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Scenario-based comparative assessment of potential future electricity systems– a new methodological approach using Germany in 2050 as an example

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Abstract – In this paper a new method for the evaluation and comparison of potential future electricity systems is presented. The German electricity system in the year 2050 is used as an example. Based on a comprehensive scenario analysis defining a corridor for possible shares of fluctuating renewable energy sources (FRES) residual loads are calculated in a unified manner. The share of electricity from PV and wind power plants in Germany in the year 2050 is in a range of 42 to 122 % and the load demand has a bandwidth of around 460 to 750 TWh. The residual loads are input for an algorithm that defines a supplementary mix of technologies providing flexibility to the system. The overall system layout guarantees the balance of generation and demand at all times. Due to the fact that the same method for residual load calculation and mixture of technologies is applied for all scenarios, a good comparability is guaranteed and we are able to identify key characteristics for future developments. The unique feature of the new algorithms presented here is the very fast calculation for a year-long simulation with hourly or shorter time steps taking into account the state of charge or availability of all storage and flexibility technologies. This allows an analysis of many different scenarios on a macro-economic level, variation of input parameters can easily be done, and extensive sensitivity analysis is possible. Furthermore different shares of FRES, CO_2-emission targets, interest rates or social acceptance of certain technologies can be included. The capabilities of the method are demonstrated by an analysis of potential German power system layouts with a base scenario of 90 % CO_2-reduction target compared to 1990 and by the identification of different options for a power sector with a high degree of decarbonisation. The approach also aims at a very high level of transparency both regarding the algorithms and regarding the input parameters of the different technologies taken into account. Therefore this paper also gives a comprehensive and complete overview on the technology parameters used. The forecast on all technologies for the year 2050 regarding technical and economic parameters was made in a comprehensive consultation process with more than 100 experts representing academia and industry working on all different technologies. An extensive analysis of options for the design of potential German energy supply systems in 2050 based on the presented methodology will be published in a follow-up paper.

Keywords: energy scenario, scenario analysis, residual load calculation, German electricity system

1 Introduction

The paper presents a newly developed method for the evaluation and comparison of potential future electricity systems. It was developed within the Academies' project "Energy Systems of the Future". Within this project the working group "Flexibility Concepts" aimed at comparing the flexibility demand and different ways to provide the required flexibility for potential future German electricity systems in the year 2050. Flexibility in this case is defined as all measures to balance fluctuating generation from PV and wind power and the load demand. That can be flexible generation (conventional power plants, concentrated solar power, geothermal energy), storage technologies (e.g. batteries, hydrogen storage), demand-side-management (DSM) and power-to-X-technologies. The approach is described using the German power system as an example. However, the method can be applied to any other power supply system as long as sufficient transmission grid capacity is available for the region under investigation and the necessary input data - especially concerning scenarios and weather data - are available.

Due to different boundary conditions, modelling approaches and parameter assumptions, energy system studies in general are hard to compare. This becomes obvious while analysing the resulting electricity system configuration from different studies for Germany as for instance in [1]. The installed power of storage technologies in 2050 varies from around 5 GW to 40 GW. The different assumptions in the underlying studies make it hard to identify and distinguish the different drivers for storage demand. Another example is investment costs for the used technologies. The studies employ different assumptions depending on several factors. Investment costs for pumped hydro for example vary in the range of 300 to 3700 €/kW and 1 to 1000 €/kWh [1]. The selection of technologies strongly depends on their costs if the usage and installed capacities are optimized endogenously in the models. As a result of these different assumptions studies are not comparable amongst each other.

A closer look at the modelling framework of several studies focussing on the German energy system shows further reasons for a low comparability. Table 1 presents important characteristics of the used models like time resolution and simulation period, European integration of the German power system, the grid modelling approach and the determination method of the installed power of fluctuating renewable energy sources (FRES) (wind and PV in Germany) and storage technologies. While some studies treat generation and storage capacity as exogenous[1] parameters that are varied [2], [3], [4], others optimize these values endogenously [5], [6], [7]. Also combinations of both are used [8], [9]. All considered studies use a "copper plate" approach for the German grid and some optimize the power transfer capacities between European countries. Germany is either treated as an isolated electrical system or as part of a European electricity grid with either optimized or non-optimized transfer capacities. The time resolution of the models is one hour in all studies and all models besides DIMENSION [10] use a full year as simulation period. In DIMENSION, typical days are used describing representative system states like weekdays and weekend days in different seasons. This approach makes the evaluation of long time storage demand difficult [11]. The REMod-D model [12] is the only model optimizing the electricity and heat sectors together but does not consider a European integration. The REMix model is the only model optimizing FRES and other generation/flexibility technologies together on a European level. The Market Simulation model [13] and SimEE [14] both use an approach where the installed power of technologies is set exogenously while their operation mode is optimized endogenously. In [9] ELIAS is used for optimizing the technology mix whereas PowerFlex optimizes the operation mode of the exogenously defined (by ELIAS) technologies.

Table 1: Comparison of different energy system studies for Germany in 2050

Study	**Model name**	**Resolution, simulation period**	**European integration**	**Grid modeling**	**Installed power FRES**	**Installed power/capacity storage technologies**
[2]	Market Simulation [13]	1 hour, 1 year	yes	copper plate (Germany)	exogenous	exogenous
[3]	Market Simulation [13]	1 hour, 1 year	no	copper plate	exogenous	exogenous
[8, 15]	DIMENSION [10]	1 hour, Typical days	yes	copper plate (Germany)	exogenous	endogenous, no long term storage
[4]	SimEE [14]	1 hour, 4 years	not optimized	copper plate	exogenous	exogenous, electrolysis dimensioned to use 99 % of surplus energy

[1] Exogenous parameters are not optimized within the model but set externally. In contrast, endogenous parameters are optimized within the model.

[5]	REMix [16]	1 hour, 1 year	yes, especially Norway	copper plate (Germany)	endogenous	endogenous, no DSM included
[6]	REMod-D [12]	1 hour, 1 year	no	copper plate	endogenous	endogenous
[7]	Based on [17]: REMix	1 hour, 1 year	yes	copper plate (Germany)	endogenous	endogenous, no DSM included
[9]	ELIAS, PowerFlex	1 hour, 1 year	yes	copper plate (Germany), im-/export optimized	exogenous	endogenous

Each of these approaches has its own strengths and weaknesses and the results of the studies are of course valid relative to the assumptions made and under consideration of the restrictions of their models.

On an international level, a comprehensive model overview is given in [18–23]. Selected examples are summarized in Table 2. Similar to the findings for German energy scenarios and models, international modelling approaches also differ in many dimensions, as for example time resolution and the considered energy sectors.

Table 2: Comparison of different international energy system models

Source	**Model name**	**Model type**	**Resolution, simulation period**	**Sectors**	**Scope**	**Origin**
[24]	UK-Calliope	Power system model	1 hour/24 hours (dynamic), 1 year [25]	Power	Optimization of installed capacities and dispatch in the power sector	Imperial College London, UK
[26]	EnergyPLAN	Energy system optimization model	1 hour, 1 year [20]	Power, heat, traffic	Cross-sector simulation of regional/national energy system operation	Aalborg University, Denmark
[27, 28]	MARKAL/TIMES	Energy system optimization model	Typical days [25], max. 50 years	Power, heat, traffic	Scenario-based analysis of global/national energy system transformation process	International Energy Agency
[29]	LEAP	Energy system simulation model	Integral method [25], no limit in years	Power, heat, traffic	Scenario-based analysis of national energy system transformation processes	Stockholm Environment Institute, US
[30]	“Stabilization	Qualitative	50 years,	Power,	Show options	Princeton

	Triangle"	and mixed-methods scenario	integral calculations (no simulation)	heat, traffic	for a reduction of carbon emissions	University, US

In [31] the different models are grouped into energy system optimization models, energy system simulation models, power systems and electricity market models and qualitative and mixed-methods scenarios. Table 1 shows an example for each type. Our proposed method can be classified as an intermediate of a power system model and a mixed-methods scenario. We use a comprehensive meta-analysis of published energy scenarios of different kinds to identify key characteristics of a 2050 power system (see section 2.2) together with a simplified power systems model yielding a cost-minimal mix of flexibility technologies (see sections 2.4-2.6.). Four key modelling challenges are also given in [31],. These are addressed with our proposed method as follows:

1. Resolving details in time and space

Especially for high shares of fluctuating renewables, a high resolution in time and space is necessary [32]. We are using an hourly time resolution for one year (8760 time steps), with wind data from more than 70 measuring stations and solar data for PV from 18 representative locations in Germany.

2. Uncertainty and transparency

Comprehensive expert knowledge is used to create a common basis for our evaluations. In 10 sub-working groups around 100 experts from science and industry defined a common set of technical and economic parameters for all relevant technologies with a forecast towards 2050 (given in the Appendix). The parameter sets represent the expected mean values of technologies in 2050 resulting from the aggregation of a large number of single units for each technology. The process is described in [33] and in the fact sheets of the sub-working groups which are available online (http://www.acatech.de/flexibilitaetskonzepte-2050, [34–41]). For photovoltaics for example, parameters for the components (modules, inverters, balance-of-system) of typical rooftop and open space installations with different cell technologies were examined based on learning curves until 2050. The mean value for PV technology was calculated from a mix of these installations with different orientations using the mean value of best and worst case assumptions. An 11th sub-working group analysed German energy scenarios for 2050 (see section 2.2). A scenario corridor describing the role of FRES generation and electricity demand in 2050 was the basis for the residual load calculations as input for the newly developed method for finding appropriate system configurations.

3. Complexity and optimization across scales

We focussed our investigations on the power sector and include interactions with the traffic and heat sectors in a simplified manner (see section 4.2). By doing so, the method and the produced results remain straightforward. We therefore do not aim at yielding better or more accurate results than the well-established models mentioned above. But by applying our unified method over a bandwidth of different possible system configurations we are able to compare these systems among each other and identify drivers for certain developments. While our method has a lower complexity in covering interdependencies between neighbouring countries and sectors, it allows for a faster calculation of many different parameter sets in comparison to the approaches used in other studies. Whereas complex large-scale energy system models require up to several days for one optimisation run [31], our tool (coded in MATLAB) optimises 9 scenarios for a given set of parameters within about 15 minutes on a standard PC (2.8 GHz, 6 GB RAM). This allows for the first time an almost “real-time” calculation of the impact of changes in input parameters or assumptions while still based on analysing a full year in hourly resolution and taking into account all the potential technologies, which should be available with a high level of confidence in 2050.

4. Capturing the human dimension

With the proposed method we are able to include political and social preferences like CO_2-emission targets and the exclusion of specific technologies with low public acceptance. We are also able to take into account different technology parameter sets, or limited resources such as biomass by adapting the parameter sets accordingly.

The proposed methodology can be applied to a wide area of strategic topics in the power sector. By using the same boundary conditions and calculation method we are able to reach a high comparability of different options and scenarios within a uniform modelling framework. Our methodology can be applied, among others, to the following topics:

- Dependency of the power system layout and levelized cost of electricity (LCOE) on CO_2-reduction targets, as e.g. analysed in [42–45].
- Identifying different options for a high degree of decarbonisation, as for example investigated in [43, 44, 46].
- Options to reduce or avoid natural gas imports. Related literature can be found in [47–50].
- Influence of biomass potentials on power system layout and LCOE. A high number of country-specific investigations on biomass potentials can be found (refer to e.g. [51–55]) as well as studies in the field of biomass usage for power generation, e.g. [56–58].
- Dependency of power system layout and LCOE on the usage of concentrated solar power (CSP) and carbon capture and storage (CCS) technology. Investigations on the importation of CSP electricity to Europe can be found in [59–61]. An overview on papers on CCS is given in [62]. Detailed investigations on the role of CCS are given in [63–65].

In the related literature, investigations are often focussed on one specific topic with a high accuracy in power system modelling. Due to different assumptions and model concepts however results are not comparable among each other. Our methodology uses a simplified approach but offers the possibility to address a large bandwidth of topics with comparable assumptions. By doing so we are able to generate conclusions from a large set of different comparable investigations. In this paper, the proposed methodology is used to identify different options for power system designs with a high degree of CO_2-reduction (see section 3.5) as an example. In a follow-up paper, we will use the developed methodology for a comprehensive assessment of potential future power systems in Germany in 2050.

Some parts of this work are reported in an academy working paper [33], for which the general method was developed. For this paper, the method was refined in several respects[2] so that results are not directly comparable in detail. Nonetheless the general findings stand.

The remainder of the paper is organized as follows. In section 2 we describe the different steps of our method: the scenario analysis, residual load calculation and the method of cost-based technology mapping. Section 3 presents some illustrative results to demonstrate the capabilities of the method. This is done by a comprehensive analysis of the results of a reference case, by a comparison of power systems with a CO_2-reduction target of 90 % and a sensitivity analysis. Furthermore, we show an application example of our methodology in detail. In section 4, limitations of our method are discussed and their consequences are assessed. Finally, section 5 concludes this paper with a summary and an outlook to our follow-up paper giving comprehensive results.

2 Methodology

In this section the used methodology is described in detail. Beginning with an overview, the scenario selection process, the residual load calculation and the algorithm for cost-based technology mapping including the modelling of the different technology types are explained.

2.1 Overview

The overall methodology can be divided into four steps and is illustrated in Figure 1:

1. A scenario analysis is used to identify illustrative scenarios. For Germany, 8 illustrative scenarios (plus one supplementary scenario) are selected, which can be regarded as representative for potential power systems in 2050.

2. Based on the delivered energy from PV and wind and the load demand, residual load curves for one year with hourly resolution are calculated in a unified way for the scenarios.

3. The residual load curves are input to the cost-based technology mapping algorithm. This algorithm identifies a mix of technologies which is able to balance generation and demand for

[2] We, for example, included hydropower in cost calculations, the energy from wind onshore is set exactly to the value from original scenarios, the CO_2-target can be set for each scenario individually, double use of limited resource such as biomass for different technologies is inhibited and we calculated some further variations.

all hours of the year. For that a comprehensive parameter set is used. Technologies are selected based on minimal macroeconomic costs. A CO_2-reduction target is set as a boundary condition. The results are the installed powers of the different used technologies, their usage during the year including fuel consumption, their CO_2-emissions and the overall levelized cost of electricity (LCOE) of the system for all scenarios. Other considerations, such as low public acceptance of certain technologies, are taken into account in various parameter variations by limiting the maximum potential of these technologies.

4. By using different boundary conditions and different assumptions regarding other parameters, a comparative assessment of possible future power systems can be made.

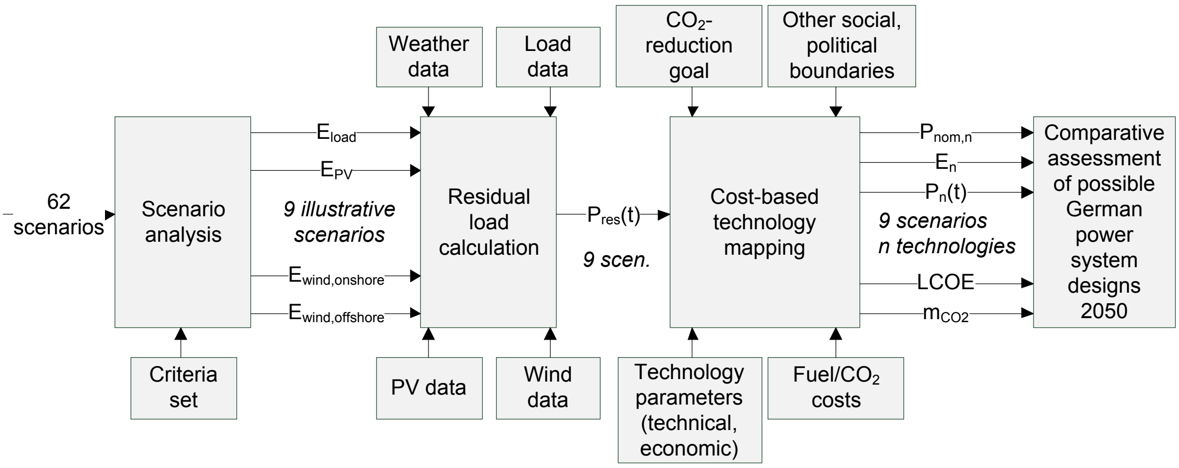

Figure 1: Overview on the employed methodology for potential German power systems in 2050 as an example.

