VDE Study

Storage facilities for the energy turnaround

Storage requirements and effects on the transmission network for scenarios up to 2050

ETG

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Authors

ETG Task Force on Energy Storage

Dr. Franziska Adamek, formerly ETH Zurich (Federal Network Agency since 2012)
Thomas Aundrup, RWE Westfalen-Weser-Ems Netzservice GmbH
Wolfgang Glaunsinger, VDE|ETG
Dr. Martin Kleimaier, Consultant
Hubert Landinger, Ludwig-Bölkow-Systemtechnik GmbH (LBST)
Dr. Matthias Leuthold, RWTH Aachen (ISEA)
Benedikt Lunz, RWTH Aachen (ISEA)
Univ.-Prof. Dr.-Ing. Albert Moser, RWTH Aachen (IAEW)
Dr. Carsten Pape, Fraunhofer IWES Kassel
Helge Pluntke, Technical University of Kaiserslautern
Niklas Rotering, RWTH Aachen (IAEW)
Univ.-Prof. Dr.-Ing. Dirk Uwe Sauer, RWTH Aachen (ISEA)
Prof. Dr.-Ing. Michael Sterner, Regensburg University
Univ.-Prof. Dr.-Ing. Wolfram Wellssow, Technical University of Kaiserslautern

Imprint

VDE ASSOCIATION FOR ELECTRICAL,
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Power Engineering Society within VDE (ETG)
Stresemannallee 15 · 60596 Frankfurt am Main
Phone +49 69 6308-346 · Email etg@vde.com · http://www.vde.com/etg

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Storage requirements and effects on the transmission network for scenarios up to 2050

Study by the
Energietechnische Gesellschaft im VDE (ETG)

Summary of findings

Contents

1 Scope

The abandonment of nuclear energy by the year 2022 and the expansion of generation from renewable energy sources to cover a share of at least 80 % in gross power generation, which is to be achieved by the year 2050 according to the German government's "Energy Concept 2050", are central components of the energy turnaround. In the year in which the "Energy Concept 2050" was adopted, the share of renewables was around 17 %. According to that plan, a renewables share of 40 % is to be achieved in the impending decade.

The intended expansion of renewables is to be based for the most part on expansion of onshore and offshore wind power and photovoltaic systems. The "2010 Long-Term Scenarios" of the Federal Ministry of the Environment (BMU) which were compiled for the ministry by a consortium comprising DLR, Fraunhofer IWES and IfNE, predict for example that the volatile and supply-dependent generation of electricity from wind and solar energy will account for around 75 % of generation from renewables in the year 2050.

Such large proportions of volatile and supply-dependent generation place major technical challenges on the German power supply system, extending from system stability, security of supply and expansion of the transmission and distribution networks to the central issue of balancing generation and consumption.

Such balancing requires flexibility in the electricity supply system, which can fundamentally be provided by energy storage facilities, flexible thermal power plants, flexible consumers (demand side management) and controllable renewables systems. The study therefore addresses the question of what storage capacities are required for balancing of future renewables-dominated generation systems, taking account of the flexibility of the remaining portfolio of thermal power plants and the preparedness to flexibilize feed-in from renewables.

The reference year is 2010 (share of renewables 17 % with the renewables capacities at the start of 2010), and the study considers the long-term renewables expansion target of 80 % (80 % scenario, year 2050), but also the short-term renewables expansion target of 40 % (40 % scenario, year 2020 – 2025) and prospects above and beyond the "Energy Concept 2050" of a possible renewables expansion target of 100 % (100 % scenario).

In addition, this study analyzes the effects of adding and using storage facilities on the operation of the transmission network and its expansion.

The study disregards the need for expansion of and storage facilities in the distribution network, and the various aspects of system stability to which storage facilities can also contribute. A VDE study, "Energy storage in power supply systems with a high share of renewable energy sources" in 2009 identified the possible applications in this respect: These extend from balancing power through voltage quality, bottleneck management, voltage stability, network stability and supply quality to network splitting.

The VDE study from 2009 has also shown that various technical solutions for storage facilities are available and either already suitable for use in power supply systems or can be expected to reach an adequate level of technical development. These storage technologies range, with a view to the balancing function, from pumped storage power plants, compressed air reservoirs, chemical storage in hydrogen or methane via power-to-gas and various battery technologies, to demand side management. The technological conclusion of the VDE study from 2009 is that there is no optimum storage technology. In principle, therefore, the storage technologies can be divided into two classes:

- **Short-term storage facilities** with high cycle efficiency (≥ 75 %) but small storage volume, such as pumped storage power plants, compressed air reservoirs, batteries and demand side management.
- **Long-term storage facilities**, to date with low cycle efficiency (≤ 40 %) but large storage volume, such as chemical storage as hydrogen or methane (power-to-gas).

For that reason, the present study, "Storage facilities for the energy turnaround" considers the technology of the storage facilities in the abstract and examines the storage requirement of the electricity system separately for the classes of short-term and long-term storage facilities, for which representative values of cycle efficiency and storage volume are assumed.

2 Methods adopted

Figure 2.1 shows the methodology adopted in this study. The starting point is a consideration of different variants of added storage and the storage classes selected for them, with the findings on storage requirements derived from a comparison of these:

- **Variant A**: The flexibility for balancing is provided by thermal power plants and a reduction of generation from renewables. No further storage facilities are added to those already in existence.
- Variant B: The flexibility is provided by thermal power plants and added short-term storage facilities. The scope of this added storage reflects the actual operationally usable potential (full addition).
- **Variant C**: The flexibility is provided by thermal power plants and a full addition of long-term storage facilities.
- **Variant D**: The flexibility is provided by thermal power plants and a full addition of short-term and long-term storage facilities.
- **Variant E**: The flexibility is provided by thermal power plants and a storage facility portfolio consisting of short-term and long-term storage facilities with storage capacity halved in relation to variant D.

Short-term storage facilities are modelled in these variants with a cycle efficiency of 80 % and an energy to power ratio of 5 Wh/W; long-term storage facilities are modelled with a cycle efficiency of 40 % and unlimited storage volume.

