energies

MDPI

Article

Operative Benefits of Residential Battery Storage for Decarbonizing Energy Systems: A German Case Study

Natapon Wanapinit [1,*], Nils Offermann [2], Connor Thelen [1], Christoph Kost [1] and Christian Rehtanz [2]

[1] Department Energy System Analysis, Fraunhofer Institute for Solar Energy Systems ISE, 79110 Freiburg, Germany
[2] Institute of Energy Systems, Energy Efficiency, and Energy Economics ie³, TU Dortmund University, 44227 Dortmund, Germany
* Correspondence: natapon.wanapinit@ise.fraunhofer.de

Abstract: The reduction in PV prices and interest in energy independence accelerate the adoption of residential battery storage. This storage can support various functions of an energy system undergoing decarbonization. In this work, operative benefits of storage from the system perspective, namely, generation cost reduction and congestion mitigation, are investigated. Germany is chosen as a case study due to its strong reliance on variable renewable energy. For the analysis, an economic dispatch model with a high spatial resolution is coupled with a pan-European transmission grid model. It is shown that the system's generation costs are highest when the assets are used only to maximize PV self-consumption, and the costs are lowest when the storage also reacts to the market dynamics. This amounts to a 6% cost reduction. Both operation strategies result in an equal level of grid congestion and infrastructure loading. This is improved with a strategy that accounts for regional peak reduction as a secondary objective. The high congestion level emphasizes that grid expansion needs to keep pace with the generation and electrification expansion necessary to decarbonize other sectors. Lastly, policymakers should enable multipurpose utilization, e.g., via the introduction of market-oriented retail electricity prices with intervention options for grid operators.

Keywords: prosumer; battery storage; generation cost; transmission grid congestion; optimization

check for updates

Citation: Wanapinit, N.; Offermann, N.; Thelen, C.; Kost, C.; Rehtanz, C. Operative Benefits of Residential Battery Storage for Decarbonizing Energy Systems: A German Case Study. *Energies* **2024**, *17*, 2376. https://doi.org/10.3390/en17102376

Academic Editor: Adrian Ilinca

Received: 5 April 2024
Revised: 3 May 2024
Accepted: 8 May 2024
Published: 15 May 2024

Copyright: © 2024 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

The rapid expansion of variable renewable energy generation and its integration into energy systems are indispensable measures to decarbonize many economies around the world and to keep the rising global temperature within the target of the Paris Agreement [1]. This expansion leads to the increase in the variability of energy supply both in the long- and short-term, for example, from the feed-in of wind- and solar-based electricity generation, respectively. The supply variability can be addressed by various flexibility measures ranging from regulatory adjustments, infrastructure expansion, deployment of controllable generation, or storage technologies [2].

There exists a variety of energy storage technologies suitable for different applications in energy systems [3]. Pumped hydro storage can store a large amount of energy over a prolonged period, making it ideal for balancing seasonal variability [4]. However, due to its topographical requirements [5] and resistance from local residents [6], the expansion potential of pumped hydro storage is limited. The decarbonization of the European power sector requires a significant expansion of storage technologies; it is estimated that the EU will need battery capacity ranging from 80–351 GWh by 2050 [7], particularly to counteract the diurnal fluctuation of PV generation. Among battery technologies, lithium-based ones are considered very promising for both mobile and stationary energy storage applications due to their high specific energy and load capacity, long lifetime, and low self-discharge rate [8]. Driven by the research and development for the automotive and consumer electronics industries [9], the costs of lithium-ion cells, scaled by energy capacity, have

fallen by 97% since their commercial introduction in 1991 [10]. In Germany, the markets for residential and large-scale battery storage are dominated by lithium-ion technologies, and this trend is expected to continue [11].

Driven by the motivation of financial savings, environmental protection, or improving the security of supply [12], including by own-interest in the technologies, the adoption of PV–battery systems by private consumers has gained increasing momentum in the past years [13]. In Europe, the newly installed capacity of residential battery systems in 2021 amounts to 2.3 GWh: doubling from the previous year. Moreover, the average attachment rate between batteries and PV systems increased to 27% from 23%. In Germany, Europe's largest PV–battery market, 70% of new residential PV systems are equipped with battery storage [14]. Ref. [14] projects that cumulative residential battery capacities will amount to 23–44 GWh by 2026. With the consideration of its prospective growth, residential battery storage (RBS) can be a key flexibility measure of decarbonizing energy systems.

The reasons for residential end-users to install battery storage are mainly to increase their self-sufficiency and independence from electricity grids; for example, according to a preference survey conducted in Australia, 70% of the respondents wish to be disconnected from the electricity grid [15]. According to [16], the interest in battery storage also increases when end-users lack trust in their energy utilities or when the energy supply is unreliable. Ref. [17] studied the economic feasibility of residential PV–battery systems in Germany. Among other factors, the improvement in self-sufficiency depends on the demand, PV generation profile, and system sizing. On average, self-sufficiency can improve from 38% for systems without storage to 65% in the early years and to 57% at the end of the lifetime for systems with battery storage. The reduced performance is due to capacity degradation, which is assumed to be 20% reduction after 5000 charge–discharge cycles. Beyond the perspectives of end-users, battery storage can also benefit energy providers. In ref. [18], peak-shaving operation of battery storage in medium-voltage distribution grids can significantly reduce the grid reinforcement costs; however, this application is deemed economical at a battery price of EUR 60–80/kWh. For comparison, the battery price for small- and medium-sized customers in Germany in 2023 was approximately EUR 600–800/kWh [19]. Ref. [20] found that the optimal siting and sizing of flow batteries can defer the expansion of low-voltage grids despite the increasing peak load from the adoption of heat pumps and electric vehicles. The utilization of RBS can also be shared among actors: namely, the PV customers, energy providers, and distribution network operators. While this multi-service operation model can improve the return on battery investments, its implementation in vertically disintegrated systems must address the issues on regulations and on revenue allocation [21]. Similarly, the investigation in ref. [22] demonstrates the technical feasibility of aggregated residential batteries providing frequency containment reserves without jeopardizing the self-sufficiency of end-users. Thus, the literature suggests that RBS is a valuable asset not only for the owner but also for providing services to the system.

The literature on the benefits of RBS largely focuses on the asset owners and, to some extent, on the distribution grids. To the best of our research, the effects of increasing RBS adoption on energy markets or transmission grids are not well studied. In ref. [23], the effects of different battery adoption and utilization strategies on electricity generation costs in China are investigated, for which the geographic representation is on the provincial level. However, the study did not explicitly address the transmission grids. Furthermore, the context of existing studies is on power systems with an increasing share of variable renewable energy but not on energy systems undergoing decarbonization. The contribution of this work is to investigate the benefits of RBS with different operation objectives for electricity markets and transmission grids of decarbonizing energy systems. The case study for this is Germany, which has a target to become fully decarbonized by the year 2045. Concretely, this paper addresses the following questions:

1. How do different operation objectives of residential battery storage—namely, to react to spot market prices, to increase own self-consumption, and to reduce the regional peak load—affect the total generation costs of the system?
2. What are the impacts of residential battery storage operation on regional self-sufficiency?
3. What are the effects of these operation objectives on the utilization and congestion of transmission grids?

To answer these questions, an economic dispatch model, i.e., a market model, is coupled to a transmission grid model. The geographic resolution of the models is NUTS-3 (Nomenclature of Territorial Units for Statistics) [24] and each transmission node in Germany, respectively. Ref. [25] provides the basis for the capacity expansion and electrification of heating, transport, and industrial sectors to achieve the decarbonization target.

The paper is structured as follows: The methods are presented in Section 2. The case study is described in Section 3. The results are presented in Section 4 and are discussed in Section 5. Lastly, Section 6 concludes the paper.

2. Methodology

The method applied in this work combines an economic dispatch model (ENTIGRIS) with a transmission grid model for Germany (MILES). Both models are softly coupled to one another, i.e., the results from the dispatch model are passed onto the grid model without direct feedback. Figure 1 provides a high-level overview of the method. First, from left to right, the technology capacities and energy demand and variable renewable energy profiles from a national study on the transformation pathway for Germany are disaggregated for all NUTS-3 regions for each modeling year. Second, the dispatch model optimizes the time-resolved operation of all technologies to minimize the operative costs of the system. The dispatch model virtually comprises three levels: namely, the level of a residential prosumer with rooftop PV and battery storage, the regional level with the remaining generation and storage technologies, and the market level. In a default setting, the latter level controls the operation of every technology in the system. The resulting withdrawal load profiles of each region are fed into the grid model for power flow optimization. This load is calculated by subtracting all electricity generation from the demand. The grid model analyzes the frequency and severity of inland grid congestion. Sections 2.1 and 2.2 explain the dispatch and grid models, respectively.

