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Comparison of the Effects of Industrial Demand Side Management and Other Flexibilities on the Performance of the Energy System

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Abstract: In order to ensure security of supply in a future energy system with a high share of volatile electricity generation, flexibility technologies are needed. Industrial demand-side management ranks as one of the most efficient flexibility options. This paper analyses the effect of the integration of industrial demand-side management through the flexibilisation of aluminium electrolysis and other flexibilities of the electricity system and adjacent sectors. The additional flexibility options include electricity storage, heat storage in district heating networks, controlled charging of electric vehicles, and buffer storage in hydrogen electrolysis. The utilisation of the flexibilities is modelled in different settings with an increasing share of renewable energies, applying a dispatch model. This paper compares which contributions the different flexibilities can make to emission reduction, avoidance of curtailment, and reduction of fuel and CO_2 costs, and which circumstances contribute to a decrease or increase of overall emissions with additional flexibilities. The analysis stresses the rising importance of flexibilities in an energy system based on increasing shares of renewable electricity generation, and shows that flexibilities are generally suited to reduce carbon emissions. It is presented that the relative contribution towards the reduction of curtailment and costs of flexibilisation of aluminium electrolysis are high, whereby the absolute effect is small compared to the other options due to the limited number of available processes.

Keywords: demand-side management; demand response; storage; heat storage; flexibility; sector coupling; renewable energy system; dispatch

1. Introduction

The transformation of the energy system towards low carbon emissions and renewable energies is a necessary shift to tackle the challenge of emission reduction and climate change. An energy system based on volatile renewable energy sources would meet this challenge, but is in need of flexibility technologies to provide security of supply. Even though the exact amount of flexibility needed for a renewable energy based electricity system is hard to define, according to Kondziella et al., there is no doubt that flexibilities play a crucial role in a future energy system [1]. Huber et al. point out that these flexibilities are particularly needed when the share of PV in the energy supply rises above 30% [2]. Maia et al. propose a huge storage increase to meet the flexibility needs [3]. There are many publications that examine the effects of single flexibility options. Hilpert shows that heat pumps can replace short-term storage units in an energy system with high shares of renewable energy [4]. Finck et al. include the whole building and the controlling of heating and cooling devices to show a possible flexibility potential from buildings [5]. Tena et al. explore the impacts of flexible charging of electric vehicles on the energy system [6]. They point out that controlled charging of electric vehicles has great potential to reduce peak demands. In addition, Gunkel et al. show that an increase in the flexibility of electric vehicles, from controlled charging to vehicle-to-grid concepts, further reduces system costs and carbon dioxide (CO_2) emissions [7]. Jabir et al. show that the implementation of demand side management (DSM) into an energy system can increase the reliability and minimise the costs of electrical power systems [8]. Nebel shows that small-scale flexibilities located in the distribution grid can even be used to avoid congestion in the transmission grid [9]. A broad overview of the different flexibility options in the energy system is given by Lund et al. [10]. Some studies on synergies and trade-offs of certain flexibility options for the energy system have been conducted with a focus on storage, grid expansion and DSM. Brown et al. point out that the use of the flexibilities from battery electric vehicles, power-to-gas units, and long-term thermal energy storage contribute significantly to a minimisation of system costs. As these flexibilities are implemented, the benefits of additional grid expansions decrease [11]. Krüger et al. showed in a case study that especially the integration of DSM measures such as controlled charging of electric vehicles can reduce the variation in residual loads significantly compared to grid extension and storage expansion [12].

This paper contributes to these investigations by focusing on the competition between various flexibility options and their impact on the overall energy system that has a rising share of renewable energy. In contrast to the existing work, this paper incorporates a specific industrial DSM process into the considered flexibilities. A case study is done for Germany and a future energy system based on a carbon neutral energy scenario of Gebert et al. [13]. For this scenario, dispatch with different possible flexibility configurations is optimised and the impacts of these flexibility options on the energy system are determined by a difference analysis. This paper aims to show the contribution and trade-offs of different flexibility options with a special focus on the demand-side management of the aluminium electrolysis. This macroeconomic analysis does not yet exist in scientific literature and is particularly valuable as a basis for evaluating this flexibility in a cost-benefit analysis.

2. Materials and Methods

In the following, the basic functionality of the dispatch model used for the analyses is explained (Section 2.1). In this section, the purpose of the model and the structural configuration are described. Also, the underlying framework used for the model setup and the criteria applied for the selection of this framework are briefly introduced. Based on a compilation of the input data, an overview of the narrative of the simulated energy scenario is given in Section 2.2. The depiction within the dispatch model and the most important characteristics of the flexibility options that are the focus of the analyses are described in detail in Section 2.3. Finally, Section 2.4 gives an overview of the different configurations that were applied to compare the flexibility options.

2.1. Basic Functionality of the Dispatch Model

The dispatch model used to answer the research questions is part of the WISEE-ESM, where the Energy Supply Model (ESM) is embedded in the Wuppertal Institute System Model Architecture for Energy and Emission Scenarios (WISEE). The ESM consists of two modules and can calculate both the cost-optimal expansion (invest—module 1) and the cost-optimal operation (dispatch—module 2) of energy generators, infrastructures and sector coupling technologies to cover given energy demands. In the study presented here, the capacity expansion module 1 is not applied, but dispatch (module 2) is performed with installed capacities based on [13].

2.1.1. Structure and Objective

In the dispatch module, the use of all system components during one year is optimised in hourly resolution. The objective function is the minimisation of the operating costs, i.e., the CO_2, fuel and operating costs, while a given demand has to be met in every hour as the main boundary condition. The optimisation is done with perfect foresight over the whole year.

Figure 1 shows all the components that are mapped in the underlying system configuration. In order to compare the different flexibility options, the operation of the future power system is modelled in different variants in which either all, none, or single flexibility options are considered. The components that are switched on and off are highlighted in red in Figure 1 and are described in detail in Section 2.3. The electricity, heat and hydrogen (H_2) loads are input parameters and are each considered as one node for the whole of Germany (see Section 2.2.1). Therefore no grid restrictions are assumed within this region. For electricity generation, wind on- and offshore, photovoltaics (PV), run-of-river, biomass and geothermal generation as well as fossil power plants are considered. The latter are modelled as individual plants based on the current power plant fleet. The expansion or shutdown for future years is implemented in accordance with the installed capacities in the underlying scenario. For the adjacent sectors of hydrogen and heat, only those generation or conversion technologies and loads that have implications for the operation of the electricity system are taken into account. Accordingly, only combined heat and power plant (CHP), Power-to-Heat (P2H) and large heat pumps are modelled for the supply in the district heating networks (DHN), but individual heating is not. For hydrogen supply, only water electrolysis is considered as Power-to-Gas (P2G) technology. Additional flexibility in the electricity system is created by taking buffer storage into account in the adjacent sectors. In addition to the use of flexibility options, the optimisation variables are the use of conventional power plants, controllable renewable generation, and the curtailment of volatile renewable generation.

