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Full-length article

Influence of flexibility options on the German transmission grid — A sector-coupled mid-term scenario

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ABSTRACT

Germany must decarbonise all energy sectors to meet international and national climate goals. This task necessitates linking the electricity with the gas, heat and mobility sectors. On the one hand, sector coupling increases the demand for electrical energy and changes well-known demand patterns requiring updates to the grid infrastructure. On the other hand, the newly coupled sectors offer flexibility options to support the grid infrastructure and reduce expansion needs.

This study employs a highly detailed model of the German transmission grid to analyse the impact of sector coupling comprising additional electricity demands and flexibility options on grid and storage expansion needs in the year 2035. The results demonstrate that utilising flexibility options can reduce system costs and lower CO_2 emissions. The research adheres to open source and open data principles, with all data and tools being publicly accessible.

1. Introduction

The transition to a low-carbon energy system requires the coupling of the electricity sector with other sectors such as gas, heat and mobility. Sector coupling can increase the flexibility and efficiency of the energy system but also leads to higher demands for electrical energy and changes in known demand patterns, which necessitates expanding the grid infrastructure. To meet international and national climate goals, it is crucial to understand the grid expansion and flexibility needs in a future sector-coupled energy system. This paper focuses on a mid-term scenario for the year 2035 in Germany, which is characterised by a significant share of renewable energies and a progressing sector coupling, but which is not yet completely decarbonised. This paper aims to answer fundamental research questions related to this topic considering the German transmission grid:

- What are grid expansion and flexibility needs in a sector-coupled energy system in a mid-term scenario for the year 2035?
- Where are flexibility options optimally used and expanded in the transmission grid? Is there a correlation between grid and storage expansion?
- Which potential to reduce system costs and CO_2 emission can be realised by applying flexibilities?

The challenges and potentials of sector coupling are subject to several current scientific works. Various researchers identify the need for sector coupling and flexibility options to meet climate goals and increase the share of renewable energy [1–5]. Integrated grid planning approaches are required to minimise transport losses according to Fridgen et al. [6]. Sector-coupled energy system analysis' agrees with these findings, mostly by focusing on a 100% renewable or zero-emissions energy system [7–10]. Brown et al. [7] as well as Göke et al. [8] deal with the European system whereas the works of Maruf [10] and Gils et al. [9] focus on the German system as in two regions [10] or 16 federal states and its neighbouring countries [9]. Nebel et al. [11] model a one-node German energy system in 2030 analysing the main drivers for used flexibilities.

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Table 1
Considered flexibility options in different scenarios.

flexibility	*base*	*mediumflex*	*lowflex*
grid expansion	✓	✓	✓
battery expansion	✓	✓	✓
demand side management*	✓	✓	
dynamic line rating*	✓	✓	
flexible e-mobility charging*	✓	✓	
heat stores*	✓		
hydrogen tank stores	✓	✓	✓
hydrogen salt cavern stores*	✓		
fuel cells*	✓		
methanation*	✓		

* These flexibility options are examined in sensitivity analyses by separately adding them to the *lowflex* scenario.

However, the state-of-the-art lacks more investigations on how sector coupling affects the energy system in a mid-term scenario. Correlations between the spatial allocation of used flexibilities and expansion needs remain largely unexamined, as the considered spatial resolutions, especially for Germany, remain relatively low.

The present work uses a comparably spatially high-resolved model of the German system considering energy exchange between foreign countries in a mid-term scenario for 2035.

Three different scenarios with the same demand and supply options are optimised to analyse the effect of flexibility options (Table 1). Scenario *base* represents the energy system in 2035 considering a fast roll-out of flexibility options. Scenario *mediumflex* represents a future energy system where low-cost electric flexibility options have been expanded, but seasonal flexibility has not been targeted. If the implementation of flexibility options is not targeted at all, the energy system can be represented by scenario *lowflex*. This scenario includes neither seasonal stores nor short-term flexibility options and also reduces the options of sector-coupling technologies. In addition, the flexibility options are analysed more in detail by separately adding them to the *lowflex* scenario. All these scenarios are compared to quantify the effect of different flexibility options on the energy system and on its expansion needs until the year 2035.

2. Materials and methods

This study was conducted as part of the *eGo*-framework which aims to develop a model covering the electricity grids on all voltage levels in a top-down approach [12]. The presented work focuses on the results of the transmission grid, which are generated using the open-source tool *eTraGo* [13]. The downstream analyses of the distribution grids within the tool *eDisGo* [14] are not part of this work, but resulted in additional requirements influencing the model concept and data. In *eTraGo*, energy demands, energy supply and flexibility options from lower grid levels are aggregated per medium-voltage grid district (MVGD), as defined by Hülk et al. in [15], and attached to the corresponding high voltage/medium voltage (HVMV) substation.

2.1. Modelling concept

The modelling concept follows an integrated approach of combining electricity and methane grids as well as the heat and mobility sector in one optimisation problem. Within this problem, grid expansion, flexibility usage and sector-coupling capacities of the gas sector are optimised. Demands and capacities of power plants, power-to-heat and charging infrastructure are pre-defined following the grid development plan (GDP) [16]. These capacities need to be pre-defined to allow feasible analysis of the underlying distribution grids with an acceptable complexity. Additionally, this allows better comparison to results of the GDP and reduces the complexity of the model.

The modelling tools and their structure follow the components of *PyPSA* [17], an open source toolbox for modelling energy systems. It provides methods to optimise operation and investment costs of integrated energy systems including power, heat and gas networks.
The modelling tools accommodate sector coupling by using different *PyPSA* components, with the *base* scenario considering various technologies illustrated in Fig. 1. The subsections below describe the modelling concepts of the different sectors for the *base* scenario and highlight its differences from the scenarios *mediumflex* and *lowflex*.

2.1.1. Electricity sector

The electricity sector is represented by power plants, demands and different storage technologies. Generation capacities and potential feed-in time series of fluctuating renewable generation are defined exogenously whereas generator dispatch is subject to optimisation.

The installed capacities of pumped storage power plants and home batteries are exogenously defined while the capacities of large scale batteries and the dispatch of all storage units are optimised.

Electricity demands from households, commercial, trade and service (CTS) and industry are modelled as exogenous demand time series. Demand-side management (DSM) is modelled as an energy storage equivalent operation following the approach of Kleinhans [18]. The shiftable power per time step and the time frame within the shifting can be conducted is limited using a storage-equivalent buffer.

Dynamic line rating (DLR) is represented by a weather-depending time-varying maximal capacity of all overhead transmission lines in Germany following the method used in the GDP [16].

2.1.2. Transport sector

Motorised individual travel (MIT) is based upon fleets of aggregated battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). The electric vehicle (EV) modelling concept is inspired by Brown et al. and Wulff et al. [7,19] using additional constraints on an hourly basis. The model involves driving demands and batteries of the fleets. The batteries are constrained by an hourly state of charge (SoC) band allowing to shift charge times during the parking time of EVs while preserving initial (minimum) and final (maximum) SoC from driving simulation in *SimBEV* [20]. The charging infrastructure is unidirectional and its maximum power per hour is set to the available charging power of grid-connected EV from the *SimBEV* simulation data. In the scenario *lowflex*, MIT does not provide flexibility. Instead, fixed user-driven charging is used: EVs are plugged in on arrival and charged with maximum available power until they leave or are fully charged.

Heavy-duty transport (HDT) needs satisfied by fuel cell drives are modelled as constant loads attached to hydrogen nodes.

2.1.3. Gas sector

The central element of the gas sector is the methane transmission grid with exogenously defined pipeline capacities. Natural gas and biogas can be fed into the grid, its dispatch is subject to optimisation constrained by a maximum dispatch per hour and per year. Methane can be stored in the grid itself and in caverns with fixed maximum capacities.

Hydrogen can be produced and consumed locally, a grid is not considered. Methane can be turned into hydrogen with steam methane reforming (SMR) and vice versa with methanation. Hydrogen can be stored in steel tanks and underground at spatial intersections of salt caverns and substations, both options with capacities being optimised. In this mid-term scenario, those geological hydrogen stores are considered as pure electrical flexibility.

Industrial gas demand time series are defined exogenously.