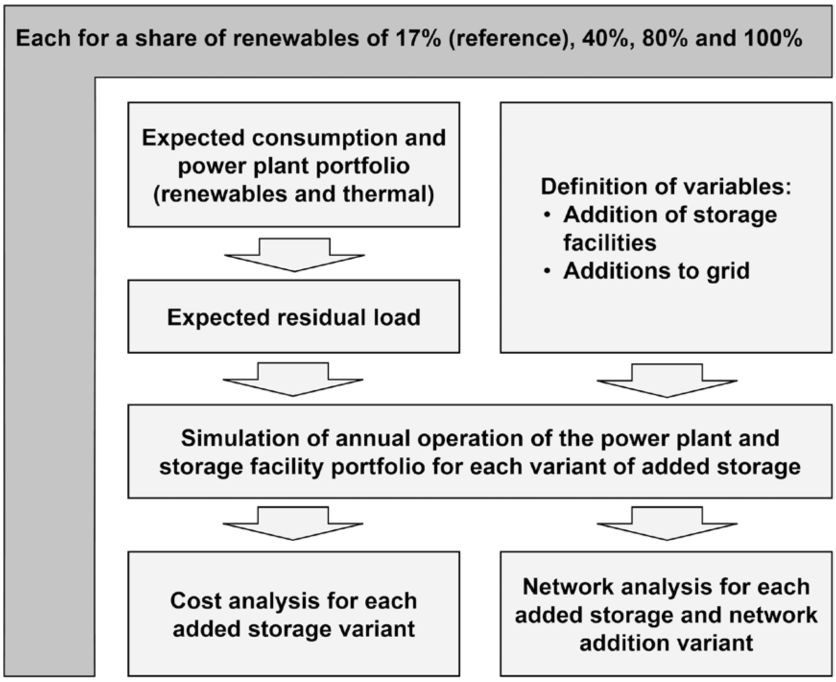
The addition of storage facilities always took place in the variants in addition to the pumped storage portfolio available in Germany in 2010, which consisted of a total pumping power of 7.2 GW, a total turbine power of 8.2 GW and a total storage volume of 48 GWh.

The central part of the analysis represents a simulation of the annual operation of the power plant and storage facility portfolio, drawing upon an established method in use at the Technical University of Aachen (RWTH). For a given curve of residual load, corresponding to load minus feed-in from renewables, this method indicates the minimum-cost deployment of storage facilities and power plants for each hour of the year on which it is based. The important additional results of this analysis step are the storage volumes used, the reduction in renewables generation, the primary energy consumption and the CO_2 emissions.

The load curves for feed-in from renewables are derived using a tried and tested model established by Fraunhofer IWES Kassel from the renewables systems expected to be installed in future in the “2010 Long-Term Scenarios”, their geographical distribution and high-resolution weather data from the German meteorological office’s COSMO-EU model.

The cost analysis evaluates the results of the annual operation simulation, and calculates the capital and operating costs of the storage facilities and the total electricity production costs on that basis. The cost analysis of the short-term and long-term storage facility portfolios is based on a more detailed storage model from RWTH Aachen which takes account of a service life dependent on use and, with real dimensioning, also the permissible depths of discharge.

Figure 2.1: Methodological procedure



Similarly to the procedure for determining the need for added storage facilities, an increasing expansion of the German transmission network is also considered in five variants. A model developed by the Technical University of Kaiserslautern is used. An the basis of the actual condition in the year 2010, a network development takes place for the requirements in the scenarios for an expansion of renewables to 40 % and 80 %. This reflects the currently valid version of the German Energy Line Extension Act and recognized network studies by Deutsche Energieagentur GmbH (Dena), and is supplemented by our own proposals for expansion of the grid. In order to specify the influence of added storage facilities on the transmission network, the locations for the storage facilities are chosen at two extremes, once at load nodes in proportion to the load (LOAD variant) and once at renewables feed-in nodes in proportion to the renewables feed-in (REN variant). The subsequent network analysis evaluates the network expansion variants with the aid of load flow calculations and failure simulations, drawing on the use of power plants and storage facilities indicated in the simulations of annual operation.

3 Assumptions and input data

Every study, and therefore also this VDE study on “Storage facilities for the energy turnaround”, makes assumptions and uses input data which are important to know in the interpretation and classification of the results. In this case, these are the following:

- The future requirement for energy storage will essentially be determined by its balancing function. Further storage functions such as controlling power, voltage quality, bottleneck management, voltage stability, network stability and supply quality ranging up to network splitting are additional functions or of subordinate importance with regard to the demand for power and energy, and are not therefore taken into account.
- The future deployment of storage facilities and power plants for the purpose of (energy management) balancing will be controlled according to the principles of the electricity markets in place today, which lead to minimized variable electricity production costs.
- In the determination of storage requirements in the annual operating simulation, the electrical grid is first considered as a “copper plate” (point model). The study assumes that the requirements of the electrical grid will lead neither to forced deployment of power plants or storage facilities nor prevent the use of power plants or storage facilities. In consequence, it is assumed that there will be sufficient expansion of the grid, the scope of which is determined for the transmission network in the course of the network analyses, and sufficient technical alternatives in the grid for the provision of system services with the exception of reserve power.
- Load curves with a resolution of one hour are considered in the study, corresponding to the balancing function under consideration.
- Complete annual load curves are considered, so as on the one hand to cover annual cycles of the weather-dependent energy sources of wind and solar energy, and on the other hand to include situations relevant to dimensioning, such as relatively long periods of calm or extreme weather situations such as storms. The study is based on the weather year 2007 which contains both extremes. A consideration of other weather years may possibly lead to slightly different results.
- As this study focuses on the German requirement for energy storage, driven by the expansion of generation from renewables in Germany, the system under consideration is “Germany only”, i.e. neither imports nor exports of electricity for balancing of the German system are assumed. The resulting demand for storage identified does not however necessarily have to be satisfied by storage facilities in Germany, and could be covered by storage facilities abroad if sufficient network capacities are available.

- The study assumes a nationally determined security of supply. This means that there are always a sufficient number of power plants available to cover the loads of consumers and the reserve requirements of the transmission network operators in Germany at all times. The portfolio of power plants is therefore only partly an input parameter, and is partly also a result of this study.
- The study only considers the electricity supply system. Links with other energy systems such as mobility, heating or natural gas supply are not taken into account beyond the consideration of the short-term and long-term storage facilities, the combined heat and power plants and the demand-related consumption of electrical heat pumps, electric vehicles and air conditioning systems.
- The input variables for the expected installed generation capacity and load are taken from the data framework provided by the “2010 Long-Term Scenarios”, which are updated each year and serve as an accepted basis for the energy market development of the electricity sector.
- Generation and load have only been modified in deviation from the “2010 Long-Term Scenarios” to such an extent that there is no import of electricity generated from renewables from the European interconnected network grid and no major industrial use of wind or solar-powered electrolysis for manufacture of a chemical fuel such as hydrogen or methane as a substitute for natural gas.
- Apart from the power plants in the “2010 Long-Term Scenarios”, additional power plants may be required to ensure the security of supply. It is assumed in this study that the gas-fired power plants expected in the “2010 Long-Term Scenarios” and those required for withdrawal from the long-term storage facilities will be implemented as combined cycle plants, and that all gas-fired power plants required above and beyond those to ensure the security of supply will be implemented as gas turbines.
- The 100 % scenario was derived from the 80 % scenario in a simplified procedure in which the demand for electricity was kept constant and the generation from renewables escalated to 100 % of the load.
- The curve for load with the exception of network losses, electric vehicles, air conditioning and heat pumps is oriented towards the load curve for 2007 published by ENTSO-E. The load curve for electric vehicles, air conditioning and electrical heat pumps was mapped on a pure user basis, drawing upon data on time series for heat demand and use of mobility.
- The amount of reserve power to be made available to the transmission network operators by the power plants and storage facilities, and which is therefore not available for balancing functions and has to be taken into account accordingly in the calculation of the storage requirement, is determined with the aid of a standard probabilistic

method which takes account both of errors in forecasting of feed-in from renewables and of power plant downtimes.

