Comparison of spatially and temporally resolved energy system models with a focus on Germany's future power supply

Hans Christian Gils[1,*], Thomas Pregger[1], Franziska Flachsbarth[2], Mareike Jentsch[3], Constantin Dierstein[4]

[1]Department of Energy Systems Analysis, Institute of Engineering Thermodynamics, German Aerospace Center (DLR), Pfaffenwaldring 38-40, 70569 Stuttgart, Germany
[2]Öko-Institut e.V., Energy & Climate Division, Merzhauser Str. 173, 79111 Freiburg, Germany
[3]Fraunhofer IEE - Institute for Energy Economics and Energy System Technology, Königstor 59, 34119 Kassel, Germany
[4]Technical University Dresden, Faculty of Business and Economics, Chair of Energy Economics, Münchner Platz 3, 01069 Dresden, Germany

[*]Corresponding author: +49-711-6862-477, hans-christian.gils@dlr.de

Abstract

Energy system models usually have different data structures and mathematical approaches and therefore arrive at different results that are mostly not directly comparable. This aspect has a high relevance with regard to model-based scenario analyses for future energy systems. In addition, the variable nature of wind and solar power and their intended further expansion raise new questions of increasing complexity, such as the future role of different load balancing options. In this context the present contribution adds a new approach of systematic model comparison considering energy system models with a regional and hourly resolution. We carried out a model experiment under conditions that allow for a transparent comparison of modelling approaches and thus link differences in the results with properties of the models. The analysis includes different scenarios for a mostly renewable power system with sector coupling for Germany. The quantitative results reveal the impact of different technology modelling approaches when using input data that are as identical as possible. In addition the analysis provides new conclusions for the possible role of different load balancing options and the robustness of the underlying modelling. Furthermore, it provides insight into the lessons learnt from designing an energy system model experiment.

Highlights

- New approach of systematic model comparison with harmonized input data
- Lessons learnt from a model experiment with four high resolution power system models
- Identification of impacts of different technology modelling approaches on the results
- Detailed results of three scenarios for the German power supply system in 2050
- New quantitative results for the future use of different load balancing options

Keywords

Energy systems analysis, model comparison, renewable energy, energy scenario, sector coupling, energy systems modelling

Declarations of interest

none

1. Introduction

The German energy transition aims for a strong expansion of renewable energies (RE), especially for electricity generation. Due to the variable nature of wind and solar power the further development of energy infrastructures is accompanied by questions of increasing complexity. Against this background, a large number of model-based scenario analyses of the energy system have been developed in recent years. These are based on a multitude of different models tailored to different focal points, including the cross-sectoral modelling of system transformation pathways [1], multi-scenario analysis for the power sector [2], the economics of RE expansion [3], the implementation of power-to-heat [4], and the phase-out of coal power generation [5]. These and other energy system models rely on different data structures and mathematical approaches and arrive at different results that are mostly not directly comparable. This has been addressed in previous publications providing an overview of existing models with a particular focus on national and international energy policy [6], the identification of modelling trends [7], renewable energy integration [8] and technical model characteristics [9]. In order to be able to discuss and classify the model results in a qualified manner, it is becoming increasingly important to present the models transparently and to consider the results of the model analyses carefully [10]. The project 'Model experiments and comparison for simulation of pathways to a fully renewable energy supply' (RegMex) started at this point. In the frame of this project the authors carried out so called 'model experiments' under conditions that allow transparent comparison of the modelling approaches and thus link differences in the results of the model calculations with properties of the models. A jointly defined and parameterized case study examines the German energy system in 2050 in the European context and under the assumption of a very high share of variable renewable energies (VRE). The results can lead to different conclusions. On the one hand, sensitive parameters and effects of different model properties can be examined and help to deeper understanding of the modelling approaches, their weaknesses, and strengths. On the other hand, comparing 'consistent' model results can improve the robustness of scenario-based calculations and conclusions for the further development of the energy system transformation.

1.1. State of research

Model comparisons in energy systems analysis look back on a long history. In addition to model experiments that approach specific questions using different models from different research institutions, the establishment of platforms or forums created an environment for practical exchange of experience between modellers. For example, the "Energy Modeling Forum (EMF)" at Stanford University has existed in the USA since 1976, from which 35 model experiments have now been performed, with topics including electric load forecasting, macroeconomic and climate change impacts, electricity and fuel markets, and global energy modelling [11]. The balancing of variable renewable power generation in an integrated energy system has not been in the focus of an experiment so far. In Europe, the research project "CAse Study Comparisons And Development of Energy Models for INtegrated Technology Systems (CASCADE MINTS)" is to be mentioned. From 2004 to 2006, eight European research partners dealt with the modelling of energy systems and scenario evaluation using various models. The focus here was primarily on the interactions of the electricity system with the hydrogen economy and technologies such as CCS [12]. In the ENSEMBLES multi-model experiment, ten global climate and Earth System models were employed to evaluate energy scenarios for climate change mitigation [13]. Later, another EU project entitled "Assessment of Climate Change Mitigation Pathways and Evaluation of the Robustness of the Mitigation Cost

Estimates (AMPERE)" was carried out using 17 integrated assessment models (IAM) of international research partners from 2011 to 2014 to answer questions on decarbonisation paths and the modelling of climate systems [14]. Similar questions were addressed in an earlier model comparison of five IAMs [15]. A comparison of different IAMs was also performed within the ADVANCE project [16]. An ongoing project is the "Energy Modelling Platform for Europe (EMP-E)", which provides an online platform and organises an annual conference [17], but does not perform dedicated model experiments. The "Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland (Forum for energy models and energy systems analysis in Germany, FORUM)" was established for the first time in Germany in 1997. Here the exchange of experience between the modellers themselves as well as the users from research, economy and politics was the focus. A total of five model experiments emerged from the FORUM. With a focus on national energy supply, topics such as the future role of RE in liberalized markets [18], the phase-out of nuclear energy [19] or the impact of technology innovation [20] were considered. The activities lasted until 2007. In addition, there are other more recent studies which also formulate conclusions for best practice approaches and for the robustness of model results through model comparisons. Different model formulations were investigated with a systematic approach using a common data set for a European region and thus statements were made on the accuracy and simulation time [21]. The work was carried out with an open source model in which the number of variables was varied by different types of clustering. Another recent paper presented a model comparison for a future electricity system of the USA with high RE supply share [22]. The aim of this work is to use 'both harmonized and native input assumptions to isolate the impact that model structures might have on deployment outcomes'. The focus is on the endogenously calculated deployment rate for wind and solar energy as a function of various influencing factors and different model representations.

So far, no model experiments have been presented for Germany and Europe comparing state-of-the-art power system models with the focus on sector coupling, spatial and hourly load balancing, and applying different models using a harmonised input data set as far as possible. Sector coupling here refers to the enhanced linkage of power, heating, transport and industry sectors through electric heating and driving as well as the production of synthetic gases and fuels. These options for direct and indirect electrification are widely seen as keys for a deep 'decarbonisation' of the energy system and the large-scale integration of VRE power generation. Furthermore, the available studies for Germany are focused on the development in the near future, and do not evaluate the balancing needs and system operation at high VRE supply shares. Given that the input data of past energy system model experiments has not or only to a limited extend been harmonized, conclusions regarding modelling details could not be drawn.

1.2. Scope and focus of this paper

This paper adds to the available literature by providing insight into the methodological, technical and content-related lessons-learnt from the preparation of a first-of-its-kind model experiment with four high resolution power system models. Such models play a central role in policy advice for efficient climate protection. A systematic model comparison is an essential element for their improvement and validity. Thus, this work makes an important contribution to improving the quality of model-based energy scenario studies. More specifically, the three main objectives of this paper are: (1) to provide insight into the lessons learnt from the preparation of a model experiment with four high resolution power system models, (2) to present results of three scenarios for the German power

supply system in the year 2050 considering a RE supply share of about 90% and all major balancing options including energy sector coupling, and (3) to evaluate the impact of different technology modelling approaches on the results. At the centre of the model experiment is the analysis of differences in the results of optimizing power system models, which result from the respective technology modelling approaches when using input data that are as identical as possible. This is done by modelling the hourly use of load balancing options over the course of a year which is strongly influenced by the variable nature of renewable power generation. The load balancing options under consideration include international and national electricity exchange, the use of power-to-power energy storage, dispatchable conventional and renewable power plants, the curtailment of VRE generation, demand response (DR) and flexible coupling to the heat and transport sectors via combined heat and power (CHP), heat pumps (HP), direct electric heat generation, battery electric vehicles (BEV), and decentralized hydrogen electrolysis. The model comparison is based on the need for various load balancing options and the annual utilization of all installed capacity. In addition, the annual supply costs and the resulting CO_2 emissions are compared. Three scenarios for the year 2050 are evaluated in the experiment. The model experiment is performed applying four models: REMix (DLR), PowerFlexEU (Öko-Institut), SCOPE (Fraunhofer IEE) and ELMOD (Technical University Dresden). Based on a detailed description of the procedure, models, input data and evaluation indicators (Section 2) the paper provides insight into the results of the model experiment (Section 3). Conclusions on the procedure and results are compiled in Section 5.

2. Data and methodology

The focus of the model experiment is on the evaluation of the model characteristics. For this reason, a uniform set of input parameters is used in all models. It consists of framework assumptions as well as the results of an upstream analysis. To reduce the complexity and degree of freedom of optimization, the model experiment is limited to Germany. However, the great importance of international electricity exchange in systems with high RE shares is taken into account by performing upstream Europe-wide calculations with the REMix model [23-25]. Time series of the hourly electricity exchange between Germany and its neighbours determined there are taken into account in the actual experiment in all models as an exogenous input. This procedure is shown in Figure 1. The electricity demand in Germany and the European countries is determined by means of a target-oriented framework scenario. A minimum power plant fleet is also defined based on available scenario studies. REMix is then used to optimize the expansion of additional power generation and storage capacities across all regions. Depending on the scenario, an endogenous expansion of the power transmission grid is also considered. The resulting RE and CHP capacities installed in Germany are also used as input parameters in the model experiment.

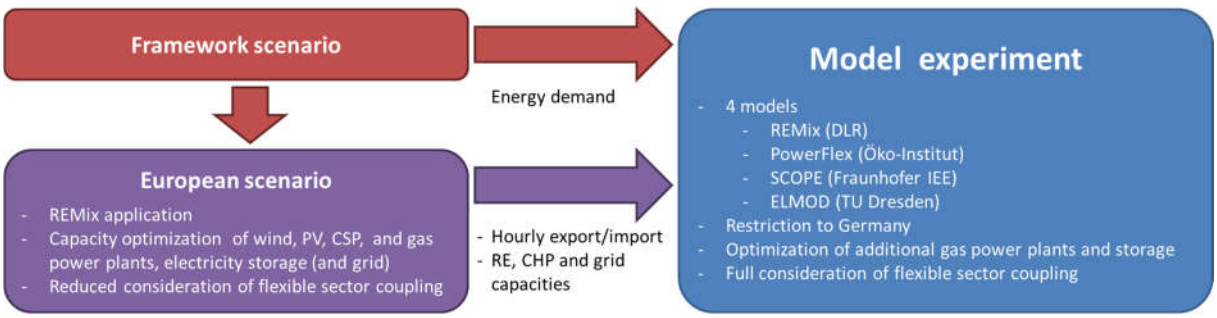


Figure 1: Overview of the modelling procedure

The model experiment relies on a model parameterisation developed at DLR in recent years, which maps a goal-oriented development path of the energy transition in the German electricity sector. For consistency reasons, this development is also assumed in principle for Europe. No explicit assumptions are made on socio-economic development and there is no claim to a scenario that is as robust and cost-minimised as possible for society as a whole. In this respect, the parameterization and underlying framework assumptions have an exemplary character in order to be able to use an appropriate and proven analytical framework from a model perspective. The main framework assumptions are the demand for electricity and electricity-based hydrogen in the various sectors of the energy system. Demands from transport and industry as well as the use of electricity for HP are considered in detail. The conventional electricity demand, the final energy consumption of hydrogen in industry and transport, and the electricity demand of HP and industrial process heat generation are assumed according to the Ambitious Scenario in [26]. Other key assumptions for the German energy system include the potential and costs of RE and the specific costs of all technologies depicted, including storage facilities and power transmission lines. Capacities of different power plant technologies were also explicitly specified. These assumptions were derived from previous scenario studies and own modelling within the framework of various research projects [24, 27-29].

