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Impact of sector coupling on the market value of renewable energies – A model-based scenario analysis

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HIGHLIGHTS

- Analysis of flexibility in the electricity sector offered by sector coupling.
- Efficient sector coupling can substantially increase the market value of RES.
- It is essential to increase electricity load during periods of high RES feed-in.
- Short-term flexibility through load shifting has only a minor influence.
- Flexible electric district heating significantly increases the market value of RES.
- Flexible electric vehicles and heat pumps only marginally affect the market value.

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ABSTRACT

Decarbonizing the energy supply by substituting fossil fuels with renewable energy sources (RES) is a key task for the coming decades in order to achieve the EU's ambitious climate protection targets. Information about the possible development and marketability of RES in the electricity sector is essential for assessing future funding needs. However, rising shares of fluctuating RES generation in the energy system reduce the average market prices and increase price volatility. Balancing price variations requires a considerable degree of flexibility. Additional flexibility in the electricity market through closer interconnection between the electricity sector and other demand sectors makes it possible to keep the market values of RES closer to the general market price level, irrespective of their shares. Such sector coupling can thus contribute to a cost-efficient transition to a low-carbon energy system. This paper examines the impact of efficient sector coupling on the market values of RES in a European energy system with ambitious decarbonization. We analyze different scenarios by applying the Enertile model, which uses an integrated cost optimization approach with flexibility options due to sector coupling and provides a detailed future development of RES. In our analysis, we examine three flexibility options: smart charging of electric vehicles, decentralized heat pumps in buildings, and multivalent district heating grids. We show that the flexible use of electricity in district heating has a significant impact on market values, while the impact of both flexible electric vehicle charging and flexible heating with heat pumps is rather small. Short-term flexibility due to load shifting of the charging or heating process shows only a limited effect on market values. Fuel switching in district heating, however, offers the possibility to change the absolute demand for electricity in direct response to RES feed-in and drastically reduces the curtailment of RES.

1. Introduction

Climate change requires decisive measures to counteract an increase in global warming and its future effects. The European Union (EU) aims to be climate-neutral by 2050, which means achieving net-zero greenhouse gas (GHG) emissions. This ambitious goal reaffirms the EU's commitment to limiting the global temperature increase to well below 2 °C as stipulated in the Paris Agreement of 2015 [1]. In this context, the European Commission has developed a strategic long-term vision exploring pathways to a climate-neutral economy [2]. Furthermore, the European Commission is legally embedding the objective of climate neutrality in 2050 in the European Green Deal, which constitutes a

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roadmap for a sustainable EU economy [3]. Accomplishing this transition represents an urgent challenge encompassing policies and measures in all sectors, such as energy, industry, transport, agriculture and forestry. In this fundamental transformation process, however, the decarbonization of energy supply is attributed a crucial role, as it is responsible for a large share of GHG emissions. Beyond energy efficiency, the substitution of fossil fuels with renewable energy sources (RES) is essential to reduce and mitigate emissions. Hence, the comprehensive electrification of the energy system combined with RES expansion is a promising solution for a low-carbon energy transition. However, this increases the pressure on the electricity sector to ensure a secure, affordable and sustainable electricity supply that is low-carbon in the short term and carbon–neutral in the long term. Under these conditions, a key task in the coming decades is the integration of increasing shares of RES in the electricity sector. In order to achieve this, greater flexibility in the electricity sector is required. While electricity storage or grid expansion provide flexibility within the electricity system, closer interconnection with other demand sectors can provide additional flexibility through load shifting or load shedding, including the use of non-electric energy storage. Such so-called sector coupling can support the integration of fluctuating RES into the energy system and thus contributes to a cost-efficient transition to a low-carbon energy system and to meeting climate protection targets.

In the EU, the share of energy from RES in gross electricity consumption rose from 14% in 2004 to 32% in 2018, which demonstrates that the carbon intensity of electricity supply has already decreased considerably [4]. Currently, support schemes often promote the integration of RES into the electricity system. In order to assess future funding requirements, information about the potential development and marketability of RES in the electricity sector is essential. In general, their long-term competitiveness depends not only on the future development of their specific electricity production costs, but in particular on their revenue potential on the electricity market. Market values often serve as an indicator of RES revenues on the electricity market. However, due to the low marginal costs of RES, their feed-in has the effect of lowering the exchange price on electricity markets. This correlation is known as the *merit order effect* and has been studied extensively [5–14]. In contrast to conventional generation or controllable RES, wind and solar energy can only respond to high or low market prices to a limited extent because of their limited feed-in controllability. Consequently, the market values of these RES will develop differently compared to the general market price level. Furthermore, for fluctuating RES such as wind and solar energy, the market values tend to sink as the share of RES increases [15–18]. Therefore, increasing the share of RES in the electricity system in order to achieve climate protection targets can undermine their profitability.