To keep the overall process manageable and to be able to regard a large set of different boundary conditions within a reasonable simulation time, we introduced some simplifications and assumptions:

- The calculations are limited to one nations' electricity system; for the German case import of electricity is only modeled for concentrated solar power (CSP) systems.
- The model is limited to the electricity sector. The heat and traffic sectors are only regarded with respect to their flexibility provisions for the electricity sector (power-to-heat, flexibility by demand-side-management)
- The selection of technologies is based on a macroeconomic approach. The levelized cost of electricity (LCOE) is minimized based on investment and operation and maintenance (O&M) costs of the overall electricity system. Microeconomic aspects and market regulations are not taken into account.
- All calculations are made for the year 2050 with a greenfield strategy. The transformation from now until 2050 is not modeled.
- For the levelized cost of electricity (LCOE) calculation we use a simplified definition not including revenues, taxes or incentives. It is therefore a static picture of the projected technology status in the year 2050. However, the projected technology

parameters for 2050 are based on learning curves presuming a certain technology development and market volume.

- No grid restrictions apply (copper plate approach) besides a set of simulations where Germany is split into three regions which are not connected to each other and therefore fluctuations must be levelized in each region separately.
- Fuel costs and CO_2-costs for Germany in 2050 are taken from [8]. Costs for natural gas are 33.10 EUR/MWh$_{th}$ and costs for CO_2-emissions are 76 EUR/t. Cost assumptions for other fuels are given in the Appendix.
- All cost calculations are based on prices from 2014 without consideration of inflation and an interest rate of 8 % is used.

Important effects and implications of these assumptions are discussed in section 4. However, we would like to emphasize that the algorithm is designed to allow any parameter such as fuel or CO_2-costs to be changed without any limitation and to analyze the impact on the system design within a short period of time. This facilitates interactive use.

2.2 Scenario analysis

The electricity system is subject to ongoing change processes which are determined by many internal and external factors. Due to the system complexity and the variety of technological, economical, societal and political influence factors, the future development of the system cannot be predicted in a precise way. It is instead characterized by a high degree of uncertainty. Energy scenarios are therefore an analytical tool for the discussion of various designs of an energy system under consideration of this uncertainty. For a numerical simulation of an energy system, specific values have to be assigned to uncertain input parameters, hence assumptions are made. The simulation then calculates various output parameters, thus allowing one to analyze the influence of the input parameters on the overall system. Energy scenarios therefore describe possible future systems and identify interrelations in the energy system. They do not predict the development with the highest probability but illustrate possible future paths which could occur if the assumptions made hold true.

For Germany as an example, a meta-analysis was carried out for previously published energy scenarios with focus on the electricity system. Assuming that all relevant possible developments of the energy system are represented in one of the existing energy scenarios, this meta-analysis represents the solution space of possibilities for the future development of the energy system. Furthermore an overview on the key characteristics of possible future energy systems is generated.

Based on a comprehensive literature study, 8 scenarios were selected which are regarded as representative for specific characteristics and political frameworks and which help to describe the space of possibilities for the electricity system 2050 as illustrative scenarios. These 8 illustrative scenarios are the basis for further calculations. The selection and characterization of scenarios was structured in four steps, as follows.

1. Identification of scenario studies

For Germany, 18 recently published energy system studies with a total of 62 different scenarios were identified. The selected scenarios differ mainly in terms of climate protection goals (trend development versus climate protection at least according to the goals of the German government), the possible use of carbon capture and storage (CCS) and in particular the share of fluctuating renewable energies in electricity production. This share ranges between 40 and 90 % in the regarded scenarios for 2050. Nuclear phase-out has been assumed in all scenarios as decided by the German government by 2022[3].

2. Restriction of scenarios

In a second step, a preselection of scenarios for a closer evaluation is made. Selected scenarios must be published in 2009 or later, energy and installed power of electricity producers have to be given in a quantitative manner and the studies themselves have to be available free of charge.

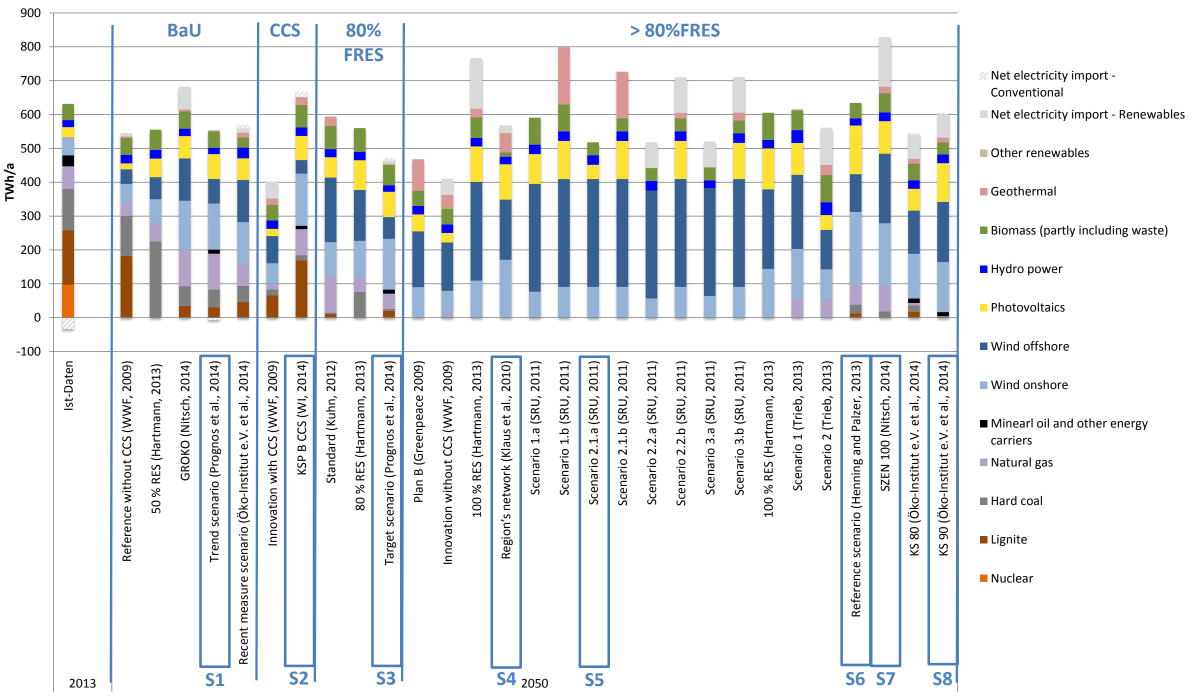

Figure 2: Gross electricity production in the 29 remaining scenarios. The 8 illustrative scenarios are highlighted (S1 to S8).

From a current perspective, the solution space for the year 2050 is well covered by the 29 selected scenarios. There is a significant spread in the power demand (400 to 800 TWh) as well as in the mix of technologies, refer to Figure 2. However, one possible development we

[3] Besides that, economic analysis shows that nuclear power will hardly find a place in a cost optimized system design. Prices such as more than 120 €/MWh plus inflation as guaranteed by the British government for 35 years of power plant operation are well above future electricity costs according to this and many other studies.

consider possible has not been covered: a system with a significant over-installation of FRES. This represents possible systems beyond 2050 or disruptive developments in the energy markets or in wind and PV costs. We therefore consider a supplementary scenario which represents this option (see section 2.3.1).

3. Matching of scenarios and characteristics of electricity systems

In a third step, the remaining 29 scenarios were compared with respect to their main characteristics determining the flexibility demand.

Every scenario was checked for the following characteristics. When applying the method to other countries, different characteristics could be appropriate.

- Business-as-Usual (BaU)-oriented development (nuclear-power exit by 2022, no ambitious climate protection goals until 2050 in particular)
- Ambitious climate protection with a strongly centralized generation system (CCS is used to a relevant extent)
- Oriented on the current energy and climate protection concept of the German government (share of renewable electricity production up to 80 % until 2050) [66]
- Achieving the climate protection goals and strong expansion of renewable energies for electricity production (about 80% renewable energy sources (RES)) and
    - high degree of power-to-X, i.e, producing heat, hydrogen or chemicals for use in other sectors (industry, traffic)
    - possibility of net import of electricity (from RES) to a relevant extent
    - significant limitation of power exchange with neighboring countries
    - particularly high share of fluctuating RES (FRES)
    - particularly low share of FRES
    - uniformly distributed generation from RES (high share of PV and onshore wind energy) in contrast to a highly concentrated power generation from off-shore wind farms

Table 3 shows the resulting assignment of the scenarios to the characteristics.

Table 3: Characteristics of power systems and assigned scenarios for Germany in 2050. The selected illustrative scenarios are printed in bold.

	Characteristic of future power system	**Criterion for 2050**	**Share of RES for covering load demand (2050)**	**Related scenarios**

1	No ambitious climate protection until 2050	CO_2-reduction less than 70 % (compared to 1990)	Not specified	- Reference without CCS [67] - 50 % RES [68] - GROKO [7] **- Trend scenario [15]** - Recent measure scenario [9]
2	Significant use of CCS	Share of CCS at least 15 % of power demand	Not specified	- Innovation with CCS [67] **- KSP B CCS [69]**
3	RES goal of the federal government	RES-share around 80 % (78 - 82 %)	circa 80 %	- Standard [11] - 80 % RES [68] **- Target scenario [15]**
4	Significant use of power-to-X	Share of electricity for electrolysis at least 15 %	More than 80 and up to 100 % + X	- Region's network [4] - Reference scenario [6] - SZEN 100 [7] **- KS 90 [9]**
5	Significant electricity import	Electricity import at least 15 %	More than 80 and up to 100 % + X	- 100% RES [70] - Scenarios 2.2.a, 2.2.b, 3.a or 3.b [5] - Scenario 2 [71] **- SZEN 100 [7]**
6	No electricity exchange with neighboring countries	No electricity import/export	More than 80 and up to 100 % + X	- Scenario 1.a und 1.b [5] - 80 % EE und 100 % EE [68] **- Reference scenario [6]**
7	Particularly high share of FRES	FRES-share at least 75 %	More than 80 and up to 100 % + X	- Region's network [4] - **Scenarios** 1.a und **2.1.a [5]** - 100 % RES [68] - Scenario 1 [71]
8	Particularly low share of FRES	FRES-share below 60 %	More than 80 and up to 100 % + X	- Innovation with CCS [67] - Standard [11] - Scenario 2 [71] **- SZEN 100 [7]**
9	Uniformly distributed generation from RES	Share onshore wind and PV more than 45 %	More than 80 and up to 100 % + X	**- Region's network [4]** - Reference scenario [6] - Target scenario [15]

4. Selection of illustrative scenarios

In the fourth and final step, an illustrative scenario was chosen for each of the criteria. In Table 3 the selected (illustrative) scenario for a criterion is highlighted (bold). The further analysis and calculations are based on these 8 illustrative scenarios only.

2.3 Supplementary scenarios

2.3.1 FRES share above 100 %

We enlarge the scenario corridor with a supplementary 9th scenario that is characterized by a FRES share above 100 % (refer to A.2, scenario 9). PV and wind power plants can deliver more electricity than needed in this case. It was defined based on simulation data from the project Genesys [72]. PV and wind power plants can deliver 122 % of the load demand in scenario S9.

2.3.2 Frozen scenario

As a reference and for comparison purposes we also use a so-called frozen scenario. In this scenario the predicted mix of power plants of the year 2025 [8] is "frozen", refer to Table 4. That means that the structure of the electricity system is held constant from the year 2025 onwards. With this scenario we are able to compare possible power systems of the year 2050 with a power system mix shortly after the nuclear exit in Germany. The installed power of gas turbines and CCGT technology is estimated because it is not directly specified in [8].

Table 4: Generation mix of the frozen scenario

Technology	Power in GW	Energy in TWh (gross)
Hydro power	5	19
PV	64	61
Wind onshore	30	90
Wind offshore	6	35
Hard coal	23	101
Lignite	19	143
Gas turbines	13	6.4
CCGT	18	52
Biogas CHP	18	54.6
Pumped hydro	8	
Sum	205	570

2.4 Residual load calculation

The selected eight scenarios can help to identify the bandwidth of requirements on flexibility options and their demand in future electricity systems. To do this in a unified manner, a residual load curve is calculated for each of the scenarios. The residual load time series $P_{res}(t)$ is defined as difference from the load demand $P_{load}(t)$, slightly fluctuating infeed from hydro power $P_{hydro}(t)$ (without hydro storage), and fluctuating infeed $P_{FRES}(t)$:

$$P_{res}(t) = P_{load}(t) - P_{hydro}(t) - P_{FRES}(t) \tag{1}$$

In Germany's power system the fluctuating infeed consists of PV and wind power whereas the wind power is split into onshore and offshore wind:

$$P_{FRES}(t) = P_{PV}(t) + P_{wind,onshore}(t) + P_{wind,offshore}(t) \tag{2}$$

As a basis for the residual load calculations, the yearly energy of on- and offshore wind, PV and hydropower as well as the yearly load demand of the scenarios is used. Figure 3 illustrates these values. All further parameters defined by the scenarios (e.g. capacities of different generation technologies) are omitted. The selected 8 scenarios supplemented with scenario 9 therefore describe the solution space for future FRES shares and load demands of the German electricity system in 2050. The FRES share is calculated only with energy from PV and wind power plants; hydro power stations are not considered in the FRES share as their output is less fluctuating and their share is very similar in the different scenarios. The different scenarios require significantly different amount of additional net power generation in addition to the FRES. This will affect the selection of flexibility options significantly.

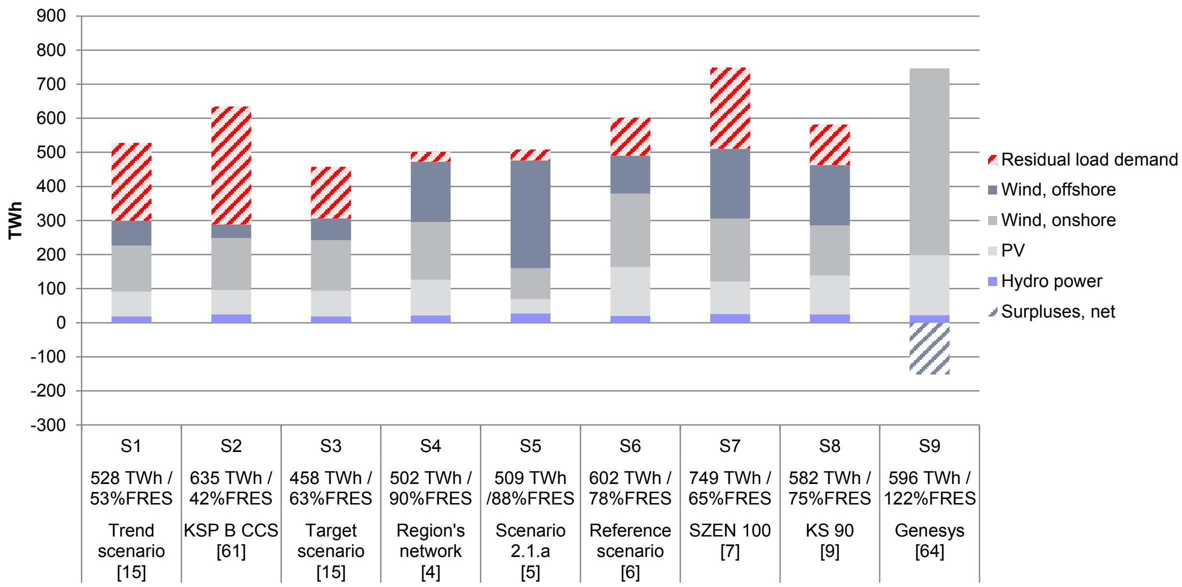

Figure 3: Net electricity production from PV, wind and hydro power, as well as the residual electricity demand in the different scenarios. Percentages of wind and PV are based on the net electricity demand and represent maximum shares without any curtailment of FRES. Scenario numbers shown will be used for further reference. Detailed figures for all scenarios are shown in appendix A.2.