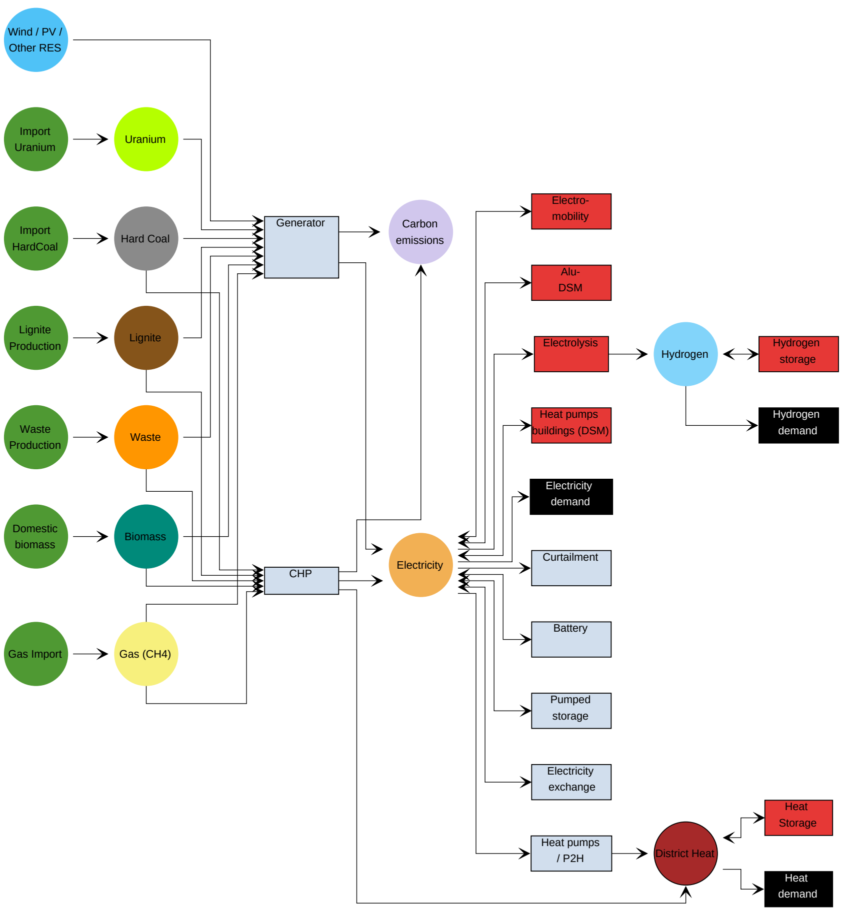

Figure 1. Components considered in the dispatch model and their inter-linkages. Flexibilities are highlighted in red.

2.1.2. Underlying Framework

The cost-efficient operation of power systems is a classical object of research in energy system modelling. In the context of open source software efforts, which greatly increased in the last ten years, several open frameworks and models have also been developed to address this question. Literature partly distinguishes between models and frameworks. Frameworks do not provide data but are limited to the equations and boundary conditions [14], as this gives the user a wide scope for designing the system configuration. According to Morrison [15], the main advantages of using and further developing open models and frameworks are the improvement of public transparency, genuine scientific reproducibility, as well as possibly increased academic productivity and quality and public trust. Due to these reasons, the WISEE- ESM is based on an open framework. The framework Python for Power System Analysis (PyPSA) [16] has been chosen for implementing the dispatch model (module 1). Apart from that chosen framework, there are a number of other open dispatch models and frameworks such as the Open Energy Modelling Framework (oemof) [17] or the Renewable Energy Pathways Simulation System (renpass) [18] (an overview is provided by the openmod initiative [19]).

When selecting the framework, the decisive criteria were the long-term development, the verification and validation through different use cases, such as Open Optimisation Model of the European Transmission System (PyPSA-EUR) [20] and the dynamic ongoing and planned development. Furthermore, the bandwidth of depictable energy sources, demand sectors and technology groups in high spatio-temporal resolution, as well as the possibility to link to different optimisation solvers, fulfilled the desired model requirements. Like many other dispatch models and frameworks, PyPSA uses a linear programming (LP) optimisation approach.

2.2. Data

Essential input data such as installed capacities are driven by the underlying scenario. Its selection is described in Section 2.2.1, as well as its basic narrative and development of energy demand and supply. Fuel and carbon prices, which are important drivers for dispatch, are also presented. In addition, supplementary data such as time series profiles for demand, the feed-in of fluctuating renewables, and a detailed picture of the current power plant portfolio were used from other sources. They are described in Section 2.2.2.

2.2.1. Underlying Scenario

Selection of the underlying scenario

To select the underlying scenario of the dispatch optimisation conducted in the study at hand, a total of ten ambitious greenhouse gas reduction scenarios with energy-related greenhouse gas emission reduction by 2050 compared to 1990 higher than 95%, from six scenario studies of relevance in the energy policy discussion at the time were analysed. Besides [13] the following energy transformation pathway studies were taken into account: [21–25]. The following criteria were decisive for the selection of the 95%-path from [13] as the framework scenario: Achieved CO_2 reduction target, high proportion of (fluctuating) renewable energies in the power generation mix, and a well-documented database for the years to be calculated (2020 to 2050 in ten-year steps) for both the supply and the demand side as well as a coverage of flexibility options and the industrial sector. In [13], this path is further differentiated in some regards; here, the path called "G95" is chosen, which is embedded in a global climate protection scenario.

Assumed development of energy demand and generation

Table 1 shows the development of demand for electricity, heat, and hydrogen for the electricity system and the adjacent sectors modelled in this study (the electricity demand for classic applications does include the demand for individual heat pumps but not for electromobility, P2H in DHN and H_2-electrolysis). Regarding the demand-side, the scenario storyline assumes, as most future energy scenarios do, a significant increase in final energy productivity in the decades ahead. On the one hand, energy efficiency improvements are assumed (e.g., by an increase in the energy-related renovation rates of the building sector), but electrification, for example, in the mobility and heating sector, also contributes to this development. These technologies are often more efficient in respect of final energy demand [26]; this applies in particular to the replacement of internal combustion engines by electric motors. The resulting additional electricity demand amounts to 88 TWh in 2050 (compare Table 1). The share of electricity in total final energy use rises from 20% in 2016 to 34% in 2050. In this year, 15% of final energy demand is to be covered by synthetic fuels, which is generated based on electricity (and is therefore also called indirect electrification) [26]. This amounts to a 50% reduction in primary energy consumption from 2008 to 2050. Since the total emission reductions by 2050 compared to 1990 amount to 95%, a reduction of 100% in energy-related emissions is assumed. The remaining emissions are mainly caused by the agricultural sector, where reduction is considered particularly challenging. This sector is not considered in this paper. In the industrial sector, a strong emphasis is placed on biomass for decarbonisation and carbon capture and storage (CCS) is used in some branches [26].

Table 1. Assumed development of electricity demand and adjacent sectors until 2050 according to [13].

Final Demand	Unit	2015	2020	2030	2040	2050
Electricity (classic applications and individual heat pumps)	TWh_{el}	515	496	487	481	459
Electricity demand for electromobility	TWh_{el}		1	19	51	88
Electricity import	TWh_{el}	33	19	56	89	82
Electricity export	TWh_{el}	83	61	54	65	86
Heat demand in DHN (provided by P2H and CHP)	TWh_{th}	81	94	111	116	100
Hydrogen demand, generated nationally	TWh_{H2}		1	4	12	51

On the supply side, electricity generation will rely on 100% renewable energies in 2050 and approximately 65% in 2030. In 2030 and 2050, the scenario assumes an almost balanced electricity import and export ratio. Compared to today, the electricity export balance is thus reduced (compare Table 1). In the dispatch model, electricity exchange with neighbouring countries is not considered as a flexibility option. It is taken into account via a heuristic as an additional load and infeed that partly compensates imbalances in the residual load. In Figure 2 the net installed generation capacity by technology according to [13] is displayed. In 2050, the system will mainly rely on 130 GW PV and 162 GW wind generation capacity, of which 37% will be installed offshore. As a backbone, gas-fired power plants will be used to potentially support the system in times of low fluctuating renewable energy infeed. The installed capacity of these power plants are assumed to be 75 GW in 2050. According to the assumptions of the underlying scenario [13], the future gas is composed of synthetic methane, the available biomethane, and a mixture of up to 3% hydrogen. Twenty per cent of the synthetic methane is to be produced domestically.

