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Optimal Sizing and Spatial Allocation of Storage Units in a High-Resolution Power System Model

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Abstract: The paradigm shift of large power systems to renewable and decentralized generation raises the question of future transmission and flexibility requirements. In this work, the German power system is brought to focus through a power transmission grid model in a high spatial resolution considering the high voltage (110 kV) level. The fundamental questions of location, type, and size of future storage units are addressed through a linear optimal power flow using today's power grid capacities and a generation portfolio allowing a 66% generation share of renewable energy. The results of the optimization indicate that for reaching a renewable energy generation share of 53% with this set-up, a few central storage units with a relatively low overall additional storage capacity of around 1.6 GW are required. By adding a constraint of achieving a renewable generation share of at least 66%, storage capacities increase to almost eight times the original capacity. A comparison with the German grid development plan, which provided the basis for the power generation data, showed that despite the non-consideration of transmission grid extension, moderate additional storage capacities lead to a feasible power system. However, the achievement of a comparable renewable generation share provokes a significant investment in additional storage capacities.

Keywords: power system flexibility; optimization; renewable energy; storage; power grid model

1. Introduction

The increased share of variable renewable energy sources (RES) in large-scale power systems leads to new challenges regarding the integration of these. Since conventional power systems are by design tailored to provide electricity from central, large-scale power plants down to the consumers, the switch to RES can be considered a paradigm shift. In our research, we take this framework into account and set up the toolbox *eGo* [1] which compromises the models *eTraGo* [2]—with a focus on the transmission system—and *eDisGo* [3] focusing on the distribution grid. In this work, we use the tool *eTraGo* which depicts the German power grid in a high spatial and temporal resolution and optimizes the extension of storage and power grid to enable RES integration. The role of flexibility and storage units in future power systems has been worked on extensively in academia regarding energy system analyses [4–8]. Especially due to the expectation that flexibility demand increases with higher shares of RES, this particular topic has seen various scientific discussions. For instance, apart from works on common storage units the role and potential forms of demand side management (DSM) as another efficient form of flexibility provision has been addressed by [9]. Demand response management as one method of DSM takes the flexibility potential of power customers into account. The complexity of such approaches for power grid modelling, which require game theoretic approaches, has been highlighted by [10,11]. However, in existing power systems storage units are currently only operating in niche markets such as providing primary reserve. Prior works on flexibility in general or storage in particular usually focus on a specific topic such as their economic performance [8], their necessity in certain (future) power systems [4,6,12] or their benefits for the overall power system. For instance, Denholm analyzed the effects of increased wind and solar power feed-in on the power system in Texas (US) [7]. However, although common parameters such as the curtailment have been looked at, transmission constraints and thus the power grid in general do not play a role in the analyses [7].

Recently, the consideration of the power grid as one of the central assets in power systems has gained attention in academia and consequently also in research focusing on flexibility. The consideration of the power grid allows for a simulation or optimization of flexibility not only to shift power according to a residual load, but also make use of the interconnection of different regions. While certain studies [4,6,13] only take net-transfer capacities between countries into account, recent works [14–16] try to include—partly for several countries—the extra-high voltage grid. This paradigm shift and its implication have been analyzed by [17], who concludes that clustering methods are necessary when working with a high spatial resolution in a comparably big network, such as Europe. While the consideration of the extra-high voltage (EHV) grid is now state of the art in power system research, the inclusion of the high voltage (HV) grid level is a relatively new field but seems to have a significant impact of results of power flow optimization [18]. Van Leeuwen did a brief analysis on the role of the HV grid level in Germany and concluded that the consideration of the HV level allows to simulate transit flows and should thus be included in power grid models [19]. Apart from that, Hinz introduced a redispatch model including the German HV level with the aim to analyze the provision of reactive power by wind power plants [20]. The fact that Hinz only looks at 16 significant snapshots and does not carry out a full-year simulation highlights that whenever a model covers a high temporal or spatial resolution, clustering methods must be applied to achieve results with acceptable computational effort. Especially with regards to flexibility optimization these clustering methods are not easy to apply [21].

In contrast to many existing works [14,15,17,22,23], we extend the power grid model from the extra-high voltage (EHV with $U_0 \geq 220$ kV) level with the consideration of the high voltage (HV with $U_0 = 110$ kV) level. The HV level has only recently gained more attraction in academia, mainly due to a lack of valid datasets. On the other hand, nowadays and increasingly in future scenarios, most power plants are decentralized and connected to the high and medium voltage (MV) level [24]. A sole focus on the EHV grid level disregards this fact and seems incomplete. By increasing the spatial resolution to the HV level, the buses connecting most power plants and their respective impact on EHV assets can be analyzed [18].

The increased spatial resolution of our model combined with our own standard of applying only open data leads to a more extensive data processing. The identification of relevant grid buses, the definition of respective grid districts and the connection of generation and demand data for this resolution has been addressed in [25]. Taking the resulting static power data model as a basis, we add a grid topology model, electrical parameters and generation and demand time series to prepare for power flow simulations and optimization [26]. All datasets have not only been created for the status quo in Germany, but also for a future scenario of the year 2035 based on the assumptions of the German grid development plan (NEP) which is designed for an RES share of 66% [22].

Several methods could be applied for optimizing the operation and installation of flexibility options under consideration of network constraints and market-based preconditions. One option is a reality-oriented process that consists of the three central parts *dispatch*, *power flow* and *redispatch* as implemented by [14,19,27] for example. There are several separate modelling tools in place for individually simulating these steps (e.g., renpassG!S [28]). Another option is to use a linear optimal power flow (LOPF) to co-optimize dispatch and installation while taking network restrictions into account. The (L)OPF method has been introduced in the 1960s and has become a standard approach ever since the 1970s [29]. Usually these approaches focus only on economic dispatch optimization under consideration of network constraints. In [30] this approach is amplified by an investment optimization. Our modelling approach is based on this approach and will be elaborated on in the following section.