2.1. Considered scenarios

Three scenarios for the year 2050 are investigated in the experiment (Figure 2). These differ in the available transmission capacities and RE supply structure. The scenarios are designed in such a way that the use of temporal load balancing options can be analysed with different characteristics of variable generation and different possibilities of spatial balancing. In this way, the impact of model differences on the results can be understood more comprehensively on the one hand and statements on the dependence of the use of flexible sector coupling on the RE generation structure can be derived on the other. The differences in the RE plant fleet and network capacities result from the assumptions made when calculating the European model runs. These assumptions include the consideration of an endogenous expansion of the electricity grid between the model regions beyond the currently existing and planned transmission capacities. In the Import scenario, additional lines with unlimited capacity can be added, whereas in the Decentralized scenario, no additional lines are allowed. In the Offshore scenario, the grid can only be strengthened within Germany. To avoid a concentration of RE generation capacities in regions with particularly good conditions, each model region has to meet its own supply requirements in all scenarios. In the Import and Offshore scenarios, a value of 65% is used for this, whereas in the Decentralized scenario, 90% is used. In order to investigate the role of an extended expansion of offshore wind power, a significantly higher installed turbine capacity is applied in the Offshore scenario.

	Import	Decentralized	Offshore
Grid expansion (excluding connection of offshore wind)	Endogenous expansion in Germany and neighbours	No endogenous grid expansion	Endogenous expansion only in Germany
Self-supply	Each model region generates 65% of its demand	Each model region generates 90% of its demand	Each model region generates 65% of its demand
Wind offshore	Minimum installed capacity in Germany: 29 GW	Minimum installed capacity in Germany: 29 GW	Minimum installed capacity in Germany: 45 GW

Figure 2: Scenarios evaluated in the experiment

Beyond the three scenarios of the model experiment, different sensitivity calculations are carried out with REMix for the scenarios Import and Decentralized. The aim of these is to focus on analysing the importance of individual technologies for load balancing. On the one hand, the regional cost-optimal design of heat storage, hydrogen storage and electric boilers in CHP systems is determined, and on the other hand the effect of inflexible operation of electrolysers, CHP plants, and HP as well as uncontrolled BEV charging is analysed (Appendix A).

2.2. Modelling of the European power system

The main objective of the upstream scenario modelling for Europe is to determine the installed RE plant capacities and the hourly international electricity exchange for the model experiment. This ensures that the generation structure adopted for Germany is part of a European supply system based mainly on RE sources and that the role of the international interconnected grid as a load balancing option is adequately and consistently taken into account. The study area covers all countries of continental Europe, minus Russia and Ukraine, and plus the United Kingdom and Ireland. Compared to the model experiment with a focus on Germany, a reduced technology variety is provided with regard to sector coupling in order to limit the computing time. Only dispatchable conventional and renewable power plants, electricity storage, the electricity grid and flexible decentralized hydrogen electrolysis are considered as balancing options. The capacity optimization includes the expansion of photovoltaic (PV), wind (onshore and offshore), concentrating solar power (CSP) and gas power plants (simple and combined cycle, SCGT/CCGT), battery and hydrogen cavern storage facilities, as well as direct current (DC) and alternating current (AC) power lines. The design of the decentralized electrolysers and the size of the hydrogen storage tanks are fixed at 4000 full load hours and 6 hours of generation, respectively. BEV charging and HP operation are assumed to be completely inflexible, CHP plants are not considered separately. Generation capacities are determined taking into account a partially existing plant fleet. This is essentially based on the "Small&Local" scenario of the eHighway study [30]. However, the national capacities determined there were partially adjusted. For example, the strong expansion of hydropower plants in Norway and Finland assumed in the study were reduced, as they lead to massive surpluses and a one-sided preference for grid expansion. For offshore wind farms, the very low installed capacity is increased on the basis of the capacities built up to date and the potentials determined [23]. In addition, the assumptions for electricity and hydrogen demand in transport were adjusted to the framework assumptions for Germany for consistency reasons. The construction of new power plants, storage facilities and power lines is primarily driven by national CO_2 emission ceilings and own-supply shares. The emission ceilings are based on a reduction of more than 80% of CO_2 emissions from electricity generation across Europe by 2050 compared to 1990. They were derived by assuming the same specific CO_2 emissions per kWh of electricity generated in the future for the individual countries.

2.3. Investigation area and technologies in the model experiment

In order to consider grid restrictions, 18 regions within Germany are examined, which are based on the control zones of the four transmission system operators (Figure 3). Any electricity grid within these regions is not considered. For each region, all facilities of the same type installed there, e.g. electricity consumers, power plants and storages are aggregated and treated as one large unit. The direct comparison of the use of different load balancing options defined as one objective of this work presupposes that the technologies under consideration are consistent in all systems (Figure 4).

Limitations of the technological and spatial resolution of the models are also important in order to make the computing time manageable for all models.

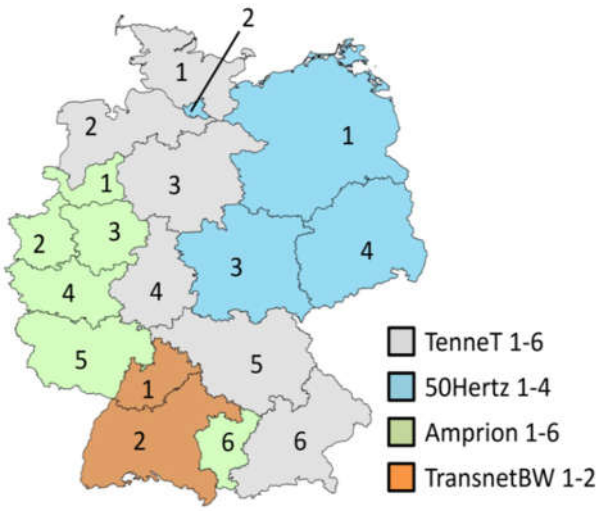


Figure 3: Regional disaggregation of Germany [31]

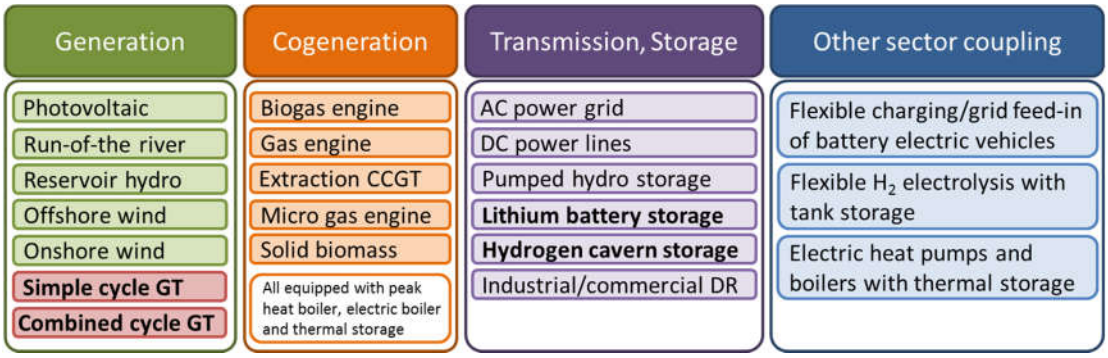


Figure 4: Overview of the technologies considered in the model experiment. The installed capacity of the highlighted technologies is determined endogenously by the models.

2.4. Input data harmonization

In order to be able to trace differences in results back to model characteristics, the input data of all models are harmonized as completely as possible. This does not apply to individual parameters resulting from specific model characteristics (Section 2.5). The input data refer to the scenario year 2050 and mainly comprise the techno-economic indicators, installed plant capacity and time series of generation, demand and international electricity exchange. The input data sheets for the three scenarios of the model experiment have been made publicly available [32].

The data transfer from the upstream European REMix runs includes the installed wind and PV capacities, the transmission grid capacities, the hourly international electricity exchange, the decentralized hydrogen electrolyzer and storage capacities, and the indicative CO_2 shadow price. Due to the assumptions made in each case, these show significant differences (Table 1). The Import scenario is characterized by a significant addition of interconnectors between the German model regions and at the international borders to twice the assumed initial state. This network expansion and the associated import of around 15% of demand significantly reduces the required RE capacity in Germany compared with the other scenarios. It also lowers the CO_2 shadow price, which reflects the marginal costs of CO_2 avoidance. In the experiment, the marginal prices for Germany resulting from

the application of the emission limit are used. Restricting electricity imports and fixing the electricity grid to the currently planned level of expansion in the Decentralized scenario leads to significantly higher installed wind and PV capacities. This results in greater fluctuations in feed-in and a greater need for load balancing. In this respect, the Offshore scenario lies between the other two scenarios. In order to analyse the flexibility provided by heat storage and electric heaters, CHP plants of various types are considered (Table 1). CHP capacities are derived by converting the CCGT capacity required in the European model runs as additional backup, taking into account the district heating potentials determined in [24]. From the electrical CHP capacity determined in this way, the respective assigned thermal peak load is calculated using the assumed power-to-heat ratios, power loss indices, the system design and the heat demand profile. This is used to determine capacities of heat storages, peak-load boilers and electric boilers. Heat storages in buildings are dimensioned to 4 hours, in engine CHP systems to 8 hours, and in combined cycle systems to 6 hours of the annual peak demand. The conventional peak boilers are designed for the peak load plus heat network losses of 10% and the electric boilers for twice the peak load. The SCGT and electricity storage capacities determined in the European analysis are not transferred to the model experiment, potentially causing a capacity gap.