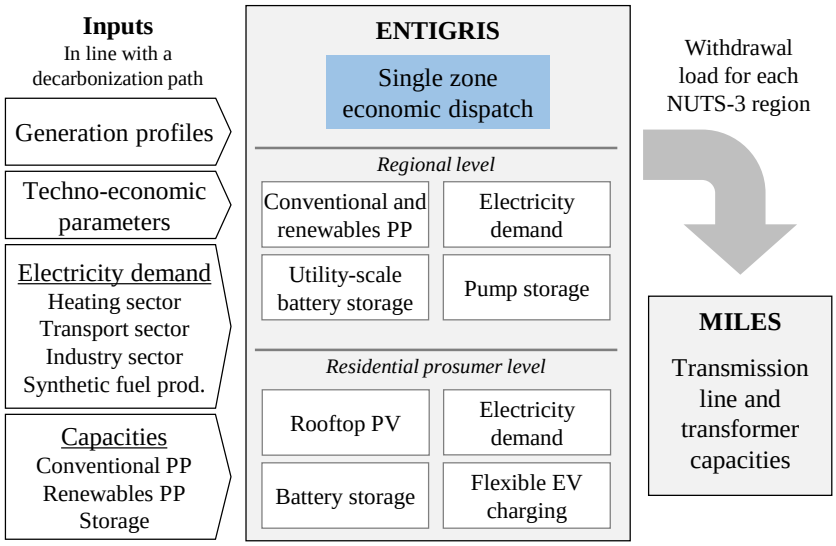

Figure 1. Overview of the methodology: power plants (PP).

2.1. Economic Dispatch Model

The model ENTIGRIS is a time-resolved and regionalized expansion and operation optimization model for an electricity sector [26]. It is formulated as a linear programming problem and is implemented in the software GAMS [27]. Its objective function is to minimize the total cost of electricity supply, which includes investment, operation and maintenance, fuel, and emissions costs. The model considers both the geographic regions and the market zones, which are defined as collections of regions. It accounts for the electricity demand from the residential and non-residential sectors, electrification in the transport and industry sectors, and the electricity demand for the production of synthetic fuels. Technology components in the model include conventional power plants, (variable) renewable energy power plants, and electricity storage. Moreover, the capacity constraints and possible expansion of electricity grids between regions or between zones can be accounted for [28].

For this work: regions are defined at the NUTS-3 level. This results in over 400 geographic regions. A single market zone is assumed. In order to manage the computational complexity, technology expansion is disabled, i.e., the model optimizes the operation given externally prescribed installed capacities for each year. Essentially, the model inputs for a given year are hourly resolved profiles of electricity demand; solar and wind energy generation, including installed capacities for individual regions; and techno–economic parameters, such as operation efficiency and fuel and emissions prices. The outputs are the operation of each technology, the withdrawal load for each region, and the operative costs of the system.

The following presents equations of the model essential to the work.

Equation (1) describes the operation constraints of fuel-fired power plants. Hourly generation gen of respective power plants pp and regions r is limited by their installed capacities cap and equals the fuel consumption $fuel$ multiplied by the efficiency η. As for variable renewable energy vre—PV, wind onshore, and wind offshore—the generation is limited by the normalized generation profile $profile$ multiplied by the respective installed capacity; see Equation (2). The model is able to constrain the ramp-up and ramp-down rate of conventional power plants; however, this feature is intentionally disabled for the sake of computational simplicity. This is deemed justified, as power plants in future energy systems should be sufficiently flexible for an hourly resolved optimization.

$$\eta_{pp} \cdot fuel_{pp,r,t} = gen_{pp,r,t} \leq cap_{pp,r} \tag{1}$$

$$gen_{vre,r,t} \leq profile_{vre,r,t} \cdot cap_{vre,r} \tag{2}$$

For storage technologies st, e.g., pumped hydro storage and batteries, Equation (3) constrains the charge ch and discharge power dch to the installed power capacity cap^{power}. The prevention of simultaneous charge and discharge, which requires the use of binary variables, is not explicitly enforced. However, due to the losses, this is discouraged by the objective function. Moreover, similar to ref. [29], it is assumed that modern pumped hydro storage can switch between the storage and generation operating modes within one hour, which is the chosen time interval for this work. However, some of the literature does include the constraint of operation changeover time, e.g., ref. [4]. Similarly, Equation (4) applies to the state-of-charge SOC. And Equation (5) represents the storage balance; γ is the charge–discharge efficiency. Flexibility from shifting the charging schedule of electric vehicles is modeled as virtual storage, for which the power and energy capacities are determined by a ratio of shiftable demand and a shiftable time period. Equations (3)–(5) also apply to the virtual storage. The modeling of flexible demand as virtual storage is developed in ref. [30] and is generalized in ref. [31].

$$ch_{st,r,t} + dch_{st,r,t} \leq cap^{power}_{st,r,t} \tag{3}$$

$$SOC_{st,r,t} \leq cap^{energy}_{st,r,t} \tag{4}$$

$$SOC_{st,r,t+1} = SOC_{st,r,t} + \Delta t \cdot (ch_{st,r,t} \cdot \gamma_{st}^{ch} - dch_{st,r,t} / \gamma_{st}^{dch}) \quad (5)$$

Equation (6) enforces the energy balance for each region; essentially, the withdrawal load *load* equals the sum of electricity demand from all demand sectors *ds* minus the regional energy generation, including the storage charge and discharge. In Equation (7), the imbalance at the market zone level, i.e., the sum of withdrawal loads from all regions in the zone, must be met by import and export between market zones.

$$\begin{aligned} load_{r,t} = \sum_{ds} demand_{ds,r,t} \\ - \sum_{vre} gen_{vre,r,t} - \sum_{pp} gen_{pp,r,t} \\ - \sum_{st} (dch_{st,r,t} - ch_{st,r,t}) \end{aligned} \quad (6)$$

$$import_t - export_t = \sum_{r} load_{r,t} \quad (7)$$

The objective function of the dispatch model is to minimize the total operative cost of the system's energy supply, which is defined in Equation (8). The total cost consists of the fixed and variable operation and maintenance costs, the fuel costs (including related emissions costs), and the electricity import costs.

$$\begin{aligned} \sum_{tec,r} (fixC_{tec} \cdot cap_{tec,r}) + \sum_{tec} \left(varC_{tec} \cdot \Delta t \cdot \sum_{r,t} gen_{tec,r,t} \right) \\ + \sum_{pp} \left((fuelP_{pp} + emisP \cdot emisFactor_{pp}) \cdot \Delta t \cdot \sum_{r,t} fuel_{pp,r,t} \right) \\ + impP \cdot \Delta t \cdot \sum_{t} import_t \end{aligned} \quad (8)$$

In its default setup, the model presents the *market-oriented* scenario when all technologies, including PV–battery, work together to minimize the operative costs of the system. These operation scenarios are based on the research questions presented in Section 1, and their interpretations are further elaborated in Section 3.

Without directly coupling the transmission and distribution grid models with the economic dispatch model, the *peak reduction* scenario is implemented by introducing an additional peak reduction objective. That is, Equation (8) is appended with peak penalty costs; see Equation (9). With the penalty, the model has the secondary incentive to flatten or curtail the withdrawal load of each region.

$$peakPenalty = peakP \cdot \sum_{r} \max_{t} |load_{r,t}| \quad (9)$$

Lastly, the *self-consumption* scenario when prosumers utilize their battery storage only in conjunction with their own PV generation and demand is modeled by separating the dispatch problem into two stages. In the first stage, the operation of the PV–battery is optimized with the objective of reducing the prosumers' electricity imports. In the second stage, the operation of the residential prosumer level is fixed, and the model continues to optimize other technologies at the regional and market levels; see Figure 1.

2.2. Transmission Grid Model

For the simulation of the German transmission grid, the Model of International Energy Systems (MILES) [32] is used. In general, MILES is used to determine pan-European current or future generation load cases and the resulting utilization of the transmission grid. Besides the simulation of the transmission grid, the model includes the regionalization of loads and RES capacities, the generation of the corresponding time series, as well as a unit commitment.

In this paper, the output data of the economic dispatch model from Section 2.1 serve as input data for the subsequent simulation of the transmission grid. However, data at the node level of the transmission grid is required to determine the grid status. Therefore,

the hourly time series of all NUTS-3 regions are first distributed to the nodes of the transmission grid using a Voronoi approach. At the high-voltage and extra-high-voltage levels, grid stations, substations, or busbars are referred to as grid nodes. The nodes are used as centroids of the Voronoi cells. The distribution key then results from the intersection of the area of the NUTS-3 region with the areas of the Voronoi cells. In addition to the hourly time series of the NUTS-3 regions, trade exchanges with all neighboring countries are also taken into account. For each border, these cross-border flows are allocated to the individual cross-border interconnectors in proportion to their capacity and are assigned to the corresponding nodes on the German transmission grid side. In this way, hourly net capacities are available for each node of the transmission grid.

For a given grid load situation, the corresponding grid's system state is obtained either by solving the nonlinear network equations using the Newton–Raphson method (alternating-current (AC) load flow calculation) or by linearizing these equations (direct-current (DC) load flow calculation) if only active power flows are of interest. Both techniques are extensively described in the literature [33]. In this paper, a multi-stage determination of the grid operating status is carried out based on [34]. First, direct-current load flow calculations are carried out to estimate the grid load. Based on the results of the load flow calculations, power-flow-controlling equipment such as high-voltage direct-current lines and phase-shifting transformers are then optimized. The aim of the optimization is to reduce the utilization of overloaded alternating-current lines. In contrast to the approach in [34], the actual calculated grid losses are not allocated to individual power plant blocks. Instead, the losses are distributed to all NUTS-3 regions—i.e., the grid nodes assigned via the distribution key—in which conventional power plants are installed in proportion to their maximum capacity.