2.1.4. Heat sector

The heat sector represents residential and CTS buildings which are assigned to three categories: houses supplied by district heating grids (DHGs), houses supplied by heat pumps and houses supplied by gas boilers. Industrial heat demands are modelled as fuel demands (hy-

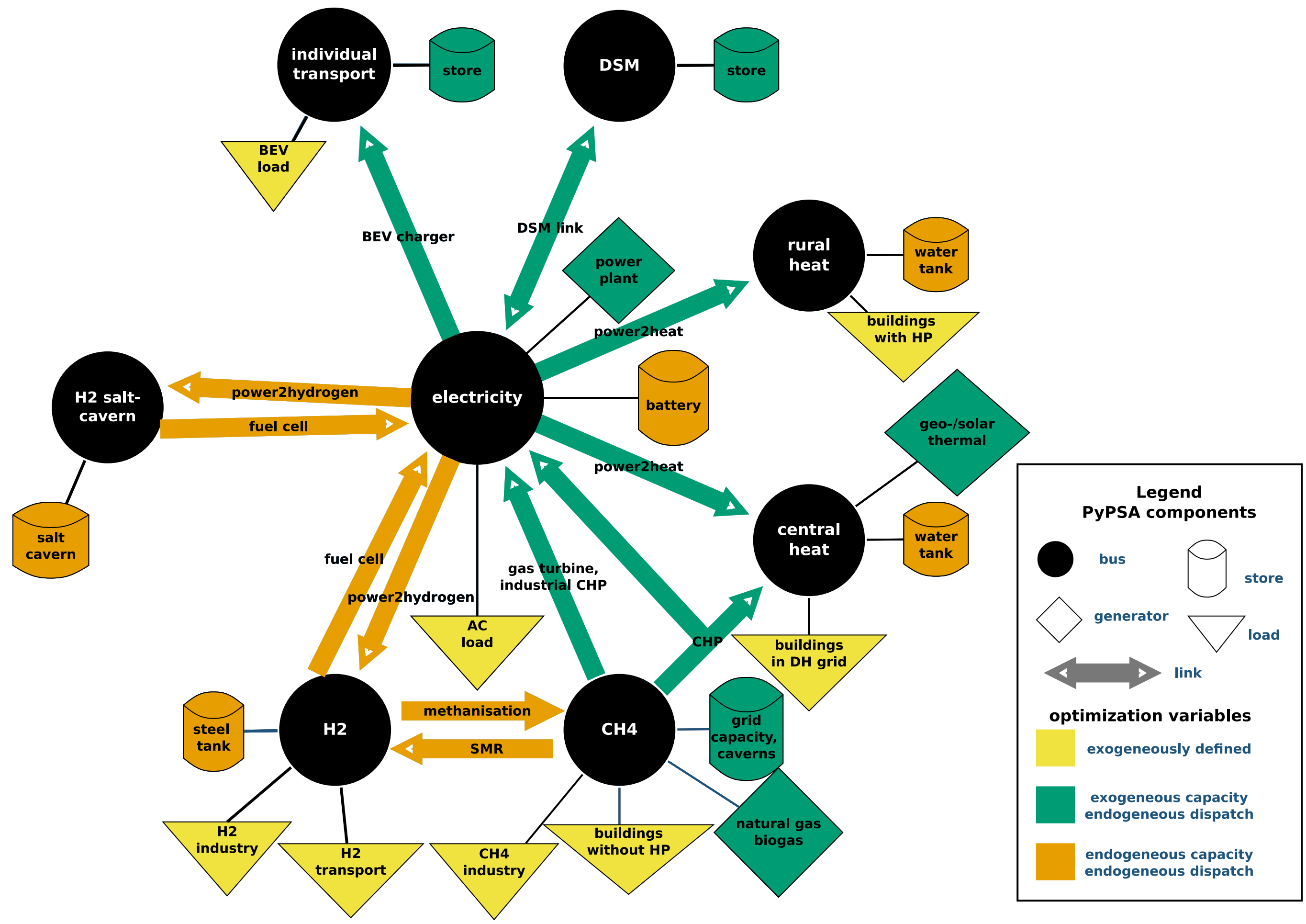


Fig. 1. Overview of the modelling concept providing information on endogenous and exogenous parameters and the *PyPSA* components used to represent the energy system.

drogen, methane or electricity) in order to cover the consumption at different temperature levels.

DHGs supply multiple residential and CTS buildings in a defined area. The transfer of heat is not considered, only the supply and demand side are modelled. DHGs are supplied by gas (combined heat and power) and electricity (heat pumps, resistive heaters and direct heat generation via solar thermal plants). Depending on the location, geothermal power plants can feed DHG. The capacities of heat supply technologies are predefined whereas the dispatch is part of the optimisation. Heat demands of DHGs can be shifted in time by large scale stores which are optimised regarding installed capacities and dispatch.

Buildings outside of DHGs are supplied by gas boilers or heat pumps. Buildings supplied by an individual heat pump are aggregated per HVMV substation. Their capacities are predefined considering the maximum heat load per building to achieve feasible solutions on the distribution grid side. The dispatch of heat pumps can be shifted using water tanks, their capacities and dispatch are optimised. All other buildings are supplied by individual gas boilers which are modelled as non-flexible methane loads.

2.1.5. Sector coupling

Electrolyzers connect electricity nodes with hydrogen nodes. In scenario *base*, fuel cells connect the same nodes in the opposite direction. For both technologies, the installed capacities and the dispatch is result of the optimisation. The capacities of all other sector-coupling technologies are defined exogenously, the dispatch is optimised.

Power to heat technologies supply rural and central heat. The temperature-dependent coefficient of performance (COP) of heat pumps is included as a time-dependent efficiency using the parameters described in [7].

Combined heat and power plants (CHPs) providing heat for DHGs are modelled considering the electricity and heat output. Constraints ensure that the power-to-heat ratio is in an allowed feasible space according to Brown et al. [7]. In the case of CHPs located at industrial sites, only the electrical side is modelled.

Open cycle gas turbines (OCGTs) can feed-in electricity by consuming methane.

2.2. Model data

The assumptions for the German energy system are based on the *GDP "scenario C2035"*, version 2021 [16]. This scenario is rather ambitious, as 77% of the installed power generation capacity is attributed to fluctuating renewables. The parameters used in this work are listed in Table 2 and Table 3. Information on foreign countries originates from the *Ten-year network development plan (TYNDP) 2020 scenario "distributed energy"* [21]. Demands and potential renewable feed-in time series are modelled in an hourly resolution for the representative weather year 2011.

The data model is created by the open source *Python* tool *eGon-data*. Further information can be found in the documentation of the tool [22].

2.2.1. Grid infrastructure

The topology of the German high and extra-high voltage electricity grid and its substations is extracted from OpenStreetMap (OSM) using data from 2021 [24] and the tool *osmTGmod* which initially was devel-

Table 2
Electricity generation capacities in Germany in 2035 according to the German grid development plan 2021, scenario C2035 [16].

Carrier	Value	Unit
gas	46.7	GW
oil	1.3	GW
pumped hydro	10.2	GW
wind onshore	90.9	GW
wind offshore	34.0	GW
solar	120.1	GW
biomass	8.7	GW
others	5.1	GW

Table 3
Considered energy demands in Germany in 2035.

Demand sector	Value	Unit	source
MIT transport	41.4	TWh_{el}	*
central heat	68.9	TWh_{th}	*
rural heat	423.2	TWh_{th}	*
electricity residential	115.1	TWh_{el}	[16]
electricity CTS	123.5	TWh_{el}	[16]
electricity industry	259.5	TWh_{el}	[16]
CH_4 industry	196.0	TWh_{CH_4}	[23]
H_2 industry	16.1	TWh_{H_2}	[23]
H_2 transport	26.5	TWh_{H_2}	*

* Own calculation.

oped by Scharf in [25]. The transmission capacities and coefficients of resistance are set using values for standard lines from Brakelmann [26]. The existing line capacities represent the lower limit of the grid capacities. Within the optimisation, those capacities can be increased up to the capacity of four parallel 380 kV lines.

The topology and capacities of the methane transport grid are defined using the *SciGRID_gas* (version 1.1.2) data sets *IGGIELGN_Nodes* and *IGGIELGN_PipeSegments* representing the methane grid in the year 2019 [27].

Neighbouring countries are included in a lower spatial resolution to model import and export. The topology of both grids is visualised in Fig. 2.