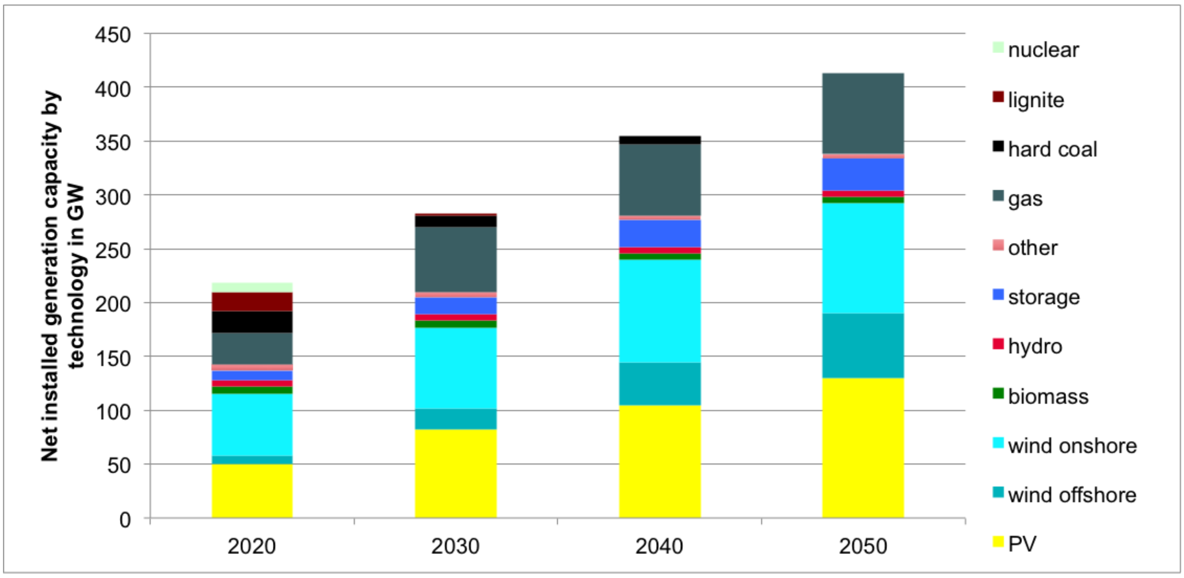

Figure 2. Net installed generation capacity by technology according to [13].

Fuel and carbon prices

The energy carrier prices of oil, hard coal, natural gas and biomass used in this paper correspond with the prices assumed in the underlying scenario. The prices are assumed to rise slightly until 2030 as shown in Figure 3, but in the long term, due to the integration of the German energy system into a global climate protection scheme (as defined in the scenario), energy prices are assumed to stagnate or decline [13]. Since there is no cost data available for lignite in [13], the assumptions of another ambitious future energy scenario [21] are used to fill the gap.

For CO_2, a strong price increase, especially between 2030 and 2040, is assumed, leading to a price of 124 € /t in 2050 [13].

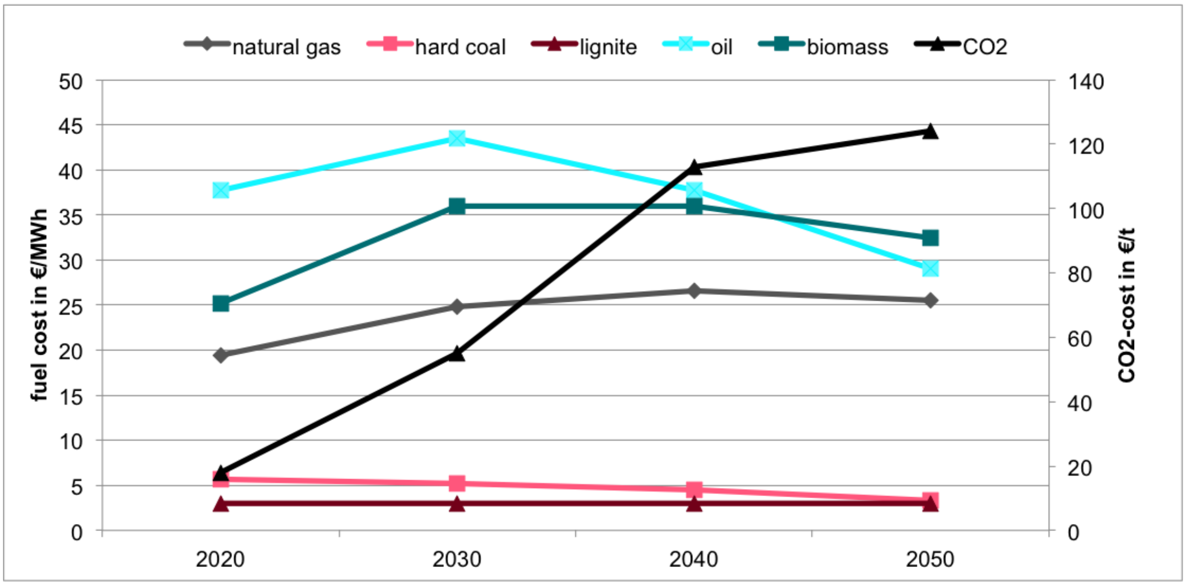

Figure 3. Underlying fuel and CO_2 cost over time, in real € 2015.

2.2.2. Supplementary Data

Power plant fleet

The basis of the conventional power plant fleet is an extended list of power plants provided by Open Power System Data (OPSD) [27], which is based on the power plant list of the Federal Network

Agency and the German Environment Agency. It includes individual power plants with their technical characteristics such as installed capacity, main energy source, technology, CHP capability, geographical information, and year of commissioning. This data source is refined, especially in respect to efficiencies, with data already available at the Wuppertal Institute.

Profiles for demand and infeed timeseries

The underlying weather year for the load time series and the renewable feed-in timeseries is 2012, the same used in [13]. This has the advantage that the use of the generation components in the study at hand can be validated in the underlying scenario study. However, the selection of the weather year 2012 does not reflect the influence of climate change in the outdoor temperature whereby an increasing need for air conditioning and ventilation is assumed in the overall annual demand. The year 2012 is considered to be a slightly under-average year in terms of power produced by wind energy, and average in respect to PV yields [28]. In February, there was a rather pronounced, two-week-long cold dark doldrum. Thus, flexibilities assumed in this study can be tested under challenging conditions. Dark doldrums are the respective longest duration of weak wind phases with simultaneous cloud cover or darkness, which lead to long lasting phases of low feed-in from renewable energies. These are also decisive for the structure of the future energy system and the dimensioning of flexibility and backup generation capacities [29]. Profiles of infeed timeseries for PV and onshore wind are taken from the data set provided by OPSD [30]. The RESTORE 2050 project [31] serves as a basis for offshore wind and hydro infeed timeseries. The OPSD data were not used for hydro, since timeseries for hydro infeed are not covered by this data package and due to low installed offshore capacities for the weather year used, the profiles of the actual offshore feed-in were not representative for the given application.

As a basis for the electricity load profile, again the recorded load data for the year 2012 provided by OPSD are used [30]. Heat is considered an adjacent sector, i.e., only the electricity-based or electricity-coupled heat supply is modelled. For this purpose, two demand profiles are used in a simplified form: one which reflects the course of the demand of direct object heating and mainly determines the use of heat pumps for this application. Here, the hourly resolved heat demand for space heating and hot water for 2012 from the data set developed by [32], also published under OPSD [33] is standardised and used. For the other heat demand profile, which reflects the demand in DHN, a simplified approach has been considered, which is however sufficiently precise for the given application with a focus on the electricity sector and the use of its flexibilities. The load profiles of district heating vary considerably, depending on the composition of the heat demand (households, GHD, industry). In order to adequately reflect this, regionally differentiated heating networks are usually modelled. Overall, a basic distinction can be made between two categories: (1) public district heating networks that mainly supply heat to private, commercial and public customers and focus on covering space heating and hot water requirements, and (2) industrial heating networks, which mainly provide process heat and only partly heat for space heating. In the present study, Germany is reduced to a single node and the heat load profiles are aggregated to national profiles accordingly. For the profile of the public district heating networks, the profile described above [32] is also used as a basis. In addition, a minimum load is defined. In district heating networks with a high proportion of residential buildings, this is typically around 10% of the maximum load [34]. A higher base load is to be expected in industrial district heating supply; the share of process heat in district heating consumption in industry can be estimated at approx. 80% on average [34], the residuum is distributed as a function of temperature. Using aggregated full load hours in the respective categories based on [35], the profiles are refined and combined into a weighted average according to the proportion of heat supplied from CHP in public or industrial district heating networks, based on [35].

2.3. Depiction of Flexibilities

Table 2 gives an overview of the flexibility options considered in this paper and describes their main characteristics such as installed capacities and energy to power ratio (E2P-ratio) ratio.

The E2P-ratio depicts the ratio of installed storage capacity (energy) and installed charging power, and thereby characterises the possible charging and discharging time. The representation of the flexibilities in the model is explained in more detail below.

