Requirements and impacts of energy storage characteristics in a highly renewable European energy system

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Abstract

The European energy system is increasing its renewable share, primarily that of wind and solar photovoltaic energy. Going forward, the system will need better interconnections and storage integration to balance the mismatch between electricity demand and renewable generation. Europe has already a large capacity of pumped-hydro storage installed. Moreover, Li-Ion batteries are emerging as a promising cost-effective storage option. Taking that into consideration, we analyze to which extent a highly renewable system benefits from an additional storage technology, named storage-X, in addition to pumped-hydro storage and batteries. In our analysis, we identify which characteristics of storage-X are required for it to play a prominent role in the system. For the study, we use an overnight capacity and dispatch-optimization model of a future decarbonized sector-coupled European energy system. In total, the system is optimized for 2,016 configurations of storage-X characteristics, including efficiency and cost properties, to define the space of feasible configurations. By comparing this space with the characteristics of storage technologies currently under development (e.g., pumped thermal energy storage, compressed air energy storage, etc.), we learn that significant improvements are needed for them to become part of the optimal solutions. Reducing energy capacity cost, increasing discharge efficiency, and reducing the cost of charging power capacity must be prioritized. As other sectors are electrified, the design space for storage-X shows similar characteristics. We find a potential system cost reduction of 10% with the best storage configuration. But for this to be realized, the storage is required to provide a high load coverage. Even in that case, renewable curtailment of 1% is still present in the optimal system.

Highlights

- Feasible combinations of storage characteristics investigated in sector-coupled system
- Energy capacity cost <10 €/kWh is required if high ($\gg$50\%) discharge efficiency is not attainable
- System cost can be reduced by 10\% from storage deployment but this requires high round-trip efficiency ($\geq$90\%)
- At the best-performing storage, 1\% renewable curtailment is still present
- Storage-X can compete with battery but does not take the role of backup power in extreme events

Keywords: Energy System Modelling, PyPSA, Renewable Energy, Storage, Sector-coupling

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I. INTRODUCTION

The European energy system is experiencing a green transformation to comply with the climate target of net-zero greenhouse gases emission by 2050 [1, 2], giving rise to an increased deployment of variable renewable generators such as wind turbines and solar photovoltaic (PV) panels. In 2020, the European (EU-27) renewable sources overtook fossil-fueled power generation for the first time, supplying 38.2% of the demand of which wind supplied 14% and solar 5% [3]. The integration of these variable renewables is associated with some challenging aspects. The uncertain intermittent power output necessitates backup reserves, and increased transmission capacity is required to even production over larger areas [4]. Extensive literature exist on the examination of the variability of solar and wind [5, 6, 7, 8]. Where diurnal cycles dominate solar generation, synoptic temporal fluctuations dominate wind. In Europe, both show a complementary seasonal cycle [9, 10], and thus, an optimal seasonal mix of wind and solar exists [11, 12].

To help relieve the aforementioned challenges, integration of electricity storage is one option. Likewise for the temporal variability of wind and solar, different time scales apply to electricity storage. For grid stability, certain technologies perform frequency or voltage regulation, intra-daily smoothing of diurnal variability, or balancing of synoptic or seasonal variation [13, 14, 15]. Currently, pumped-hydro storage (PHS) constitutes the majority (>90%) of deployed energy storage in Europe [16] with 55 GW power capacity [17] and 1.3 TWh energy capacity [18]. Battery energy storage accounts for only 1% of total energy storage used today worldwide [19]. But Lithium-ion (Li-ion), which currently accounts for 78% of the battery systems in operation, has proven its large potential: Over the last decade, Li-ion battery packs have shown learning curves of 80%, i.e., learning rates of 20% [20]. Moreover, large (~1 GW) individual grid storage facilities are already planned in California and South Australia [21].

An alternative to storage is to couple the power system with other energy-consuming sectors such as the heating, transportation, and industry sector. In this way, a more flexible demand as well as a higher global CO₂-reduction potential is possible. In such system, hydrogen (H₂) infrastructure is important [22]. In a sector-coupled European renewable energy system with the coexistence of H₂ and battery, Victoria et al. [15] find that significant storage capacities are less likely to emerge with CO₂-reductions lower than 80% relative to 1990-levels, in agreement with other studies [23, 24, 25]. But most important, Victoria et al. show that flexibility introduced by sector-coupling delays the moment in the CO₂-reduction in which large energy storage capacities will be needed.

A wide palette of storage technologies is classified as being emerging [25]. But with PHS, batteries, and H₂ as dominant storage options, it is not clear whether a room exists for additional storage technologies in an optimal system. Prior literature covers electricity storage in renewable power systems [26, 27, 28, 29, 14]. With regard to the development of storage technologies, Sepulveda et al. [26] present the idea of a technology design space containing combinations of storage costs and efficiencies to evaluate the potential for long-duration energy storage systems in North-American power grids. They show that competitiveness highly depends on the storage energy capacity cost and discharge efficiency, whereas charge and discharge capacity cost and charge efficiency are of secondary importance. Low-cost energy storage furthermore shows a high potential of reducing the total cost of the power system [27, 14]. Both Sepulveda et al. [26] and Ziegler et al. [28] find a threshold of $20/kWh energy capacity cost for the storage to become favorable to the system.

As storage investment costs are usually assumed fixed and reflect current or predicted future cost levels, prior studies are limited by the assumption of each particular technology. Additional uncertainties occur when looking at a fully sector-coupled system since sector integration both increases electricity demand and induces a more flexible electricity demand. It is, furthermore, not certain that storage is even the cost-optimal strategy, compared to overplanting renewable capacities [30]. In this study, we consider a future European energy system, which relies heavily on renewable power sources, and raise the following research questions: Is there room for additional storage, when already PHS and battery are present, in a sector-coupled renewable European energy system? If so, which characteristics does such storage technology need, to play a major role in the system, and how does it impact the system design and operation?

The scope of this paper is to use a state-of-the-art multi-sector energy system model to investigate the space of cost-competitive electricity storage technologies, on top of PHS and battery storage. This is done when already accounting for the competition from other flexibility options provided by backup reserves, interconnectivity, overplanting renewable capacities, or integrating the power system with heating, transportation, and the industry sector. We do not limit ourselves to fixed investment cost or efficiency assumptions when assessing the room for additional storage technologies nor distinguish between the expected duration time scale. Instead, we examine the required characteristics (charge and discharge power capacity cost, charge and discharge efficiency, energy capacity cost, and self-discharge time due to standing losses) of a generic storage technology to feature in the system. First, we investigate the storage deployment in the power system alone. Second, we assess it in the multi-sector energy system. The cost-competitive configurations are in this paper referred to as storage-X.