Many studies examine the influence of various factors on the market values of RES. While some focus on the impact of market design and support schemes [19–24], others asses the influence of the portfolio, must-run requirements, and ramping times of conventional power plants [16,21,22,25]. The findings reveal that an increase in storage capacity and interconnector capacity has positive effects on prices and market values [16,17,21,22,26–33]. In addition, CO_2 and fuel prices have a large influence and a positive impact on the development of market values [7,16–18,21,28,34]. Some studies determine an optimized portfolio of RES by diversifying the technology mix in order to smooth the feed-in of variable RES [10,16,28,30,35–38]. Furthermore, different technical characteristics or technological design properties like the hub height of wind turbines or the orientation of solar modules can influence the market revenues [25,28,39–44]. Geographical diversity and the interdependencies of site locations and their effect on market values are also investigated [29,30,34,36,40,45–48]. Several studies find that rising shares of variable RES generation lead to higher electricity price volatility as the residual load is more volatile than demand [20,49–51]. To counteract price fluctuations and to balance deviations, the electricity market must react quickly to changes in electricity demand and supply. This requires significant provision of flexibility to integrate the fluctuating RES generation [18,24,35,52–55]. Some analyses find that demand-side flexibility supports a positive future development of market values [20,21,29]; others conclude that the availability of flexibility options, especially heating grids and electric mobility, is more relevant for the development of market values with higher market shares [18,56]. Kirkerud et al. [57] find that linking the electricity sector with the heating sector via power-to-heat can increase the market values of RES in the Northern European power system. Bernath et al. [58] examine the impact of sector coupling on the market values of RES and also show that flexible district heating with electricity-based heating options has a major influence on market values in Germany. Consequently, additional flexibility in the electricity market and stronger linkages between the electricity sector and other demand sectors can help to keep the market values of RES closer to the general market price, even if their shares increase. Under these circumstances, the need for subsidies for fluctuating RES could be significantly reduced.

To date, there has been no thorough comparative assessment of the impact of the additional flexibility in the electricity sector offered by sector coupling on the market values of RES in the European energy system. This paper aims to remedy this. There is a variety of modeling tools for energy systems with high shares of renewables, which differ with respect to modeling approach and methodology, temporal resolution and time horizon, geographical coverage, technological and economic characteristics, and objective of the application (compare for example [59–62]). To answer the central research question of this paper, a high temporal resolution, a detailed picture of renewable energy potential and generation profiles, a model-based description of various sector coupling options for the electricity sector, and the geographical coverage of Europe are of great relevance. Therefore, we use the energy system model *Enertile*, which optimizes the balance of supply and demand in the electricity system, district heating grids, buildings with heat pumps and the hydrogen economy for Europe with hourly resolution in one single cost minimization problem. Additionally, *Enertile* provides a detailed picture of the location-specific potential of solar and wind energy, for which capacity expansion is endogenously optimized. The integrated cost optimization approach used, which includes flexibility options using sector coupling as well as a detailed future development of RES, is well suited to illustrate the effects of sector coupling on the market values of RES. Due to its high technological and hourly resolution, *Enertile* can not only confirm existing findings but can also provide new insights into the relation between weather-dependent RES generation and the corresponding need for flexibility in the energy system. The analysis focuses on ambitious decarbonization scenarios for the European energy system to reflect the EU's ambitious climate protection targets. We use several scenarios to isolate the impact of individual sector coupling options on the market value of RES. The use of electricity based mainly on renewable energies in new applications in other demand sectors is often referred to as Power-to-X (PtX). Wietschel et al. [63] differentiate options for connecting energy sectors according to the conversion process: the direct use of electricity in Power-to-Heat (PtH) and Power-to-Move (PtM), and the conversion of electricity into synthetic fuels in Power-to-Gas (PtG) and Power-to-Liquid (PtL). In our analysis, we focus on flexibility through direct use of electricity in the heating and transport sector as these technology options are already common in the market today. The indirect use of electricity by the conversion into synthetic fuels, such as hydrogen or e-fuels, may play a role in the future, but is not yet well represented in the current market. Therefore, we examine the following three flexibility options: electric vehicles, heat pumps in buildings, and multivalent district heating grids using PtH.

The remainder of this paper is structured as follows. Section 2 describes our modeling approach. Section 3 introduces the scenario design and relevant data. Section 4 presents and discusses the results. Section 5 contains the summary and conclusions.