Table 2. Overview of flexibility options considered and main characteristics.

Flexibility	Model Representation	Installed Capacity in GWel					E2P-Ratio	Category
		2020	2025	2030	2040	2050		
Pumped storage	Storage unit	6.6	7.2	7.8	7.8	7.8	Ø5.8	Reference
Li-Ion Batteries	Storage unit	1.2	4.7	8.2	17.2	22.2	Ø1.3	Reference
Aluminium electrolysis	Load shifting (DSM)	0.275	0.275	0.275	0.275	0.275	48	Alu
Heat pumps in DHN	Heat generator and storage	0.4	1.1	1.8	3.6	4.0	f(t)	P2H
Electric heaters in DHN	Heat generator and storage	0.6	1.8	2.9	6.3	11.0	f(t)	P2H
Heat pumps buildings	Load shifting (DSM)	5.7	10.7	15.7	24.3	25.7	4	P2H
H_2 electrolysis	H_2 generation and buffer	0.3	0.6	0.8	2.5	11.0	24	P2G
Electromobility	Controlled charging (DSM)	2.5	14.2	25.8	74.1	141.3	12	Emob

2.3.1. Pump Storage and Battery Storage

Pumped storage and lithium-ion battery storage, as classic storage devices, are connected solely to the respective electricity node and can be used for a temporal power shift. Each storage unit has a time-varying state of charge and different efficiencies. The storage capacity is specified as a fixed E2P-ratio. Existing plants are modelled as individual, plant-specific storage units. This is particularly important for pumped storage power plants, as there already exists a large number of plants with a wide range of E2P-ratios. The plants also differ slightly (depending on the year of construction or degree of retrofit) in their charging and discharging efficiencies. Planned, already approved projects are also taken into account on a plant-by-plant basis. For the minor expansion foreseen in the underlying scenario, one storage unit with the additionally required residual capacity is added in each regarded year. The total installed electrical capacity of the classic electricity to electricity storage units amounts to 7.8 GW in 2020 and increases to approx. 30 GW by 2050. The average E2P-ratio weighted according to installed capacity is 5.8 for pumped storage power plants. For batteries it is significantly lower at 1.33.

2.3.2. Coupling to Adjacent Sectors via P2G and P2H

Electrolysis for the production of hydrogen is made more flexible by considering a H_2 storage with the capacity to store 24 h of H_2 produced by the electrolysis. In 2020, hardly any water electrolysis is installed, but it is assumed to grow slowly until 2040 and then rapidly until 2050, reaching an installed capacity of 11 GW_{el}. A similar approach is chosen for the electric heaters and heat pumps in the DHN, to which the CHP systems also contribute. The electrically driven heat generators are assumed to have a growth in installation in a similar order of magnitude as the electrolysis. Additionally, they can be supported by a heat buffer. The heat storage charging capacity is modelled as the sum of heat generation capacities from CHP, large heat pumps and electric heaters. Individual heat pumps in buildings are not included here, but are modelled using a different approach (see Section 2.3.3).

2.3.3. Heat Pumps Buildings

Heat pumps in the object supply of households, unlike those in the DHN, are not modelled as heat generator with an additional buffer, but as a shiftable load in the sense of a DSM potential. The heat demand profile for households (compare Section 2.2.2 and [32]) is the base for the time-variable charge, discharge and storage capacities. The underlying scenario assumes a very strong expansion of this decentralised heat generation technology. It can be combined well with the strong reduction of the heat demand in households, which is to be achieved by considerable insulation activities. The installed capacities increase to approx. 25 GW_{el} by 2040. It then levels off until 2050. It is assumed, that the maximum pre- and postponement of this type of load is 4 h.

2.3.4. Aluminium Electrolysis as Exemplary Industrial DSM Potential

The characteristics of industrial DSM differ significantly among different industrial branches and applications. They need to be regarded in a very specific manner, taking into account process restrictions, in order to neither over- nor under-estimate their possible contribution. In this study, the flexibilisation of aluminium electrolysis has been considered as an exemplary industrial DSM potential. The DSM potential of the aluminium industry is described here in detail. The level of detail is due to the fact that, on the one hand, the system effects of making industrial demand more flexible, discussed using the aluminium industry as an example, are at the forefront of the analyses. On the other hand, the technology is an innovation that has not yet been considered in the literature on energy system modelling.

Usually, the production of primary aluminium in Germany is carried out in the classic "Hall-Héroult" process in large smelters by electrolytic dissolution of alumina, which is mixed with cryolite to lower the melting point. The specific electricity requirement for this process is very high at approx. 13.5 MWh per tonne aluminium [36]. The electricity consumption of the process under consideration accounted for about 3.7% of industrial electricity demand and 1.6% of total electricity demand in Germany in 2018. The electrolysis furnaces are usually operated under process conditions that are as constant as possible, as they react sensitively to changes in the operating current. Until now, short-term load reductions in particular have been identified as DSM potential in the aluminium industry. In recent years, efforts for technical upgrades of the electrolysis systems have been made and are intended to enable even more flexible operation. These upgrades need to be done in two ways: If electricity current input varies, both the heat balance and the strength of the magnetic field change in the electrolysis process must be maintained. The first is to be controlled by retrofitting the shell heat exchangers (this is implemented and scientifically monitored within the framework of project "FlexTherm", for more information see https://wupperinst.org/p/wi/p/s/pd/711/), the second by additional busbars for magnetic field compensation (this is implemented and scientifically monitored within the framework of project Kopernikus-project "SynErgie", more information can be found here: https://www.kopernikus-projekte.de/projekte/industrieprozesse). The more flexible operation mode should enable not only higher load reduction or increase, but also allow significantly longer displacement times (up to 48 h) than in the previously applied load flexibilisation of aluminium electrolysis. The "virtual battery" created could achieve a storage capacity of 13 GWh with a charging and discharging capacity of 275 MW if the full potential were to be exploited in Germany [37]. The installed electrical power for primary aluminium in Germany today amounts to 1100 MW [37] of which 90 % are currently used. It is assumed here that the full capacity can be used for DSM in all years taken into account.

To represent the DSM potential in the dispatch model at hand, we used a methodology developed by Kleinhans [38] which models them as storage units with charging, discharging and buffer capacities. Thus, only load shifting but no shedding potentials can be considered. However, this in any case meets an important requirement for the extensive flexibilisation of the primary aluminium production: the production volume should not be reduced by using the potential. Charging and discharging, as well as storage capacities, are each considered as time-variable parameters. The maximum charging power results from the difference between the maximum power consumption of the process and the planned load (reducing the load). The time-variable maximum discharging power corresponds to the non-utilisation of the planned power (increase the load). The time-variable maximum storage filling level is calculated from a maximum advance of the load until the respective point in time (borrowing energy from the grid), the minimum storage filling level from the maximum delay of the load (giving energy into the grid).

The installed charging capacity available through flexibilisation of aluminium DSM would be in the same order of magnitude in 2020 compared to water electrolysis, heat pumps and electric heaters for DHN if all production capacities available in Germany would be converted. Their installed capacity would in this year account for 3.5% of the installed capacity of the classic electricity-to-electricity storage systems. Since the available production capacity is assumed to be constant over the observation horizon, and sector coupling, in contrast, is progressing rapidly according to the scenario storyline, the flexibilities resulting from sector coupling in 2050 are also orders of magnitude larger than those of the aluminium DSM with regard to installed capacity. However, the time frame available for power shifting is large compared to the other options, leading to an over-proportional virtual buffer size.

2.3.5. Electromobility

Electromobility is in principle also represented as DSM potential according to the methodology described above. It is only considered as controlled charging and not as bidirectional use. Accordingly, only a time-variable charging power, dependent on the vehicles available to the grid and with no discharging capacity, is implemented. The available storage capacity also fluctuates over time, as this represents the sum of all the vehicle batteries connected to the grid and varies according to the usage patterns of the vehicles. The buffer is discharged when vehicles leave the charging station (and are no longer connected to the electricity grid) with a certain battery-filling level. This is taken into account as an outflow from the buffer. In addition, the vehicles returning to the charging stations with a residual state of charge are modelled via an inflow into the storage buffer. The electricity demand of the vehicles is reflected in the netted outflow–inflow.