3. Description of the Case

German energy and climate policies aim to decarbonize its economy by 2045, primarily by relying on variable renewable energy [35]. It is expected that Germany requires significant short- and long-term flexibility potentials to address the variability of supply [36], and flexibility from residential end-users holds high potential to support the system [37]. Therefore, Germany is chosen as the case study of the work.

In line with the research questions, three scenarios differentiating the operation of residential battery storage are considered:

- Market-oriented operation `MK`: Every energy storage system, together with energy technologies, operates in unison to reduce the total generation costs of the system. This is conceptually equivalent to when residential prosumers receive dynamic electricity prices based on the market prices.
- Self-consumption operation `SC`: Battery storage operates solely in response to the PV production and electricity demand of respective prosumers.
- Peak-reduction operation `PR`: In addition to the generation cost reduction, all energy technologies are also operated to reduce the peak feed-in and withdrawal of their respective regions.

For each scenario, the results for the years 2020, 2030, and 2045—the reference, intermediate, and target year, respectively—are calculated. In the following, any mention of scenarios is written in `typewriter` font.

Regarding the assumption for the transmission grid model: the status quo grid in 2020 was modeled based on the current expansion status of the grid. The assumptions for the grid model in 2030 are taken from the German Grid Development Plan created in 2019 [38]. As there are no openly available transmission grid assumptions for the year 2045, a heuristic was used to determine the expansion status based on the 2021 German Grid Development Plan [39] for the year 2035. The grid model consists of components of the 220 kV voltage level and above.

In the following, Section 3.1 presents the assumptions of technology capacities and electricity demand. Section 3.2 explains the method to disaggregate these assumptions into the individual NUTS-3 regions.

3.1. Energy System Decarbonization Pathway

The decarbonization of the German energy system requires not only the expansion of energy technologies but also the electrification of heating, transport, and industrial sectors. The study "Paths to a Climate-Neutral Energy System: The German Energy Transition in its Social Context" [25] is used as a foundational framework of the German decarbonization pathway towards the target year. This includes both the capacities of energy technologies and the transformation of energy consumption throughout the system. The study is conducted under the assumption of reaching the climate goal in 2045 (total energy-related CO_2 emissions are kept under 7.8 Gt) with the heuristic least-cost options using a time-resolved, sector-coupled energy system model. In this study, the technology operation follows a pre-defined scheme. Thus, its resulting operation is not, in a strict sense, optimized. Furthermore, this does not allow the consideration of varying operation schemes. These shortcomings are addressed in this work. Regarding the connection of the foundational work, the techno–economic parameters as well as the results of the reference scenario are used in this work.

Table 1 presents the assumptions of power generation capacities: there is a rapid demand for the expansion of variable renewable energy sources in the period observed from 2020 to 2045. The expansion encompasses a capacity of 489 GW PV and 296 GW from wind turbines in 2045, of which offshore wind power plants contribute 76 GW and onshore wind power plants contribute 220 GW. Conventional generation technologies show declining trends. Nuclear power plants are phased out in 2023, and all lignite and hard coal power plants are to be decommissioned before 2038. Gas-fired power plants must be expanded to a total of 85 GW by 2030 to compensate for the fluctuating power supply and the declining base power generation. Gas power plants are then replaced by the expansion of hydrogen power plant capacity totaling 125 GW in 2045, of which 35 GW are converted gas turbines. The capacities of biomass and run-of-the-river power plants remain at an almost constant level of 2–4 GW and 4–5 GW, respectively, due to the limited potential.

Table 1. Installed capacities in GW for electricity generation capacity by plant type: power plant (PP); run-of-the-river hydroelectricity (ROR).

Technology	2020	2030	2045
PV	67.9	214.7	488.9
WT onshore	58.1	120.9	219.7
WT offshore	8.2	28.3	75.9
Biomass-fired PP	8.5	4.0	2.1
Natural-gas-fired PP	33.4	85.4	50.4
Coal-fired PP	44.0	17.0	0.0
ROR	4.0	4.0	4.0
Hydrogen-fired PP	0.0	1.1	125.3
Nuclear PP	8.1	0.0	0.0
Oil-fired PP	4.4	0.0	0.0

The capacities of energy storage technologies are provided in Table 2. To counteract the increasing fluctuation of electricity supply, a rapid expansion of stationary batteries is needed: 70 GWh in 2030 and 117 GWh in 2045. Most of these batteries are expected to be owned by residential prosumers together with PV systems. The adoption of battery-electric vehicles is essential to decarbonize the transport sector. The study shows that over 51 million vehicles are needed. These vehicles also provide flexibility for the system, be it from system-oriented charging management or bi-directional charging. Lastly, the ca-

pacity of pumped hydro storage remains at a constant level of 40 GWh, as the potential is largely exploited.

Table 2. Energy storage capacities: battery-electric vehicle (BEV).

Technology	Unit	2020	2030	2045
Battery	GWh	0.6	70.2	116.9
BEVs	mil	0.4	22.8	51.4
Pumped hydro storage	GWh	39.6	39.6	39.6

The considered electricity demand is from residential, industrial and commercial, transport, and synthetic fuel production (PtX) sectors. Table 3 presents the total annual electricity demand. The 41% demand increase in the residential sector is due to the adoption of heat pumps and counteracts the potential decrease from energy efficiency measures. Because of the electrification of process heat generation, the demand in the industry sector doubles. Due to the rapid electrification rate in passenger and freight transport, the electricity demand for the transport sector is projected to be 215 TWh in 2045, which is a significant increase in comparison to the negligible demand in 2020. Furthermore, considerable electricity demand of over 200 TWh p.a. is expected for the domestic production of hydrogen and PtX products. In summary, the decarbonization of the German energy system requires a 2.7x increase in the total electricity demand. This presents new challenges for the power systems but also opportunities in terms of novel flexibility potential.

Table 3. Electricity demand in TWh p.a. by sector demand.

Demand	2020	2030	2045
Residential	128.9	154.8	181.8
Industry and Commercial	339.3	536.3	645.9
Transport	0.9	48.1	215.3
Synthetic Fuel Production	0	29.9	203.6

While the reference study analyzed Germany as a single region, this work models the case study at the NUTS-3 level to analyze regional self-sufficiency and transmission grid utilization in detail. Therefore, the inputs from the reference study need to be disaggregated. This process is presented in Section 3.2 following.

3.2. Disaggregation of Capacities and Demand

The information—installed capacities and energy demand—on the decarbonization pathway is on the national level without geographic differentiation. Therefore, the information is disaggregated onto the NUTS-3 regions using specific distribution keys. Sections 3.2.1–3.2.3 explain the disaggregation of the installed capacities for the years 2030 and 2045. The capacity distribution of 2020 follows the real installed capacities according to the core energy market data register (MaStR, German: *Marktstammdatenregister*) [5]. Sections 3.2.4–3.2.7 present the distribution of electricity demand.

3.2.1. Renewable Energy Resources

The distribution of PV and onshore wind turbines for the years 2030 and 2045 onto the NUTS-3 regions is based on the renewable energy potentials from scenario S3 of [40], which is the most restrictive scenario. An even penetration rate of each technology is assumed, i.e., if possible, all regions first assume the same capacity expansion rate until their respective potential limits. The algorithm then increases the expansion rates in regions with unexploited potential to compensate for the shortcoming until the target installed capacities are reached.

Offshore wind turbines are allocated to NUTS-3 regions based on their current grid feed-in points according to the MaStR [5]. The capacity distribution in the subsequent years is done for the current distribution. The distributions of the run-of-the-river power plants and biomass power plants are carried out in the same manner.

Regarding the generation profiles of variable renewable energy, the ERA-5 weather dataset provides the basis for the derivation of generation profiles of PV and onshore and offshore wind turbines for each region [41]. For the sake of comparability, the weather year of 2020 is also applied to the subsequent years. The use of region-specific generation profiles allows the modeling of unique weather patterns in each region.

3.2.2. Fuel-fired Power Plants

Coal, oil, and nuclear power plants (PPs) are expected to be decommissioned in later years. The reduction in installed capacities is done at a uniform rate for all regions that currently possess these technologies. The capacities of these PPs together with the gas-fired PPs existing in 2020 are used to define a distribution key for the gas-fired and hydrogen-fired PPs in the subsequent years. This key indicates not only the concentration of the load, i.e., load centers, but also locations with existing electricity infrastructure. Moreover, the distribution also implies that the decommissioned gas-fired PPs from 2030 onward are uniformly replaced by hydrogen-fired PPs.

3.2.3. Energy Storage Technology

The distribution of the pumped hydro storage is based on ref. [5] and is unchanged for all years. It is assumed that stationary battery storage is expanded together with variable renewable energy capacities—PV and onshore wind turbines. This represents a grid-friendly capacity expansion. The distribution of mobile storage, i.e., battery-electric vehicles, is discussed in Section 3.2.6.

3.2.4. Demand in the Residential Sector

The residential electricity demand consists of the base demand from household equipment and the demand from electrified heating, e.g., from heat pumps. A standard load profile from the German Association of Energy and Water Industries (German: Bundesverband der Energie- und Wasserwirtschaft e.V.) is used as a time-resolved basis for the base demand. The profile accounts for the variation of consumption patterns on weekdays, weekends, and public holidays [42]. The time-resolved profile of electrified heating is extracted from [25], in which the underlying operation of heating technologies considers the weather pattern, the degree of building refurbishment, and conversion efficiency [43]. Once the aggregated national demand profile is processed, it is spatially distributed to the NUTS-3 regions according to the population distribution. The population data are provided by the "DemandRegio" project [44].