Table 1: Overview of the model input for Germany

Parameter	Import	Decentralized	Offshore	Source
Grid expansion (AC)	130 GW	0 GW	26 GW	European model runs
Grid expansion (DC)	0 GW	0 GW	32 GW	European model runs
Net import	107 TWh	37 TWh	73 TWh	European model runs
PV capacities	161 GW	283 GW	185 GW	European model runs
Wind onshore capacities	117 GW	129 GW	105 GW	European model runs
Wind offshore capacities	29 GW	29 GW	45 GW	European model runs
CO_2 price	84 €/t	178 €/t	151 €/t	European model runs
CHP capacities	Natural gas engine CHP: 2.1 GW, Biogas engine CHP: 2.7 GW, Natural gas micro engine CHP: 0.2 GW, Natural gas CCGT with CHP: 4.0 GW, Solid biomass combustion CHP: 5.2 GW			European model runs
Decentralized H_2 infrastructure	Electrolyzer capacity: 28.7 GW, Tank storage capacity 59 GWh			European model runs
Hydro power plant capacities	Run-of-the-river hydro: 3.6 GW, reservoir hydro: 0.5 GW, pumped storage hydro: 8.1 GW			[30], [33], [34]
Demand response capacities	28.2 GW			[35], [36]
Heat pump capacities	Air-water HP: 4.7 GW (el), Brine-water HP: 6.0 GW (el)			Calculated from [26]
Power demand	Conventional electricity consumers: 477 TWh, BEV: 44 TWh			[26]
Hydrogen demand	Industry: 55 TWh, Transport 31 TWh			[26]
Fuel costs	Natural gas: 33€/MWh (chem), Solid biomass: 33€/MWh (chem), Biogas: 33€/MWh (chem)			Own assumption
Technology investment costs	SCGT: 437 €/kW, CCGT: 850 €/kW, battery storage: 50 €/kW (converter) and 150 €/kWh (storage), hydrogen cavern storage: 305 €/kW (charging), 850 €/kW (discharging) and 1 €/kWh (storage)			[37] [38]

Further assumptions include the power and hydrogen demand, the fuel costs, and the installed capacities of hydropower plants, demand response and electric HP (Table 1). The HP capacity results from the assumed annual heat demand of 42 TWh for air-water HP and 57 TWh for brine-water HP. The storage tanks are each designed for 2 hours of the annual peak demand. The maximum

capacities of the hydrogen cavern storage facilities are taken from [39]. In contrast, there is no upper limit on the number of battery storage units and gas-fired power plants that can be added by the models. The hourly electricity generation as well as the inflow to hydropower plants are calculated according to [23]. For wind and PV time series, the historical weather year 2011 is used, for hydropower different years depending on data availability. The regional load profiles are assumed according to the historical data for the year 2011 of ENTSOE [40]. A regional differentiation of the load profile is not considered. The profiles of uncontrolled charging, electric driving, grid contact and minimum and maximum battery levels are taken from [41]. The heat demand profile of the industry is taken from [24], that for the heating network and building supply based on [42]. The hourly and technology-specific time series of the maximum load increase or load reduction are derived from [35]. The power demand is distributed among regions according to the population shares and number of vehicles [43], the hydrogen demand according to the industrial heat demand [24] and the number of vehicles [43]. Heat demand is only included for the modelled CHP and HP systems and is spatially disaggregated according to the plant distribution.

2.5. Contributing models

The models were selected on the basis of a number of criteria, in particular with regard to the technologies depicted in the model. These were queried for a total of ten other models using a model fact sheet designed according to the specific requirements of the experiment (see Appendix B). This can serve as a basis for model selection in future comparisons. The type of programming and the mathematical solution method used did not play a role here. To ensure comparability of the results, however, the models should have an optimization algorithm and work with a time resolution of one hour. It was also assumed that system operation would be optimized for all hours of a year. On this basis, in addition to the REMix model, three models were finally selected which were suitable in scope and detail, particularly with regard to the considered load balancing options and sector coupling. The selected models include PowerFlexEU [44, 45], SCOPE [46-51] and ELMOD [52-54].

Table 2: Differences in the model characteristics in the configuration used in the experiment

	REMix	PowerFlex	SCOPE	ELMOD
		Technical and mathematical characteristics		
Programming language	GAMS	GAMS	Matlab	GAMS
		Optimisation		
Composition of the objective function	CAPEX, OPEX, fuel costs, CO_2 costs	OPEX, fuel costs, CO_2 costs	CAPEX, OPEX, fuel costs, CO_2 costs	OPEX, fuel costs, CO_2 costs
		Temporal and spatial resolution		
Regional resolution		18 regions		642 grid nodes
Optimisation horizon	1 year	9 days	1 year	1 day
		Technology consideration		
Capacity expansion	Endogenous expansion of gas power plants and electricity storage	Iterative expansion (reduced to a two-step approach) of gas power plants	Endogenous expansion of gas power plants and electricity storage	Expansion decision based on operation of backup power plants
AC grid model	DC load flow	Transport model	Transport model	DC load flow
Flexible sector coupling	CHP, electric heat pumps, battery electric vehicles, H_2 electrolysis			None

With regard to the experiment configuration used, the models show significant similarities, but also differences (Table 2). All models have a deterministic approach and consider uncertainty

through the evaluation of different scenarios and sensitivity analysis. A central common methodological feature is the use of linear programming to minimize the overall costs from the perspective of an economic planner.

$$min\{ C_{operation} + C_{fuel} + C_{emission} + C_{unsupplLoad} + C_{invest}\} \quad (1)$$

In all models, the objective function contains the variable operating costs of all technologies $C_{operation}$, fuel costs C_{fuel}, CO_2 emissions certificate costs $C_{emission}$ and penalty costs for unsupplied power demand $C_{unsupplLoad}$ (Eq. 1). In the models REMix and SCOPE, additional elements of the target function C_{invest} may result from the endogenous addition of gas power plants and power storage units, which is not considered in PowerFlex and ELMOD. However, PowerFlex uses an iterative process to evaluate the investment requirements for additional backup generation, which is reduced to a two-step optimization in this project. In the first modelling stage, virtual gas power plants with very high marginal costs start up whenever a capacity gap occurs. From these results, the capacity of CCGT plants with sufficient full load hours (1800 h/yr) is then derived. In the second modelling stage, these power plants are then available with their individual marginal costs for electricity production. The demand for additional virtual power plants remaining in the second modelling stage is assumed to be covered by SCGT. The investments required for this are determined ex-post using the parameters specified in the input data. An endogenous installation of power storage is not considered in PowerFlex in the experiment.

While the technologies considered are mostly identical in REMix, PowerFlex and SCOPE, a significantly reduced scope is considered in the ELMOD model. Due to its special focus on the power transmission network, ELMOD does not include DR and sector coupling technologies. The flexible demand of the sector coupling is taken into account indirectly by integrating the load profiles from the REMix results. In contrast to the other models, ELMOD includes a significantly higher spatial resolution and more detailed representation of the power transmission network. Since no data is specified for the individual transmission lines, ELMOD carried out an optimized network expansion for the reference year in advance, which determines the network infrastructure for scenario Import under optimal network expansion. Based on the differences in transmission capacities between the scenarios in the data, the expanded line capacities were scaled downwards in scenario Decentralized. To adequately map grid flows ELMOD also models the operation of the European power plant fleet, which is considered according to the upstream modelling in REMix. As a result, the international electricity exchange is not fixed but part of the model results. Assuming that storage capacities are generally installed to smooth demand and in particular to integrate variable renewables, a relationship is assumed between the amounts of curtailed energy calculated by ELMOD and the additional demand for storage capacities. Accordingly, based on the maximum surplus power generation over all time steps, the minimum storage capacity required and the identical maximum charging power per model region is estimated. An analogous procedure was chosen for gas power plants. There, the reference value for estimating additional capacities is the load that cannot be satisfied. It is assumed that the additional power plant capacities will be used to close the capacity gap. The load shedding per model region and time step is limited to the local demand. Depending on the maximum load shedding and the unsatisfied demand in each model region, a downstream optimization algorithm decides which combination of both generation technologies satisfies the demand at minimum cost.

There are differences in the consideration of the power grid not only with regard to the regional resolution, but also with regard to technology modelling. In SCOPE and PowerFlex, power transmission between regions is taken into account using a transport model. This implies that all connections are independent of each other and the full transmission capacities can be used. In contrast to this, REMix and ELMOD use the DC load flow approach. This linearized approach of power flow modelling takes into account the interaction between the flows over various lines connected to a node, which leads to a reduction in the actually usable transmission capacity. This approach is also available in PowerFlex and SCOPE, but could not be used as it requires additional input data, which was not provided within the experiment. In addition to the difference in modelling, PowerFlex does not endogenously calculate grid losses. Instead, these are estimated downstream on the basis of the observed flows. Another difference between the models concerns the time horizon of optimization. While REMix and SCOPE assume a perfect foresight for the entire optimization period of a year, PowerFlex and ELMOD assume a limited foresight for nine days or one day, respectively. Beyond these fundamental aspects, the models show some differences in technology modelling, to which a possible influence on the results can be attributed (Table 3). When evaluating the model comparison in Section 3, these are used to interpret the differences in results.

Table 3: Differences in the technology modelling of the model configuration used in the experiment

Technology	Modelling difference in the experiment
Hydro power	Consideration of single dams and historic water inflow data of 2011 in SCOPE
Hydrogen cavern storage	Separate dimensioning of charging, discharging and storage unit in REMix Expansion of fixed storage sizes in SCOPE (10 days, 20 days, 30 days) with identical charging and discharging capacity
Demand response	Different technology modelling in all models No consideration of variable costs in PowerFlex due to flow storage modelling approach
Battery electric vehicles	Different technology modelling in all models Regional charging and driving profiles in PowerFlex No grid feed-in from vehicle batteries in PowerFlex
Heat pumps	Temperature-dependent coefficient of performance in REMix (air-to-water heat pumps only) and SCOPE
CHP	No emergency cooler for back-pressure CHP plants in SCOPE Separate consideration of CHP disc and condensation disc in PowerFlex. Only backpressure operation of the CHP disc
Thermal energy storage	No consideration of variable costs, charging and discharging efficiency in PowerFlex due to modelling as a flow storage device, but storage self-discharge is considered

The power balance is the most important boundary condition in all models. It ensures that electricity demand and supply are balanced in each region and hour (Eq.2). Demand includes the inflexible load of conventional consumers P_{demFix}, charging of electricity storage $P_{storCharge}$, and export P_{import}. In all models except PowerFlex it is supplemented by grid losses $P_{gridLoss}$, in all models except ELMOD by demand response load increase $P_{loadInc}$ and the semi-flexible loads of electric vehicles $P_{vehCharge}$, electric heat P_{elHeat} and hydrogen production P_{H2Prod}. The supply includes the generation in all types of power plants P_{gen}, discharging of electricity storage $P_{storDischarge}$ and imports P_{import}. In all models except ELMOD further contributions can come from demand response load reduction $P_{loadRed}$, in SCOPE and REMix also from the grid feed-in of BEV P_{V2G}. To ensure feasibility of the model also when no endogenous capacity expansion is possible, a slack variable representing the unsupplied load $P_{unsupplLoad}$ is included, which can be interpreted as the generation of virtual power plants. The costs of unsupplied load $C_{unsupplLoad}$ in Eq. 1 are proportional to this variable.

$$P_{demFix}(t) + P_{storCharge}(t) + P_{export}(t) + P_{gridLoss}(t) + P_{vehCharge}(t) + P_{loadInc}(t) + P_{elHeat}(t) + P_{H2Prod}(t) = P_{gen}(t) + P_{storDischarge}(t) + P_{import}(t) + P_{loadRed}(t) + P_{V2G} + P_{unsupplLoad}(t) \quad (2)$$

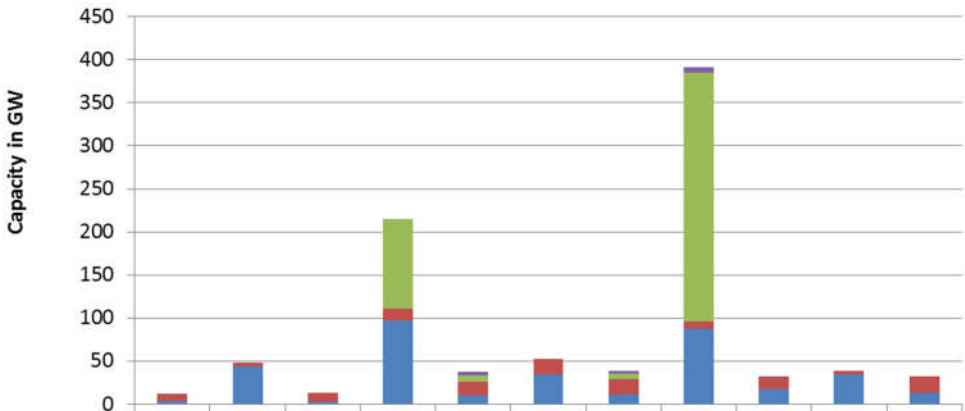
The difference in the target function caused by the endogenous installation of power plants and storage has a major impact on the system operation, as it shifts the focus from minimizing the overall amount of unsupplied load $\sum_t P_{unsupplLoad}(t)$ to minimizing its maximum value $\max_t P_{unsupplLoad}(t)$, which is equivalent to the added capacity.