The underlying scenario relies heavily on the use of electromobility in the mobility sector. The installed capacity increases from 2.5 GW in 2020 to over 140 GW. This corresponds to 33 million vehicles in 2050 in the underlying scenario [13] in 2050, which is several times higher than the installed capacity of all other flexibility options. The assumed E2P-ratio of 12.5 is also higher than the ones of classic power-to-power storage as well as the potentials in the P2H sector.

2.4. Configurations of Performed Simulations

Table 3 shows the different system configurations that are modelled to compare the flexibility options. In all configurations, pumped storage and battery storage as the classic electricity-to-electricity storage are included as basic set technologies, since the focus of this research is rather on a comparison between DSM and different sector coupling technologies than comparing these to large-scale electricity storages. In the reference case, only these two options are considered. The other configurations result from the categories introduced in Table 2 and contain the options that are assigned to the respective categories. Accordingly, apart from the reference case, configurations are differentiated that additionally take into account either only aluminium DSM, all P2H options, P2G or electromobility. Furthermore, the overall effect of all options is determined in Flex_all, in which all options are combined in order to examine their competition or synergies.

Table 3. Overview about configuration of considered flexibility option in the simulation calculations.

	Reference	Flex_Alu	Flex_P2H	Flex_P2G	Flex_Emob	Flex_all
Pumped storage	x	x	x	x	x	x
Li-Ion-Batteries	x	x	x	x	x	x
Aluminium electrolysis		x				x
Heat pumps in DHN			x			x
Electric heaters in DHN			x			x
Heat pumps buildings			x			x
H_2 electrolysis				x		x
Electromobility					x	x

3. Results—The Effects of Different Flexibilities

When examining the effects of different flexibilities, three dimensions are described here: Effects on dispatch costs, on CO_2 emissions, and on curtailment. The results, and also the discussion section,

(Section 4) are structured along these three criteria. The results regarding the interpendencies of flexibilities are also described.

3.1. Effects of Flexibilities on Fuel and Carbon Costs

In the dispatch optimisation performed here, costs include fuel, CO_2 and additional operation and maintenance costs, but no capital cost. A discussion of capital costs is done in Section 4.1. As Figure 4 shows, the cost reduction that can be achieved by flexibilities is below 5%, as long as there are significant shares of conventional power generation in the system. This is the case until 2030 (bearing in mind that pumped hydro and battery storages, which provide a certain degree of flexibility, are included also in the reference case). In 2040 cost reduction rises above 10% in "Flex_all", reaching up to 25% in 2050. That shows the importance of flexibilities in a highly renewable energy system.

The highest cost reduction comes with the controlled charging of electric vehicles in "Flex_Emob". However, similar to the effect described in the emissions section (see Section 3.3), this has to be seen in contrast to the uncontrolled charging that is applied in the other cases, which adds an additional burden to the electricity system. Despite controlled charging, the inclusion of a thermal storage ("Flex_P2H") has the highest effect on cost reduction. This flexibility option allows to exploit the cost and emission minimising of coupling the heat and electricity sector, by achieving a reduction in both, curtailment and the heat production from fossil fuels, when renewable electricity can be shifted to times of heat demand.

From a macro-economic point of view, industrial DSM in aluminium electrolysis has a limited effect due to its low capacity, but from a micro-economic perspective, price calculations show that load shifting can reduce electricity costs for the plant operator by about 5%. That is due to the fact that in the current market design, the market price for electricity is lower in times of high renewable infeed than in times of high load, and DSM leads to a shifting of energy demand to times of high infeed.

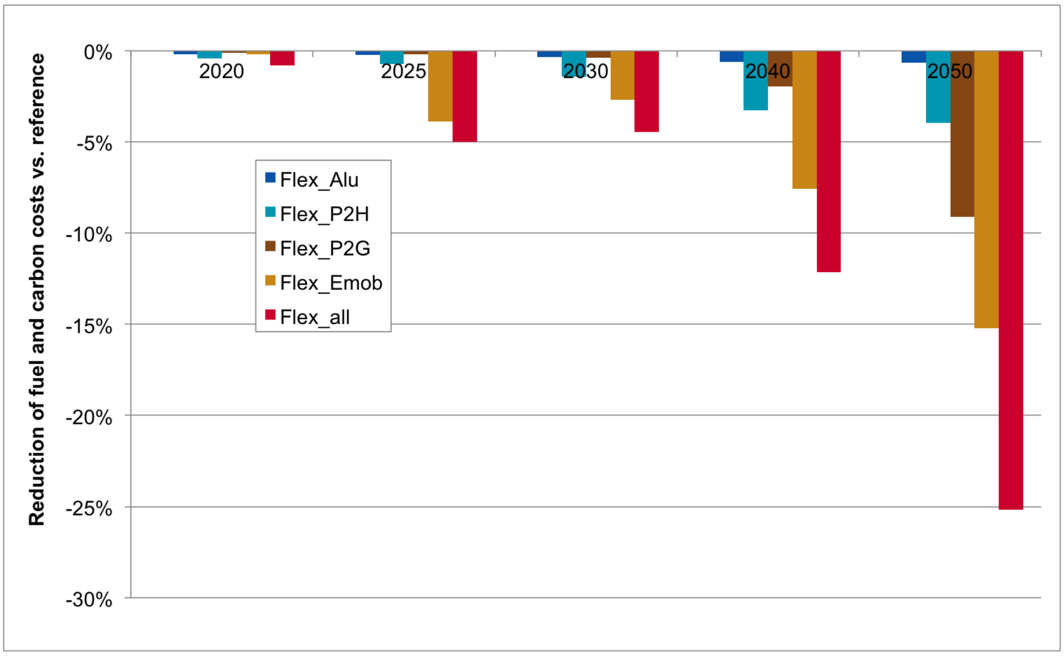

Figure 4. Reduction of operating costs.

3.2. Effects of Flexibilities on Curtailment

Curtailment occurs when renewable electricity cannot be integrated into the grid due to surplus generation or grid restrictions. Since the grid is not depicted here, renewable electricity is only curtailed in times of excess generation. Flexibilities such as storages or DSM can shift energy from times of surplus to times of demand and thereby reduce curtailment. In a cost minimising dispatch optimisation, this shifting is applied when it results in a reduced need for generating energy from other sources that are more expensive.

Figure 5 shows the amount of curtailment in different years and under consideration of different flexibilities (see Table 3 for which flexibilities are included in which configuration). When flexibilities are applied, curtailment can be reduced significantly, especially in years after 2030 with high renewable shares and strongly expanded flexibilities (as shown in Table 2). In 2020 and 2025, the level of curtailment is rather low. The share of renewables in electricity generation is assumed to be 45% in 2020 and 55% in 2025. Since grid restrictions are not included in the model, these shares do not result in high amounts of curtailments. Hence, the effects of flexibilities on reducing curtailment are low as well.

In 2040, curtailment rises up to 87.0 TWh and can be reduced to 61.4 TWh when all flexibilities are applied. In 2050, there is 98.9 TWh curtailed electricity in the reference case without additional flexibilities. These can be decreased by 1.1 TWh through DSM in aluminium electrolysis (case "Flex_Alu"), 3.2 TWh through flexibilisation of power-to-heat (case "Flex_P2H"), 8.7 TWh through a hydrogen buffer (case "Flex_P2G"), and 21.4 TWh through controlled charging of electric vehicles (case "Flex_Emob"). When a combination of all these is applied (case "Flex_all"), 41.2 TWh of curtailment can be avoided. So due to the assumed expansion of flexible capacities, it is possible to lower curtailment below the level of 2040. The share of curtailment is 15% of total renewable electricity generation in 2050 in the reference case. This is reduced to 9% in the case of "Flex_all". For a discussion of system design factors influencing the amount of curtailment see Section 4.2.