In order to ensure comparability between the different scenarios, the residual load was calculated with a uniform procedure for all scenarios. Unified technical parameters for FRES (e.g. wind speed-power output characteristics for representative wind energy converters) as well as identical assumptions for the geographical distribution of renewable energy systems were used[4]. In the following, the calculation of PV and wind infeed and the calculation of the load curve are explained. The load curve for hydro power is modelled according to [73].

2.4.1 Photovoltaics

The PV-infeed timeseries for every scenario is based on satellite data of the irradiation [74]. The irradiation data is processed together with temperature data to a PV-infeed timeseries. The technical parameters of the model are described in [75]. The regional distribution is adopted from [76]. A mixture of south-oriented and east-west-oriented PV installations is used with different tilt angles, refer to Table 5.

Table 5: PV assumptions concerning tilt angle and orientation of installed PV modules

	Tilt angle		
Orientation	**30°**	**45°**	**60°**
South	30 %	20 %	20 %
East	5 %	5%	5 %
West	5%	5 %	5 %

2.4.2 Wind power

The data base for the calculation of the wind power infeed is hourly measured wind speed and temperature data for 2008 from more than 70 meteorological stations located all over Germany. The measured wind speed is extrapolated to hub height. With the help of real wind speed-power curves, the wind speed is transformed into a normalized wind power infeed. For offshore and near-shore onshore locations, the characteristics for a Senvion 3M wind generator [77] and for onshore, the characteristics for a weakwind turbine [78] are used. The characteristics are shown in Figure 4. Power losses and availability are accounted for. The installed wind capacity is scaled according to the scenario considered. The regional distribution of the wind infeed is correlated with [76].

[4] The used method guarantees a good comparability between different scenarios. With an optimization of the geographical distribution of FRES, a minimization of the electricity distribution demand could be achieved.

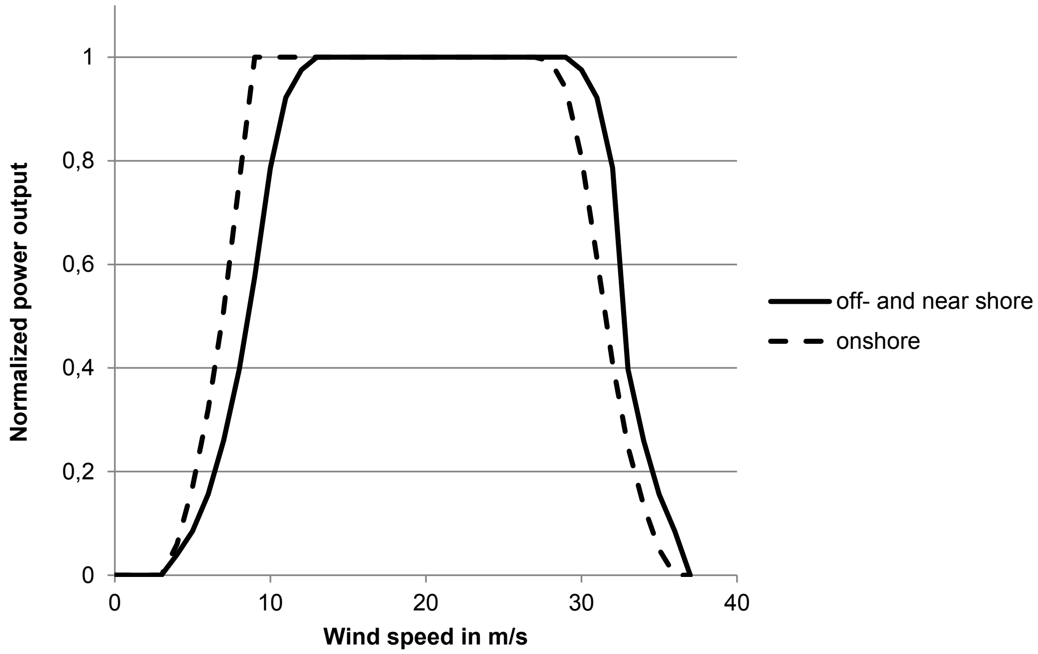

Figure 4: Characteristics of modelled wind turbines

2.4.3 Load demand

The total load given in every scenario is distributed according to the hourly load profile of Germany for 2010 [79]. To reach the total load, the hourly load values are scaled up linearly. Accordingly the peak power demand is scaled with the total load. Due to the financial and economic crises, the load profile for 2008 or 2009 is not representative. The load profile for 2010 is chosen instead. No load-shift potentials have been taken into account in the load profile which could be offered e.g. by intelligent charging strategies of electric vehicles. These potentials are instead offered to the power system as a flexibility option.

2.4.4 Results

Figure 5 shows as an example the calculated residual load curve for scenario S6. Here the effect of prolonged weather phenomena becomes clear. Periods with constantly high positive residual load occur in the hours of about 900 to 1200 (two weeks) and around the hour 8000 (three weeks). During these periods of low solar and wind power (“dark calm period”) many flexible power plants (coal, gas, biomethane, etc.) or long-term storage units are needed. Such extreme weather situations very strongly determine the necessary capacity and the appropriate mix of flexibility options. Studies using something like “average metrological data” neglect the strong impact of the longest “dark calm period” on the system design. For that reason the weather year 2008 contains some challenging periods regarding the mixture of technologies even though it still may not contain the longest “dark calm period” measured in the last 100 years.

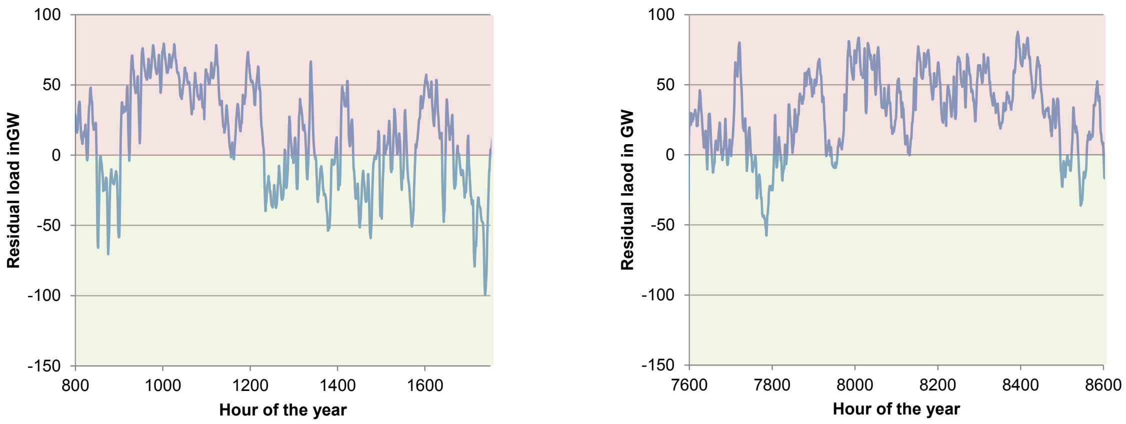

Figure 5: Residual load for scenario S6 (602 TWh, 83 % FRES)

2.5 Cost-based technology mapping

The method is basically divided into three steps (see Figure 6): Firstly, the residual load which has to be covered is determined on an hourly basis for a full year and divided into "slices" of 1 GW[5]. Secondly, all available technologies are technically as well as economically characterized in a unified manner for the specific requirements of the residual load slices. Thirdly, technologies are ranked to fulfill the load curve of all slices based on full costs and under the constraint that the residual load can be covered all the time.

Figure 6: Schematic procedure of technology assignment

To assure a stable operation of the power system, the residual load has to be zero for all times. To guarantee that, the positive residual load $P_{res,pos}$ is divided into "slices" of 1 GW:

[5] Generally any other value for the slice than 1 GW can be used. For the German energy system 1 GW slices results in approximately 70 to 80 slices and therefore generates a good resolution. However, smaller slices (increases the calculation time) or larger slices (reduces the sensitivity for different technologies) can be used.

$$P_{res,pos}(t) = \sum_{n=1}^{\text{integer}\left[\frac{\max(P_{res}(t))}{1GW}\right]+1} P_{res,pos,n}(t) \tag{3}$$

An example for this procedure is given in Figure 7.

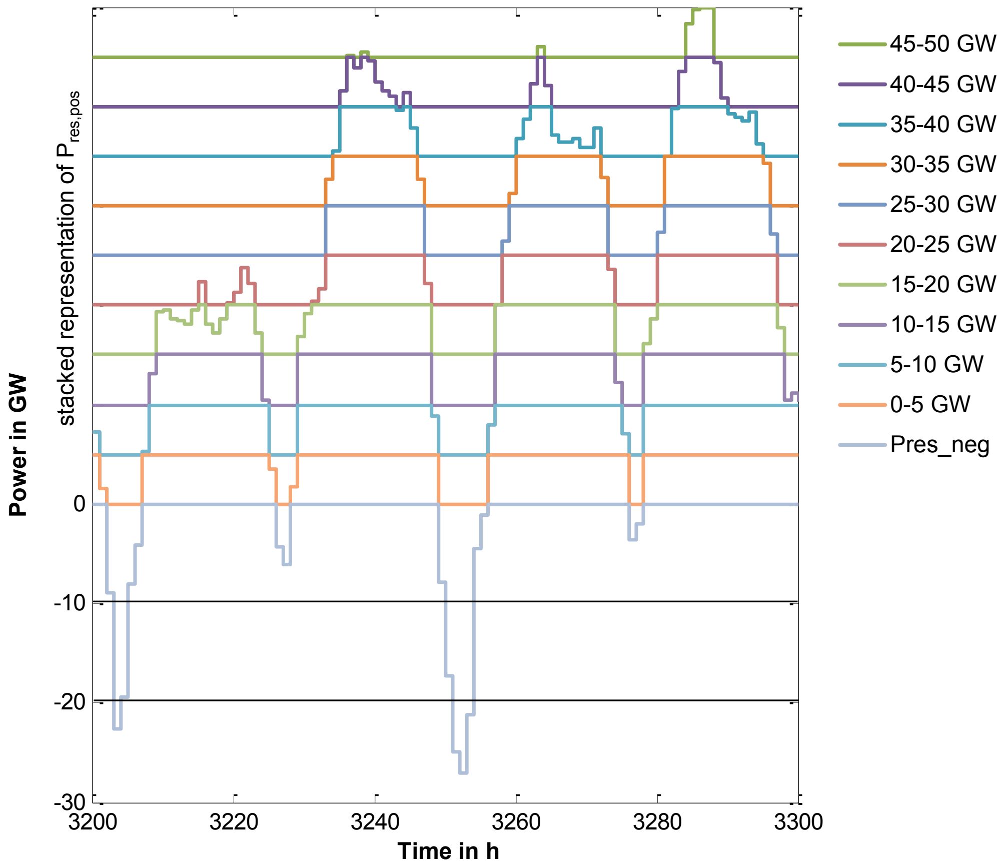

Figure 7: Positive residual load divided into “slices” of 5 GW as an example

Beginning with $P_{res,pos,1}$, a technology which is able to cover the load curve in the specific slice at minimal costs is assigned. For this, a cost assessment of all suitable flexibility technologies which are able to cover the whole power slice is made. For each power slice, the flexibility technology with the lowest cost for the particular requirements is assigned. This can be net-generating technologies such as gas-turbines using energy from fossil or biogenous resources or storage technologies using their ability to shift surpluses from the negative residual load to times with energy demand in the positive residual load.

The cost calculation is based on the annuity method covering investment, annual fixed and variable costs and also includes an optimization of the dimensioning (e.g. storage size and charging power in the case of storage technologies) and a check to see if storage and DSM-technologies can be sufficiently recharged. The calculation of costs for the different technology classes is described in section 2.6. When the last positive slice is covered and all energy needed for recharging the storage systems and serving the flexible loads is subtracted from the negative residual load hour by hour, a negative residual load is remaining. For that, the same procedure is executed, but with a different technology portfolio which is able to operate with negative loads (i.e. power-to-X technologies). Surpluses of FRES infeed can also be curtailed if no economically suitable power-to-X-technology exists.

The method is able to identify a technology mix which fulfils a certain exogenous CO_2-emission target. This is done by iteratively setting internal CO_2-emission costs to a value that guarantees reaching the CO_2-emission target. This internal CO_2-cost value is only used as a control parameter for this purpose and not for evaluating overall system costs. As an example: The CO_2-emissions of a system are higher than the target value because lignite is used. Then the internal CO_2-costs are increased and therefore the cost-effectiveness of lignite is decreased. If the internal CO_2-costs are high enough, e.g. CCGT power plants are used instead of lignite and the CO_2-emissions of the system are lowered. The cost calculation for CO_2-emissions is done in a unified matter with 76 €/t [8] regardless of the internal CO_2-cost value.

2.6 Technology classes

2.6.1 Flexible generation with unlimited storage (Type 1)

As flexible generators with unlimited storage, the following power plants are modeled: steam turbine power plants fired with hard coal or lignite (for lignite with and without CCS), gas turbine power plants, gas turbine combined cycle (CCGT) power plants and engine power plants each fueled with natural gas or biomethane, industrial combined heat and power (CHP) plants[6] and wood-fired power plants. In this technology class, heat is generated from a primary energy source in a combustion process, which is converted to mechanical power in an energy converter (e.g. turbine) and then to electrical power in a generator. These systems are characterized by their technical conversion efficiency and their specific CO_2-emissions. Economic parameters are fuel costs, investment costs combined with the plant life as well as operating and maintenance costs (including start-up costs). Each plant type can be used in the model with a limit on the installable power and/or on the primary energy used. A schematic of the technology representation is given in Figure 8.

[6] In the case of CHP-plants only the fuel and CO_2-costs proportional to the electricity generation are considered. However the full investment is regarded as we assume the installation of a CHP-system is in addition to an already existing boiler.

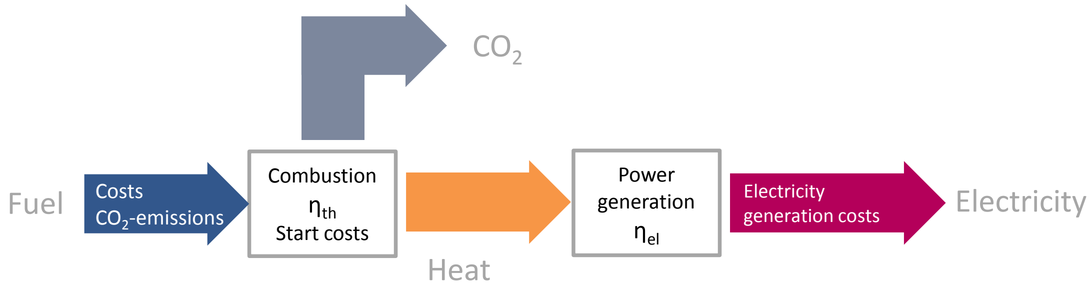

Figure 8: Schematic of type 1 technology representation.