Having set up the methodological background with these operations, we want to address several research questions in this work. A central dictum of this work is that we assume the grid topology model to be constant for all scenarios and optimization runs. Thus, we do not include grid extension measures in our optimization variables and shift this additional measure to our future research. With such a constant grid topology model depicting the status quo in Germany, we want to analyze the flexibility demand at all grid nodes for several set-ups. These set-ups are distinguished by different spatial clustering approaches, two data scenarios and sensitivity analyses. In general, our analyses are geared to the following guiding research questions:

1. How can the general location and size of storage units be described for different framework assumptions? Are central storage units preferred to decentralized ones? Do these results differ for certain regions?
2. What are the driving characteristics of the optimized storage units? Is there rather a long-term or a short-term shift in power?

Moreover, we compare our model and the optimization results to the approach and results of the German grid development plan [22] since it provides the data basis for the future power generation scenario and can be considered a reference study for the future German power system.

In Section 2 we introduce our general methodology and put an emphasis on the definition of storage units as our measure to assess flexibility demand. In Section 3 we present and discuss our results based on the economic optimization before we conclude our findings in Section 4.

2. Methods

The approach of this contribution is to assess the flexibility requirements in terms of storage units and their characteristics from a systematic point of view with the overall optimization target of lowest overall system costs. Thus, we integrate the mentioned modelling steps into a LOPF which will be elaborated on in the following.

The center of our model is a power grid model for Germany in a comparably high resolution of 3702 buses, which represent substations between the EHV/HV and the underlying MV grid (The complete dataset can be obtained from http://openenergy-platform.org/). Solely OpenStreetMap (OSM) [31] data and the extraction software *osmTGmod* [32] are used to set up this power grid model [26]. OSM is a collaborative project by volunteers with the aim of creating a free world map by collecting geographical information from the crowd. The software *osmTGmod* allows to extract relevant information from OSM and build a power grid model ready for power flow simulations based on OSM data. Cross-border capacities to neighboring countries are part of the model with the technical potential of each power line, disregarding any economical or regulatory restrictions. Once created, we assign power plant and demand data to each grid node. The year 2011 provides the historical basis for weather data and corresponding time series of power supply and demand. In this process we consider two generation scenarios: a status quo scenario as a reference and another scenario named NEP 2035 depicting the German power system with a generation portfolio designed to achieve 66% RES share in the year 2035 [22]. Demand and power grid data are by definition considered constant for both scenarios. By doing this, we also want to create a basis to examine future grid extension necessities in our further research. The generation of the power grid, the definition of the mentioned scenarios and the creation of time series for power flow simulations are described in detail in [26]. Our method to generate demand data in a high spatial resolution of 3702 buses is introduced in [25].

2.1. Integrated Method to Optimize Flexibility Options

Once the data model is generated and ready to use, we apply the tool *eTraGo* as an interface and application tool to run a LOPF with the open-source energy modelling framework "Python for Power System Analysis" (*PyPSA*) (Link: https://pypsa.org/ [30]) and the Gurobi (Link: http://www.gurobi.com/) linear programming solver. With this set-up, the optimization parameters are defined in *eTraGo* while *PyPSA* is applied to carry out the LOPF with these parameters. In a LOPF, the generation dispatch is optimized under consideration of grid constraints and always follows the central criterion of meeting the given demand. Moreover, the optimization of investment decisions may be introduced to the same problem. Thus, a prior dispatch model is not necessary. Due to the integrated approach of optimizing flexibility under consideration of grid restrictions, market conditions and in a later stage also grid extension measures, the application of an integrated tool seems preferable in contrast to a rather iterative approach as described above.

The particular objective function of the LOPF problem applied in this work is displayed in Equation (1) with n labelling buses, r generators, s storage units and t the hour of the year. The optimization variables are storage investments ($H_{n,s}$) as well as the dispatch variables of generators ($g_{n,r,t}$) and storage units ($h_{n,s,t}$). Concerning the dispatch optimization the marginal costs (EUR/MWh) for generators ($o_{n,r}$) and storage units ($o_{n,s}$) are crucial parameters. Each snapshot is weighted by the parameter w_t. The specific capital costs (EUR/MW) for each storage unit s are defined by $c_{n,s}$. A general description of the used LOPF method concerning the objective function and constraints can be found in [30].

$$\min_{\substack{H_{n,s} \\ g_{n,r,t}, h_{n,s,t}}} \left[\sum_{n,r,t} w_t \; o_{n,r} \; g_{n,r,t} + \sum_{n,s} c_{n,s} \; H_{n,s} + \sum_{n,r,t} w_t \; o_{n,s} \; [h_{n,s,t}]^+ \right] \tag{1}$$

The mentioned high resolution of our dataset which is mainly due to the consideration of the HV grid level leads to a relatively complex system and thus an increased computational effort compared to other power system models. Hence, we must apply clustering methods for the spatial and temporal resolution of the dataset. First, we reduce the number of grid buses from 3702 to $k = 500$ using a k-means clustering approach similar to [17]. The impact of this reduction and possible other choices of k will be assessed in Section 3.3. To consider the so-called (n-1)-criterion and usual safety margins of power lines and transformers, the technical maximum capacity of these is reduced to 70% for power flow calculations [33]. On the temporal dimension, we reduce the complexity by running the model for every third hour of a full year. To obtain realistic results, each time step is weighted by the factor $w_t = 3$ accordingly (see Equation (1)). Ramping constraints of thermal power plants or storage units are not considered for reasons of complexity and allow such plants to fully shift dispatch between two time steps. A literature review realized by Eickmann implies that the disregard of these constraints is acceptable when operating on an hourly scale [34].

2.2. Definition of Extendable Storage Units

To identify the flexibility demand at each grid node, we allow the installation of unlimited storage capacities at certain capital costs at all nodes within the LOPF. However, to better analyze the type of flexibility demanded, we distinguish between short-term storage units that are not dependent of local technical potentials and long-term storage units that can only be set up at locations with a sufficient technical potential.