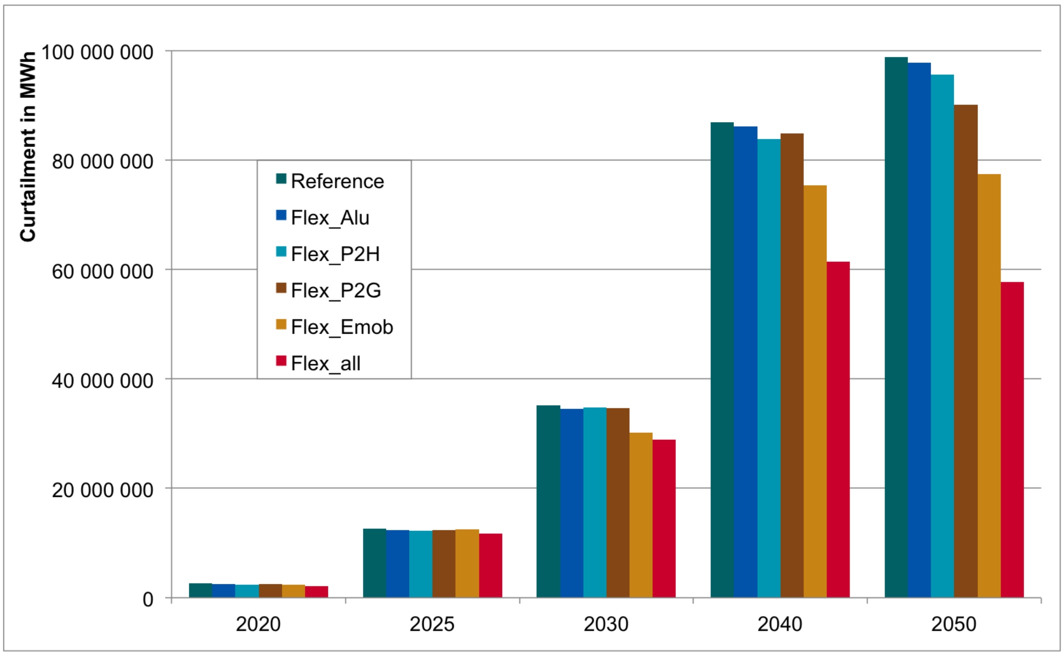

Figure 5. Effect of flexibilities on the amount of curtailment.

In Figure 6, the amount of avoided curtailment per charging capacity of flexibility is shown. In the case of heat storage (run "Flex_P2H"), charging capacity is the thermal input power of storage. In the case "Flex_P2G" it is the electrical power of the electrolysers that produce H_2, which is then stored. Regarding DSM in aluminium electrolysis ("Flex_Alu"), charging power is the flexible capacity to increase the power consumption (charging) in order to decrease it at another time (discharging). In case of "Flex_Emob", where available charging capacity depends on the share of connected vehicles in each hour, it is the mean available charging power per year. The figure shows that in case "Flex_Alu" the specific potential to reduce curtailment is very high. That is because this DSM process has a very high E2P-ratio of 48 hours and, because it is a base load process, is available at any time without temporal restrictions. So despite the low charging and discharging power in comparison to other flexibilities, it offers a disproportionately high possibility to shift energy. The specific curtailment reduction that can be achieved by the heat storage ("Flex_P2H") is rather low, although the absolute reduction is more significant (as can be seen in Figure 5). That is because in this model, the size of the heat storage was assumed to be able to meet the maximum heat production from heat pumps, electric heaters and CHP in DHN, which results in a very high charging capacity. This is a virtual capacity and is about seven times bigger than the charging capacity used on average.

3.3. Effects of Flexibilities on Carbon Dioxide Emissions

In a cost-minimising optimisation, additional flexibilities can reduce CO_2 emissions. That is because CO_2 emissions are associated with carbon costs and originate from fossil power plants, which also have fuel costs. Flexibilities can be applied to replace fossil with renewable generation or shift to a less CO_2 intense fuel. However, in power systems with a high degree of fossil generation and low carbon prices, flexibilities can have an opposite effect: they can be applied to compensate fluctuations in the residual load and thereby enhance production from fossil fuel baseload powerplants. This is how pumped hydro storages were intended to operate when they were installed in the past.

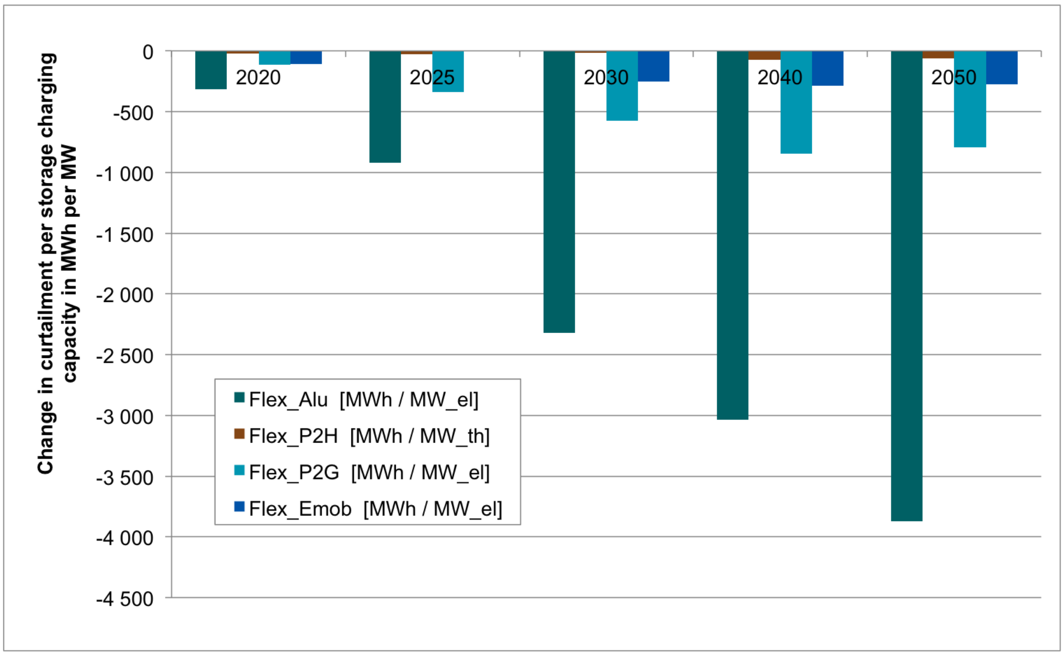

Figure 6. Change in curtailment per storage charging capacity.

Figure 7 and Table 4 depict the difference in emissions when implementing different flexibilities in comparison to the reference run without additional flexibilities (i.e., beyond the classic electricity-to-electricity storage options). In the examined system, the effect of flexibilities on carbon emissions highly depends on the year, i.e., from the share of renewables in electricity generation. In 2020 there is a very moderate reduction since the capacities of flexibilities are comparably low (see Table 2). In 2025 there are higher flexible capacities expected, having two different effects: While introducing a heat storage in "Flex_P2H" leads to a small mitigation and controlled charging of electric vehicles, ("Flex_Emob") resulting in a strong reduction of emissions, aluminium DSM ("Flex_Alu") and introducing a hydrogen buffer ("Flex_P2G") increases it.