- CHP plants (biomass and fossil) are only deployed with limited flexibility in the annual operating simulation. They are assumed to be operated in response to demand for heating, but can – assuming existing booster burners – reduce the amount of electricity they produce. An increase in electricity production over and above the heating requirement is not possible.
- The fuel prices assumed in the annual operating simulation reflect those of the “2010 Long-Term Scenarios”.
- Calculation of the annuities of investment costs is uniformly based on an imputed interest rate of 9 % and depreciation over the service life of the power plant, renewables system or storage facility.
- The investment costs of power plants and renewables systems assumed in the cost analysis reflect the “2010 Long-Term Scenarios”, supplemented where appropriate by experience values from previous studies of the energy sector by RWTH Aachen.
- The investment and operating costs of storage facilities reflect the VDE study on “Energy storage in power supply systems with a high share of renewable energy sources”, supplemented where appropriate by experience values from RWTH Aachen.
- The cost analysis assumes a mix of storage facilities whose overall efficiency approximately corresponds to the values assumed in general for the short-term and long-term storage facilities. A mix consisting of demand side management, pumped storage, compressed air reservoirs and various battery technologies is considered as a short-term storage facility. The costs of long-term storage facilities are assumed to be those of chemical storage facilities based on hydrogen, which however, without considering the costs of necessary modifications to the gas infrastructure, do not deviate significantly from those of facilities based on methane.

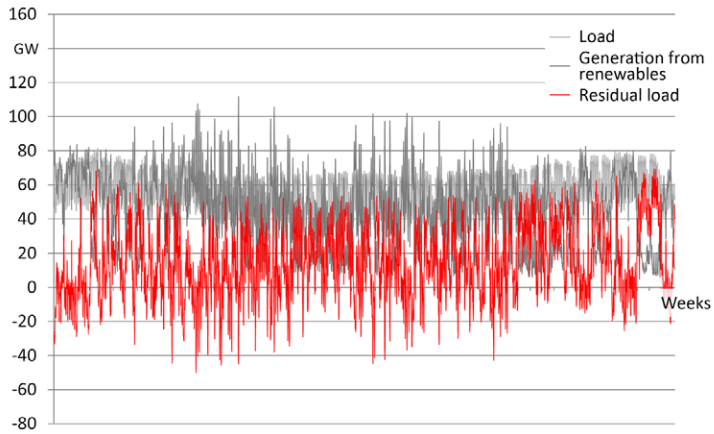
4 Summary of findings

4.1 Finding 1: The equipment in the electricity system must be used more flexibly.

The future addition of renewables systems will increasingly require greater flexibility in the energy system, on both the generation and consumption sides. In all variants studied, it was always possible to satisfy this demand for flexibility with the remaining power plant portfolio, by limiting the feed-in from renewables or by means of short-term and long-term storage facilities.

To date, electricity supply has been extensively based on stored fossil energy. Fluctuations have predominantly occurred on the demand side. With climate protection and scarcity of resources, the supply side will also exhibit significantly greater fluctuations due to the nature of energy from renewable sources. Accordingly, with the increasing expansion of renewables, the need for flexibility in the electrical power system will grow. This requirement can be determined by a statistical evaluation of the residual load (demand for electricity less feed-in from renewables) and covered by various options.
Figure 4.1 shows the development of the curves for load, generation from renewable energy sources (with the exception of biomass), and as the sum of these the residual load for the 80 % scenario. Three fundamental trends become apparent: With a growing share of renewables, volatility increases, the average falls and the number of hours with a generation surplus in the residual load rises.
In the 100 % scenario, the necessary excess installation of generation capacity from renewables causes generation surpluses of up to 80 GW, while the maximum residual load is only reduced by up to approx. 10 GW or 12.5 % in relation to 2010. The power bandwidth grows considerably.
There is a need for flexibility in both the short term (< 1 day) and long term (> 1 day). In all the variants examined in the study (A to E), it was always possible to satisfy this demand for flexibility in the short-term and long-term ranges by flexible deployment of fossil-fired power plants and CHP plants, by using the short-term and long-term storage facilities or by limiting the feed-in from renewables. In the course of this study, flexibility on the consumption side (demand side management) was regarded as a type of short-term storage.

Figure 4.1: Annual curve for load, generation from renewables and residual load in the 80 % scenario



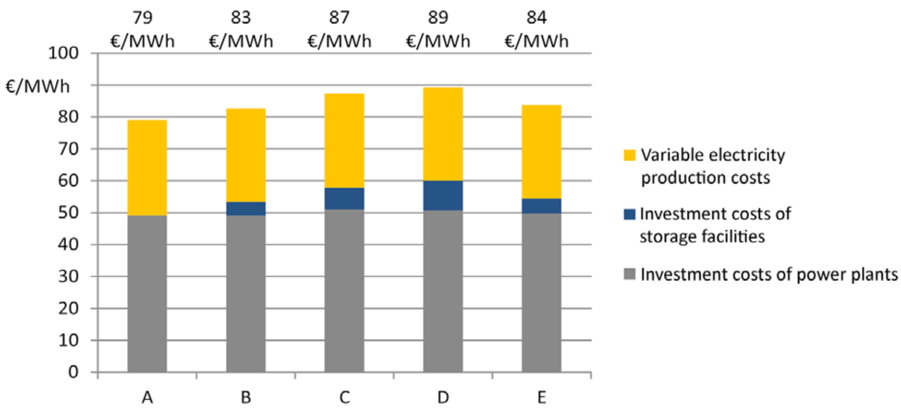
4.2 Finding 2: Up to a renewables share of 40 %, thermal power plants and a minor limitation of the feed-in from renewables can efficiently compensate for variable consumption and fluctuating generation.

Short-term and long-term storage facilities are not yet absolutely necessary for stable power supply with a share of 40 % of renewable energy sources. The use of the remaining portfolio of thermal power plants and a minor limitation of feed-in from renewables are a favourable way of providing the required flexibility.

At a renewables share of 40 %, addition of storage facilities increases the electricity production costs (variants B to E in figure 4.2). Electricity production costs must not be equated with electricity prices, which, in contrast to the costs, are influenced by price-fixing on wholesale markets and include network fees, levies and taxes.
At a renewables share of 40 %, with the assumptions made, storage facilities serve less to integrate feed-in from renewables, and more to optimize the deployment of the thermal power plants (see finding 3). The investment costs of the storage facilities then, however, slightly exceed the benefits in the variable electricity production costs, which are fundamentally fuel costs, which arise from more cost-effective deployment of the power plants.
Among the variants examined, the lowest electricity production costs arise in variant A, in which the flexibility necessary to balance generation and consumption is provided by a minor reduction in renewables generation from wind and PV of approx. 260 GWh/a (approx. one thousandth of renewables generation) and from biomass of approx. 530 GWh/a, by thermal power plants and by limiting output from the heat-led, fossil-fired CHP plants.

