Managing Temporary Oversupply from Renewables Efficiently: Electricity Storage Versus Energy Sector Coupling in Germany

Katrin Schaber[1*], Florian Steinke[2], Thomas Hamacher[1]

July 2013

An increasing share of electricity from wind and solar PV, the variable renewable energies (VREs), will lead to significant temporary electricity surpluses in Germany in the future. Commonly discussed counter measures are a European super grid or new electric storage options. Instead, we examine in this paper how energy sector coupling, i.e., the interconnection of the power, heat, hydrogen, and natural gas sector, can help to make use of this surplus energy potential in an economic manner.

To this end, we employ a detailed cost-optimizing energy system model for a German 2020 and 2050 scenario. We explore different coupling technologies and their economic interrelations, as well as their interaction with electrical storage options. The model is regionally resolved and allows to locate different technologies in accordance with regional VRE supply and transmission capabilities.

The results reveal systematic benefits of energy sector coupling compared to a purely electric storage solution. The heat sector absorbs large parts of the temporary electricity oversupply from VREs and makes long term electricity storage via hydrogen or natural gas questionable. While energy sector coupling initially reduces the need for bulk electricity transmission, transmission grid requirements increase for large VRE shares: the grid is extended to facilitate the sector coupling.

Paper presented at the *International Energy Workshop* 2013, Paris.

[1]Lehrstuhl für Energiewirtschaft und Anwendungstechnik, Technische Universtität München, Germany

[2]Siemens Corporate Technology, Munich, Germany

[*]Correspoding author, k.schaber@tum.de

1. Introduction

In many regions of the world, wind and solar power are the dominant renewable electricity sources and will play an important role in the decarbonization of the power sector [13, 9]. The integration of wind and solar power into the existing electricity sectors is, however, challenging: Sites with high wind or solar potential can be located far away from the load centers. In the temporal domain, the availability of weather dependent VREs may also not fit the load pattern. Already for VRE shares of around 30% in the yearly electricity consumption temporary electric over- and undersupply will both occur over the year [e.g. 33].

This is examined more closely in Figure 1 where the aggregated yearly electricity oversupply relative to the total electricity consumption is shown as a function of different VRE share α, and for different mixes between wind and solar energy (β). α is the amount of directly usable VRE energy, excluding oversupply. It is normalized to the yearly electricity consumption. β is the share of wind energy in total VREs, i.e., in total, solar plus wind generation. The data is based on the European timeseries analysis of Schaber et al. [26]. Europe serves as a relevant example, as ambitious targets for emission reduction and renewable energy shares have been put forward [8]. For the example of 60% directly usable VRE share, 300 TWh of excess electricity would occur every year. This corresponds to about 10% of current annual consumption in Europe.

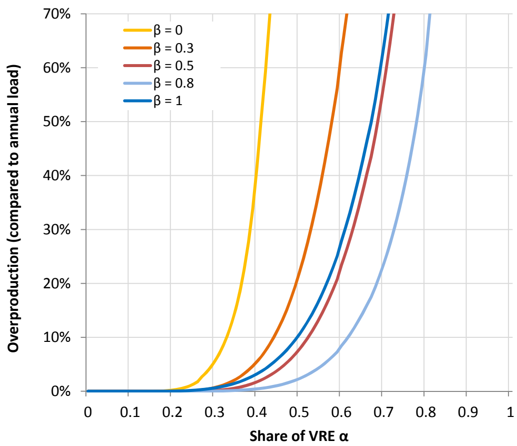


Figure 1: Average electric oversupply relative to electricity consumption as a function of different shares of directly usable VRE energy α. β is the share of wind in total VRE generation.

Different options to facilitate the integration of VREs into the power system have been discussed. Most of them focus on the electricity sector only. Major HV transmission grid extension would link remote sites with high VRE potential to the load centers and would smoothen VRE supply [e.g. 4, 7, 26]. New electrical storage would allow to shift demand from hours of high VRE supply to periods of undersupply [e.g. 16, 11]. Electrical demand side management could counteract both periods of over- and undersupply [31].

Finally, more flexible power plants would allow the power system to balance the variable generation more efficiently [e.g. 33].

In contrast to these approaches focused on the power sector only, a number of studies have widened the horizon and included other energy sectors in the analysis. This bears two advantages: other energy sectors can help to integrate fluctuating electricity generation from VRE. Second, the usage of carbon-free electricity generated from renewable energies can contribute to the decarbonization of the other energy sectors.

Mathiesen and Lund [19] provide a broad overview of the literature on energy sector coupling. For example, it has been shown for several northern European countries that through the inclusion of the heat sector the integration of wind energy can be facilitated [e.g. 21, 17, 18]. The hydrogen sector has been examined in Lund and Mathiesen [18] and Karlsson and Meibom [14], with a focus on its electrical storage capabilities and its role for the transport sector. Kuhn [16] shows in an analysis of electricity storage options for Germany, that hydrogen storage is the most promising option to store large amounts of electric energy. While the potential for pumped hydro storage and compressed air storage is limited, hydrogen storage offers the possibility to store large amounts of energy for longer times due to its high energy density. Hydrogen can also be used to generate natural gas via methanation, the so-called power-to-gas option [29]. Large-scale energy transports could then be realized via the existing natural gas-grid instead of building new electric power transmission lines.

In this paper we examine large-scale VRE integration in Germany via the coupling of the power sector to the heat, hydrogen and natural gas energy sector. We examine all these options with the cost-optimizing techno-economic model URBS-D [25] based on linear optimization. We take several plausible conversion and storage technologies into account. For each sector's underlying commodity we also model individual demands that have to be covered. In this way, energy conversion from the power to the hydrogen sector can, for example, either be used as a first step in an electric storage cycle or for directly covering an existing hydrogen demand. Moreover, our model is highly resolved within Germany and respects today's and possible future electric HV transmission grid capacities. These ingredients make our study uniquely positioned to understand the economic value of energy sector coupling for VRE integration in detail, with all its complex interrelations between the different conversion technologies, storage options, the HV grid as well as location-dependent factors. This allows us to answer the major underlying question whether electric energy storage should not in large part be replaced by a strong energy sector coupling, if economic system efficiency is to be achieved.

Germany serves as a good case study, since it has one of the most ambitious targets with respect to the reduction of greenhouse gas emissions and the installation of renewable energy technologies. We study two scenario years, 2020 and 2050, increasing the VRE capacity from about 60 GW in 2012 (35% of the total capacity) to 117 GW and 250 GW, respectively. Although the analysis is focused on Germany, general conclusions concerning the different technologies and their interaction are possible thanks to the high modeling detail.

This paper proceeds as follows. Section 2 gives a short introduction to the modeling framework and the data basis, and defines the scenarios. The results are presented in Section 3 in two steps: first, overall system advantages of the energy sector coupling for VRE integration are described. Second, individual technologies of the coupling are explored in more detail. Finally, we discuss our results and conclude in Section 4.