The full costs of a technology n of the type 1 $C_{1,n}$ consist of the capital cost C_{cap}, the annual fuel costs C_{fuel}, the annual costs for CO_2-emissions C_{CO2}, annual operation and maintenance costs $C_{O\&M}$ and the annual start-up costs C_{start} depending on the number of cold and warm starts within a year.

$$C_{1,n} = C_{cap} + C_{fuel} + C_{CO_2} + C_{O\&M} + C_{start} \tag{4}$$

The annuity method is used to calculate a yearly value of C_{cap}:

$$C_{cap} = C_0 \cdot \frac{(1+i)^u \cdot i}{(1+i)^u - 1} \tag{5}$$

In (5), C_0 is the overall investment, i is the interest rate and u is the plant life in years. The fuel costs are calculated with the delivered electrical energy E_{el}, the conversion efficiency η and the specific fuel cost $c_{fuel,th}$ related to thermal energy:

$$C_{fuel} = \frac{E_{el}}{\eta} \cdot c_{fuel,th} \tag{6}$$

The costs of CO_2-emissions are calculated by the primary energy input, the specific CO_2-emissions of the fuel e_{CO2} in t/MWh_{th} and the cost per tonne of CO_2 c_{CO2}:

$$C_{CO_2} = \frac{E_{el}}{\eta} \cdot e_{CO_2} \cdot c_{CO_2} \tag{7}$$

Annual operation and maintenance costs are calculated as a percentage $c_{O\&M}$ of the overall investment:

$$C_{O\&M} = C_0 \cdot c_{O\&M} \tag{8}$$

The start-up costs account for all costs in relation to a starting process. These are for example higher deterioration, extra fuel feed and extra personnel costs. Starting processes from a cold and warm state are distinguished. The specific costs for a starting process c_{start} are multiplied by the number of starts n_{start}:

$$C_{start} = c_{start,cold} \cdot n_{start,cold} + c_{start,warm} \cdot n_{start,warm} \quad (9)$$

The detailed technology parameters and the definition for cold and warm start for the used technologies are displayed in appendix A.1.2

2.6.2 Flexible generation with renewables and thermal storage (Type 2)

Concentrated solar power (CSP) and geothermal power plants are modeled as “Flexible generation with thermal storage”. In the simplest case, the energy from a primary renewable heat source (fluctuating in the case of CSP) is converted to electricity. In contrast to type 1 technologies, type 2 plants can be equipped with a thermal storage and a co-firing unit. These additional units increase the degree of freedom in designing the size of the collector field (solar collector or geothermal collector) and enable the technologies to complement the fluctuating generation from PV and wind. The size of the collector field, the thermal storage and the co-firing unit are optimized in the model for each slice independently. For geothermal power plants, no co-firing unit is considered.

Technical parameters for type 2 technologies are conversion efficiencies, efficiencies and restrictions of the thermal storage and the co-firing unit as well as specific CO_2-emissions of the co-firing unit. Fuel costs for co-firing, investment for collector field, energy converter and thermal storage combined with the plant life as well as O&M costs are the economic parameters. The technologies can be restricted in the potential for the primary thermal energy, installable electrical power and the share of co-firing. Technologies of type 2 are represented according to Figure 9.

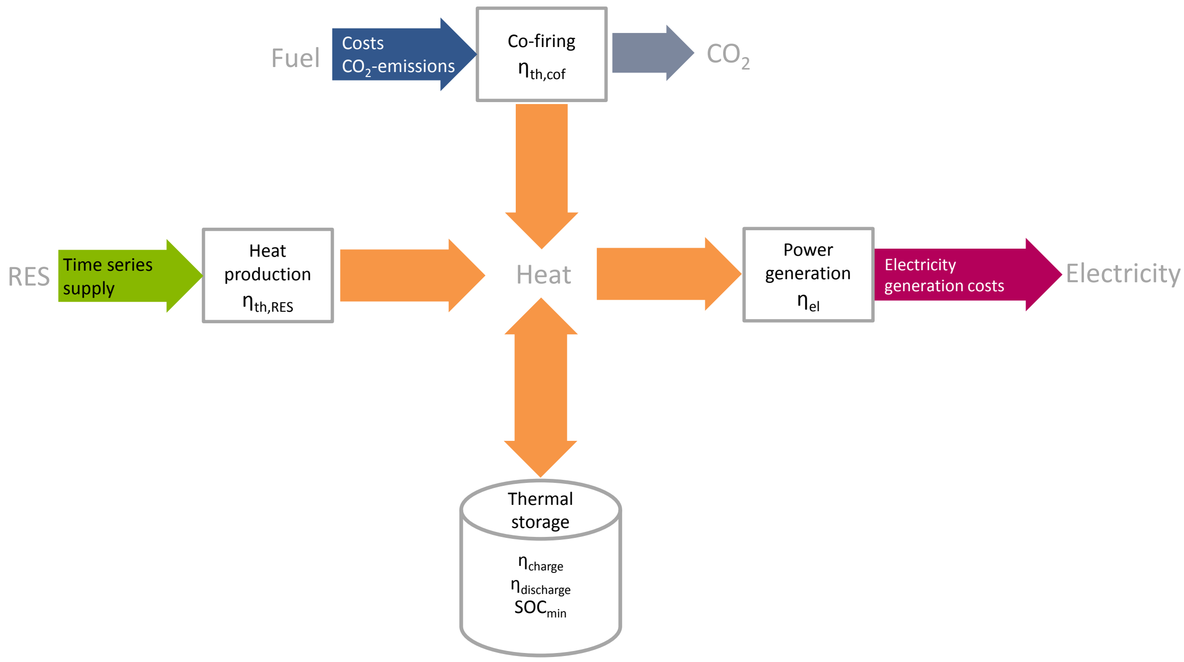

Figure 9: Schematic of type 2 technology representation.

For each “slice” of the residual load, an optimization of the plant design is made with the goal to minimize the individual LCOE of the technology.

The logic design of the optimization process for a CSP system is shown in Figure 10. First, the residual load is evaluated for its peak power demand $P_{el,nom}$ under consideration of the HVDC transmission losses from a site in North Africa or Southern Europe to Germany. Then, the outer loop is entered, where the collector field output power $P_{th,solar}$ is optimized via sequentially decreasing its yearly mean thermal power output from an upper estimate ($2*P_{el,nom}/\eta_{th\rightarrow el}$) until no further cost reduction is observed. For each step inside this loop, the co-firing (COF) share is optimized together with the size of the thermal storage. For all loop iterations, the necessary net storage capacity $E_{storage,th}$ is calculated (as explained in section 2.6.3) and full costs of the current setting are computed. Placing a limit on the share of electric energy provided by co-firing is implemented and accounted for in the optimization process.

The full costs of CSP-systems (type 2) $C_{2,n}$ are calculated in a manner similar to technologies of type 1. The overall investment C_0 comprises the independently sized parts collector field C_{coll}, power block C_{PB} (including co-firing unit), thermal storage $C_{storage,th}$ and HVDC (high-voltage direct-current) electricity transmission to Germany C_{HVDC}. In addition to O&M costs, a factor for contingencies is considered for the CSP system. For other technologies contingencies are included in the investment costs or are considered to be negligible.

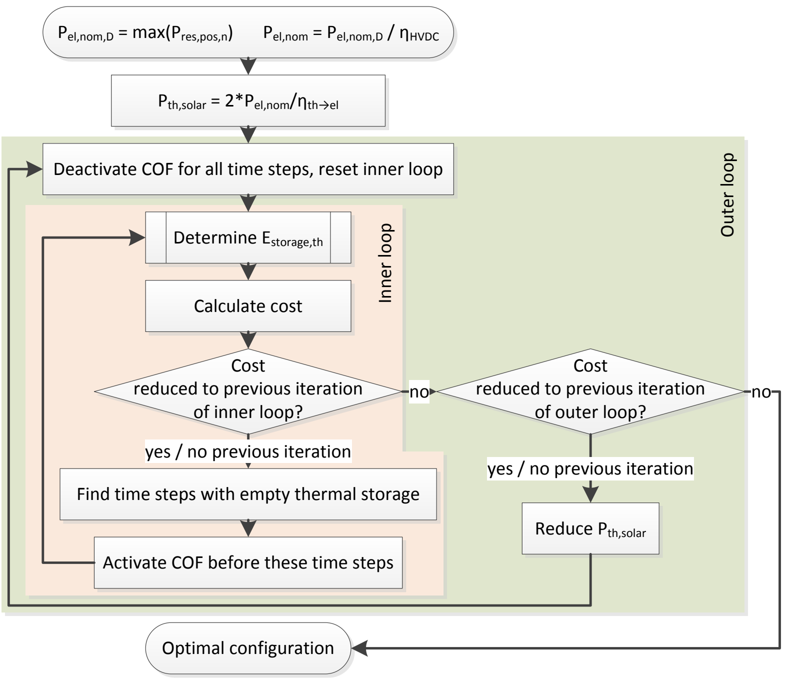

Figure 10: Logic design of optimization for flexible generation with thermal storage.

The costs of the collector field are calculated as follows:

$$C_{coll} = A_{coll} \cdot c_{coll} = \frac{P_{th,solar}}{\eta_{sol\rightarrow th} \cdot e_{solar}} \cdot c_{coll} \tag{10}$$

A_{coll} is the size of the collector field and c_{coll} the area-related costs of the field. The size of the collector field is calculated using thermal power $P_{th,solar}$, mean solar radiation e_{solar} and the collector efficiency $\eta_{sol\rightarrow th}$.

The costs of the thermal storage are determined with storage net capacity $E_{storage,th}$, the specific thermal storage costs $c_{storage,th}$, the storage efficiency (roundtrip, mean value) $\eta_{storage}$ and the minimum state-of-charge SOC_{min} of the thermal storage:

$$C_{storage,th} = \frac{E_{storage,th}}{\eta_{storage} \cdot (1 - SOC_{min})} \cdot c_{storage} \tag{11}$$

The fuel costs and costs for CO_2-emissions are calculated in a manner analogous to technology type 1.

Due to the low direct irradiation level in Germany, only CSP locations in southern Europe or North Africa with a long-distance electricity transmission are considered. For estimating the transmission costs, the costs for a direct HVDC-transmission C_{HVDC} are taken into account:

$$C_{HVDC} = \frac{P_{el,nom,D}}{\eta_{HVDC}} \cdot c_{HVDC} \cdot l_{HVDC} \tag{12}$$

$P_{el,nom,D}$ is the power which has to be delivered to the German power system, η_{HVDC} is the transmission efficiency, c_{HVDC} are the power related specific costs including converter stations and transmission lines/cables and l_{HVDC} is the length of the transmission system. The transmission efficiency has also to be considered for the dimensioning of the CSP system, since the losses have to be covered by additional generation.

The optimization of geothermal plants is done in a manner analogous to CSP systems, not regarding HVDC costs and without co-firing.

The parameters for type 2 technologies can be found in appendix A.1.3.

2.6.3 Storage technologies (Type 3)

Type 3 technologies are pumped hydro storage, adiabatic compressed air energy storage, hydrogen storage, methane storage and battery storage. In addition, demand-side management (DSM) measures in the household sector, trade, commerce and services sector and in industry are treated as storage technologies. Controllable consumers are modeled as non-flexible in the load time series and their load shifting potential is modeled as added virtual storage. Especially for the household sector, the potential in 2050 is assumed to be high due to electric vehicle batteries, PV battery systems and thermal storage systems for domestic hot water demand [33]. It is assumed that they can supply 65 GW of positive and negative flexibility for up to two hours or respectively longer at proportionally reduced power. Further details on technical and economic assumptions are shown in appendix A.1.4. The potential of DSM measures in the industry sector is assumed comparatively small as only processes with known flexibility potential are considered. The potential for 2050 will be most likely much higher, but could not yet be quantified sufficiently. This is an interesting research question for further studies.

Storage technologies can convert electricity into a storable type of energy in a conversion unit. This type of energy (potential, chemical, kinetic or thermal energy) is temporarily stored in a storage unit and converted back into electrical power later using a power conversion unit. For example, for hydrogen or methane storage, electricity is converted to chemical energy via electrolysis optionally followed by methanation for storage. The storage media is hydrogen or methane respectively and the type of energy is chemical. It is then converted back to electricity using gas turbine or CCGT technology. Fuel cells are also an option for converting chemical energy into electricity. They still need significant cost reductions and lifetime increase and therefore are not treated as a standard option. Storages serve a positive slice with energy that was stored previously from a negative residual load or from a flexible generation unit with unlimited power generation potential from coal, gas or biomass from a slice with idle operation in between. The schematic for type 3 technologies is shown in Figure 11.

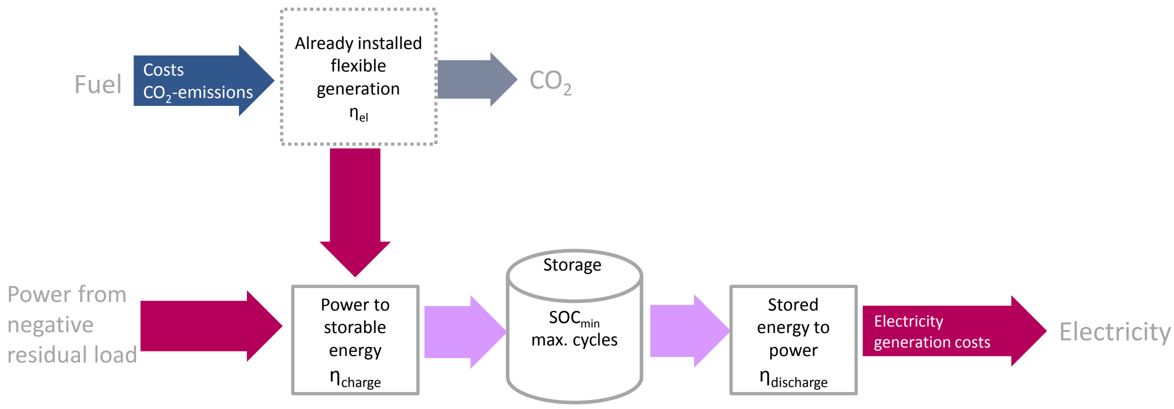

Figure 11: Schematic of type 3 technology representation.

Type 3 technologies are technically characterized by their charging/discharging efficiency as well as restrictions in the storage unit. The lifetime of a storage unit is modeled with a cyclic and a calendric part which allows considering the relevant aging processes of the application. Economic parameters comprise the investment costs of charging/discharging and the storage unit, O&M costs as well as possible fuel and CO_2-emission costs for charging from net generating technologies.

The calculation for storage technologies also involves optimization to determine the cost-optimal size of capacity and charging unit for any slice of the residual load. The optimization follows the logic design shown in Figure 12. First, the discharge power $P_{el,discharge}$ is fixed by the needs of the current slice and then setting the charge power $P_{el,charge}$ to the largest meaningful value. For charging, the full remaining negative residual load is considered. The two nested loops optimize the recharge from flexible generation in slices below the current slice by activating it for critical time steps, while optimizing the charge power by decreasing it until no further cost reduction is observed. For all loop iterations, the necessary storage size $E_{storage}$ is determined and the full costs are calculated. For recharging from flexible generation, the mean costs and CO_2-emissions of the technology mix below the current slice are taken into account. The implementation covers additional options not shown here like constraints for the power to capacity ratio, power and/or capacity limits and bidirectional charge/discharge units.