Short-term storage units operate in our definition on an hourly scale and can store and provide energy for six hours at full capacity. Relevant technologies for these storage types are pumped hydro power plants (PHP), adiabatic compressed air energy storage units (AA-CAES) or large-scale battery storage facilities. While PHP and AA-CAES are highly dependent on local technical potentials due to the necessity of either topological preconditions or the existence of suitable underground caverns, battery storage units are feasible at almost any location and do not have such preconditions.

In Germany, the extension potential for PHP is very low. While there are currently around 7 GW of PHP capacity installed [35,36], the development of further sites is limited according to [37,38]. Having this in mind and knowing that the flexibility provided by PHP can in terms of modelling alternatively be depicted by abstracted battery storage units, we only consider existing PHP plants and do not expect a further increase in capacities.
Similarly to PHP, AA-CAES power plants are usually operated as a storage to smooth daily fluctuations. Thus, we again use batteries to represent this storage type, that could also be provided by AA-CAES given the local potential.

Seasonal storage characteristics cannot be depicted by uniform battery storage units, since their losses over time are relatively high [39]. Apart from PHP with enormous storage reservoirs, the storage of hydrogen in underground caverns is the only technology capable of seasonal balancing [39]. Since large PHP reservoirs cannot be found in Germany, we focus on hydrogen storage as the only seasonal storage technology. In the following, the two resulting storage types, uniform extendable battery storage units and seasonal hydrogen storage units will be characterized in detail. Generally, we consider the charging/discharging ratio of all storage units to be 1:1. The total investment costs per Megawatt (MW) of installed capacity C_{total} are calculated using the same approach for both technologies: Costs per MW C_{power} and per MWh C_{energy} are added up considering the respective maximum charging/discharging time max_t, see Equation (2). Using the method of Equivalent Annual Costs with an interest rate of 5%, these total investment costs are brought down to an annualized net present cost value. O&M costs are calculated applying a fixed factor of 1% for batteries and 3.5% for hydrogen storage units [39] to the yearly investment costs.

$$C_{total}[\mathrm{EUR/MW}] = C_{power}[\mathrm{EUR/MW}] + C_{energy}[\mathrm{EUR/MWh}] \times max\_t[h] \tag{2}$$

2.2.1. Uniform Extendable Battery Storage Units

As mentioned above, battery storage units contrast with other large-scale storage systems not dependent of any local technical preconditions but can be installed at almost any site. Thus, we allow the installation of battery storage as a flexibility option at any grid node (Cases where substations are in urban areas and have limited space for a storage installation are known but disregarded for uniformity here). Relevant technical parameters as for instance the maximum charging/discharging duration at full load or the capacity costs are predefined and thus influence the resulting flexibility demand. There is a broad picture on these parameters in academia, for instance [5] provides general assumptions for storage parameters that have been used by numerous works [6,17,40]. Other relevant studies providing relevant data on storage costs are [41–43]. However, due to being relatively up-to-date and defining parameters not only for batteries, but also for underground hydrogen storage units, we apply the parameters defined by [39] for the two generation scenarios. Generally, we choose the Lithium-Ion technology as a reference for uniform battery storage units. A collection of all relevant parameters can be found in Table 1.

2.2.2. Seasonal Hydrogen Storage Units

As noted above, long-term or seasonal storage units are in our model only depicted by hydrogen storage units in underground salt caverns. According to [44,45], salt caverns are the most suitable and flexible underground formation since they allow "much higher injection and withdrawal rates and the flexibility to handle frequent cycles" [44]. Apart from hydrogen, most salt caverns are also suitable to store compressed air or natural gas. While the preconditions of AA-CAES storage units are stricter and allow storage only in certain depths and pressures, the preconditions for natural gas and hydrogen are the same and allow caverns within wide pressure ranges of 60–180 bar and depths from −500 m to −2500 m below surface [45]. Although hydrogen and natural gas have the same requirements, we do not expect a distinctive competition of the technologies for suitable sites [46]. Apart from the suitability of salt formations in its size and quality, the location of the formation close to the sea is important with regards to the disposal of the brine as a product of the solution mining [47]. Figure 1 shows in light blue the salt formations in Germany, which occur only in the northern part of the country. Since there are no specific datasets on salt formations suitable for underground hydrogen storage units, we assume general suitability at the illustrated formations. A more in-depth analysis on the real potential at these sites is desirable and would probably reduce the number of sites significantly. However, since the substation must not be directly at the site of the storage facility, we assume there is some flexibility in the siting of the storage. The resulting substations located right on top of salt formations are indicated in Figure 1 in orange and currently add up to 248 potential sites in Germany.

Table 1. Storage parameters for battery and hydrogen storage units for the scenarios status quo and NEP 2035 based on [39]. The indicated parameters represent complete power-to-power cycles, i.e., costs and efficiency for electrolysis, storage, and fuel cell.

Parameter	Status Quo	NEP 2035
Battery Storage		
Capacity costs [EUR/MW]	160,000	72,500
Storage costs [EUR/MWh]	445,000	141,000
Max. hours [h]	6	6
Total Investment costs [EUR/MW]	2,830,000	918,500
Operation years [a]	20	25
Investment costs per year [EUR/MW/a]	227,087	65,170
O&M costs [EUR/MW/a]	2271	652
Total storage costs per year [EUR/MW/a]	229,357	65,822
Round-trip Efficiency	0.86	0.87
Hydrogen Storage		
Capacity costs [EUR/MW]	1,215,000	815,000
Storage costs [EUR/MWh]	450	450
Max. hours [h]	168	168
Total Investment costs [EUR/MW]	1,290,600	890,600
Operation years [a]	25	25
Investment costs per year [EUR/MW/a]	91,571	63,190
O&M costs [EUR/MW/a]	3205	2212
Total storage costs per year [EUR/MW/a]	94,776	65,402
Round-trip Efficiency	0.25	0.31