The paper is structured as follows. Section II introduces the concept of storage-X and presents the room for additional storage technologies. Section III delineate the accommodating system impact. Section IV encapsulates our findings in a discussion on whether current technologies can appear within the derived space, followed by the main conclusion of our work in Section VII. Materials and methods are found in Section VII.
named storage-X, could potentially cover a wide range of different storage technologies. We define a discrete space of configurations to identify the combinations of storage parameters that techno-economically provide substantial energy capacity to the system. Fig. 1 depicts the parameters defining storage-X, and highlights the components defined prior to optimization, i.e., input parameters. The store itself is characterized by a storage energy capacity cost $\hat{c}$ and a self-discharge time $\tau_{SD}$. The storage self-discharge is the time constant of an exponential decay, see Fig. 6 and Eq. 5, and it represents the number of days until the storage is discharged due to self-discharging. The storage is connected directly to the electricity bus (high-voltage) with links that represent charge and discharge technologies, e.g., if storage-X were a H2 store, the links could for instance correspond to electrolyzers and fuel cells. The links are characterized by charge and discharge power capacity costs, $c_c$ and $c_d$, and charge and discharge efficiencies, $\eta_c$ and $\eta_d$. Installed energy capacity and power capacities, $E^x$, $G_c^x$, and $G_d^x$, are all outputs of the optimization. The combination of the six input parameters constitutes the configuration of storage-X. Similar to the study by Sepulveda et al. [26], we enclose all feasible combinations into a design space of storage configurations able to play a substantial role in the decarbonized energy system. The Europe-aggregate energy capacity $E^x$ (Eq. 5) and the load coverage $LC^x$ (Eq. 6) are used as metrics to signify the potential of each storage configuration within the design space. The former indicates the storage size and the latter represents the relative contribution to matching power supply with demand. Rasmussen et al. [31] find that additional balancing from backup capacities is reduced substantially when ideal storage (100% efficiency) equivalent to 6 times the average hourly load (av.h.l.), corresponding to approximately 2 TWh energy capacity, is deployed in the system. As not all combinations within the parameter space yield such deployment, we define, subsequent to the optimization, a lower threshold of 2 TWh energy capacity (accounting for efficiency losses) which the storage needs to fulfill. If below this limit, we omit the configuration from the design space.

Storage-X is made available in a model comprising a highly-decarbonized European energy system, which has reached a 95% CO2 emissions reduction relative to 1990-levels. We provide each parameter range into a discrete parameter space and sample all 2,016 combinations, for three systems: 1) The power system without sector-coupling, 2) The power system integrated with heating and land transport, and 3) The power system integrated with heating, land transport, industry, shipping and aviation, and biomass, hereinafter referred to as the fully sector-coupled system. The system is modeled with a 37-nodes network in the PyPSA-Eur-Sec framework. For a description of the energy system model, we refer to the Materials and Methods (section VII). On top of PHS, which is included exogenous to the optimization, our model allows batteries, with fixed cost and efficiency assumptions, to expand as well.

See Table 2 for storage-X parameter space and Table S3 for battery costs assumptions.

A. Integration of the reference storage

In this section, we consider one set of input parameters describing storage-X, hereinafter the reference storage, see Table 2. We investigate the integration of storage-X in the power system, and subsequently the sensitivity to each storage input parameter. To understand the dynamics of how the mismatch between renewable generation and the electricity load, hereinafter the residual load, $\Delta g$ (the bar indicates that it is normalized), is balanced in the model, and to emphasize that storage-X is far from the only flexibility option, we show the distribution of the residual loads (Eq. 3) within the modeled year. In Fig. 2 this is shown for Great Britain. See Fig. S11 for the temporal balance of the Europe-aggregate electricity system.

First, we see the effect of grid interconnection, as a large share of the residual load is balanced out by imports/exports. In events with large renewable deficits, the system compensates by activating gas power plants (both open-cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT)) as well as discharging battery stores and PHS. Batteries and PHS are charged in case of a large excess renewable generation relative to the nodal load. When looking at the operation of storage-X, it is primarily charged with excess renewable generation (i.e., the generation that exceeds the load). But in addition, the system also finds it optimal to import power to charge its storage capacities, or oppositely use storage dispatch to export electricity, in periods with positive residual loads. In the considered Great Britain-node, the largest source of electricity generation is wind (Fig. S7) and the largest storage capacity is storage-X (Fig. S8). In contrast, e.g., Spain acquires most of its electricity from solar PV, balanced by battery and PHS, and does not have room for the reference storage-X (Fig. S10).

We also consider two systems with sector-coupling. Fig. S12 presents the resulting dispatch in the system that includes the heating and transportation sectors, obtained with the reference storage-X. Electrification of the heating sector entails a higher seasonality in the electricity demand, which could favor a higher deployment of storage. But for the reference storage-X, this is not the case, as it does not take part in the system. This can be attributed to the more flexible demand introduced by including land transport since the model allows smart charging of EV batteries (we assume 85% of land transport to be electrified and 15% to be fuel cell electric vehicles).
Our results are obtained assuming a 95% CO₂ reduction relative to 1990-levels. The time horizon of this reduction depends on the transition pathway taken and is still uncertain. To address this, we evaluate the sensitivity of the storage deployment to the level of emissions reductions, see Fig. S10. As the CO₂-emissions are reduced from 10% of the 1990-levels to 0%, the change in storage energy capacity exceeds the alteration obtained when changing the storage parameters, with storage capacity $E^\alpha$ ranging from 10 MWh to 23 TWh. The results are thus strongly impacted by the CO₂-emissions reductions. But, from this finding, if storage-X is competitive at 5%, this will also be the case at emissions reductions beyond this. On the other hand, when connecting the power system with other sectors, we see that the need for reference storage-X is largely decreased since the emergence of H₂ infrastructure and EV batteries provides additional flexibility to the system.

### B. Design space of storage-X

To derive the feasible design space, we sample all combinations of the parameters in Table 2. For the power system, Fig. S10 shows the storage energy capacity in units of dispatchable electricity for four levels of charge and discharge power capacity cost, $c_c$ and $c_d$. In each subfigure, the energy capacity cost, $c$, and charge and discharge efficiency, $\eta_c$ and $\eta_d$ are varied. For readability, the figure shows the round-trip efficiency, $\text{RT}\text{E} = \eta_c \times \eta_d$. When comparing the subfigures, we see that results are more sensitive to increased charge power capacity cost compared to discharge power capacity cost, as fewer configurations occur in the upper-right corner than in the lower-left (consistent with Fig. 2). I.e., the size of the storage is more impacted by the investment costs of the charging capacity than the discharging.

