers instead of alkaline electrolyzers was likewise studied. Finally, the impact of varying the cost of the fuel cell from €1000/kW_e to €1300/kW_e was also investigated.

In addition, as hydrogen cavern storage is geographically constrained, further analysis on the implications of changes to the hydrogen storage cost was undertaken. This included increasing the CAPEX of the hydrogen storage (€15/kWh) [62] while maintaining the other assumptions from the ‘Base’ case scenario.

Lithium-ion batteries, despite being a key technology in a low carbon future, are highly dependent on critical materials to maintain low costs. However, as deployment continues, economies of scale should lead to decreasing costs of this technology. Therefore, it is conceivable that in the near future the cost of lithium-ion batteries may decrease or increase, depending on market forces. To study this impact on system design, the cost of the lithium-ion battery was varied from €200/kWh to €500/kWh.

Finally, as the newest technology, accurate costs of EHEB at scale are difficult to estimate [24,25,28]. Therefore, ‘low’ (€100/kWh) and ‘high’ (€180/kWh) costs for PTES, and ‘ultra-low’ (€25/kWh) and ‘low’ (€60/kWh) Rankine costs were also studied.

Impact of technology absence. While future energy systems are likely to involve all technologies, it is important to understand the influence of certain technologies on others. Therefore, several scenarios were considered and their absence on the deployment of Carnot batteries was assessed. This comprises the exclusion of further solar PV or wind generation, the removal of hydrogen conversion and storage, or the removal of further lithium-ion battery deployment. Understanding these restrictions could help researchers and planners understand the role EHEBs may play in future energy systems and how they interact with said technologies.

3. Results and discussion

The following section summarizes the results of the current study and discusses their significance.

Table 2

ETHOS.FINE Inputs for various technologies [12,15,24,25,28,54–57].

Parameter	Unit	Value	REF	Parameter	Unit	Value	REF
Fixed-axis Solar PV							
CAPEX (variable)	€/kW	740	[12]	OPEX	€/kW-yr	9.56	[12]
Lifetime	years	20	[12]	Maximum Capacity	GW	289.9	[54]
Offshore Wind							
CAPEX	€/kW	2590	[12]	OPEX	€/kW-yr	61.73	[12]
Lifetime	years	20	[12]	Maximum Capacity	GW	66.9	[54]
Onshore Wind							
CAPEX	€/kW	1010	[12]	OPEX	€/kW-yr	26.14	[12]
Lifetime	years	20	[12]	Maximum Capacity	GW	246.5	[54]
Gas Turbine operated with Biomethane							
CAPEX	€/kW	690	[12]	OPEX (fixed)	€/kW-yr	12.00	[12]
OPEX (variable)	€/kWh-yr	0.00393	[12]	Minimum Run	% Full Load	10	
Maximum Size	% Demand	10		Lifetime	years	20	[12]
Fuel Cost	\$/GJ	14.19	[58]	Fuel Cost	€/kWh	0.05	[58]
H₂ Fuel Cell							
CAPEX (fixed)	€/kW _e	1122	[59]	OPEX	€/kW _e -yr	11.39	[59]
H ₂ -to-Elec Efficiency	%	75	[59]	Stack lifetime	hours	40,000	[59]
Plant lifetime	years	15	[59]				
H₂ Electrolyzer Alkaline							
CAPEX	€/kW _e	633.25	[55]	OPEX	€/kW _e -yr	9.50	[55]
Elec-to-H ₂ Efficiency	%	67	[55]	Stack lifetime	hours	67,500	[55]
Plant Lifetime	years	15	[55]				
H₂ Electrolyzer Polymer electrolyte membrane (PEM)							
CAPEX	€/kW _e	828.75	[55]	OPEX	€/kW _e -yr	12.43	[55]
Elec-to-H ₂ Efficiency	%	58	[55]	Stack lifetime	hours	60,000	[55]
Plant Lifetime	years	15	[55]				
Electrical Heater and Rankine Cycle (EHR)							
CAPEX	€/kWh	94	[25,60]	OPEX (variable)	€/kWh-yr	0.94	[25]
Discharge Efficiency	%	45	[25]	Charge Efficiency	%	98	[25]
Self-Discharge [thermal]	%/day	0.7	[25]	Lifetime	years	30	[25]
Pumped Thermal Energy Storage (PTES)							
CAPEX	€/kWh	140	[24,25,28]	OPEX	€/kWh-yr	1.4	[24,25,28]
Charge Efficiency	%	100	[24,25,28]	Discharge Efficiency	%	67	[24,25,28]
Self-Discharge [thermal]	%/day	1	[24,25,28]	Lifetime	25		[24,25,28]
Li-ion Battery							
CAPEX	€/kWh	275.4	[15,57]	OPEX (variable)	€/kWh-yr	1.7	[15,57]
Charge Efficiency	%	100	[15,57]	Depth of discharge	%	87.5	[15,57]
Self-Discharge	%/day	0.2	[56]	Lifetime	years	20	[15,57]
H₂ Storage							
CAPEX	€/kWh	3.11	[59]	OPEX (fixed)	€/kWh-yr	0.056	[59]
Charge Efficiency	%	100	[59]	Depth of Discharge	%	70	[59]
Lifetime	Years	30	[59]				

Table 3

Investigated Technology Costs in the Current Study.