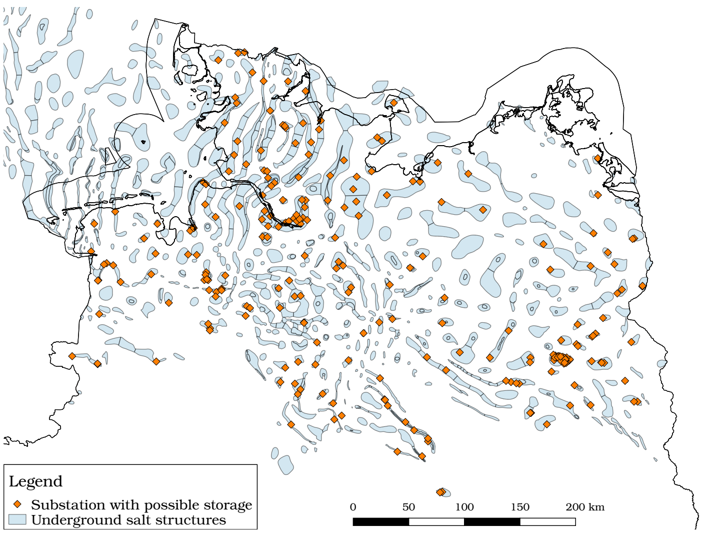

Figure 1. Salt formations in northern Germany (light blue) and substations located on top of these (orange diamonds) as possible sites for underground hydrogen storage units with connection to the power grid. Source for data on salt formations: *Salzstrukturen* ©BGR, Hannover, 2015

3. Results and Discussion

In this section, the results obtained with the model and approach described above are presented. First, the results with regards to our central research questions (see Section 1) concerning additional storage capacities are analyzed. In the following Section 3.2 some further analyses of the overall optimization outcome are highlighted while sensitivity analyses and a critical appraisal of our model complete this section.

3.1. Additional Storage Capacities

The optimization results show that no additional storage capacity is required for the referencing status quo scenario with a RES generation share of 35.4%, which could be expected due to the large thermal power plant capacities in Germany's power system today. The results for the main scenario NEP 2035 reveal the surprising result that only a few storage facilities and comparably small overall capacities are required to obtain an optimal and feasible result. When applying the reduction method of a spatial k-means clustering with $k = 500$ grid nodes for a full-year optimization of the data model, five additional storage units with a total capacity of 1601 MW are required. Considering existing pumped hydro storage units in Germany, the additional storage units lead to an increase in storage capacity by 17% to 10.9 GW. In contrast to our assumptions of no additional pumped hydro storage units due to the limited potential in Germany (Section 2), the German grid development plan [22] as our generation data source for the NEP 2035 scenario assumes a pumped hydro power capacity of 12.7 GW in 2035. Compared to this value, our resulting capacity is lower by 14%. Furthermore, the resulting optimal installed storage capacity of 10.9 GW is substantially below the installed renewable energy capacity of 180 GW and thermal generation capacity of 61 GW in our data model for Germany. The location and capacity of the additional storage units are depicted in Figure 2. While all four battery storage units with a total capacity of 587 MW are situated in the southern parts of Germany, there is one large hydrogen storage with a capacity of 1015 MW in north-western Germany. The location of the additional storage units tends to be dependent of the respective generation characteristics in a region. Figure 3 shows that the northern part of Germany is dominated by wind power capacity (offshore and onshore) which shows not only hourly, but also strong seasonal variations and thus requires long-term storage options such as underground hydrogen.

Due to the fact that we did not consider any grid extension measures compared to today's network, seasonal storage in the north seems to compensate a structural lack of north-south transmission capacity. In southern Germany on the other hand solar power generation shapes the generation portfolio while wind power is significantly lower than in the north. Thus, short-term battery storage units are fit to level out hourly or daily generation fluctuations. Generally, the locations of additional storage units show that regions that are shaped by a certain technology of fluctuating power generation require storage capacities that fit their respective generation characteristic. Figure 4 indicates the production balance, i.e., total generation vs. total demand for the full year for different regions. The red dots clearly show a generation deficit in central and south-western Germany while generation exceeds load in the north and east. Our results indicate that critical network junctions do not seem to be defining storage requirements, neither are former large power plant sites which could be expected due to the data set being a future scenario considering a significant phase-out of thermal generation capacity. One of the central parts of our research questions (see Section 1) was to evaluate if according to the optimization additional storage capacities are of rather central or decentralized nature. In terms of our data model, a decentralized distribution would have resulted in small capacities at many different grid nodes since the possibility to set storage capacities was given at any node for battery storage units and at potential nodes in northern Germany for hydrogen storage units (see Section 2). However, the resulting storage at only five nodes indicates that a few, but rather large storage capacities are optimal.