2. Model setup and data

2.1. URBS-D model setup

To study the role of energy sector coupling for the integration of VRE in the German power system, we employ a regionally and temporary highly resolved model of the German electricity, heat, hydrogen and natural gas sector. The model URBS-D is based on linear optimization of total system costs [25]. It computes the cost-optimal production schedule for dispatchable power plants and other generation technologies. On demand it can also optimize the infrastructure, i.e. the addition of generating and grid capacity. The energy sectors and conversion technologies combined in URBS-D are shown in Figure 2.

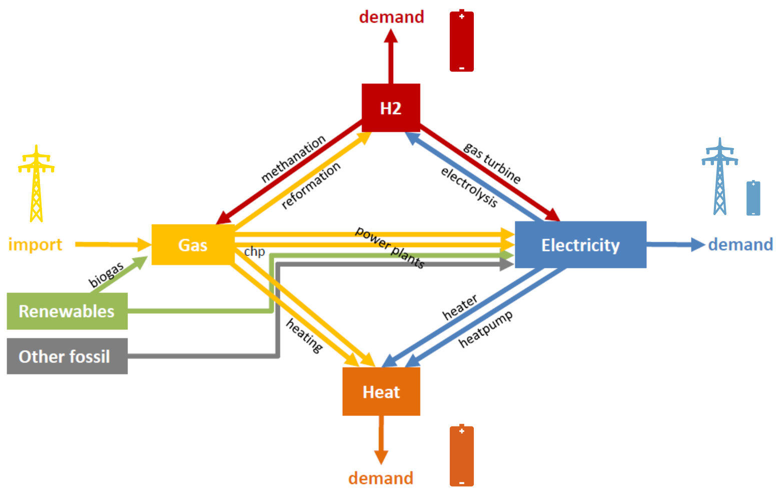


Figure 2: Energy sector coupling in URBS-D: commodities and technologies

In each model region, electricity can be generated from renewable resources, natural gas or other fossil resources. Natural gas can be replaced by biogas. In the scenarios, power generation from renewable energies mainly stems from variable resources, such as wind and solar. Bioenergy and hydro power plants are assumed to increase only little in future scenarios. The heat sector is not modeled in full technological depth, but with a focus in a specific reference technologies, namely natural gas heating. Heat not produced directly from gas heaters may come from combined heat and power generation (CHP). Moreover, the power sector can export energy to the heat sector via electric heaters and heatpumps. Hydrogen is supplied by reformation of natural gas and oil-refinery by-products in Germany [28]. It is assumed, that only the gas reformation is replaceable by electrolysis, which couples the power to the hydrogen sector. Furthermore, hydrogen can be used to produce natural gas via methanation. Alternatively, hydrogen can also be retransformed into electric power via gas turbines, forming a long term storage option for electricity.

Energy storage is possible in all sectors. However, the hydrogen sector has the largest storage size, due to the high energy density of the hydrogen gas. In the power sector, only the existing pumped storage is included, as the potential of other long term electricity storage options, such as compressed air storage, is limited, and battery costs are still prohibitive for large scale deployment. Energy transport is possible via HV power transmission or via the natural gas-grid.

The model URBS-D includes transformation, storage and transport losses for all technologies, as well as ramping constraints for baseload power plants, such as coal and nuclear power plants. For decentralized heat and CHP plants, additional restrictions are included in order to simulate their head-led operation realistically.

The model regions are defined in accordance with the dena II study [6] (see Figure 3). They reflect comparatively well connected areas of today's electricity grid. In this paper international energy transport (power or natural gas) is neglected.

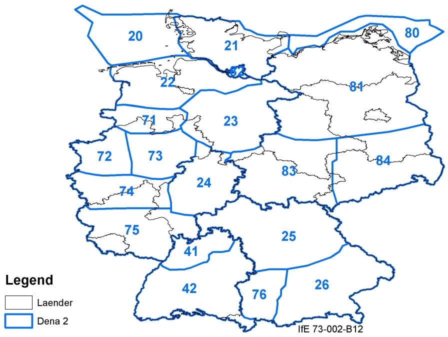


Figure 3: Model regions

The model has hourly resolution. The optimization is performed for six representative weeks of one year. The selected weeks include the minimal and maximal residual electricity demand of the year, they are distributed uniformly across seasons and have minimal deviation from the annual residual electricity demand in Germany.

2.2. Scenario definition

To investigate the interaction of different options for energy sector coupling, all storage and conversion technologies introduced in Figure 2 are implemented in the model. We

Scenario Name	grid extensions	heat coupling	hydrogen coupling	gas price [€/MWh]	electrolysis costs [€/kW]	storage size[a] (elec.) [predefined size]	storage size[a] (heat) [hrs. of mean demand]	storage size (H2)
Base	✓	✓	✓	25	500	1	1	unlimited
No New Grid, No Coupling	-	-	-	25	500	1	1	unlimited
New Grid, No Coupling	✓	-	-	25	-	1	1	unlimited
No New Grid, Coupling	-	✓	✓	25	500	1	1	unlimited
New Grid, No Heat Coupling	✓	-	✓	25	500	1	1	unlimited
gas price sensitivity	✓	✓	✓	50, 75	500	1	1	unlimited
electrolysis sensitivity	✓	✓	✓	25	200, 1000	1	1	unlimited
Methanation (2050)	-	-	✓	75	500	1	1	unlimited

Table 1: Parameter settings for the scenarios

[a] Storage size is given in different units. The electric storage is given relative to today's instalation (see Table 2). For the heat storage, it is assumed that it is large enough to store the average heat demand for one hour.

examine two scenario years, 2020 and 2050. For each scenario year, a *Base* scenario and a set of interesting variations are defined. In the *Base* scenarios, the optimization choses the economically most viable mix between the offered technologies (Table 1).

In a second step, the integration measures are studied individually and parameter variations are carried out to study the sensitivity of the relative roles of the technologies and energy sectors.

2.3. Database for the German heat, hydrogen and electricity sector

For each energy sector, the existing infrastructure is included in the scenarios. The assumptions for the energy infrastructure, the energy demand per sector as well as the costs are summarized in this section.

Table 2 gives an overview on the assumptions on infrastructure per energy sector.

Based on a detailed geo-referenced power plant database (see [25]), the regional distribution of conventional power plants in 2020 is determined. Furthermore, planned capacity additions and political targets are taken into account [33]. For 2050, the conventional power plant fleet is optimized. For renewable energies, especially VREs, important capacity additions until 2020 and 2050 are assumed, following a report prepared for the German Ministry of Environment [15]. These scenarios reflect the political targets as well as the regional, installed capacities, growth rates and technical potential.