The reduction in renewables generation from wind, PV and biomass considered here refers only to reductions which are necessary to balance generation and consumption. The figures do not include reductions caused by insufficient development of the transmission or distribution networks.

Figure 4.2: Electricity production costs for different added storage variants (variants A to E) with a renewables share of 40 %



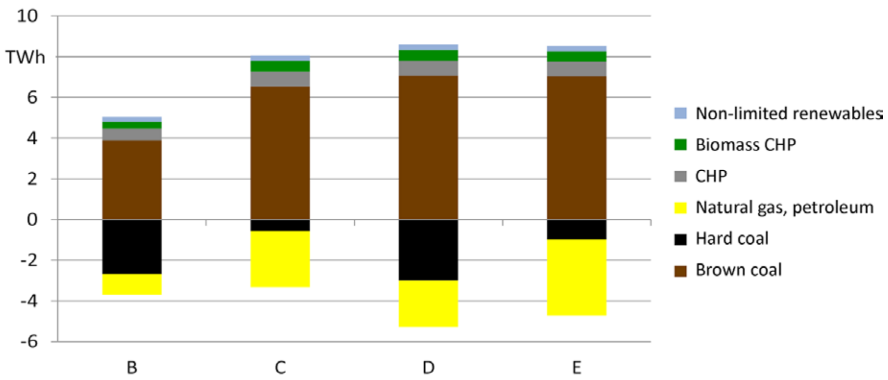
4.3 Finding 3: Up to a renewables share of approx. 40 %, only a small amount of storage facilities are required to store electricity from renewables.

If 40 % of gross electricity consumption is covered by renewable energy sources, negative residual loads, i.e. situations in which renewables generation exceeds consumption, only occur in around 44 of 8760 hours in the year. For this reason, storage facilities will in the near future predominantly serve to optimize the deployment of thermal power plants and less to store electricity from renewables.

In the 40 % scenario, under the assumptions made, the total energy generation surplus is merely 0.26 TWh/a. That corresponds to only around one thousandth of the total generation from renewables. The greatest negative residual load, at 9.8 GW for one hour, corresponding to the current output of around 10 nuclear power plants, is however relatively high. It was assumed in these analyses that the feed-in from the heat-led CHP plants fired by biomass, which is also included in renewables generation, can be reduced when there is surplus generation.
Accordingly, there is hardly any need in this scenario for storage of electricity from renewables. On the contrary, with a renewables share of 40 % storage facilities will – as today – predominantly be used to optimize the deployment of thermal power plants by smoothing out the residual load so that more of the less flexible power plants with lower generation costs, the so-called base load power plants, can be used.

The output from the storage facilities is not absolutely necessary in this scenario because the secured output from the conventional power plants is sufficiently high.
Figure 4.3 presents the results of the annual operating simulation of the portfolio of power plants and storage facilities for the added storage variants examined (variants B to E). In that figure, positive values can be interpreted as surplus generation and input into storage, and negative values as shortfalls in generation and withdrawal from storage. The effect of using the storage facilities in the 40 % scenario is therefore predominantly a displacement of natural gas and hard coal-fired power plants in favour of a stabilization of the brown coal-fired power plants.

Figure 4.3: Shifts in power generation as a consequence of different added storage variants (variants B to E) with a renewables share of 40 %

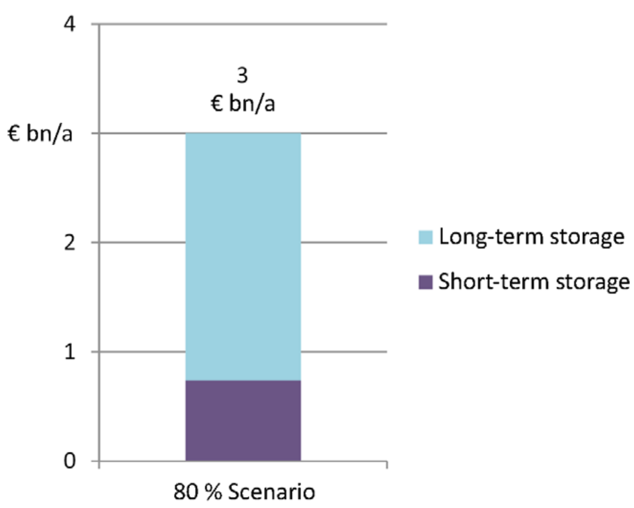


4.4 Finding 4: A combination of short-term and long-term storage and reduction in output from renewables plants is advisable.

With a renewables share of 80 %, an economically favourable electricity system requires around 14 GW or 70 GWh (5 hours) of short-term storage and approx. 18 GW or 7.5 TWh (17 days) of long-term storage in addition to the storage facilities available today.
The "2010 Long-Term Scenarios" are based on firm expansion targets for renewables in the 80 % scenario. Without added storage (variant A), however, generation from renewables in that portfolio would have to be reduced by approx. 30 TWh or approx. 7 %, with the result that this variant A would not meet the target of a renewables share of 80 % in gross electricity consumption and would only achieve a renewables share of 75 %. The calculations show that a dimensioning of storage capacity to use renewables generation in full and store all power peaks (variant D) does not appear sensible. On the contrary, a combination of storage and reducing the output from renewables plants (variant E) is recommended. With the halving of the theoretically required capacities of the short-term and long-term storage facilities as performed in that variant, renewables generation will have to be reduced, under the assumptions made, by less than 1 %.

The addition of short-term storage facilities in variant E with a power of 14 GW and a capacity of 10 GWh corresponds approximately to twice the currently available capacity of pumped storage power plants. For the cost calculation of short-term storage, the portfolio of storage facilities was assumed to comprise storage batteries (in particular lead-acid, lithium-ion and sodium-sulphur batteries), compressed air reservoirs, new pumped storage power plants and demand side management.
The long-term storage facilities with a power of 18 GW have a storage capacity of around 17 days, as a result of which only very large storage capacities come into question and the storage costs relative to energy must be low if a cost-effective solution is to be achieved. In Germany, therefore, only storage systems based on power-to-gas come into consideration. The two energy sources of hydrogen and methane are suitable and can be stored in dedicated caverns (predominantly hydrogen) or in the existing gas grid and gasometers (predominantly methane). Gas-fired power plants, distributed CHP systems or fuel cell systems are necessary for reconversion of the hydrogen or methane gas into electricity. In comparison with current gas consumption in Germany (approx. 850 TWh/a), the energy throughput in the long-term storage facilities is very low (approx. 16 TWh/a), in the region of less than 2 %. Storage facilities using hydrogen were used as the basis of the cost calculation, and, disregarding the costs of necessary modifications to the gas infrastructure, these differ very little in principle from those using methane.
Taking account of the cost reduction potential of the storage technologies, annuitized investment costs of approx. □ 3 bn/a can be estimated for the portfolio of facilities. Around 75 % of the costs are accounted for by the long-term storage facilities (figure 4.4). The costs of the withdrawal units for the long-term storage facilities (e.g. gas-fired power plants, fuel cells or CHP systems) are not included in the costs of the storage facilities, but in those of the power plant portfolio.

