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Residual load, renewable surplus generation and storage requirements in Germany☆

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HIGHLIGHTS

- I examine the effects of fluctuating renewable energy on residual load.
- Surplus energies are generally low, but there are high surplus power peaks.
- Increasing the flexibility of thermal generators substantially reduces surpluses.
- Allowing curtailment of 1% renders storage investments largely obsolete by 2032.
- Both storage requirements and the share of seasonal storage increase by 2050.

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ABSTRACT

I examine the effects of increasing amounts of fluctuating renewable energy on residual load, which is defined as the difference between actual power demand and the feed-in of non-dispatchable and inflexible generators. I draw on policy-relevant scenarios for Germany and make use of extensive sensitivity analyses. Whereas yearly renewable surplus energy is low in most scenarios analyzed, peak surplus power can become very high. Decreasing thermal must-run requirements and increasing biomass flexibility substantially reduce surpluses. I use an optimization model to determine the storage capacities required for taking up renewable surpluses. Allowing curtailment of 1% of the yearly feed-in of non-dispatchable renewables would render storage investments largely obsolete until 2032 under the assumption of a flexible power system. Further restrictions of curtailment as well as lower system flexibility strongly increase storage requirements. By 2050, at least 10 GW of storage are required for surplus integration, of which a sizeable share is seasonal storage. Results suggest that policy makers should work toward avoiding surplus generation, in particular by decreasing the must-run of thermal generators. Concerns about surpluses should not be regarded as an obstacle to further renewable expansion. The findings are also relevant for other countries that shift toward fluctuating renewables.

1. Introduction

The German government has decided to phase out nuclear power completely by 2022. At the same time, renewable power generation is to be expanded substantially. Renewable energy sources (RES) have to account for at least 35% of German gross electricity consumption by 2020 (BMWi and BMU, 2010). This share was around 6% in the year 2000 and grew to 23% by 2012 (BMU, 2013). The target values for 2030, 2040 and 2050 are 50%, 65% and 80%, respectively. The largest part of renewable power will come from wind and photovoltaics (PV). According to the medium scenario of the network development plan drafted by German transmission system operators (TSOs) in 2012, onshore and offshore wind account for around 45% of gross power demand by 2032, whereas PV contributes around 10% (NEP, 2012, scenario 2032B). Afterwards, the shares of wind and solar are projected to grow further until 2050 (cp. DLR, et al., 2012).[1]

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[1] An English summary of DLR et al. (2012) is provided by Pregger et al. (2013).

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Wind power and PV differ from conventional power generators in many respects (cp. Joskow, 2011, Hirth, 2013). In particular, their power production is fluctuating, as the hourly generation capacity strongly depends on weather and season, as well as on the time of the day. Moreover, generation is only weakly correlated with hourly load profiles. Growing shares of these technologies thus have a strong influence on residual load, for example resulting in temporary situations of both power shortage and renewable surplus generation (Denholm and Hand, 2011). Integrating growing amounts of wind and PV into the power system thus increasingly requires the application of dedicated integration measures, among them different types of energy storage, demand-side measures, network expansion, flexible thermal back-up plants and renewable curtailment (NREL, 2012).[2]

In this paper, I study the effects of future renewable expansion on residual load in Germany under a range of varying assumptions. I am particularly interested in the power and energy of temporary renewable surplus generation, as renewable surpluses have recently attracted increasing attention of policy makers.[3] It is also investigated which capacities of different storage technologies would be required for taking up temporary renewable surpluses. In doing so, three stylized types of storage are distinguished: batteries, pumped hydro storage (PHS), and power-to-gas. As an alternative to electricity storage,[4] temporary curtailment[5] of renewable generation is considered. The interrelation of storage and renewable curtailment is explored: how do storage requirements vary different levels of allowed curtailment? The analysis includes a large number of sensitivities with respect to the development of the plant fleet, thermal must-run restrictions, the flexibility of biomass generators, various meteorological years for wind and PV feed-in, and improvements in energy efficiency. The scenarios used draw on quasi-official projections of the German network development plan (*Netzentwicklungsplan*, NEP, 2012) for the years 2022 and 2032, and on a quasi-governmental long-term scenario for 2050 (DLR et al., 2012).

Different aspects of renewable surplus generation, curtailment and storage requirements have been analyzed in the international literature. Denholm and Sioshansi (2009) show how wind power revenues could be improved in U.S. power systems by avoiding curtailment with a mix of storage and network investments. Denholm and Hand (2011) simulate different scenarios with high shares of variable renewables in the Texas power system. They show that increasing system flexibility substantially reduces surpluses. For very high renewable penetrations, both daily storage and demand-side management are required for avoiding excessive curtailment. Lamont (2013) develops a model for determining optimal storage investments, both in terms of charging/discharging and reservoir capacity, and calibrates it to price and load parameters from California. He finds that storage-related changes in spot prices not only have an impact on the penetration of storage itself, but also on optimal investments in fluctuating renewables and other generation technologies. Carson and Novan (2013) evaluate the social benefits of additional bulk storage in Texas. Because of low renewable penetration, storage cannot be used to avoid renewable curtailment. As a consequence, additional storage increases base load generation and emissions of CO_2 and SO_2. Esteban et al. (2012) determine the storage capacities required in a 100% renewable power scenario for Japan largely based on wind and solar power. In this system, which has a peak demand of more than 240 GW, nearly 20 GW of pumped hydro would be necessary. In addition, battery storage with a capacity of 41 TWh is required. Mason et al. (2013) develop a fully renewable scenario for New Zealand and find that wind curtailment can be largely eliminated by PHS. Yet this system is hydro-dominated with wind constituting only around a quarter of the energy mix, so it can hardly be compared to systems with high shares of fluctuating renewables.

Next, related literature with a European focus is presented. Pérez-Arriaga and Batlle (2012) review the challenges of integrating increasing amounts fluctuating renewables into power systems and identify necessary regulatory adjustments. Lise et al. (2013) quantify the costs of renewable integration and present European residual load duration curves, according to which considerable renewable surpluses occur by 2050 even under the assumption of extensive interconnection. According to Rasmussen et al. (2012), a fully renewable pan European power system could be achieved with a combination of moderate over-capacities of wind and solar, 2.2 TWh of short-term storage and 25 TWh of seasonal storage because of synergies between storage and balancing. Tuohy and O'Malley (2011) analyze the impact of additional pumped storage on wind curtailment in the Irish power system. They find that building new storage is only economic for very high levels of wind penetration, whereas curtailment is cheaper for moderate shares of wind power.

As for Germany, the much-discussed '*Energiewende*' has increased interest in the future development of residual load, renewable surpluses and storage requirements. Wagner (2014) develops a model for residual demand in order to simulate the effect of fluctuating renewables on prices in the German day-ahead market. Steffen and Weber (2013) use load–duration curves to model efficient electricity storage investments for the integration of fluctuating renewables. Agora (2012) simulates German residual load in the year 2022, drawing on weather data of 2011.[6] Excluding must-run constraints and trade with neighboring countries, they determine around 200 h of renewable surplus generation. EWI (2013) use a cost-minimizing dispatch model that includes internal transmission constraints and cross-border trade to show that hardly any renewable curtailment should be expected until 2022 in Germany if existing transmission bottlenecks are removed. BET (2013) determine yearly surplus generation of around 2 TWh by 2020 and 35 TWh by 2030 for Germany, assuming thermal must-run of 10 GW in 2020 and 5 GW in 2030 and flexible biomass generation. With sufficient flexibilization of both the demand side and the supply side, additional storage capacity is required only after 2030. Nicolosi (2012) applies a

[2] Renewable integration studies that focus on specific flexibility options in the German context are provided by Dena (2011) and VDE (2012a, 2012b and 2012c). Sioshansi et al. (2012) point to technical issues as well as policy-related barriers to actual storage deployment in power markets. Borden and Schill (2013) review policy efforts for storage development in the U.S. and Germany.

[3] See, for example, The Economist (2013). The left-hand side of the residual load curve, i.e., peak load, is not a major concern in this analysis, as generation capacity is adequate in all scenarios analyzed in this study.

[4] To be more precise, I focus on power-to-power storage, which draws power from the grid and feeds back power to the system in later periods. I do not consider other storage options that transform electric power to other energy carriers, for example power-to-heat or power-to-gas. Beaudin et al. (2010) review the status quo, development potentials and challenges of different electricity storage technologies that can be applied for wind and solar power integration. Østergaard (2012) compares different storage options in a 100% renewable energy scenario for a Danish city and shows that electricity storage can better facilitate wind integration compared to biogas storage or heat storage.

[5] Jacobsen and Schroder (2012) define different categories of renewable curtailment. Drawing on case studies, they show that – contrary to public belief – some level of curtailment of variable renewables is optimal from a system cost perspective, for example by avoiding excessive grid investments.

[6] In September 2013, Agora published updated simulations for the years 2023 and 2033 in the form of presentation slides. However, a written report of this analysis, which also includes a spatial component, is not available so far. Importantly, Agora shows renewable and conventional generation in a graphic representation for every subsequent hour of the year. In contrast, I present simulation results in an aggregated form, for example in the form of load-duration curves, bar charts and histograms.

linear dispatch and investment optimization model to different scenarios of 2020 and 2030. Storage investments – in this case, compressed air energy storage – are negligible in most scenarios, except for the cases with restricted renewable curtailment. Hirth (2013) applies a cost-minimizing dispatch and investment model to the Northwestern European power system. Under the assumption that renewable curtailment does not incur any costs, he finds that no investments into new PHS take place even in a scenario with a 30% wind share.[7] VDE (2012a) analyze cost-minimizing renewable curtailment and the demand for additional storage capacity for renewable shares of 40%, 80% and 100%. They find 44, 2329 and 4271 h of negative residual load for the respective scenarios. Peak surplus power is 10 GW (40%), 50 GW (80%), and 81 GW (100%), respectively. Hardly any additional storage is required in the 40% scenario. With 80% renewables, 14 GW/70 GWh of short-time storage and 18 GW/7.5 TWh of seasonal storage are required in an optimized scenario that also makes use of other flexibility options. In order to avoid the remaining curtailment, storage capacities would have to double. Storage requirements increase further in the 100% scenario. SRU (2011) also develops a 100% renewable power scenario for Germany. If large-scale power exchange with either Scandinavia or Northern Africa is not possible, temporary surplus power generation may rise to 209 GW (scenario 1.b), and total yearly surplus energy may exceed 53 TWh (scenario 1.a). Accordingly, up to 37 GW of new compressed air storage would be required in order to accommodate a large share of these surpluses.[8]

The previously mentioned studies deal with different aspects of residual load, renewable surpluses and electricity storage. What is missing, however, is a comprehensive analysis that combines a simulation of the impacts of fluctuating renewables on residual load with an endogenous determination of surplus-related storage requirements. The present analysis aims to fill this gap, based on very recent scenarios for the development of variable renewables in Germany. It moreover sheds light on the interaction of electricity storage and renewable curtailment. Extensive sensitivity analyses provide insights how residual load and storage requirements depend on the development of exogenous key parameters, in particular regarding the flexibility of thermal generators. This allows drawing more general conclusions which are not only relevant for Germany, but also for other countries with thermal power systems that undergo a transformation towards fluctuating renewable power.