2.2.2. Demands

Annual electricity demand of residential, CTS and the industry sector follow the assumptions from the GDP [16]. The distribution on NUTS3-level is taken from *demandRegio* [28], further disaggregation is performed taking the number of households (residential) [29], heat demand (CTS) [30], OSM-data (industry) [24] and available information on industrial sites from different sources [31–33] into account. Hourly load time series for industry and CTS are created based on standard load profiles (SLPs) from [28]. Time series for private households are created using a variety of synthetically created bottom-up profiles described by Büttner et al. in [34].

The potential of DSM comprises the shifting of loads within the sectors of industry and CTS. Loads eligible to be shifted mainly derive from heating and cooling processes and selected energy-intensive industrial processes. Flexible shares are identified using parameters elaborated by Heitkötter in [35].

Heat demand covers space heating and drinking hot water demand of residential and CTS buildings. The distribution of the overall demand per year is taken from the Pan-European Thermal Atlas (Peta) [30] and scaled to meet heat demands for future scenarios. The creation of residential heat demand time series is described by Büttner et al. in [34]. CTS demand curves are created using gas SLP from *demandRegio* [28]. Industrial methane and hydrogen demand time series are taken from the *eXtremOS* project [23].

Profiles for MIT are generated using *SimBEV* [20] for BEVs and PHEVs. These profiles involving driving, parking and (user-oriented) charging times on an hourly basis are created based upon survey data from *Mobilität in Deutschland* [36] for different travel destinations and region types according to the *Federal Ministry of Transport and Digital Infrastructure* [37]. Different vehicle classes as well as charging probabilities for multiple types of charging infrastructure are presumed in accordance with Helfenbein and *The National Centre for Charging Infrastructure* [38,39]. Given these assumptions, a pool of 33.000 EV-types is generated. Assuming a total of 15.1 million vehicles in Germany according to the GDP [16], EVs are subsequently allocated randomly to each substation using relative shares derived from vehicle registration [40] and population [41] data. Flexibility can only be provided by plugged-in vehicles in order to not alter user behaviour. Moreover, flexible charging is restricted to vehicles connected to private charging infrastructure at home and work; public charging is assumed not to provide flexibility.

HDT covers e-trucks with a number of 100.000 trucks according to the GDP [16]. In this work, all of them are assumed to be FCEVs. The required hydrogen is spatially distributed along traffic volume data from the *Federal Highway Research Institute* [42] and aggregated on NUTS3-level. The refuelling is assumed to take place at a constant rate.

2.2.3. Generation and storage capacities

The national capacities for electricity generators are taken from the GDP [16] and spatially allocated using technology-specific methods. The distribution of solar ground-mounted and wind power plants is based on Marktstammdatenregister (MaStR) [43–46] and eligible areas taken from Amme et al. [47,48]. Capacities for solar rooftop plants are assigned to HVMV substation based on the spatial distribution of electricity demands from households and CTS. The distribution of conventional as well as other renewable power plants and pumped hydro storage units are based on information on the current power park taken from MaStR [43]. The maximum feed-in time series for fluctuating renewables are created with the tool *atlite* [49] which uses weather data from *ERA5* [50] for the year 2011.

National capacities and locations for biogas production arise from the *Biomethane Map* [51] and for natural gas from *SciGRID_gas* data [27] (*IGGIELGN_Productions*). The overall biogas and natural gas productions over the year are limited by the values for their respective productions for 2030 of the *NEP Gas* [52].

Methane can be imported via the grid from neighbouring countries where gas production capacity includes the national biogas and natural gas production according to the TYNDP [21] as well as the country-specific liquefied natural gas (LNG) import capacity according to *SciGrid_gas* [27] (*IGGIELGN_LNGs*). The cost for imported methane is set to the weighted mean value of biogas production, natural gas production and LNG import potentials per country. Considering the current political situation, the costs for gas imported from Russia are set to LNG costs, assuming that LNG imports will be the mid-term alternative in Germany to replace it.

The capacities and locations of methane caverns are taken from *SciGRID_gas* [27] (*IGGIELGN_Storages*). The storage capacity of the grid itself is distributed uniformly to each node using the overall capacity according to [53].

Different stores are part of the optimisation and therefore represented using investment costs (Table 4) and a range of allowed capacities. Extendable batteries are assigned to every substation within the electrical grid. A lower limit is set to represent the installed capacities of home batteries according to the GDP [16]. Home batteries are spatially distributed along the installed photovoltaic (PV) rooftop capacity. Hydrogen overground stores are optimised without any limitation whereas hydrogen underground storage potentials are limited by the salt cavern capacities of the geographical location of the store using data from the *Federal Institute for Geosciences and Natural Resources* [54]. Rural and central heat stores are optimised without upper limits, rural heat stores are represented by water tanks whereas central heat stores represent pit thermal energy storages.

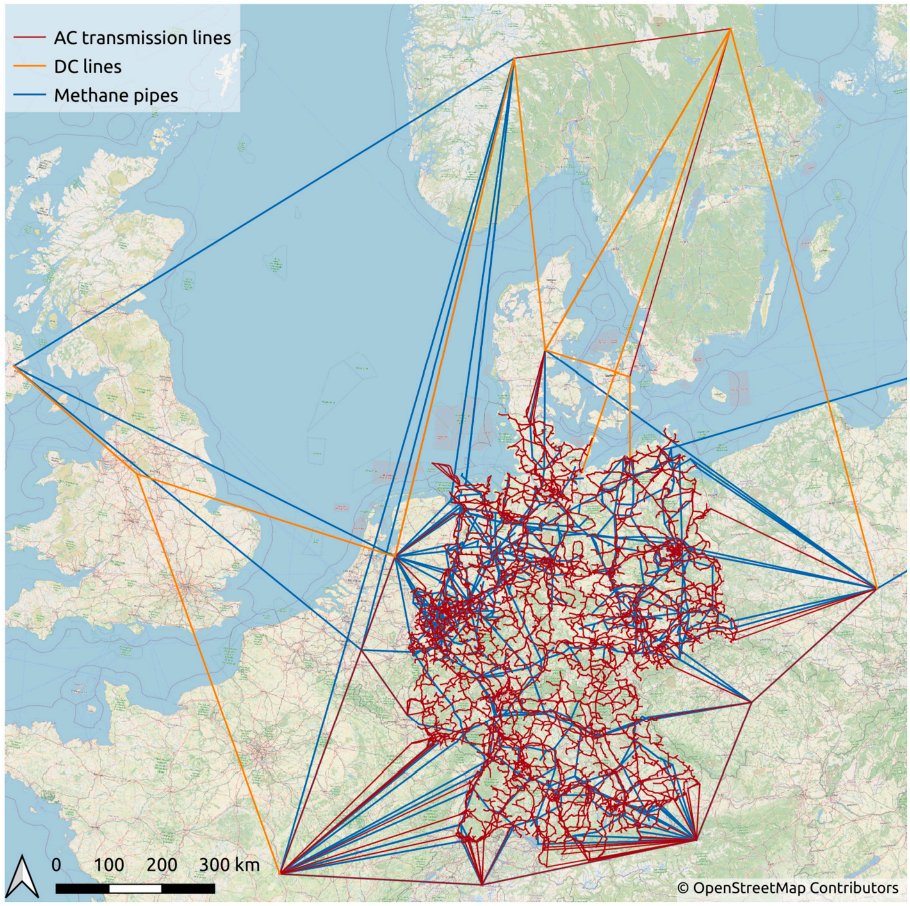


Fig. 2. Visualisation of grid topologies including the methane transport grid, the AC transmission grid (110-380 kV) and DC lines.

Table 4
Projected overnight investment costs for the year 2035.

Technology	Capital cost		Lifetime		Source
Battery*	838.00	€ / kW	27.5	a	[58]
110 kV line	0.23	€ / kVA/ km			[59]
220/380 kV line	0.70	€ / kVA/ km			[16]
H_2 overground store	35.98	€ /kWh	20	a	[58]
H_2 underground store	1.75	€ / kWh	100	a	[58]
Electrolysis	375.00	€ / kW_{el}	31	a	[58]
Fuel cell	1025.0	€ / kW_{el}	10	a	[58]
Methanation	252.00	€ / kW_{CH_4}	30	a	[60]
Steam methane reforming	540.56	€ / kW_{CH_4}	25	a	[58]
Pit Thermal Energy Storage	0.52	€ / kWh_{th}	25	a	[58]
Decentral water tanks	1.84	€ / kWh_{th}	20	a	[55]
Water tank (dis-)charger	0.00	€ / kW_{th}	-		[58]
Discount rate	5	%			[55]

* Incl. costs for power and energy using a fixed energy-to-power-ratio of 6 h.