As one follows the diagonal, i.e., a concurrent increase of both charge and discharge power capacity cost, the efficiency requirements increase. That is, in order to obtain a given storage deployment in the system, the storage needs to exert higher performance in terms of higher round-trip efficiency. If this is not feasible, storage energy capacity costs should be reduced. Conversely, when both charge and discharge power capacity costs are low, high efficiency is not an essential requirement. Disaggregating the round-trip efficiency, in Fig. S17 reveals that deployed storage capacity is more sensitive to changes in discharge efficiency than in charge efficiency. This is indicated by the higher number of configurations that exist in the low charge-high discharge efficiency subfigure, compared to the off-diagonal high charge-low discharge. As an extension to the analysis, we consider certain technologies (e.g., pumped thermal energy storage, see S1) that are capable of charging their storage with an energy efficiency beyond 100% (electricity to heat). We allow such high charge efficiency to occur, in combinations with discharge efficiencies ≤50%, and showcase it in the design space as a distinct additional option, but do not include it in the remaining results. In that case, deployment is still more sensitive to discharge efficiency.
FIG. 3: Cost-optimal Europe-aggregate capacity of storage-X
(top) Energy capacity (full line and left y-axis) and power capacity (dashed line and right y-axis) sensitivity to the six considered storage parameters. Note that the x-axis is reversed in some of the subplots. See Fig. S15 for similar depiction including PHS and battery storage.
(bottom) Energy capacity at a given charge (columns) and discharge (rows) power capacity cost, energy capacity cost (x-axis), self-discharge time (bandwidth), and round-trip efficiency RTE (band color). Note that the second axis uses a log-scale. Energy capacity is multiplied by discharge efficiency to obtain units of dispatchable electricity. Storage solutions contained in the red region define the storage design space resulting in a Europe-aggregate capacity of ≥2 TWh dispatchable electricity (6 av.h.L1). The number of configurations surpassing this limit, and the number of configurations contained in each subfigure (in parenthesis), are indicated in grey. For a similar depiction, with subfigures ordered by the efficiency, see Fig. S17.
The configurations that suffice the threshold of ≥2 TWh dispatchable electrical energy can be mapped in a radar plot, of which the boundaries confine the design space of storage-X. Fig. 4 presents the radar chart for the power system with the resulting 195 qualifying storage configurations. In this depiction, ideal storage with 100% efficiencies, zero standing losses, and free capacities would be coinciding with the inner grey polygon located in the center of the chart. Moving towards the exterior in one of the six axes is equivalent to slacking on either cost (i.e., higher investment cost), efficiency (i.e., lower conversion efficiency in the charging or discharge stage), or higher energy losses (i.e., lower self-discharge time). Hence, a fully covered radial plot indicates that the system selects the storage-X even for very pessimistic input parameters of the storage. Conversely, a small radial plot indicates the need to attain optimistic parameters in order to be selected. An additional feature is the load coverage, proportional to the intensity of the color. We see that if high load coverage (>10%) is desired, the storage is restricted to a high charge and discharge efficiency. Despite of high power capacity cost (750 €/kW), >10% load coverage is still achievable. A darker red color at the exterior of the discharge power capacity cost axis, compared to the same location for the charge power capacity cost, signify once again that changing the discharge capacity cost impacts the result less with regard to storage-X deployment and operation. At low efficiencies (≤50%), storage is still deployed but accompanied by low load coverage. Energy capacity cost of 20 €/kWh is feasible, but only in combinations with low charge capacity cost and high discharge efficiency. When lowering it to ≤10 €/kWh, we start to see combinations with other parameter inputs. By contrast, the self-discharge time does not appear to be a limiting factor with respect to the possible level of load coverage.

Conditioned by the storage energy carrier, certain charging processes can be attained at energy efficiencies above 100%, e.g. pumped thermal energy storage (PTES) [33]. For this reason, additional configurations are included in the figure, marked by green, which have such high charge efficiencies but round-trip efficiencies below 100%. In such a case, it is illustrated that the design space is expanded on the discharge efficiency-axis. But still, this only occurs at a low energy capacity cost (<10 €/kWh).

As more energy-consuming sectors become electrified, the total electricity demand in the system increases. Concurrently, more flexible demand is induced. To that end, it is challenging to predict the outcome with regard to the capacities of storage that will optimally be deployed. Fig. 4b and 4c indicate that the design space is enlarged as more sectors are electrified. For the system including heating and transportation, and the fully sector-coupled system, storage configurations with energy capacity costs of 30 €/kWh and 40 €/kWh, respectively, are now present. This is, however, only the case when charge and discharge efficiencies are high.

To showcase one application of the derived storage-X design space, a comparison with emerging storage technologies is made, with results found in Fig. [31]–[33]. We here show that adiabatic compressed air energy storage (aCAES), thermal hot...
rock energy storage (TES), and PTES have the potential of being within the additional room of storage investigated in this paper. Hydrogen storage with fuel cells, if disconnected from the hydrogen network, could work as a storage-X as well. But due to high costs related to fuel cells, the configuration exceeds the boundary of the feasible space on the discharge capacity cost-axis (Fig. S4).

III. RESULTS (2/2): SYSTEM IMPACTS

The storage design space was derived according to the objective of sufficing a certain level of deployed storage energy capacity. Here, we investigate whether and to what extent different storage-X configurations impact the optimal design of the energy system.

A. Generation mix

The large renewable penetration in the considered scenario leads to wind and solar being the base load capacities balanced by gas power plants, hydro (including both reservoir and run-of-river), and storage such as battery, PHS, and storage-X (Fig. S11). Fig. S18, S19, and S20 present the capacities and generation mix sorted by the storage-X load coverage, for the power system and the two sector-coupled systems. The wind-solar generation mix is robust in the sense that wind consistently provides the major electricity share (46%, 48%, 56%) and solar the second-largest (30%, 33%, 36%) for the three systems. We see a higher renewable share in the sector-coupled systems due to CO₂ emissions being shifted to other sectors, and thus, carbon-emitting power plants are displaced. Common for the systems, is that wind capacity decreases and solar increases concurrent with a larger load coverage of storage-X.

On the other hand, what is not fixed, is how the system deploys backup power generators and storage capacities. For the power system, gas (including both OCGT and CCGT) and battery capacities are both impacted as storage-X capacity increases and provides higher load coverage. But it is more clear that the battery capacity is displaced by storage-X as it consistently decreases. Storage-X does not replace the temporal characteristics of batteries since they show distinct energy-power ratios (discharge times). Batteries show discharge times within 3 and 6 hours, whereas storage-X are within 1 and 4 days (Fig. S21). Gas capacity is more impacted by the combination of storage capacities and is slightly reduced but sustains a substantial magnitude, even at high penetration of storage-X. This implies that storage-X can substitute battery but is incapable of taking the role of backup power capacity to cover extreme events (e.g., sudden renewable droughts). Similar effects are observed in the sector-coupled systems. Here, combined heat and power (CHP) is weakly impacted, since it is deployed primarily to deliver district heating.

For the fully sector-coupled system, the change in solar and wind capacities is now more clearly pronounced. Including industry now offsets the CO₂ even more, which does not leave much room for carbon-emitting generators. Instead, the system relies more heavily on renewables. Gas power plants show a capacity of <50GW, and a minor capacity of nuclear (<10GW) is present in the system as well. They are both displaced by storage-X as load coverage increases (>7.5%). But here, CHP plants take and sustain the role of backup power, for all configurations. Furthermore, with the availability of biomass, the CHP is now primarily delivered from this source.

B. System cost

As our results rely on least-cost optimization, storage is only deployed when it entails a more cost-effective solution compared to alternative options covered in this paper. Here, we show the potential of reducing the system cost when considering the configurations within the design space. The potential of reducing the system cost is enlarged as the storage contributes with a higher load coverage (Fig. S14). However, to attain large system cost reduction, high round-trip efficiency is required. At 2.5% load coverage, system cost reduction is within 1% and 4%, and at 6.5% load coverage, it is within 2% and 7%. Four distinct groups occur, which differ in round-trip efficiencies. At its best, integration of storage-X entails a reduction of 12%, which is slightly reduced for the sector-coupled systems (8% and 6%), see Fig. S27.

C. Renewable curtailment

An alternative to new storage facilities is deploying excess capacity of renewable generators, which entails a less efficient system as more energy is curtailed instead of being utilized. Fig. S5 shows the percentage of renewable curtailment in the system at all configurations of storage-X. Reference storage entails 6% of renewable energy being curtailed, which for the cross-sectoral systems is reduced to <3%. Despite storage-X being a substantial part of the system (indicated by high load coverage), curtailment is still a part of the optimal system. Curtailment shows a uniform distribution, indicating that no favorable level of curtailment exists. Lastly, when comparing renewable curtailment and system cost reduction (Fig. S23), we see that a low curtailment (∆≤6% for the power system) is a necessity but not the driver to obtain a considerable system cost reduction.

IV. DISCUSSION

Whether a room exists for an additional storage-X, on top of PHS and batteries, depends on two aspects. Both are inspected in this study.