For the heat sector, natural gas heating is assumed as reference technology. Its

Parameter assumptions

Infrastructure	2020	2050
Capacity		
Electricity		
Conventional	set by scenario	optimized (Gas CCGT and GT)
Renewables	set by scenario	set by scenario
Wind	57 GW	122 GW
Solar PV	60 GW	129 GW
Heat		
chp plants	bioenergy & decentral chp set	bioenergy & decentral chp set, gas chp additions optimized
gas heating	60% of today, rest optimized	optimized
Hydrogen		
gas reformation	80% of today, rest optimized	50% of today, rest optimized
Storage size		
Electricity	current (67 TWh)	set to 80 TWh
Heat	1h of average demand	1h of average demand
Hydrogen	unlimited	unlimited
Grid size		
Natural gas	unlimited	unlimited
Electricity	current HV transmission grid (ENTSO-E + dena I), extension optimized	current HV transmission grid (ENTSO-E + dena I), extension optimized
Demand		
Electricity	560 TWh annual demand, load profile as published by European Network of Transmission System Operators for Electricity (ENTSO-E) [10], regional distribution based on GDP and population	
Heat	1410 TWh annual demand, load profile based on ambient temperature and day profiles, regional distribution based on ambient temperature, GDP and population	
Hydrogen	60 TWh annual demand, constant load profile, regional distribution based on GDP	

Table 2: Assumptions for infrastructure and demand per energy sector in 2020 and 2050

capacity in 2020 and 2050 is deduced assuming an average lifetime of 30 years.

In the hydrogen sector, only the natural gas reformation is modeled and a lifetime of 50 years is assumed. The capacities per technology are listed in Table 5 in the Appendix.

Energy storage is possible in all energy sectors. However, in the heat and the electricity sector it is rather limited. Only in the hydrogen sector, long term storage is possible (see also [16]). Due to the high energy density of hydrogen, the hydrogen storage size is assumed to be unlimited. Long term storage of electricity thus consists of three steps: electricity is transformed to hydrogen via electrolysis, which is than stored and finally re-transformed to electricity via a gas turbine. The natural gas sector also offers the possibility to store energy.

The HV power transmission grid is deduced from a detailed database of the German 220 and 380 kV transmission grid [32]. It is furthermore assumed, that the grid extensions identified in the dena I study [5] are realized. For the natural gas grid, the transport capacities between regions are determined by the optimization.

As indicated in Figure 2, electricity, heat and hydrogen demand are included in the model. Annual demand is given in Table 2. In the analysis in this paper, not all hydrogen and heat demand is assumed to be replaceable. For hydrogen, we assume, that the hydrogen generation from refinery by-products is not replaceable. As a consequence, only 30 TWh annual load are endogenous to the model. The heat demand consists of space heating (780 TWh), warm water (110 TWh) and process heat (530 TWh) demand [1]. Within the process heat segment, only low-temperature process heat (268 TWh), below 500^{o}C, can be supplied via CHP plants or electric heating technologies [3].

The hourly load profiles per sector are deduced based on different assumptions, as indicated in Table 2. Electricity load profiles are based on existing data [10]. The hydrogen load is assumed to be constant throughout the year. The heat load profile results from a detailed separate computation: space heating demand is determined based on degree days (temperature data from Rienecker et al. [24]) and daily load profiles [2]. Warm water and process heat demand are assumed to be constant throughout the year.

The wind and solar supply timeseries are extracted from high resolution reanalysis data for Germany [15]. Based on wind speed and global irradiation from 2007, capacity factor time series for wind and solar PV power are computed for every HV-grid-node in Germany. For the analysis in this paper, the values are aggregated for each model region assuming a capacity distribution within each model region as projected for 2050 [15].

Costs assumptions per technology are based on scientific studies [12, 20, 22, 27]. They are given in Table 3-4 in the appendix. We assume a cost reduction of VRE technologies in 2020 and 2050 (Table 4).

3. Results: Energy sector coupling as advantageous VRE integration measure

The optimization results show that energy sector coupling facilitates the integration of VREs into the German power sector. The description of the result starts with an overview of the systematic advantages of the energy sector coupling. Second, the individual coupling technologies and their interrelations are explored in more detail.

3.1. System effects of energy sector coupling in Germany

Figure 4 and Figure 5 provide an overview of the energy flows between the modeled energy sectors as they result from our model.

The most prominent effect in the model is the strong coupling between the power and the heat sector. It increases with increasing VRE contribution, i.e., from the *Base*

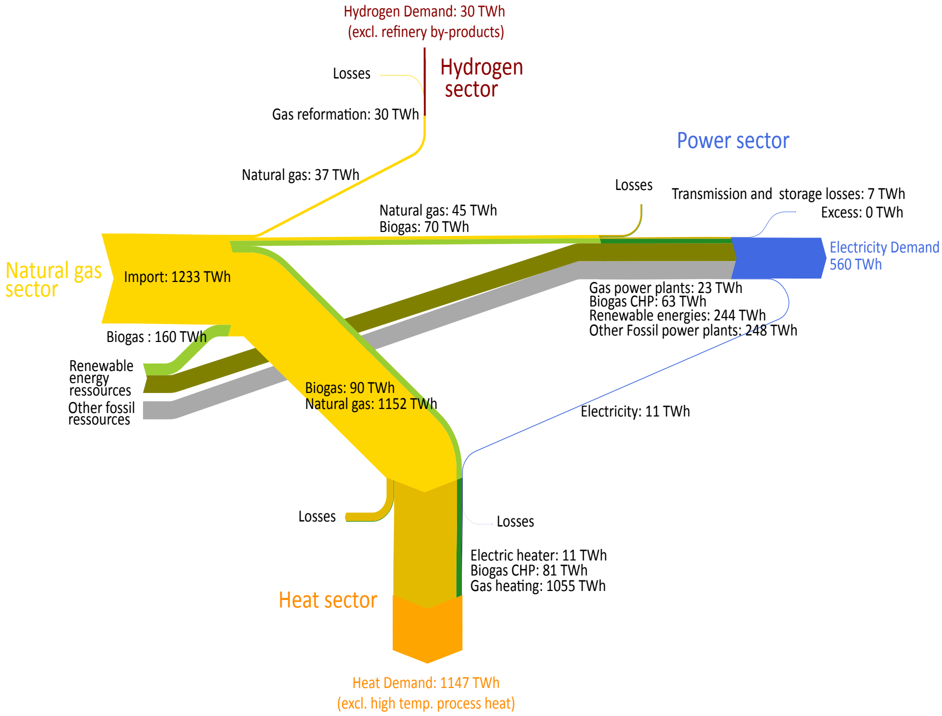


Figure 4: Sankey diagram of the energy flows in the *Base 2020* scenario. Power plant conversion losses of other fossil resources are not shown.

2020 to the *Base 2050* scenario. Natural gas for heat production is substituted with electricity. In most cases, this electricity stems from VREs which cannot be integrated in the power sector: in hours of high VRE supply, temporary electricity oversupply is used to power electric heaters. In the 2020 *Base* scenario, an export of 11 TWh electricity to the heat sector results. In the 2050 scenario, the coupling between power and heat increases to 137 TWh of heat generated by electric heaters and also CHP is used for more efficient use of natural gas.

The options to use hydrogen as long term electricity storage or to produce gas from hydrogen via methanation are not used in the *Base* scenario for both years. The electricity oversupply is used to satisfy the heat demand and is thus no longer available to be exported to the hydrogen sector.