Figure 4.4: Apportionment of the annuitized storage costs to short-term and long-term storage facilities for the 80 % scenario (variant E)



4.5 Finding 5: Storage facilities should be dimensioned according to quantities of energy and not according to power peaks.

Limiting the rare but large power peaks from renewable energy sources is fundamentally more economical than dimensioning the storage facilities to accommodate those high power values. Research is to be performed in future into the optimum relationship between generation capacity, storage and limitation.

As a result of the limited number of full load hours from renewables, the “2010 Long-Term Scenarios” provide for the installation, even in the 40 % scenario, of wind energy and photovoltaic systems with a power over and above the maximum load of approx. 80 GW, at 98 GW. In the 80 % scenario, a total of 144 GW, and in the 100 % scenario even 191 GW of photovoltaic and wind energy systems are installed. Analyses of the residual load show, however, that large power peaks from renewables occur relatively seldom (figure 4.1). In the 80 % scenario, there are maximum surpluses of approx. 50 GW and maximum shortfalls of approx. 70 GW.

If the portfolio of storage facilities is dimensioned with the aim of making no reduction to output from renewables, annuitized investment costs of approx. □ 5.1 bn/a are required (table 4.1). If the storage capacities are reduced, for example, to around half of the original charging capacity in each case, around 400 GWh (approx. 0.1 % of total annual electricity consumption) in renewables output from wind and PV systems has to be throttled back. In contrast, however, the annuitized investments in the storage facilities are reduced by □ 2.1 bn/a. Furthermore, the energy throughput in the long-term storage facilities is not significantly lower, despite the reduction in capacity. This leads to considerably lower energy throughput costs and thus to greater cost-effectiveness.

It can be deduced from these observations that it is not appropriate to dimension the storage facilities to accommodate generation peaks. The optimum relationship between generation capacity, storage and output limitation, and the optimum relationship between input and output power at the storage facilities will have to be found in further studies.

Table 4.1: Comparison of the different degrees of storage expansion for the 80 % scenario; reduction in output from renewables disregarding network bottlenecks and network operation

	Reduced storage facility portfolio (Variant E)	**Storage facilities for full utilization of renewables (Variant D)**
Short-term storage facilities		
charging /	14 GW	28 GW
discharging power	14 GW	28 GW
energy	70 GWh	140 GWh
Long-term storage facilities		
charging /	18 GW	36 GW
discharging power	18 GW	36 GW
energy	7 TWh	8 TWh
Reduction in renewables energy from wind and photovoltaic systems	0.4 TWh/a	0 TWh/a
Annuitized investment costs of the storage facilities	□ 3 bn/a	□ 5.1 bn/a

4.6 Finding 6: With a renewables share of 80 %, short-term and long-term storage facilities are useful for climate protection.

From the point of view of climate protection, short-term and long-term storage facilities are not necessary under the assumptions made when the share of renewables is 40 %. On the regular electricity market, the use of storage facilities only leads to a reduction in CO_2 emissions of around 10 percent in addition to the total emission reduction of 85 % in the electricity system already achieved relative to 1990 when the renewables share is 80 %.

With a renewables share of 40 %, short-term and long-term storage facilities are only rarely used to store electricity from renewables, and predominantly to optimize deployment of the thermal power plants. The consequences are, on the one hand, increased production of electricity from fossil-fired, thermal power plants to cover the storage losses (cycle efficiency 40 % for long-term storage and 80 % for short-term storage) and, on the other hand, to a squeezing out of electricity production from natural gas and hard coal in favour of production from brown coal. The energy market optimization of the thermal power plants by means of storage therefore leads to CO_2 emissions which are up to 1.8 % higher than in variant A without added storage (see variants B to E in figure 4.6 with a renewables share of 40 %). With a renewables share of 80 % (figure 4.5), the storage facilities reduce the CO_2 emissions by up to 10 % – and that in addition to the considerable reduction attributed to the expansion of renewables. The reason is that at a renewables share of 80 % the storage facilities take in a considerable amount of electricity from renewables and replace fossil natural gas electricity when releasing it (figure 4.6).

Figure 4.5: CO_2 emissions with the added storage variants examined, with different shares of renewables

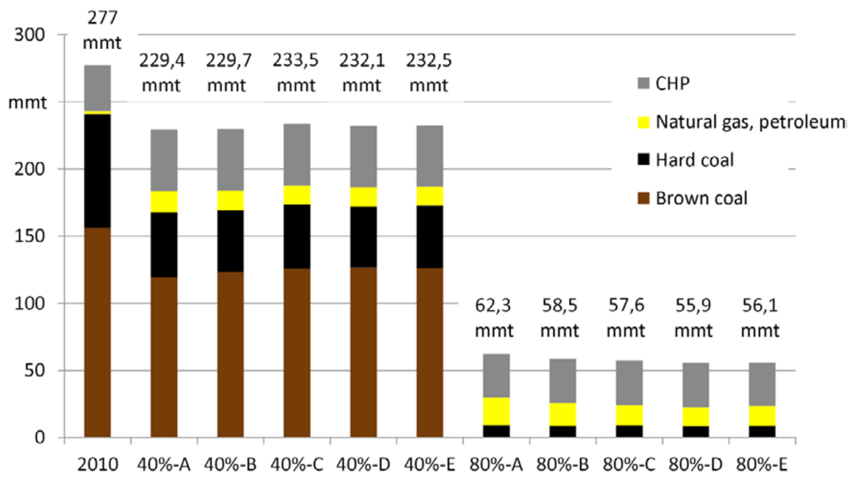
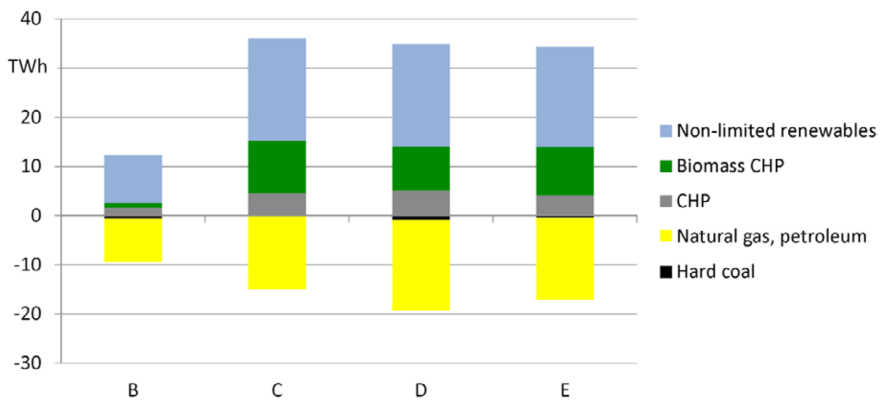


Figure 4.6: Shifts in power generation as a consequence of different added storage variants (variants B to E) with a renewables share of 80 %