The first one covers the significance of cost and efficiency of each storage component. Our results indicate that the discharge efficiency and storage energy capacity cost are the parameters that potentially, if improved, entail the highest rise in storage deployment, in line with prior studies [29]. Here we show that charge power capacity cost is also important. We can to some extent explain the results by the serial connection of the storage-X components of which the discharge stage is the last chain. As an example, the discharge efficiency could be reduced, while keeping the other input parameters fixed. In that case, to ensure the same storage electricity output, the energy
and power capacity in the preceding chains must be enlarged as compensation. This requires higher investments in both of the components. As a comparison, capacity cost does not have this serial-accumulating impact but only alters the investments in the considered component. The energy capacity cost is linked to the (cost-competitive) size of the store, which is why we see such high sensitivity to this parameter. Charge capacity cost is associated with the level of renewable curtailment. The system can either deploy, if cost-optimal, sufficient charge capacity to utilize the full renewable potential, or, in lack of storage charge capacity, curtail it. It is thus a trade-off between investments in larger charge capacity or more renewable curtailment, which can explain the significance of this input parameter.

The results presented do not link directly to the possible limitations that may be present within real storage designs. To address this, we compare the derived design space of storage-X with an ensemble of real emerging technologies. From our findings, the system desires a high discharge efficiency. If this is not attainable, the storage needs to have a low energy capacity cost. Worth mentioning are technologies that have charge (energy) efficiencies above unity, which entails room for slack in the discharge efficiency. This is the case for PTES, which has a low discharge efficiency (25%) compared to e.g. aCAES (65%), but is not penalized due to its high charge efficiency. Driven by their low energy capacity costs, we show that aCAES and PTES have a chance of taking part in the system. But if these should be fulfilled, the energy capacity costs should be reduced to <10 €/kWh. The acquired data on existing storage designs reports that all have self-discharge times of at least 100 days. Since we identified this parameter as less important when above at least 18 days, such long periods (>100 days) do not cause any bottlenecks of operation or deployment.

The second aspect analyzes the impact of storage-X on the system. Without the integration of other sectors, the power system at the allowed level of CO$_2$-emissions prepares for events with renewable deficits by deploying a considerable capacity of gas (OCGT and CCGT) power plants and batteries. The deployment of storage-X is observed to have a link to the abundance of batteries: We see a decline in battery capacity as configurations entail higher penetration of storage-X. This does, however, not mean that the temporal characteristics of batteries (discharge time of 6 hours or less) are replicated by the storage-X, since most configurations show discharge time longer than 1 day. With transportation and heating included in the system, a higher seasonality is induced in the electricity demand. The seasonal shift is mostly balanced by CHP plants that supply central heating in urban areas. Alternatively, this share could have been met by an electrical heating source, e.g., heat pumps, requiring another option to accommodate the seasonal fluctuation. Here, we do not see such seasonal storage within the space of storage-X solutions which at maximum show discharge times of less than a week. Note that the majority of CHP in this system relies on having installed carbon-capture technology, which increases the investment costs of these facilities.

The potential system impact of deploying a substantial capacity of the unspecified new storage technology is studied. The total system cost is shown to be reduced as storage-X emerges in the system. We show that at its best, a system cost reduction of approximately 10% can be achieved, which is considerably lower compared to prior studies $^{14}$. This can be related to the curtailment of solar and wind energy that, despite storage playing a large role, is still optimal, reaching magnitudes of 6% and 10% respectively. The renewable curtailment observed in this system is still less compared to other studies comparing the value of storage versus overplanting renewables $^{30}$.

In this paragraph, the limitations of this study are discussed. Our findings yield a design space that ideally new storage de-
velopers could use as a crosshair for possible further development. The findings of our study are driven by certain assumptions that should be accounted for. The hydrogen carrier in our model does not have a direct link to the electricity bus, i.e., fuel cells are not used for power generation. If cost-effective and disconnected from the hydrogen network, such a storage setup would have been contained by the additional usage option of the H₂ carrier. Electric vehicles offer flexible charging. An additional flexibility option would be vehicle-to-grid, which is not included in this study. If this was made available, the room for the battery-displacing storage-X configurations would most likely reduce.

The study is made with a network consisting of 37 nodes with a 3-hourly resolution. We showed that reducing the degrees of freedom in the temporal domain from 1 hour to 3 hours time steps does not have a large impact on the deployment of storage-X. Conversely, the results show high sensitivity to the spatial resolution of the network. As the bottlenecks in the grid are better resolved, the need for storage increases. Our results are thus limited to having a 37-nodes network resolution.

Furthermore, as we investigate flexibility options and suggest gas power plants as new backup capacities, this is established on cost assumptions that do not reflect the current development of commodity prices of, e.g., gas. We perform an overnight optimization that does not correspond to a specific year but is to resemble a possible near-future system prior to full decarbonization. In the system today, a large number of central fossil-fueled power plants are still either active or kept on stand-by. Thus, some of these flexibility options might still be valuable assets in commission which the backup capacity in our study also could represent.

V. CONCLUSION

To explore the room for an additional storage technology, storage-X, we attained a design space established on 2,016 storage samples to identify the configurations that would lead to substantial storage deployment. This was defined as an energy capacity of ≥6 time the average hourly load in the European electricity system. We show that a room exists, also when including other sectors in spite of more flexible electricity demand being induced. But this requires either a high discharge efficiency (90%) or low energy capacity cost (<10 €/KWh). We furthermore investigated the system impact within the design space. System cost reduction is at its best not larger than approximately 10%, concurrent with a renewable curtailment of 1%, obtained by storage-X.

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VII. MATERIALS AND METHODS

This study performs an overnight cost-optimization of the generation and storage capacity layout and operation in a future highly decarbonized European electricity network consisting of 37 nodes spanning over 33 countries, all members of the European Network of Transmission System Operators for Electricity (ENTSO-E). The network topology is shown in Fig. 5. The model is simulated using the open energy system model PyPSA-Eur-Sec [34]. The model assumes an ideal market with perfect competition between all included technologies and long-term market equilibrium, i.e. market is liberalized and energy technology recovers exactly its full costs. Furthermore, the model assumes perfect foresight of energy supply and demand. The dispatch and capacity of generators and stores in each node are optimized such that the total system cost is minimized.

\[
\min \sum_{n,s,t} c_{n,s} G_{n,s} + \sum_{n,s} \hat{c}_{n,s} E_{n,s} + \sum_{l} c_{l} F_{l} + \sum_{n,s,t} o_{n,s,t} g_{n,s,t} \]

s.t. \[
\sum_{n,s} g_{n,s,t} + \sum_{t} o_{n,t} f_{l,t} = d_{n,t}
\]

Where \(c_{n,s}\) and \(\hat{c}_{n,s}\) are the annualized costs for generator and storage power capacity \(G_{n,s}\) and storage energy capacity \(E_{n,s}\) for technology \(s\) in node \(n\). \(c_{l}\) are the fixed annualized costs for the capacity \(F_{l}\) of the links \(l\). \(o_{n,s,t}\) are the marginal costs of generation and storage dispatch \(g_{n,s,t}\) at time \(t\). The optimization is subject to a list of equality and inequality constraints, of which two of them are listed here. First, the energy balance of demand with generation, dispatch/charging of stores, and import/export. Here, \(f_{l,t}\) is the power flow through link \(l\) at time \(t\) and \(o_{n,t}\) include the direction and efficiency of the flow in the links. Second, the sum of all greenhouse gas emissions, \(\epsilon_s \frac{\text{CO}_2}{\text{MWh}}\), over all nodes, time steps and technologies in the network must not exceed the global CO₂ constraint \(\text{CAP}_{\text{CO}_2}\), in percentage of 1990-levels. Here, \(\epsilon_s\) is the CO₂ intensity in tonne CO₂ per MWhha, and \(\eta_{n,s}\) is the efficiency.