Technology	'Base' Cost	'Low' Cost	'High' Cost
Solar PV	€740/kW	€650/kW	€1000/kW
Onshore Wind	€1010/kW	€800/kW	€1300/kW
Offshore Wind	€2590/kW	€1200/kW	€3000/kW
Alkaline Electrolyzer	€633.25/kW _e	€550/kW _e	€800/kW _e
PEM Electrolyzer	€828.75/kW _e	–	–
H ₂ Fuel Cell	€1122/kW _e	€1000/kW _e	€1300/kW _e
H ₂ Storage	€3.11/kWh	–	€15/kWh
Lithium Ion Batteries	€275.4/kWh	€200/kWh	€500/kWh
PTES	€140/kWh	€100/kWh	€180/kWh
EHR	€94/kWh	€60/kWh	€25/kWh*

* under this scenario the cost indicated is for an 'ultra low' cost.

Table 4

Technology Capacity Limits according to Risch et al. [54].

Technology	Average Maximum Capacity (GW)	Theoretical Maximum Capacity (GW)	Theoretical Minimum Capacity (GW)
Solar PV	289.9	456.1	123.6
Onshore Wind	246.5	403.0	90.0
Offshore Wind	66.9	99.6	34.1

3.1. Base case

Under the base case, all technologies are assessed concurrently, with the technology resulting in the lowest system cost options being selected and are summarized in Table 5. Note that these capacities only refer to additional capacities to meet the residual load besides the existing ones, i.e. they are smaller than the overall capacities of, e.g., wind turbines and solar PV.

The generation, hydrogen conversion and reconversion, and storage profiles were also calculated and are summarized in Figs. 5–7. The generation profiles (Fig. 5) reveal a strong seasonal dependence of the potential future energy system. While the generation from wind is generally consistent throughout the year, the solar output clearly peaks through the summer months. The shortfall this creates in winter is partly balanced by the backup plant which only runs during a small number of periods throughout the winter, while the hydrogen storage is used to meet shortfalls in the summer and winter (Fig. 6). From this figure, a

Table 5

Summary of Technology Capacities- Base.

Source Technology	Capacity (GW)	Storage Technology	Capacity (GWh)
Solar PV	70.83	PTES	14.74
Onshore Wind	116.38	H ₂ Storage	3097.51
Backup Plant	27.15	Li-ion Battery	23.12
Alkaline Electrolyzer	22.76		
Fuel Cell	14.05		