3. Results and Discussion

In accordance with the content-related objective of this work, the scenarios examined in the model experiment offer a wide range of insights into the role of load balancing with high shares of variable power generation. The comparison of the Import and Decentralized scenarios underline that a stronger expansion of the power grid compared to more decentralized generation results in a significantly reduced need for additional dispatchable backup power plants and power storage facilities (Figure 5). Across all models, the use of load balancing options is generally reduced by strengthening the grid and lowering regional import limits and consequently increasing the concentration of RE generation capacities in regions with good resource availability (Figure 7, Figure 8 and Figure 9). This is emphasized by the resulting endogenous optimization of decentralized hydrogen infrastructure and the flexible design of CHP and HP in the sensitivity analysis (Appendix A), which leads to significantly lower capacities for electrolysers, hydrogen storage, heat storage and electric boilers in scenario Import than in scenario Decentralized. The non-availability of power-controlled heat generation and flexible BEV charging leads in scenario Import to a greater use of existing balancing options, while in scenario Decentralized additional power storage is built. This results from an oversizing of the power grid in the upstream European modelling where no other flexibilities are considered as well as of exogenously defined storage in heat and hydrogen production. The Offshore scenario – focussing on expanding offshore wind turbines in the North and transmitting their generation to the south of Germany – lies, as expected, between the two other scenarios which are more pointed with regard to the need for load balancing options and their use. The model results are valid for the assumptions made regarding the future development of demand, installed power plants and techno-economic technology parameters. All of these are subject to a very high degree of uncertainty, which also applies to the model results. A systematic record and quantification of this uncertainty are beyond the scope of this paper.

The analysis of model differences, which is a methodical objective of this work, is based on a comparison of results for different parameters. These include the need for additional power plants and storage facilities, as well as the operation of the load balancing options considered. Furthermore, the power supply costs and annual CO_2 emissions are compared. Due to the significantly higher effort involved in model parameterization, only the Import and Decentralized scenarios are considered in ELMOD. The interpretation of the results is based on the model differences listed in Section 4.3.5. Despite the many load balancing options taken into account, the specified generation capacities are not sufficient to cover demand in every hour of the year. This implies that flexible sectoral coupling technologies cannot replace the SCGT and storage capacities, which were endogenously added in the upstream model runs. Consequently, capacity requirements remain, which are covered in the REMix and SCOPE models by the investment in additional power plants and storage facilities (Figure 5).

Across all scenarios the overall added generation capacity reaches comparable values in both models. However, there are clear differences in the distribution between the technologies. Due to the independent dimensioning of the charging, discharging and storage units, more hydrogen storage is built in REMix. In the Decentralized scenario, not only is the discharge capacity significantly larger at 4.6 GW compared to 3.3 GW, but also the charging capacity (14.3 GW/3.3 GW) and storage size (1.6 TWh/0.5 TWh). In the Offshore scenario, hydrogen storage is only added in REMix and reaches 5.9 GW for charging, 1.5 GW for discharging and 0.4 TWh for the storage size. The independent dimensioning of the charging and discharging unit has a significant effect on the use of RE generation peaks. If a larger design of the charging unit is possible, the RE curtailment can be reduced, but at the expense of higher storage losses (Figure 6, Figure 8). Endogenous addition of battery storage occurs only in scenario Import and reaches similar capacities in both models. The slightly higher power plant demand in SCOPE in all scenarios is due to the smaller hydrogen reservoirs and reduced amount as well as flexibility of hydroelectric power generation.



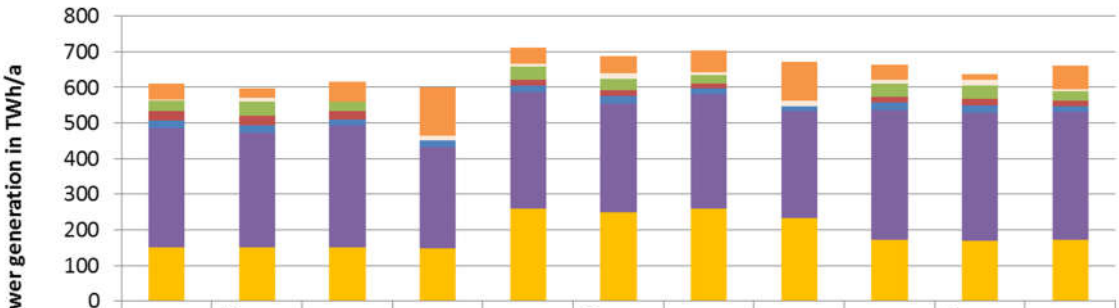
	Import				Decentralized				Offshore		
	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE
Hydrogen storage	0	0	0	0	5	0	3	6	2	0	0
Battery storage	0	0	0	104	7	0	7	289	0	0	0
CCGT	9	4	12	14	15	18	18	9	13	5	19
SCGT	4	43	2	97	10	35	11	88	18	34	14

Figure 5: Comparison of the endogenous capacity installation of gas power plants and electricity storage.

PowerFlex determines a slightly higher capacity requirement (Figure 5), which can be explained methodically. While in the case of endogenous capacity expansion, the flexibility available in the system is primarily used to minimize the need for additional power plants and thus the investment costs C_{invest} in Eq. 1, in PowerFlex it is primarily used to minimize operation of virtual gas-fired power plants with very high marginal costs represented by $C_{unsupplLoad}$. Since these costs do not scale with the coverage gap but only with the amount of energy, this tends to lead to a higher need for additional power plants. The two-stage approach used for the determination of SCGT and CCGT capacities in PowerFlex (see Section 2.5) tends to cause an underestimation of the optimal CCGT capacity – including reconversion of hydrogen to electricity – in comparison to REMix and SCOPE. An increase in the number of iterations is likely to reduce these differences.

Similar to PowerFlex, ELMOD attempts to avoid the amount of energy not provided $P_{unsupplyLoad}$. This effect is a much more pronounced due to the detailed consideration of the power grid as well as the separate quantification of the capacity demand for each grid node. The method of estimating the storage expansion used in ELMOD also leads to significantly higher values,

resulting from the fact that bottleneck-related VRE curtailments are compensated by additional storage capacity. This effect is intensified in the case of an asymmetrical expansion of decentralized generation plants and grid elements, since the VRE power cannot be completely transported away through the grid. Furthermore, the reported capacity demand is increased by the independent determination of additional storage and power plant capacities. This implies that synergies between the grid nodes as well as interactions between storage and generation capacities are not taken into account. For several indicators, a direct comparison of the results of ELMOD and the other models proves to be difficult, due to its fundamentally different model structure and objective as well as the different input data requirement, which made a complete harmonization impossible. When selecting the models, ELMOD was deliberately chosen as a model that clearly distinguishes itself from the other models in terms of its scope. The aim was to investigate how the demand for electricity storage and power plants, as well as their use, changes through a detailed analysis of the transmission grid. However, the model results show high deviations from the other models, which cannot be attributed solely to the more precise modelling of the power grid. Rather, the given input data of the experiment were not sufficient for the parameterization of ELMOD, and the assumptions necessarily made in addition were not consistent with this. As a consequence, the results of ELMOD are only partially comparable with those of the other models. An extension of the input data set to the additional parameters required in ELMOD, including the capacities of individual transmission lines and an exact assignment of demand and generation to the network nodes could not be achieved within the setting of the experiment. Consequently, no statement can be made as to whether the extension of the input data set would lead to an increase in comparability in the results.

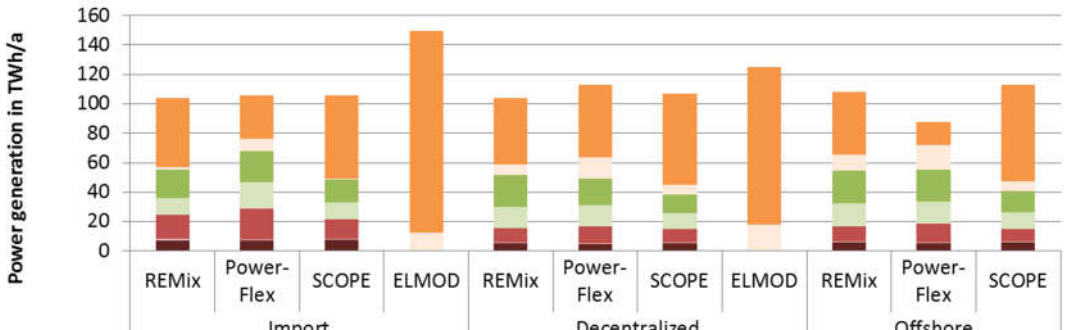


	Import				Decentralized				Offshore		
	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE
Sum	611	598	616	600	710	687	703	670	664	636	660
CCGT	47	29	57	137	45	49	62	108	43	16	65
SCGT	2	9	1	13	7	14	7	18	11	17	7
Bio CHP	31	39	27	0	36	33	24	0	38	37	26
Gas CHP	25	29	21	0	16	17	15	0	17	19	15
Hydro	21	21	17	17	21	21	17	12	21	21	17
Wind	337	322	344	286	327	305	320	301	365	358	360
PV	150	150	150	147	259	249	260	232	171	169	171

Figure 6: Comparison of the power generation structure.

The power generation structure is similar in all models, resulting from the high supply share of the exogenously defined wind and PV capacity (Figure 6). SCOPE systematically generates about 20 % less electricity from hydropower, which can be attributed to the detailed modelling of dams and cascades and the use of data from the weather year 2011, which was statistically a rather poor year for hydropower generation. Both variable and overall power generation are in PowerFlex and ELMOD lower than in the other models. In PowerFlex, lower demand results from the neglect of grid losses.

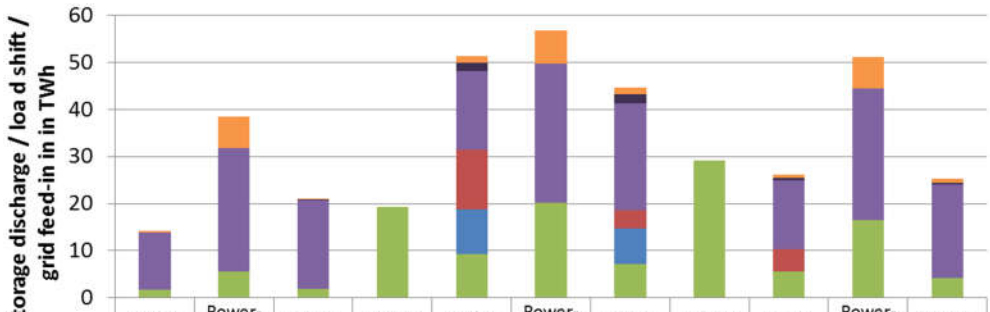
This combined with the reduced foresight and the lower availability of power storage in the Decentralized and Offshore scenarios leads to higher RE curtailment. In ELMOD, the higher RE curtailment is due to additional grid restrictions, while the lower total overall generation results from the realization of higher electricity imports.



	Import				Decentralized				Offshore		
	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE
CCGT	47	29	57	137	45	49	62	108	43	16	65
SCGT	2	9	1	13	7	14	7	18	11	17	7
Biomass CHP	19	21	15	0	21	19	13	0	23	22	15
Biogas CHP	11	18	11	0	14	14	11	0	15	15	11
CCGT-CHP	16	21	13	0	10	11	9	0	11	13	9
µ CHP	1	1	1	0	1	0	1	0	1	0	1
Eng. CHP	7	7	8	0	5	5	6	0	6	5	6

Figure 7: Comparison of the power generation in dispatchable power plants and CHP plants.