2.2.4. *Sector-coupling technologies*

The overall capacities for exogenous sector-coupling technologies in Germany are derived from the GDP [16] and its supplementary documents. Within the data model creation, these capacities are further disaggregated: OCGT and CHPs are distributed using the information on existing plants and their location from MaStR [43–46]. New CHPs is distributed according to the list of conventional power plants in the GDP [16]. Technical parameters are taken from *PyPSA technology data* [55] for the year 2035.

Heat pumps and resistive heaters for DHGs are distributed according to the heat demand which is not covered by solar- and geothermal or CHPs. Heat pumps supplying individual houses are randomly distributed to single buildings and aggregated per HVMV substation. The COP is calculated for each location using temperature data from *ERA5* [50] parameters representing a variety of heat pumps that were published by Staffell et al. [56].

Methanation, steam methane reforming, electrolysis and fuel cell capacities are optimised considering investment costs shown in Table 4. No upper expansion limit is set for these technologies. CO_2 needed for the methanation process is assumed to come from direct air capture for costs of 100 € per ton [57]. Costs for CO_2 certificates are neither included in the methanation process nor in the use of synthetic methane, it is assumed that these costs level out each other.

2.3. *Complexity reduction*

The resulting model is characterised by a large spatial (about 8,000 electrical nodes, 600 gas nodes) and temporal (8,760 hours) complexity which is not feasible to solve on the available computational resources. To reduce the spatial and temporal complexity of the optimisation problem, clustering methods are applied.

A *k-medoids Dijkstra Clustering* is used to separately reduce the spatial complexity of the electrical and methane grid down to a number of nodes per grid being a configurable input. The method combines a *k-medoids Clustering* and a *Dijkstra's algorithm* allowing a good representation of the overall topology by especially avoiding false meshes. It is implemented in *eTraGo* [13] and described in detail in Esterl et al. [61].

Components of the heat, hydrogen and mobility sectors as well as components representing DSM are grouped based on their connections to the clustered electrical and methane grid. Components of sectors either connected to electricity or gas are clustered according to the corresponding grid. The heat sector is connected to both grids, its components are aggregated if the connected gas and electricity node is part of the same cluster.

This method is applied to cluster the grid resulting in 300 electrical nodes and 80 methane nodes, the overall number of buses (including all sectors) results in about 2,600.

In order to reduce the temporal complexity, the time series are downsampled to every fifth time step [62]. The considered snapshots are weighted respectively to account for the analysis of one entire year.

2.4. Optimisation method

The model is solved using the techno-economical Linear Optimal Power Flow (LOPF) from the *PyPSA* tool [17] which simultaneously optimises capacity expansion planning and generator dispatch subject to linearised power flow constraints. The aim of this optimisation is to minimise overall system costs, described by term (1).

The LOPF considers passive branch flows, but the linear optimisation of passive branch capacities does not involve updates of electrical parameters. This can be compensated by running multiple iterations and updating the electrical parameters to the expanded grid between the iterations as shown in [63] by Hagspiel et al. In this work, four iterations of the LOPF are performed for each scenario, which showed reasonable results in previous calculations [64].

The calculations were applied on a server with 256 GB DDR4 Reg. ECC RAM and an AMD EPYC 7502P 32-Core processor. The calculation time for each scenario was about 48 hours.

$$\min_{F_\ell, F_l, H_{n,s}, g_{n,r,t}, h_{n,s,t}, f_{n,f,t}} \Bigg[\sum_\ell c_\ell F_\ell + \sum_l c_l F_l + \sum_{n,s} c_{n,s} H_{n,s} + \sum_{n,r,t} (w_t \cdot o_{n,r} \cdot g_{n,r,t}) + \sum_{n,s,t} (w_t \cdot o_{n,s} \cdot [h_{n,s,t}]^+) + \sum_{n,l,t} (w_t \cdot o_{n,l} \cdot f_{l,t}) \Bigg] \quad (1)$$

ℓ: index passive branch (AC-line)
n: index node
r: index generator
s: index store
l: index gas link (electrolysis, fuel cell, SMR, methanation)
t: snapshot
c_ℓ: CAPEX passive branch
F_ℓ: capacity passive branch
w_t: snapshot weighting
$o_{n,r}$: OPEX of generator *n, r*
$g_{n,r,t}$: dispatch of generator *n, r, t*
$c_{n,s}$: CAPEX of store *n, s*
$H_{n,s}$: capacity of store *n, s*
$o_{n,s}$: OPEX of store *n, s*
$h_{n,s,t}$: dispatch of store *n, s, t*
c_l: CAPEX of link *l*
F_l: capacity of link *l*
o_l: OPEX of link *l*
$f_{l,t}$: dispatch of link *l, t*

3. Results

The following section presents the results of all the optimisations. First, the results for scenario *base* are presented. Afterwards, they are compared to the *mediumflex* and *lowflex* scenarios. To gain a better understanding of the effects of single flexibilities and their influence on the system, the different flexibility options were examined separately at the end of this section.

Table 5
Central optimisation results for the German energy system for each scenario.

	unit	*base*	*mediumflex*	*lowflex*
battery expansion	GW	4.95	4.95	4.95
H2 store expansion	GWh	42.58	40.37	45.02
heat store expansion	GWh	7285.34	0.00	0.00
fuel cell expansion	GW	0.00	0.00	0.00
electrolyzer expansion	GW	20.78	6.12	6.48
methanisation expansion	GW	10.80	0.00	0.00
renewable generation	TWh	606.42	570.40	553.93
grid expansion	TW*km	11.08	9.86	13.80
system costs*	10^9 EUR/a	37.15	37.32	37.81
investment costs**	10^9 EUR/a	1.46	0.63	0.71
marginal costs***	10^9 EUR/a	35.69	36.69	37.10
CO_2 emissions****	Mio. t CO2	515.94	528.42	530.16

* Incl. investment and marginal costs.
** Annualised, incl. electrical grid, storage, and hydrogen infrastructure expansion.
*** Incl. fuel, VOM, CO_2 costs and costs for transnational energy trading.
**** Incl. neighbouring countries.

3.1. Scenario base

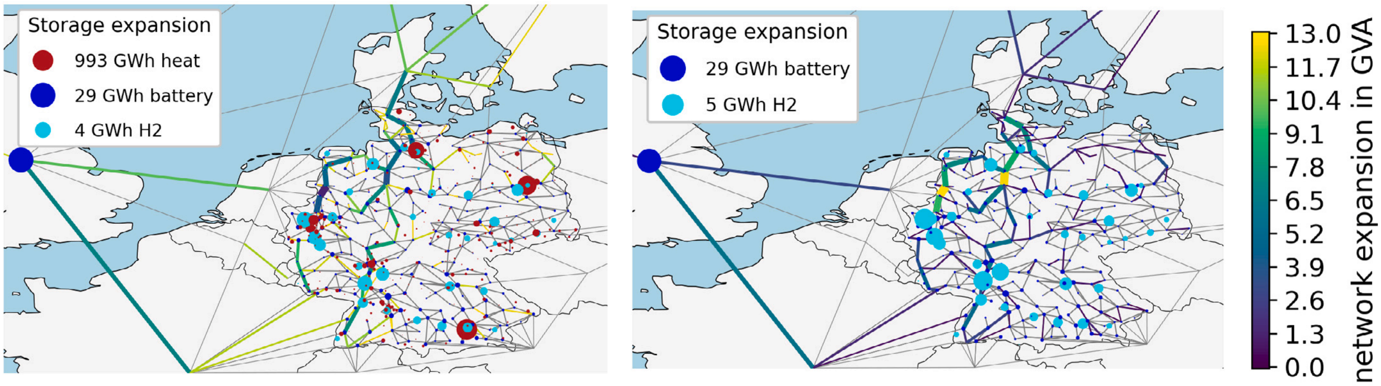
In scenario *base* including all available flexibility options, the system costs (equation (1)) are the lowest of all three scenarios (see Table 5). Expanded transmission lines are mostly located in the north of Germany, especially close to connection points of German wind offshore parks. Transmission lines are expanded up to 11.7 GVA in the northwest. The expansion of transmission lines and stores is visualised in Fig. 3.