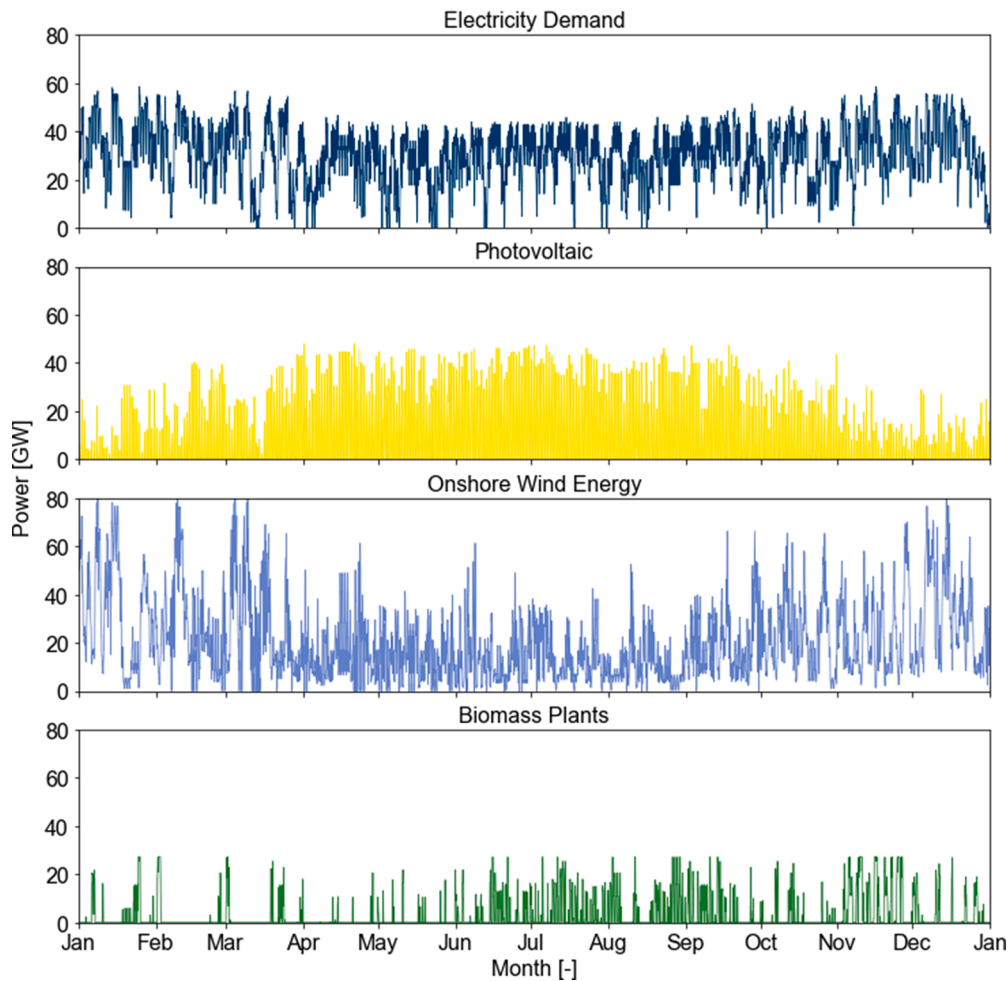


Fig. 5. Summary of Generation Profile – Base.

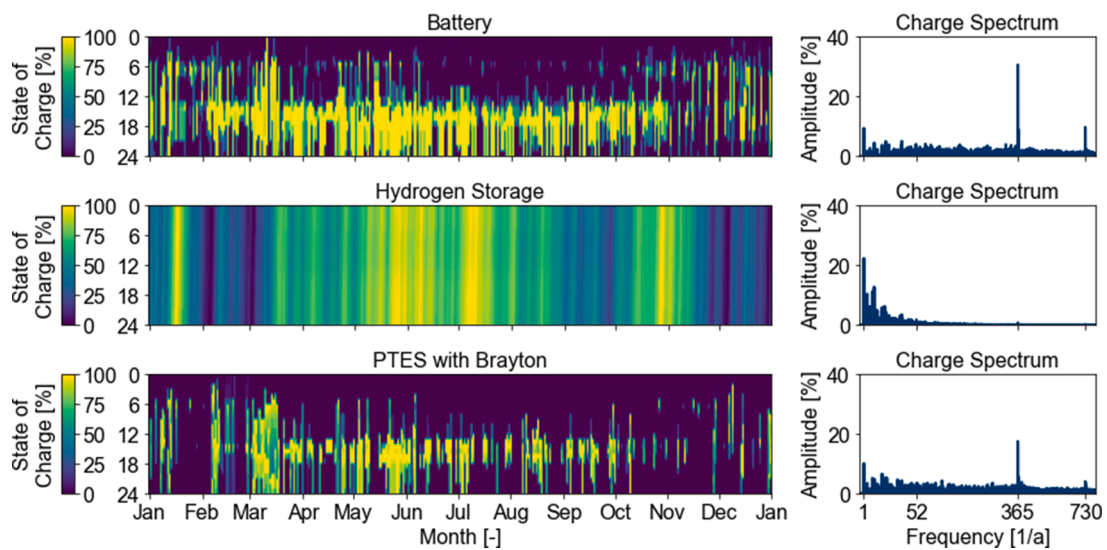


Fig. 6. Summary of Storage State of Charge – Base.

strong seasonality in the storage technologies is likewise apparent, with the hydrogen storage slowly being charged during the summer, then emptying, before being charged again during autumn for the winter. The battery usage is comparatively consistent throughout the year and is only engaged for several hours at a time, similar to the PTES, which,

while also discharged on most days, is mainly engaged for shorter periods of time. It can be concluded from Fig. 6 that while both batteries and PTES complement each other, they ultimately appear to perform similar roles within the electricity network. That is, the battery and PTES systems predominantly perform the role of intra-day storage rather than

the inter-day and seasonal storage of the hydrogen system. This can be explained by the higher self-discharge rates and capacity-specific costs of PTES and batteries, predestining them for shorter storage cycles with lower storage capacities. Note that the employed clustering approach for speeding up the calculations was enabled to account for seasonal storage for PTES and batteries as well using the method proposed by Kotzur et al. [63], however, the optimization neglected this option as an economically non-viable one. The hydrogen storage is used to move the bulk of the energy from the oversupply during the ‘off-peak’ months to under supply during the ‘peak’ months. Lastly, the output from the fuel cell and electrolyzer are approximately consistent throughout the year, with a slight increase in usage throughout the summer months (Fig. 7). However, it should be noted that while the fuel cells and electrolyzers are engaged most days, they do so largely at reduced operation rates with the exception for when the seasonal storage is engaged. Therefore, these technologies are likely to ‘trickle charge and discharge’ throughout the year but be fully engaged during winter. In the current study, the backup plant is assumed to be powered by biomethane. According to a biomethane production report by the Guidehouse B.V. [64] the biomethane production in Germany for 2030 will be approximately 8 bcm/year. In determining the amount of biomethane to operate the backup plant, it was found that approximately 2.6 bcm/year would be required. Therefore, it is feasible that a backup plant could be operated this way if sufficient biomethane was available.