3.2.5. Demand in the Industrial and Commercial Sectors

In [25], the time-resolved electricity demand of the industrial and commercial sectors is provided for the considered years. For the base demand in the year 2020, the industrial electricity demand is distributed onto the economic branches via the data on the energy consumption in each economic branch from the dataset "Environmental–Economic National Account" compiled by the Federal Statistics Office [45]. Then, the demand is distributed onto the NUTS-3 regions using the statistics on the regional employment by economic branches from the "DemandRegio" project [44].

The demand increase in 2030 and 2045 (see Table 3) is largely due to the electrification of process heat supply; thus, the increase is allocated to economic branches strongly characterized by high process heat demand. The allocation regards: (1) the proportion of process heat that can be electrified, which varies by the temperature level, (2) the potential energy efficiency achievable from the fuel switch, which is particularly relevant for branches

with centralized low-temperature heating, and (3) the realistic electrification rate, e.g., the heat pump adoption or technology readiness level specific to each branch.

The procedure results in time-resolved demand profiles for each NUTS-3 region and each economic branch. Lastly, demand is aggregated over the economic branch dimension, as modeling of individual industrial economic branches is not of interest for this work.

3.2.6. Demand in the Transport Sector

A distinction of the electricity demand in the transport sector is made between battery-electric vehicles (BEVs) and cargo transport. The demand from cargo transport is distributed to the NUTS-3 region based on the number of employees as a proxy for region-specific economic output. The corresponding charging profile from ref. [43] is used for all regions. The demand from BEVs, which is proportional to the BEV number, is geographically distributed using the population distribution. The study "Mobility in Germany" [46] provides a time-resolved charging profile for seven specific region types ranging from a village area to a metropolitan region. These profiles are the basis for the regional BEV charging profiles.

3.2.7. Demand due to Synthetic Fuel Production

It is assumed that synthetic fuel production (PtX) is concentrated near either variable renewable energy generation or the hydrogen demand from the selected industrial branches. In other words, the placement of PtX shall relieve the electricity and gas grids. Ref. [47] assesses prospective energy-intensive companies in Germany for the adoption of synthetic fuel. All regions are scored by these two factors with an equal weight. Then, the PtX demand is assigned to 250 regions with the highest scores. This restriction is introduced to prevent too-small PtX demand, which is unlikely to occur due to the infeasibility of small projects. The demand profile from ref. [25] is applied for all regions.

4. Results

Sections 4.1 and 4.2, respectively, present results relevant to the research questions in Section 1.

4.1. Generation Costs and Technology Utilization

The annual operative (generation) costs are presented by scenario in Figure 2. Across all scenarios, the total operative costs increase as time progresses. This is mainly due to the strong increase in electricity demand from the electrification of heating and transport end energy uses. In terms of the cost structure: the technologies' operation and maintenance costs steadily increase. Fuel costs see a rapid jump between years because of the higher natural gas price and, later, the higher hydrogen price. The total operative costs in the `MK` scenario are the lowest and amount to EUR 91.9 billion p.a. in 2045. This is followed by EUR 94.1 and 97.8 billion in `PR` and `SC`, respectively. In other words, the costs in 2045 reduce by 6.1% when prosumer storage is utilizable by the system. In 2030, the cost reduction is slightly lower at 5.4%.

The scenario `MK` is also optimized completely without residential battery storage. The resulting generation costs are EUR 26.7, 68.4, and 98.0 billion p.a. in 2020, 2030, and 2045, respectively. That is, the presence of battery storage can reduce the costs by 0.0, 2.9, and 6.2%, respectively, which is an increasing amount as the years progress.

In Figure 3, the volumes of electricity supply by source and total demand are depicted. The share of variable renewable electricity generation (VRE) from solar and wind energy compared to the electricity demand increases from 34% in 2020 to 83% in 2045. That is, the electricity system strongly relies on VRE. The generation from coal-fired power plants stops after 2038, which is in line with the goal set by the federal government. Based on the assumed economic parameters, nuclear power plants are not dispatched. We deem this to be irrelevant, as nuclear generation is planned to be phased out in the intermediate and target years and as nuclear power plants would firmly serve the base load. Furthermore,

the utilization of natural gas is phased out between 2030 to 2045 to decarbonize the system. Lastly, the electricity supply from biomass, hydropower, and import from neighboring countries plays only a small part: less than 6%.

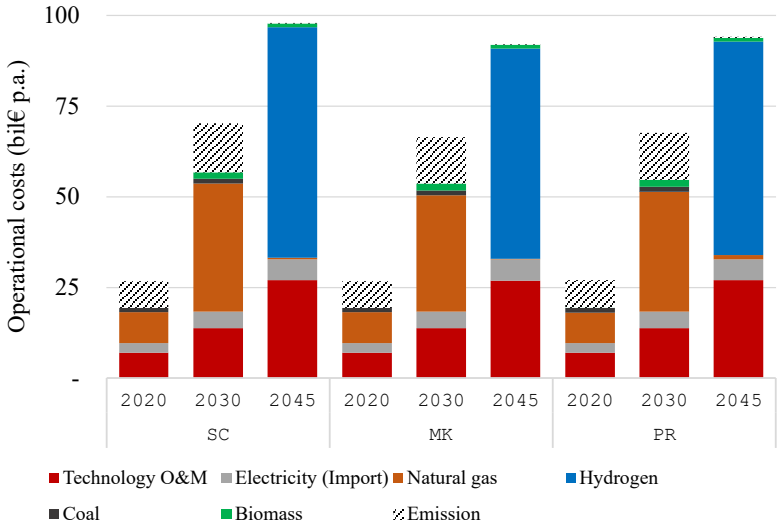

Figure 2. Annual generation cost by scenario.

The difference in terms of energy supply between scenarios is small and lies mostly in the utilization of gas- or hydrogen-fired power plants, which is complementary to the utilization of VRE. In 2045, the electricity production from hydrogen amounts to 172.1 in `MK`, 169.3 in `PR`, and 185.6 TWh p.a. in `SC`. That is, when prosumer storage is strictly reserved for PV self-consumption, the generation from peak power plants increases by 7.0% compared to `MK`. However, the level of peak generation in both scenarios is similar.

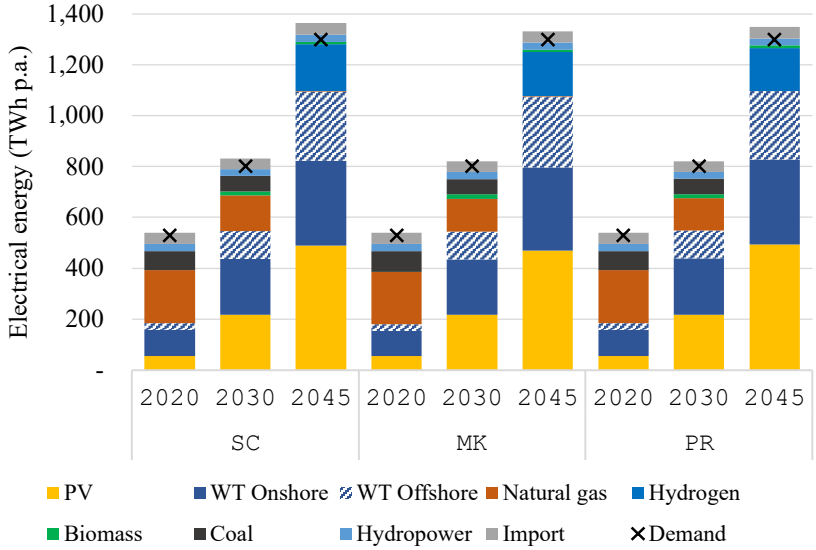

Figure 3. Annual electricity supply by scenario: wind turbine (WT).

Regarding the operation, Figure 4 presents the electricity supply of representative days in summer, transition, and winter periods for the scenario `MK-2045`. The generation from offshore wind turbines is relatively constant throughout the day, whereas the generation from onshore wind turbines is strong during the night. Generation from wind energy is at its highest during winter; this complements the generation from solar energy on the seasonal timescale. The electricity demand profile in 2045 is characterized by a large midday

peak. This is due to the assumption that the electricity consumption from sector-coupling processes is partly flexible. The supply–demand gap is mainly bridged by hydrogen-fired power plants and, to some extent, by cross-border import.