Heat stores are built in nearly every DHG, especially large cities such as Berlin and Munich are equipped with high heat store capacities. Compared to the overall heat store capacity of 7,285 GWh, hydrogen store capacities are significantly lower (43 GWh). Hydrogen stores are mainly built as overground tanks, the optimised capacity of salt cavern stores for hydrogen is negligibly low (<1 MWh). Battery capacities in Germany are not expanded and remain at the lower limit of PV home batteries according to the GDP [16].

Electrolysis is located at grid nodes with large capacities of renewable generation (wind offshore in the North, hydro in the South) or large industrial hydrogen demands (Fig. 4). For example, the highest capacity of electrolysis is built close to Hamburg which is close to renewable energy plants and industrial demands. Fuel cells are not expanded to a significant extent. The main hydrogen consumer in Germany with about 65 TWh is methanation feeding the processed hydrogen into the methane grid.

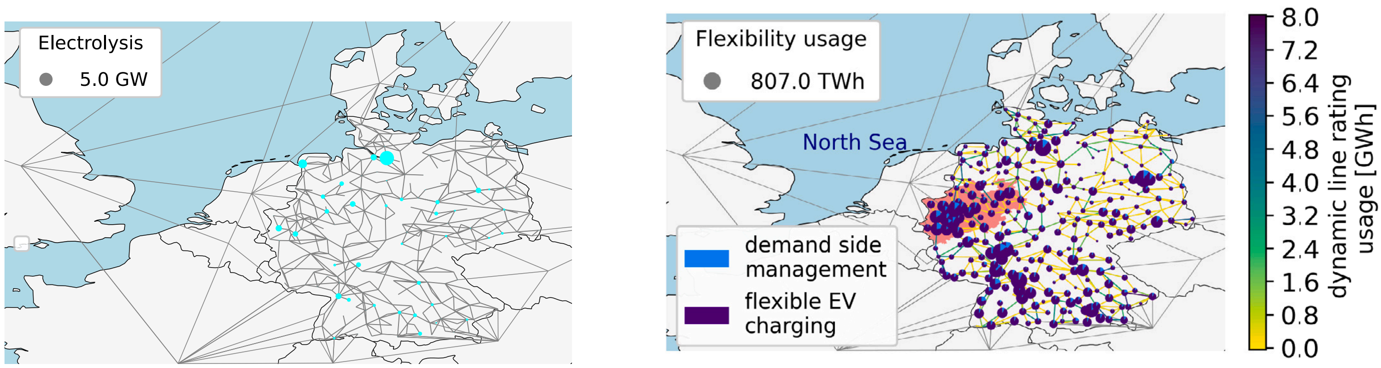
The spatial distribution of flexible EV charging, DSM and DLR deployment over the year is visualised in Fig. 4b. It indicates that their usage is driven by their potential as well as renewable energy production and high demand areas. In regions with high flexibility potentials for DSM and flexible EV charging, also more deployment can be observed. Hence, utilisation is high in western Germany where a high amount of demand is located. The largest DLR potential is in the north and northeast regions of Germany. However, lines connecting regions with large renewable capacities to those with high demands, such as lines between wind parks in the North Sea and North Rhine-Westphalia (marked in red), show significant use of DLR.

The dispatch of heat and methane stores (Fig. 5) shows seasonal behaviour, those are mostly charged during summer and discharged in winter. The abrupt charging of heat stores in autumn is the result of a high dispatch of wind turbines. In contrast, hydrogen stores are charged and discharged frequently over the year and are not used as seasonal flexibility (Fig. 6). The dispatch pattern of hydrogen stores is driven by the feed-in of fluctuating renewables and industrial hydrogen demands. Hydrogen used for methanation is not temporarily stored in hydrogen



(a) *base* (b) *lowflex*

Fig. 3. Expansion of electricity grid and storage units. The line widths and colours show the expanded capacities of transmission lines. Storage expansion per technology is shown by the size and colour of circles.



(a) Optimised electrolysis capacities (b) Dispatch of electric flexibility options; red: North Rhine-Westphalia

Fig. 4. Spatial distribution of flexibility deployment in scenario *base*, showing installed capacities of electrolysis in (a) and demand side management, dynamic line rating and flexible EV charging in (b).

storages but directly converted into methane, as huge methane store capacities are available. The use of one exemplary heat and one hydrogen store near Hanover is shown in B.10.

DLR potential has a seasonal pattern, it is higher in winter and autumn and lower in summer (Fig. 5). The usage of the additional transmission capacities is significantly lower than the overall potential, as suitable weather conditions must occur in combination with flexibility needs, which is not the case for all transmission lines (Fig. 4). There is a correlation between the seasonality of DLR potential and usage as high wind speeds not only increase the DLR potential but also the feed-in of wind energy.

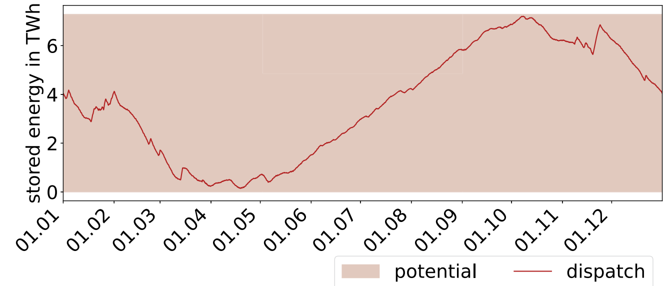
DSM and flexible EV charging are frequently used as a short-term flexibility option. Fig. 6 visualises the potential and dispatch of these flexibility options in Germany in the first two weeks of the year, showing that the available flexibility is fully exploited frequently. The dispatch correlates to prices of electrical energy - when the costs are high, DSM and flexible EV charging allow to reduce the demand by postponing to time steps with lower energy costs (as seen in B.9). Battery dispatch is sensitive to price changes, small cost changes result in abrupt (dis-)charging.

Fig. 7 presents a duration curve illustrating the utilisation of the considered flexibility options in Germany throughout the year. The percentage of hours in which each option is dispatched is shown. Heat stores exhibit the highest amplitude in both positive and negative directions. However, a substantial amount of energy is only shifted during a limited number of hours (less than 10%). Flexible e-mobility charging is employed more than 50% of the year in both directions, with a maximum use of approximately 9 GW. Hydrogen can shift up to 6 GWh in one hour, but a significant amount of the shifted energy is limited to approximately 20% of the hours. The smallest flexibility option is DSM, which can shift a maximum of 2 GW.

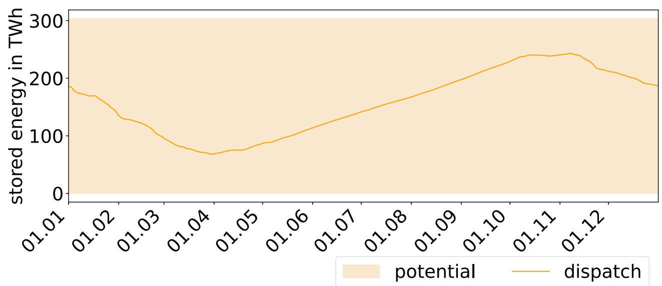
3.2. Scenarios mediumflex and lowflex

The main difference between the *base* and *mediumflex* scenario is the option to invest in heat stores and methanation plants in the *base* scenario since the option to expand hydrogen salt caverns and fuel cells is not used. This results in savings of about 171 million Euro for the German energy system (investment and operation) per year. The higher costs in the *mediumflex* scenario are driven by higher operational costs for using conventional energy in the electricity and heat sector. Investment costs are lower since no investments in heat stores and methanation plants are made. The capacity of electrolysis is decreased by around 70% compared to the *base* scenario since the main hydrogen demand (methanation) is not available. The capacity of hydrogen stores is 2 GWh higher in *mediumflex*, their spatial distribution shows that especially the ones close to hydrogen demands reach high capacities. In the *mediumflex* system, the heat supply is less flexible and depends more on conventional gas. This not only results in rising system costs but also in 12.5 million tons higher CO_2 emissions. Heat stores in *base* increase the utilisation of geothermal and solar thermal plants.