The differences in the available power plant as well as storage capacities and the evaluation method used for quantifying additional capacities are the main drivers for deviations in the usage of the flexibility provided by load balancing options, such as dispatchable power plants, energy storage and demand response. Across all scenarios, the different usage of the available flexibility for reducing unmet energy demand or operation of virtual back-up with high marginal costs $\sum_t P_{unsupplLoad}(t)$ on the one hand, and for reducing unmet capacity demand $\max_t P_{unsupplLoad}(t)$ on the other has a major impact on the operation of load balancing options. The annual electricity generation in CHP and gas power plants is shown in detail in Figure 7. As a result of the more extensive RE curtailment, electricity generation in gas power plants in ELMOD is significantly higher than in the other models. There, the total amount of controllable generation is almost identical in the Import scenario. Differences in the composition arise mainly in PowerFlex, and result from the differences concerning the investment decision. With lower CCGT capacity, CHP plants are used more frequently in order to minimize the operation of the virtual back-up. The lower CCGT capacity is also the reason for the higher power generation of extraction condensing CHP plants (biomass, CCGT) in REMix compared to SCOPE. In the Decentralized scenario, the controllable power generation in PowerFlex and REMix are relatively similar, such as the CCGT capacity (Figure 5). Only the usage of SCGT is significantly higher due to lower electricity storage capacities. The comparatively high CCGT use in SCOPE indirectly results from the lower hydrogen storage capacity, which favours the use of renewable electricity for heat production and thus a lower CHP utilisation. This also explains the differences between REMix and SCOPE in the Offshore scenario. There, PowerFlex and REMix have again similar results except the use of SCGT and CCGT as an effect of the deviating investment decisions and the lower demand in PowerFlex. The lack of an emergency cooler in backpressure CHP systems in SCOPE results in a limitation of the annual power output by the corresponding heat demand. This becomes visible in the output of the biogas systems which is the same across all scenarios.



	Import				Decentralized				Offshore		
	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE	ELMOD	REMix	Power-Flex	SCOPE
DSM ind./comm.	0.3	6.7	0.3	0	1.4	7	1.4	0	0.8	6.7	0.8
BEV grid feed-in	0.03	0	0.01	0	1.88	0.00	1.99	0	0.52	0.00	0.47
BEV charge control	12.2	26.2	19	0	16.6	29.6	22.7	0	14.5	27.9	19.9
Hydrogen storage	0	0	0	0	12.8	0	3.9	0	4.8	0	0
Lithium battery	0	0	0	0	9.5	0	7.6	0	0	0	0
Pumped hydro	1.7	5.6	1.8	19.3	9.2	20.2	7.1	29.2	5.6	16.5	4.1

Figure 8: Comparison of storage and demand response operation

With regard to the contribution of flexible sector coupling to the balancing of VRE power generation in future energy systems, the model results demonstrate the high attractiveness of controlled BEV charging to reduce system costs (Figure 8). On the other hand, with the battery degradation costs assumed here, there is hardly any grid feed-in from BEV. Taking variable costs into account, DR in industry and commercial sectors makes as well hardly any major contribution to load balancing. Its role is then limited to peak shaving aiming at a reduction of the need for additional power generation capacity. Due to the available electricity storage capacities and the differences in modelling, there are some significant differences in the use of electricity storage and DR between the models. Comparing REMix and SCOPE, this primarily concerns the discharging of hydrogen cavern storage and BEV charge control. The former results directly from the differences in charging and storage capacity, whereas the differences in the use of the BEV charge control are presumed to result from details of the modelling, but cannot be directly associated. Significantly larger deviations can be seen in comparison with PowerFlex and ELMOD. In PowerFlex, this is clearly related to the lack of endogenous investment additional generation or storage capacity, which strongly fosters the usage of the available balancing options to minimize the unmet power demand associated to very high costs. Additionally, the perfect foresight over the whole year considered in REMix and SCOPE leads to a highly rational dispatch result, which underestimates the use of the flexibility options compared to the reduced foresight of only nine days in PowerFlex. Furthermore, the high usage of DR and BEV charge control result from the neglect of costs and the assumption of a completely flexible vehicle fleet, respectively. Against the background of possible costs and restrictions for consumers, however, this is a rather optimistic assessment of the DR potential. ELMOD shows an even higher use of PSH, which is clearly related to the lack of other temporal balancing options. The unavailability of BEV charge control can almost completely be compensated by the available PSH plants.

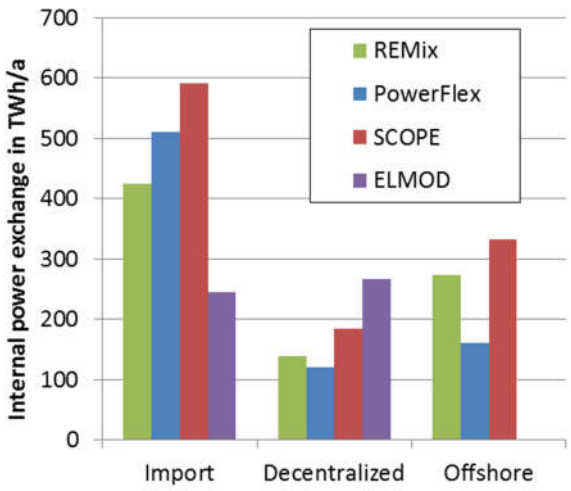


Figure 9: Comparison of power transmission over region borders.

The model comparison of transmission grid usage shows no systematic patterns throughout the scenarios (Figure 9). The results of REMix and SCOPE are an exception. By considering the physical power flow, the use of the DC load flow approach in REMix across all scenarios leads to a 20-40% reduction in annual transmission compared to the transport model approach in SCOPE, which corresponds to a higher transmission capacity over all lines. Despite the significantly higher line utilisation, however, the higher transmission capacity in SCOPE does not lead to a lower endogenous expansion of power plants and storage facilities. Consequently, network modelling does not appear to have a significant effect on capacity requirements in the experiment. With PowerFlex compared to REMix, line utilization is higher in scenario Import, which is consistent with the SCOPE results, but lower in the other scenarios. In Decentralized this is presumably related to the hydrogen cavern storage endogenously built in REMix and SCOPE. The geographic concentration of this storage increases the need for grid usage while PowerFlex uses the available distributed flexibility options instead. The notably lower power transmission in scenario Offshore is furthermore influenced by the differences in the composition and operation of gas power plants. With less CCGT and more distributed SCGT capacity available, less power transmission is needed. In ELMOD, the relatively small quantities of electricity transmitted in scenario Import result from the interdependency of line flows within a meshed grid. As a consequence, single lines restrict the possible exchange in a way that remaining transmission capacities on lines could not be utilized. Although the total transmission capacity between regions is decreased in the Decentralized scenario, internal power exchange increases, due to the distribution of supply and demand is more favourable to the utilization of the given grid infrastructure. Differences in available line capacity between the Import and Decentralized scenario derive from a preparatory expansion model and therefore differ less in ELMOD than in the other models.

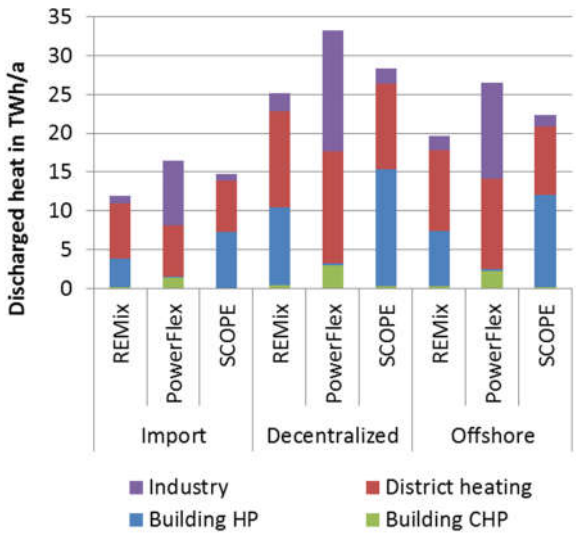


Figure 10: Comparison of the usage of thermal energy storage

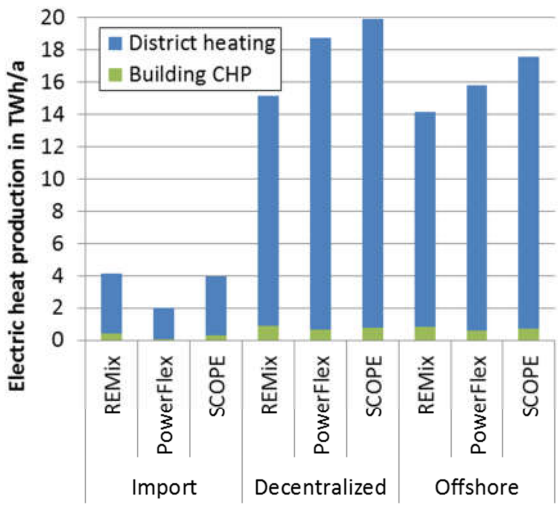


Figure 11: Comparison of the usage of electric boilers in CHP systems

The power-controlled operation of heat pumps and CHP plants offers further possibilities for temporal load balancing. This is made possible in particular by TES and, in the case of CHP systems, by electric boilers. The use of the exogenously defined capacities differs considerably between the scenarios and models (Figure 10, Figure 11). According to the share of VRE generation, it is consistently lowest in the Import scenario and highest in the Decentralized scenario. A comparison of the models shows that the amount of heat stored is in all scenarios smallest in REMix and largest in PowerFlex. The latter relates to the neglect of variable costs and storage losses in PowerFlex, which are of particular relevance for the TES in industrial CHP systems. The significantly higher utilisation of the TES in building heat pumps in SCOPE and REMix is related to the consideration of a time-variable COP, which favours a partial adjustment of the heat pump operation of the heat source temperature. Regarding the usage of electric boilers, the model comparison does not give a uniform picture. The lower values in REMix compared to the other models in the Decentralized and Offshore scenarios result from the comparatively high charging capacity of the hydrogen storage tanks, which enables a significantly more extensive use of RE generation peaks. The energy stored there is then not available for electric heating, which is also related to the lower use of TES in these scenarios. Since no endogenous storage expansion occurs there, this effect is not observed in the Import scenario,

resulting in a high correspondence between REMix and SCOPE. The systematically lower usage of electric heating in PowerFlex compared to SCOPE is related to the higher CHP operation (Figure 7), driven by the high cost of back-up power generation.

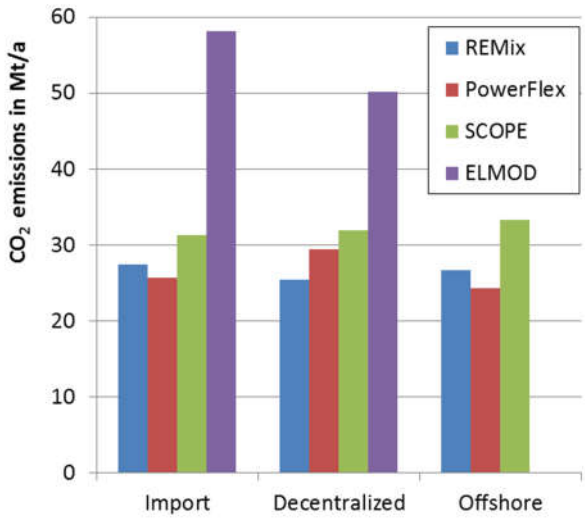


Figure 12: Comparison of the CO_2 emissions

The annual CO_2 emissions in the modelled part of the energy system are directly correlated with the use of gas power plants and CHP plants. Accordingly, by far the highest emissions are detected in ELMOD (Figure 12). According to gas-based power generation, the CO_2 emissions are also very similar in SCOPE, PowerFlex and REMix. In the Import and Offshore scenarios, the lowest CO_2 emissions are calculated in PowerFlex, as all the available flexibility is used to avoid the operation of the expensive virtual back-up generation, which also has the highest specific CO_2 emissions. In Decentralized, a comparably high CCGT capacity is erected in PowerFlex. Given their low variable power generation costs, the CCGT partially reduce the Biomass CHP operation and push the overall CO_2 emissions to a higher level than in REMix.