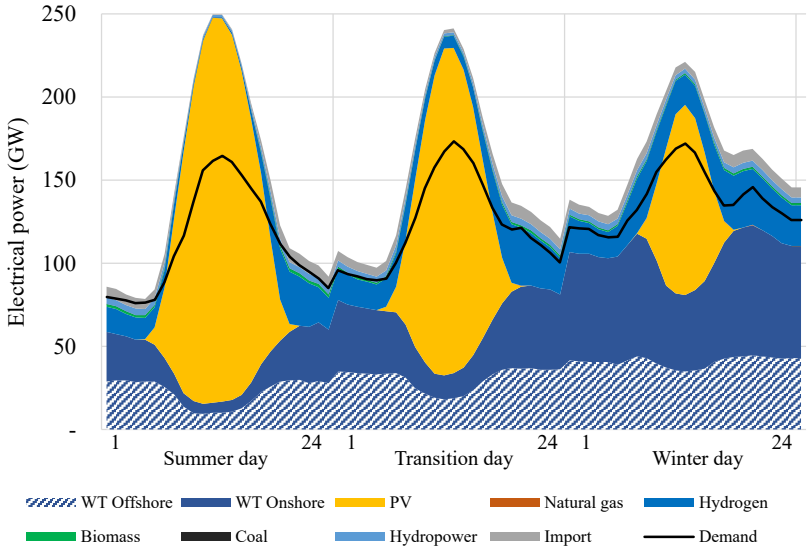

Figure 4. Electricity supply on representative days for the scenario `MK-2045`: wind turbine (WT).

The following presents results on the operation of energy storage. Figure 5 plots the utilization of pumped hydro storage, residential battery storage, and the management of flexible EV demand. The higher supply volatility and installed capacities on a year-on-year basis lead to an increase in the utilization of flexibility. Overall, the usage is lower in `MK` compared to other scenarios; this is due to the averaging effect from the single-market-zone assumption. The additional objective to reduce the regional power peak in `PR` incentivizes further storage utilization despite the additional costs related to energy losses. Lastly, this line of reasoning also explains the highest utilization rate in `SC`, where the additional constraint forces residential battery storage to solely react to regional PV generation and demand profiles. Lastly, while being unaffected by the additional constraint, the utilization of pumped hydro storage and flexible EV in `SC` is slightly higher.

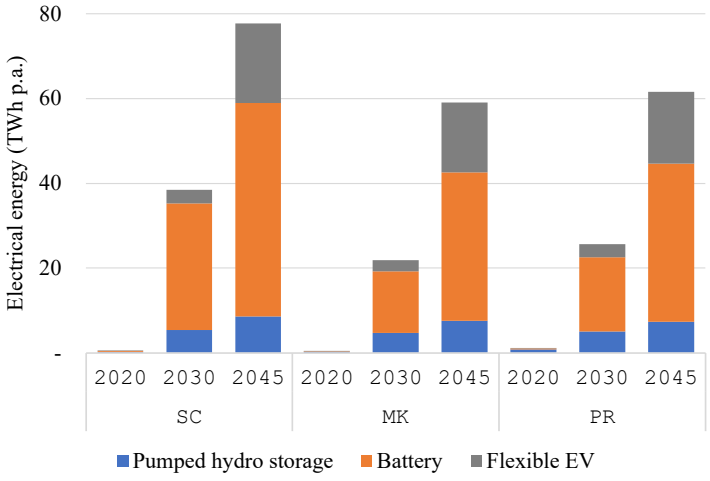

Figure 5. Annual charged energy by scenario.

Figure 6 compares the operation profiles between the self-consumption (thick lines) and market-oriented (dashed lines) scenarios. In the former, residential battery storage is used to store surplus PV generation within respective regions, whereas in the latter, it is used in response to any surplus. This is observed by two charging periods: at night and during midday. In SC, both the flexible EV and pumped hydro storage are utilized more, especially at night in winter, to compensate for the unavailability of residential battery storage to react to a system-oriented signal.

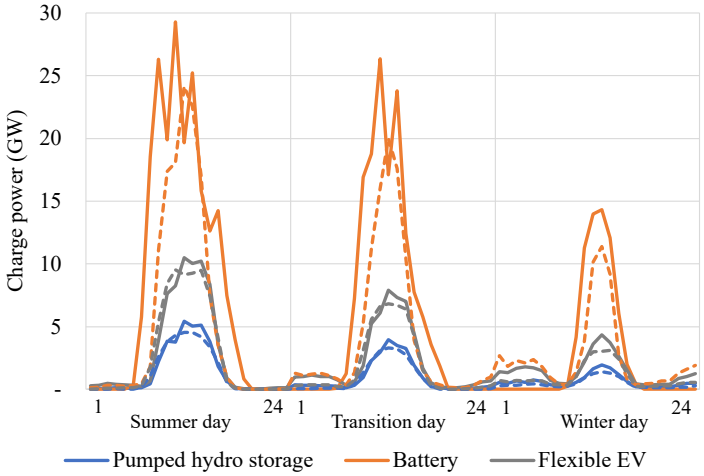

Figure 6. Charged electricity on representative days for the scenarios SC-2045 and MK-2045 presented as thick and dashed lines, respectively.

4.2. Regional Withdrawal Load and Self-Sufficiency

Figure 7 plots the balanced residual load (a residual load refers to the remaining demand not covered by variable renewable energy generation, which differs from a withdrawal load) of all NUTS-3 regions in Germany for the years 2020, 2030, and 2045. There are notable differences in the coverage of the electricity demand in the various regions: particularly between load centers and between the northern region and the rest of the country.

In 2020, only 67 regions were able to cover their total electricity demand from renewable energy generation. The federal states of Lower Saxony, Mecklenburg–Western Pomerania, and Schleswig–Holstein account for 59% of the electricity surplus from these 67 regions, which is due to their superior wind generation potentials.

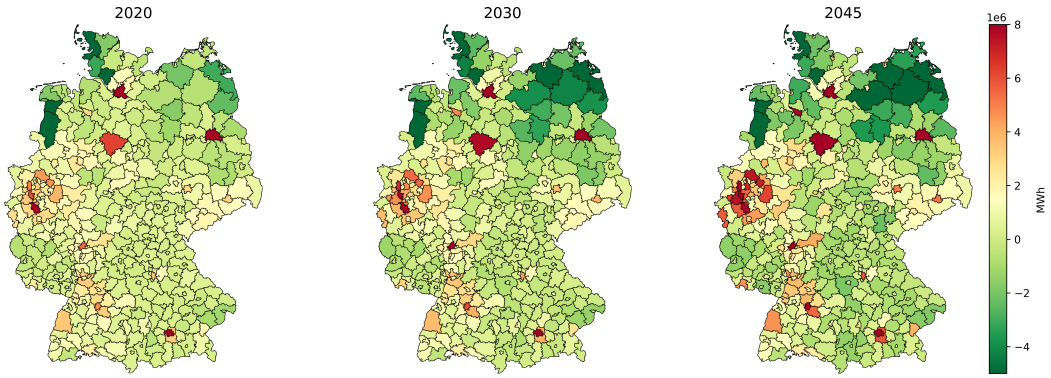

Figure 7. Residual loads of NUTS-3 regions for the years 2020, 2030, and 2045.

It can also be seen that conurbations such as Hamburg, Munich, and Berlin have a high positive residual load, which indicates that the electricity demand is higher than the supply. This is based on the low availability of potential areas for wind and ground-mounted PV systems. Another contribution to the high residual load is the concentrated energy

demand from the household, industrial, and commercial sectors. Even if all potentials for rooftop PV systems in the major cities are exploited from 2030 onwards, positive residual loads are to be expected due to the sharp rise in electricity demand in the household and transport sectors.

From a year-on-year comparison, the number of regions with generation surpluses is increasing. A negative residual load is expected in 136 regions in 2030 and 161 regions in 2045. The number of federal states with a balanced electricity surplus is also increasing. On the federal state level, Brandenburg, Mecklenburg–Western Pomerania, Lower Saxony, Rhineland–Palatinate, Saxony, Saxony–Anhalt, and Thuringia will have a negative residual load balance in 2045, i.e., these states are expected to be net exporters of renewable energy generation.

The balanced difference in residual load from 2020 to 2045 for Bavaria is halved if the available potential for variable renewable energy (VRE) is used in the same proportion as in the other federal states. In contrast, the difference in residual load increases from 2020 to 2045 for Baden–Württemberg (+13%), Hessen (+34%), Nordrhein–Westfalen (+56%), and Saarland (+20%). Although an even penetration of the available VRE potential was assumed, the balanced electricity gap of the residual load cannot be closed completely. It can be deduced that these states must make greater efforts to utilize their available VRE potentials or promote energy efficiency if the aim is to be less dependent on other federal states.

Figure 8 plots the distribution of the loading factor, which is defined as the mean-to-max ratio of the absolute withdrawal load for respective regions over the year. A high value indicates a flattened withdrawal load profile, and with it, a high loading factor on main transformers. The loading factors decrease as the year progresses due to the higher regional variable renewable energy generation. The difference between 2045 and 2020 in the `MK` scenario is approximately 17%. Moreover, the effect on the peak reduction from the introduced penalty can be observed, i.e., the loading factor in the `PR` scenario is higher than other scenarios, especially in 2045. The penalty also closes the difference between 2045 and 2020.

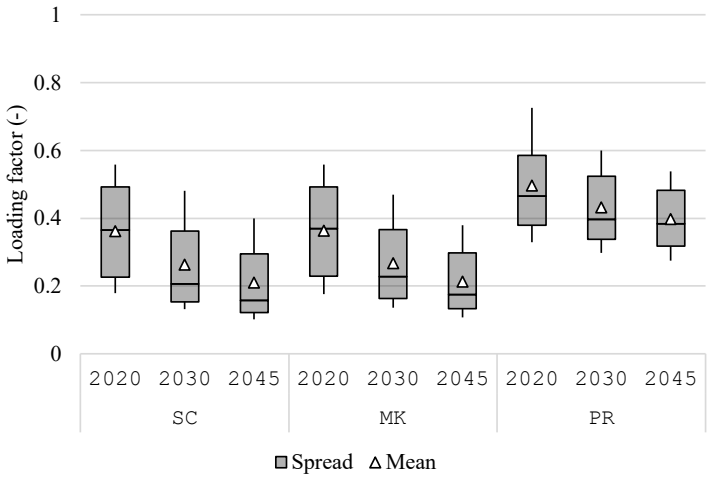

Figure 8. Distribution of regional loading factor by scenario.