3.2. Alternate scenarios

In this section, the impact of differing assumptions on the system design and cost are analyzed. These include the impact of technology costs, capacity of on- and offshore wind farms, and choice of thermal storage or electrolyzer technology.

3.2.1. Impact of limited technology potentials

As the ‘Base case’ does not approach the maximum theoretical capacity allowed from Risch et al. [54] only the minimal potentials are examined. In applying a technology capacity limit on Solar PV and onshore wind, it can be seen that while there is enough capacity for solar PV installations to increase to 112 GW, the limit is reached on onshore wind installations, which requires further generation from offshore wind to offset. This change in generation technologies favors the use of hydrogen generation, and battery and hydrogen storage, resulting in no deployed TES technologies. However, when an optimization at full temporal resolution is run, TES technologies are present once more with

an installed capacity similar to the ‘base’ case scenario, although Pumped Thermal Energy Storage (PTES) is preferred rather than Electric Heater and Rankine Cycle (EHR) in the ‘Base’ case. Therefore, even with generation constraints imposed by land unavailability, an impact on TES capacity is unlikely.

3.2.2. Impact of technology costs

To determine the impact of variable technology costs on the design of the system, and in particular, the impact on thermal storage capacity, various studies involving changing the cost of uncertain components was undertaken. This involved varying the cost of PV systems, wind turbines, choice of electrolyzer chemistry, etc., with the results summarized in Fig. 8.

Impact of PV cost. Under the low-cost PV scenario, there is a slight increase in PV generation and lithium-ion battery storage capacities. This is most likely due to the synergy of daily generation of PV and daily storage of lithium-ion batteries. Conversely, the other technologies such as hydrogen conversion and storage, as well as TES storage capacity are marginally reduced. The opposite is true for high-cost solar PV, with the capacities of hydrogen generation and TES increasing whereas battery storage decreases. Interestingly, under the high-cost solar PV scenario, the PTES capacity decreases while the EHR capacity significantly increases. This may be due to the lower storage capacity cost of EHRs compared to PTES. Therefore, as more PV is added to the system, longer duration storage is needed, favoring technologies with lower storage-capacity costs.

Impact of wind farm cost. For both the low-cost on- and offshore wind farm scenarios, there is a slight increase in TES storage capacity. This increase in storage capacity is used to offset less hydrogen generation and storage, and lower battery storage requirements. At higher wind farm costs, hydrogen generation and storage are preferred, with TES storage capacity being reduced. Again, this highlights the differing generation and storage profiles where wind is better suited to longer-term storage profiles offered by TES and hydrogen but an increase in TES can reduce the need for seasonal (hydrogen) storage.

Impact of electrolyzer and fuel cell costs. Low-cost hydrogen generation or re-electrification positively impacts TES storage capacity, with their storage capacity rising by between 3 and 9% in these scenarios. For the other technologies, changes in the hydrogen generation or conversion prices have little effect, with high costs favoring the use of lithium-ion batteries. From these results, there appears to be a weak positive correlation between an increase in hydrogen generation and re-electrification, and TES storage capacity. This correlation could be due

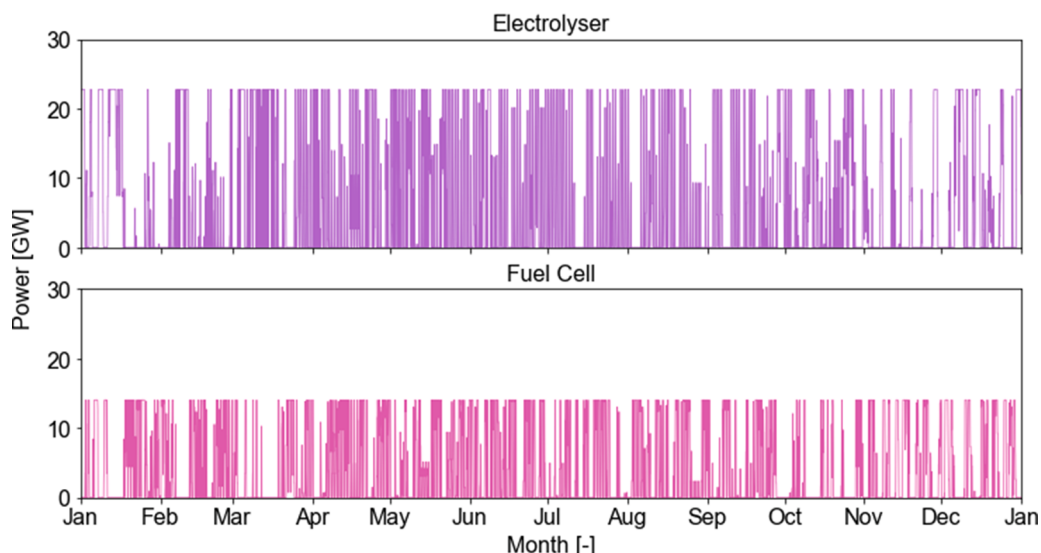


Fig. 7. Summary of Conversion Profile – Base.