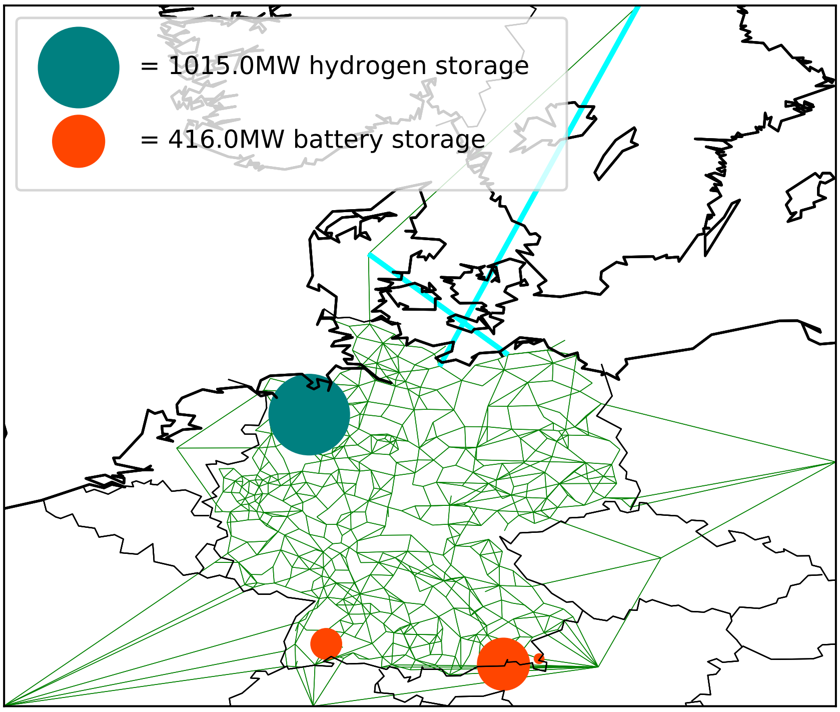

Figure 2. Spatial distribution of additional storage units. The size of a dot represents the storage capacity in MW. Blue dots show hydrogen storage units, red dots indicate battery storage units. Cross-border DC power lines are depicted in light blue.

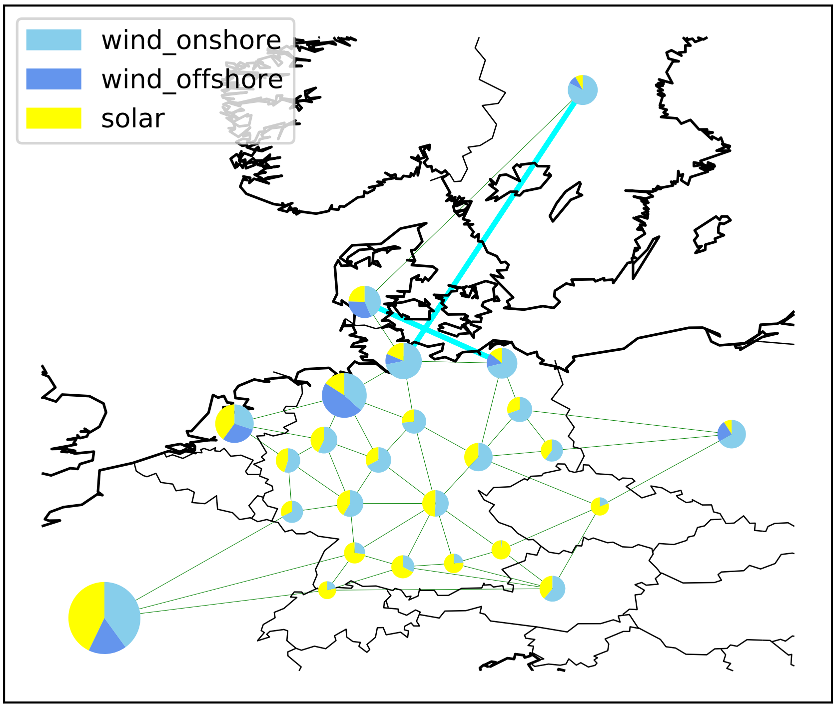

Figure 3. Installed capacity of selected renewable energy sources by region. The size of the dot represents the installed capacity in MW. Note: The full network has been clustered to 25 buses for better visualisation.

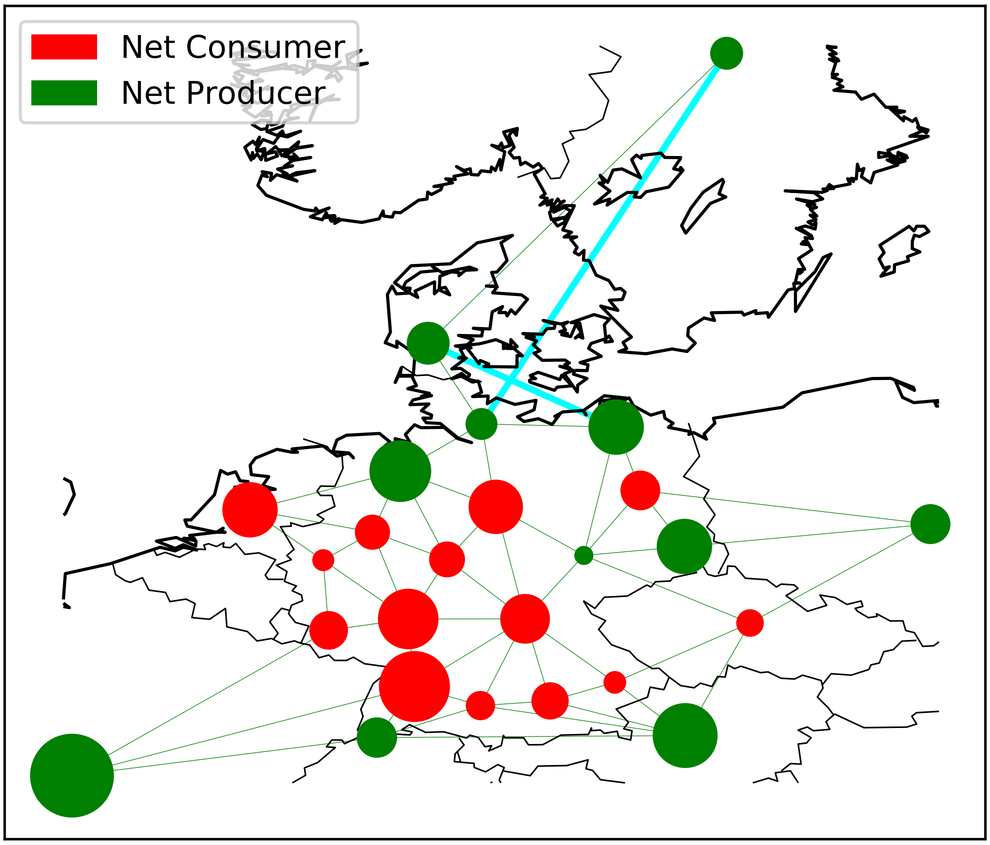

Figure 4. Annual balance of power generation and load by region. Red dots show regions with a generation deficit, green dots represent a generation surplus. Note: The full network has been clustered to 25 buses for better visualisation.