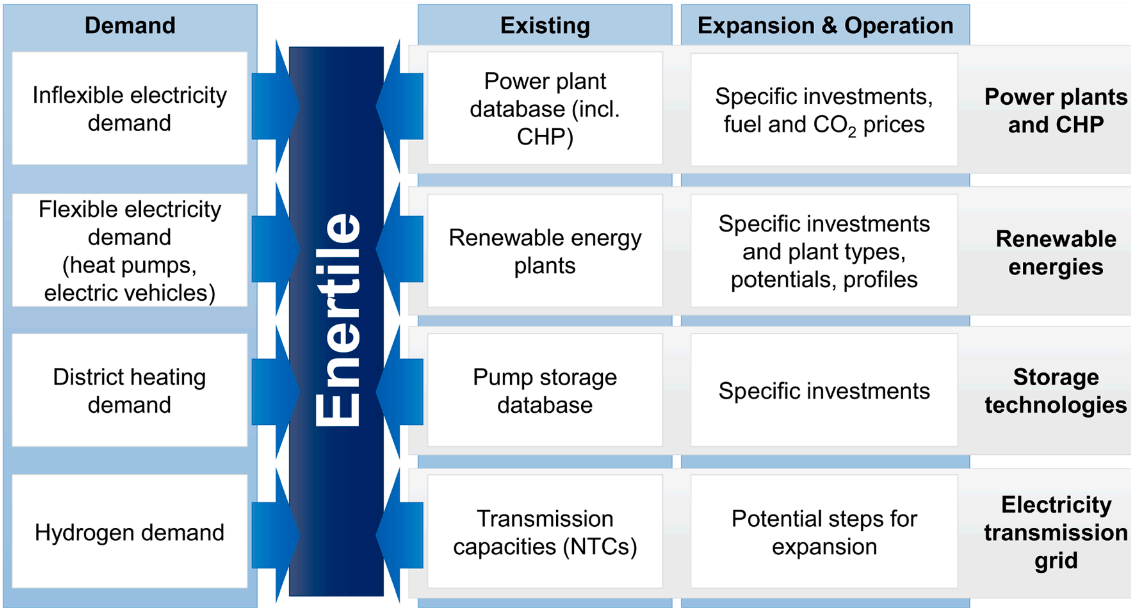

Fig. 1. General structure of the energy system model *Enertile*.

2. Methodology

In this paper, we examine the effects of additional flexibility provided by sector coupling on the market values of RES in Europe. We conduct a model-based scenario analysis using the energy system model *Enertile*. This approach explicitly models the supply of electricity, heat, and hydrogen including different options for sector coupling, with a high temporal and spatial resolution for solar and wind energy.

2.1. Energy system model Enertile

Enertile is a detailed techno-economic optimization model for energy systems, which minimizes the costs for energy generation, transmission and storage until the year 2050 [64]. Fig. 1 illustrates the general structure of the energy system model *Enertile*. It focuses on the electricity sector, but also covers interdependencies with other sectors like the heating and transport sector, and with the supply of hydrogen. The model simultaneously optimizes capacity expansion and hourly dispatch of all system components based on the exogenously specified demand for electricity, heating, and hydrogen. The modeled infrastructures include conventional power plants, renewable energy technologies, combined heat and power (CHP), cross-border transmission capacities, energy storage technologies, centralized heating technologies in district heating grids, hydrogen generation technologies and demand-side flexibility. The following briefly describes the most relevant characteristics of the *Enertile* model for this analysis. A more detailed description and the relevant equations of the linear optimization problem are found in [65–68]. Pfluger [65] presents the original electricity system model and [66–68] describe the extensions including the heat and hydrogen supply.

The **objective function** of the cost minimization problem contains all the costs caused by the modeled technologies and infrastructures. The decision variables of the linear problem are the installed capacities and their hourly dispatch. Therefore, incurred costs include fixed costs for the capacity expansion, and variable costs for their hourly operation. Fixed costs comprise discounted annualized investments as well as fixed operation and maintenance (O&M) costs. Variable costs comprise fuel costs including CO_2 costs and variable O&M costs.

The key **constraints** of the model ensure that the demand for electricity, heat, and hydrogen is met in every region and hour. These so-called demand–supply equations consider the inflexible demand (exogenously given) and the flexible demand (endogenously derived) for each modeled energy output of electricity, heat, and hydrogen. The interdependencies between different energy production and energy consumption variables from sector coupling options are integrated in the flexible demand. For example, electric heat pumps require a certain amount of electricity to produce one unit of heat. The heat generation variable of the heat pump in the heat supply equation and the electricity demand variable of the heat pump in the electricity supply equation are directly linked to each other by the pump's efficiency. Therefore, another set of constraints dictates that the energy required by a technology is directly related to the amount of energy produced and the efficiency of that technology's conversion process. Other constraints control that the hourly output of a production unit does not exceed its capacity, that electricity transmissions between regions do not exceed the maximum capacity of the respective grid connection, and that storages only operate within the limits of their technical configuration.