The optimization is performed for one year with hourly resolution (design space is obtained with 3-hourly resolution). The costs are thus annualized assuming a lifetime of each asset and a discount rate \(r\) of 7%:

\[
c_{n,s} = c_{n,s}^{inv} \left( \frac{1+r}{1+r} \right)^t - 1
\]

Where \(c_{n,s}\) are the annualized costs and \(c_{n,s}^{inv}\) are the capacity costs.

The total CO₂-emissions of the European electricity system are constrained to 5% relative to the 1990-level, corresponding to 74.1 MtCO₂. Electricity load reflects historical national consumptions from 2013 reported at ENTSO-E, collected from Open Power System Data [35]. Technology cost is based on
assumptions for 2030 to account for expected technology cost reduction while selecting a year relatively close to the present to reduce uncertainty in cost estimations \cite{36,37}. The internal transmission capacity is exogenously included in the model and equals the capacity of current transmission lines with the addition of lines under construction expected to be commissioned according to the Ten Year Network Development Plan (TYNDP 2018) by ENTSO-E \cite{38}.

As a preliminary step, a univariate study is performed to evaluate the sensitivity of the cost-optimal storage energy capacity to storage inputs. This is done by varying the storage inputs from a given reference point (defined in Table 2), each parameter at a time. For efficiencies, we assume intermediate ones, both at 50%. Self-discharge time of 30 days enables short-duration operation as well as operation within a synoptic and seasonal timescale.

TABLE 1: Model assumptions.

| Assumption            | Value       |
|-----------------------|-------------|
| CO\(_2\) reduction    | 95\%        |
| Time resolution       | 3 h         |
| Network resolution    | 37 nodes    |
| Transmission          | TYNDP       |
| Sectors               |             |
| (a) Electricity\*     |             |
| (b) Electricity + Heating |         |
| + Land transport      |             |
| (c) Electricity + Heating |         |
| + Land transport + Industry |       |
| + Shipping + Aviation |             |
| Weather year          | 2013        |

\* If not mentioned otherwise, shown results are derived from the electricity system without sector-coupling.

A multivariate study is performed to confine the design space of the storage able to reach a substantial energy capacity, which we here consider as configurations entailing \(\eta_E \geq 2 \text{TWh}\), equivalent to 6 times the average hourly load \(\langle v_{h1.0} \rangle\) of the European electricity system.

The workflow to obtain the space of feasible storage configurations is shown in Fig[4]. First, we use an open energy system modelling framework, PyPSA-Eur-Sec, described in the following sections, to perform a univariate analysis to assess the sensitivity of each assumption related to the storage and the model. Subsequently, we sweep through the space of all parameters, a total of 2,016 different storage configurations, to locate the space of feasible parameter combinations. The room can contain existing technologies, as well as not-yet-existing ones, and highlights the design flexibility of each parameter. For this reason, we will from here on now refer to it as the design space, as proposed by Sepulveda et al. \cite{26}.

A. Generators

The renewable generators that are available to the system are wind (off- and onshore), solar PV (utility and rooftop), and hydropower (reservoir and run-of-river). We distinguish between two voltage levels in the grid: High voltage (transmission grid) and low voltage (distribution grid). The renewable generators are connected to the high-voltage grid, except solar rooftop which is attached to the low-voltage. For wind and solar, the installable capacity is limited by the estimated potentials. The potentials are estimated by the available land use from the Corine Land Cover (CLC) database \cite{39} subtracting Natura 2000 protected areas \cite{40}. The following limits are imposed, based on the study by Victoria et al. \cite{32}. On- and offshore wind are limited to 20% of available land, utility-scale solar PV to 9%, whereas rooftop PV potential is estimated according to population density. See Supplemental Fig[55] for the nodal technical available renewable potential. Hydropower capacities are included exogenously, since most of the potential is assumed to be exploited, and kept fixed at today’s capacity (99.6 GW for reservoir and 34.5 GW for run-of-river \cite{41}). Time series of wind and solar capacity factors and hydro inflow are produced with ATLITE \cite{42} and ERA5 \cite{43} weather data for 2013. The CO\(_2\)-constraint still allows CO\(_2\)-emitting conventional power plants to balance the system in some periods with low renewable generation. Open-cycle gas turbine (OCGT), combined cycle gas turbine (CCGT), nuclear, and coal power plants can be installed. Investment and O&M cost predictions of power generation technologies, subject to optimization, for 2030 are presented in Table [S2] in Supplemental Material. Capacities and locations of conventional power plants that are not optimized, but included exogenously, are acquired from Powerplantmatchv0.5.3 \cite{41}.

B. Storage

Storage is included in each node of the network. We will include the capacity of electricity storage that has already been deployed (pumped-hydro storage) and new storage that, if optimal, is built on top of this. The latter is here constituted by batteries, which most studies expect to be a part of the solution, and storage-X that represents all existing and future alternative storage solutions. Besides electricity stores, hot-water tanks and H\(_2\) storage can be deployed as well, to shift in time the production from the heating and H\(_2\) consumption. H\(_2\) stores can not convert directly back to electricity with e.g. fuel cells. If disconnected from the hydrogen network, storage with electrolysis-H\(_2\)-fuel cells is intended to be represented by storage-X.

This subsection describes how electricity storage is implemented in our model.

1. Storage-X

The input parameters of the reference storage and storage-X are given in Table [2].

The storage is non-ideal and for this reason, we assume some standing loss. For power-heat-power storage, this could
**TABLE 2: Storage-X parameter space.** Cost, efficiency, and self-discharge of the reference storage (first column) and parameter space (second column).

| Parameter | Reference | Discrete space |
|-----------|-----------|----------------|
| \(c\)     | 3 €/kWh   | \([1,2,5,10,20,30,40]\) |
| \(c_c\)   | 350 €/kW_e| \([35,350,490,700]\) |
| \(\eta_c\) | 50%       | \([30,50,95,200]\) |
| \(c_d\)   | 350 €/kW_e| \([35,350,490,700]\) |
| \(\eta_d\) | 50%       | \([30,50,95]\) |
| \(\tau_{SD}\) | 30 days | \([10,30]\) |

* 2030 cost of underground H\(_2\) storage \([36]\)
** 2030 cost of H\(_2\) storage tank \([36]\)
*** Only in combinations with discharge efficiency ≤50%.

represent thermal loss. The storage state-of-charge, when not being either charged or discharged, is assumed to decrease following an exponential decay, as depicted in Fig. 6. The given self-discharge time \(\tau_{SD}\) in Table 2 represents the time constant of the exponential function in Equation 3:

\[
e_{c_t} = 1 - \exp\left(-\frac{t}{\tau_{SD}}\right)
\]

(3)

**FIG. 6: Standing loss represented by an exponential decay.** Normalized state of charge at self-discharge time \(\tau_{SD}\) equal to 10, 30, and 100 days.

The state of charge of storage-X, \(e_{n,t}\), in node \(n\) at time \(t\), can be generalized to the following energy balance, when accounting for standing loss (\(\eta_s\)) and efficiency losses (\(\eta_c\) and \(\eta_d\)) related to charging/discharging:

\[
e_{n,t} = \eta_0|e_{n,t-1}| + \eta_c|g_{n,t}^c| - \eta_d|g_{n,t}^d|
\]

s.t. \(0 \geq e_{n,t} \geq E_n\)

(4)

Where \(|g_{n,t}^c|\) is the absolute electricity stored and \(|g_{n,t}^d|\) is the dispatched electricity. The state of charge can not exceed the storage energy capacity \(E_n\).