The significantly higher use of gas power plants causes that the variable operating costs are also by far the highest in ELMOD. In the other models, similar values are obtained. The minor differences are in line with the dispatchable power generation available in each case, and in particular the use of gas-fired power plants (Figure 13). Due to the high CO_2 emission costs, these contribute significantly to the variable costs, and also superimpose the effect of the variable costs not considered in PowerFlex, e.g. of demand response and heat storage. As PowerFlex assumes that there is no perfect foresight over the whole year and uses smaller optimization horizons of nine days, the minimization of costs has to be a suboptimal solution compared to SCOPE and REMix and should produce higher costs.

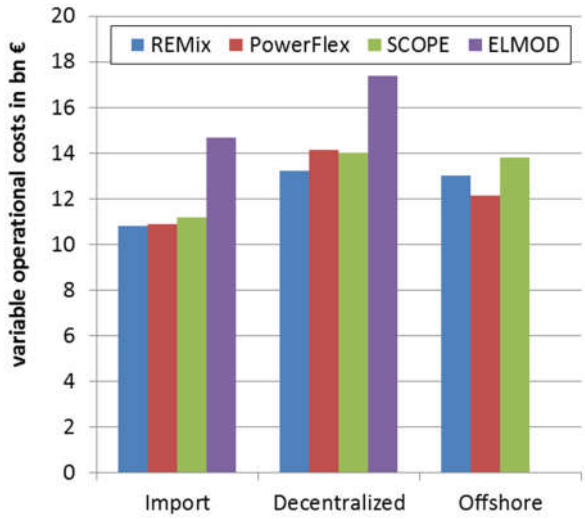


Figure 13: Comparison of the variable operational costs

4. Conclusion and outlook

The central finding of the model comparison is that the models that are based on identical data do not arrive at identical but nevertheless very similar results. Furthermore, the results reveal that even if there are no significant deviations in the structure of power generation and in the expansion of storage facilities, the utilisation of flexibility options can be very different. Here, differences in the model representation of individual technologies play an important role. The model results show a relatively high robustness with regard to the aggregated use of dispatchable power plants on the one hand, as well as the sum of the load balancing provided by battery electric mobility, electricity storage, heat storage, and demand response on the other. Within these two categories there are larger deviations, which can be traced back to the many and varied differences in details of the modelling. Due to the approach chosen in the model experiment, effects of individual differences cannot be quantified as they superimpose each other. This follows directly from the fact that individual model differences are not analysed separately, which thus remains a task for future projects. Experience from the model experiment suggests that for a detailed and technology-specific investigation of effects on the results due to differences in technology modelling, a limitation to models with comparable objectives and input data requirements should be preferred. Against the background of the overlapping model differences, no final conclusions can be drawn for the degree of detail required for modelling, e.g. with regard to the electricity grid. Nevertheless, the model comparison allows the derivation of significant new qualitative statements with regard to differences in the technology representation. The results for instance show that estimating the need for additional power plants without endogenous optimization and based on minimizing the unmet electricity demand leads to an overestimation of required capacity. This effect can be reduced by iteratively determining the required capacity based on a minimum level of annual full load hours of unmet demand. Even though it was here only demonstrated in a reduced two-step application, results similar to an endogenous optimization could be achieved by this approach. With regard to the endogenous expansion of energy storage, the model comparison shows that a free dimensioning of the charging, discharging and storage units can lead to significant differences in design compared to assuming the same charging and discharging capacity and fixed storage sizes.

Implementing a systematic model comparison requires a high effort of preparatory coordination. The first step is to gain a common understanding of the models involved, with regard to model

structures, model properties and input data required for parameterization. The level of detail of the model template used proved to be sufficient for model selection, but does not provide a comprehensive picture of all model details relevant to the experiment. Some differences in data requirements and capabilities of the models involved did not emerge from the template. This underlines the importance of a comprehensive exchange and understanding of model and data structures. Although the models participating in the experiment show significant differences in their properties and details of the technology modelling, they are identical in their mathematical foundation. All models are based on linear optimization, and minimize the target function of system costs. This favours comparability in the model results, but leads to a restriction of the perspective. Against this background, an extension to other objective functions and optimization methods, but also to fundamentally different modelling approaches, is very desirable. Furthermore, our lessons learnt suggest that at least selected mathematical parameters as well as the time periods and working memory capacities required to solve the systems of equations should also be included in model comparisons.

The described model experiment was developed by one of the participating modeller groups and the other models were integrated with suborders. Due to the design of the underlying project, these subcontracts included only relatively little working time, which meant that not all participants were able to work with the same level of detail. This potentially results in an interpretational imbalance, since the design of the experiment was essentially driven from the point of view of one model, which could result in a perception as a reference model. For future experiments this results in the recommendation of a balanced working time for all models involved in order to avoid such effects. In this way, a design can take more account of the strengths of all models and present the different perspectives in a more balanced way.

The work carried out in this contribution has a significance and novelty with regard to different aspects of energy system modelling and points to several further research needs. For the first time, various state-of-the-art power system models with sector coupling from completely different developments have been compared with a harmonised focus and approach. In particular, we implemented the most complete possible standardization of input data. This was favoured by high similarity of the models used and the comparatively low data requirements. A disadvantage of the chosen approach is clearly the great need for coordination with regard to required input data and the exploration of model differences. On the other hand, this results in significantly better possibilities to attribute differences in results to the model properties. However, this is subject to restrictions resulting from the fact that the models differ in numerous points, which makes a clear quantification of individual effects impossible. Future model experiments should take up this aspect and analyse the effect of details of technology modelling considering strongly reduced systems. The insight into different modelling approaches and their discussion represents a central added value for the scientific community helping to identify best practices. The collected findings also provide important points of orientation for setting priorities and structuring future model comparisons.

5. Acknowledgement

The research for this paper was performed within the RegMex project supported by the German Federal Ministry of Economic Affairs and Energy under grant number FKZ BMWi 0325874. The authors thank Diana Böttger, Matthias Koch, Hannes Hobbie, Christine Krüger, Dietmar Schüwer,

Stefan Lechtenböhmer, Philip Sterchele, Yvonne Scholz, Felix Cebulla and Karl-Kiên Cao for the fruitful discussions on the design of the scenarios and the interpretation of the results.

6. References

[1] Palzer A, Hennings, HM. A comprehensive model for the German electricity and heat sector in a future energy system with a dominant contribution from renewable energy technologies – Part II: Results. Renewable and Sustainable Energy Reviews 2014;30:1019-34. https://doi.org/10.1016/j.rser.2013.11.032

[2] Lunz B, Stöcker P, Eckstein S, Nebel A, Samadi S, Erlach B, et al. Scenario-based comparative assessment of potential future electricity systems – A new methodological approach using Germany in 2050 as an example. Applied Energy 2016; 171:555-80. https://doi.org/10.1016/j.apenergy.2016.03.087

[3] Coester A, Hofkes MW, Papyrakis E. Economics of renewable energy expansion and security of supply: A dynamic simulation of the German electricity market. Applied Energy 2018; 231:1268-84. https://doi.org/10.1016/j.apenergy.2018.09.143.

[4] Bloess A. Impacts of heat sector transformation on Germany's power system through increased use of power-to-heat. Applied Energy 2019; 239:560-80. https://doi.org/10.1016/j.apenergy.2019.01.101.

[5] Heinrichs H, Markewitz P. Long-term impacts of a coal phase-out in Germany as part of a greenhouse gas mitigation strategy. Applied Energy 2017; 192:234-46. https://doi.org/10.1016/j.apenergy.2017.01.065.

[6] Pfenninger S, Hawkes A, Keirstead J. Energy systems modeling for twenty-first century energy challenges. Renewable and Sustainable Energy Reviews 2014; 33:74–86. https://doi.org/10.1016/j.rser.2014.02.003.

[7] Lopion P, Markewitz P, Robinius M, Stolten D. A review of current challenges and trends in energy systems modeling. Renewable and Sustainable Energy Reviews 2018; 96:156-66. https://doi.org/10.1016/j.rser.2018.07.045.

[8] Connolly D, Lund H, Mathiesen BV, Leahy M. A review of computer tools for analysing the integration of renewable energy into various energy systems. Applied Energy 2010; 87:1059–82. https://doi.org/10.1016/j.apenergy.2009.09.026.

[9] Ringkjøb HK, Haugan PM, Solbrekke IM. A review of modelling tools for energy and electricity systems with large shares of variable renewables. Renewable and Sustainable Energy Reviews 2018; 96:440-59. https://doi.org/10.1016/j.rser.2018.08.002.

[10] Müller B, Gardumi F, Hülk L. Comprehensive representation of models for energy system analyses: Insights from the Energy Modelling Platform for Europe (EMP-E) 2017. Energy Strategy Reviews 2018; 21:82-7. https://doi.org/10.1016/j.esr.2018.03.006.

[11] Stanford University. Energy Modeling Forum, https://emf.stanford.edu (Accessed 2 August 2019).

[12] Capros P, Panos V, Mantzos L, Zeka-Paschou M, Papandreou V, Argiri E, et al. CASCADE MINTS: CAse Study Comparisons And Development of Energy Models for Integrated Technology Systems, Final Report, 2006. https://cordis.europa.eu/docs/publications/1247/124729481-6_en.pdf (Accessed 2 August 2019).

[13] Johns TC, Royer JF, Höschel I, Huebener H, Roeckner E, Manzini E, et al. Climate change under aggressive mitigation: the ENSEMBLES multi-model experiment. Climate Dynamics 2011; 37:1975-2003. https://doi.org/10.1007/s00382-011-1005-5.

[14] Kriegler E, Riahi K, Petermann N, Bosetti V, Capros P, van Vuuren DP, et al. Assessing Pathways toward Ambitious Climate Tar-gets at the Global and European Levels: A synthesis of results from the AMPERE project. IIASA Policy Report 2014. https://core.ac.uk/download/pdf/33971598.pdf (Accessed 2 August 2019).

[15] Edenhofer O, Knopf B, Barker T, Baumstark L, Bellevrat A, Chateau B, et al. The Economics of Low Stabilization: Model Comparison of Mitigation Strategies and Costs. The Energy Journal 2010; 31:11-48. https://www.jstor.org/stable/41323490

[16] Luderer G, Kriegler E, Delsa L, Edelenbosch O, Emmerling J, Krey V, et al. Deep Decarbonisation Towards 1.5 °C – 2 °C Stabilisation, Policy findings from the ADVANCE project, 2016. http://fp7-advance.eu/sites/default/files/documents/WP7/ADVANCE-Synthesis-Report.pdf (accessed 2 August 2019)

[17] Energy Modelling Platform for Europe, http://www.energymodellingplatform.eu/ (accessed 18 April 2019).

[18] Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland. Energiemodelle zum Klimaschutz in Deutschland, Strukturelle und gesamtwirtschaftliche Auswirkungen aus nationaler Perspektive. Berlin: Springer; 1999.

[19] Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland. Energiemodelle zum Kernenergieausstieg in Deutschland. Berlin: Springer; 2002.

[20] Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland. Energiemodelle zu Innovation und moderner Energietechnik. Analyse exogenen und endogenen technischen Fortschritts in der Energiewirtschaft. Münster: LIT Verlag; 2007.