2. Materials and methods

The analysis includes a large number of sensitivities which requires making a range of simplifying assumptions. First, Germany is considered to be both an island and a copper plate.[9] The study

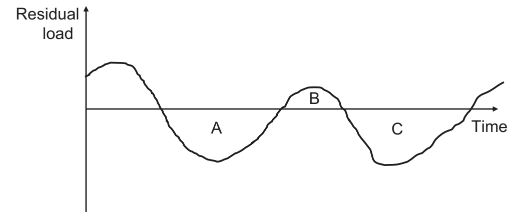

Fig. 1. Calculation of connected surplus energy.

thus neglects power exchange with adjacent countries and assumes perfect network extension within the country. Moreover, the model abstracts from a detailed representation of flexibility restrictions of thermal generators. Instead, flexibility restrictions are approximated with an aggregated thermal must-run constraint. Regarding storage, three stylized technologies are included. Other flexibility options such as demand-side management or transmission expansion are not considered.

2.1. Calculation of residual load and renewable surpluses

"Residual load" is not uniquely defined in the literature. In the following, it is calculated by not only subtracting hourly generation of onshore wind, offshore wind, PV and run-off-river hydro from hourly demand data, but also the must-run requirements of thermal generators. Generation from biomass, which here refers not only to the combustion of solid biomass, but also biogas and biogenic shares of municipal waste, is also subtracted in the cases in which it is assumed to be inflexible. Residual load, renewable surpluses and load gradients are then sorted in descending order so as to derive load-duration curves. In addition, I evaluate the cumulative surplus energy of all contiguous hours during which residual load is negative ("connected surpluses"). For every surplus event (for example, area A in Fig. 1), it is checked if the cumulative energy of the subsequent period of positive residual load (B) is larger than the previous connected surplus energy. If this is not the case, I add the energy of the next surplus event (C) to the connected surplus, and subtract the positive residual energy in between the two surplus events (connected surplus energy=A−B+C), and so on. This approach leads to a lower number of connected surplus events and at the same time to higher surplus energy compared to just looking at isolated surplus events, and is well suited to illustrate the requirements for storage.

2.2. A model to determine storage requirements

In order to determine storage requirements for taking up excess renewable generation, a simple linear cost minimization model is used which simultaneously optimizes storage investments and hourly dispatch of both power plants and storage capacities.[10] It should be noted that storage investments are optimized in the context of exogenous generation capacities. Peak load supply is not a concern in the scenarios used here. In an optimized system with endogenous generation capacities, storage may have a capacity value, which is neglected here. In addition,

[7] Both Hirth (2013) and Hirth (2015) argue that the potential contribution of storage to wind integration is rather limited compared to, for example, transmission investments or more flexible thermal generators. The limited reservoir size of PHS facilities is identified as a main driver for this outcome. The present analysis, however, indicates that PHS with a reservoir size of 8 hours is an appropriate technology choice in the case of constrained curtailment (compare Section 3.3). Accordingly, its energy-to-power ratio may not constitute the main barrier to the deployment of PHS, but rather its relatively high specific investment costs. Both Hirth (2013 and 2015) and the present analysis neglect the provision of ancillary services by PHS facilities, such that their system value is underestimated.

[8] In a survey article, Steffen (2012) reviews the current developments and medium-term prospects of PHS in Germany and finds that there is now a surge of new projects after around three decades without major developments. Yet the profitability of many of these projects remains questionable.

[9] Given the existing European interconnection, neglecting cross-border flows of electricity appears to be a rather stronger assumption. The integration of fluctuating renewables can undoubtedly be achieved more cost-effectively in an interconnected European power system compared to a German "island" solution. The domestic approach chosen here, however, is highly relevant for policy makers, as the German *Energiewende* in the power sector is not much coordinated with neighboring countries. Likewise, policy makers are interested in internal measures for renewable integration, including storage requirements. As for the "copper plate" assumption, this approach is justified by the official methodology of NEP (2012), according to which internal German transmission bottlenecks must be completely removed.

[10] An actual review of numerical dispatch and investment models is provided by Hirth (2015).

the possible system value of storage due to the provision of ancillary services is not considered (cp. Beck et al., 2013).

Exogenous model parameters include hourly power demand, generation capacities, the availability of renewable generators, and variable generation costs.[11] Storage investment costs and roundtrip-efficiencies are also exogenous. Endogenous variables include storage investments, dispatch of existing and new storage capacities, conventional power plant dispatch, and renewable curtailment. Table 5 in the Appendix provides a list of sets and indices, parameters and variables.

$$\min cost = \sum_{t,tech} vc_{tech} q_{tech,t} + \sum_{t,stor} vstc_{stor} storout_{stor,t} + \sum_{stor} ic_{stor} inv_{stor} \tag{1}$$

subject to

$$q_{tech,t} - \overline{q}_{tech} \leq 0 \quad \forall tech, t \tag{2}$$

$$mustrun - \sum_{tech} q_{tech,t} \leq 0 \quad \forall t \tag{3}$$

$$bio_t - \overline{bio} \leq 0 \quad \forall t \tag{4}$$

$$\sum_t bio_t - \overline{yearlybio} \leq 0 \tag{5}$$

$$rencurt_t - windon_t - windoff_t - pv_t - hydro_t \leq 0 \quad \forall t \tag{6}$$

$$\sum_t rencurt_t - allowcurt \sum_t (windon_t + windoff_t + pv_t + hydro_t) \leq 0 \tag{7}$$

$$storin_{stor,t} - \overline{storin}_{stor} - inv_{stor} \leq 0 \quad \forall stor, t \tag{8}$$

$$storout_{stor,t} - \overline{storout}_{stor} - inv_{stor} \leq 0 \quad \forall stor, t \tag{9}$$

$$storlevel_{stor,t} - storlevel_{stor,t-1} - storin_{stor,t}\eta_{stor} + storout_{stor,t} = 0 \quad \forall stor, t \tag{10}$$

$$storlevel_{stor,t} - \overline{storlevel}_{stor} - inv_{stor} epratio_{stor} \leq 0 \quad \forall stor, t \tag{11}$$

$$\sum_{tech} q_{tech,t} + windon_t + windoff_t + pv_t + hydro_t + bio_t + \sum_{stor} (storout_{stor,t} - storin_{stor,t}) - rencurt_t - dem_t = 0 \quad \forall t \tag{12}$$

Renewables do not appear in the objective function (1) as they are assumed to generate power with zero marginal costs. In contrast, generation $q_{tech,t}$ from thermal generators incurs positive variable costs vc_{tech}.[12] Storage output $storout_{stor,t}$ may also have positive marginal costs $vstc_{stor}$.[13] Furthermore, investment into storage technologies inv_{stor} incurs (annualized) investment costs ic_{stor}. Conventional generation faces a capacity constraint $\overline{q}_{tech}$ (2). Dispatch of thermal generators may be constrained by an aggregated must-run requirement $mustrun$ (3). Flexible generation bio_t from biomass is not only restricted by a capacity constraint $\overline{bio}$ (4), but also by a yearly energy constraint $\overline{yearlybio}$ (5). In case of inflexible biomass generation, the variable bio_t is fixed to a yearly average value, such that aggregated generation over the year equals $\overline{yearlybio}$. Hourly renewable curtailment $rencurt_t$ has to be smaller than the sum of fluctuating renewable generation from onshore wind ($windon_t$), offshore wind ($windoff_t$), PV (pv_t), and run-off-river hydro ($hydro_t$) (6). Overall yearly renewable curtailment may be restricted by a factor of allowed curtailment $allowcurt$ of yearly generation from non-dispatchable renewables (7). Such restrictions of curtailment may not be optimal from a system cost perspective, but can be practically relevant for environmental or political reasons. For example, curtailing power with zero CO_2 emissions may be problematic from a climate policy perspective, in particular if combined with thermal must-run capacity. Moreover, uncompensated curtailment harms the profits of renewable generators. Combined with uncertainty about compensation this may increase the financing costs of renewable investments (compare Jacobsen and Schroder, 2012).

Storage inflows $storin_{stor,t}$ and outflows $storout_{stor,t}$ are restricted by initial capacities $\overline{storin}_{stor}$ and $\overline{storout}_{stor}$ and additional capacity investments inv_{stor} (8 and 9). The storage level $storlevel_{stor,t}$ follows a law of motion equation, considering storage inflows and outflows as well as losses due to imperfect roundtrip efficiency η_{stor} (10). The upper bound for the storage level variable is given by initial storage capacity $\overline{storlevel}_{stor}$ and storage capacity investments (11). As for the latter, a fixed energy-to-power ratio $epratio_{stor}$ is assumed, which links investments into charging and discharging power inv_{stor} (in MW) to the storage's energy capacity (in MWh). The scenario analysis includes three distinctive storage technologies with different energy-to-power ratios. There is no upper bound for storage investments. An energy balance restriction requires hourly demand dem_t to match supply any time (12).