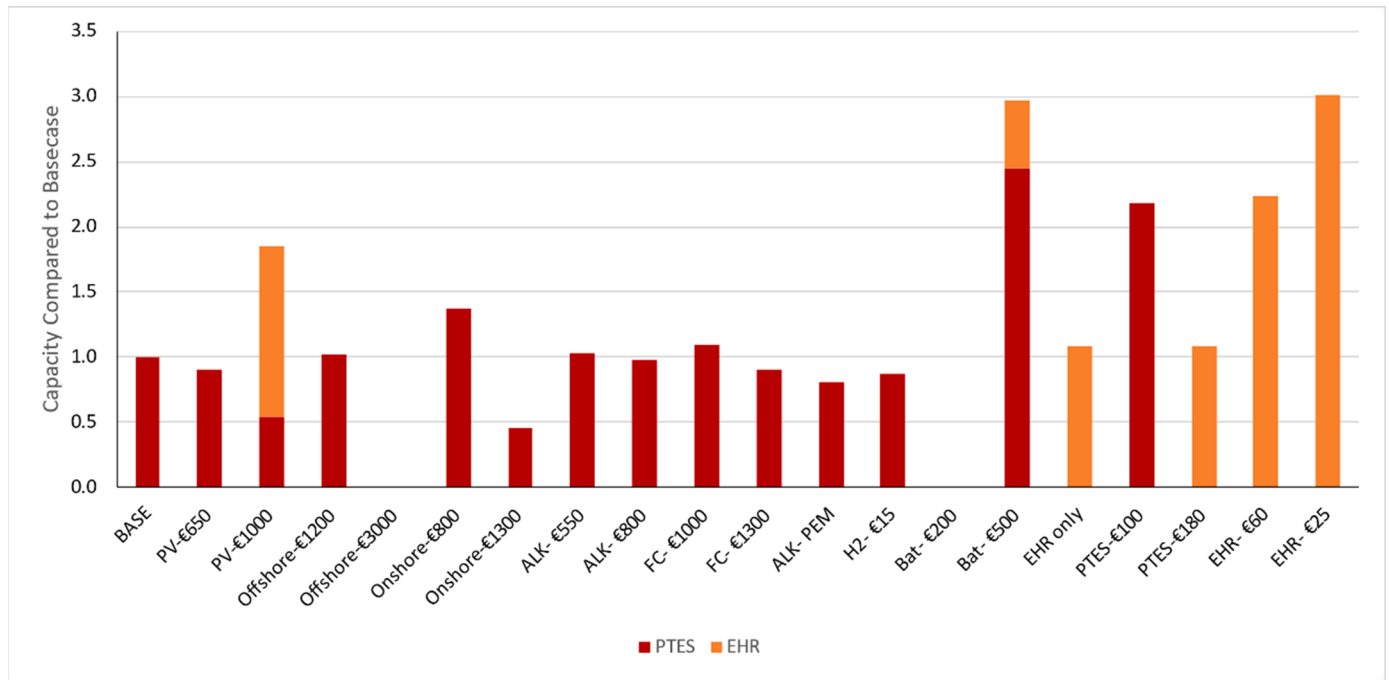


Fig. 8. Impact of Technology Cost compared to 'Base' Case for Thermal Storage Capacity.

to the storage profiles of TES and hydrogen in that as hydrogen infrastructure is built, it can also service the daily needs while TES serves the multi-hour needs. While the current study considers the fuel cell and electrolyzer to be separate systems, previous research has shown how they could be combined to deliver both conversion and reconversion (see Glenk and Reichelstein [65]) which could alternatively influence results.

Impact of hydrogen storage costs. While salt cavern storage would be the preferred method for large scale hydrogen storage, it may not be in the location required. Therefore, an alternate method of hydrogen storage using tanks was investigated. As these tanks require manufacturing, the cost assumed (€15/kWh [62]) was much higher than a salt cavern, however, is still comparatively low. As such, the impact on the other storage technologies is minimally felt, however, hydrogen storage capacity is significantly reduced while generation capacity increases. This highlights the excess system storage capacity, which is only achievable, and beneficial, under very low-cost storage scenarios. Absent these costs, long-term storage significantly decreases. As TES is better suited to intra-hour/day storage, it is largely unaffected by the cost of seasonal storage.

Impact of Li-ion battery cost. The cost of the lithium-ion battery has one of the greatest impacts on TES storage capacity. Under a low-cost scenario, TES is not required, and lithium-ion capacity is approximately three times that of the base case. Conversely, at high battery costs, PTES and EHR are both deployed with storage capacities approximately three times higher than the base case. This result seems to highlight that the intra-hour/day storage gap will be filled by lithium-ion, PTES, or EHR, dependent on cost. Therefore, there does seem to be some competition between TES and batteries for this market as each could be substituted for the other, although as discussed earlier, TES can also play a role in the longer-duration market to complement hydrogen technologies assuming discharge rates are low and conversion as well as reconversion efficiencies are high.