Figure 6 shows this effect in more detail. In the uncoupled case, important electricity oversupply results from the model for both scenario years. National HV transmission grid extensions already reduce the overproduction considerably. In the 2020 scenarios, national grid extensions and energy sector coupling both achieve to almost entirely eliminate the overproduction individually. In the 2050 scenarios, this can only be realized with energy sector coupling and HV transmission grid extensions working together.

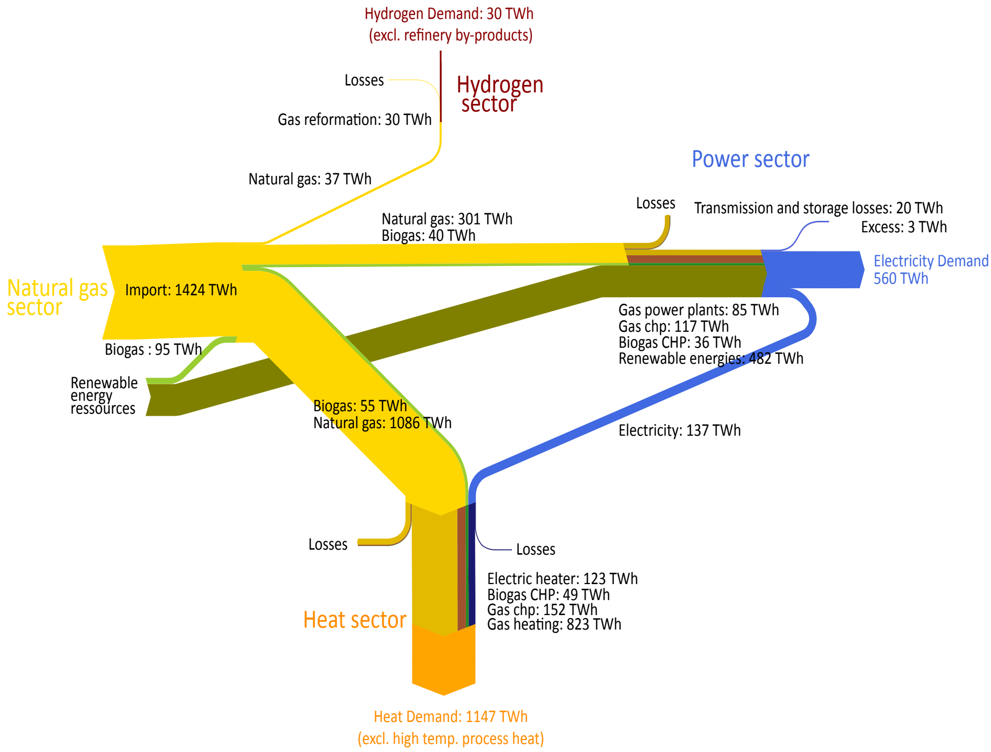
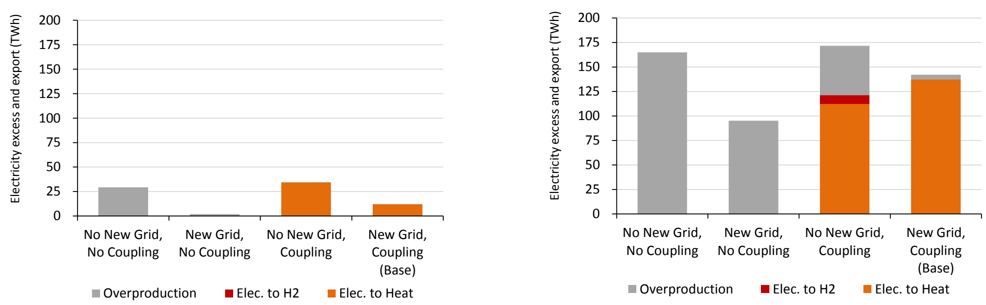


Figure 5: Sankey diagram of the energy flows in the *Base 2050* scenario



(a) 2020 (b) 2050

Figure 6: Effects of energy sector coupling to overproduction and cross-sector balance

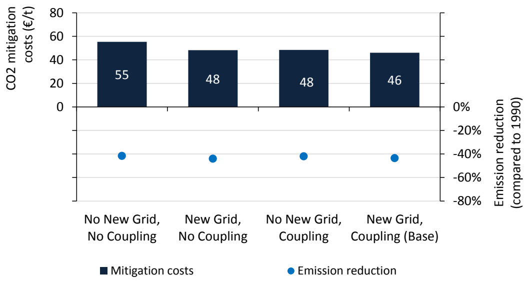
It is furthermore interesting to note, that in the *No New Grid, Coupling* scenario in 2050, electrolysis is part of a cost-optimal system. The large electricity oversupply can not be absorbed by the regional heat sectors alone and in regions with high VRE capacities, export of electricity to the hydrogen sector occurs simultaneously. With grid extensions (*New Grid, Coupling (Base)* scenario), the regional electricity oversupply can be transported to other regions and used to supply the heat demand in other regions. In this case, the *Base* case, and in the 2020 scenarios, the coupling of the electricity sector to the hydrogen sector is uneconomic. This is due to the lower investment costs of the coupling technology for the case of the heat sector: an electric heater is assumed to cost only 90 €/kW$_{el}$, while the investment costs for electrolysis is estimated at 500 €/kW$_{el}$ for the future scenarios. Yet, the possible savings per MWh are similar, as the replaced fuel (natural gas) is the same in the two cases.

The third conclusion which can be drawn from Figure 6, is that the role of the transmission grid changes. While in the 2020 scenarios, energy sector coupling decreases with transmission grid extensions, in the 2050 scenarios, energy sector coupling increases with grid extensions. With intermediate VRE shares (2020), energy sector coupling can help to mitigate grid extensions for the integration of VREs. With high VRE shares, transmission grid extensions are used for stronger energy sector coupling: the amount of heat generated from electricity increases with increasing power transmission capacities. The local electricity oversupply is too high to be absorbed by the local heat sector and thus transmission grid extensions are necessary to export local electricity oversupply to other regions' heat sector.

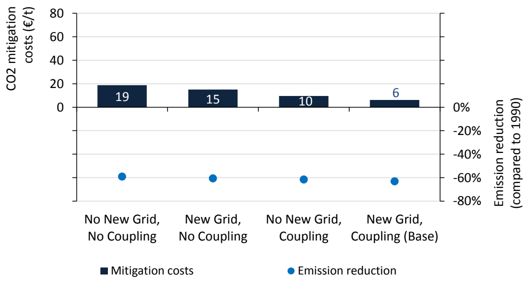
In addition to the reduction of oversupply, the energy sector coupling has another advantage: if electricity from VREs replaces natural gas, total emissions can be reduced. The results show that the electricity sector and the carbon free excess electricity act as drivers for emission reductions in other sector. As figure Figure 7 indicates, the emission reduction in the *Base 2020* amount to 40% (compared to 1990 levels) and to more than 60% in the *Base 2050* scenario. In the 2020 scenario, the sector coupling does not lead to additional emission reductions compared to the uncoupled *No New Grid, No Coupling* case. The coal power plants are partly used to power the electric heaters. This effect is compensated by reducing the discarded excess electricity from VREs. In the 2050 scenarios, the change in total emission reduction from the *No New Grid, No Coupling* case to the *Base* scenario amounts to 4 percentage points. This additional emission mitigation occurs mainly in the heat sector. It is driven by the excess electricity from VREs.