2. Pumped-hydro storage

Current installed pumped-hydro storage (PHS) in Europe constitutes approximately 55 GW power capacity \([?\ ]\) and 1.3 TWh \([17]\). Although Gimeno-Gutierrez and Lacal-Arantegui \([44]\) identify a technical potential for expanding the current capacity of PHS, including social and environmental constraints, we assume the cost-optimal potential to be fully exploited. PHS is thus added exogenously to the model, keeping it fixed at today's capacity. Using plant-specific data from Powerplant-matching v0.5.3, this aggregates to 56 GW power capacity, and using discharge times from Geth et al. \([17]\), this corresponds to 1.4 TWh energy capacity. A charge and discharge efficiency of 86% is assumed \([36]\).

3. Battery storage

Battery storage in the high-voltage grid is included in the objective of the optimization problem, where energy and power capacity are subject to independent optimization. The cost and performance assumptions reflect data from the Danish Energy Agency \([36]\) on utility-scale Li-Ion batteries. Residential batteries are included in the low-voltage grid, with cost assumptions from Ram et al. \([45]\). Assumed investment and O&M costs in 2030 are presented in Table \([35]\) in Supplementary Material.

C. Metrics

A comparison of the storage configurations is made, first on the resulting storage contribution to the system based on the installed Europe aggregate energy capacity \(E^k\) and charge/discharge power capacity, \(G^k_c\) and \(G^k_d\), from Eq. 5:

\[
E^k = \sum_{n} E^k_{n}
\]

\[
G^k_c = \sum_{n} G^k_{c,n}
\]

\[
G^k_d = \sum_{n} G^k_{d,n}
\]

(5)

Here, \(E^k_{n}\), \(G^k_{c,n}\), and \(G^k_{d,n}\) are the installed energy, charge and discharge power capacity of storage-X in node \(n\). Second, we assess the storage potential signified by the Europe-aggregate load coverage \(LC\) with Eq. 6:

\[
LC^k = \frac{\sum_{n} g^k_{n,t} \eta_{n,t}}{\sum_{n} L_{n,t}}
\]

(6)

where \(L_{n,t}\) is the electricity load and \(g^k_{n,t}\) electricity dispatched by storage-X in node \(n\) at time \(t\). The former includes both exogenously defined load (national electricity load, including demand from the industry) and the additional endogenous load which arises when electrifying the heating and transportation. Furthermore it also covers the additional load originating from building the H\(_2\) infrastructure needed in a decarbonized
sector-coupled energy system. Including load coverage in the assessment yields a useful indication of how much the storage is taking part in meeting the load in the system. Furthermore, it can also be a reflection of how much it needs to dispatch in order to recover its cost.

Energy capacity can be converted into units of average hourly electricity load in Europe with Eq. 7

\[
\text{av.h.l.}_{\text{el}} = \frac{\eta_d E^x}{325 \text{ GWh}}
\]

With 325 GWh being the average electricity load in the network contained in Fig. S5 and accounting for efficiency losses in the discharging stage by multiplying the energy capacity \( E^x \) with the discharge efficiency \( \eta_d \).

Normalized residual loads is calculated with Eq. 8

\[
\Delta \bar{g}_{n,t} = \frac{L_{n,t} - (g^\text{wind}_{n,t} + g^\text{solar}_{n,t} + g^\text{hydro}_{n,t})}{\max L_{n,t}}
\]

D. Sector-coupling

For detailed documentation of the sector-coupled model, we refer to [46]. Fig. 8 summarizes the most important assumptions related to how electricity flows between the different sectors. As previously covered, the high-voltage electricity bus has renewable generators and electricity stores (PHS, battery, and storage-X) connected to it. Gas is linked with the electricity bus through Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) power plants, and with the heating bus through combined heat and power (CHP) plants or gas boilers. Furthermore, for all three systems covered in the paper, \( \text{H}_2 \) storage is connected with electrolyzer links as well. Hydrogen can be converted into methane through the Helmeth or Sabatier processes. Conversely, \( \text{H}_2 \) can be produced with steam-methane reforming (SMR) with or without carbon capture (CC), corresponding to blue and grey \( \text{H}_2 \) respectively, and electrolysis. \( \text{H}_2 \) is fed into industry and transportation but is not needed directly back to the electricity bus. \( \text{H}_2 \) network is installed if cost-optimal. A hydrogen store as power-to-power storage (electrolysis-\( \text{H}_2 \)-fuel cell) is here intended to be represented by the storage-X, but only if disconnected from the hydrogen network. Only smart-charging is considered a flexible option for the grid, but not vehicle-to-grid.

E. Data availability

All code used for plotting is openly available with a GNU GPLv3 license at Github: [ebekyh/storageX.git](http://ebekyh/storageX.git)
Storage parameters

- Storage energy capacity cost: \( \hat{C} \)
- Charge power capacity cost: \( C_c \)
- Charge efficiency: \( \eta_c \)
- Discharge power capacity cost: \( C_d \)
- Discharge efficiency: \( \eta_d \)
- Storage self-discharge time: \( \tau_{SD} \)

PyPSA-Eur-Sec

Design space

FIG. 7: Workflow used to derive the design space of storage-X.

**FIG. 8:** Schematics of storage-X integration in the sector-coupled energy system. Storage-X is linked to the high-voltage (HV) electricity bus. Hydrogen is only used as a power-to-X technology and does thus not have a direct link back to the HV electricity bus. Such setup (Power-H2-Power) is intendedly resembled by the storage-X. Furthermore, smart charging, here named grid-to-vehicle (G2V), is included when adding land transport, allowing flexible charging of the electric vehicle (EV) batteries. Vehicle-to-grid (V2G), i.e., EV battery supplying power to the high-voltage electricity bus, is now allowed.
S1. Emerging storage technologies compared with the derived design space

This supplemental note mentions six storage technologies that all have been demonstrated at scales > 1 MW power capacity. A thorough review is found in [25]. The purpose of this inclusion is to evaluate the prospects of each technology based on the derived design space obtained in our study. Below is shortly described which processes are assumed for charging and discharging, as well as which storage facility is used. Subsequently, assumptions with regard to investment costs and efficiencies from [25] and [26] are presented in Table S1 and compared with the findings of our analysis in Fig. S1, S2, and S3 for the power system, the heating and land transport system, and the fully sector-coupled system.

A. Adiabatic compressed air energy storage (aCAES)

Electrical energy is used, to compress atmospheric air to high-pressure air, which is stored, usually in an underground cavern or an overground pressurized tank. Thermal energy generated in the compression is stored in parallel, making it an adiabatic compressed air energy storage. When discharged, compressed air is released and heated by discharging the thermal energy storage, to run a turbine that produces electricity back to the grid [25].

B. Redox-flow battery (RFB)

Vanadium redox flow battery converts electricity into chemical energy through a reversible reduction and oxidation (redox) reaction [26].

C. Molten-salt energy storage (MSES)

Electrical resistive heaters are used for heating the salt storage, which in this case is assumed to be a singular tank since it operates as power-to-power storage. Discharging is with a Rankine cycle [25].

D. Pumped thermal energy storage (PTES)

The dual tank system is charged with a heat pump cycle which ensures a charge efficiency above 100%. Storage consists of a packed bed of rocks. Air is used as the working fluid, to run a Brayton cycle in the discharging stage [25].

E. Thermal energy storage (TES)

Electrical resistive heaters are used for heating the storage containing stacked firebricks. Discharging is with a Brayton cycle [26]. Also known as Carnot batteries [47].