2.3. Scenarios for 2022 and 2032

The scenarios for 2022 and 2032 draw on generation capacities of the German network development plan (NEP, 2012). This plan has been drafted by the German TSOs and was approved by the regulator after a series of public consultations. It is a major component of the *Bundesbedarfsplan* (Federal Requirements Plan) of 2013 and thus constitutes a quasi-official document. The NEP (2012) includes three scenarios for the year 2022 (A, B, C) with varying assumptions on renewable and conventional capacity developments. Scenario A is designed to achieve the German government's energy and climate targets. Scenarios B and C are more ambitious with respect to renewable energy deployment. Scenario B, which is regarded as a reference scenario, is extended to 2032. Table 1 shows installed capacities for all scenarios. Overall conventional generation capacities are largely the same in all future scenarios, with more lignite and coal in scenario A and more natural gas in scenarios B and C. Natural gas comprises open cycle gas turbines, steam turbines, and combined cycle. Nuclear power is phased out completely by 2022 according to German legislation. Renewable capacities increase strongly, which reflects their comparatively low capacity factor. Among the 2022 scenarios, wind onshore and offshore capacities are largest in scenario C, whereas the largest PV capacity is found in scenario B. Renewable capacities are largest in B 2032. Around 90% of the renewable capacity in B 2032 consists of fluctuating wind and solar power.

NEP (2012) includes PHS capacities of 6.3 GW in 2010, and 9.0 GW in all other years. In the model analysis, $\overline{storin}_{PHS} = \overline{storout}_{PHS} =$ 6.3 GW for all years as shown in Table 1, as storage capacity investments are modeled endogenously. I assume an initial PHS energy storage capacity of 44 GWh, and average roundtrip efficiency of existing PHS plants of 75%. Average availability is 90% for conventional generators, biomass and storage.[14]

[11] It is important to note that storage investments are optimized in the context of exogenous generation capacities. Peak load supply is not a concern in the scenarios used here. In an optimized system with endogenous generation capacities, storage may have a capacity value, which is neglected here. In addition, the possible system value of storage due to the provision of ancillary services is not considered (cp. Beck et al., 2013).

[12] In the application presented in the following, conventional technologies *tech* are elements of a technology set *TECH* which includes nuclear, lignite, hard coal, natural gas, oil and other technologies.

[13] Storage technologies *stor* are elements of a technology set *STOR*, which includes hourly, daily and seasonal storage. The numerical application abstracts from variable storage costs other than roundtrip losses.

[14] In practice, a share of the available PHS capacity may be set aside to provide control power. The same is also true for many conventional generators.

Table 1
Generation capacities in the scenarios for 2022 and 2032 in GW (NEP 2012).

	2010	A 2022	B 2022	C 2022	B 2032
Nuclear	20.3	0	0	0	0
Lignite	20.2	21.2	18.5	18.5	13.8
Hard coal	25.0	30.6	25.1	25.1	21.2
Natural gas	24.0	25.1	31.3	31.3	40.1
Oil	3.0	2.9	2.9	2.9	0.5
Other	3.0	2.3	2.3	2.3	2.7
Pumped hydro	6.3	6.3	6.3	6.3	6.3
Total conventional	**101.8**	**88.4**	**86.4**	**86.4**	**84.6**
Hydro (run-of-the-river)	4.4	4.5	4.7	4.3	4.9
Wind onshore	27.1	43.9	47.5	70.7	64.5
Wind offshore	0.1	9.7	13.0	16.7	28.0
PV	18.0	48.0	54.0	48.6	65.0
Bio and other	6.7	9.5	10.6	8.7	12.3
Total renewable	**56.3**	**115.6**	**129.8**	**149.0**	**174.7**
Total	**158.1**	**204.0**	**216.2**	**235.4**	**259.3**

Table 2
Assumptions on variable costs of conventional plants for NEP scenarios.

	Fuel prices in Euro/ $MWh_{thermal}$		Variable cost in Euro/ $MWh_{electric}$	
	2022	**2032**	**2022**	**2032**
Lignite	2	2	20	26
Hard coal	12	13	44	47
Natural gas	25	25	68	72
Oil	53	62	166	202
Other	7	7	33	37

Must-run requirements of thermal generators are assumed to take on values of 0 GW, 10 GW or 20 GW. These aggregated must-run levels reflect a combination of economic, technical, system-related and institutional factors, for example, minimum load restrictions and non-convex start-up costs for thermal generators, heat-related restrictions of combined heat and power generation, and minimum operating levels due to the provision of spinning reserves and other ancillary services (FGH et al., 2012).[15] It is reasonable to assume that all of these factors may change in the future, for example because of improved power plant flexibility, more flexible operation modes of combined heat and power generation, and the provision of ancillary services by renewable generators and/or the demand side.

Table 2 lists fuel prices and variable costs of conventional electricity generation for the NEP scenarios. Variable costs are calculated using own assumptions on average plant efficiencies and CO_2 prices of 20 €/t in 2022 and 30 €/t in 2032. Renewable generation is assumed to be free of variable cost.[16]

Regarding hourly feed-in of onshore wind, offshore wind and PV, all data provided by German TSOs up to the year 2012 is used. Onshore wind data is available since 2006; the offshore wind time series starts in 2010.[17] PV data is available only since 2011. Hourly availability factors are calculated for all renewable technologies by relating the actual hourly feed-in to the installed capacity of the respective year. To do so, official end-of-year installation data is used, assuming linear capacity increase throughout the year. Fig. 2 shows sorted availability factors of all yearly time series of onshore wind, offshore wind, and PV in a sorted order, as well as the mean values.

In order to derive hourly renewable generation, hourly availability factors are multiplied with the generation capacities of the respective scenario. Average hourly utilization factors of onshore wind vary between 0.16 in 2010 and 0.21 in 2007. Offshore wind achieves much higher full-load hours. The average hourly utilization factor is between 0.39 in 2010 and 0.43 in both 2011 and 2012, although data is not as representative as in the case of onshore wind. PV is characterized by a much steeper load-duration curve with average utilization factors between 0.10 in 2011 and 0.11 in 2012 as power generation is restricted to daytime hours.

Hydro power is assumed to generate at a constant level throughout the year, based on extrapolations of overall generation in 2010. Generation from biomass is assumed to either be perfectly inflexible, i.e., generating at a constant level during all hours of the year, or flexible within the constraints (4) and (5). Thus, two extreme assumptions on future biomass flexibility are captured. In both cases, overall yearly power generation from biomass is equal. Renewable curtailment is assumed to be either free, or restricted to 1%, 0.1% or 0% of the maximum yearly generation of wind onshore, wind offshore, PV and hydro.

Hourly load data is derived from values provided by ENTSO-E (2013a) for 2010. For statistical reasons, these do not cover total net power consumption. I thus scale the hourly profile linearly such that it fits official government data on net power consumption. The methodology described in NEP (2012) is applied, according to which non-observed consumption has the same profile as observed consumption. Adding 5% network losses on top of net power consumption results in an annual power demand of 562 TWh. Network losses, which are also assumed to have the same profile as observed load, are included because these represent real power consumption which has to be provided by generators.[18] Load is generally assumed not to change in the NEP scenarios compared to 2010. However, I include sensitivity runs in which load decreases by 10% or 20% in all hours, which is in the range of the German government's goals (BMWi and BMU, 2010).

There are three stylized types of possible new storage investments: lithium-ion batteries (hourly storage), new pumped hydro (daily storage), and power-to-gas[19] (seasonal storage). These technologies vary with respect to energy/power ratios, roundtrip efficiency and investment costs (Table 3). Specific investments are

[15] Non-convex start-up costs give thermal power plant operators an incentive not to shut down single blocks for short periods of time (compare Schroder et al., 2013). Regarding spinning reserves and other ancillary services, thermal must-run may also be related to institutional arrangements such as daily, weekly or monthly tendering schedules for control reserves (Müsgens et al., 2012).

[16] This is also true for biomass, although biomass generation usually incurs positive fuel costs. This assumption is not critical in the context of this analysis, as I do not analyze overall system costs. I implicitly assume that a support scheme exists which incentivizes either perfectly inflexible or perfectly flexible generation from biomass plants.

[17] Offshore wind capacity in Germany was small by the end of 2012. Available data between 2010 and 2012 reflects power generation from two offshore parks in the North Sea, alpha ventus and Bard Offshore I. alpha ventus became fully operational in spring 2010, whereas the other offshore park has been gradually connected to the grid since late 2010. The data thus represents very specific feed-in situations of two distinctive wind farms. Future generation from offshore wind turbines should be smoother than in the past because of spatial leveling and reduced distortions by outages.

[18] As a consequence of including network losses, a peak load value of 92 GW in 2010 is derived. This value is in line with the methodology described by German TSOs in NEP (2012), but higher than in many other analyses that neglect network losses. Interestingly, a study of generation adequacy in Germany, which has also been drafted by the TSOs, neglects network losses and thus contradicts the NEP reasoning (50Hertz et al., 2012). The sensitivity analyses with decreasing load indicate in which direction results change if network losses are neglected.

[19] More precisely: power-to-gas-to-power, indicating that hydrogen is converted to electricity again.