The type of storage unit being built at a grid node is obviously to a certain extent dependent of the generation portfolio in the node. Since the two available storage technologies are quite different in their technical properties, i.e., their capacity or efficiency, they show distinct operation modes. Battery storage units reach a relatively high efficiency while their storage capacity is limited to six hours at full charging or discharging power (see Section 2) making batteries a short-term storage. Use and state of charge of the four battery storage units confirm that there is only a very limited seasonal variation while the operation changes with a relatively high frequency (see Figure 5). The long-term hydrogen storage in contrast has a comparably low efficiency combined with a large storage capacity. Due to the low efficiency, charging is the dominant mode for the hydrogen storage while times of discharging are significantly lower (Figure 5). The trend of states of charge for the two technologies (Figure 6) illustrates a much higher frequency for the battery storage units while from a seasonal perspective a slightly higher state of charge can be sensed in summer, likely due to amplified solar power production. The storage level for hydrogen on the other hand changes only gradually and has its peaks during periods of high wind power feed-in in autumn and spring.

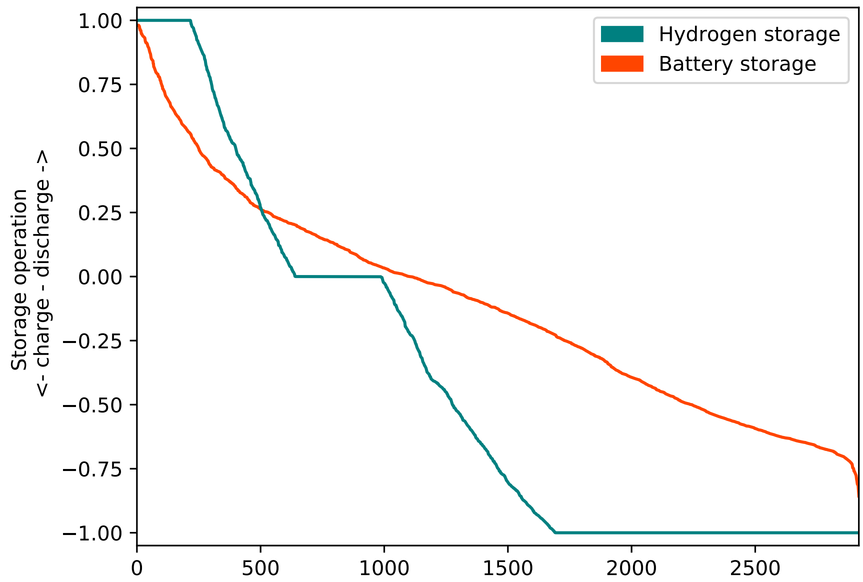

Figure 5. Sorted annual duration curve of the operation mode by storage technologies. Negative values indicate storage charging, positive values indicate discharging. The blue line shows the hydrogen storage, the red line illustrates battery storage units which have been accumulated for better visualisation.

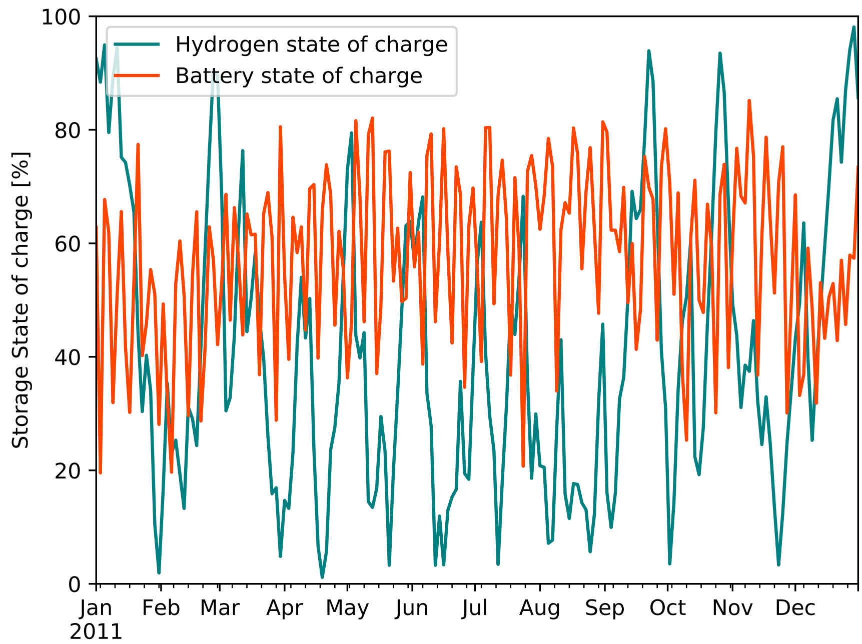

Figure 6. Annual trend of storage unit state of charge by technology. The blue line shows the state of charge of the hydrogen storage, the red line illustrates battery storage units which have been accumulated for better visualisation. Values have been clustered to an average of 48 hours per item.