F. Liquified air energy storage (LAES)

In the charging stage, ambient air is cooled down to cryogenic temperatures and stored as liquified air in a low-pressure tank. When discharged, the air is exposed to atmospheric air and expands, which is used to run a turbine that produces electricity [25].

G. Hydrogen electricity storage (H2)

Hydrogen storage charged with electrolysis and discharged with fuel cells, here assumed to be disconnected from the hydrogen network, is also considered a storage-X option. Superscript X is used to signify the distinction from the H2 store already included in our model which could not convert directly back to electricity.

In the considered technology costs reviews, reported power capacity costs cover expenses related to both charging and discharging. It is given by the aggregate power capacity cost $C_P$, accompanied by the power capacity cost ratio $r_C$. To disaggregate $C_P$ into a charge and discharge power capacity cost, $c_c$ and $c_d$, we define the following two equations:

$$C_P = \frac{1}{\eta_{RT}} c_c + c_d \quad (S1)$$

$$r_C = \frac{c_c}{c_d} \quad (S2)$$

where $\eta_{RT}$ is the round-trip efficiency, which is acquired from the literature, along with the ratio $r_\eta$ between the charge and discharge efficiency, $\eta_c$ and $\eta_d$. 

16
To disaggregate the round-trip efficiency, we define the following two equations:

$$\eta_{RT} = \eta_c \times \eta_d$$  \hspace{1cm} (S3)

$$r_\eta = \frac{\eta_c}{\eta_d}$$  \hspace{1cm} (S4)

To convert standing loss per day into a self-discharge time, when assuming an exponential decay (Eq. 3), the following equation can be used:

$$\tau_{SD} = -\ln(1 - \Delta\bar{e})^{-1}$$  \hspace{1cm} (S5)

where $\Delta\bar{e}$ is the energy lost due to self-discharge per day normalized by its state of charge.

TABLE S1: Cost and efficiency assumptions for six emerging storage technologies. Gray columns are either derived from the remaining columns, using Eq. S1-S5, or acquired directly from the given source. As costs are in USD, a conversion factor of 0.96 is used to convert them into Euro. Values marked with (*) are in Euro.

| Technology | $\eta_{RT}$ [%] | $r_\eta$ | $\eta_c$ | $\eta_d$ | $C_P$ [USD/kW] | $r_C$ | $c_c$ | $c_d$ | $\dot{c}$ [USD/kWh] | $\Delta\bar{e}_{SD}$ [%] | $\tau_{SD}$ [days] |
|------------|-----------------|---------|---------|---------|----------------|-------|-------|-------|---------------------|------------------------|---------------------|
| aCAES [25] | 60              | 1.4     | 92      | 65      | 1200          | 0.5   | 327   | 655   | 27                  | 1                      | 100                 |
| RFB [26]   | 73              | 1       | 85      | 85      | 435           | 1     | 183   | 183   | 120                 | -                      | -                   |
| MSES [25]  | 42              | 2.3     | 99      | 43      | 1341          | 0.1   | 108   | 1083  | 18                  | 1                      | 100                 |
| PTES [25]  | 55              | 8.8     | 220     | 25      | 1300          | 0.5   | 340   | 680   | 20                  | 1                      | 100                 |
| TES [26]   | 37              | 2.6     | 98      | 38      | 1007          | 0.04  | 40    | 900   | 8                   | 1                      | 100                 |
| LAES [25]  | 53              | 1.2     | 77      | 65      | 1700          | 1     | 585   | 585   | 32                  | 0.5                    | 200                 |
| H$_2$ [36] | 34              | 1.4     | 68      | 50      | 1431*         | 0.4   | 450*  | 1100*  | 11.2                | -                      | -                   |
FIG. S1: Design space with existing technologies for the power system. Comparison of the derived design space for the power system with six storage technologies: (a) adiabatic compressed air energy storage (aCAES), (b) redox-flow battery (RFB), (c) molten-salt energy storage (MSES), (d) pumped thermal energy storage (PTES), (e) thermal energy storage (TES), (f) liquefied air energy storage (LAES). If white space is contained within the technology (black line) and the design space (colored area), the technology is not capable of entering the design space of storage-X. If it qualifies, the marker at the smallest color intensity decides the load coverage it would result in.
FIG. S2: Design space with existing technologies for the heating and land transport system. Comparison of the derived design space for the heating and land transport system with six storage technologies: (a) adiabatic compressed air energy storage (aCAES), (b) redox-flow battery (RFB), (c) molten-salt energy storage (MSES), (d) pumped thermal energy storage (PTES), (e) thermal energy storage (TES), (f) liquified air energy storage (LAES). If white space is contained within the technology (black line) and the design space (colored area), the technology is not capable of entering the design space of storage-X. If it qualifies, the marker at the smallest color intensity decides the load coverage it would result in.
FIG. S3: Design space with existing technologies for the fully sector-coupled system. Comparison of the derived design space for the fully sector-coupled system with six storage technologies: (a) adiabatic compressed air energy storage (aCAES), (b) redox-flow battery (RFB), (c) molten-salt energy storage (MSES), (d) pumped thermal energy storage (PTES), (e) thermal energy storage (TES), (f) liquified air energy storage (LAES). If white space is contained within the technology (black line) and the design space (colored area), the technology is not capable of entering the design space of storage-X. If it qualifies, the marker at the smallest color intensity decides the load coverage it would result in.
FIG. S4: **Design space compared with hydrogen electricity storage.** Comparison of the derived design space for (a) the power system, (b) the heating and land transport system and (c) the fully sector-coupled system with hydrogen storage. Note that this storage is different from the H$_2$ storage which was already included in our model but which could not convert directly back to electricity.
## S2. Technology cost assumptions

| Generators                  | Investment cost | Lifetime (Years) | FOM   | VOM       |
|-----------------------------|-----------------|------------------|-------|-----------|
| OCGT*                       | 435 €/kW        | 25               | 1.78 %| 4.5 €/MWh|
| CCGT**                      | 830 €/kW        | 25               | 3.35 %| 4.2 €/MWh|
| Nuclear***                  | 7940 €/kW       | 40               | 1.4 % | 3.5 €/MWh|
| Coal****                    | 3846 €/kW       | 40               | 1.6 % | 3.5 €/MWh|
| Solar (utility)             | 376 €/kW        | 35               | 1.93 %| 0         |
| Solar (rooftop)             | 784 €/kW        | 30               | 1.24 %| 0         |
| Onshore wind                | 1036 €/kW       | 30               | 1.22 %| 1.35 €/MWh|
| Offshore wind               | 1573 €/kW       | 30               | 2.29 %| 2.67 €/MWh|
| offwind-ac-connection-submarine | 2685 €/MW/km  | 30               | 0     | 0         |
| offwind-ac-connection-underground | 1342 €/MW/km  | 30               | 0     | 0         |
| offwind-ac-station          | 250 €/kW        | 30               | 0     | 0         |
| offwind-dc-connection-submarine | 2000 €/MW/km  | 30               | 0     | 0         |
| offwind-dc-connection-underground | 1000 €/MW/km  | 30               | 0     | 0         |
| offwind-dc-station          | 400 €/kW        | 30               | 0     | 0         |