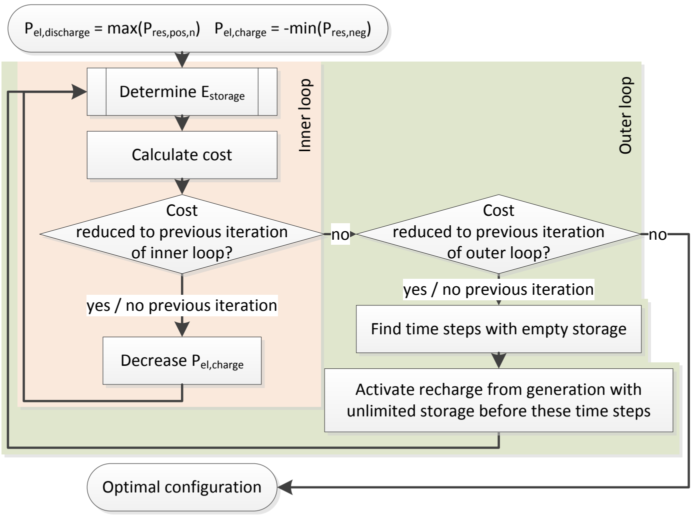

Figure 12: Logic design of optimization for storage technologies.

Determining the necessary storage capacity from any given storage power time series is done as follows: Given such a storage power time series, the total amount of energy going into the storage must be greater than the total amount of energy drained from the storage plus any losses. We integrate the power time series to get the corresponding energy time series E(t) for the case of no upper or lower capacity limits (see Figure 13). From this energy time series, the capacity is mostly determined by the largest relative discharge difference, i.e. the largest positive difference $E(t_1) - E(t_2)$ between the values of the curve at any two points t_1 and t_2 with $t_1 < t_2$. The initial SOC is set accordingly, so that the energy time series bottoms at 0 SOC. In case we want to ensure $E(t_{end}) \geq E(t_0)$, we have to increase the capacity (Capacity_adj) by $E(t_0) - E(t_{end})$, if this difference is positive, and the initial SOC also needs to be adjusted.

When the optimization is finished, the actual power flow is evaluated and the negative residual load is updated by subtracting the energy consumed by the storage device.

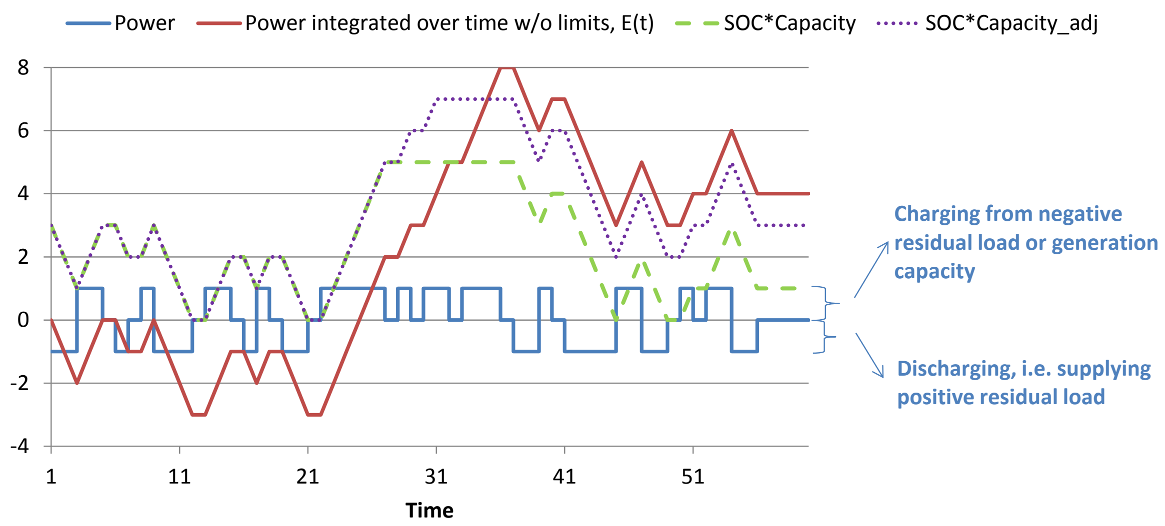

Figure 13: Exemplary power and energy time series for storage capacity determination.

The costs of a storage system comprise capital costs C_{cap}, costs for fuel $C_{fuel,recharge}$ and CO_2-emissions $C_{CO2,recharge}$ from recharging from power plants and O&M costs $C_{O\&M}$:

$$C_{3,n} = C_{cap} + C_{fuel,recharge} + C_{CO_2,recharge} + C_{O\&M} \tag{13}$$

The investment comprises the storage unit (calculated analogue to thermal storage, eq. (11)) and the charging and discharging systems. For each of these components, an individual depreciation time is used [80]. The depreciation time of the storage unit $u_{storage}$ is calculated by the minimum of cyclic and calendric lifetimes (l_{cyclic}, $l_{calendric}$):

$$u_{storage} = \min(l_{cyclic}, l_{calendric}) \tag{14}$$

The cyclic lifetime is calculated using maximum numbers of cycles n_{cyclic}, the storage gross capacity $E_{storage,gross}$ and the energy throughput $E_{throughput}$ per year:

$$l_{cyclic} = \frac{n_{cyclic} \cdot E_{storage,gross}}{E_{throughput} / year} \tag{15}$$

The parameters for type 3 technologies can be found in appendix A.1.4.

Energy from the negative residual load is offered to the storage systems at no cost and no CO_2 emissions. CO_2 emissions do not occur because the negative residual load is generated from renewable energies only. The costs are already on the balance sheet, because the full investment and O&M cost for wind and PV generators are taken into account in the overall cost calculation.

2.6.4 Power-to-X

The remaining negative residual load, after the energy used by storage technologies is subtracted, can be used by power-to-X technologies. We consider power-to-heat and power-to-gas. The technology assignment is made in a similar manner as the positive residual load is assigned to technology class 1. As they generate a value by producing gas or heat, a credit is given for displaced fuel and CO_2-emission costs under the assumption that natural gas would be used otherwise. These technologies are only deployed if they can generate a positive value by considering the investment and O&M costs on the one hand and the credits by displaced natural gas and CO_2 on the other hand. If the costs are higher than the credits, fluctuating renewable generation is curtailed. The parameters for power-to-X technologies can be found in appendix A.1.5.

2.7 MATLAB implementation of algorithm for cost-based technology mapping

The algorithm for cost-based technology mapping is implemented in MATLAB. A complete schematic overview is given in Figure 14. Inputs for the algorithm are the time series of the residual load $P_{res(t)}$, a CO_2-emission target $e_{CO2,target}$, an initial value for internal CO_2-costs $c_{CO2,initial}$ and a technology parameter set.

In a first loop with n_{max} iterations (number of positive load slices), a technology mix for covering the positive residual load is calculated. In each loop iteration all technologies are evaluated for the present load slice. In in the calculation process for type 1 technologies, the technology-specific LCOE $C_{1,n}/E_n$ and the emissions of all technologies of the group “Flexible generation with unlimited storage” are evaluated. For storage technologies, the remaining negative residual load has to be evaluated in each loop iteration by considering the already used negative residual load $P_{res,used}(t)$.

In a second loop, the negative residual load which remains after assigning technologies for covering the positive residual load is evaluated for Power-to-X usage. For each slice of the negative residual load $P_{res,neg,n\_neg}(t)$ (in total there are $n_{neg,max}$ negative load slices) the Power-to-X technology with the highest revenues is selected. If Power-to-X-technologies cannot generate a positive value, the energy is curtailed.

After these two loop evaluations a valid technology mix was calculated, resulting from the initial internal CO_2 costs. An outer iteration loop now adapts the internal CO_2 costs c_{CO2} in way that the total CO_2-emissions $e_{CO2,sum}$ are close to the defined CO_2-target $e_{CO2,target}$. For that a bisection algorithm is used [81] which increases internal CO_2 costs if $e_{CO2,sum} > e_{CO2,target}$ and decreases internal CO_2 costs if $e_{CO2,sum} < e_{CO2,target}$.

For calculating a complete set of scenarios, the algorithm has to be run for each residual load curve of the scenario set.

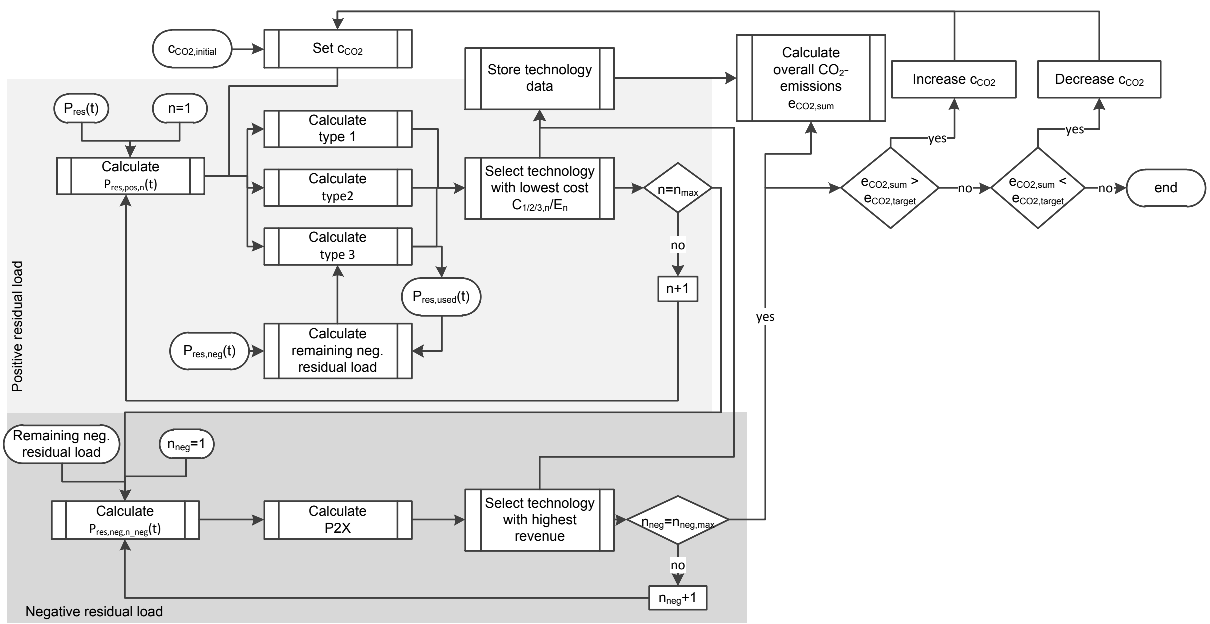

Figure 14: Schematic overview on algorithm for cost-based technology mapping.

3 Results

Selected results are shown in this section to demonstrate the capabilities of the developed method. Comprehensive results are to be given in a follow-up paper.

3.1 Frozen scenario

For the frozen scenario, no residual load calculation and technology assignment is performed as the installed power and delivered energy of the different technologies is directly defined (see section 2.3.2). With the reference technology parameters for 2050 we calculate the key figures summarized in Table 6.

Table 6: Summary of key figures of the frozen scenario.

Annual investment costs (annuity)	17.3 bn	€/a
Annual O&M costs including startup costs	6.8 bn	€/a
Annual fuel costs	13.4 bn	€/a
Annual costs for CO_2-emissions (costs for CO_2-certificates 76 €/t)	15.7bn	€/a
Total costs (costs for CO_2-certificates 76 €/t)	53.3 bn	€/a
Total costs (costs for CO_2-certificates 0 €/t)	37.6 bn	€/a
Overall levelized cost of electricity (costs for CO_2-certificates 76 €/t)	98	€/MWh
Overall levelized cost of electricity (costs for CO_2-certificates 0 €/t)	69	€/MWh
Annual CO_2-emissions	207 m	t/a
Specific CO_2-emissions	381	g/kWh

Reduction of CO_2-emissions compared to 1990	49 %

Due to the high overall CO_2 emissions CO_2-certificate costs have a very high influence on the total costs and on the overall LCOE. The LCOE are around 40 % higher under consideration of CO_2 costs of 76 €/t than without. With the technology mix in the frozen scenario, the CO_2 reduction compared to the level in 1990 is less than 50%.

3.2 Reference case

The reference case in our study is based on the FRES shares and the load demand in scenario S3, the target scenario of the German government [8]. The reference case scenario is used for comparison purposes. Based on these settings we calculate a mix of flexibility technologies with the presented method. Critical technologies with respect to poor social acceptance and political feasibility are not included in the technology portfolio of the reference case.

3.2.1 Assumptions

For the reference case we use the reference cost and technology parameters shown in appendix 7A.1. Furthermore a discount rate of 8 % is used. Due to a low social acceptance, lignite CCS technology is not part of the technology portfolio of the reference case. CSP electricity import is not used in the reference scenario as an option due to uncertainties regarding political feasibility. But CCS and CSP technology have been taken into account in variations of the scenario not shown here. The potential for bioenergy is assumed to be 100 TWh_{th}, which is in the range of today's bioenergy usage in Germany (estimated on basis of [82]).

3.2.2 Technology assignment – results of optimization for the reference scenario S3

In addition to the fluctuating energy sources, gas turbines and CCGT power plants are used as well as CHP systems (see Figure 15). Some of the CCGT plants use biomethane as fuel to meet the overall CO_2-emissions target of a 90 % reduction compared to 1990. Coal power plants are not employed in this case.

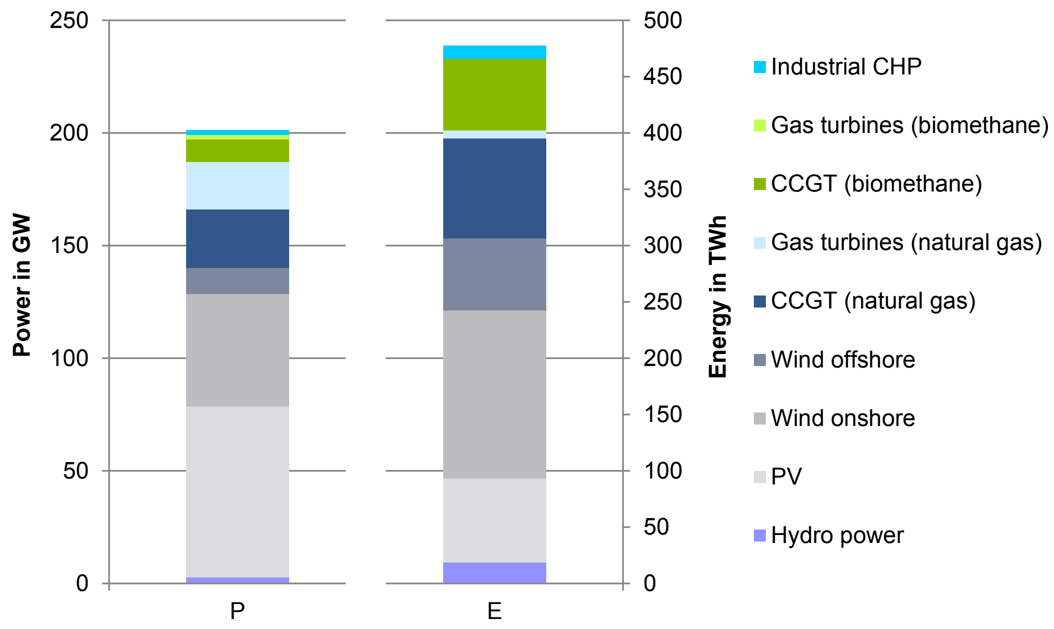

Figure 15: Mix of generation technologies in reference case S3. P: power, E: energy.