3.2. General Optimization Results

Apart from storage-specific results, the optimization also reveals some interesting insights into the overall model. It has been mentioned that the total storage capacity can be considered relatively low, especially when considering that only today's grid is assumed. At the same time, the share of renewable energy generation amounts to 53% which is significantly below the possible share of 65.8%

of the NEP [22] that shaped our generation scenario. Since there is no strict limit to carbon emission, but only an indirect consideration through emission costs for thermal power generation, our model has no incentive to increase RES generation share besides their marginal cost of 0 EUR. The combination of high RES capacities with a relatively low RES production share yields high curtailment rates. For the German RES plants, we observe annual curtailment rates compared to the available feed-in of 4% for solar energy, 6% for hydro power, 15% for onshore wind and 47% for offshore wind. Compared to the maximum of 3% for onshore wind in the mentioned NEP [22], these numbers are extensive. One approach to explain this difference compared to the NEP is the chosen modelling logic combined with the fact that our transmission capacities remain constant at today's rates. The NEP process tries to replicate the real power system process by starting with a market simulation that results in the dispatch per power plant. In a second step, the transmission demand is determined by a power flow, which is again followed by the possibility to redispatch to come up for congestions. The LOPF carried out for our model compromises this iterative process into one optimization problem. Consequently, power plants that are far from regions with large loads and possibly located "behind" a congestion are harder to dispatch. On the other hand, imports from neighboring countries partly compensate this deficit which results in the fact that Germany is a net-importer of energy and covers around 12% of its total yearly demand by imports. Explanations for this circumstance are low-priced generation portfolios in neighboring countries combined with the fact that in contrast to many other power market models, we consider cross-border capacities with their thermal capacity, i.e., their technical potential and disregard any market-based or strategic limitations.

A quantitative comparison of the results on required additional storage capacities to other studies is limited for instance due to the detailed consideration of the power grid through applying a LOPF. The focus on a power system with 66% RES share also impedes a comparison since most studies cover 100% RES scenarios [17,48]. However, an indicative comparison to studies reviewed by [49] can be drawn. For the European power system, Kondziella analyzes an economic flexibility demand of 60–70 GW at a RES share of 60% [49]. In our model considering only Germany and its electrical neighbors and thus a smaller geographical area, a flexibility demand of only 36 GW including existing storage units is found. A study by Schill examines the flexibility demand for Germany only and finds that while fully accepting curtailment, no additional storage capacity is required at a RES share of 58% [50]. Compared to this result, the relatively low additional storage capacity of 1601 MW found in this work seems to be in general accordance.

3.3. Sensitivity Analyses

For a broad picture of the robustness of our results, we conduct several sensitivity analyses. First, we analyze the impact of the spatial clustering which is applied due to computational reasons. Carrying out the optimization with $k = 200$, $k = 300$ and $k = 400$ instead of the standard $k = 500$ yields RES shares in the same range (52%), but a significantly lower additional storage capacity from around 200 MW for $k = 200$ and $k = 300$ to 470 MW for the $k = 400$ case. This observation supports the assumption that the consideration of the power grid in a high degree of detail leads to additional grid restrictions and thus increased storage requirements and overall system costs. To assess the suspicion that the grid capacity is still over-estimated for the $k = 500$ case, we reduce the overall thermal line capacity from the standard 70% to 50% but obtain only a shift from hydrogen to battery storage capacities with an overall increase of storage capacity by 100 MW or 6.3%. Hence, the transmission capacity seems to be adequately represented and its impact to the overall results appears to be moderate. The resulting additional storage capacities are dependent of the respective cost assumptions introduced in Section 2. The specific impact is analyzed by changing the total annual costs for storage units by $+/-5\%$ and $+/-10\%$ and depicts an almost linear dependency. Decreasing capital costs by 5% results in an addition of 100 MW storage capacity, increasing the capital costs yields a decrease of storage capacity by 100 MW. The distribution of additional storage units to regions or technologies remains constant.

It was mentioned above that the RES share of the overall generation is significantly lower than the RES share of the generation capacities. Thus, we introduced a constraint to the optimization that considers meeting a minimum RES generation share. Compared to the other sensitive parameters this constraint shows considerable impact to the results, see Table 2. The total annual system costs depicted are mainly compromised of dispatch costs for thermal generation and the annualized capital costs for additional storage units. Unfortunately, the NEP does not provide costs for the 2035 scenario which makes a direct comparison with this reference impossible. Table 2 shows that with an increased RES generation share of 62% the costs grow by 20.6% and a RES generation share of 67% leads to an increase of 43.3% compared to the standard case with 53% RES generation share. At the same time, the curtailment rates are significantly lower than in the reference case. Offshore wind power still sees the highest curtailment rates but amounts to only 8% of the yearly production compared to 47%.

Table 2. Impact of different renewable energy generation shares to significant parameters.

RES Generation Share	53%	62%	67%
Total annual system costs	100%	121%	143%
Additional storage capacity [MW]	1601	5741	13,578
RES curtailment of annual production	19%	13%	6%

However, the additional storage capacity required to obtain these increased RES generation shares are extensive. To achieve the RES generation share of 67%, 13,578 MW of additional storage capacity are necessary, equaling almost eight times the original case. The share of hydrogen storage increases to over 84% illustrating that seasonal storage capacities are required when grid extension measures are disregarded. The distribution of storage units across Germany remains relatively constant, still hydrogen storage units show large capacities in the north-west spreading to the north-east while battery storage units remain dominant in the south (see Figure 7).

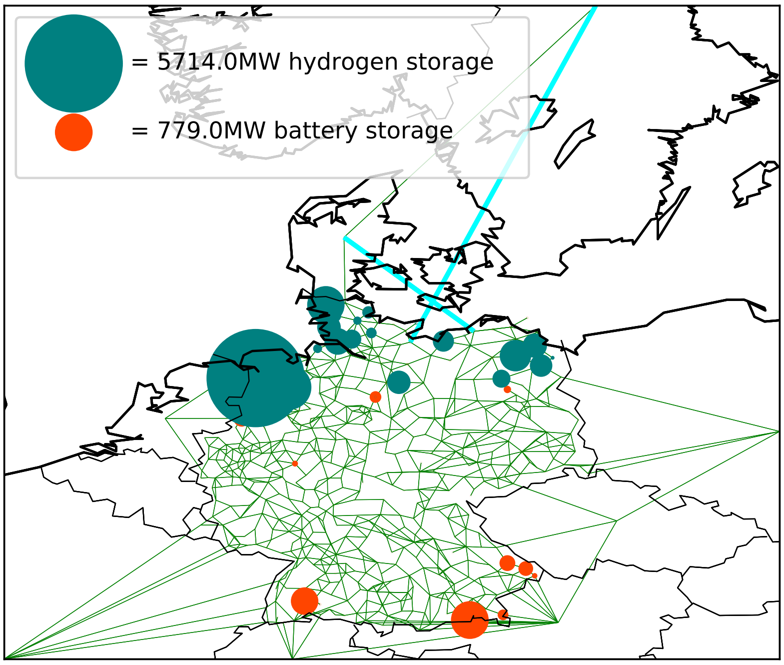

Figure 7. Spatial distribution of additional storage units for a RES generation share of 67%. The size of the dot represents the storage capacity in MW. Blue dots show hydrogen storage units, red dots indicate battery storage units. Note: The dot size has been scaled down in contrast to Figure 2 for better visualisation.