Regarding overall self-sufficiency on the regional level, Figure 9 presents the distribution of the electricity import-to-demand ratio. The lower this ratio is, the closer a region is to becoming self-sufficient. As more VRE potentials are exploited, each region imports less electricity from the national system. However, this trend stagnates during the later years, and no region becomes fully self-sufficient. This is due to the increase in electricity demand and the fluctuating nature of VRE. The latter means that a region can generate a surplus on an annual balance, but in some hours, it still needs generation from external sources. Lastly, the average ratio over the three years for the different scenarios is 38.6% for `SC`, 38.4% for

MK, and 37.7% for PR. The marginal difference between various operations of residential battery storage suggests that the choice of price signal hardly affects the self-sufficiency of the system.

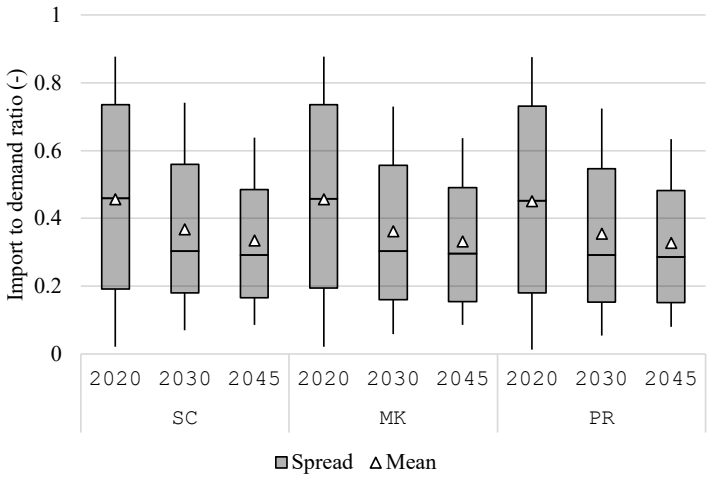

Figure 9. Distribution of regional import-to-demand ratios by scenario.

4.3. Utilization of the Transmission Grids

The annual congestion work on lines that are 220 kV or higher is presented in Figure 10 by scenario. Note that congestion on transformers is not taken into account here as it is assumed that they are cheap to be replaced compared to overhead lines. Across all scenarios, the annual congestion work increases from around 0.5 TWh in 2020 to over 2 TWh in 2030 and to about 7 TWh in 2045. A reason for this is the strong increase in feed-in from variable renewable energy sources. While the annual congestion work in 2045 in scenarios MK and SC differs only slightly, the PR scenario shows a significantly lower congestion work of −27%. This is due to the assumption that residential battery storage and other flexibility in the PR scenario are also used to reduce the feed-in and withdraw peak of the NUTS-3 region they are installed in.

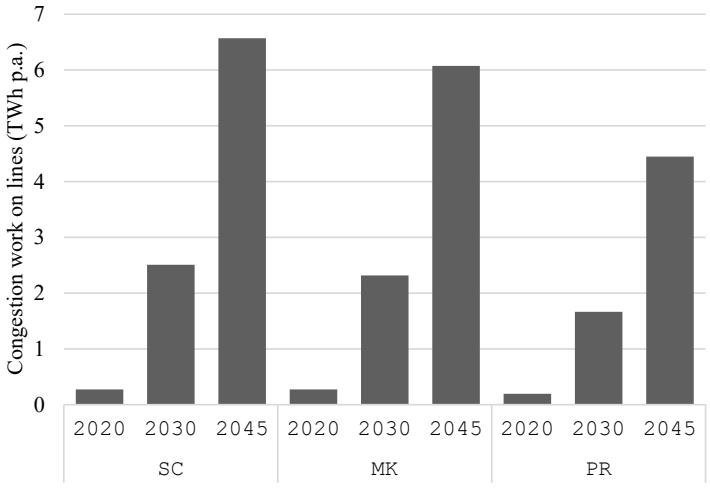

Figure 10. Annual congestion work by scenario.

The higher congestion work across the years is caused by increasing of the installed power of renewable energy sources. As discussed in Section 4.2, while photovoltaic power plants are mainly installed in the southern part of Germany, wind power plants are built close to the coastal area and the northern regions. As the feed-in from these sources is very volatile, these regional disparities lead to transmission needs from north to south and

vice versa. Figure 11 shows the annual maximal line loading exemplary for the scenario `MK-2030`. It can be seen that lines on the north–south connection are heavily utilized. In addition, the lines near the start and end nodes of the HVDC lines (dashed lines) are highly utilized, which indicates heavy use of the HVDC lines to transport energy from north to south. Similar results are observed in other scenarios.

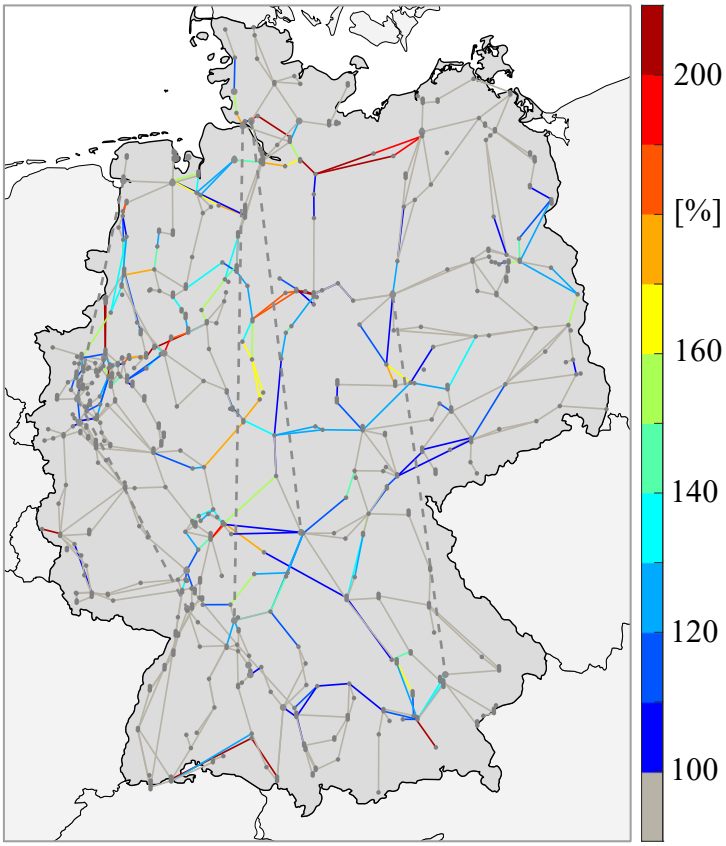

Figure 11. Annual maximal line loading for scenario `MK-2030`.

5. Discussion

Regarding the research questions in Section 1: The results show that when residential battery storage (RBS) is operated in a market-oriented manner, the total generation costs can be reduced by 6% compared to operation strictly reserved for self-consumption. The additional constraint to reduce the regional peak power placed on the RBS can increase the costs by 2%. The significant expansion of distributed energy resources over the years improves regional self-sufficiency; however, a large discrepancy between NUTS-3 regions can still be observed. Namely, northern regions generate electricity in large surplus, whereas conurbations have significant generation deficits due to low renewable energy potentials and higher demand concentration. The latter is exacerbated via the electrification of heating processes and the transport sector. The results also show that the RBS operation assumption has marginal impacts on regional self-sufficiency. Lastly, the transmission grid congestion is highest when the RBS is operated in the market-oriented manner or to increase self-consumption. The peak reduction operation can improve the regional loading factor and reduce transmission grid congestion. However, it does not eliminate the need for grid expansion. Some lines, particularly in northern Germany, can reach very high loading.

The comparison between different phases of decarbonization shows that the benefits of RBS are slightly higher in the year 2045, i.e., in the fully decarbonized phase, than in 2030. The higher benefits in future years are likely due to the higher surplus generation, the higher installed capacities of RBS, and the utilization of renewable hydrogen. It also stands to reason that the improvement between different operation assumptions is small, as

future energy systems have other short-term flexibility resources at their disposal: namely, flexible electricity demand from the heating and transport sectors.

The results present the economic benefits for the system when RBS is operated in a market-oriented manner, e.g., responding to electricity prices from the market. However, this operation does not lead to the highest charge–discharge cycle; see Figure 5. This notion together with Figure 6 suggest that the benefits of RBS do not entirely depend on the volume of shifted energy but also on the period of the shift. Moreover, from the perspective of a single-market system, battery storage is less necessary when the surplus PV generation can be transmitted to and utilized by neighboring buildings or regions. Thus, the higher RBS operation in the self-consumption scenario can result in unnecessary energy losses from the conversion. This insight should be considered in the design of price-based incentive schemes, e.g., time-varying electricity tariffs, such that they do not over-encourage unnecessary charge–discharge cycles.