Enertile has a high **temporal resolution** with 8,760 h in each analyzed year. Especially for energy systems with high shares of fluctuating RES, the temporal resolution of the model is of particular importance. With this hourly resolution, extreme weather events like long calm or low wind periods are considered, and short-term weather-related fluctuations in the production of electricity or in heat demand are mapped. All the scenarios in this analysis depict one year, but *Enertile* also projects development paths for multiple years, which are optimized in a single model run using perfect foresight.

Enertile's **geographical coverage** comprises countries in Europe, North Africa, the Middle East, and China with its neighboring countries. Typically, each country represents one model region, but splitting or aggregating countries is also possible. For this analysis, the scenarios cover Europe including all current 27 member states of the EU plus Norway, Switzerland, and the United Kingdom, resulting in a total of 30 model regions.

The **electricity grid** is modeled for the transmission of electricity between different model regions using net transfer capacities (NTCs). Local grid restrictions within regions are not considered, as unlimited electricity exchange within a region is assumed. The transmission grid offers flexibility by providing opportunities for inter-regional balancing, which is particularly valuable when high shares of RES are present. The transfer capacities limit the possible electricity exchange between model regions, and the expansion of initial capacities is part of the optimization that takes into account the investments required as well as grid losses.

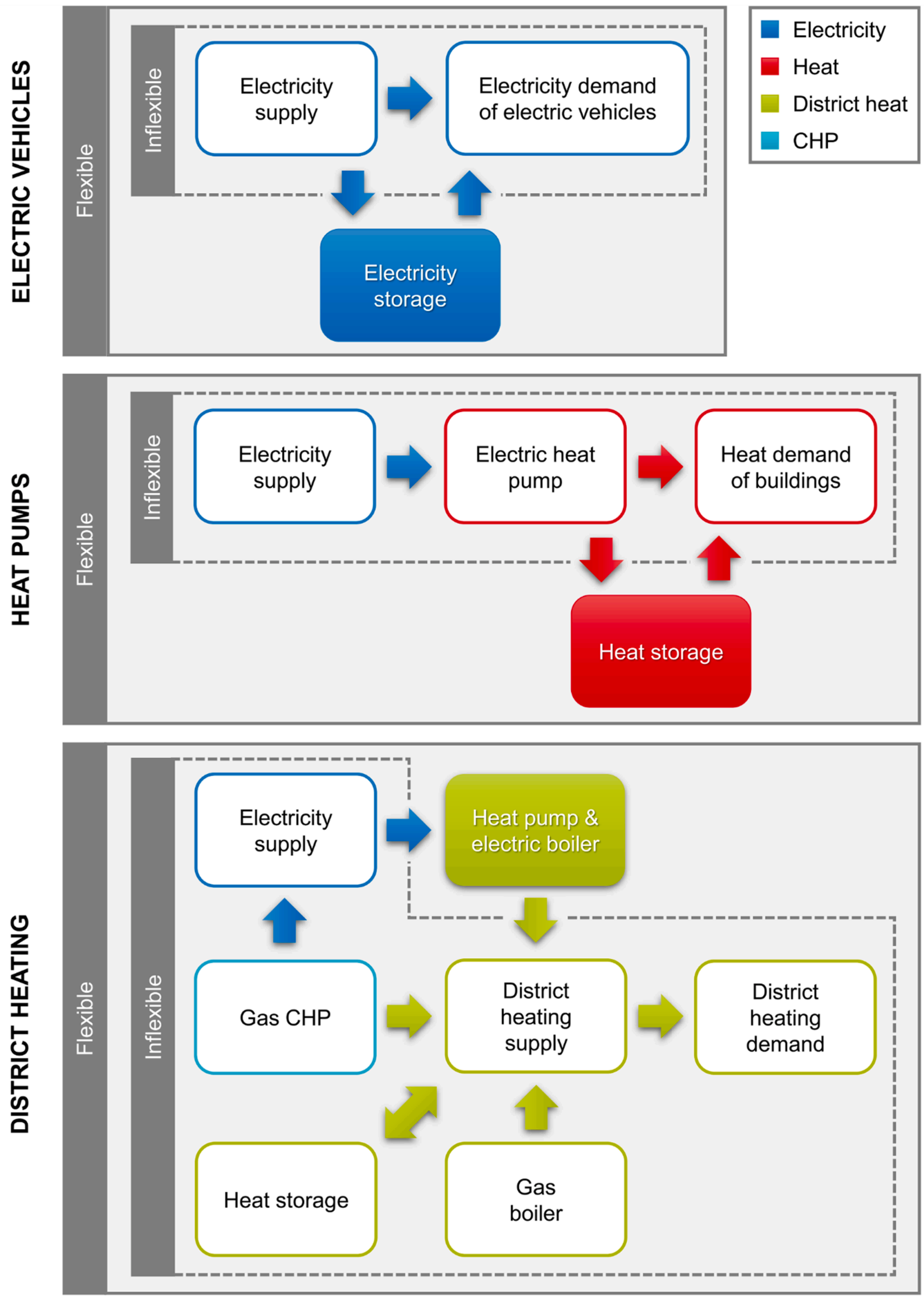

Fig. 2. Modeling the inflexible and flexible operation of electric vehicles, decentralized heat pumps in buildings, and multivalent district heating grids.