[21] Pavičević M, Kavvadias K, Pukšec T, Quoilin S. Comparison of different model formulations for modelling future power systems with high shares of renewables – The Dispa-SET Balkans model. Applied Energy 2019; 252:113425. https://doi.org/10.1016/j.apenergy.2019.113425

[22] Mai T, Bistline J, Sun Y, Cole W, Marcy C, Namovicz C, Young D. The role of input assumptions and model structures in projections of variable renewable energy: A multi-model perspective of the U.S. electricity system. Energy Economics 2018; 76:313-24. https://doi.org/10.1016/j.eneco.2018.10.019

[23] Scholz Y. Renewable energy based electricity supply at low costs: development of the REMix model and application for Europe. PhD Thesis, University of Stuttgart, 2012. http://dx.doi.org/10.18419/opus-2015 (accessed 18 April 2019).

[24] Gils HC. Balancing of Intermittent Renewable Power Generation by Demand Response and Thermal Energy Storage. PhD Thesis, University of Stuttgart, 2015. http://dx.doi.org/10.18419/opus-6888 (accessed 18 April 2019).

[25] Gils HC, Scholz Y, Pregger T , de Tena DL, Heide, D. Integrated modelling of variable renewable energy-based power supply in Europe. Energy 2017; 123:173-88. http://dx.doi.org/10.1016/j.energy.2017.01.115.

[26] Lechtenböhmer S, Palzer A, Pregger T, Gils, HC, Sterchele P, Kost C, et al. RegMex - Modellexperimente und Vergleiche zur Simulation von Wegen zu einer vollständig regenerativen Energieversorgung. Project report, 2018. https://elib.dlr.de/121339/ (accessed 3 August 2019).

[27] Nitsch J, Pregger T, Naegler T, Heide D, Trieb F, Scholz Y et al. Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global. Project report, 2012. http://elib.dlr.de/76043/ (accessed 3 August 2019).

[28] Pregger T, Luca de Tena D, O'Sullivan M, Roloff N, Schmid S, Propfe B, et al. Perspektiven von Elektro-/Hybridfahrzeugen in einem Versorgungssystem mit hohem Anteil dezentraler und erneuerbarer Energiequellen. Project report, 2012. https://elib.dlr.de/77130/1/BMWi0328005A-C.pdf (accessed 3 August 2019).

[29] Scholz Y, Gils HC, Pregger T, Heide D, Cebulla F, Cao KK, et al. Möglichkeiten und Grenzen des Lastausgleichs durch Energiespeicher, verschiebbare Lasten und stromgeführte KWK bei hohem Anteil fluktuierender erneuerbarer Stromerzeugung. Project report, 2014. https://elib.dlr.de/93240/1/BMWI_Lastausgleich_Schlussbericht_Juni%202014.pdf (accessed 18 April 2019).

[30] Bruninx, K. el al. D 2.1 Data sets of scenarios for 2050. June 2014. e-HIGHWAY 2050 - Modular Development Plan of the Pan-European Transmission System 2050.

[31] Gils HC, Bothor S, Genoese M, Cao KK. Future security of power supply in Germany – The role of stochastic power plant outages and intermittent generation. International Journal of Energy Research 2018; 42(5):1894-913. https://doi.org/10.1002/er.3957

[32] Gils HC, Scholz Y, Cebulla F, Cao KK, Luca de Tena D, Pregger T. Data input for the RegMex model experiment on the power system and flexible sector coupling, 2019. https://www.dlr.de/tt/en/desktopdefault.aspx/tabid-2885/4422_read-45643/ (accessed 3 August 2019).

[33] Frankfurt Institute for Advanced Studies (FIAS). Powerplantmatching: hydro_aggregation_beta, 2017. https://github.com/FRESNA/powerplantmatching (accessed 3 August 2019).

[34] Bundesnetzagentur. Kraftwerksliste zu der Genehmigung des Szenariorahmens für die Netzentwicklungspläne Strom 2017-2030, 2017.

https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/20190630_kraftwerksliste_bnetza_2030_0.pdf (accessed 3 August 2019)

[35] Gils HC. Assessment of the theoretical demand response potential in Europe. Energy 2014; 67:1-18. https://doi.org/10.1016/j.energy.2014.02.019 .

[36] Gils HC. Economic potential for future demand response in Germany - Modeling approach and case study. Applied Energy 2016; 162:401-15. http://dx.doi.org/10.1016/j.apenergy.2015.10.083.

[37] Cebulla F. Storage demand in highly renewable energy scenarios for Europe: The influence of methodology and data assumptions in model-based assessments. PhD thesis, University of Stuttgart, 2017. http://dx.doi.org/10.18419/opus-9761 (accessed 04.09.2019)

[38] Garcia Teruel, A. Perspective of the energy transition: technology development and investments under uncertainty, Master thesis, Technical University Munich, 2015.

[39] Michalski J, Bünger U, Crotogino F, Donadei S, Schneider GS, Pregger T, et al. Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition. International Journal of Hydrogen Energy 2017; 42(19):13427-43. https://doi.org/10.1016/j.ijhydene.2017.02.102.

[40] ENTSO-E, "ENTSO-E load and consumption data." https://www.entsoe.eu/publications/statistics-and-data/ (accessed 3 August 2019).

[41] Luca de Tena D. Large Scale Renewable Power Integration with Electric Vehicles. PhD Thesis. University of Stuttgart, 2014. http://dx.doi.org/10.18419/opus-2339 (accessed 3 August 2019).

[42] Gerhardt N, Böttger D, Trost T, Scholz A, Pape C, Gerlach AK et al. Analyse eines europäischen - 95%-Klimazielszenarios über mehrere Wetterjahre. Project report, 2017. http://publica.fraunhofer.de/documents/N-439079.html (accessed 3 August 2019).

[43] Kraftfahrt-Bundesamt. Kraftfahrzeugbestand nach Kraftfahrzeugarten, Stichtag 01.01.11 – regionale Ebenen.

[44] Matthes F, Flachsbarth F, Loreck C, Hermann H, Falkenberg H, Cook V. Zukunft Stromsystem. Teil2: Regionalisierung der erneuerbaren Stromerzeugung. Project report, 2018. https://www.oeko.de/fileadmin/oekodoc/Stromsystem-II-Regionalisierung-der-erneuerbaren-Stromerzeugung.pdf (accessed 3 August 2019).

[45] Koch M, Bauknecht D, Heinemann C, Ritter D, Vogel M, Tröster E. Modellgestützte Bewertung von Netzausbau im europäischen Netzverbund und Flexibilitätsoptionen im deutschen Stromsystem im Zeitraum 2020–2050, Zeitschrift für Energiewirtschaft, 2015. DOI: 10.1007/s12398-015-0147-2

[46] Antoni O, Sager C, Gerhardt N. Wärme-Roadmap und Handlungsempfehlungen. Project report, 2015. https://www.iee.fraunhofer.de/content/dam/iwes-neu/energiesystemtechnik/de/Dokumente/workshops/2015_05_03%20-%20Abschlussworkshop_Waerme_4-W%C3%A4rmeroadmap.pdf (accessed 3 August 2019).

[47] Gerhardt N. SCOPE: Sektorenübergreifende Einsatz- und Ausbauoptimierung für Analysen des zukünftigen Energieversorgungssystems, 2016. https://www.iee.fraunhofer.de/content/dam/iwes-neu/energiesystemtechnik/de/Dokumente/Broschueren/2018_F_SCOPE_Einzelseiten.pdf (accessed 3 August 2019).

[48] Härtel P, Korpås M. Aggregation Methods for Modelling Hydropower and Its Implications for a Highly Decarbonised Energy System in Europe. Energies 2017; 10(1841):2–28. https://doi.org/10.3390/en10111841

[49] Jentsch M. Potenziale von Power-to-Gas Energiespeichern. Modellbasierte Analyse des markt- und netzseitigen Einsatzes im zukünftigen Stromversorgungssystem. PhD Thesis, University of Kassel, 2014. http://publica.fraunhofer.de/dokumente/N-336756.html (accessed 18 April 2019).

[50] von Oehsen A. Entwicklung und Anwendung einer Kraftwerks- und Speichereinsatzoptimierung für die Untersuchung von Energieversorgungsszenarien mit hohem Anteil erneuerbarer Energien in Deutschland. PhD Thesis, University of Kassel, 2012. https://kobra.bibliothek.uni-kassel.de/bitstream/urn:nbn:de:hebis:34-2013050742706/5/DissertationAmanyVonOehsen.pdf (accessed 18 April 2019).

[51] Trost T. Erneuerbare Mobilität im motorisierten Individualverkehr. Modellgestützte Szenarioanalyse der Marktdiffusion alternativer Fahrzeugantriebe und deren Auswirkungen auf das Energieversorgungssystem. PhD Thesis, University of Leipzig, 2017. http://publica.fraunhofer.de/documents/N-432324.html (accessed 18 April 2019).

[52] Schweppe FC, Caramanis MC, Tabors RD, Bohn RE. Spot Pricing of Electricity. Boston: Kluwer Academic Press; 1988.

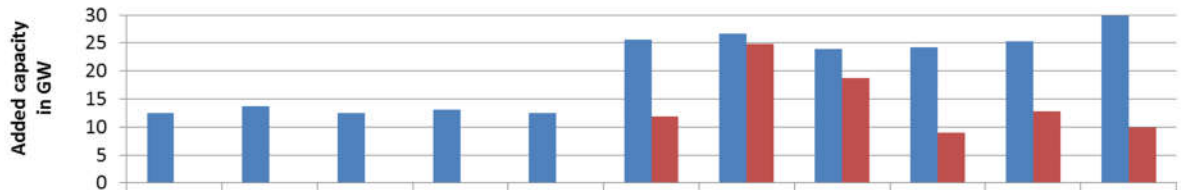
[53] Stigler H, Todem C. Optimization of the Austrian Electricity Sector (Control Zone of VERBUND APG) under the Constraints of Network Capacities by Nodal Pricing. Central European Journal of Operations Research 2005; 13:105–25.

[54] Leuthold F, Weigt H, von Hirschhausen, C. ELMOD - A Model of the European Electricity Market. Networks and Spatial Economics 2012; 12:75-107. http://dx.doi.org/10.2139/ssrn.1169082

Appendix A: Sensitivity analysis focused on flexible sector coupling

The aim of the sensitivity analysis is an in-depth analysis of the significance of individual technologies for load balancing. REMix is used to perform supplementary model calculations for the scenarios Import and Decentralized, and the results are then compared with those of the corresponding scenario.

Assuming uncontrolled charging and non-availability of grid feed-in for BEV (NoEVFlex) results in an increase in gas power plant demand of about 1 GW in both scenarios. While this is mostly covered by CCGT in the Import scenario, the increase in power plant capacity in the Decentralized scenario is mainly attributed to SCGT. An additional endogenous storage expansion is required only in the Decentralized scenario. It almost only occurs for batteries and amounts to more than 12 GW, corresponding to almost a tripling of the installed capacity (Figure 14). These additional stationary batteries completely take over the function of the vehicle batteries, so there are almost no changes in the use of DR, flexible heat generation and the power grid. The stored electricity increases from 32 TWh to 46 TWh (Figure 15). The higher storage losses are compensated by 2 TWh of additional generation in gas power plants. In contrast, the lack of flexibility of the battery vehicles in the Import scenario is mainly compensated for by the load balancing options available. This is possible because the design of transmission capacities in upstream European modelling does not take flexible sectoral coupling into account and is therefore rather oversized. In addition, the design of the heat storages is also larger than required, as the other sensitivity runs show. In detail, the use of PSH and DR is almost tripled, and the use of heat storage and electrical heat generation increases by about a third. There was also a slight increase in transmission and a slight shift in the generation of CHP plants to gas power plants. The additional losses amount to approximately 2.5 TWh and are compensated by gas power plants.