The utilization of distributed RBS resources must also address the design of the coordination mechanism as well as the allocation of costs and benefits. The shared asset utilization can be especially challenging in vertically disintegrated systems [21]. While price-based incentives are not always adequate for dealing with grid congestion, they are highly effective at mobilizing distributed flexibility resources according to market prices [48]. Fortunately, these resources indirectly mitigate grid congestion to some extent and promote decarbonization by avoiding the utilization of fossil-fired power plants. Lastly, as long as the coordination mechanisms also respect the primary purpose of increasing self-consumption, the impacts of the operation mode on the asset owners are minimal [49].

Noteworthy novelties of the work are a benefit analysis from the system perspective, i.e., beyond the scope of individual prosumers, the consideration of a fully decarbonized energy system, and the detail level of the geographic resolution. The former is essential for the justification of nationwide policy implementation, e.g., on price-based incentives for residential battery storage. On the modeling resolution, the developed method considers regional characteristics of renewable energy generation as well as demand concentration in detail. The limitations of the work include the exclusion of technology expansion in the optimization problem. This disconnects the effects of the operation strategy from the optimal sizing of RBS. However, one can argue that RBS sizing is mainly concerned with PV capacity and demand; therefore, the RBS capacities, in reality, should be the same in all scenarios. Furthermore, this work assumes perfect information foresight and focuses only on the operative benefits of RBS based on the day-ahead energy market. Indeed, these resources are useful for dealing with stochastic generation and can participate in auxiliary markets, e.g., to provide a frequency containment reserve [50].

Lastly, the developed methodology considers the physical constraints and the assumption of efficient and competitive electricity markets. Its geographic structure is modeled in an abstract manner. Therefore, the method can be applied to other energy systems for which the latter assumption holds. Otherwise, modification to the models is needed. The extrapolation of the findings to other systems should be done with caution, as generation potentials, consumption characteristics, and decarbonization strategies can vary from country to country.

6. Conclusions

The growing public interest in self-sufficiency, government subsidies, and decreasing PV prices drives the expansion of residential battery storage (RBS). Therefore, this work studies the operative benefits of RBS in terms of generation cost reduction and congestion mitigation at the system level. An economic dispatch model with the geographic resolution of NUTS-3 is coupled with a transmission grid model to enable comprehensive analyses of the case study from 2020 to 2045. The dispatch model is modified to analyze different operation strategies of RBS—market-oriented, self-consumption, and peak-reduction. The results for a German case study show that the generation costs are highest when storage is operated only to increase the PV self-consumption. These costs are reduced by over

6% in 2045 if storage can serve the system as a whole, e.g., when the spot market price signal is passed on to residential customers. In both scenarios, the regional infrastructure loading declines due to increasing adoption of variable renewable energy, and the grid congestion level increases over time. These metrics are improved when peak reduction is introduced as an additional operation objective, at the expense of a slight generation cost increase. The use of RBS beyond increasing the self-consumption of asset owners improves the economic efficiency of the generation and the infrastructure utilization factor of the distribution and transmission grids. The challenge lies in the design of coordination mechanisms that ensure fair cost–benefit allocations among actors and efficient asset utilization. For this, it is recommended that the introduction of a time-varying price signal based on spot market prices together with a possible intervention from distribution grid operators should be considered. Further research could take into account additional costs such as investment and transactional costs, as these are likely to reduce the cost savings. Different implementation models should be identified and investigated for each customer group. Furthermore, the system benefits of RBS compared to other short-term flexibility resources and the effects on optimal sizing should be studied.

Author Contributions: Conceptualization by all authors; methodology, software, validation, formal analysis, investigation, data curation, visualization, and writing—original draft by N.W., N.O. and C.T.; writing—review and editing by all authors; supervision by N.W., C.K. and C.R.; project administration and funding acquisition by C.K. and C.R. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the German Federal Ministry for Economic Affairs and Climate Action under the grant 03EI1014A.

Data Availability Statement: The data presented in this study are available on request from the corresponding author.

Acknowledgments: The authors would like to thank Sven Längle for his contribution to data preparation.

Conflicts of Interest: The authors declare no conflicts of interest.

Nomenclature

Parameters

Δt	time interval
η	generation efficiency
γ	storage efficiency
cap	installed capacity
$demand$	electricity demand
$emisFactor$	emission factor
$emisP$	emission price
$fixC$	fixed cost
$fuelP$	fuel price
$impP$	import price
$peakP$	peak power price
$profile$	generation profile
$varC$	variable cost

Set indexes

ds	demand sector
pp	fuel-fired power plant
r	region
st	storage
t	time step
tec	generation technology
vre	VRE power plant

Variables

ch	storage charge
dch	storage discharge
$export$	export
$fuel$	fuel consumption
gen	electricity generation
$import$	import
$load$	effective withdrawal load
$peakPenalty$	penalty for regional peak power
SOC	state of charge

References

1. International Renewable Energy Agency IRENA. *World Energy Transitions Outlook 2023: 1.5 °C Pathway*; International Renewable Energy Agency IRENA: Masdar City, United Arab Emirates, 2023. Available online: https://www.irena.org/Publications/2023/Jun/World-Energy-Transitions-Outlook-2023 (accessed on 2 January 2024).
2. Cochran, J.; Miller, M.; Zinaman, O.; Milligan, M.; Arent, D.; Palmintier, B.; Mueller, S. Flexibility in 21st Century Power Systems. 2014. Available online: https://www.nrel.gov/docs/fy14osti/61721.pdf (accessed on 2 January 2024).
3. Zhang, Z.; Ding, T.; Zhou, Q.; Sun, Y.; Qu, M.; Zeng, Z.; Ju, Y.; Li, L.; Wang, K.; Chi, F. A review of technologies and applications on versatile energy storage systems. *Renew. Sustain. Energy Rev.* **2021**, *148*, 111263. [CrossRef]
4. Dimitriadis, C.N.; Tsimopoulos, E.G.; Georgiadis, M.C. Optimization-based economic analysis of energy storage technologies in a coupled electricity and natural gas market. *J. Energy Storage* **2023**, *58*, 106332. [CrossRef]
5. Bundesnetzagentur. Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen. *Marktstammdatenregister (MaStR)*, 2023. Available online: https://www.marktstammdatenregister.de/ (accessed on 2 April 2024).
6. Thema, J.; Thema, M. *Nachnutzungskonzept: Braunkohle-Tagebaue als Pumpspeicherkraftwerk? Energiewirtschaftliche Tagesfragen*; Wuppertal Institute for Climate, Environment and Energy: Wuppertal, Germany, 2019. Available online: https://epub.wupperinst.org/frontdoor/index/index/docId/7291 (accessed on 3 May 2024).
7. Golombek, R.; Lind, A.; Ringkjøb, H.K.; Seljom, P. The role of transmission and energy storage in European decarbonization towards 2050. *Energy* **2022**, *239*, 122159. [CrossRef]
8. Saldarini, A.; Longo, M.; Brenna, M.; Zaninelli, D. Battery Electric Storage Systems: Advances, Challenges, and Market Trends. *Energies* **2023**, *16*, 7566. [CrossRef]
9. Hesse, H.; Schimpe, M.; Kucevic, D.; Jossen, A. Lithium-Ion Battery Storage for the Grid—A Review of Stationary Battery Storage System Design Tailored for Applications in Modern Power Grids. *Energies* **2017**, *10*, 2107. [CrossRef]
10. Ziegler, M.S.; Trancik, J.E. Re-examining rates of lithium-ion battery technology improvement and cost decline. *Energy Environ. Sci.* **2021**, *14*, 1635–1651. [CrossRef]
11. Figgener, J.; Stenzel, P.; Kairies, K.P.; Linßen, J.; Haberschusz, D.; Wessels, O.; Angenendt, G.; Robinius, M.; Stolten, D.; Sauer, D.U. The development of stationary battery storage systems in Germany—A market review. *J. Energy Storage* **2020**, *29*, 101153. [CrossRef]
12. Ugulu, A.I. Barriers and motivations for solar photovoltaic (PV) adoption in urban Nigeria. *Int. J. Sustain. Energy Plan. Manag.* **2019**, *21*, 19–34. [CrossRef]
13. Alipour, M.; Irannezhad, E.; Stewart, R.A.; Sahin, O. Exploring residential solar PV and battery energy storage adoption motivations and barriers in a mature PV market. *Renew. Energy* **2022**, *190*, 684–698. [CrossRef]
14. Gorremans, J.; Lits, C.; Rossi, R.; Schmela, M. *European Market Outlook for Residential Battery Storage 2022–2026*; SolarPower Europe: Bruxelles, Belgium, 2022. Available online: https://www.solarpowereurope.org/insights/thematic-reports/european-market-outlookfor-residential-battery-storage-1 (accessed on 5 January 2024).
15. Agnew, S.; Dargusch, P. Consumer preferences for household-level battery energy storage. *Renew. Sustain. Energy Rev.* **2017**, *75*, 609–617. [CrossRef]
16. Familia, T.; Horne, C. Customer trust in their utility company and interest in household-level battery storage. *Appl. Energy* **2022**, *324*, 119772. [CrossRef]
17. Truong, C.; Naumann, M.; Karl, R.; Müller, M.; Jossen, A.; Hesse, H. Economics of Residential Photovoltaic Battery Systems in Germany: The Case of Tesla's Powerwall. *Batteries* **2016**, *2*, 14. [CrossRef]
18. Mateo, C.; Reneses, J.; Rodriguez-Calvo, A.; Frías, P.; Sánchez, Á. Cost–benefit analysis of battery storage in medium–voltage distribution networks. *IET Gener. Transm. Distrib.* **2016**, *10*, 815–821. [CrossRef]
19. PEC. Comparison of the Costs of Residential Battery Storage Systems in 2023: Vergleich der Stromspeicher Kosten im Jahr 2023. 2023. Available online: https://pro-ec.de/photovoltaik/stromspeicher-kosten-preise-2023/ (accessed on 19 March 2024).
20. Roos, M.H.; Geldtmeijer, D.; Nguyen, H.P.; Morren, J.; Slootweg, J.G. Optimizing the technical and economic value of energy storage systems in LV networks for DNO applications. *Sustain. Energy Grids Netw.* **2018**, *16*, 207–216. [CrossRef]
21. Keck, F.; Lenzen, M. Drivers and benefits of shared demand-side battery storage—An Australian case study. *Energy Policy* **2021**, *149*, 112005. [CrossRef]