* OCGT efficiency $\eta = 41\%$, fuel cost = 20.1 €/MWh
** CCGT efficiency $\eta = 0.58\%$, fuel cost = 20.1 €/MWh
*** Nuclear efficiency $\eta = 0.33\%$, fuel cost = 2.6 €/MWh
**** Coal efficiency $\eta = 0.33\%$, fuel cost = 8.15 €/MWh
| Stores                      | Investment cost | Lifetime (Years) | FOM   | VOM   |
|-----------------------------|-----------------|------------------|-------|-------|
| Battery storage             | 142 €/kWh       | 25               | 0     | 0     |
| Battery inverter*           | 160 €/kW        | 10               | 0.34% | 0     |
| Home battery storage        | 202.9 €/kWh     | 25               | 0     | 0     |
| Home battery inverter*      | 228.06 €/kW     | 10               | 0.34% | 0     |
| H₂ storage tank             | 11.2 USD/kWh    | 20               | 0     | 0     |
| H₂ electrolysis**           | 450 €/kW        | 30               | 2%    | 0     |

* Inverter round-trip efficiency $\eta = 96\%$
** Electrolysis efficiency $\eta = 68\%$
FIG. S5: The network of the power system used in the model. The network consists of 37 nodes distributed over 33 countries. The size of the nodes corresponds to annual electricity consumption. Transmission lines (AC and DC) include the TYNDP by [33].
FIG. S6: Technical potential of renewable power capacities.
FIG. S7: **Power capacity of generators and electricity stores.** Results are attained with reference storage-X (Table 2) for the power system under a global CO₂-constraint of 5% relative to 1990-levels. Solar includes both utility-scale in the high-voltage grid and rooftop panels in the distribution grid. Similarly, battery storage covers both stores connected directly to the high-voltage grid and home batteries that are linked to the distribution grid.
FIG. S8: Energy capacity of electricity stores. Results are attained with reference storage-X (Table S1) for the power system under a global CO$_2$-constraint of 5% relative to 1990-levels. Battery covers both stores connected directly to the high-voltage grid and home batteries that are linked to the distribution grid.
FIG. S9: Balancing of residual load in Great Britain for the electricity-only system. Shown results are for the power system in Great Britain under a global CO₂-constraint of (top) 0% and (bottom) 5% relative to 1990-levels, with reference storage-X parameters. Storage is charged and discharged when shown on the negative and positive y-axis respectively.
Balancing of residual load in Spain for the electricity-only system. Shown results are for the power system in Spain under a global CO₂-constraint of (top) 0% and (bottom) 5% relative to 1990-levels, with reference storage-X parameters. Storage is charged and discharged when shown on the negative and positive y-axis respectively. Storage-X does not appear since it does not take part in the balancing in this node.
FIG. S11: Europe-aggregate balance of the electricity-only system. 8-hourly moving average electricity generation and storage dispatch (positive y-axis), and load and storage charging (negative y-axis), for the system including the reference storage-X parameters. Hydro includes both reservoir, run-of-river, and PHS. Storage-X does not appear since its parameter combination does not entail it to take part in the system.
FIG. S12. Europe-aggregate balance for the system including electricity + heating + land transport. 8-hourly moving average electricity generation and storage dispatch (positive y-axis), and load and storage charging (negative y-axis), for the system including the reference storage-X parameters. Hydro includes both reservoir, run-of-river, and PHS. Storage-X does not appear since its parameter combination does not entail it to take part in the system.
FIG. S13: **Europe-aggregate balance for the fully sector-coupled system.** 8-hourly moving average electricity generation and storage dispatch (positive y-axis), and load and storage charging (negative y-axis), for the system including the reference storage-X parameters. Hydro includes both reservoir, run-of-river, and PHS. Storage-X does not appear since its parameter combination does not entail it to take part in the system.
FIG. S14: **Balancing of residual load in Europe for the three systems.** Shown results are Europe-aggregate values for the (top) power system, (middle) heating and land transport, and (bottom) fully sector-coupled energy system, under a global CO$_2$-constraint of 5% relative to 1990-levels, for the reference storage-X parameters. Storage is charged and discharged when shown on the negative and positive y-axis respectively. Storage-X does not appear since its parameter combination does not entail it to take part in the system.
FIG. S15: **Battery and PHS capacities for the electricity-only system.** Shown is a comparison of battery and PHS capacities with the obtained storage-X deployment in the power system when conducting a singular-parameter sweep. Batteries show a minor impact of singular improvement of storage-X parameters. Green hydrogen infrastructure is not optimal when looking solely at the power system. PHS capacities are included exogenously and thus do not change. Batteries include both high- and low-voltage grid connections.

FIG. S16: **Storage-X energy capacity at different CO₂-constraints.** Shown is the energy capacity obtained with the reference storage-X, for the power system (‘E’), the power system integrated with the land transport and heating sector (‘E-T-H’), and for the fully sector-coupled energy system (‘E-T-H-I-B’). Without changes in the storage-X parameters, sector-coupling reduces the optimal energy capacity by more than an order of magnitude, when considering a fully decarbonized system.
FIG. S17: Cost-optimal Europe-aggregate storage energy capacity of storage-X. Energy capacity at a given charge (columns) and discharge (rows) efficiency, energy capacity cost (x-axis), self-discharge time (bandwidth), and corresponding round-trip efficiency RTE (band color). Note that the second axis uses a log-scale. Energy capacity is multiplied by discharge efficiency to obtain units of dispatchable electricity. Storage solutions contained in the red region define the storage design space resulting in a capacity of ≥ 2 TWh dispatchable electricity (6 av.h.LEl). The number of configurations sufficing this limit, and the number of configurations contained in each subfigure (in parenthesis), are indicated as well.
FIG. S18: **Electricity generation and capacity for the electricity-only system within the design space of storage-X.** (top) Normalized electricity generation and storage capacities, and (bottom) annual generation mix, under a global CO$_2$-constraint of 5% relative to 1990-levels. Thick lines show moving averages based on 15 neighboring configurations. Batteries and solar include both assets connected to the high- and low-voltage grid. Gas includes both open-cycle and combined cycle gas turbine power plants.
FIG. S19: **Electricity generation and capacity in the system including electricity + heating + land transport, within the design space of storage-X.**

(top) Normalized electricity generation and storage capacity, and (bottom) annual generation mix, under a global CO₂-constraint of 5% relative to 1990-levels. Thick lines show moving averages based on 15 neighboring configurations. Batteries and solar include both assets connected to the high- and low-voltage grid. Gas includes both open-cycle and combined cycle gas turbine power plants.
FIG. S20: Electricity generation and capacity in the fully sector-coupled energy system within the design space of storage-X. (top) Normalized electricity generation and storage capacity, and (bottom) annual generation mix, under a global CO$_2$-constraint of 5% relative to 1990-levels. Thick lines show moving averages based on 15 neighboring configurations. Batteries and solar include both assets connected to the high- and low-voltage grid. Gas includes both open-cycle and combined cycle gas turbine power plants.
FIG. S21: **Energy-power ratios of deployed batteries and storage-X.** Shown are energy-power ratios which resemble the duration of which the storage is discharged when dispatched at full capacity. Results are for the (top) power system, (middle) heating and land transport, and (bottom) fully sector-coupled energy system, under a global CO$_2$-constraint of 5% relative to 1990-levels.
FIG. S22: System cost vs renewable energy curtailment. Scatter and distribution plot of the renewable energy curtailment (x-axis) and the normalized system cost (y-axis) of all ≥2 TWh storage configurations. The scatters are colored according to their round-trip efficiency (RTE), and the distribution of both variables is depicted with the histograms.
FIG. S23: **System cost and renewable curtailment.** Shown results are Europe-aggregate values for the (top) power system, (middle) heating and land transport, and (bottom) fully sector-coupled energy system, under a global CO$_2$-constraint of 5% relative to 1990-levels.