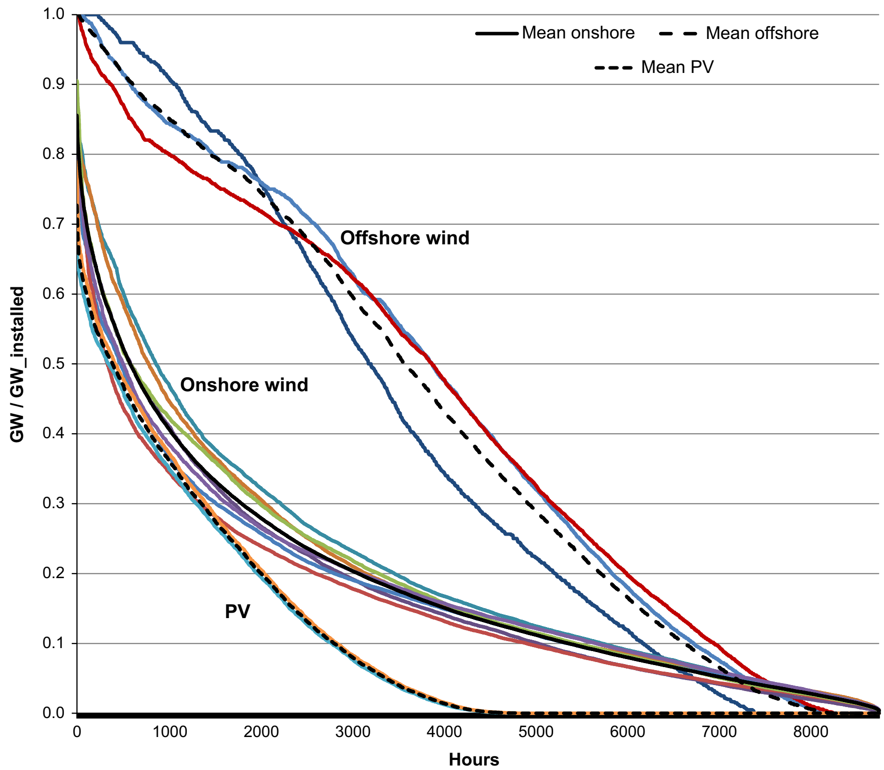

Fig. 2. Historic availability factors for wind power and PV.

Table 3
Assumptions on storage technologies.
Sources: Fuchs et al. (2012), own assumptions.

	Energy/Power ratio ($epratio_{stor}$)	Roundtrip efficiency (η_{stor})	Specific investment in €/kW	Economic lifetime in years	Annualized investment in €/kW (ic_{stor})
Hourly storage ("Li-ion battery")	2	0.89	665	15	78
Daily storage ("Pumped hydro")	8	0.79	850	30	76
Seasonal storage ("Power-to-gas-to-power")	500	0.35	1500	20	153

The parameters represent average values for the period 2012–2030.

annualized, drawing on specific economic lifetimes and an 8% interest rate. Parameters are derived from Fuchs et al. (2012) and VGB (2012a) and represent averages for the period 2012–2030. The same parameters are used in all scenarios, as assumptions on future parameter changes are highly speculative and complicate interpretation.

Summing up, I vary the following input parameters in the model application, resulting in 12,096 distinctive NEP runs:

- Generation capacities according to NEP scenarios (A 2022, B 2022, C 2022, B 2032);
- Yearly profiles of wind power and PV (7 for onshore wind, 3 for offshore wind, 2 for PV)[20];
- Load (100%, 90%, 80%);
- Must-run requirements of thermal generators (0, 10, 20 GW);
- Biomass flexibility (flexible or constant generation);
- Allowed renewable curtailment (no restriction, 1%, 0.1%, or 0% of yearly generation from non-dispatchable renewables).

2.4. A long-term outlook for 2050

Complementary to the NEP scenarios, I present an outlook for 2050, leaning on scenario '2011 A' of a quasi-governmental long-term study (DLR et al., 2012).[21] This scenario assumes a renewable share of 86% in final power consumption by 2050. Conventional generation capacity is largely substituted by renewables (Table 4). Lignite is phased out completely, whereas some hard coal capacity remains. Gas-fired plants make up the major part of remaining thermal capacity.[22] Due to strongly increasing fuel and CO_2 prices, generation costs are assumed to be 136 €/MWh for hard coal and 131 €/MWh for natural gas. As in the NEP scenarios, existing PHS is assumed to be constant at 2010 levels since additional storage capacities are modeled endogenously.

Installed capacities of hydro power, wind onshore, wind offshore, PV and biomass are comparable to the scenario B 2032. In addition, there are 3 GW of geothermal power and 10.5 GW of renewable power imported from other countries. Biomass, geothermal

[20] All yearly time series of onshore wind, offshore wind and PV are permuted, assuming that there is no correlation between the yearly feed-in patterns of these three technologies.

[21] The scenario was designed for and published by the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. An English summary has been published as Pregger et al. (2013).

[22] In the 2050 scenario, hard coal includes other solid fuels. Gas plants are fueled not only with natural gas, but also with renewable hydrogen to some extent.

Table 4
Generation capacities in the 2050 scenario in GW (Leit 2011 A of DLR et al., 2012).

	2050
Hard coal	4.6
Natural gas	33.5
Pumped hydro	6.3
Total conventional	**44.4**
Hydro (run-of-the-river)	5.2
Wind onshore	50.8
Wind offshore	32.0
PV	67.2
Bio	10.4
Geothermal	3.0
Renewable imports	10.5
Total renewable	**179.1**
Total	**223.5**

power and imports are modeled in an aggregated way, assuming that these three technologies are either fully flexible or fully inflexible. In the first case, restrictions (4) and (5) apply for this aggregate, with *yearlybio* consisting of 59 TWh for biomass, 19 TWh for geothermal and 61 TWh for imports, respectively. In the latter, constant average hourly feed-in is assumed. Generation of wind and PV is calculated as described above.

Power demand is much lower in the 2050 scenario compared to the 2022 and 2032 scenarios, as DLR et al. (2012) assume large energy efficiency improvements. Overall power consumption in 2050 is 413 TWh, a decrease of 27% compared to the NEP scenarios. Peak load accordingly decreases to 67 GW. Such linear scaling neglects possible load profile changes due to new and flexible consumers such as electric vehicles or electric heat pumps. All other parameters of the 2050 scenario are equal to the NEP scenarios.

I again carry out sensitivity analyses, using all available yearly profiles of wind and PV generation (7 onshore, 3 offshore, 2 PV), 3 distinctive must-run requirements (0, 10, 20 GW), 2 assumptions on biomass flexibility, and 4 levels of allowed renewable curtailment (no restriction, 1%, 0.1%, 0% of yearly generation). In contrast to the NEP scenarios, I abstract from simulating the effects of decreasing load, as overall demand is already very low, and further reductions appear not to be meaningful. Accordingly, 1008 simulations for the 2050 scenario are carried out.

3. Results

In the following, I first present results for the NEP scenarios for 2022 and 2032. Section 3.1 includes general outcomes of the residual load simulations, followed by a more detailed examination of renewable surpluses in 3.2. Section 3.3 contains the results of the optimization model for storage requirements. Afterwards, Section 3.4 presents selected outcomes for the 2050 scenario.

3.1. Residual load in NEP scenarios

Due to the limited correlation of fluctuating wind and solar generation with hourly demand, increasing capacities of these technologies do not result in a linear decrease of residual load. The largest effect can be found on the right-hand side of the residual load curve (Fig. 3).[23] The decrease becomes more pronounced with more renewables, and is largest for scenario B 2032. In contrast, peak residual load hardly changes compared to 2010 levels. In other words, fluctuating renewables substitute a large amount of fossil fuels, but hardly decrease the capacity requirements of the system. These results confirm earlier findings by Ueckerdt et al. (2013). Fig. 3 also shows the effect of different flexibility assumptions on residual load. Compared to a perfectly flexible system with no must-run requirement and flexible generation from biomass, a system-wide thermal must-run requirement of 20 GW combined with inflexible biomass generation substantially decreases residual load. Under inflexibility assumptions, residual load would be negative during 40% of all hours of the year in scenario B 2032. This compares to 5% of all hours under the assumption of flexible generators. In addition, the absolute value of the negative (surplus) peak is larger than the positive residual load peak. With improving energy efficiency, residual load decreases further. There is considerable variation in negative peak values, depending on the combination of meteorological years. In B 2032, the negative peak varies up to 20 GW. The choice of historical feed-in patterns accordingly has a strong effect on projected extreme values of residual load. This finding is relevant for any analysis that deals residual load in power systems with large shares of renewables.

Aside from residual load levels as such, hourly changes of residual load are of increasing importance in power systems based on fluctuating renewables because they indicate how quickly the dispatchable generators in the system have to ramp up or down their output. In other words, residual load gradients indicate how flexible the power plant fleet is required to be.[24] Fig. 4 shows positive and negative hourly residual load gradients in a sorted order (means for all different combinations of meteorological wind and PV years). The largest positive residual load change between two subsequent hours in 2010 was +11.4 GW, and the smallest negative value was −7.2 GW. With increasing capacities of fluctuating renewables, these values become much more extreme: in scenario B 2032, the largest hourly increase of residual load is +21.9 GW, whereas the largest decrease is −26.5 GW. This corresponds to 24% of the system's peak load, or 29% respectively. BET (2013) calculate comparable numbers for 2030, but slightly underestimate the negative extreme value. Average positive and negative gradients also increase. Accordingly, dispatchable power plants, storage, and the demand side have to become more flexible to allow for such large hourly gradients.

3.2. Renewable surplus generation in NEP scenarios

In this section, I focus on events of renewable surplus generation, i.e., on the negative part of the residual load curve. Fig. 5 shows load-duration curves of surpluses for all NEP cases under the assumption of reference load, no must-run requirements, and flexible bio generation. Curves for the largest and smallest surpluses are provided, depending on meteorological years used, as well as means for all simulations. In general, the curves have a very steep shape. Whereas surpluses generally show high peak power, overall surplus energies are relatively low. In B 2022, there are on average 43 surplus hours; this number grows to 471 in B 2032. The findings are generally in line with EWI (2013) and VDE (2012a), although the methodology slightly differs. Agora (2012) determines a somewhat higher number of 200 surplus hours because only one specific wind year is used (2011), network losses seem to be neglected, and biomass is assumed to be largely inflexible.

Any measure specifically designed for taking up peak renewable surpluses would thus achieve only a small number of full-load

[23] The figure shows mean values for all combinations of yearly availability factors for wind onshore, wind offshore and PV. Note that the different lines do not represent the same order of single hours.

[24] Hence, the analysis of residual load gradients complements other parts of the present analysis, as the dispatch model used here largely abstracts from flexibility constraints of thermal power plants.