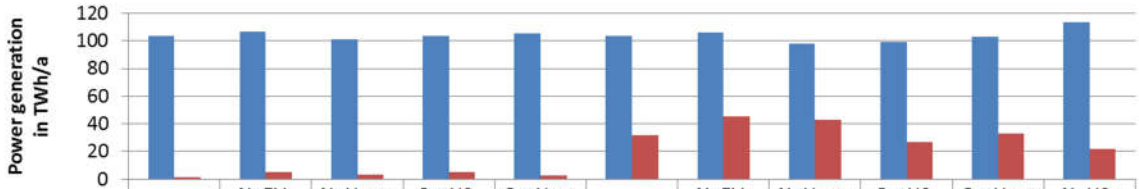
	Import					Decentralized					
	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	NoH2-Cavern
Gas PP	12	14	12	13	12	26	27	24	24	25	30
El. Storage	0	0	0	0	0	12	25	19	9	13	10

Figure 14: Endogenous installation of gas power plants and electricity storage in the sensitivity runs[1]

Inflexible operation of CHP plants and heat pumps (NoHeatFlex) has significant effects on the electricity and heat supply. In both scenarios, the operation of CHP plants is reduced and must be compensated by a doubling of the heat production in peak boilers. In the power supply, similar patterns can be seen as with inflexible operation of the battery vehicles. In the Decentralized scenario, an additional expansion of battery and hydrogen cavern storage facilities by a total of 7 GW

[1] NoEVFlex describes the variants with uncontrolled BEV charging, NoHeatFlex the variants without heat storage and electrical heat generation in CHP systems, OptH2Flex the variants with endogenous optimisation of the design of decentralized electrolysers and hydrogen tank storage, OptHeatFlex the variants with endogenous optimisation of the design of heat storage and electrical heat generation in CHP systems, and NoH2Cavern the variant without consideration of hydrogen cavern storage.

or 25 % takes place (Figure 14). The use of electricity storage is increasing to an even higher extent, while there are no changes in BEV charging and DR. The additional storage and the elimination of electrical heat generation reduces the demand for and use of gas-fired power plants by around 10 % each. In the Import scenario, for the reasons mentioned above, no additional power storage is added endogenously, but the existing load balancing options are used more intensively. The increase is particularly significant in the use of PSH (+100 %, 1.7 TWh) and RE curtailment (+100 %, 1.2 TWh), but also affects gas power plants, DR and BEV controlled charging.



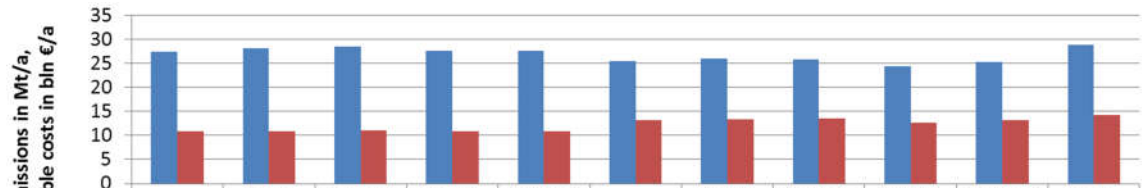
	Import					Decentralized					
	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	NoH2-Cavern
Dispatchable PP	104	106	101	104	105	104	106	98	99	103	113
El. Storage	2	5	3	5	3	32	46	43	27	33	22

Figure 15: Power generation in dispatchable power plants and electricity storage in the sensitivity runs

An optimization of the design of decentralized electrolysers and hydrogen tank storage (OptH2Flex) has contradictory effects in the scenarios considered. In the Import scenario, endogenous expansion results in a 25% lower electrolysis and hydrogen storage capacity of about 21 GW and 94 GWh, respectively. In the Decentralized scenario, electrolysis capacity increases by 20% to 34 GW and the hydrogen storage capacity more than doubles to 323 GWh. As a consequence of the changed flexibility in hydrogen production, the required backup capacity is reduced in scenario Decentralized, whereas it increases in Import. In the Decentralized scenario, there is also a significant reduction in endogenous storage capacity expansion, by 32% for battery storage, and by 13% of the discharge capacity for central hydrogen storage (Figure 14). The different design of the hydrogen infrastructure does not cause any significant changes to the power generation structure in the Import scenario. However, there is a significant increase in the use of all temporal load balancing options, which amounts to almost 200% for PSH, 20% for controlled BEV charging, over 500% for the grid feed-in from vehicle batteries, 35% for TES and 120% for other DR. Thus the model uses the flexibility available but not exploited in the reference case. In the Decentralized scenario, the optimised design of the decentralized hydrogen infrastructure results in notable reductions of RE curtailment (9%) and storage usage (15%), whereas it increases the feed-in from battery vehicles (16%).

The endogenous optimization of heat storage and electric boilers (OptHeatFlex) has significant effects, particularly in the scenario Import, in which the power grid is designed for extensive load balancing. This results in a significantly smaller design of the heat storage tanks by a total of 75% or 250 GWh. This applies in particular to building heat supply, for which no storage tanks are built. In contrast, in the case of CCGT-CHP plants, storage units are expanded in the same magnitude than exogenously defined. The heat stored in the storage tanks is reduced by 53%, corresponding to 6 TWh. The installed capacity of the electric boilers is 93% lower than the exogenous value and adds up to 5 GW. They are preferably considered in combination with natural gas-fired CHP plants. Despite the significantly lower capacity, the use of electric boilers only decreases by 15% or 0.6 TWh. The heat production in CHP is slightly reduced by 2 TWh and compensated by the peak boilers. The other balancing options tend to benefit from the lower flexibility in heat generation; in absolute figures,

the use of PSH (+60%, 1 TWh) is increasing in particular. In the Decentralized scenario, flexible heat generation plays a much more important role, which is also evident in the endogenous design of heat storages and electric boilers. The installed heat storage capacity is only 10% (30 GWh) lower than the endogenous value. However, it is distributed differently between the technologies, with smaller designs for biomass and biogas CHP and brine-water heat pumps, and larger designs for gas CHP and air-water heat pumps. The lower capacity of the heat storage tanks is compensated by additional electricity storage, including battery and hydrogen cavern storage, with a total capacity of 70 GWh and a converter capacity of 1 GW. Less than the capacity, the use of the heat storages is reduced by 3%, corresponding to 0.7 TWh. Analogous to the Import scenario, the endogenous design of the electric boilers yields significantly lower values than the exogenous specification. The total capacity amounts to 15 GW, which is 75% lower. However, this only reduces heat generation in the electric boiler by 11% or 1.5 TWh. Power generation, power storage use, RE curtailment, controlled BEV charging and DR are by less than 5% affected by the smaller design of the heat storages and electric boilers.



	Import					Decentralized					
	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	Ref.	NoEV-Flex	NoHeat-Flex	OptH2-Flex	OptHeat-Flex	NoH2-Cavern
CO2 emissions	27.44	28.16	28.39	27.65	27.66	25.43	25.89	25.83	24.43	25.23	28.83
variable costs	10.80	10.93	11.02	10.93	10.87	13.24	13.35	13.60	12.73	13.21	14.30

Figure 16: CO_2 emissions and variable system operation costs in the sensitivity runs

If in the Decentralized scenario no hydrogen cavern storage may be built (NoH2Cavern), compensation is provided by additional gas power plants with a total capacity of about 4 GW (Figure 14). The elimination of long-term storage also leads to an increase in the endogenous expansion of short-term storage, here represented by the batteries. With no long-term storage available curtailed RE power generation more than doubles to 40 TWh. In contrast, generation in gas-fired power plants increases by 20% to about 63 TWh and is accompanied by an increase in emissions. Due to the lower storage capacity, the amount of electricity stored decreases by about one third. A decline by about 10% is found for BEV charge control and DR. In contrast, electrical heat generation in CHP systems increases by 30% with no change in thermal storage output.

The reduced availability and optimized design of load balancing options in the sensitivity runs influences the CO_2 emissions and variable operating costs of the system (Figure 16). For the Import scenario, there is an increase in emissions and variable costs for all variants. This results consistently from an increased use of gas power plants. In the variants with optimized decentralized hydrogen infrastructure and flexible heat generation, savings in system costs of 0.5% and 3.9%, respectively, are achieved due to lower installed capacities. For the Decentralized scenario, a slight reduction in emissions and variable costs can be achieved by optimising the design of thermal storages and electric boilers. In all other variants, however, there are increases in both values. The savings in system costs due to the optimized design reach 1.4% for the decentralized hydrogen infrastructure and 2.4% for the flexible heat supply.

Appendix B: Model fact sheet

Model description

REMix model description

Basic characteristics

Model name: REMix (Renewable Energy Mix)

Author: DLR – German Aerospace Center, Institute of Engineering Thermodynamics

Licence: proprietary

Model scope: development and analysis of energy supply scenarios

Model type: energy system model with cost minimization approach for capacity expansion planning and operation optimization

Technical focus: power supply and its linkages to heat and transport sector

Technical and mathematical basis

Environment: GAMS

Programming technique: linear programming, mixed-integer linear programming

Preferred solver: CPLEX

Consideration of uncertainty: scenario analysis and sensitivities

Deterministic (Y/N): Yes

Optimization

Objective function: minimization of system costs

Composition of the objective function:

- annuities of all assets
- fixed and variable operational costs of all assets, including fuel costs and CO_2 emission certificate costs
- costs of unsupplied demand, if applicable

Temporal and spatial scales

Typical geographic assessment area: Europe, North Africa and Middle East

Regional subdivision in Germany: either 18 regions of the transmission system operators' *Regionenmodell* or 16 federal states

Minimum calculation interval: 1 hour

Typical investigation period or years: 2020, 2030, 2040, 2050

Technological coverage

Considered power generation technologies:

- Thermal power plants (e.g. fossil, nuclear, biomass, geothermal, CSP)
- CHP (e.g. fossil, nuclear, biomass, geothermal)
- Other renewables: run-of-the-river hydro power, reservoir hydro power, photovoltaic and wind power

Considered power transmission technologies:

- High-voltage direct current
- High-voltage alternating current

Considered balancing technologies:

- Electricity-to-electricity storage
- Thermal energy storage
- Demand response / demand side management
- Hydrogen electrolysis and storage

Considered linkages to heat and transport sector:

- Electrical heat pumps and boilers
- Battery electric vehicles with adjustable charging and vehicle-to-grid technology
- Hydrogen production from electricity for utilization in fuel cell vehicles and industry
- Methanization and gas network feed-in

Considered system services

- Demand for and provision of secondary and tertiary reserve

Possible restrictions in the composition of the supply system:

- Definition of supply shares and ratios for specific technologies
- Definition of minimum firm power generation capacity
- Definition of domestic supply shares

Data

Model input data:

Parameter	Temporal differentiation	Technological differentiation	Spatial differentiation
Conversion efficiencies	-	Yes	-
Technology availability	(Yes)*	Yes	(Yes)*
Technology potentials and technical restrictions	-	Yes	-
Operational costs	-	Yes	-
Investment costs	-	Yes	-
Fuel and emission certificate costs	-	Yes	-
Demand profiles for power, heat and hydrogen	Yes	-	Yes
Capacities for energy conversion, storage and transport	-	Yes	Yes
Demand response potentials	Yes	Yes	Yes
Capacity reserve demand relative to load and renewable energy power generation	-	-	-

* optional consideration of regional time series of conventional power plants

Model output data:

Parameter	Temporal differentiation	Technological differentiation	Spatial differentiation
Hourly operation profiles of all assets for energy conversion, storage and transport	Yes	Yes	Yes
Capacity expansion of all assets for energy conversion, storage and transport	-	Yes	Yes
Supply costs	-	Yes	Yes
Power supply marginal costs	Yes	-	Yes
Fuel input	Yes	Yes	Yes

Documentation

Publications providing model documentation:

…

Publications providing recent model results:

…