Impact of EHEB cost. Much like the results when varying the cost of lithium-ion batteries, varying the cost of EHEBs significantly impacts their storage capacity. For example, when only EHRs are available or the cost of PTES is high, the EHR storage capacity is approximately the same of the PTES in the base case with only a moderate cost increase. Under

the low-cost PTES assumption, installed storage capacity rises by approximately 2.2 times while for low-cost EHRs, installed storage capacity is approximately three times higher. For the ultra-low cost EHRs (€25/kWh), the storage capacity is also approximately three times higher.

It should be noted that the aforementioned electric-heat-electric batteries (EHEBs) are based on standalone heat generation, however, the cost of the system can be significantly reduced if the system is integrated into existing steam power plants as suggested by Krüger et al. [66]. Therefore, it is likely that the current study underestimates the potential of EHEB deployment.

3.3. Impact of technology absence

In this section, the impact of technology unavailability is explored. Initially, the impact of no additional PV, or no additional wind turbines is explored before assessing the impact of no additional electrolyzers, thermal batteries or lithium-ion batteries. The results are summarized in Fig. 9.

In a system in which solar PV cannot be sourced, onshore wind capacity increases (by 50%) to offset this shortfall. There is also a slight increase in hydrogen conversion capacities, which helps fill the increased hydrogen storage capacity (52% greater). Lastly, there is a slight decrease in the capacity of PTES and lithium-ion storage (20% and 66%, respectively). This result suggests that wind-only systems are better suited for hydrogen conversion and immediate utilization, reducing the need for hourly or intra-day storage technologies such as TES or batteries.

For systems which cannot source additional onshore wind, a far greater generation capacity of solar PV is required, highlighting the more constant output and higher capacity factor of wind power. Additionally, a maximum amount of offshore wind is also installed. In this scenario, the solar PV generation is largely stored in lithium-ion batteries or converted to hydrogen to be stored and then reconverted to electricity later. This result is in contrast to the no additional PV scenario in which hydrogen is generated and converted immediately to electricity rather than being stored. This result also highlights that as there is minimal correlation for solar PV generation and wind generation, they

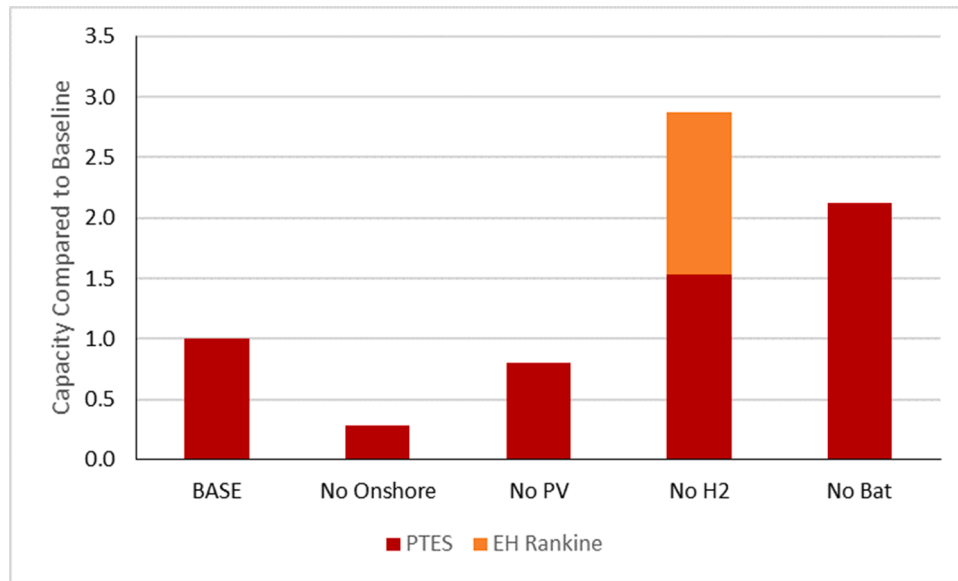


Fig. 9. Impact of Technology Absences compared to 'Base' Case for Thermal Storage Capacity.

can work together to reduce generational and storage overcapacities. Unlike the storage capacity of lithium-ion which increases when onshore wind is no longer available, the storage capacity of hydrogen storage and TES is significantly reduced. It is therefore likely that while hydrogen generation increases, only shorter-term storage is needed as it is used to complement the intra-daily storage requirement of solar PV-heavy systems, for which lithium-ion batteries are currently better suited to. It should be noted that of all the technologies studied, the absence of wind power is most economically felt.

When hydrogen conversion is impossible, the generation of solar PV and wind is increased, with a preference to solar PV. There is also a slight increase in the capacity of the backup power plant. The absence of hydrogen technologies has a marked impact on the system design as the storage capacity of TES and lithium-ion battery systems which both significantly increase (by 1.87 and 7.68 times, respectively) to compensate for the lack of hydrogen storage. It is worth noting that despite the increase in storage capacities of TES and lithium-ion batteries, their combined storage capacity is far smaller than the hydrogen

storage capacity in the 'base' case, highlighting the significant exploitation of low-cost generation of hydrogen capacity to take advantage of low storage costs. While there is a significant increase in TES in this scenario, the increase is far less than for battery technology. This highlights that while TES is useful for intra-day storage cycles, under the assumptions of the current study, lithium-ion batteries are still preferred for this market. Lastly, less variation is seen when thermal storage or lithium-ion batteries are not available, with each technology taking over for the other if the other is not available.