The emission reduction is computed based on an estimate of 1990 CO_2 emissions. The 1990 emissions of the modeled sectors are estimated by backcasting the model results for the *Base 2010* scenario following the real emission reductions in Germany from 1990 to 2010. Emissions from CHP are split to the heat and power sector in accordance to the CHP coefficient. The 2010 model results are in accordance with statistic data: the United Nations Climate Change Secretariat (UNFCCC) reports 949 mio. tons of CO_2 for the analyzed energy sectors [30]: 302 mio. tons from the power sector and 647 mio. tons from the remaining energy sector excluding the transport sector. The model results are only 3% lower (923 mio. tons).

While the level of achieved emission reduction compared to 1990 only changes very little due to the energy sector coupling, the CO_2 mitigation costs are reduced considerably, as Figure 7 shows. In the *Base 2020* scenario, the mitigation costs are reduced by more



(a) 2020



(b) 2050

Figure 7: Effects of energy sector coupling to emission reduction and CO_2 mitigation costs

than 16% compared to the *No New Grid, No Coupling* scenario, thanks to national grid extensions and the coupling. In the 2050 *Base* scenario, a reduction of more than 65% is achieved. The mitigation costs are computed compared to a reference 2010 scenarios, simulating todays system. The overall cost reduction results mainly from reduced fuel costs, but also from the assumed cost reduction for VRE.

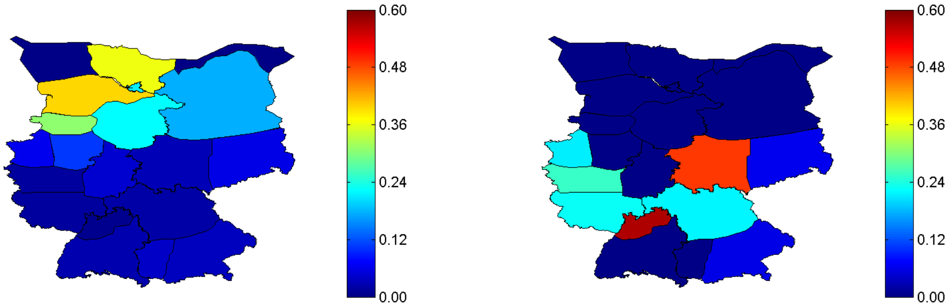
3.2. Relative roles of the coupling technologies

3.2.1. Heat sector

In the *Base 2050* case, 10% of the heat demand is covered by electric heating technologies. Another 10% are supplied by natural gas CHP plants. These two technologies lead to a strong coupling between the power and the heat sector in the *Base 2050* scenario. In the *Base 2020* scenario the coupling is less strong.

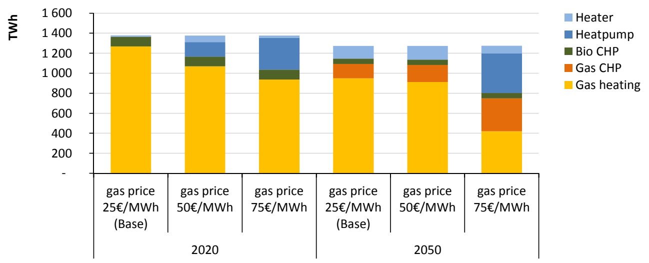
The results from the regionally resolved model show, that these two heating technologies are used for different purposes. While the electric heater is used in the north, gas CHP plants are used in the south (see Figure 8). The highly fluctuating wind energy leads to highly fluctuating electricity excess with rather high peaks. Thanks to its low investment costs, the electric heater is well suited to absorb such fluctuations. The electric heatpump is not used in the *Base 2050* scenario, as its investment costs are comparatively high.

In the south, power generation from solar PV is predominant. As identified by Richter for the city of Augsburg [23], the power generation from heat-led CHP combines well with the residual load. This is reconfirmed on a German level by the results shown in Figure 8. Electricity generation from heat-led CHP power plant is anti-correlated to the power supply from solar PV in Germany: it is high in winter and low in summer, when a large share of electricity is covered by solar power. In response to the projected regional distribution of wind and solar capacities, this leads to regional differences in the heating technology mix.

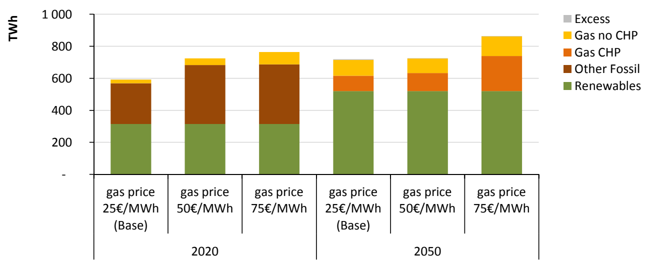


(a) Heat from Electricity (*Base 2050*) (b) Heat from Gas CHP (*Base 2050*)

Figure 8: Share of heat supply from electricity and gas CHP power plants per region in the 2050 *Base* scenario



(a) Heat generation



(b) Electricity generation

Figure 9: Sensitivity of heat and electricity generation to the assumed gas price

A sensitivity analysis towards the assumed gas price (see Table 1) reveals further important properties of the technologies. As Figure 9 shows, higher gas prices lead to stronger replacement of natural gas in the model results. In the 2020 scenarios, where a total of 44 GW of coal, lignite and nuclear power plants are still on line, these cheap baseload power plants are used to feed electric heaters and heatpumps to reduce gas-consumption for very high gas price scenarios. Due to their high efficiency, electric heatpumps are an attractive technology if high gas prices are assumed. The same effect occurs in the 2050 scenarios. Furthermore, due to their high efficiencies, the usage of CHP plants increases with the gas price. For very high gas prices of 75 €/MWh, CHP plants are used to generate electricity efficiently, which is then in turn used to supply heat demand with heatpumps.

3.2.2. Hydrogen sector

Because of its smaller absolute size and the high costs of the coupling technologies in comparison with the heat sector, the hydrogen sector plays a smaller role in the energy sector coupling.