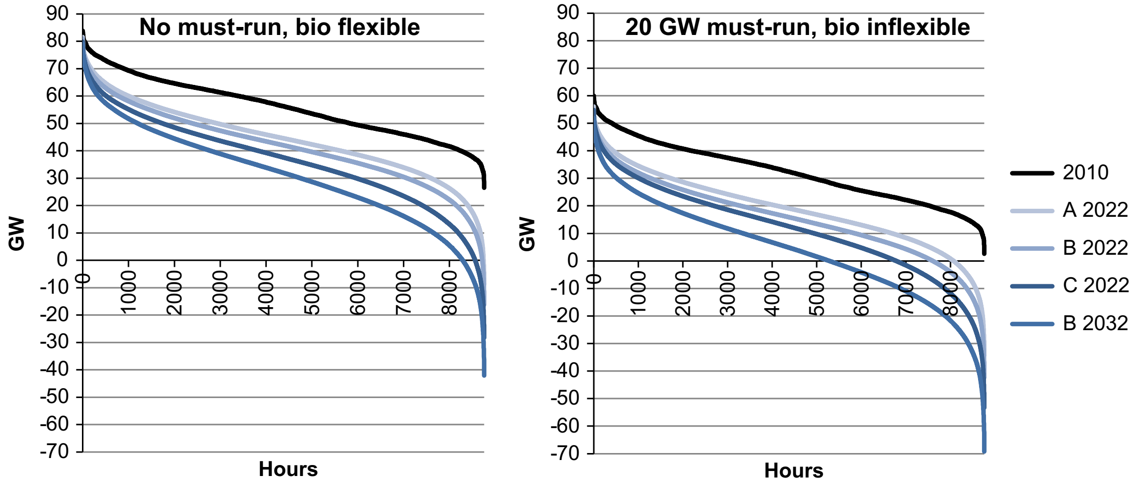

Fig. 3. Residual load in NEP scenarios (reference load, means).

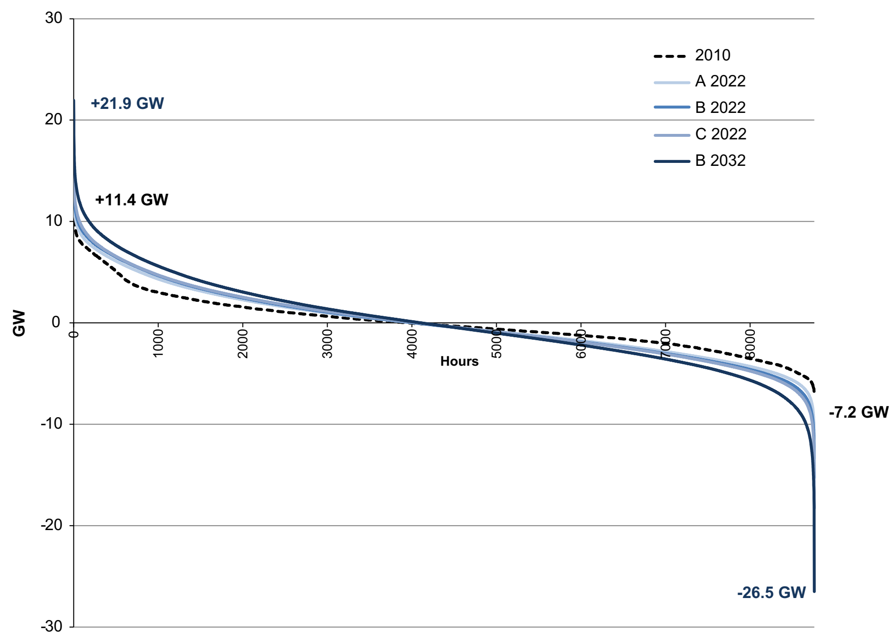

Fig. 4. Hourly residual load gradients (means).

hours over the whole year. The growth of the surplus between B 2022 and C 2022 is explained by increasing onshore wind capacity. The further increase between C 2022 and B 2032 is caused by additional PV and offshore wind on top of high onshore wind capacities. Using different meteorological years has only a moderate effect on peak surplus generation, but a large effect on overall surplus energy. In B 2032, overall surplus varies between 2.5 and 7.5 TWh, depending on the data used. This corresponds to around 0.4% or 1.3% of yearly load, respectively. If generation from biomass is assumed to be inflexible, while still assuming no thermal must-run, surpluses roughly double in all cases, but the shapes of the curves hardly change.

Overall surplus energy substantially increases with growing must-run requirements and decreasing load, as shown exemplarily for B 2032 in Fig. 6. 10 GW of must-run increase the yearly surplus from 4.5 to 12.1 TWh, corresponding to around 2% of yearly demand. A must-run requirement of 20 GW further increases surplus energy to 28.6 TWh (5%). Decreasing load to 90% or 80% of baseline levels has a similar, but somewhat smaller effect, as 10% of load correspond to a peak load decrease of around 9 GW and an off-peak decrease of only around 4 GW. Combining must-run requirements of 20 GW with a load of 80% results in very large yearly surplus generation of 69.5 TWh, corresponding to around 12% of yearly demand. Accordingly, removing the thermal must-run is crucial for avoiding large surpluses. This is particular true if the government's targets on improving energy efficiency are realized.

Fig. 7 shows both the time of day distribution and the monthly distribution of surpluses (hourly percentages of total surpluses). Exemplarily, case B 2032 is depicted under the assumption of no thermal must-run requirement and flexible biomass generation. The largest part of excess generation occurs around noon due to PV feed-in.[25] The time of day distribution of surpluses becomes

[25] The concentration around noon is even stronger in the scenarios A 2022 and B 2022 due to higher PV shares in these scenarios. Due to daylight saving time, hours are slightly distorted over the course of the year. Correcting for this effect, a part of the surpluses shown in the figure should move one hour to the left. The peak would accordingly be found in the hour between 12:00 and 13:00 in most cases.

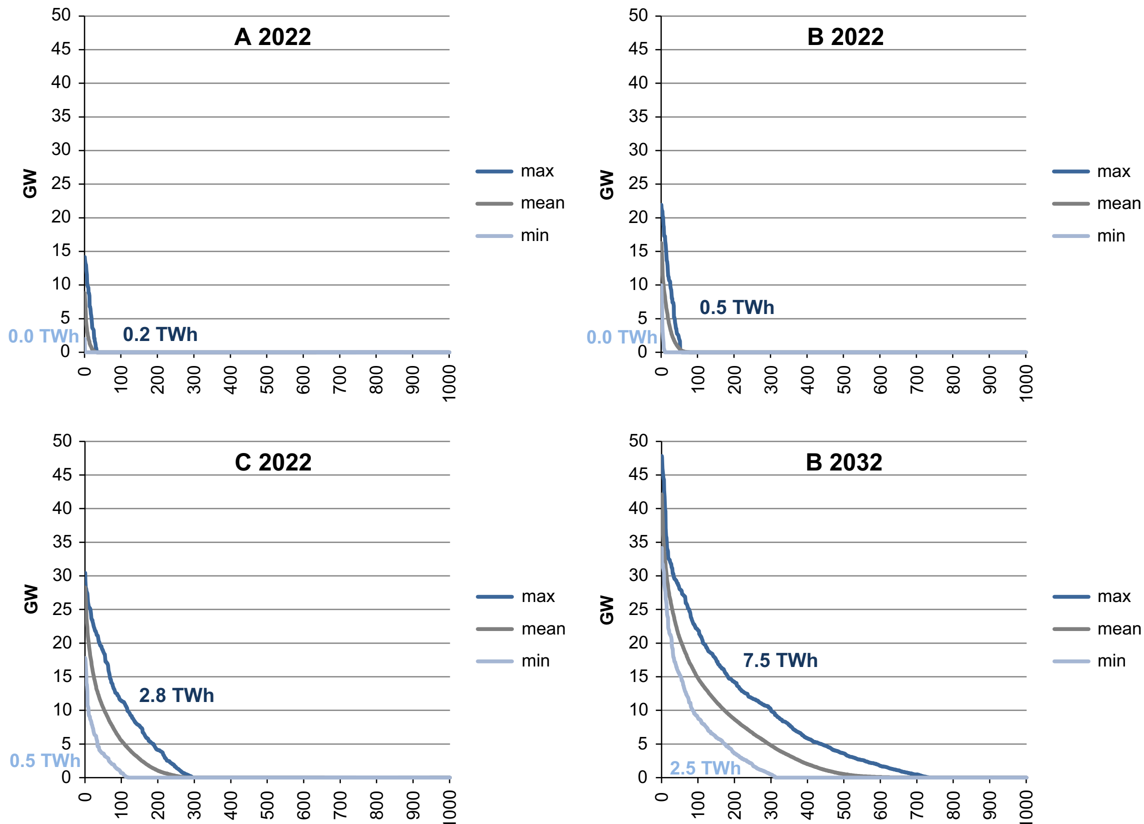

Fig. 5. Load–duration curves of surplus generation (reference load, no must-run, bio flexible).

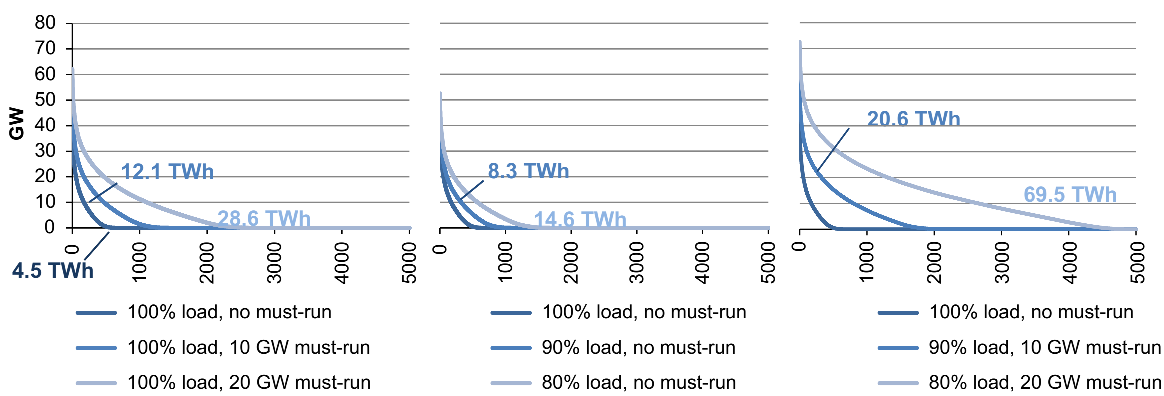

Fig. 6. Surplus for varying assumptions on load and must-run (B 2032, means, bio flexible).