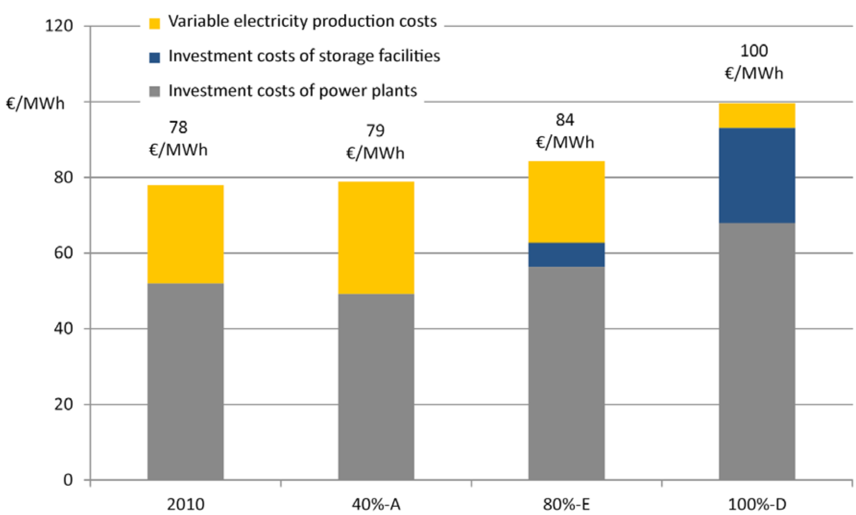


4.7 Finding 7: Electricity production costs will only rise by approx. 10 % in the energy turnaround up to 2050, even with the use of storage facilities.

With a renewables share of 80 %, the electricity production costs will only rise by approx. 10 % in comparison with the year 2010.

Figure 4.7 compares the electricity production costs in selected added storage variants with different shares of renewables. Electricity production costs must not be equated with electricity prices, which, in contrast to the costs, are influenced by price-fixing on wholesale markets and include network fees, levies and taxes.
The rise in installed capacity for renewables and the associated investment costs are opposed by a cost degression for renewables facilities, as taken from the Environment Ministry's "2010 Long-Term Scenarios" and used in this study for calculation of the electricity production costs. The "2010 Long-Term Scenarios" provide for a decrease in costs to 40 % for offshore wind turbines, to 33 % for PV systems and to 70 % for onshore wind turbines in the period between 2010 and 2050. In total, therefore, the electricity production costs arising from capital expenditure on the power plants only increase by a moderate amount.
With an increasing renewables share, the variable electricity production costs fall, because the share of thermal generation with variable costs falls until, with a renewables share of 100 %, essentially only the variable electricity production costs of biomass remain. The assumed rise in the costs of fossil primary energy cannot compensate for this effect.
All in all, as a consequence of expanding renewables to a share of 80 %, there remains a rise of 10 % in electricity production costs in relation to the reference year of 2010.

Figure 4.7: Electricity production costs for selected added storage variants with different renewables shares



4.8 Finding 8: On increase of the renewables share from 80 % to 100 %, the storage requirement triples.

If the share of renewable energy sources is increased from 80 % to 100 %, it will be necessary to triple the portfolio of short-term and long-term storage facilities. The electricity production costs will then rise by approx. 19 %. The last 20 % increase in the renewables share is more expensive than the increase of 63 % from 17 % in 2010 to 80 %.

The electricity production costs comprise the annuitized investment costs of the portfolio of power plants (thermal plants and renewables systems, and the withdrawal units for the long-term storage facilities), the annuitized investment costs of the portfolio of storage facilities, and the variable electricity production costs (fuel costs). The imputed interest rate used in this study is 9 %, and the depreciation period is assumed to equal the service life of the component in each case. The development of electricity production costs and their breakdown into investment and operating costs are shown in figure 4.7.
It can be seen that the electricity production costs in the 40 % scenario (variant A with no added storage) are approximately equivalent to those in the reference year of 2010. The electricity production costs in the 80 % scenario are around 7 % higher. In that context, the costs of the portfolio of storage facilities contribute approx. 8 % to the electricity production costs. The installed storage powers and capacities are shown in table 4.2.
With further expansion of renewables by 20 % to achieve complete supply from renewable energy sources, the portfolio of storage facilities also has to be correspondingly expanded. The short-term storage power and capacity are then 2.5 times greater, and the long-term storage power and capacity 3.5 times greater, than in the 80 % scenario. The electricity production costs rise by approx. 19 % in comparison with the 80 % scenario. The costs of energy storage then play a decisive role, as they account for approx. 25 % of the electricity production costs. In these calculations, the costs of the withdrawal units for the long-term storage facilities are included in the costs of the power plant portfolio. Necessary modifications to the gas infrastructure for long-term storage are disregarded.

Table 4.2: Portfolio of storage facilities in the 80 % and 100 % scenarios

	80 % Scenario (Variant E)	**100 % Scenario (Variant D)**
Short-term storage facilities (charging / discharging power / energy	14 GW / 14 GW / 70 GWh	36 GW / 35 GW / 184 GWh
Long- term storage facilities (charging / discharging power / energy	18 GW / 18 GW / 7 TWh	68 GW / 42 GW / 26 TWh
Annuitized investment costs of the storage facilities	□ 3 bn/a	□ 12 bn/a

4.9 Finding 9: Power plants and long-term storage facilities will continue to ensure security of supply in the future.

The remaining fossil-fired power plants and the withdrawal units for the long-term storage facilities – predominantly in the form of gas-fired power plants, fuel cell systems and CHP facilities – will in future form the backbone of security of supply. Up to a renewables share of 80 %, the installed generation capacity (power plants, central and distributed CHP) will always be around the magnitude of peak load.

If security of supply is to be preserved even in long periods of calm and low insolation, units with a high level of availability – fossil and biomass-fired power plants and CHP plants, withdrawal units for the long-term storage facilities operated with renewable sources, hydro power plants and geothermal power plants – are needed to supply the consumers at those times. Figure 4.8 shows the power plant and facility portfolio required for this security of supply with the added storage variants examined.

The declining trend from the reference year through the 40 % scenario to the 80 % scenario is attributable both to falling electricity consumption and to the associated reduction in peak load, and is also a result of the fact that there is excess capacity in the power plant portfolio of the reference year.

As the power to be provided by power plants does not significantly differ between variants A and B, it can be deduced that short-term storage facilities do not make a significant contribution to security of supply.

Long-term storage facilities, in contrast, make a considerable contribution to security of supply, as is revealed by a comparison of variant C with variant A: The required power from fossil gas power plants is reduced by around the amount in which there is power output from long-term storage facilities. In the 100 % scenario, the withdrawal units for the long-term storage facilities and the CHP plants are fired with renewable gas (hydrogen or methane).