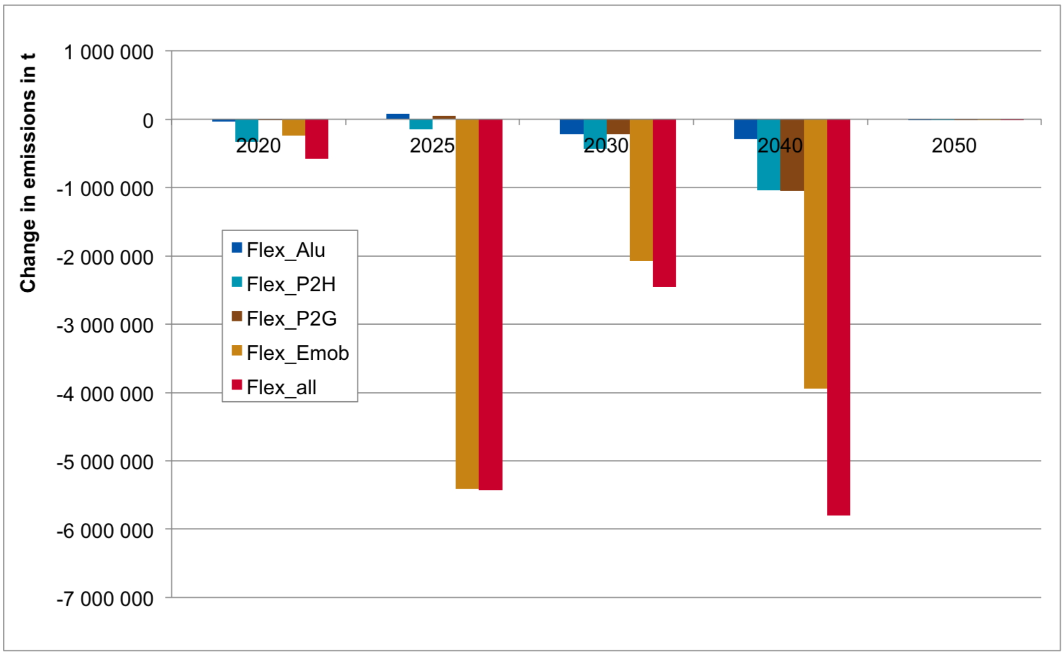

Figure 7. Change in emissions vs. reference.

Table 4. Total emissions in mio t.

	2020	**2025**	**2030**	**2040**	**2050**
Reference	212.5	173.1	103.2	47.1	5.3
Flex_all	212.0	167.7	100.8	41.3	5.3

Heat storage and controlled charging are flexibilities in which availability fluctuates daily and seasonally depending on the thermal energy required and the connected charging capacity of the vehicles. Renewable electricity surpluses from wind power in winter can be used for covering heat demand, thanks to the heat storage. This in turn leads to a shift from heat generation from fossil CHP power plants to the use of renewable electricity in heat pumps or electric boilers and thus to a reduction in emissions. The significant reduction of emissions through controlled charging of electric vehicles is due to the fact that in the case of uncontrolled charging (as it is reflected in the reference case), the electric vehicles increase existing load peaks in the midday and especially evening hours and lead to higher curtailment and emissions in the electricity system. This negative effect of the electric vehicles is repealed by the possibility to control the charging behaviour as shown in the strong emission reductions achieved in the simulation configurations that take this flexibility into account ("Flex_Emob" and "Flex_all"). In contrast to the other flexibilities, the flexibility of aluminium electrolysis and hydrogen storage is continuously available. This availability in combination with an assumption of relatively low CO_2 prices of 36.5 €/t in the year 2025 and the high fossil share of 45% in electricity generation leads to more emission-intensive generation. Under these circumstances, total system costs are lower if the flexibilities are used to increase residual load in times of low prices, so that a shift from low-emission gas-fired power plants to more emission-intensive lignite and hard coal fired power plants takes place. In 2030, overall emissions are at a significantly lower level slightly above 100 mio t. The overall carbon reducing effects are therefore lower than in 2025. Between 2030 and 2040, the share of renewables in electricity generation rises from 63% to 75%, going along with a significantly higher degree of curtailment. This leads to a higher reduction of emissions up to nearly 6 mio t, which is about 12% of the overall emissions in 2040. In 2050, the energy system is assumed to be nearly fully decarbonised, so flexibilities cannot achieve a significant reduction in emissions.

Despite that, the need for flexibilities is especially high in a fully renewable system, which can be seen in the effect of flexibilities on curtailment (see Section 3.2) and costs (see Section 3.1).

3.4. Interplay of Different Flexibilities

Regarding the interplay of flexibilities, it can be expected that the effects of single flexibilities do not add up when several flexibilities are used in combination. That can be seen in case “Flex_all”, where all flexibilities are implemented together. Neither in emission nor cost reductions is the effect of the combined flexibilities as high as the sum of the single effects. The full potentials of the different flexibilities cannot be exploited at the same time. The effect on curtailment is an exception to this: In the years 2040 and 2050, with their high renewable shares, the reduction of curtailment in “Flex_all” is higher than the sum of curtailment reductions in the other cases, so the dispatch optimisation leads to a synergistic appliance of flexibilities.

This interplay is explained in more detail for the case of aluminium DSM. In 2020, 2025, and 2050, the sum of energy that is shifted via aluminium DSM is higher in “Flex_Alu” than in “Flex_all”. However, in 2030 and 2040, the amount of shifted energy is even higher when there are other flexibilities. In the following graph, this is examined in temporal resolution (see Figure 8). The black line in the figure is the filling level of the virtual buffer of aluminium DSM in “Flex_Alu”, the red line is this buffer in “Flex_all”. The other filling levels are also from “Flex_all”. It can be observed that the buffer level of aluminium is kept higher when it is the only flexibility (black line). In that case, it needs to compensate the intraday deviations of residual load. However, when there are other flexibilities (red line), the advantage of the high E2P-ratio (which reflects the long possible shifting time in the DSM application) can be used. So the high buffer capacity of the aluminium DSM is exploited best when combined with other flexibilities that have a higher power but lower E2P-ratio.

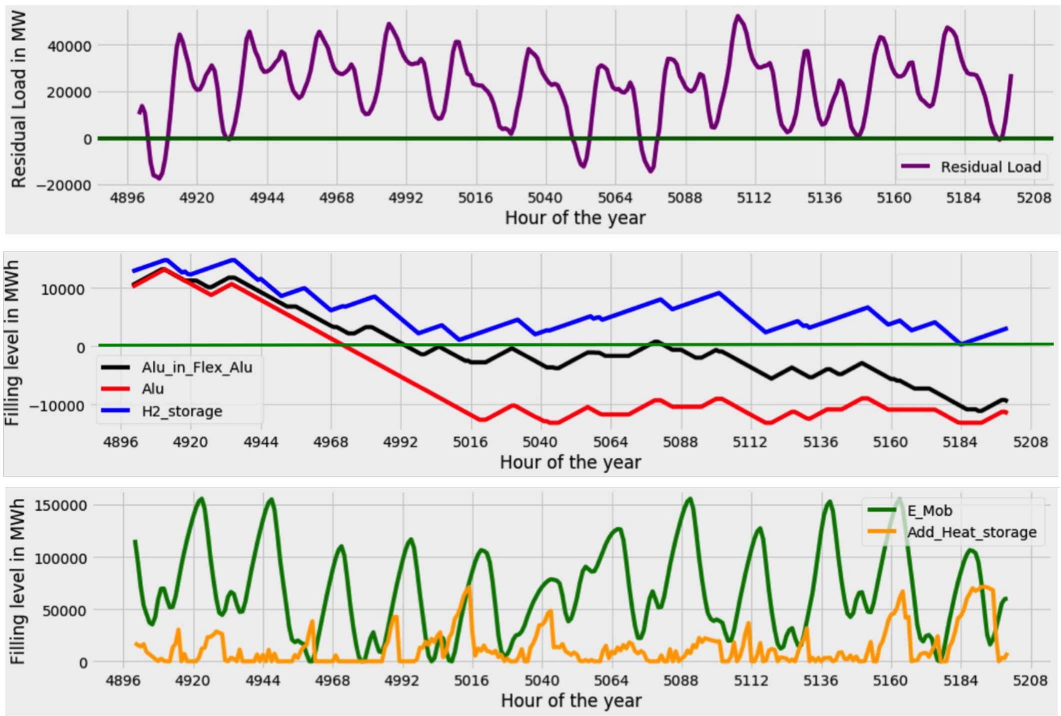

Figure 8. Residual load and storage levels in hours 4900 to 5200 of the year 2030.