In addition to flexible generation, storage technologies are used, see Figure 16. DSM measures in the household and industry sector are expected to be an economic solution for providing flexibility in 2050. Figure 16 also shows the very small usage of the DSM potentials. While the required DSM capacities are 4 GW, their contributions in terms of energy is extremely low.

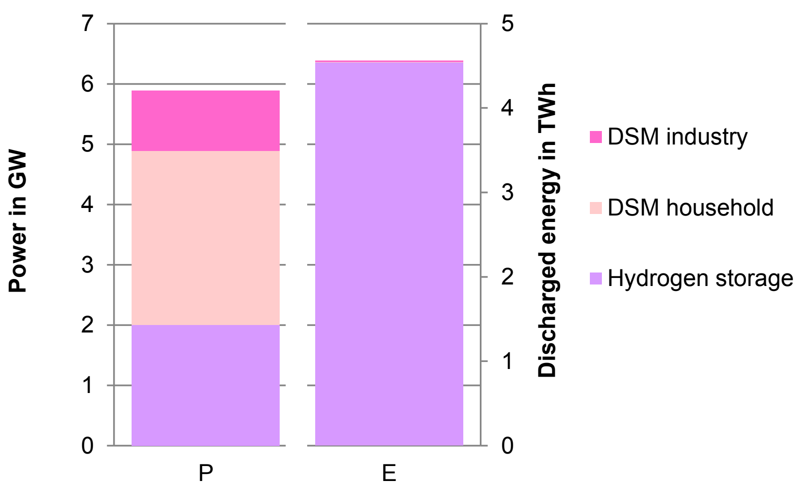

Figure 16: Mix of storage technologies in reference case S3. P: power, E: energy.

3.2.3 Costs

Table 7 shows the individual LCOE of the used technologies. The overall LCOE in the reference case, including 76 €/t CO_2-costs, are 82.6 €/MWh. The total share of the energy provided by FRES compared with the total power consumption is 52 %. FRES deliver electricity below this value, PV and onshore wind have the lowest costs. CCGT power plants and CHP plants fired with biomethane and natural gas have comparatively high full load hours and deliver the majority of the residual power demand. Gas turbines are used for covering peaks with low utilization. 2 GW of biomethane gas turbines are only used as backup for a very few hours in the year. The generation technologies are complemented with storage technologies. In the reference case, 2 GW (discharge power) of hydrogen storage is used with a capacity of around 250 hours at nominal power. The full capacity is used 6.1 times a year (equivalent full cycle number). The DSM measures are only used for covering peaks with a very low utilization and therefore high individual LCOE. However, the levelized costs of power (LCOP) are the smallest among all technologies. Power-to-heat is used for the utilization of surpluses from FRES generation. The full potential of 10 GW of this technology[7] is used and a mean surplus of 43 €/MWh is generated.

Table 7: Key figures for used technologies in the reference case

	Installed power in GW	Delivered energy in TWh	Full load hours/full cycles	Annuity in bn EUR	LCOE in €/MWh	LCOP in €/kW/a
Hydro power	5	18.627	3500	1.164	63	233
PV	79	74.850	950	4.310	58	55
Wind onshore	50	149.254	3000	8.247	58	165
Wind offshore	12	63.682	5500	5.010	79	418
Gas turbines (natural gas)	21	7.553	360	1.786	291	85
Gas turbines (biomethane)	2	17	9	0.094	5475	47
CCGT (natural gas)	26	88.667	3410	9.395	145	361
CCGT (biomethane)	10	63.476	6348	6.392	101	639
Industrial CHP	2	11.700	5850	1.015	119	508
Hydrogen storage	2	4.542	6.1	0.658	150	329
DSM household	3	6	1	0.068	10705	23
DSM industry	1	16	2.6	0.010	635	10
Power-to-heat	-10	-8.517		-0.362	-43	36

3.3 90 % CO_2-reduction goal for all scenarios

With the assumptions of the reference case, a technology mix for all 9 scenarios is calculated. The results are shown in Figure 17. Using the same technology parameters and the same method for all 9 scenarios guarantees a good comparability. Different questions can be answered by this analysis (and will be discussed in depth in a follow-up paper). For example, how is the technology mix influenced by the share of FRES?

[7] For power-to-heat only heat demand with no seasonal fluctuations is regarded which limits the potential to 10 GW.

Low FRES shares in combination with an ambitious CO_2-reduction target lead to the utilization of geothermal energy (S1 and S2). At higher FRES shares biomass is used to various extents (S3, S6-S8). And at high FRES shares small amounts of lignite in combination with natural gas are used.

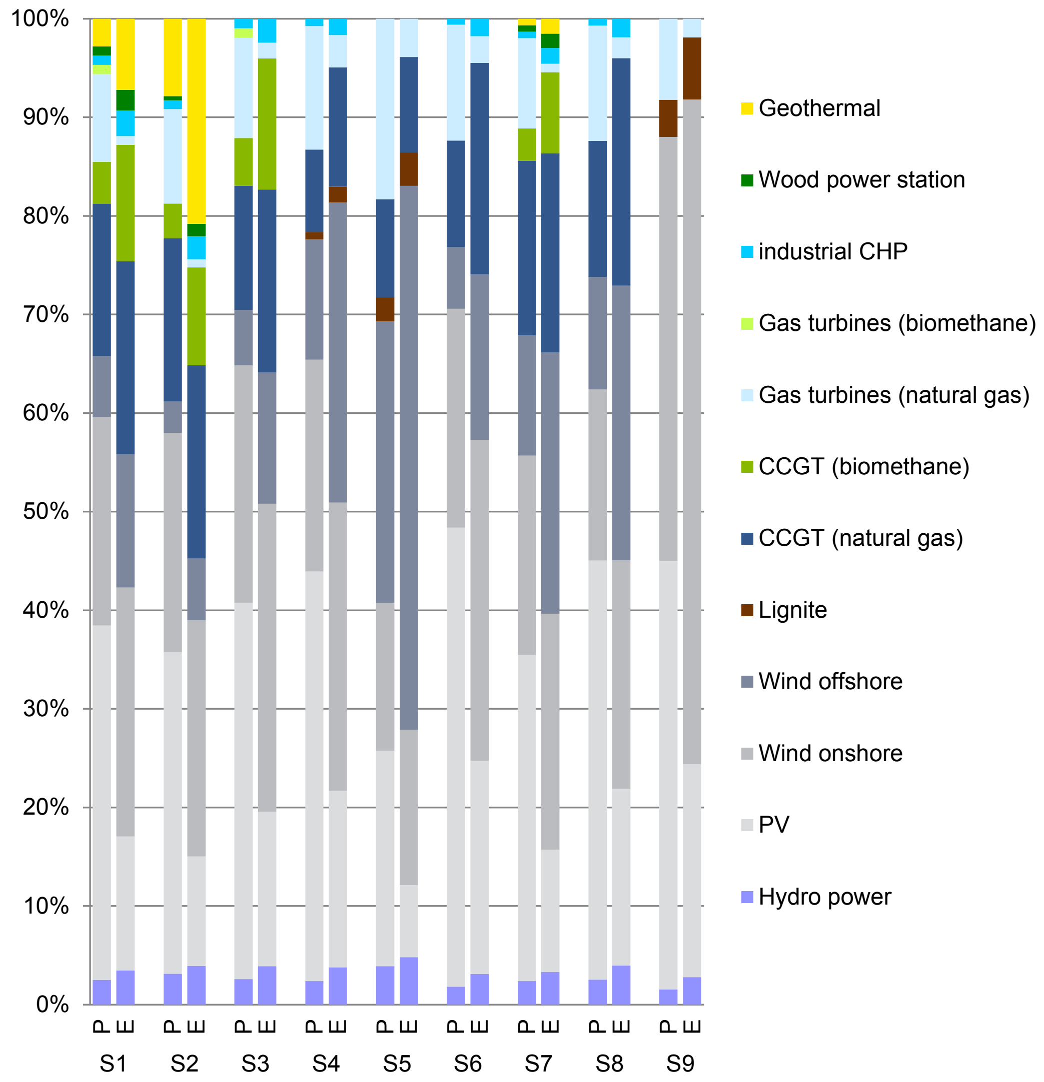

Figure 17: Mix of generation technologies for a CO_2-reduction of around 90 % compared to 1990. Storage technologies are not shown. P: power, E: energy.

3.4 Sensitivity analysis

To demonstrate the capabilities of the developed method, the sensitivity to the CO_2-emission target and the discount rate are shown.

3.4.1 CO_2-emissions

For scenario S3, three different CO_2-emission targets were evaluated: 80 %, 90 % and 100 % reduction compared to 1990. The differences in the mix of generation technologies can be seen in Figure 18. In a system with only 80 % reduction of CO_2 emissions, lignite is used as generation technology. At 90 % CO_2-reduction, lignite is substituted by biomethane and natural gas fired in CCGT power plants. At an emission target of 100 % biomethane and wood power plants as well as geothermal energy are used. Additionally hydrogen storage with a discharge power of 23 GW, a charge power (electrolysis) of 97 GW and a capacity of 13 TWh is used.

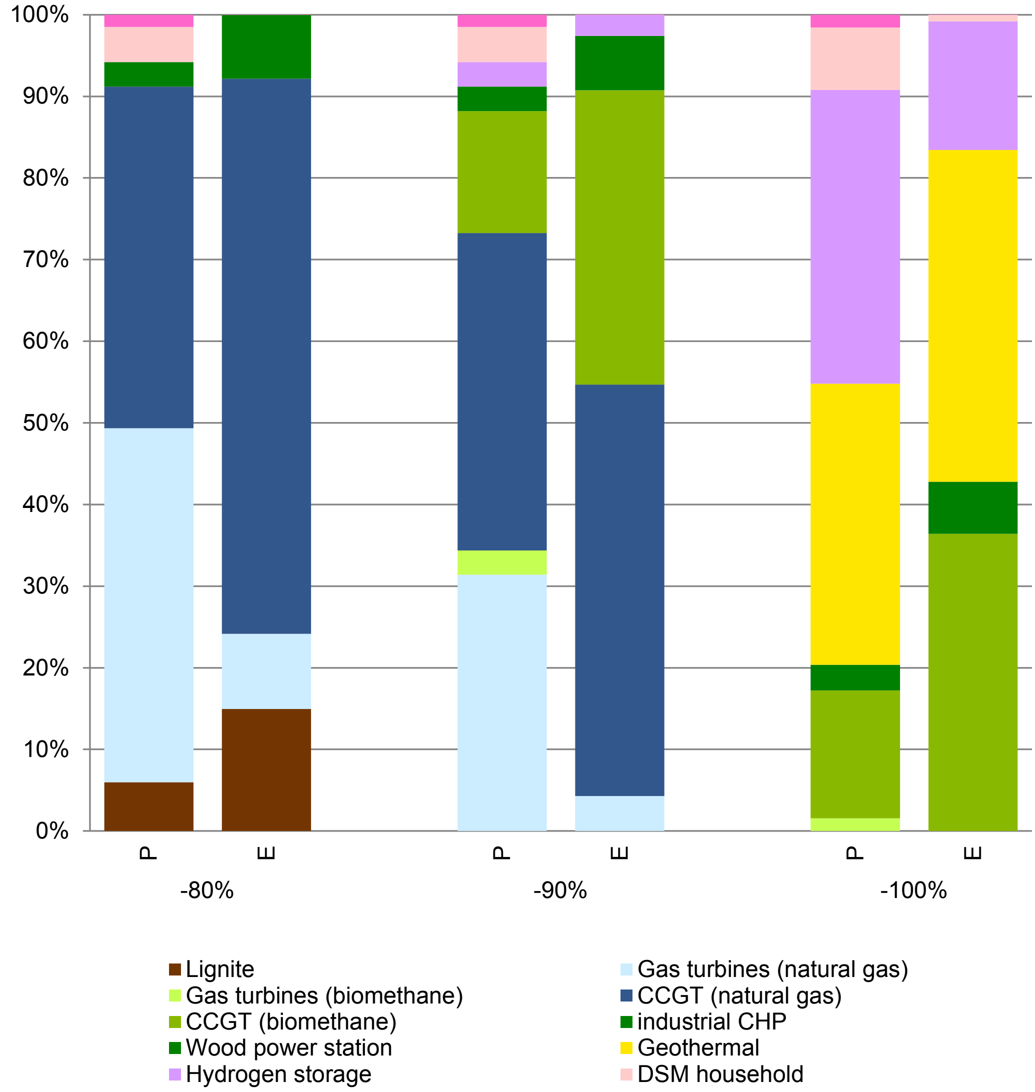

Figure 18: Mix of flexibility technologies (without FRES) in scenario S3 for CO_2-emission targets of 80 %, 90 % and 100 % reduction compared to 1990. P: power, E: energy.

3.4.2 Discount rate

The sensitivity of the technology mix to different discount rates becomes obvious in the installed power of hydrogen storage technology in scenario S9. As this is a technology with comparatively high investment costs, the cost effectiveness of hydrogen storage in comparison to other flexibility options is very sensitive to the discount rate. While only around 5 GW of hydrogen storage are used with 12 % discount rate, almost 40 GW are used with a discount rate of 4 %. At 12 % discount rate, gas turbines (with low capital costs) are used instead of hydrogen storage. The effect on the overall LCOE is also very significant: The costs are approximately 20 % higher with 12 % discount rate and around 20 % lower with 4 % discount rate compared to the case with 8 % discount rate.

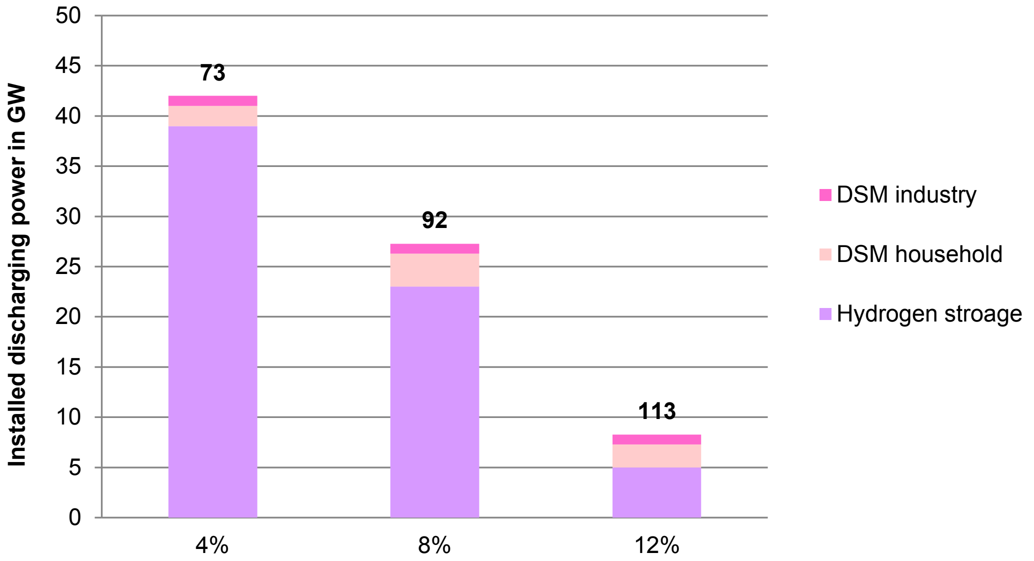

Figure 19: Installed discharging power of storage technologies depending on discount rate for S9 (122 % FRES). Overall LCOE in EUR/MWh is shown on top of the bars.