A more detailed spatial resolution is used to calculate the **generation potential of RES**. Five different technologies are distinguished: photovoltaics (PV), PV on rooftops, concentrating solar power (CSP), wind onshore, and wind offshore. The calculation is performed on an equiangular model grid, with the size of each tile varying between 10 km^2 and 100 km^2 depending on the latitude. Europe accounts for about 240,000 tiles. The electricity generation potential for the five technologies is determined for each tile. First, the available area in each tile is identified considering land use and terrain, and hourly weather time series of temperature, solar radiation, and wind speed from several weather years are transferred to the model grid. Using all these data, the possible long-term generation output, the installable capacity, and the specific generation costs are determined for each tile and technology. Due to the high number of variables, not every single tile can be included in the optimization of the power supply. For this reason, the technology-specific generation potentials are aggregated for tiles with comparable production costs within a region in the form of cost-potential curves, which are directly included in the optimization. A more detailed description of this calculation of potential can be found in [69]. The capacity and generation from other RES like biomass, hydro, and geothermal energy are mostly predetermined based on hourly profiles.

2.2. Modeling flexibility options

This paper examines three electrical applications modeled in *Enertile* as flexibility options: electric vehicles, decentralized heat pumps in buildings, and multivalent district heating grids. For each of these three flexibility options, we define a flexible and an inflexible operation mode for the analysis. Flexible operation offers the possibility to shift parts of the electricity demand over time or even change the total load. This demand shifting or load changing is not possible with inflexible operation. Fig. 2 shows the three analyzed flexibility options and their two different operation modes we describe in the following.

2.2.1. Electric vehicles

Total electricity demand increases strongly with the growing use of electricity in the transport sector. Assuming an intelligent charging infrastructure and sufficient incentives for customers to charge their vehicles variably, this additional electricity demand can be considered flexible to a certain extent. The load profile of the additional electricity demand as well as the potential flexibility in the transport sector are heavily dependent on the driving profiles and time slots for charging. In *Enertile*, different profiles are used that define charging times and necessary states of charge for specific times. For example, battery electric vehicles (BEV) and plug-in hybrid vehicles (PHEV) must be fully charged in the morning to allow their owners to commute to work. However, when they return home in the evening, the charging process does not necessarily have to start immediately. If the owners are willing to participate in smart charging, the charging process can be postponed to times when it is more cost-effective for the electricity system. The annual electricity demand of electric vehicles per country usually stems from specific and detailed models for the transport sector, which consider for example changes in the car fleet composition, total number of cars, and driving distances. Within *Enertile*, different driving profiles from Germany are used to derive the hourly demand from the annual values used as input. These German profiles are used for all countries, as this data is not available in sufficient detail for each specific country. For more details on linking *Enertile* with transport models, compare for example the SET-Nav project [69,70].

In this study, for **inflexible** operation of electric vehicles we assume that none of the vehicle owners participates in smart charging. This corresponds to a situation where electric vehicles charge immediately upon reaching a charging station with maximum charging capacity, without considering the current state of the electricity system. In this case, the predefined hourly electricity demand of the electric vehicles must be met immediately. In contrast, for **flexible** operation we assume that all vehicle owners use smart charging. This means that the electric vehicles are charged when it is most beneficial to the electricity system, still taking into account the defined driving profiles. This corresponds to modeling a temporary intermediate electricity storage that offers short-term flexibility through load shifting of the charging process of electric vehicles. The hourly state of charge of this intermediate storage is defined by predetermined minimum and maximum states of charge, the inflow from the electricity supply, and the outflow to the electric vehicles. Fig. 2 shows the two different approaches for modeling the inflexible and flexible operation of electric vehicles in this analysis. In reality, the proportion of participants in smart charging will always range between these two extreme cases. However, comparing these two boundary paths reveals the maximum effect due to the flexibility option in the analysis.