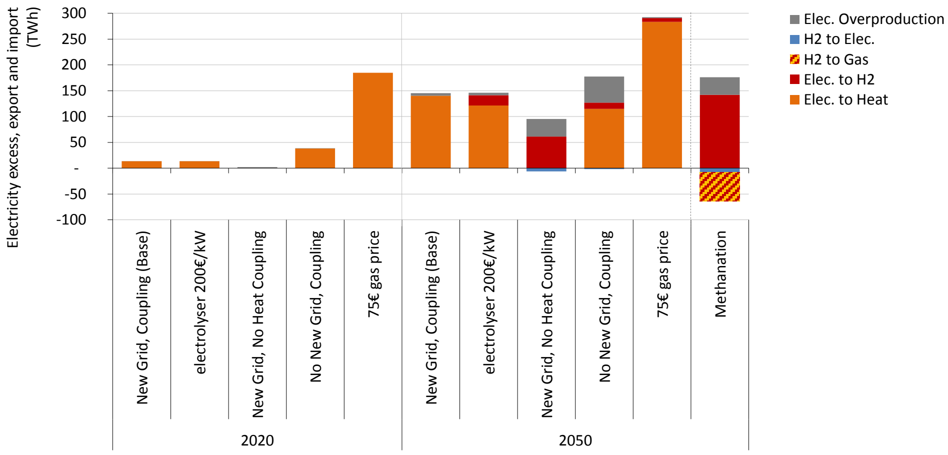


Figure 10: Electricity excess and flows to and from other sectors: sensitivity of hydrogen coupling to heat coupling. All values are shown in electrical energy (TWh_{el}), except the hydrogen used for methanation, which is shown in terms of the lower heating value of hydrogen (TWh_{H2}).

In the 2020 scenarios, only little excess electricity occurs and all of it is exported to the heat sector, even if electrolysis costs of 200 €/kW_{el} are assumed (see Figure 10). This competitive situation becomes more evident for the 2050 scenarios. Without the coupling to the heat sector (*New Grid, No Heat Coupling*), about 45 TWh hydrogen is produced by 15 GW of electrolysis capacity. The market potential of the electrolysis is reduced to zero through the coupling of the heat sector to the electricity sector (*Base 2050* scenario). With high gas prices or without grid extensions, the coupling to the hydrogen sector is cost-optimal in regions with high VRE shares and 3-4 GW of electrolysis capacity results from the model. If the costs of electrolysis remain at today's level of 1000 €/kW_{el}, it is not used in the model in both scenario years.

In the *Base* scenarios, long term hydrogen storage is not used for seasonal electricity storage. However, in the 2050 scenario, where no heat coupling is possible (*New Grid,* *No Heat Coupling*), hydrogen is used as seasonal storage. The total hydrogen storage capacity that is necessary to realize this scenario amounts to 18 TWh. This is in accordance with other studies. Based on an intertemporal optimization Kuhn [16] determines the storage additions for Germany until 2050. He finds, that about 11 TWh of hydrogen storage need to be added until 2050, assuming perfect interconnection within Germany. Due to the regional resolution in this analysis, our resulting storage size is larger than the one found in Kuhn [16].

If transmission grid extensions in Germany are not allowed, but the coupling to the heat sector is (*No New Grid, Coupling* scenario), the hydrogen storage is used as well, but a lot less than in the above described case (*New Grid, No Heat Coupling* scenario). Hydrogen storage is only used in regions with very large VRE supply and where the heat sector is not large enough to absorb the electricity oversupply[a].

The power-to-gas option is also not used in the Base scenarios. The overall costs of power-to-gas, including electrolysis and methanation are very high and it therefore it is only used in the model if a high gas price, no transmission grid extensions and an exclusive coupling of the power sector to the hydrogen sector are assumed. In this so-called *Methanation* scenario (Table 1), about 140 TWh or 20% of power production are transformed to hydrogen, of which about 50% is then transformed to gas (see Figure 10). The other half of the produced hydrogen is used directly (25%) and retransformed to electricity after seasonal storage (25%). The natural gas generated from hydrogen allows to export the excess electricity to other regions. The electricity which cannot be used in the respective regions is transported via the gas-grid. The total annual transport amounts to 10% of the regional gas demand at its maximum. The existing gas grid infrastructure may thus be sufficient to realize the additional gas energy transport.

4. Discussion and Conclusion

In this paper we examined energy sector coupling, electricity storage and national grid extensions as large-scale VRE integration measures. We employed the detailed techno-economic energy system model URBS-D and analyzed scenarios for Germany in 2020 and 2050.

Our simulations show that the heat sector provides a large sink for the temporary electricity oversupply caused by VREs. Moreover, the export of electricity to the heat sector is economically more attractive than the export to the hydrogen sector due to its relative costs structure. While cost savings for replacing conventional fuel in the heat or hydrogen sector are comparable – in both cases natural gas is replaced, the investment costs for coupling the power to the hydrogen sector are higher. Given the large thermal demand and the relatively cheap coupling technology in the heat sector compared to the hydrogen sector, our model shows that the cost-optimal system would not employ

[a]We have assumed that hydrogen can not be transported over longer distances

long-term electricity storage via hydrogen generation both in the 2020 and the 2050 scenario. Instead, the power sector is strongly coupled to the heat sector.

Thanks to our regionally resolved and technology specific modeling, the optimal conversion paths from power to heat can be resolved for different locations. We find that the deployed heating technologies are complementary to the regional VRE power supply: highly flexible electric heaters are used in northern Germany close to variable excess electricity from wind energy. Heat generation from CHP is centered in the south because its seasonal supply pattern is anti-correlated to the large supply from solar PV in these regions. With increasing gas prices, electric heat pumps become more attractive, because of their high efficiency and the resulting natural gas savings.

Denying our model the option for coupling power to heat, other measures to manage VRE oversupply are deployed in the simulations. Especially for the high VRE shares in the 2050 scenarios long term electricity storage via hydrogen becomes cost-efficient. However, the power-to-gas option, i.e. using the natural gas grid as a high-capacity energy transport infrastructure, is uneconomic in our model; it is only part of the cost-optimal solution, if further restrictions and a high gas price is assumed.

Another observation from our calculations is that the role of the national transmission grid changes from 2020 to 2050. In the 2020 scenarios, the absorption of regional power oversupply through the heat sector makes grid extensions initially less attractive. With increasing VRE shares in the 2050 scenarios, the regional sink, i.e. the regional heat demand, is insufficient to absorb all the oversupply, especially in regions with large VRE capacities. In this case the model decides to realize transmission grid extensions to strengthen the energy sector coupling. Electric oversupply from northern Germany is then exported to the heat sectors of other regions.

In sum, energy sector coupling helps to reduce green house gas emissions of the complete system. Emissions in the power sector rise slightly in comparison to the electric storage option since VRE undersupply situations cannot be covered with stored carbon free energy but have to be closed with fossil fuel. However, emission savings in the other sectors, heat and/or hydrogen, overcompensate this increase. This can be explained by the low efficiency of long-term electricity storage which makes direct use of temporary VRE surpluses even for "low quality" energies like heat beneficial. Economically, energy sector coupling helps to reduce mitigation costs by about 15% and 65% compared to the uncloupled case in 2020 and 2050, respectively. In the light of ambitious green house gas reduction pledges in Germany and Europe, these cost-reduction potentials should not remain unused.

Having drawn these conclusions it should be noted that our results should be interpreted with caution. Our analysis is centered around the challenge to integrate the VREs into the power sector and thus does not include all technical details of the hydrogen and the heat sector. Specifically, our scenarios do not consider direct renewable supply for the heat and hydrogen sector, or likely efficiency measures to reduce demand. In this case the amount of electric energy that can be exported to these sectors would be reduced. Moreover, we did not consider the transport sector where electric or gas driven cars could provide large new sinks for electric surpluses. Given the high value of energy in the transport sector, this option could change the picture significantly, potentially in favor of the power to gas path with its large implicit storage potential. Despite these restrictions, we believe that our results concerning the usage of electric heaters to absorb electrical oversupply from VREs are rather robust, as this mature, low-cost technology can still fit well into other heat supply structures. In contrast, usage of electric energy in the transport sector depends significantly on new technologies that are not market competitive today.