4. Discussion

4.1. Effects on Costs

The implementation of additional flexibilities in an energy system that is dispatched to minimise operation costs will always have a cost-cutting effect. To evaluate the advantage of an implementation, a cost-benefit analysis shall be performed. This paper contributes to such an analyses in showing the possible range of dispatch cost reduction for different flexibility options. In general, a flexibility option can reduce the fuel and CO_2 costs more if there are fewer flexibility options in the system. The more flexibility in the system, the smaller the marginal effect of an additional flexibility. If the cost reductions are compared, the aluminium electrolysis, as an example of the industrial demand side management, shows a higher relative cost reduction potential. Whether it makes sense to implement DSM measures depends in particular on the investment requirements of the individual flexibility options. Depending on market conditions, such measures can also reduce industrial electricity costs, contributing to refinancing investment. Costs of flexibilities do not only include dispatch costs, but also capital costs. These are not included in this examination, since the research design is focused on comparing the dispatch enhancements of installed flexibilities. In that regard it should be noted that some flexibilities incur only minor additional investment costs, since their capital costs arise for their primary purpose (heating, transport, hydrogen production). Provision of flexibility can generate an additional revenue. A proper allocation of capital costs to the different purposes of possible flexibility options has not been part of this study. However, especially for electric vehicles, it is important to stress the necessity of a controlled charging strategy, since large scale uncontrolled charging leads to significantly higher system costs and emissions.

4.2. Effects on Curtailment

The avoidance of curtailment is not a direct objective of the optimisation. However, the curtailment can be reduced by implementing further flexibility in the energy system. The effect on the magnitude of curtailment of the flexibilities assumed in this paper is, nonetheless, significantly lower than the composition of the power plant portfolio. In addition to the flexibility options considered here, the amount of curtailment could also be reduced by the implementation of seasonal storage (e.g., via hydrogen storage) or a higher level of exchange with the neighbouring countries. In that context it should especially be noted that the investigations in this paper do not consider grid restrictions within Germany. If these are considered, a stronger curtailment can be expected, and the value of local flexibility in the concerned grid areas increases. Whether industrial load management is suitable for this task needs to be further investigated. Since the locations of industrial loads hardly correlate with the locations of renewable energy production, this is doubtful.

4.3. Effects on Carbon Dioxide Emissions

The composition of the power plant portfolio also has a much greater influence on CO_2 emissions than the amount of flexibility implemented. Nevertheless, flexibilities are able to further reduce CO_2 emissions. This is mainly achieved by integrating renewable energy, i.e., by reducing curtailment. Additional flexibilities can also lead to slightly increasing emissions by raising the utilisation of conventional base load power plants. However, this effect can only be observed with a special system configuration including coal-fired power plants that have free capacities and low carbon prices. Since the implementation of new flexibilities, and especially of the specific industrial DSM option considered in the study at hand, requires a comparatively long period of time in advance and this effect will no longer occur in the mid-term, this finding should not lead to omitting this flexibility option. In general, flexibilities will be crucial for the integration of high shares of renewable energy and an extensive reduction of CO_2 emissions.

4.4. Limitations

In the sense of a scenario, only one of many possible energy futures is exploratively modelled with the path under consideration; the result is correspondingly sensitive to variations in the underlying assumptions of the anticipated trends. Since these trends and the resulting underlying system configuration are taken from an already much discussed and recognised study [26], a detailed sensitivity analysis of essential system-driving assumptions (with the exception of the composition of the flexibility options) is not included in the study at hand. The resulting limitations will be discussed in the following. A different development of generation capacities or energy demand would also lead to a different use of flexibilities. In particular, the ratio of wind energy, PV and load has an influence on the need for balancing. In respect to the demand, failure to achieve the ambitious insulation targets would, for example, increase the demand for heat and place other needs on the resulting heat supply technologies and thus this sectors flexibility. Also with regard to a changed composition of drive concepts in the transport sector the present analysis is subject to sensitivity. A larger share of combustion engines would result in fewer electric vehicles and thus less flexibility potential from this technology, while at the same time generating a higher demand for synthetic fuels. Depending on the assumptions regarding its import possibilities, higher power generation capacities could become necessary to guarantee the supply of domestic green synthetic fuels. A different development in fuel and CO_2 prices is also relevant. If, for example, the scenario were not embedded in a global climate protection scheme and strong fuel price increases were already assumed in the short term, the use of the power plant park, and thus also the use of the flexibilities would change. The consideration of seasonal storage would also cause differences in the use of flexibilities.

In addition, there are limitations due to the simplified representation in the model. The neighbouring countries have not been modelled explicitly, but energy exchange has been included as a heuristic solely based on the German balancing need, not taking into account residual load characteristics or even the dispatch of flexibilities in the other countries. Within Germany, no grid restrictions have been considered. If these were included, that would lead to higher amounts of curtailment on a local scale.

As described in Section 4.1, capital costs of flexibilities have not been taken into account, since their allocation has not been part of this study. Also, modelling does not take into account business management factors such as other earning opportunities that could rival the provision of flexibility.

At this point in time, it is not possible to validate the system results for the year 2020 comparing it to real data, since on the one hand, official data for this year has not been published yet, and on the other hand, the COVID-19 pandemic has a strong effect on the energy demand that is not depicted in the assumptions made for the study. Nevertheless, a validation is approximated by comparing resulting emissions with the emissions data published for 2018 [39]. In 2018, the energy industry sector had emissions of 295 mio t carbon dioxide equivalent (CO_2_eq). The modelling results in emissions of 212 mio t CO_2, which is 28% lower. Possible reasons for that deviation, apart from the difference between CO_2 and CO_2_eq that accounted for a plus of 2% in 2018 according to [39], can be the fact that no grid restrictions within Germany have been taken into account that could hinder the integration of renewable electricity, and no restrictions on start up or load change of conventional power plants have been considered. However, the main driver behind that difference presumably is the development of the renewable power plant fleet: In 2018, the installed capacity of fluctuating renewable electricity was 104 GW according to [40], whereas the simulation considers 127 GW for 2020.

5. Conclusions

In this examination, the flexibilisation of aluminium electrolysis is investigated as one possible option for industrial DSM. Industrial DSM ranks as one of the most efficient flexibility options. Its relative contribution towards the reduction of curtailment and costs are high. Due to technical constraints, the potential for this flexibility option is limited to a small number of processes. Therefore the absolute contribution of a controlled charging strategy for electric vehicles or the flexibilisation of heat networks with heat storages exceed the absolute contribution of the industrial demand side management.

The biggest influencing factor in carbon emissions surely is the power plant fleet. In general, flexibilities are suited to reduce carbon emissions to a certain degree. However, this paper also shows that an increase of flexibility options with certain characteristics could even lead to higher green house gas emissions in the short term. As long as there are emission-intensive coal power plants in the market and carbon prices are low, an economical optimisation of the dispatch increases the capacity utilisation and emissions of these power plants. In certain system configurations with low carbon prices, the decrease of emissions due to the reduced curtailment is not able to offset the increased emissions from coal-fired power plants. In these cases, the increase in flexibility also increases green house gas emissions.

The study stresses the rising importance of flexibilities in an energy system based on high shares of renewable electricity generation. The effects of additional flexibilities on costs, curtailment and emissions in the current system with a degree of below 50% of renewable electricity generation may be marginal, whereas they rise significantly with the share of renewables. In 2050, a cost reduction up to 25% can be reached. Or, in other words, when new technologies are introduced into the system, such as hydrogen electrolysis or electromobility, their potential flexibility should be used urgently via, for example, buffer storages or controlled charging.

There is a need for further research on how the provision of flexibility can be implemented commercially, and how it can be combined with other revenue opportunities. In this context, it is also necessary to consider the cost of capital that can be allocated to the provision of flexibility. The spatially resolved interaction of flexibilities with the electricity grid should also be further considered in order to identify suitable flexibility options for dealing with local curtailment. Also, the cross-border interplay of flexibilities could be of further interest.

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Abbreviations

The following abbreviations are used in this manuscript:

CHP	combined heat and power plant
CO_2	carbon dioxide
CO_2_eq	carbon dioxide equivalent
CCS	carbon capture and storage
DHN	district heating networks
DSM	demand side management
ESM	Energy Supply Model
E2P-ratio	energy to power ratio
H_2	hydrogen
LP	linear programming
oemof	Open Energy Modelling Framework
OPSD	Open Power System Data
renpass	Renewable Energy Pathways Simulation System
PV	photovoltaics
PyPSA	Python for Power System Analysis
PyPSA-EUR	Open Optimisation Model of the European Transmission System
P2H	Power-to-Heat
P2G	Power-to-Gas
WISEE	Wuppertal Institute System Model Architecture for Energy and Emission Scenarios

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