2.2.2. Decentralized heat pumps in buildings

A growing substitution of fossil heat generation by electric heat pumps also leads to an increase in total electricity demand. By using heat storages and controlled charging of these storages, the additional electricity demand is at least partially flexible. In *Enertile*, a decentralized heat pump system comprises a building with a defined heat demand, a heat pump and a heat storage. The building type, the insulation standard, and the architecture determine the annual heat demand of the building. The hourly heat demand depends on ambient temperature, specific transmission and ventilation losses, and internal and solar heat gains. The efficiency of heat pumps depends on the temperature of the heat source and the flow temperature of the heating circuit. The modeled heat storage in *Enertile* consists of the storage capacities of the building itself and that of a hot water storage in the heating system with certain heat losses. This approach takes into account direct effects on the electricity system including the possible use of excess RES generation and the costs of additional electricity generation in the case of high electricity demand and low renewable electricity generation. The annual demand of heat pumps per country typically results from specific and detailed models for the building sector, which take into account for example country specific building stocks, refurbishment measures, and different technological options for heating. Within *Enertile*, the country-specific hourly heating demand is determined primarily based on hourly temperature data for the individual countries. For more details on linking *Enertile* with building-stock models, compare for example the SET-Nav project [69,70].

In this study, we distinguish between controlled and uncontrolled heat generation of electric heat pumps. We model these two operating modes by the presence or absence of a heat storage. For **inflexible** operation, there is no heat storage and the heat pump reacts directly to the hourly heat demand of the building without considering the current situation in the electricity sector. In contrast, there is a heat storage available in **flexible** operation to enable load shifting of the heat pump. The heat storage is able to cover two full-load hours of maximum heat demand. Fig. 2 shows the two different approaches for modeling the inflexible and flexible operation of electric heat pumps in this analysis. Again, we deliberately choose these two operation modes to reveal the greatest possible effects.

2.2.3. Multivalent district heating grids

District heating grids mainly supply heat for hot water and heating purposes in buildings and show a typical seasonal pattern of heat demand. Usually, more than one energy source is used for heat generation, which is also called multivalent heat generation. Depending on the technologies used, switching between different heating technologies and using heat storages can provide flexibility for the electricity sector. For example, if there are high levels of renewable electricity generation, this power can be used to generate heat with electricity-based technologies. If there are only low levels of available renewable electricity generation, gas boilers, CHP plants or the heat storage can be used instead. In *Enertile*, various technology options are available in the modeled district heating grids. These include CHP plants, gas boilers, electric boilers, large heat pumps using electricity and ambient heat, and heat storages. The decisions about investments in heating technologies and their dispatch to cover district heating demand are directly integrated in the system optimization. The annual demand for district heat is usually based on results of demand models for buildings. Within *Enertile*, this annual demand is scaled to hourly demand using country-specific outdoor temperature and type-days derived in Germany.

In this study, we model the two different operation modes of district heating by the availability of certain technology options. As the use of electricity-based technologies is a potential flexibility option for the electricity sector, we vary the availability of these technologies in the two operation modes. For **inflexible** operation, large heat pumps and electric boilers are not part of the technology options. Consequently, only gas boilers, CHP plants and heat storages can be used for district heat supply. In contrast, in **flexible** operation, large heat pumps and electric boilers can be deployed in a system-optimized way. Fig. 2 shows the two different approaches for modeling the inflexible and flexible operation of multivalent district heating grids in this study. Again, we define these two operation modes to reveal the maximum effect of the modeled flexibility option on the electricity system.

2.3. Calculation of market values

The hourly marginal costs (shadow prices) of electricity demand are one output of the model in the context of the optimization and represent the costs that arise from the production of one additional unit, in this case 1 MWh of electricity. They reflect both the fixed and variable costs of all electricity generation technologies. This approach presupposes that the market participants are able to realize their full costs on the market and that the investments that are cost-optimal from a system perspective are also refinanced by the market. Furthermore, negative prices cannot occur in the selected modeling approach as the derivative is always greater than or equal to zero. Therefore, the minimum price is zero.

The shadow prices of electricity demand can serve as an indicator for the price development on the electricity market. In this analysis, we therefore use these values as electricity prices when calculating the market values of RES. We derive the market values from the sum product of the hourly generation of the respective RES technology and electricity price, divided by the total amount generated by the technology in the analyzed period, e.g. one year.

$$MV^{t} = \frac{\sum_{h\in H}\left(g_{h}^{t}\cdot p_{h}\right)}{\sum_{h\in H} g_{h}^{t}} \quad (1)$$

Parameter	Description
g_h^t	Electricity generation of technology t in hour h
p_h	Electricity price in hour h
$h \in H$	Hours of a year

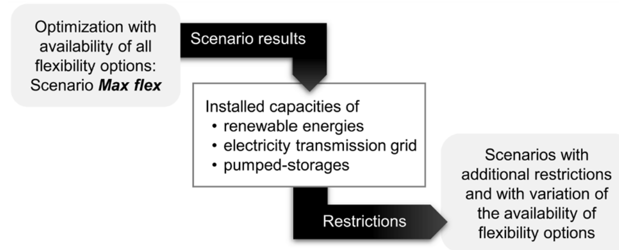

Fig. 3. Procedure for the calculation of the scenarios.