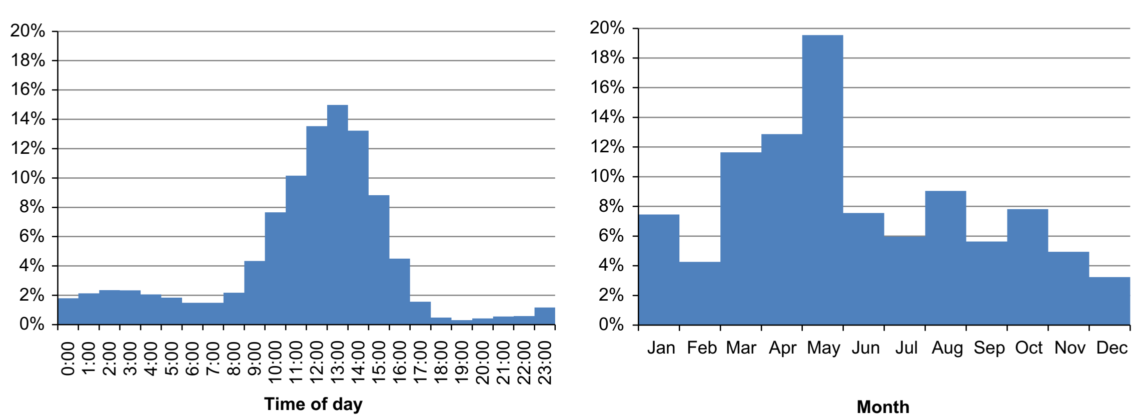

Fig. 7. Time of day distribution and monthly distribution of surpluses – hourly percentages of total surpluses (B 2032, reference load, no must-run, bio flexible, means).

smoother in an inflexible system with a must-run of 20 GW and inflexible biomass. Under such assumptions, not only overall surpluses increase considerably, but also the relative importance of wind-related off-peak surpluses. As for the monthly distribution of surpluses, there is a peak in the month of May in all NEP scenarios. In scenarios with higher relative shares of PV (A 2022 and B 2022), the concentration on May is even stronger. In both 2011 and 2012, German PV generation was highest in the months of May. Under the assumption of high thermal must-run and inflexible biomass, which goes along with much-increased surpluses, the monthly distribution gets more evenly distributed.

Fig. 8 shows the distribution of connected surplus energies as defined in Section 2 for scenario B 2032 (means for all meteorological years). The distribution has a very long tail on the right side. Under the assumption of a flexible system, the majority of connected surpluses are in the range of existing German PHS capacity (around 40 GWh). Nonetheless, connected surplus events with cumulative energies of more than 40 GWh constitute the majority of total surplus energy. On average, the energy of the largest connected surplus in B 2032 is 544 GWh. This corresponds to 0.1% of yearly demand, or around 12 times the existing German PHS capacity; for one specific combination of meteorological years there is even a maximum connected surplus of 1020 GWh (0.2%, 23-fold German PHS capacity). Accordingly, the choice of historical wind and PV data has a large effect on the extreme values of connected surpluses. In an inflexible system with 20 GW must-run and inflexible biomass, connected surplus energy massively increases, and the right tail of the distribution is even longer. Under these assumptions, surpluses could hardly be accommodated by existing pumped hydro capacities, as nearly 99% of yearly surplus energy is made up of connected surpluses larger than 40 GWh. The largest mean connected surplus in B 2032 is larger than 6 TWh (1.1% of yearly demand, more than 130-fold German PHS capacity), the largest single value for a specific combination of meteorological years is nearly 11 TWh (1.9%, more than 250-fold). Any measure that is to absorb such surplus energies is thus required to have a very large capacity.

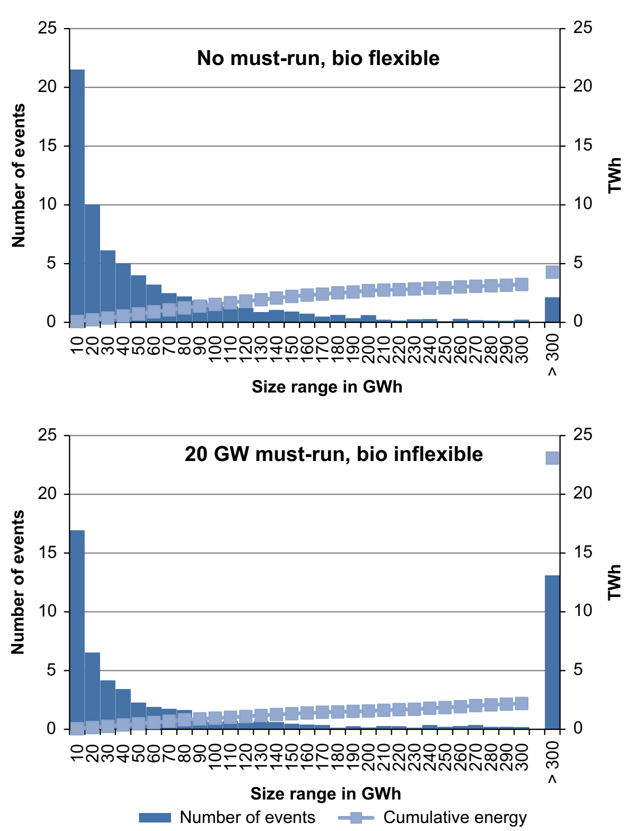

Fig. 8. Frequency distribution of connected surplus energy (B 2032, reference load, means).

3.3. Storage requirements in NEP scenarios

In the following, I show how much storage would be required for taking up the renewable surpluses discussed above, drawing on the optimization model described in Section 2. Fig. 9 shows optimal storage investments for all NEP scenarios, allowing for different levels of curtailment.[26] We first look at the case of a flexible system. No additional storage is needed in any NEP scenario if curtailment is not restricted. This confirms the finding of VDE (2012a), according to which hardly any storage is required in a scenario with a renewable share of 40%. Accordingly, integrating surplus energy (on average, between 0.1 TWh in A 2022 and 4.5 TWh in B 2032) by means of storage would be more expensive than generating an according amount of power in thermal plants. Relating annualized storage investments to the amount of avoided curtailment results in specific costs of full surplus integration in the range of several thousand Euros per MWh in C 2022 and B 2032, assuming a flexible system. This is because substantial amounts of storage are required, but these are rarely used for renewable integration, as surpluses are very small. Assuming an inflexible system, not only storage requirements increase, but also storage utilization because of more frequent surplus generation. Accordingly, the specific costs of fully avoiding curtailment are lower, but still in the range of several hundred Euros per MWh, way above the costs of generating power with conventional plants.

A similar result is found if renewable curtailment is restricted to 1% of the yearly feed-in of wind onshore, wind offshore, PV and hydro power. Under these assumptions, there is only minor investment in B 2032 into daily storage of less than 1 GW. Allowing a small fraction of curtailment thus renders obsolete virtually all storage investments. If curtailment is further restricted, storage requirements, however, strongly increase. If only 0.1% of the yearly feed-in of non-dispatchable renewables may be curtailed, mean storage investments increase to more than 9 GW in C 2022 and nearly 22 GW in B 2032. If no curtailment is allowed, storage requirements increase to 4, 12, 26 and 41 GW in the four NEP scenarios. This is because all surplus peaks have to be integrated, even very high and rare ones. Virtually all of these storage capacities are daily storage. The higher roundtrip efficiency of hourly storage cannot compensate its disadvantage in terms of specific costs and energy storage capacity compared to daily storage.[27] Likewise, seasonal storage is hardly required in a flexible system, as connected surpluses are relatively small.

The right-hand side of Fig. 9 shows storage investments in an inflexible system with a 20 GW must-run requirement and inflexible generation from biomass. Again, no storage is built in case of unrestricted curtailment. For all other cases of restricted curtailment, however, storage requirements are much larger compared to a flexible system because of larger surpluses. If curtailment is restricted to 1% of the yearly feed-in of non-dispatchable renewables, average storage investments are around 4 GW in A 2022 and

[26] As noted above, optimality only refers to the arbitrage value of storage and its potential for taking up renewable surplus generation in a system with exogenous generation capacities; additional system benefits related to the provision of firm capacity and/or ancillary services are not considered.

[27] Hourly storage technologies such as batteries or kinetic storage systems have specific advantages in short-term applications which are not considered in this analysis. For example, Li-ion batteries are well suited for providing primary frequency control.

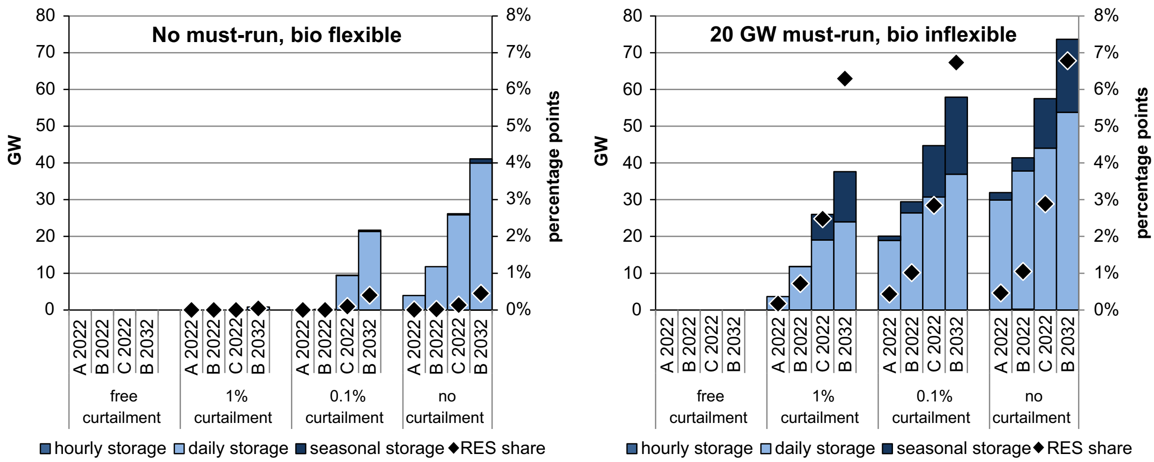

Fig. 9. Storage investment and storage-related increase of RES share in electricity consumption (reference load, means).