3.5 Application example: Possible power systems with a very high degree of CO_2-reduction

The developed method can for example be used to investigate different options for power systems with a high degree of CO_2-reduction. A full decarbonisation of the power system can only be reached by using renewable energy for power generation. For this case we investigate the influence of CSP usage for the German power system. If certain remaining emissions are allowed the power system layout has higher degrees of freedom. E.g. a small amount of fossil generation can be used to balance fluctuations from renewables. Within the defined scenario corridor of FRES, a maximum of 4 % remaining emissions compared to the 1990 level occurs in scenario S2. Due to low renewable generation in this scenario, the residual load demand can only be covered with the usage of 80 TWh_{th} natural gas in 25 GW of gas power stations. In S2 and S7, no valid system configuration can be found with only using renewable generation. The potential of CO_2-free generation from biomass is not sufficient to cover the residual demand. For scenario S1 with 53 % FRES a valid power system design can be found without using fossil generation, but at very high costs (refer to Figure 20 and Figure 21). Here, 32 GW of geothermal power generation is used with technology-specific LCOE of 250 €/MWh. If a small amount of remaining emissions is allowed in S1 (refer to Figure 21), the usage of 40 TWh_{th} natural gas is sufficient to lower the LCOE substantially. Natural gas power stations then deliver 24 TWh of electric power, see Figure 22.

The usage of CSP has the biggest effect on LCOE in scenario S1 and S2 with the lowest FRES share. By using CSP, the LCOE is around 15 % lower. However, in S1 34 GW of CSP power is used. It has to be discussed at a political level whether an import of CSP power of that magnitude is desired and realisable or not. At FRES shares between 60 and 80 % the cost lowering effect of CSP is smaller (around -5 %) and above 80 % FRES the influence of CSP usage on LCOE is negligible or zero (S9). In S9, allowing remaining emissions has no cost-lowering effect. For a high degree of CO_2-reduction scenario S9 with 122 % FRES share has the lowest LCOE, independent of CSP usage.

In S1, only small amounts of surplus energy are used for Power-to-heat (see Figure 22). Due to the limited potentials of CO_2-free generation surplus energy has to be used to a large extent. Even in scenario S4 (90 % FRES) curtailment and Power-to-heat usage is fairly low at 15 TWh. A large amount of the surplus energy of around 100 TWh is used by hydrogen storage systems, which deliver 45 TWh of power. Only at very high FRES shares (S9, 122 % FRES) is the surplus energy used by Power-to-heat (19 TWh) or curtailed (110 TWh). Even at these high amounts of surplus energy it cannot be used by power-to-gas technology in a cost-covering manner. This would only be possible with lower investment costs (we assumed 800 €/kW, see appendix A.1.5) for power-to-gas plants or higher revenues for the generated gas.

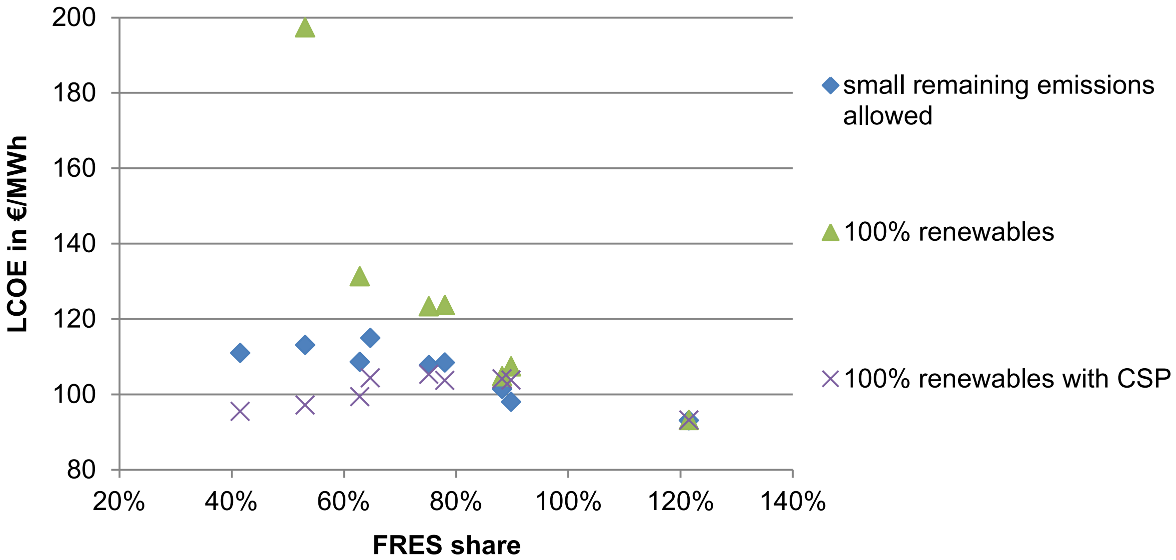

Figure 20: LCOE depending on FRES share at a very high degree of CO_2-reduction.

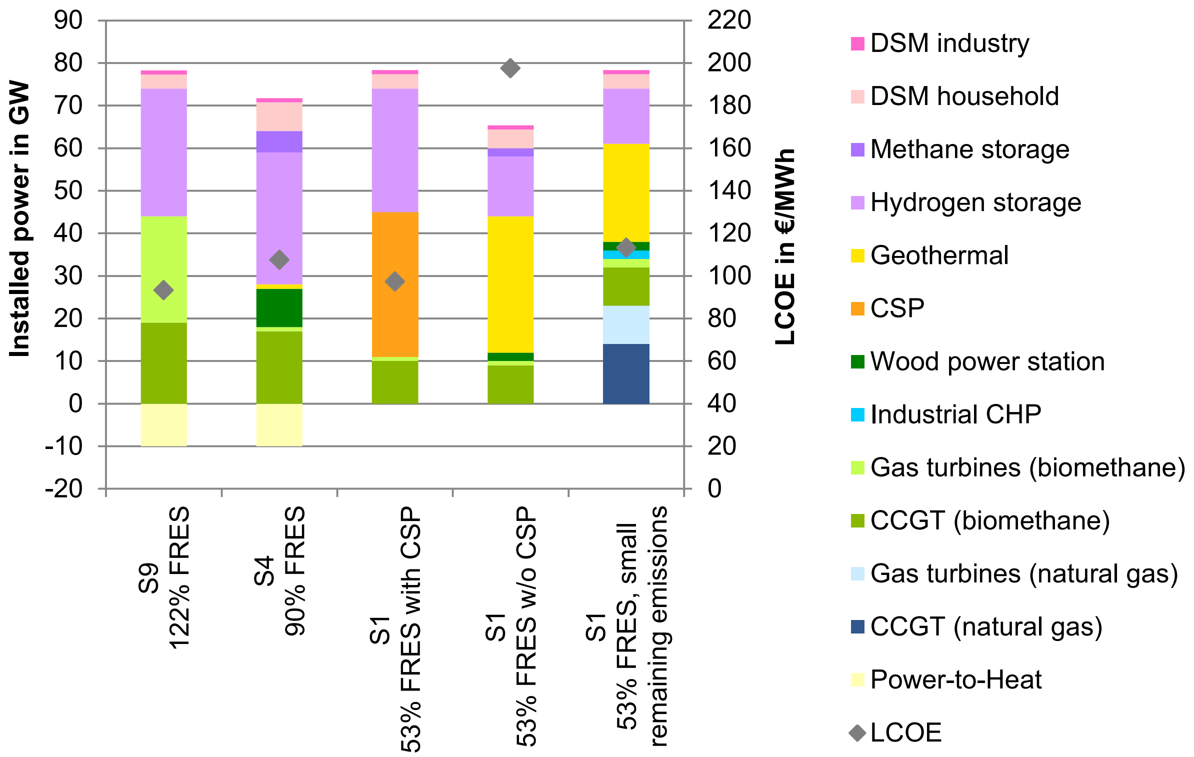

Figure 21: Installed power and LCOE of power systems with a very high degree of CO_2-reduction.

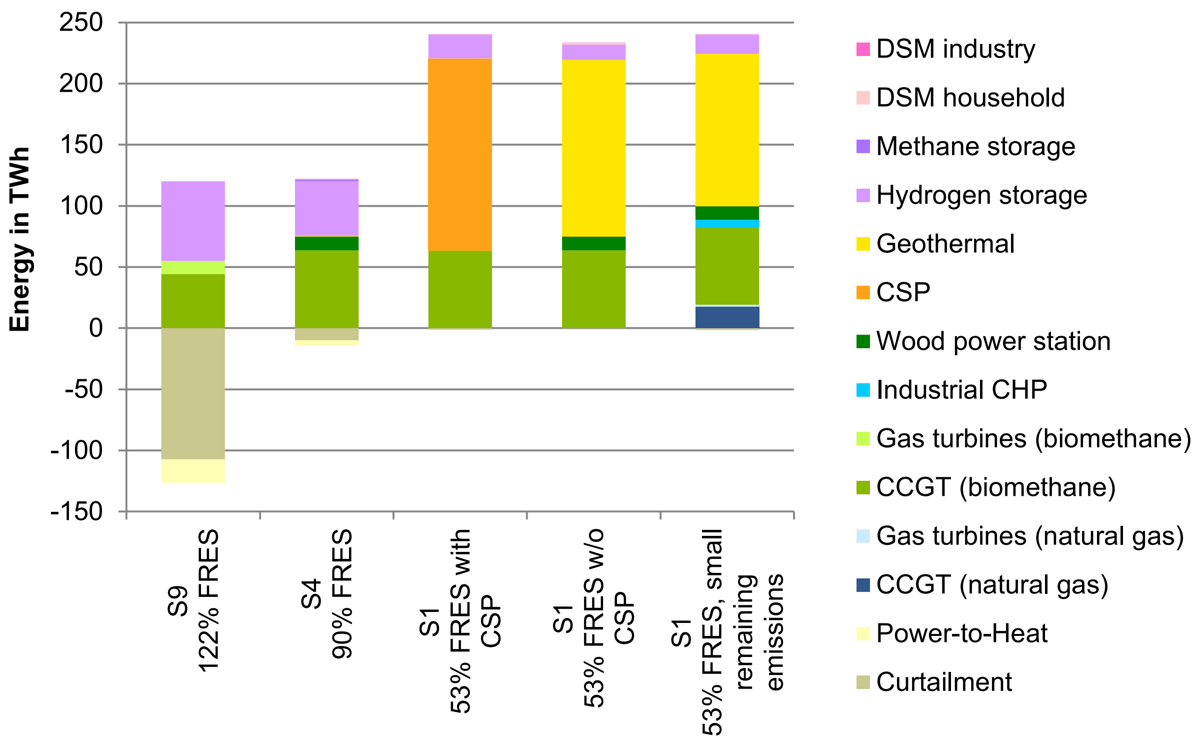

Figure 22: Energy delivered in power systems with a very high degree of CO_2-reduction.

As a conclusion for strategic decisions in energy policy we can identify, that FRES shares above 100 % are the cheapest option for a CO_2-free power sector. From an investment perspective, risks are relatively low if the target of a decarbonized power sector is bindingly defined. Our investigations show that technologies such as lignite power stations, CSP or geothermal power generation do not play a role in these kinds of systems. This is due to the fact that the utilization of these technologies would be very low and therefore their power generation costs comparatively high.

4 Discussion

The presented method was developed so that many options for a future electricity system can be evaluated in a manageable period of time. Therefore some restrictions had to be applied to keep the model simple with respect to its structure and system boundaries. By regarding a large variety of different system alternatives, uncertainties of future developments can be covered. The results therefore are not predictions of future power system designs but allow for a better understanding of different alternatives, of different political decisions regarding specific technologies or capacity limits and finally the resulting consequences. Analysing and comparing a large variety of alternatives helps to identify important influence factors for an adequate mix of flexibility options and to identify interdependencies in the system. The most important restrictions are discussed in the following.

4.1 Limitations of the algorithm for cost-based technology assignment

Technologies for covering the residual load are assigned based on a decomposition of the residual load in power slices. We do not formulate a global optimization problem covering all interdependencies between the technologies. Most economic technologies are assigned to the power slices in a hierarchical matter regarding the characteristic of each power slice. This guarantees that the maximum load in the system can be covered at all times. Further optimization potential lies in covering one power slice by a mixture of technologies. The results of our method therefore are conservative with respect to system costs. The effect of a further optimization of the technology mix is to be evaluated in following studies.

The share of wind and PV is set by the scenarios and is not part of our optimization. The basis for our optimization is the residual load curve; we therefore only optimize complementary technologies in addition to FRES. Due to the large bandwidth of FRES shares in the scenario corridor (refer to section 2.2) different variants of electricity systems can be compared. These examinations allow for conclusions about the effects of different FRES shares on, for instance, the costs and mix of flexibility technologies.

Other system simulation and optimization tools for example used in the underlying scenarios S1-S8 of course have a higher accuracy and are able to cover more complex interdependencies. But these models also have higher runtimes in the range of days or weeks which do not allow for covering a large set of parameter variations. Our model has a runtime of around 15 minutes on one core of a standard PC for one parameter set and 9 scenarios. The unique added value of our model is therefore the possibility of evaluating a large set of possible electricity systems in combination with a large set of different parameters to identify important influence factors on the mix of technologies. Even though we have evaluated more than 200 system variants we are not able to cover all possible combinations. Therefore the parameter set for the variations was developed in a broad consultation process with experts to minimize the risk of not including important cases. The tool could be used by ministries, utilities and component manufacturers to analyse how changes in parameters and boundary conditions will change the overall system design. The high computational speed allows for a comprehensive analysis of the interdependencies.

4.2 Limitation to electricity sector

Our analysis is focused on the electricity sector although only one third of end energy is supplied by electricity [15]. But the balancing of generation and demand is most challenging in the electricity sector as other sectors like heat and traffic have large inherent storage capacities (gas grid, fuel tanks). To some extent we have included these sectors in our analysis by modeling electric vehicle batteries and heating systems as flexibility options for the electricity system (see section 2.6.3). Further possibilities for an integration of these sectors are in the area of power-to-X-technologies, which are able to deliver heat or gas to other sectors.

The interconnection with the heat sector could only be taken into account for constant load heat consumers, as no seasonal and daily fluctuating heat demand curves have been integrated into the model so far. The potential of CHP systems for industry is around 2 GW in this case and for power-to-heat (industry, district heating) of around 10 GW [33]. Including also fluctuating heat demand increases these potentials significantly and should be subject to further research.

4.3 European integration

For the example of Germany the investigations are focussed on the national electricity system and we do not consider import or export of electricity besides the import of electricity from CSP systems in southern Europe or North Africa. Many studies show that an integrated European electricity system has lower overall electricity costs [83]. These studies mostly assume a strong enhancement of grid exchange capacities between neighboring countries. Furthermore the FRES share is often smaller in the neighboring countries than in Germany even in 2050. This results in a high flexibility supply for Germany by conventional power plants from abroad. To incorporate these effects, it would have been necessary to define scenario corridors for all European countries as we did for Germany. This was not possible within our study and could be an interesting topic for further research. Anyway, with further decreasing costs for FRES other European countries will also increase their FRES share due to economic reasons. In case of a similar roll-out of FRES in European countries the effect of strong grid interconnection will be quite limited. The reason is the dominating effect of the longest “dark calm” period. “Dark calm” periods of two or three weeks only occur under very stable weather conditions with almost no barometric pressure differences throughout Europe. This simply means, “dark calm” periods of several weeks are not a phenomenon of a national country but of major parts of the continent. Therefore other countries cannot help to minimize the flexibility demand in Germany with their FRES capacities in these situations. However, as long as the FRES shares in the different nations are very unequal, strong grids help to reduce the flexibility demand.