If additional generation plants with very low utilization rates are necessary to cover the additional electricity demand, this can lead to very high shadow prices of several tens of thousands of €/MWh in individual hours. This can occur particularly in the context of optimizing a single year. These extreme price peaks, however, depend on many different factors, and cannot lead to direct conclusions about critical situations in the supply system. The consideration of extremely high price peaks due to the modeling approach thus leads to an unrealistic increase in the market values of RES. To counteract this effect, we do not include extreme price peaks when calculating the market values. Prices greater than 9,999 €/MWh are capped and limited to this value. As negative prices cannot occur, the avoidance of negative prices using flexibility options is not directly modeled. Due to this downward limitation, the positive effect of flexibility on the market value is slightly underestimated. In this analysis, we aggregate the market values from all countries (modeled regions) to determine one market value for Europe. Calculating the market values does not differ from the formulae in Eq. (1) considering all countries and their electricity generation.

As well as market values, the base price is often taken as an indicator for the general market price. It is typically calculated as the mean of the hourly electricity prices in the considered region. In this analysis, we calculate a European base price according to Eq. (2) as an electricity demand weighted average of base prices for all model regions.

$$BP^{Europe} = \frac{\sum_{r\in R}\left(BP_{r}\cdot TD_{r}\right)}{\sum_{r\in R} TD_{r}} \quad (2)$$

Parameter	Description
BP_r	Base price (mean electricity price) in region r
TD_r	Total electricity demand of region r
$r \in R$	Model regions

3. Definition of scenarios and framework conditions

In order to examine the impact of sector coupling in the electricity sector on the market values of RES under the EU's ambitious climate protection targets, we define different scenarios for a highly decarbonized European energy system in 2050. The scenarios aim for an emission reduction in electricity supply of around 95% in 2050 compared to 1990 values, leading to a very high share of RES in electricity supply. For these high shares of fluctuating RES generation, the opportunities for balancing using the European electricity transmission grid play a central role. The initial existing transmission grid capacities are based on the latest "Ten-Year Network Development Plan" (TYNDP) of the European Network of Transmission System Operators for Electricity (ENTSO-E) [71]. We assume that the reference grid of the TYNDP in 2027 is implemented as a minimum for the transmission capacities in 2050. Further grid expansion beyond these capacities is not limited and part of the optimization result. The current 27 countries of the European Union plus Norway, Switzerland and the United Kingdom are included in the analysis. Each of these countries corresponds to one model region,

Table 1
Overview of the available flexibility options in the scenarios.

	Max flex	DH inflex	HP inflex	EV inflex	DH + HP inflex	DH + EV inflex	HP + EV inflex	Min flex
Electricity in district heating (DH)	✓		✓	✓			✓	
Heat pumps in buildings (HP)	✓	✓		✓		✓		
Electric vehicles (EV)	✓	✓	✓		✓			

Table 2
Assumed CO_2 and fuel prices in 2050.

CO_2 price (€$_{2020}$/t)	Fossil fuel prices (€$_{2020}$/MWh)				
	Hard coal	Lignite	Natural gas	Crude oil	Uranium
250	6.2	3.7	31.2	42.5	3.1

Table 3
Annual demand for electricity, heat, and hydrogen in Europe in 2050.

	Electricity (TWh$_{el}$)		Heat (TWh$_{th}$)		Hydrogen (TWh)
	General	Electric vehicles	Heat pumps in buildings	District heating	
Total EU 27 + 3	3,961.1	369.2	802.1	429.7	556.7

resulting in 30 model regions. For each scenario, the linear optimization problem is defined for the year 2050 and the minimum cost solution is determined. Even though *Enertile* is able to determine development paths for multiple years, we deliberately do not use this feature for this analysis. Optimizing individual scenario years makes it possible to examine the influence of individual flexibility options. When analyzing longer time paths, the effect of individual influencing factors is much more difficult to identify and isolate due to intertemporal shifts.

3.1. Scenario design

In order to analyze the impact of individual sector coupling options on the market values of RES, we need a reference scenario for comparison. In the *Max flex* scenario, all the modeled flexibility options are available. Based on these scenario results, we define additional restrictions for all other scenarios. As market values depend strongly on their market share, interconnector and storage capacity, these characteristics must be consistent in all scenarios to specifically analyze the impact of the flexibility options. Therefore, we fix the main characteristics of the resulting electricity system in the *Max flex* scenario such as installed renewable energy, transmission grid, and pumped-storage capacity. Consequently, the additional restrictions prevent a reduction or additional expansion of these capacities. In the subsequent scenarios, we systematically vary the availability of the flexibility options to isolate and analyze their influence on the market values of RES. Conventional capacities cannot be fixed in order to maintain solvability of the linear problem. Therefore, the conventional power plant park is optimized in each scenario. However, the hourly dispatch of these technologies within the year is still part of the optimization. Fig. 3 shows the general procedure for calculating the different scenarios for the analysis.