38 GW in B 2032. If no curtailment is allowed, these values increase to 32 GW in A 2022 and 74 GW in B 2032. The latter corresponds to 80% of the system's peak demand. A substantial amount of seasonal storage is required in addition to daily storage in the cases with large renewable capacities. For example, 20 GW of seasonal storage is built in B 2032 on top of 54 GW of daily storage in the case with no curtailment. These investments into the more expensive seasonal storage technology are explained by the fact that surpluses are not only more frequent, but also larger in size compared to the flexible system. Thus, a full integration of surpluses–which are still relatively small compared to yearly load–requires very large capacities both in terms of storage power and energy. Storage investments increase under the assumption of decreasing load, corresponding to increasing surpluses.[28]

I have shown that additional storage is not required in any NEP scenario if curtailment is not restricted. Curtailment, however, decreases the amount of renewable energy used in the power sector. Fig. 9 shows how forced surplus integration by means of storage increases the share of renewables in overall power consumption. Assuming a flexible system, renewable shares range between 37% in scenario A 2022 and 58% in B 2032 in case of free curtailment. Storage-related increases in these shares are well below 1 percentage point in all NEP scenarios, as overall surplus generation is low. Such changes may be considered negligible from a policy point of view. In contrast, the impact of storage on RES shares is much larger in an inflexible system, as surpluses are higher. This is particularly true for scenarios C 2022 and B 2032. Assuming 20 GW must-run and inflexible biomass, renewable shares in case of free curtailment are around 45% and 52% in C 2022 and B 2032. Full surplus integration by storage substantially increases these shares by 3 or 7 percentage points, respectively. Accordingly, renewable shares increase to 48% in C 2022 and 59% in B 2032. In general, the RES targets of the German government are exceeded in all NEP scenarios, even under the assumption of free curtailment.[29]

3.4. Selected results for the 2050 scenario

Complementary to the NEP simulations, I present selected results for a long-term outlook to 2050. Assuming a flexible system, Fig. 10 shows load-duration curves of surplus generation for the means of all combinations of meteorological years as well as for the largest and smallest yearly surpluses.[30] Surplus generation occurs on average during 1707 hours of the year, or 19% of all hours. Mean overall surplus energy is nonetheless rather small with around 18 TWh, corresponding to around 4% of yearly demand. Peak surplus power also increases only slightly compared to B 2032 and reaches 53 GW on average. Under the assumption of 20 GW must-run and inflexible biomass, surpluses would occur in 8004 hours (91% of all hours). Surplus energy would also increase drastically to 195 TWh (47% of yearly demand) with a peak of 89 GW. Accordingly, assumptions of high thermal must-run requirements and inflexible biomass appear to be inconceivable in a 2050 scenario. A perfectly flexible system is thus assumed in the following.

Fig. 11 shows storage investments for the 2050 scenario, again for the means of all combinations of wind and PV data and for the two extreme combinations. Mean storage investments increase for all levels of curtailment compared to 2032. What is more, the share of seasonal storage increases because connected surpluses are larger. In a flexible system, around 10 GW of storage are optimal on average even in case of free curtailment.[31] Renewable curtailment accordingly is no longer the least-cost option, and some level of storage investment no longer has to be enforced. The main reason for this finding, aside from increased surpluses, is the much higher cost of fossil generation compared to the NEP scenarios.[32] In addition to around 3 GW of daily storage, nearly 7 GW of seasonal storage are optimal in case of free curtailment. There is nonetheless curtailment of around 40 GW in the peak surplus hour. If curtailment is restricted to 1% or 0.1% of the yearly generation of non-dispatchable renewables, average storage requirements increase to 16 GW or 37 GW, respectively. If no

[28] Storage requirements vary for different combinations of meteorological years because of the underlying variations of surpluses discussed above. The lower extreme value is generally much closer to the mean than the upper extreme value, reflecting the fact that extremely large surpluses only occur for very few combinations of wind and PV years.

[29] The only exception is A 2022, in which the (linearly interpolated) target of 38% is narrowly missed. This finding is in line with the findings of a meta-analysis carried out by Dena (2013), which concludes that electricity storage is of relatively minor importance for achieving renewable and emission targets in Germany.

[30] I select the largest and the smallest surplus in terms of overall energy, not regarding peak surplus. The largest surplus power in a single hour is 64 GW in the flexible case and 100 GW in the inflexible case.

[31] The figure shows specific costs of avoided curtailment only for the cases in which curtailment is actually restricted. In other words, it shows the specific costs of forced storage investments beyond the level that would be optimal in case of free curtailment.

[32] Additional simulations show that peak load could also be met without additional storage capacities, but at higher costs.

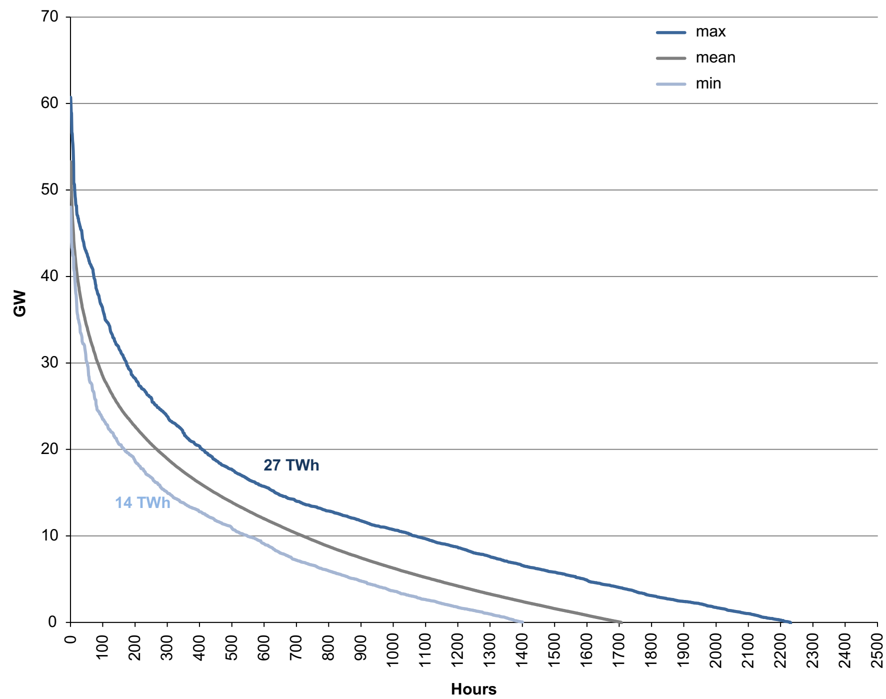

Fig. 10. Load–duration curves of surplus generation 2050 (no must-run, bio flexible).

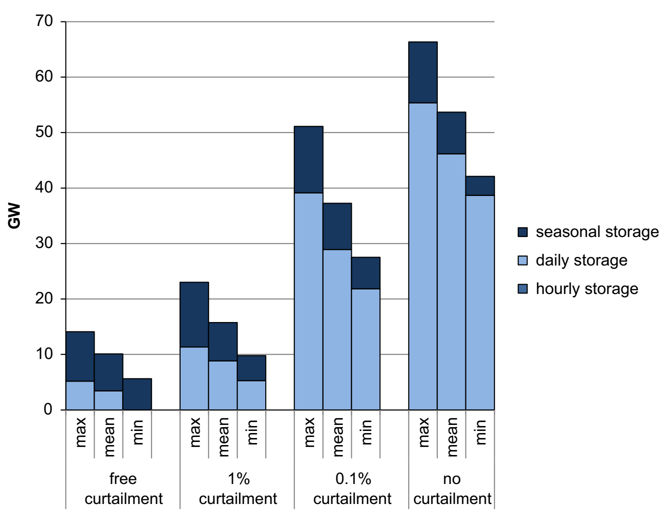

Fig. 11. Storage investment 2050 (no must-run, bio flexible).

curtailment is possible at all, 54 GW of storage are required, of which around 7 GW are seasonal storage. Renewable shares in overall power consumption are hardly affected by forced storage investments compared to the case of unrestricted curtailment. The mean value in the case of free curtailment is 95%; it is increased by a little more than 1 percentage point to nearly 97% in case of full surplus integration.[33]

4. Discussion of limitations

The simulations have been carried out under a range of simplified assumptions in order to make room for a large number of sensitivities. In the following, I briefly discuss the effects on simulation outcomes. I start with a discussion of such assumptions that lead to an underestimation of surpluses and/or storage requirements, followed by a discussion of factors resulting in a respective overestimation. It is uncertain which factors prevail.

First, I disregard local network constraints within Germany by implicitly assuming that transmission networks will be expanded according to NEP (2012), such that possible local surplus events are neglected. In recent years, local curtailment due to network constraints was small, but tended to grow (74 GWh in 2009, 127 GWh in 2010, 421 GWh in 2011 and 385 GWh in 2012, Bundesnetzagentur and Bundeskartellamt, 2013). According to EWI (2013), congestion-related renewable curtailment may increase up to 8 TWh by 2022 if networks are not extended as planned. Second, the linear dispatch model neglects flexibility constraints of thermal generators.[34] In particular, start-up and ramping are considered to be both costless and perfectly flexible. More realistic assumptions on power plant flexibility may result in higher surpluses as well as larger storage investments. Third, I do not endogenously determine optimal generation capacities, but draw on exogenous NEP capacities, which are sufficient to satisfy demand in all hours. Accordingly, the potential capacity value of additional storage for supplying peak load is not captured. A similar interpretation is that storage cannot benefit from scarcity prices. Storage's capacity value could in principle be captured in a dynamic modeling framework with endogenous generation capacities. Fourth, it is assumed that the thermal must-run requirement can be decreased to 10 or even 0 GW without specifying, for example, how ancillary services are to be provided. Although the optimal provision of ancillary services in power systems with high shares of fluctuating renewables remains a question for further research, it appears reasonable to assume that electricity storage facilities could provide at least a share of these services while still taking up renewable surplus generation. This contributes to a

[33] Renewable shares are larger compared to DLR et al. (2012) mainly because of neglected combined heat and power generation in plants fired with hard coal and natural gas.