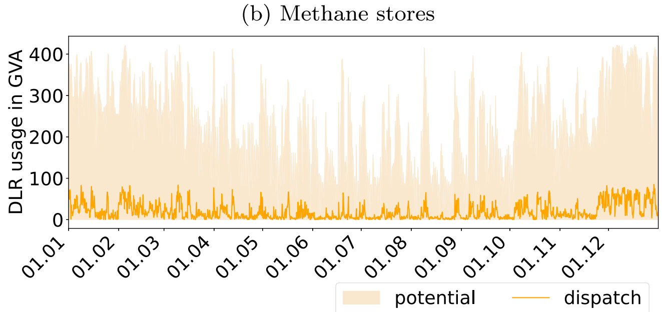
In scenario *lowflex* with the lowest penetration of flexibility options, the annual system costs in Germany are about 661 million Euro (2%) higher compared to the *base* scenario. This difference is caused



(a) Heat stores

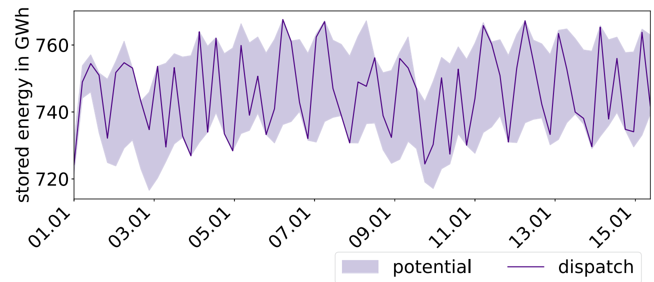


(b) Methane stores

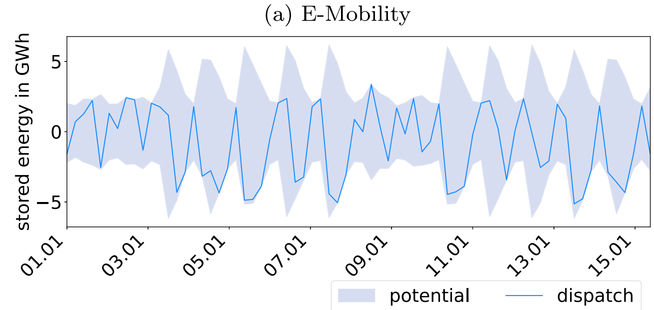


(c) Dynamic line rating

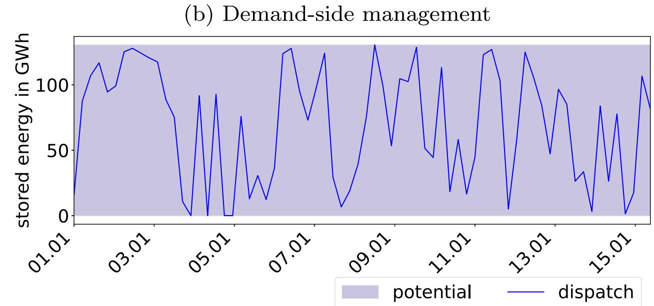
Fig. 5. Potential and optimised dispatch of long-term flexibility options in Germany during the year.



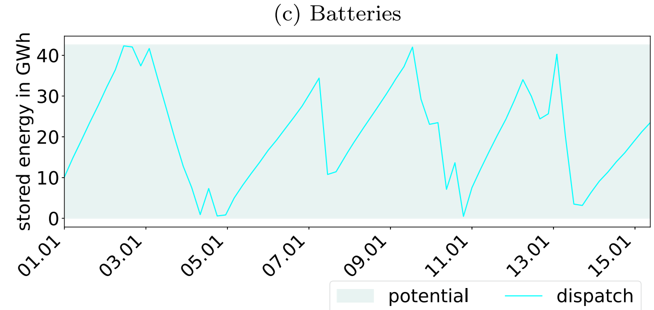
(a) E-Mobility



(b) Demand-side management



(c) Batteries



(d) Hydrogen stores

Fig. 6. Potential and optimised dispatch of short-term flexibility options in Germany in the first two weeks.

by higher operational costs for dispatching conventional energy. Renewable energy's dispatch in the national electricity and heat sector is reduced by 52 TWh. The overall investment costs in scenario *lowflex* are about 0.7 billion Euro per year lower due to fewer investments in stores and methanation, whereas investments in grid expansion are higher.

The need for grid expansion is higher with fewer flexibility options. In comparison to *base*, grid expansion is needed in the same regions (see Fig. 3), but lines are expanded more. Some lines from the west to the east only need to be extended when there is less flexibility. The installed capacity of electrolysis is 70% lower in scenario *lowflex*. This is driven by the missing option to build methanation as the pure hydrogen demand in a 2035 system does not trigger the expansion of larger electrolysis capacities.

The distribution of remaining extendable hydrogen and battery stores is comparable to the *base* scenario. There are some more and larger hydrogen store capacities built, but hydrogen stores do not replace heat stores, so the overall storage capacity is significantly lower. The usage of these stores is comparable to the other scenario, hydrogen stores still do not provide additional seasonal flexibility.

The CO_2 emissions in all considered countries can be reduced by about 14 million tons per year (3%) when the German energy system has access to flexibility options.

3.3. Sensitivity analysis

The influence of every single flexibility option was examined as a sensitivity analysis. Therefore, each flexibility that is not considered in the *lowflex* scenario is added separately to the *lowflex* scenario (ceteris paribus). The availability of flexible EV charging, heat stores, DLR and methanation in descending order have the highest cost reduction potential for the overall system compared to the *lowflex* scenario as it can be seen in Fig. 8. The influence of DSM is significantly lower and the effects of available hydrogen salt cavern stores and fuel cells are negligibly small. Savings that can be achieved by adding multiple flexibility options in the scenarios *base* and *mediumflex* are significantly higher than adding only one flexibility option. The cost savings occur to varying degrees in Germany and the overall system, depending on the technology studied. An extreme example is methanation, which generates additional costs in Germany but leads to remarkable cost savings for the overall system. Additionally, Table C.6 in the appendix shows that the different options affect renewable generation, grid expansion needs and CO_2 emissions to different degrees.

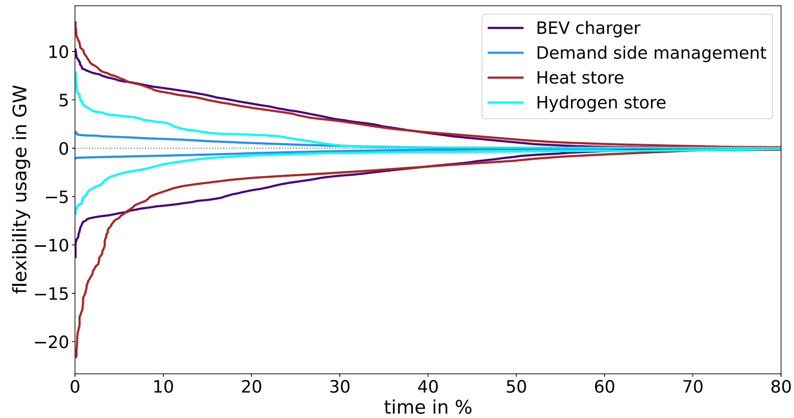


Fig. 7. Technology specific duration curve of flexibility usage throughout the year.

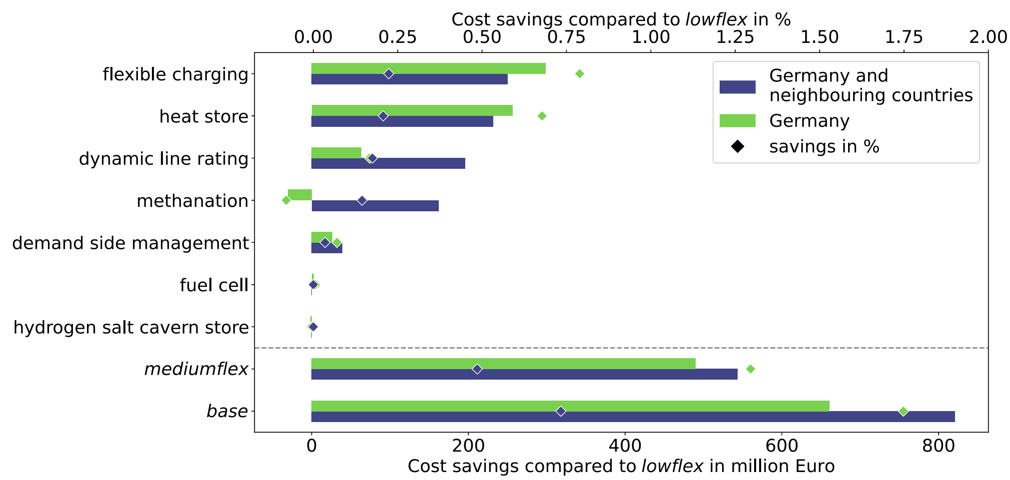


Fig. 8. Absolute (bars) and relative (points) savings of system costs in Germany and the overall system for each flexibility option, *base* and *mediumflex* are added for comparison.