4.4 Greenfield approach for 2050

Our study uses a greenfield approach for the year 2050. That means all necessary components have to be built in 2050 on a “green field” and no transition process is modeled. Only opencast lignite pits are regarded as existing; it is assumed that no completely new opencast lignite pits will be built in Germany. No further existing and written-off assets are considered. The grid infrastructure is assumed to be ideally available (“copper plate” approach) and the costs for this infrastructure are not included. The “copper plate” approach is in line with many other studies in this field (see section 1).

Scenarios for the year 2050 require estimates of the future technology development and resulting efficiencies and costs of the technologies modeled. The assumptions for parameters are mostly based on already existing technologies with a continuous development until 2050. These parameters are based on expert opinion and were compiled in an extensive consultation process with more than 100 experts from science and industry within the Academies’ project “Energy Systems of the Future” [84].

The year 2050-based approach implies that support policies or market introduction incentives and their effects on technology parameters cannot be modeled for the transition process from today until 2050. However, the technology parameters for 2050 were compiled based on technology learning curves. These learning curves presume continuous research and development as well as certain production volumes. By that, supporting measures are implicitly included in the development of technology parameters. As technology parameters can easily be varied we are able to investigate the influence of e.g. different cost assumptions for renewable generation on total system costs. With that we are able to identify technologies with the highest impact on overall LCOE in dependence on several boundary conditions. This analysis can be the basis for the development of effective support policies and investments in research and development.

The results from this greenfield approach for 2050 can therefore assist todays decisions in politics, society and industry. General regulations should be designed in a way that a transition towards a 2050 intended electricity system is incentivized. Given the technical plant life of some power plant technologies of up to 50 years, investments in energy technologies today which are not needed anymore in 2050 can be questioned. Summarized, the developed method generates indications for investments and strategic decisions regarding technological developments which are necessary today to reach the goals for 2050. Furthermore, consequences from societal preferences can be illustrated: For instance, what are the differential costs when particular technologies are excluded?

4.5 Macroeconomic versus microeconomic perspective

The technology assignment is based on a simplified macroeconomic perspective. Technologies are selected in a way that the overall electricity costs are minimized considering boundary conditions like technology availability or a CO_2-reduction goal. The cost analysis is limited to the electricity system including investment, O&M expenses and fuel costs as well as costs for CO_2-certificates. Further macroeconomic effects like effects on employment, reduction of imports of energy carriers or investments in research and development are not considered.

The study therefore evaluates the cost-minimal mix of technologies for different FRES shares and other boundary conditions. In a second step beyond this study adequate market regulations need to be designed to foster the transition of the electricity system from today to 2050. A major challenge will be to find an economically efficient way for that.

4.6 Universality of the methodology

Although the developed methodology for cost-based technology mapping is explained with the German power system in the year 2050 as an example, it can be applied to arbitrary power systems which meet the following criterion: A set of different residual load curves representing possible power system configurations has to be available. In general, residual load curves can be calculated if time series for fluctuating power generation and the load demand exist. For Germany as an example, residual load curves are calculated based on a scenario analysis. If a scenario analysis is not possible or not desired, a systematic variation of the installed power of different fluctuating generators as well as the load demand can be made.

5 Conclusions

We have presented a method for analysing potential future electricity systems based on a systematic scenario analysis, residual load calculation and a newly developed method to design a macroeconomic cost-efficient power system. The scenario analysis uses objective criteria to identify a set of scenarios from existing literature describing the space of possibilities for potential future power systems of a nation. From this scenario corridor, the determining factors for a residual load calculation are extracted. Taking Germany in 2050 as an example, the share of electricity from PV and wind power plants is in a range of 42 to 122 % and the load demand has a bandwidth of around 460 to 750 TWh. The calculation of residual load curves for each scenario is done with the same assumptions concerning technology characteristics, spatial distribution of plants and weather data to guarantee a good comparability of the results. Using the residual load curves as input data, a newly developed method for defining a complementing mix of flexibility technologies was presented. The technology parameters were identified in a large expert working group and are given in the appendix of this paper. The MATLAB-implemented algorithm uses some simplifications to reach a high simulation speed but still simulates a whole year in hourly resolution. With that we are able to calculate a complete set of 9 scenarios within around 15 minutes. The fast simulation capabilities make it possible to perform almost “real-time” calculations of the impact of changes in input parameters or assumptions and taking into account a large set of technologies. The method is able to incorporate certain political and societal restrictions like CO_2-emission targets as well as the exclusion or limitation of technologies. Based on the results, discussions about the future electricity system can be made on a factual level. As we are not developing one optimal solution for the future power system but consider a broad solution space, different solutions can be compared and their advantages and disadvantages identified. On the example of power systems with a high degree of CO_2-reduction we have demonstrated the capabilities of the methodology. It could for instance be shown, that capital-intensive generation technologies like concentrated solar power only play a role in power systems with a FRES share below 80 %. If a full decarbonisation of the power sector is set as the target, a FRES share above 100 % (FRES deliver more electricity than the load demand) should be aimed at.

The strengths of the proposed method can be fully used by analysing a large set of different options for power system design. As the methodology guarantees comparability among these different possibilities, comparative analyses can be made and general conclusions can be identified. In a follow-up paper we will investigate, among others, dependencies of the power system layout and LCOE on the degree of decarbonisation, natural gas imports, biomass potentials and the usage of CSP and CCS technology.

6 Acknowledgement

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A Appendix

A.1 Technology parameters

A.1.1 Fluctuating generation

	Hydro power
LCOE in €/MWh (calculated based on renewable energy law, EEG)	62.5

Photovoltaics	Reference case		Technological progress case	
	PV rooftop installation	PV field installation	PV rooftop installation	PV field installation
Efficiency modules %	29.5	29.5	35	35
Mean electricity production in kWh/kWp	1095	1095	1190	1190
Module costs in €/kWp	300	250	200	140
Inverter costs in €/kWp	65	50	50	40
Balance of system costs in €/kWp	225	165	200	120
O&M cost in €/kWp/a	10	10	10	10
Lifetime modules and installation in years	37.5	37.5	40	40
Lifetime inverter in years	25	25	30	30
LCOE in €/MWh (8 % discount rate)	66	49.5	52	35
Share of total installed power in %	50	50	50	50

	Reference case	Technological progress case

Wind energy	Wind onshore	Wind offshore	Wind onshore	Wind offshore
Full load hours	3000	5500	3000	5500
Wind turbine incl. installation in €/kW	950	2750	800	1500
Grid access in €/kW	75	485	30	170
Rent for land use in €/MWh	7.5	0	5	0
O&M costs in €/MWh	12.5	15	10	10
Lifetime in years	22.5	22.5	25	25
LCOE in €/MWh (8 % discount rate)	58.5	78.7	39.2	42.4

A.1.2 Flexible generation with unlimited storage

	Steam turbine power plant (ST) hard coal 600 MW-class	ST dried lignite 600 MW-class	ST dried lignite 600 MW-class, incl. CCS	Gas turbine (GT) (natural gas)
Efficiency (best) in %	50%	50%	42%	46%
Investment per GW_{el}	1.400 bn €	1.800 bn €	2.700 bn €	375 m €
Depreciation time in years	40	40	40	33
Operation and maintenance costs per Investment and year	2.6%	3.3%	3.3%	3.5%
Costs for cold start per GW_{el} and event	60,000 €	30,000 €	30,000 €	25,000 €
Minimum idle time for cold start in hours	24	24	24	24
Costs for warm start per GW_{el} and event	40,000 €	20,000 €	20,000 €	17,500 €
Fuel costs per GWh_{th}	16,000 €	1,500 €	1,500 €	33,100 €
Specific CO_2-emissions in t/GWh_{th}	342	410.4	32.8	201.6
Limit on primary energy in GWh_{th}/a	-	420,000	420,000	-

	GT (biomethane)	CCGT (natural gas)	CCGT (biomethane)	Engine power station (natural gas)
Efficiency (best) in %	46%	64%	64%	45%
Investment per GW_{el}	375 m €	700 m €	700 m €	475 m €
Depreciation time in years	33	33	33	25
Operation and maintenance costs per Investment and year	3.5%	3.0%	3.0%	5.5%
Costs for cold start per GW_{el} and event	25,000 €	120,000 €	120,000 €	30,000 €
Minimum idle time for cold start in hours	24	24	24	24
Costs for warm start per GW_{el} and event	17,500 €	60,000 €	60,000 €	5,000 €
Fuel costs per GWh_{th}	54,090 €	33,100 €	54,090 €	33,100 €
Specific CO_2-emissions in t/GWh_{th}	0	201.6	0	201.6
Limit on primary energy in GWh_{th}/a	100,000	-	100,000	-

	Engine power station (biomethane)	Industrial CHP 1MW-class	Wood power station 5MW-class
Efficiency (best) in %	45%	77%[8]	38%
Investment per GW_{el}	475 m €	750 m €	3.870 m €
Depreciation time in years	25	25	25
Operation and maintenance costs per Investment and year	5.5%	9%	3.4%
Costs for cold start per GW_{el} and event	30,000 €	30,000 €	70,000 €
Minimum idle time for cold start in hours	24	24	24
Costs for warm start per GW_{el} and			

[8] Under consideration of heat production

event	5,000 €	5,000 €	35,000 €
Fuel costs per GWh_{th}	54,090 €	33,100 €	16,905 €
Specific CO_2-emissions in t/GWh_{th}	0	201,6	0
Limit on primary energy in GWh_{th}/a	100,000	-	30,000

A.1.3 Flexible generation with thermal storage

Geothermal energy	**Reference**	**Progress**
Efficiency at nominal power (thermal-electric)	14%	17%
Limit on installed electrical power in Germany in GW_{el}	32,5	32,5
Limit on primary energy in TWh_{th}/a	1,926	1,926
Thermal efficiency storage	98%	98%
Investment per GW_{el} (on the surface parts)	4.527 bn €	3.600 bn €
Investment per GW_{el} (reservoir)	4.750 bn €	1.500 bn €
Depreciation time in years	35	35
Operation and maintenance costs per investment and year	3.5%	2.0%
Investment thermal storage per GWh_{th}	11.5 m €	11.5 m €
Operation and maintenance costs per investment and year (thermal storage)	2.0%	2.0%

Concentrated Solar power	**Reference**	**Progress**
Efficiency HVDC	87%	87%
Depreciation time HVDC	40	40
Length of HVDC circuit in km (Morocco-Germany)	2600	2600
Investment HVDC per GW and km	325,000 €	250,000 €

Efficiency turbine (steam-electricity)	45%	45%
Efficiency co-firing (natural gas-electricity)	48%	50%
Overall efficiency (solar-electricity)	20.5%	22.0%
Auxiliary power demand	10%	10%
Thermal efficiency storage	98%	98%
Investment powerblock per GW_{el}	670 m €	590 m €
Investment thermal storage per GWh_{th}	13.5 m €	11 m €
Investment collector field per m^2	68 €	55 €
Depreciation time CSP-system in years	30	30
Mean solar irradiation in W/m2 (Morocco)	335	335
Operation and maintenance costs per investment and year	2%	2%
Contingencies	27%	25%
Fuel costs co-firing per GWh_{th} (natural gas)	33,100 €	33,100 €
Specific CO_2-emissions co-firing in t/GWh_{th}	201.6	201.6

A.1.4 Storage technologies

	Pumped hydro storage	Adiabatic compressed air energy storage	Hydrogen storage	Methane storage GT
Discharging efficiency	89%	78%	58%	46%
Limit on total installed discharging power in GW_{el}	-	-	-	-

Investment discharging unit per GW_{el} (0 for bidirectional devices)	438 m €	351 m €	375 m €	375 m €
Depreciation time discharging unit in years	40	40	32.5	32.5
Charging efficiency	88%	87%	78%	66%
Limit on total installed charging power in GW_{el}	-	-	-	-
Investment charging unit per GW_{el} (0 for bidirectional devices)	412 m €	299 m €	200 m €	800 m €
Depreciation time charging unit in years	40	40	18	25
Limit on total installed capacity in GWh (gross)	100	88	-	-
Minimum state-of-charge (SOC) related to gross capacity	0%	60%	35%	35%
Maximum cycle number related to gross capacity	-	100,000	100,000	100,000
Investment storage unit per GWh gross (0 for a fixed ratio of charging/discharging power, costs are then included in investment costs charging unit)	50 m €	23 m €	0.45 m €	0.200 m €
Depreciation time storage unit in years	40	40	40	40
Operation and maintenance costs per investment and year	1.2%	1.0%	3.5%	2.5%
Minimum energy-to-power-ration (E2P) related to gross capacity	0	0	0	0
Maximum E2P	-	-	-	-
Fixed ratio charging/discharging power	-	-	-	-
Fixed ratio charging power/capacity	-	-	-	-

	Methane storage CCGT	Battery storage	DSM household	DSM industry
Discharging efficiency	64%	95%	100%	100%

Limit on total installed discharging power in GW_{el}	-	-	65	-
Investment discharging unit per GW_{el} (0 for bidirectional devices)	700 m €	- €	- €	- €
Depreciation time discharging unit in years	32.5	-	-	-
Charging efficiency	66%	95%	100%	100%
Limit on total installed charging power in GW_{el}	-	-	65	0.3
Investment charging unit per GW_{el} (0 for bidirectional devices)	800 m €	45 m €	25 m €	- €
Depreciation time charging unit in years	25	30	10	-
Limit on total installed capacity in GWh (gross)	-	-	130	6,8
Minimum state-of-charge (SOC) related to gross capacity	35%	0%	0%	0%
Maximum cycle number related to gross capacity	100,000	12,000	-	-
Investment storage unit per GWh gross (0 for a fixed ratio of charging/discharging power, costs are then included in investment costs charging unit)	0.2 m €	150 m €	- €	- €
Depreciation time storage unit in years	40	25	-	-
Operation and maintenance costs per investment and year	2.5%	1.0%	60.0%	30 m €[9]
Minimum energy-to-power-ration (E2P) related to gross capacity	0	0.1	0	0

[9] Only variable costs

Maximum E2P	-	-	-	-
Fixed ratio charging/discharging power	-	1	1	0.1
Fixed ratio charging power/capacity	-	-	0.5	-

A.1.5 Power-to-X

	Power-to-gas	**Power-to-heat**
Efficiency	66%	100%
Limit on total installed power in GW_{el}	-	10
Investment per GW_{el}	800 m €	70 m €
Depreciation time in years	25	15
Operation and maintenance costs per investment and year	2.5%	2%
Costs for substituted primary fuel per GWh_{th}	33,100 €	36,778 €
Specific CO_2-savings by substituting fuel by electricity in t/ GWh_{th}	201.6	224
Limit on delivered energy in GWh_{th}	-	78,000

A.2 Scenarios

Installed power in GW_{el}

Technology	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**	**S7**	**S8**	**S9**
Hydro power	5	7	5	6	8	6	7	7	6
PV	77	75	79	109	44	151	101	120	185
Wind onshore	45	51	50	57	30	72	62	49	183
Wind offshore	13	7	12	32	58	20	37	32	-

Energy in GWh_{el}

Technology	S1	S2	S3	S4	S5	S6	S7	S8	S9
Hydro power	18,627	25,000	18,627	22,000	27,600	20,588	25,490	25,000	22,637
PV	72,854	71,000	74,850	104,000	41,900	143,114	95,808	114,000	175,681
Wind onshore	135,323	153,000	149,254	170,000	90,600	215,622	184,790	147,000	548,681
Wind offshore	72,637	40,000	63,682	177,000	316,900	111,144	204,472	176,850	0
Load demand	528,212	635,000	457,661	502,000	509,000	602,000	749,000	582,000	596,000