[34] To a certain degree, flexibility restrictions are approximated by the system-wide must-run constraint, as explained in Section 3.1.

possible underestimation of optimal storage investments in the model. Finally, I do not consider any costs of curtailment related to the institutional framework, for example financial compensation of renewable generators. Including such costs should tend to decrease curtailment and increase optimal storage investments. Currently, renewable generators in Germany are compensated in case of curtailment; however, the future development of the institutional framework is uncertain.

Other simplified assumptions have an opposite effect, i.e., lead to an over-estimation of surpluses and/or storage investments. For example, the linear scaling of historical feed-in patterns of fluctuating renewables neglects adjustments in generator design or site choices, which are expected to align feed-in patterns somewhat better with power demand. Examples are improved orientation of solar PV panels in east-western direction or changed generator design of wind turbines which results in relatively lower peak generation, but higher full-load hours. Because of such improvements, which may be triggered by future market integration of RES, future surplus power tends to be overestimated in this study.[35] Likewise, the permutation of different yearly availability factors of onshore wind, offshore wind and PV together with load data from 2010 may result in exaggerated surplus power, connected surpluses and storage requirements. Generation from wind and PV tend to be negatively correlated as very windy days generally coincide with a higher cloud cover, hence lower PV feed-in. There may also be some level of correlation between wind feed-in and load. Next, including network fees for storage facilities would reduce storage investments. There is currently a high regulatory uncertainty in Germany regarding the future development of network fees and surcharges attributable to power drawn from the grid by storage facilities (Dena, 2014). A major overestimation of storage requirements originates from the fact that other flexibility options are neglected, in particular demand-side management, future electric vehicle fleets, the use of electricity in the heat sector (power-to-heat), and the possibility of exchanging power with neighboring countries. In the medium to long run, all of these options are capable of taking up a sizeable share of temporary surpluses and thus reduce electricity storage requirements. Of these, power-to-heat appears to be particularly promising, as investment costs of electric heating elements are low (VDE, 2012a). Moreover, surpluses can be exported to other countries on a large scale. According to ENTSO-E (2013b), the average simultaneous net transfer export capacity (NTC) from Germany to the Netherlands, France and Switzerland is around 8.5 GW (2010 data). In addition, there are interconnections with other neighboring countries. Even if the capacity that can actually be utilized in any given hour may be smaller than this NTC value, there is large room for exports. Furthermore, cross-border capacities will increase in the context of European power market integration.

5. Conclusions and policy implications

I have analyzed the effects of future renewable expansion in Germany on residual load and renewable surplus generation for policy-relevant scenarios which cover the years 2022, 2032 and 2050. Moreover, I have determined how much storage would be required for taking up renewable surpluses for varying levels of accepted curtailment. The study makes extensive use of historical renewable feed-in data and includes numerous sensitivity analyses, particularly regarding must-run requirements and the flexibility of biomass generators.

The expansion of fluctuating renewables only has a small effect on peak residual load, but leads to a strong decrease of the right-hand side of the residual load curve. In a system without thermal must-run and with flexible biomass generation, residual load becomes negative during 5% of all hours of the year in 2032. In a less flexible system with a must-run requirement of 20 GW and inflexible biomass generation, this value increases to 40% of all hours. By 2050, surpluses would occur during 19% of all hours assuming a flexible system, and during 91% of all hours assuming an inflexible system. Accordingly, there is no room for thermal must-run in a scenario with renewable shares above 80%. Maximum and minimum gradients of hourly residual load also become much more extreme with increasing amounts of fluctuating renewables. Accordingly, flexibility of the supply side and/or demand side has to increase substantially. The load-duration curves of renewable surplus generation generally have a very steep shape, with high peaks of surplus power and low full-load hours over the whole year. The distribution of connected surpluses has a very long right tail. In most scenarios, the energy of connected surplus events is substantially larger than the existing German pumped hydro capacity. The choice of historic feed-in patterns strongly influences the extreme values of residual load and surpluses. This should be taken into account in any analysis that deals with projections of residual load or surpluses in power systems with large shares of renewables.

The analysis of optimal storage investments—which abstracts from additional values of storage related to the provision of firm capacity and ancillary services—shows that no additional storage is required in any NEP scenario if curtailment is not restricted. In contrast, full surplus integration would require additional storage capacities of 4, 12, 26 and 41 GW in the four NEP scenarios, as even very large and rare surplus events would have to be integrated. Storage requirements grow and comprise larger shares of seasonal storage under the assumption of increasing thermal must-run requirements and limited biomass flexibility. In the case of free curtailment, storage investments are justified under model assumptions only in the 2050 scenario, in which around 10 GW of storage are triggered by larger surpluses and higher costs of fossil generators. Whereas storage investments are generally larger in 2050 compared to the 2022 and 2032 scenarios, the share of seasonal storage is also higher. The effect of curtailment on the shares of renewable energy in overall power consumption is negligible under the assumption of a flexible system in all scenarios. Curtailment does not impede achieving the German government's RES targets in the scenarios analyzed here.

Based on the simulations presented in this paper I draw conclusions that are not only relevant for Germany's '*Energiewende*', but also for other countries shifting towards fluctuating renewables. First, I conclude that renewable surpluses can be minimized by decreasing must-run requirements of thermal generators and by enabling biomass to generate power in a more demand-oriented way. Thermal must-run, which may be caused by economic or technical factors or related to the provision of ancillary services, can be diminished, for example, by retrofitting existing plants such that lower minimum load levels or faster start-up are enabled. Likewise, combined heat and power generation should become more flexible, for example by coupling such plants with heat storage facilities. Further, must-run can be decreased if ancillary services are provided by renewable generators, storage facilities and/or the demand side. This may require changes in reserve market rules. Generation from biomass could become more flexible by increasing the power rating of these installations, coupled with sufficient biogas storage capacities. In the context of growing shares of fluctuating renewable energy, increasing system flexibility should thus become a priority for policy makers. Different energy storage technologies may contribute to such flexibilization.

[35] I thank an anonymous reviewer for pointing out that, at the same time, overall surplus energy may possibly be underestimated because of higher full-load hours of renewable generators.

In case of very large RES shares, and if the system is already sufficiently flexible, electricity storage becomes more relevant. This is indicated by at least 10 GW of storage investments in the flexible 2050 scenario. I however conclude that full surplus integration by means of electricity storage will never be optimal even in a perfectly flexible system because of the nature of surpluses shown in this paper. Taking up the highest peaks and the greatest connected energies of renewable surpluses would require very large storage capacities both in terms of power and energy. At the same time, storage facilities of such dimensions would achieve few full-load hours over the whole year.

While only curtailment and electricity storage are considered in this analysis, there is much room for other flexibility options between these two extreme approaches. In particular, surpluses can be exported, i.e., balanced over a larger geographic area. Moreover, there are large low-cost potentials for using renewable power surpluses in the heat sector. Other flexibility options such as demand-side management and grid-connected electric vehicles may also play a role in the medium to long term.

As a guideline for policy makers concerned with excess renewable generation, I suggest (i) avoiding renewable surpluses by making thermal generators more flexible in the first place, (ii) making use of different flexibility options for the remaining surpluses, including but not limited to electricity storage, and (iii) making use of curtailment to cut the highest peaks of surplus power. Given these multiple options of handling temporary excess generation, concerns about surpluses should not be regarded as an obstacle to further renewable expansion. As for technology policy, I propose focusing on research and development of energy storage technologies instead of demand-pull measures such as investment grants or low-interest loans for the time being, as the analysis indicates that substantial deployment of storage is required only in the long run.

Several questions remain for future research, in particular regarding the optimal mix of storage, curtailment and other flexibility options. Examining the interaction of different energy storage technologies with network expansion, thermal plants and power-to-heat appears to be a particularly promising field of research. Moreover, the full system value of storage technologies should be investigated, including their capacity value and the provisions of ancillary services. To do so, sufficiently detailed power sector models are to be applied, which should not only include a realistic representation of the flexibility constraints of thermal power plants, but also restrictions related to the provision of ancillary services.

Appendix

See Table 5.

Table 5
Sets, indices, parameters and variables.

Sets and indices	Description	Units, allowed values or instances
$t \in T$	Time	Hours
$tech \in TECH$	Conventional technologies	Nuclear, lignite, hard coal, natural gas, oil, other
$stor \in STOR$	Storage technologies	Daily, hourly, seasonal
Parameters		
$allowcurt$	Allowed curtailment factor	Between 0 and 1
$\overline{bio}$	Biomass capacity constraint	MW
dem_t	Hourly demand	MWh
$epratio_{stor}$	Energy-to-power ratio	MWh/MW
η_{stor}	Roundtrip efficiency	Between 0 and 1
$hydro_t$	Hourly generation from	
ic_{stor}	Storage investment costs	€/MW
$mustrun$	Aggregated must-run requirement	MW
pv_t	Hourly generation from PV	MWh
$\overline{q}_{tech}$	Capacity constraint for conventional generation	MW
$\overline{storin}_{stor}$	Initial storage charging power	MW
$\overline{storlevel}_{stor}$	Initial storage capacity	MWh
$\overline{storout}_{stor}$	Initial storage discharging power	MW
vc_{tech}	Variable costs of conventional generation	€/MWh$_{el}$
$vstc_{stor}$	Variable costs of storage	€/MWh$_{el}$
$windoff_t$	Hourly generation wind onshore	MWh
$windon_t$	Hourly generation wind onshore	MWh
$\overline{yearlybio}$	Yearly energy constraint for biomass generation	MWh
Variables		
bio_t	Generation from biomass	MWh
$cost$	Total cost	€
inv_{stor}	Storage investment	€/MW
$q_{tech,t}$	Hourly generation from conventional plants	MWh
$rencurt_t$	Renewable curtailment	MWh
$storin_{stor,t}$	Storage loading	MWh
$storlevel_{stor,t}$	Storage level	MWh
$storout_{stor,t}$	Storage discharging	MWh

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