22. Hollinger, R.; Diazgranados, L.M.; Braam, F.; Erge, T.; Bopp, G.; Engel, B. Distributed solar battery systems providing primary control reserve. *IET Renew. Power Gener.* **2016**, *10*, 63–70. [CrossRef]
23. Peng, L.; Mauzerall, D.L.; Zhong, Y.D.; He, G. Heterogeneous effects of battery storage deployment strategies on decarbonization of provincial power systems in China. *Nat. Commun.* **2023**, *14*, 4858. [CrossRef]
24. EUROSTAT. NUTS—Nomenclature of Territorial Units for Statistics. 2021. Available online: https://ec.europa.eu/eurostat/web/nuts/overview (accessed on 5 January 2024).
25. Sterchele, P.; Brandes, J.; Heilig, J.; Wrede, D.; Kost, C.; Schlegl, T.; Bett, A.; Henning, H.M. Paths to a Climate-Neutral Energy System: The German Energy Transition in its Social Context. 2020. Available online: https://www.ise.fraunhofer.de/en/publications/studies/paths-toa-climate-neutral-energy-system.html (accessed on 4 June 2023).
26. Kost, C. Renewable Energy in North Africa: Modeling of Future Electricity Scenarios and the Impact on Manufacturing and Employment. Ph.D. Thesis, Technische Universität Dresden, Dresden, Germany, 2014. Available online: https://nbn-resolving.org/urn:nbn:de:bsz:14-qucosa-176538 (accessed on 1 February 2024).
27. GAMS Software GmbH. *General Algebraic Modeling System*, v38.3.0; GAMS Software GmbH: Frechen, Germany, 2004. Available online: https://www.gams.com/ (accessed on 1 February 2024).
28. Senkpiel, C.; Hauser, W. Systemic Evaluation of the Effects of Regional Self-Supply Targets on the German Electricity System Using Consistent Scenarios and System Optimization. *Energies* **2020**, *13*, 4695. [CrossRef]
29. Naval, N.; Yusta, J.M.; Sánchez, R.; Sebastián, F. Optimal scheduling and management of pumped hydro storage integrated with grid-connected renewable power plants. *J. Energy Storage* **2023**, *73*, 108993. [CrossRef]
30. Katz, J.; Balyk, O.; Hevia-Koch, P. The Impact of Residential Demand Response on the Costs of a Fossil-Free System Reserve. In Proceedings of the 11th Conference on Energy Economics and Technology: Energy Efficiency and Demand Response, Dresden, Germany, 8 April 2016; Technische Universität Dresden: Dresden, Germany, 2016. Available online: https://orbit.dtu.dk/en/publications/the-impact-of-residential-demand-response-on-the-costs-of-a-fossi (accessed on 7 May 2018).
31. Wanapinit, N.; Thomsen, J.; Kost, C.; Weidlich, A. An MILP model for evaluating the optimal operation and flexibility potential of end-users. *Appl. Energy* **2021**, *282*, 116183. [CrossRef]
32. Spieker, C. Europäische Strommarkt- und Übertragungsnetzsimulation zur Techno-ökonomischen Bewertung der Netzentwicklung. Ph.D. Thesis, Technische Universität Dortmund and Shaker Verlag, Herzogenrath, Germany, 2019.
33. Seifi, H.; Sepasian, M.S. *Electric Power System Planning: Issues, Algorithms and Solutions*; Power Systems; Springer: Berlin/Heidelberg, Germany, 2011.
34. Spieker, C.; Klein, D.; Liebenau, V.; Teuwsen, J.; Rehtanz, C. European electricity market and network simulation for energy system analysis. In Proceedings of the 2016 IEEE International Energy Conference (ENERGYCON), Leuven, Belgium, 4–8 April 2016; IEEE: Piscataway, NJ, USA, 2016; pp. 1–6. [CrossRef]
35. German Federal Government. Bundes-Klimaschutzgesetz (Federal Climate Change Act): KSG. 2023. Available online: https://www.gesetze-im-internet.de/ksg/ (accessed on 19 October 2023).
36. Agora Energiewende. Climate-Neutral Power System 2035: How the German Power Sector Can Become Climate-Neutral by 2035. Available online: https://www.agora-energiewende.org/publications/climate-neutral-power-system-2035-summary (accessed on 23 February 2024).
37. Agora Energiewende; Forschungsstelle für Energiewirtschaft e.V. Haushaltsnahe Flexibilitäten nutzen: Wie Elektrofahrzeuge, Wärmepumpen und Co. die Stromkosten für alle Senken Können. 2023. Available online: https://www.agora-energiewende.de/publikationen/haushaltsnahe-flexibilitaeten-nutzen (accessed on 2 April 2024).
38. *Bedarfsermittlung 2019–2030: Bestätigung Netzentwicklungsplan Strom*; Bundesnetzagentur: Bonn, Germany, 2019.
39. *Bedarfsermittlung 2021–2035: Bestätigung Netzentwicklungsplan Strom*; Bundesnetzagentur: Bonn, Germany, 2019.
40. Risch, S.; Maier, R.; Du, J.; Pflugradt, N.; Stenzel, P.; Kotzur, L.; Stolten, D. Potentials of Renewable Energy Sources in Germany and the Influence of Land Use Datasets. *Energies* **2022**, *15*, 5536. [CrossRef]
41. C3S. ERA5 Hourly Data on Single Levels from 1940 to Present. Available online: https://cds.climate.copernicus.eu/cdsapp#!/dataset/10.24381/cds.adbb2d47?tab=overview (accessed on 14 May 2024).
42. BDEW. Standard electricity load profile (Standardlasprofile—Strom). 2017. Available online: https://www.bdew.de/energie/standardlastprofilestrom/ (accessed on 10 September 2023).
43. Palzer, A. Sektorübergreifende Modellierung und Optimierung eines Zukünftigen Deutschen Energiesystems unter Berücksichtigung von Energieeffizienzmaßnahmen im Gebäudesektor: Cross-Sectoral Modeling and Optimization of a Future German Energy System, Taking Energy Efficiency Measures into Account in the Building Sector. Ph.D. Thesis, Karlsruhe Institute of Technology, Karlsruhe, Germany, 2016. [CrossRef]
44. Gotzens, F.; Gillessen, B.; Burges, S.; Hennings, W.; Müller-Kirchenbauer, J.; Seim, S.; Verwiebe, P.; Schmid, T.; Jetter, F.; Limmer, T. Harmonization and Development of Methods for Modelling of Energy Demands in Spatial and Temporal Resolutions (DemandRegio). Available online: https://www.ffe.de/veroeffentlichungen/demandregio-harmonisierung-und-entwicklung-von-verfahren-zur-regionalen-und-zeitlichen-aufloesung-von-energienachfragen/ (accessed on 10 September 2023).
45. Statistisches Bundesamt. *Classification of Economic Activities (WZ 2008)*; Statistisches Bundesamt: Wiesbaden, Germany, 2008. Available online: https://www.destatis.de/DE/Methoden/Klassifikationen/textbaustein-klassifikationen.html (accessed on 4 February 2024).

46. Nobis, C.; Follmer, R.; Herter, M.; Bäumer, M. Mobility in Germany 2023. Available online: https://www.mobilitaet-in-deutschland.de/hintergrund-en.html (accessed on 4 January 2024).
47. Neuwirth, M.; Fleiter, T.; Manz, P.; Hofmann, R. The future potential hydrogen demand in energy-intensive industries—A site-specific approach applied to Germany. *Energy Convers. Manag.* **2022**, *252*, 115052. [CrossRef]
48. Wanapinit, N.; Thomsen, J.; Weidlich, A. Find the balance: How do electricity tariffs incentivize different system services from demand response? *Sustain. Energy Grids Netw.* **2022**, *32*, 100948. [CrossRef]
49. Fett, D.; Fraunholz, C.; Keles, D. Diffusion and system impact of residential battery storage under different regulatory settings. *Energy Policy* **2021**, *158*, 112543. [CrossRef]
50. Martins, J.; Miles, J. A techno-economic assessment of battery business models in the UK electricity market. *Energy Policy* **2021**, *148*, 111938. [CrossRef]

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.