3.4. Critical Appraisal

The results illustrated in Section 3 need to be recognized with the knowledge of certain limitations of the modelling approach. In Section 2 we introduced the dataset applied, which is quite detailed since we consider the HV power level, but still disregards LV and MV grids and thus most parts of the distribution grids. Although this is true for most power system models, this lack of a large share of the power system must be acknowledged when assessing the results.

Since the preferred storage technology seems to depend on the generation portfolio in the area of the node (see Section 3.1), the presented results may vary according to the chosen year as reference for weather data. Probably this does not change the spatial allocation of storage units, but their capacities. The fact that our dataset is based strictly on open data leads to a possible uncertainty regarding data quality. For instance, the power grid model uses crowd-sourced OpenStreetMap data which heavily relies on the quality standards of its users. Müller et al. addressed this factor in [26] which should be particularly considered when it comes to comparisons to other grid models such as the NEP. In this context, it should be noted that the NEP can be considered a power grid study directly addressing "real-life" grid measures while the model presented in this work certainly involves limitations to its transfer into concrete assets or measures. Moreover, quality of publicly available datasets may obstruct the application of the model framework to other regions or countries.

Another factor that could significantly impact the results is the fact that we do not consider unit commitment constraints such as minimal up or down times of power plants or storage units in any way. Especially with regards to large thermal power plants this is certainly a simplification. Possibly, this circumstance is one of the reasons for the relatively low RES generation share in the standard case because conventional power plants are considered to be very flexible.

At last, the power flow and dispatch results are produced by a LOPF and hence disregard non-linear effects of power transmission in AC systems, such as reactive power flows or voltage stability.

4. Conclusions

The aim of this work was to develop a method to optimize and assess the storage requirements of a future high-resolution power system. A model with a high spatial resolution considering the HV power level provided the data basis and was complemented by power generation data based on the German grid development plan for the year 2035. Applying this data model, LOPF simulations were carried out using the open-source tools *eTraGo* and *PyPSA*.

To investigate the flexibility requirements two representative storage technologies were defined by their respective technical and economical parameters. By allowing the installation of short-term battery storage units at each grid node as well as long-term hydrogen storage units at selected nodes with an underground cavern potential, the optimization identifies flexibility requirements in a high spatial resolution.

The optimization revealed the surprising result of relatively small additional storage requirements of 1601 MW equaling an increase of existing pumped hydro storage capacities by 17% for the 2035 scenario in Germany. These capacities are even more noticeable when considering the fact that our grid model remains on today's status, hence disregarding any grid extension measures until the year 2035. The total additional storage capacity of 1601 MW is subdivided into one third of battery storage capacity in four separate units and two thirds of hydrogen storage in one large plant (Figure 2). This apportionment indicates the tendency that central storage facilities are more beneficial than decentralized ones. Moreover, the results illustrate that the location of additional storage units is mainly driven by the power generation portfolio in a region. While regions shaped by seasonally fluctuating wind power require hydrogen storage units with a large storage capacity, short-term battery storage units fit to regions characterized by a high solar power share. Apart from the location of storage units also the use in terms of charging and discharging as well as the state of charge over time supports this correlation.

Since the German NEP provided not only the basis for the generation data for our central scenario but can also be characterized as a reference for German power system models, a comparison of the results seemed obvious. The NEP process is based on a completely different modelling approach and is primarily set up to identify extension measures of the transmission grid for several future scenarios. However, some distinctive parameters can be compared. Due to the dissimilar modelling approach our optimization reaches a RES generation share of only 53% while the generation portfolio would allow for a much higher share of up to 70%. Therefore, the RES curtailment rate reaches 19% compared to a maximum of 3% in the NEP. Another factor for this discrepancy is the limitation of our transmission grid to today's capacities with no possibility to any extension. The NEP on the other hand identifies several additional measures, mainly DC lines linking north and south Germany.

A sensitivity analysis with a predefined RES generation share of at least 66% revealed that a RES share in the same range as the NEP can be reached with our model to the cost of an increase in additional storage capacity from 1601 MW to 13,578 MW. Hence, it seems evident that increased seasonal storage capacities have a similarly positive effect to RES integration as grid extension measures. Overall, our results illustrate that the disregard of grid extension measures in our model leads to a decreased RES generation share while it still allows for an optimal and feasible power system with very moderate additional storage capacities. Increasing the RES generation share requires significant larger storage capacities but yields feasible results. In our future work we will extend the data scenario to a fully renewable power generation model to assess transmission and flexibility requirements for the long-term target of a carbon-free power system. Another focus of our future work is the consideration of grid extension measures as another variable to obtain the combined optima of grid and storage extension. Due to the open-source modelling and data approach applications of the developed framework in other scenarios or regions are desirable.

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Abbreviations

The following abbreviations are used in this manuscript:

AA-CAES	Adiabatic Compressed Air Energy Storage
AC	Alternating Current
DC	Direct Current
DSM	Demand Side Management
EHV	Extra-high Voltage
HV	High Voltage
LOPF	Linear Optimal Power Flow
MV	Medium Voltage
NEP	Netzentwicklungsplan (German Grid Development Plan)
OSM	OpenStreetMap
O&M	Operation and Maintenance
PHP	Pumped Hydro Power Storage
RES	Renewable Energy Sources

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