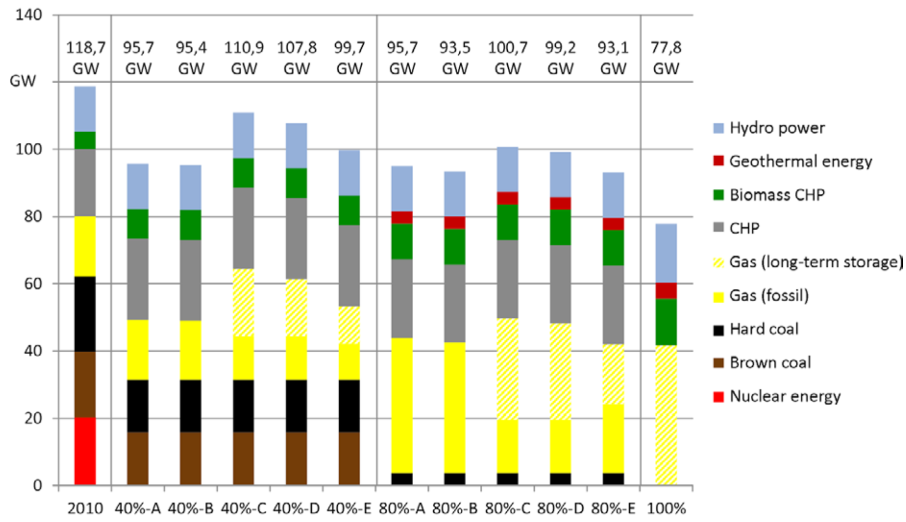


Figure 4.8: Necessary power plant capacities with high availability for different added storage variants and different renewables shares

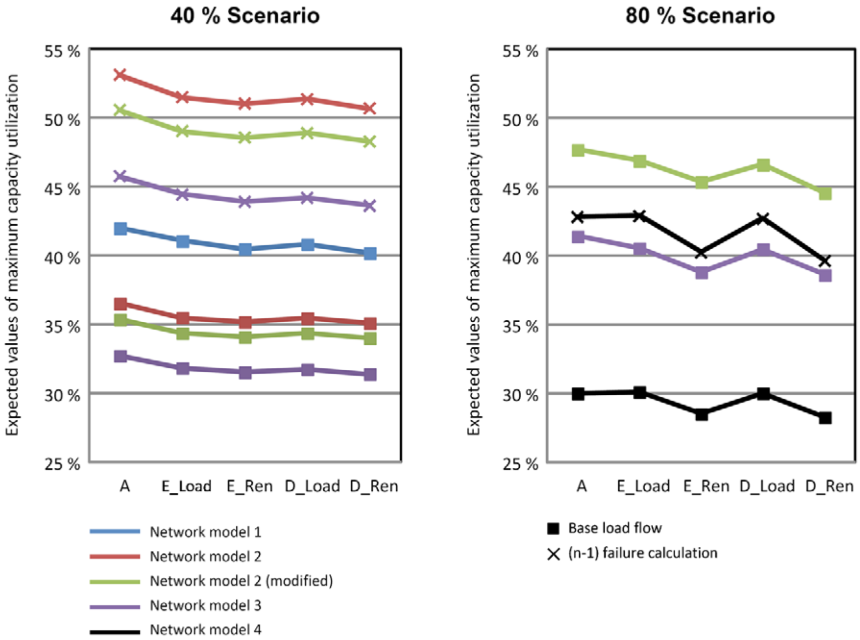
4.10 Finding 10: Disregarding network operation, storage facilities have hardly any effect on transmission networks.

The use of short-term and/or long-term storage facilities, to the extent that it takes place without regard to the condition of the network, does not lead to any significant increase or decrease in the stress on the network and therefore, disregarding different geographical locations for storage and withdrawal, does not have any effect on the required expansion of the transmission system.

The capacity utilization of network components is defined as the ratio of their operating current to their thermal current limit. In the course of the network analysis, the maximum capacity utilization of each network component (lines and transformers) was determined separately for the base and (n-1) cases along the annual time series, and the expected value calculated for each network and storage variant. The expected values of maximum component utilization for each of the network models examined in the 40 % and 80 % scenarios are presented in relation to the storage variant in figure 4.9.
Four network models representing different development variants of the German transmission system were developed in the course of the study. The increase in efficiency from network model 1 to network model 4 can be seen clearly from the associated drop in expected values. In the base case, network expansion reduces the expected value in the 40 % scenario by around 9 %, and by around 17 % for the variants examined in the 80 % scenario.
The storage facilities do of course bring about a reduction in the maximum capacity utilization of the network components, but their influence is minor. The expected values are only reduced by 1.4 % (absolute) in the 40 % scenario in the base case,. In the variants examined in

the 80 % scenario, the reduction is 2.6 % (absolute) on average. The optimized use of storage facilities for balancing of generation and consumption does not therefore lead in either scenario to a significant reduction of stress on the networks.
Fundamentally, though, storage operation opens up new opportunities in network operation, for instance in redispatching to avoid local network overloads or coupling with other energy networks such as gas or heating grids. These opportunities were not considered in this study.

Figure 4.9: Expected values of maximum component utilization in comparison



4.11 Finding 11: No preference for storage facility location close to load or close to generator.

Owing to the situation-dependent influence of the storage facilities on the transmission network, to the extent that storage is used without regard to the network condition and input to and output from storage are at the same location, no recommendation can be made for location of the storage facilities close to generators or close to loads.

Figure 4.10 presents examples of the system conditions determined as results of the (n-1) failure calculation in storage variant D_{Ren}. Each dot marks a pair of values from the total network load and the corresponding feed-in of power from wind and solar generation, each normalized to the maximum value. A green dot represents a permissible network operating condition, while a red dot indicates that at least one network component is in an impermissible operating condition. The network variant shown is therefore impermissible.

Three extreme areas in the clusters of dots are highlighted, and the numbers of impermissible system conditions in these are totalled for each storage variant in table 4.3.

Figure 4.10: System conditions in the 40 % scenario, network model 2, storage variant D_{Ren} (n-1)