4. Discussion

The results show that the *base* scenario with the highest flexibility potential has economic and ecologic advantages. The system costs include higher investment costs which are also beneficial for future years when an increasing share of renewable energy might lead to higher expansion needs of the grid infrastructure. The *mediumflex* scenario with less seasonal flexibility potential results in less decarbonisation, especially in the heat sector. The higher usage of conventional energy also leads to a less future oriented system. With reduced seasonal and short-term flexibility in the *lowflex* scenario, the system costs are even higher and the usage of renewable energy is limited. The additional sensitivity analyses underline the significance of flexible EV charging, heat stores and DLR to reduce system costs. Especially methanation and DLR enable higher shares of renewable generation in comparison to the *lowflex* scenario. Overall, the picture emerges that the various flexibilities are not much in competition with each other, but are an important complement to each other in driving forward the energy transition.

The results are first discussed with regard to the input data and methods. Subsequently, the results are compared to other studies.

As it is the case for every energy system model, assumptions had to be made concerning technical and economic parameters. The modelling results can be very sensitive for specific parameters, therefore comprehensive sensitivity analyses would be necessary but are not part of this study. Additionally, the development of energy systems relies on national and international policies and regulations which are not completely predictable. Therefore, the results should not be seen as a definitive outlook on the future, but rather as a possible development. Conclusions from the results should be drawn from the comparison between the individual scenarios rather than considering each result on its own.

Even in the scenario *base* with the most flexibility options, flexibility potentials are limited using conservative assumptions. Flexible charging infrastructure for EV could be extended to other options besides private charging to increase the flexibility potential. Another major leverage is the implementation of vehicle-to-grid which is not available in the model. DSM is only considered for selected industrial processes and CTS, whereas DSM for private household appliances implying the highest potential (according to [35]) is not taken into account. Besides, the actual technical potential for DLR is likely higher than assumed in the GDP [16]. However, regarding the scenario year 2035, it is a reasonable assumption that flexibility options have not yet been fully implemented.

The high complexity of the original model requires complexity reduction which comes with the drawback of losing accuracy. Within the spatial complexity reduction, the network topology is changed and bottlenecks within a cluster are neglected. Nevertheless, sufficiently high accuracies are expected as the depiction of the original network with the method used in this work has turned out to be comparably accurate [61]. In addition, flexibility options are summarised per technology. In case of EV this for example results in aggregated battery capacities allowing mutual charging (exchange between BEVs connected to the same node). However, compared to other modelling approaches (e.g. in [7]), the resulting uncertainty is significantly reduced by additional constraints as well as by rather conservative assumptions on flexibility potentials. Nevertheless, this also affects DSM, heat and battery stores and the remaining error can not be quantified within this work. The temporal complexity reduction smoothes out peaks from the time series or by randomly selecting peaks overestimates their duration. While this may not have a significant impact on overall results, there may be local differences for specific time periods. In particular, optimising dispatch for each hour of the year could enhance the use of short-term flexibility options. All in all, the chosen complexity is high compared to other works (e.g. [9,10]). Furthermore, former works show that the chosen methods and the chosen resolutions are reasonable ([65,61]). Nevertheless, the need to quantify the uncertainties evolving from complexity reduction remains.

The general model design influences the results of the different calculations. One critical aspect is the decision on exogenous and endogenous variables. In this study, only flexibility options which require the construction of large capacities are part of the investment optimisation, whereas other options (DSM, EV charging and DLR) are provided at no costs. This was done to lower the model complexity assuming that accessing these flexibility options is much less expensive and probably even part of the legal framework of future energy systems. However, it needs to be considered when comparing the resulting system costs of the different scenarios. The annualised investment costs to install and the yearly costs to maintain the DSM components needed to provide the flexibility potential given in the *base* scenario are around 7.22 million Euro according to [35]. Costs for installing DLR at every overhead transmission line in Germany are around 172.4 million Euro per year, considering costs from [66]. Building the considered private EV charging infrastructure for bi-directional and flexible charging would add up to 223 million Euro using cost assumptions from [67]. Costs for uni-directional controlled charging are lower but were not available. The costs for each of this flexibility are lower than the savings in system costs can be achieved by adding them separately, which indicates that these investments would have been made also if they had been subject to optimisation.

This study analyses the impact of flexibility options for the year 2035 when the system is not completely decarbonised. It is very likely that the advantages of flexibility options will increase towards a completely decarbonised system as increasing penetration of sector coupling and digitalisation makes additional flexibilities accessible. At the same time, more and especially more seasonal flexibility is needed when less conventional flexible generation is available. Furthermore, new technologies, demands and infrastructures (e.g. synthetic fuels for aviation or hydrogen grid) will be needed in a 100% renewable system. Studies such as Neumann et al. show that the construction of a hydrogen transport infrastructure offers potential for system cost reduction in a fully decarbonised energy system [68]. Even though the named technologies will be relevant in long-term scenarios, they are not part of the mid-term scenario considered here.

According to the findings, hydrogen is not a significant support to the electrical grid, but it can aid in decarbonising the gas and heat industry through methanation. Methane is more prevalent in the gas sector as existing methane storage facilities are present in the system at no additional costs in contrast to hydrogen storage. Additionally, the assumed demands for methane in a system for the year 2035 are higher than the hydrogen demands which will change in a fully decarbonised system. The lack of underground hydrogen storage facilities can be attributed to the absence of hydrogen demand at those locations and to the absence of a hydrogen network in this mid-term scenario. Although the hydrogen produced there could serve as pure electricity flexibility, it is not utilised due to its relatively low efficiency and high costs.

The findings indicate that heat stores are predominantly installed in DHGs. Although they can not support the electrical grid directly, the low investment costs lead to a high expansion and frequent usage. Nearly all heat store capacities are located in DHGs, investment costs for individual supplied buildings are higher and since only a minority of houses are equipped with individual heat pumps, the potential is much lower. The maximum size of a DHG store was not limited, the largest store in Munich reaches capacities over 800 GWh in scenario *base*. Even if this could also represent multiple smaller storage units, local feasibility must be examined.

This study indicates that flexibility options of all energy sectors can decrease system costs by up to 661 million Euro per year and CO_2 emissions by up to 14 million tons. The feed-in of renewable energy can be increased and curtailment decreased by using flexibility options for all sectors. Although these are significant savings, the differences in percentage are not very high. The main reason for that is the fact that a mid-term scenario for the year 2035 is calculated where there still are relatively high restrictions on flexibility usage and remaining conventional power plants in Germany and its neighbouring countries.

The importance of flexibility options, especially in the heat sector, can also be observed in other studies. Bernath et al. analyse a 100% renewable system in Germany where flexibility options allow higher shares of renewable energies and reduce gas consumption and flexible district heating has a high impact on their results [69]. Also Strbac et al. state that flexibility options can reduce system costs and increase renewable feed-in, they conclude that especially combined planning of heat and electricity system is needed. Nebel et al. analyse a German energy system in 2030, identifying the heating sector and batteries as the most important flexibility options in a mid-term system [11]. The hydrogen sector does not have a large impact on the system, which is comparable to the results of this study.

In comparison to the results of the German transmission grid plan [16], the overall need for grid expansion is significantly lower. This is caused by different input parameters (e.g. capacities of the existing grid) and the fundamental difference of a two-step methodology (separated market and grid simulation) with heuristics for grid expansion and the integrated dispatch and expansion optimisation in the GDP [16]. Additionally, the present work only allows to expand the capacity of already existing lines and does not consider the development of new lines. However, the routes of lines with expansion needs in this study are similar to expanded lines in the GDP [16] (e.g. the north-south connection *Süd Link*).

5. Conclusion and outlook

This study presents data and optimisation methods to model the German transmission grid for the year 2035 considering demands, supply and flexibility options from the electricity, gas, heat and mobility sector. Three scenarios with different penetrations of flexibility options were analysed to quantify the economic and ecologic benefits of flexibility options to the overall energy system.

The presented work indicates that flexibilities arising from the coupling of different sectors to the electricity sector, as well as additional electrical flexibility options (such as DSM or DLR), do clear the way for the integration of renewable energy production and hence lower CO_2 emissions already in a mid-term scenario. Furthermore, system costs (investment and operation) are lowered due to the improved utilisation of comparatively cheap renewable energy production.