The presented study shows that the inclusion of other energy sectors into the power sector for the integration of VREs improves the economic efficiency of the entire system. The heat sector can absorb the occurring temporary overproduction efficiently, saving natural gas and reducing emissions. Due to this efficient direct use of the oversupply from the power sector, long term electricity storage and the power-to-gas option become unattractive.

A. Input data

Technology	Inv. Costs	Fix O&M Costs	Var. Cost[a]	η
Electricity sector	€/kW$_{el}$	€/kW$_{el}$	€/MWh$_{el}$	%
Coal	1400	35	21	46%
Gas GT	400	18	68	38%
Gas CCGT	650	18	44	60%
Geothermal	2800	80	4	100%
Lignite	2300	40	13	43%
Oil GT	800	18	126	35%
Oil CCGT	900	18	89	50%
Nuclear	3000	65	12	33%
Hydro run of river	1400	20	5	75%
Hydro storage	1539	20	-	85%
HV lines ,€/MWkm	400	0.7	-	4% loss/1000km
HV cable ,€/MWkm	1300	0.7	-	4% loss/1000km
Combined heat and power	€/kW$_{el}$	€/kW$_{el}$	€/MWh$_{el}$	%
Bioenergy chp	1000	50	2	90%
Gas chp	400	8	34	90%
Gas/Bio peak load boiler	330	3	0/15	90%
Heat sector	€/kW$_{heat}$	€/kW$_{heat}$	€/MWh$_{heat}$	%
Gas heating	300	3	34	90%
Electric heater	100	2	endogenous	90%
Electric heatpump	2000	40	endogenous	200%
Hydrogen sector (H2 production)	€/kW$_{H2}$	€/kW$_{H2}$	€/MWh$_{H2}$	%
Gas reformation	500	50	38	80%
Electrolysis	676	10	endogenous	74%
Hydrogen sector (H2 as fuel)	€/kW$_{gas/el}$	€/kW$_{gas/el}$	€/MWh$_{gas/el}$	%
Methanation	1100	22	(70)	77%
Hydrogen fueled GT	380	10	(100)[b]	39%

Table 3: Investment, fixed operation & maintenance and total variable costs and technical parameters per process. The variable costs include fuel costs and variable operation & maintenance costs, but not the emission allowance costs. All costs are given with respect to the kW / MWh of the output commodity, where for natural and hydrogen gas the lower heating value is used.

[a] If electric power is used as input, the marginal costs have to be taken into account as fuel costs. The same holds for methanization and hydrogen based GT, the numbers in brackets are computed based on hydrogen generated by reformation. ; [b] Variable costs arising from hydrogen generated by gas reformation. Changes if electrolysis is used.

Technology	2010 Costs (€/kW$_{el}$)	2020 Costs (€/kW$_{el}$)	2050 Costs (€/kW$_{el}$)	η %
Wind Onshore	1600	1000	800	100%
Wind Offshore	3400	2000	1000	100%
Solar PV utility	2000	1100	600	100%

Table 4: Cost scenarios for VRE technologies. Fix costs are assumed at 2% of the investment costs, variable costs are zero.

[GW]	2020		2050	
Conventional	min.	max.	min.	max.
Nuclear	4.1		0	0
Coal	24.3		0	0
Lignite	12.9		0	0
Oil	1.4		0	0
Gas GT	22.6		0	unlimited
Gas CCGT	19.5		0	unlimited
Gas CHP	0		0	unlimited
Renewables				
Hydro	5.4		3.9	
Biogas[a]	18.0		10.56	
Solar PV	60		129.4	
Wind Onshore	41.6		74.9	
Wind Offshore	15.8		43.2	
Pumped storage				
In/Output power	10		12	
Reservoir size (TWh)	67		80	

Table 5: Total capacity limits per type and scenario year

[a] All bioenergy power plants are run as CHP plants. For 2020 it includes gas and waste CHP. For 2050, parts of the biogas is fed to the natural gas grid to provide more flexibility.

References

[1] AG Energiebilanzen e.V. *Anwendungsbilanzen für die Endenergiesektoren in Deutschland in den Jahren 2009 und 2010*. Bundesministerium für Wirtschaft und Technologie, Projektnummer 23/11, November 2011. 8

[2] Bundesverband der deutschen Gas- und Wasserwirtschaft. *Anwendung von Standardlastprofilen zur Belieferung nicht-leistungsgemessener Kunden. Praxisinformation P2006/8 Gastransport/Betriebswirtschaft*. Wirtschafts- und Verlagsgesellschaft Gas und Wasser mbH, 2006. 8

[3] Bundesverband Kraft-Wärme-Kopplung e.V. *Kraft-Wärme-Kopplung in der Industrie. effizient produzieren - nachhaltig wirtschaften*. B.KWK Bundesverband,

Berlin, Germany, 2011. URL www.bkwk.de/industrie/Broschuere_KWK_in_der_Industrie.pdf. 8

[4] G. Czisch. *Szenarien zur zukünftigen Stromversorgung , Kostenoptimierte Variationen zur Versorgung Europas und seiner Nachbarn mit Strom aus erneuerbaren Energien*. PhD thesis, Elektrotechnik / Informatik der Universität Kassel, 2005. 2

[5] Deutsche Energie-Agentur GmbH. *dena-Netzstudie I: Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020, Endbericht*. Deutsche Energie-Agentur GmbH, Berlin, Germany, 2005. URL http://www.dena.de/de/themen/thema-esd/publikationen/publikation/netzstudie/. Study conducted by DEWI, E.ON Netz, EWI, RWE Transportnetz Strom and VE Transmission. 8

[6] Deutsche Energie-Agentur GmbH. *dena-Netzstudie II: Integration enerneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015-2020 mit Ausblick 2025*. Deutsche Energie-Agentur GmbH, Berlin, Germany, 2010. URL www.dena.de/fileadmin/user_upload/Publikationen/Erneuerbare/Dokumente/Endbericht_dena-Netzstudie_II.PDF. Study conducted by Amprion GmbH, BARD Engineering GmbH, BMU, BMWi, BDEW, EnBW Transportnetze AG, E.ON Netz GmbH, EWE Netz GmbH, Siemens AG, Stiftung Offshore Windenergie Offshore Forum Windenergie GbR, TenneT TSO GmbH, FNN, BWE, VDMA, VGB PowerTech e.V., ZVEI and 50Hertz Transmission GmbH . 5

[7] Deutsches Zentrum für Luft- und Raumfahrt (DLR). *Trans-Mediterranean Interconnection for Concentrating Solar Power (TRANS-CSP), Final Report*. German Aerospace Center (DLR), Institute of Technical Thermodynamics, Section Systems Analysis and Technology Assessment and Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), Germany, 2006. URL www.dlr.de/tt/desktopdefault.aspx/tabid-2885/4422_read-6588/. 2