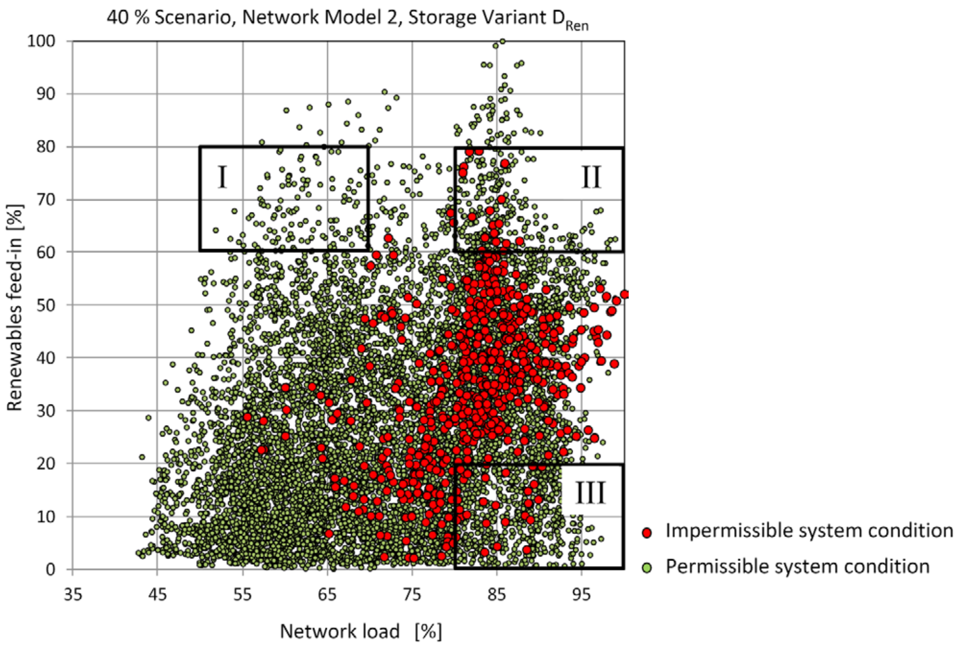


Table 4.3 shows that no generally valid statement can be made as to which of the storage facility location variants is more beneficial. Depending on the situation, one or the other location has the effect of reducing the stress on the network. With the storage facilities located close to generators in D_{Ren} and E_{Ren} in this example, all impermissible system conditions in area I (high renewables feed-in and low load) are eliminated as the power generated is stored directly without having to be transmitted through the network.

Table 4.3: Impermissible system conditions per area in the 40 % scenario, network model 2, all storage variants

	Number of impermissible system conditions			
	Per area			Total
	I	II	III	
A	15	9	57	594
E_{Load}	8	29	26	572
E_{Ren}	0	21	34	565
D_{Load}	9	28	21	579
D_{Ren}	0	18	29	558

In contrast, however, the same allocation leads in area III (low renewables feed-in, high load) to a higher number of impermissible system conditions than with location close to the load, as the loads have to be supplied in this case from the remote storage facilities. All in all, there is a slight tendency towards lower numbers of impermissible system conditions in the variants with added storage facilities.

5 Conclusions and prospects

Research and development are required to prepare storage systems for the market.

Storage facilities will be an indispensable part of the electricity system in the long term. Intensive research and pilot and demonstration projects are urgently recommended now in order to develop storage technology for the long-term deployment which is required. A suitable market launch is to be prepared in good time to achieve the required level of added storage by 2050. Apart from balancing, other matters concerning the future electricity supply system are as yet unresolved, and storage facilities will be able to make a contribution to these.

Storage facilities will be an important part of the electricity supply system in the long term. The analysis of the electricity supply system under the assumptions made and with the methods stated has however shown that the requirement for storage in the energy turnaround will only become significant when the share of renewable energy sources exceeds 40 %.

The fluctuations caused by the expansion of renewables can also be extensively compensated for in the short and medium terms by a flexible portfolio of power plants and flexible biomass generating facilities. Assuming, as has been done here, that input into and output from storage will take place at the same location, the use of storage facilities will have almost no effect on the required expansion of the transmission network. At a renewables share of 40 %, the use of storage will primarily serve to optimize and stabilize power generation from fossil fuels, and will therefore only have a favourable effect on total emissions from electricity generation in the long term when emissions from the portfolio of power plants are correspondingly lower. For these reasons, priority should be given now to the expansion of the electricity grid, the flexibilization of the power plant portfolio and the addition of controllable renewables facilities (e.g. biomass).

If the necessary storage facilities are to be usable economically on an industrial scale in future and are to be available in time, technologically neutral research, development and demonstration projects for further development of the storage technologies are urgently recommended today. As the requirement for storage is not yet immanent in the short and medium terms, there is time for that work and that time should be used so that the impending demand for storage can be fulfilled in future with as innovative and efficient storage technology as possible.

At the same time, it stands to reason that we should now consider how the addition of storage facilities in good time is to become part of the energy policy master plan for the turnaround. This initially requires the

compilation of a sound market launch plan which includes incentives where necessary. It is however clear that the majority of the technologies discussed will only become cost-effective when a high rate of production is achieved.
One possibility is an evaluation process of the storage projects supported in the coming years by government, researchers and industry, with the aim of identifying the most promising technologies. These can then be expedited by corresponding market launch programmes leading to the necessary cost degression which has also been assumed in this study. All sponsorship programmes are to be closely linked to the actual demand for storage in relation to all other flexibilization options, so as to avoid overfunding and the establishment of unsustainable sectors of industry.
This VDE study has concentrated on the need for storage in the electricity system to balance volatile generation and consumption. Many further questions in relation to the future electricity supply system, to which storage facilities may make a contribution or which may affect storage facilities, remain unanswered and will also be addressed by VDE in its future studies:

- Further light is to be shed on the interactions between the use of storage facilities and the networks. With suitable modes of operation (e.g. redispatching), it will be possible for network operators to use storage facilities to manage bottlenecks in both the distribution and transmission networks, with the consequence that they will contribute to network security, function in part as substitutes for network expansion, and also lead to additional demand for storage capacity. In this context, the electricity and gas networks will have to be considered together, as the power-to-gas storage concept opens up new opportunities here.

- The optimum mix for flexibility in the electricity supply system, which will consist of various storage technologies, flexible power plants, demand side management and flexible renewables facilities, will also have to be identified.

- Further examination of security of supply is also required. This study is based on the 2007 weather year. The behaviour of the system in extreme situations, e.g. extremely long periods with no wind, requires further studies, which may indicate a need for further storage, above all in terms of volume.

- There is also a need for investigation of the matter of future power-frequency control when the classical means such as large-scale power plants with rotating steam turbines in base load operation are no longer available. In this regard, short-term and long-term storage facilities may also make a contribution in addition to their balancing function, as may specially suitable ultra-fast storage systems such as flywheel energy stores or superconductive magnetic stores.

- In future, technical and commercial optimization should not only take place within the electricity system. On the contrary, further studies are to take a broader approach and also cover the energy systems of gas, heating and traffic.

- No account has been taken in this study of the exchange of energy with our European neighbours. This can lead to a perpetuation of the use of renewable energy sources and to a reduction in costs, especially with regard to storage costs in the 100 % scenario, and is therefore also to be considered in future studies.

- The design of the electricity market itself is to be adjusted in the course of expanding the use of renewables, so as to provide the required flexibility not only by means of storage facilities, but also by means of flexible loads, gas-fired power plants and flexible feed-in from renewables, on a sound commercial basis. The future design of the electricity market will therefore have to provide appropriate remuneration for power and flexibility.

- Together with the design of the electricity market, network regulation, which comes from a world of vectored load flows from large-scale power plants in the transmission network through the distribution network to the consumer, will have to be adjusted to meet the requirements of an electricity supply system with a greater importance of storage facilities and distributed generation. This includes, but is by no means limited to, the question of network fee design and the provision of and remuneration for system services.

VDE

**ASSOCIATION FOR ELECTRICAL,
ELECTRONIC & INFORMATION TECHNOLOGIES**
Stresemannallee 15
60596 Frankfurt am Main

Phone +49 69 6308-0
Email service@vde.com
http://www.vde.com