Flexibilisation of heat systems, especially by stores in DHG, significantly reduces system costs and CO_2 emissions. Furthermore, electric flexibility options (DSM and DLR) and flexible charging of EV can support the grid and increase the share of renewable energy by creating only comparatively low investment costs.

The results allow analysing regional difference: Grid and electrolysis expansion and the usage of DLR is mainly driven by renewable feed-in. DSM and flexible charging of EV are limited by regional flexibility potential. Heat stores are expanded to high capacities, especially in big cities with large DHGs.

Further sensitivity analysis can improve the validity of the results, but are not part of this study due to high computational effort and limited resources. It is planned to further analyse the effect of clustering methods as well as modelling assumptions regarding flexibility options.

The advantages of flexibility options are likely stronger in a completely decarbonised system where most likely also the need for hydrogen will change.

In the future, the presented data and methods will be used to model 100% renewable systems allowing to investigate this. Unlike the present work, this one will also consider the future construction of a hydrogen network and its impact on the overall system. In addition, the presented results will not only be used to quantify the need for grid expansion and flexibility options in the German transmission grid but also in underlying distribution grids. Further research and improvements are simplified by open source and open data principles, which increase transparency and allow other researchers to use and update existing data and methods.

CRediT authorship contribution statement

Clara Büttner: Conceptualization, Methodology, Software, Visualization, Writing – original draft, Writing – review & editing. **Katharina Esterl:** Methodology, Software, Writing – original draft, Writing – review & editing. **Ilka Cußmann:** Methodology, Software, Writing – original draft, Writing – review & editing. **Carlos Andrés Epia Realpe:** Methodology, Software, Writing – original draft. **Jonathan Amme:** Methodology, Writing – original draft. **Amélia Nadal:** Methodology, Writing – original draft.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The result data used for this work can be obtained at https://zenodo.org/records/10160482 [70].

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Appendix A. Acronyms

BEV	battery electric vehicle
CHP	combined heat and power plant
CTS	commercial, trade and service
COP	coefficient of performance
DHG	district heating grid
DLR	dynamic line rating
DSM	demand-side management
EV	electric vehicle
FCEV	fuel cell electric vehicle
HDT	heavy-duty transport
HVMV	high voltage/medium voltage
LNG	liquefied natural gas
LOPF	Linear Optimal Power Flow
MaStR	Marktstammdatenregister
MIT	motorised individual travel
MVGD	medium-voltage grid district
GDP	grid development plan
NUTS	Nomenclature des unités territoriales statistiques
OCGT	open cycle gas turbine
OSM	OpenStreetMap
Peta	Pan-European Thermal Atlas
PHEV	plug-in hybrid electric vehicle
PV	photovoltaic
SLP	standard load profile
SMR	steam methane reforming
SoC	state of charge
TYNDP	Ten-year network development plan

Appendix B. Results for node near Hannover

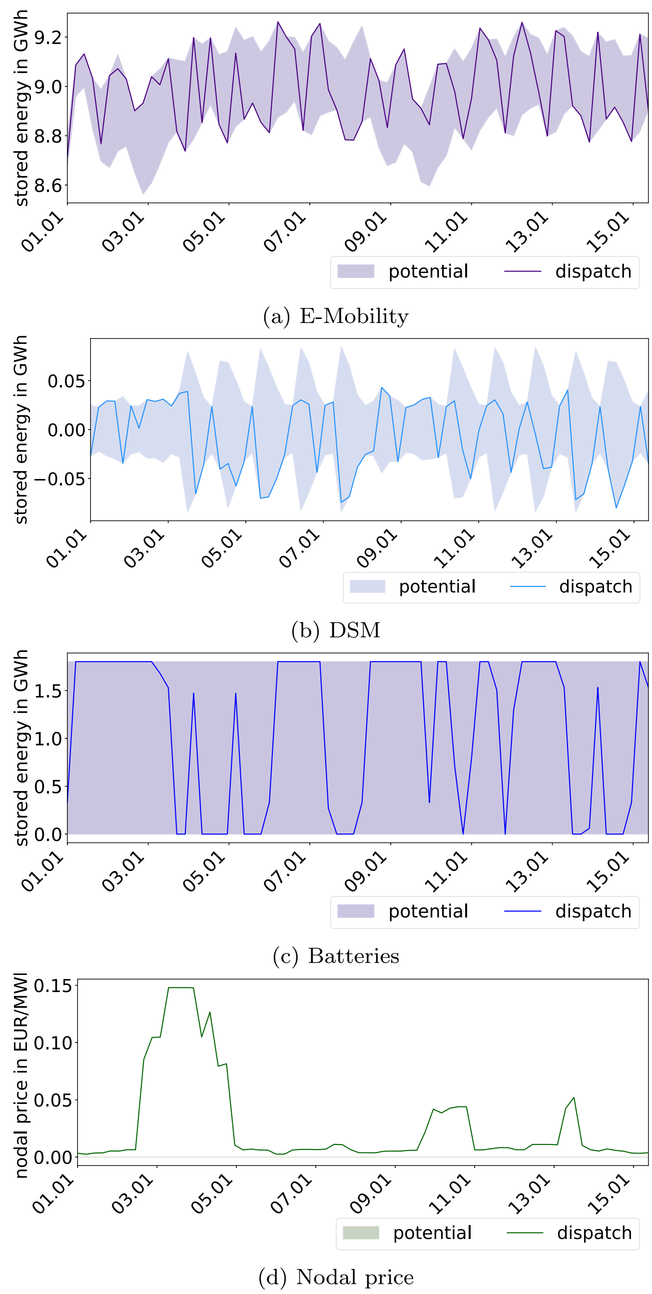
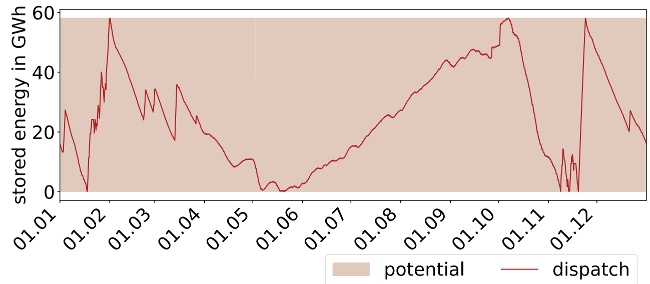
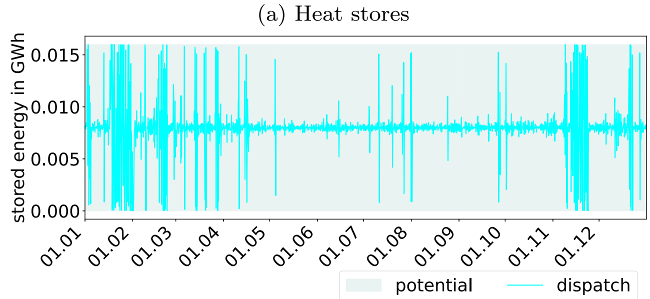


Fig. B.9. Potential and dispatch of short term flexibility options at a bus near Hannover.



(a) Heat stores



(b) Hydrogen stores

Fig. B.10. Potential and dispatch of long term flexibility options at a bus near Hannover.

Appendix C. Results of sensitivity analysis

Table C.6
Central results of sensitivity analysis.

		lowflex	demand side management	heat store	dynamic line rating	flexible charging	methanation
battery storage	GWh	4.95	4.95	4.95	4.97	4.95	4.95
H2 store	GWh	45.02	43.49	43.46	44.44	39.48	47.49
heat store	GWh	0.0	0.0	7653.40	0.00	0.00	0.00
fuel cell	MW	0.0	0.00	0.00	0.00	0.00	0.00
electrolyzer	GW	6.48	6.42	6.43	6.31	6.24	21.36
methanisation	GW	0.0	0.0	0.0	0.0	0.0	11.13
renewable generation	TWh	553.93	554.26	557.74	570.28	555.85	600.13
costs overall	10^9 EUR	111.93	111.89	111.70	111.73	111.68	111.77
costs Germany	10^9 EUR	37.81	37.79	37.56	37.75	37.51	37.84
CO_2 emission	10^6 tons	530.16	530.01	527.95	529.74	529.17	519.24

* Fuel cell and salt cavern results do not differ from lowflex and are therefore not listed.

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