[8] European Commission. A Roadmap for moving to a competitive low carbon economy in 2050. *Communication from the European Commission*, 112, 2011. URL http://ec.europa.eu/clima/documentation/roadmap/docs/com_2011_112_en.pdf. 2

[9] European Commission. Renewable Energy: Progressing towards the 2020 target. *Communication from the European Commission*, 31, 2011. URL http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0031:FIN:EN:PDF. 2

[10] European Network of Transmission System Operators for Electricity (ENTSO-E). Statistical Data, 2010. URL https://www.entsoe.eu/. 7, 8

[11] D. Heide, L. von Bremen, M. Greiner, C. Hoffmann, M. Speckmann, and S. Bofinger. Seasonal optimal mix of wind and solar power in a future, highly renewable Europe. *Renewable Energy*, 35(11):2483 – 2489, 2010. 2

[12] International Energy Agency (IEA). Interactive renewable energy calculator - re-calculator - renewable energy cost and benefit to society, 2009. URL `http://recabs.iea-retd.org/energy_calculator`. 8

[13] International Energy Agency (IEA). *World Energy Outlook 2012*. OECD, Paris, France, 2012. ISBN 978-92-64-18084-0. 2

[14] K. Karlsson and P. Meibom. Optimal investment paths for future renewable based energy systems-using the optimisation model Balmorel. *Int. J. Hydrogen Energy*, 33:1777–1787, 2008. 3

[15] Kombikraftwerk 2. Das regenerative Kombikraftwerk. *Projektbericht (in Vorbereitung)*, 2012. URL `http://www.kombikraftwerk.de`. 6, 8

[16] P. Kuhn. *Iteratives Modell zur Optimierung von Speicherausbau und -betrieb in einem Stromsystem mit zunehmend fluktuierender Erzeugung*. PhD thesis, Technische Universität München, Lehrstuhl für Energiewirtschaft und Anwendungstechnik, 2012. 2, 3, 7, 15

[17] H. Lund. Large-scale integration of wind power into different energy systems. *Energy*, 30:2402–2412, 2005. 3

[18] H. Lund and B.V. Mathiesen. Energy system analysis of 100% renewable energy systems-the case of denmark in 2030 and 2050. *Energy*, 34:524–531, 2009. 3

[19] B. V. Mathiesen and H. Lund. Comparative analysis of seven technologies to facilitate the integration of fluctuating renewable energy sources. *IET Renewable Power Generation*, 2:190–204, 2009. 3

[20] McKinsey, KEMA, The Energy Futures Lab at Imperial College London, Oxford Economics, and European Climate Foundation. *RoadMap 2050: A practical guide to a prosperous, low-carbon Europe: Technical Analysis: Volume I*. European Climate Foundation, 2010. URL `http://www.roadmap2050.eu/`. 8

[21] P. Meibom, J. Kiviluoma, R. Barth, H. Brand, C. Weber, and H.V. Larsen. Value of electric heat boilers and heat pumps for wind power integration. *Wind Energy*, 10:321–337, 2007. 3

[22] PricewaterhouseCoopers (PWC), Potsdam Institute for Climate Impact Research (PIK), International Institute for Applied System Analysis (IIASA), and European Climate Forum (ECF). *100% Renewable Energy: A Roadmap to 2050 for Europe and North Africa*. PricewaterhouseCoopers LLP, 2010. 8

[23] S. Richter. *Entwicklung einer Methode zur integralen Beschreibung und Optimierung urbaner Energiesysteme. Erste Anwendung am Beispiel Augsburg.* PhD thesis, Lehrstuhl für Experimentelle Plasmaphysik, Wissenschaftszentrum Umwelt, Universität Augsburg , Max-Planck-Institut für Plasmaphysik, Garching, 2004. 12

[24] M. M. Rienecker, M. J. Suarez, R. Gelaro, R. Todling, J. Bacmeister, E. Liu, M.G. Bosilovich, S. D. Schubert, L. Takacs, G.-K. Kim, S. Bloom, J. Chen, D. Collins, A. Conaty, and A. da Silva et al. MERRA - NASA's Modern-Era Retrospective Analysis for Research and Applications. *J. Climate*, pages 3624–3648, 2011. doi: 10.1175/JCLI-D-11-00015.1. 8

[25] K. Schaber, F. Steinke, and T. Hamacher. Transmission Grid Extensions for the Integration of Variable Renewable Energies: Who Benefits Where? *Energy Policy*, 43:123–135, 2012. 3, 4, 6

[26] K. Schaber, F. Steinke, P. Mühlich, and T. Hamacher. Parametric study of variable renewable energy integration in Europe: Advantages and costs of transmission grid extensions. *Energy Policy*, 42:498–508, 2012. 2

[27] K. Siala. *Technical, Economic and Ecological Analysis of Conventional and Innovative Power Transmission Technologies*. Bachelor thesis, Lehrstuhl für Energiewirtschaft und Anwendungstechnik, Technische Universität München, 2012. 8

[28] M. Staudacher. *Analyse der Herstellungs- und Anwendungsverfahren für Wasserstoff und Synthesegas*. Bachelorthesis, Lehrstuhl für Energiewirtschaft und Anwendungstechnik, Technische Universität München, 2011. 5

[29] M. Sterner. *Bioenergy and renewable power methane in integrated 100% renewable energy systems*. PhD thesis, Universität Kassel, Frauenhofer IWES, Institut für Rationelle Energiewandlung, 2009. 3

[30] United Nations Climate Change Secretariat (UNFCC). Summary of GHG Emissions for Germany, 2011. URL `http://unfccc.int/files/ghg_emissions_data/application/pdf/deu_ghg_profile.pdf`. 11

[31] Verband der Elektrotechnik Elektronik Informationstechnik e.V. (VDE). *Demand Side Integration - Lastverschiebungspotenziale in Deutschland*. VDE, Frankfurt am Main, Germany, 2012. URL `https://www.vde.com/de/InfoCenter/Seiten/Details.aspx?eslShopItemID=db6adb35-482e-4ae6-be64-07964dc8f2c7`. 2

[32] Verband der Elektrotechnik Elektronik Informationstechnik e.V. (VDE). Übersichtsplan "Deutsches Hochspannungsnetz", 2012. URL `http://www.vde.com/de/fnn/dokumente/seiten/uebersichtsplan.aspx`. 8

[33] Verband der Elektrotechnik Elektronik Informationstechnik e.V. (VDE): Energietechnische Gesellschaft (ETG), Task Force Flexibilisierung des Kraftwerksparks. *Erneuerbare Energie braucht flexible Kraftwerke - Szenarien bis 2020*. VDE, ETG, Frankfurt am Main, Germany, 2012. URL `www.vde.com/de/fg/ETG/Arbeitsgebiete/V1/Aktuelles/Oeffentlich/Seiten/StudieFlexibilisierung.aspx`. 2, 3, 6