3.4. Impact of clustering

In order to reduce computing time, clustering is a powerful tool to obtain quick and accurate results. However, dependent on the clustering type and number, some information can be lost. Therefore, for certain scenarios, optimizations at full temporal resolution were also run, a comparison of which can be found in Fig. 10.

When comparing the clustered with the fully resolved 'Base' case

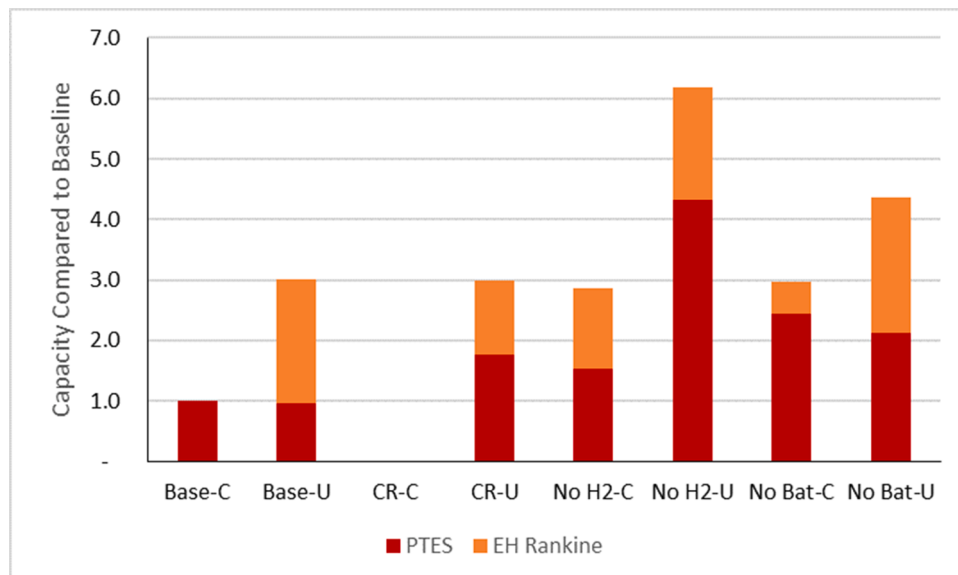


Fig. 10. Impact of Clustering on TES Capacity for Selected Scenarios. CR=capacity restricted, C=clustered, U=unclustered

scenario, it is clear that clustering significantly reduces the TES capacity. Moreover, while the EHR is not present in the 'Base' case, it is in the fully resolved case. A similar trend is found for the other scenarios where the clustered optimization significantly underestimates the total TES capacity. It appears that some of the services assigned to lithium-ion or hydrogen storage in the clustered scenarios are better suited to TES, however, the longer studied time periods do not allow TES to fill this role. Overall, it can be concluded that care must be taken when using clustering for assessing TES systems as some of their advantages may be missed or undersold.

4. Limitations

Despite the authors' best intentions, the current study involves some simplifying assumptions which may influence the results. These simplifying assumptions were made in an attempt to better understand the system and therefore provide better context for follow-up studies. These simplifications were also necessary to assist with the modeling and minimize computational time. In this section, some of the major simplifications are outlined and their likely impact on the study is discussed.

Islanded single-node system. The current system models the German network as not importing or exporting electricity. While this assumption is incorrect in reality, predicting energy flows of other countries is outside of the scope of the current paper and would therefore result in an over- or under deployment of technologies. From experience it can be said that increasing electricity exports would increase the capacity of generation resources, potentially reducing the need for short-term storage. Similarly, increasing imports could also limit short-term storage as energy could be imported from neighboring countries with a different energy profile. However, dependent on the generation potential of neighboring jurisdictions, electricity imports could increase the need for intra-week or seasonal storage. Furthermore, the single-nodal structure of the model neglects transmission lines in general and potential local bottlenecks, i.e. it can be assumed that storage capacities in a spatially resolved model with transmission line restrictions are in general likely higher.

No sector coupling. The current study only investigates the impact of TES on the electricity grid. As TES can also provide heat, this technology could also be used in this sector. Therefore, as this technology is capable of providing additional services to the energy system, it is likely that including the heat sector in future studies would increase the benefits from and potential of thermal storage.

Static demand. As indicated by Robinius et al. [67], estimating demand in future scenarios can create vastly different generational capacities and requirements. Therefore, the current study investigated the near-term potential of a storage technology using the demand from 2021 to try and guide near-term targets. It should be noted that the studied year was still impacted from the corona pandemic, in which electricity demand was lower than in previous years. However, as energy demand has decreased in the following years, falling electricity demand (compared to pre-pandemic times) may not be unrealistic, at least in the short-term. In general, it can be noted that as energy demand increases, the need for storage also increases, assuming consumption behavior stays the same. However, consumption changes to use more energy when it is generated, (e.g., through time-of-use tariffs, smart meters, timers, etc.), which would reduce the need for storage.

Static generation structure. Another shortcoming of the current study is the assumption that all renewable generation from existing capacities will remain constant and only the residual load is subject to the optimization (i.e., existing renewable generation is like-for-like replaced). This may not take into account that their generation profile in 2021 did not take full advantage of their generation capacity. Therefore, underutilization of these assets would decrease the need for storage in future scenarios. Conversely, as these assets are removed from the system, they may be replaced with lower cost options, of which TES

could be one. As previously mentioned in Section 3.2.2, there is the potential of TES to be integrated into existing facilities at reduced cost, thereby increasing its deployment.

Differing weather and demand years. Due to the unavailability of some data, differing years of weather profiles for generation (2019) and demand (2021) were utilized. Therefore, calculation of the residual load may differ on a temporal basis. As storage aims to rectify this temporal imbalance, the impact of increased peak hourly generation will increase storage requirements. Further studies should be undertaken on differing weather and demand years to properly assess this impact.

Temporal aggregation. Despite the fact that the temporal aggregation configuration was adapted to minimize the deviation from the fully resolved case with state-of-the-art aggregation techniques [47,68], and cumulative investment into storage technologies varied by less than 1% for the chosen clustering configuration, the trade-off between inter- and intra-daily operation, and thus the distribution of investments into different storage technologies, can slightly deviate. In particular, the segmentation tends to smooth intra-daily variance which could potentially lead to a slight undersizing of intra-daily storage such as PTES and batteries

Renewable dispatch load. In the current study, 10% of the electrical load could be met by a biomethane peaking plant. This plant would therefore only be operated as required but could always fill in a shortfall of demand. While the current study assumes this to be met by biomethane, in reality this could be met by any dispatchable technology or import. Similar to the limitation of an Islanded Single-Node System, access to dispatchable electricity generation/supply reduces the need for storage in general.

However, despite these limitations, the current study gives a first insight into the interactions and impacts of thermal storage on the electricity system. Further studies will aim to address these shortcomings to better understand the potential role of Carnot batteries.

5. Conclusion and implications

In the current study, we assess the potential benefits of thermal batteries for a future greenhouse gas neutral German electricity system. Using the energy system modeling framework (ETHOS.FINE), the total annualized costs of defossilizing the energy supply of the current electricity system were minimized using a single-nodal capacity expansion model. By varying the cost and availability of certain technologies, it was also possible to study the impact of the assumptions in the current study on Carnot battery deployment. In regard to thermal storage, systems with low wind or thermal storage costs, or high hydrogen conversion or lithium-ion costs, would see an increased penetration of thermal storage in the Germany electricity grid. At the current assumed costs, the greater efficiency experienced by pumped thermal storage makes it the preferred method of thermal storage, although electrically charged thermal storage with Rankine systems could become significantly more economical and potentially supply most of the short-to-medium term storage currently met by lithium-ion batteries if existing infrastructure can be used. Lastly, while lithium-ion and thermal storage compete for similar markets, there is certainly scope for co-existence where the advantages of each technology can be maximized.

Therefore, several insights and conclusions can be drawn:

- Lithium-ion batteries and thermal storage are both part of the least-cost system design, but work on a daily basis only, whereas hydrogen storage with very low storage specific costs works on a seasonal scale and has a capacity that is about two orders of magnitude larger than those of TES and lithium-ion batteries. Still, the yearly annualized costs of all three technologies are of the same order of magnitude underlining the fundamentally different operation of hydrogen storage compared to batteries and TES.
- Lithium-ion batteries are well suited for daily cycling, while electric heat batteries can also cycle daily but are more utilized in summer

when a higher generation from solar PV during daytime takes place, and therefore more intra-daily storage is needed. Hydrogen storage is filled during the off-peak seasons (i.e., spring and autumn) and released during peak demand seasons (i.e., cold, dark doldrums).

- The uptake of thermal storage for electricity production will depend on several factors including technology cost, wind generation capacity, availability of hydrogen conversion technologies, as well as lithium-ion and hydrogen storage costs.
- Beneficial influences for thermal storage uptake include increased lithium-ion storage costs, reduced thermal storage costs, increased PV costs, and reduced wind costs.

Future work could include better information on the location of each technology choice as well as the transmission required to move the energy from one location to another. A better understanding of more granulated location data is critical to ensure that the produced energy can be consumed effectively. In regards to thermal storage, the integration of a German thermal network would also be worthwhile. In connecting the electrical system to the thermal system, the advantage of thermal storage can be better realized as it is able to supply energy to both systems rather than just the electrical system as analyzed in the current study.

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

Data will be made available on request.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at [doi:10.1016/j.rset.2023.100059](https://doi.org/10.1016/j.rset.2023.100059).

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