To investigate the interdependencies of the flexibility options as well, we study all combinations of available flexibilities. As there are three different flexibility options examined in this paper, this results in eight scenarios for the analysis, including the *Max flex* scenario. The availability of a flexibility option in a scenario indicates that the flexible operation mode of the respective option is allowed. If the flexibility option is not available in a scenario, only inflexible operation is possible (compare Fig. 2). Table 1 lists all the scenarios and the corresponding availability of the three flexibility options: Electricity in district heating (DH), heat pumps in buildings (HP), and electric vehicles (EV). All the scenarios are based on the *Max flex* scenario, in which all three flexibility options are available. In the next three scenarios, one of the flexibility options is not available: *DH inflex*, *HP inflex*, and *EV inflex*. In the next three scenarios, only one flexibility option is available and the other two are not available: *DH + HP inflex*, *DH + EV inflex*, and *HP + EV inflex*. Finally, none of the three flexibility options is available in the last *Min flex* scenario.

3.2. Data and assumptions

3.2.1. CO_2 and fossil fuel prices

For cost minimization, assumptions about the future development of CO_2 and fossil fuel prices are very important as they have a significant impact on the results of the optimization. The CO_2 price determines the

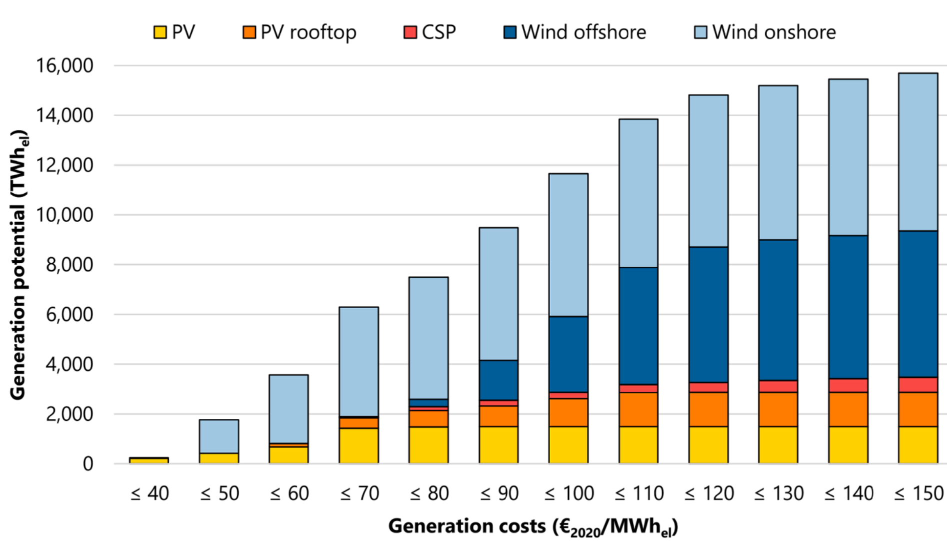

Fig. 4. Electricity generation potentials of renewable energies in Europe in 2050.

Table 4
Techno-economic parameters of conventional power plants in 2050.

Unit	Lifetime years	Investment $€_{2020}/kW_{el}$	Fixed O&M $€_{2020}/kW_{el}$	Variable O&M $€_{2020}/MWh_{el}$	Efficiency %
Coal steam plant	40	1,700	42.5	1.5	49%
Lignite steam plant	40	1,900	57.0	1.5	47%
Combined cycle gas turbine	30	950	11.3	3.0	61%
Gas turbine	30	450	7.5	2.7	40%
Pumped-storage	40	1,000	10.0	0.5	91%

level of ambition of decarbonization. Low CO_2 prices mean fewer sanctions on the use of fossil fuels, which leads to higher overall emissions. With rising CO_2 prices, RES become increasingly competitive and even replace fossil power plants. As this study looks at a highly decarbonized European energy system in 2050, the CO_2 price needs to be very high. We assume a CO_2 price of 250 $€_{2020}$/t in 2050 for all scenarios. Furthermore, fossil fuel prices and their relative ratios strongly influence the development of the power plant portfolio and, consequently, how the market values of RES develop. In this study, we do not vary CO_2 and fuel prices, as their influence on market value has already been extensively investigated. The assumed fuel prices are based on the *450 scenario* of the "World Energy Outlook 2016″ of the International Energy Agency (IEA) [72]. As fuel prices are only given until 2040, the previous trend is extrapolated to the year 2050. For other fuels such as lignite and uranium, we use own price assumptions, as no price paths were published in the study. Table 2 shows our assumptions for CO_2 and fuel prices in this study.

3.2.2. Energy demand for electricity, heat, and hydrogen

The future development of different energy demand areas and their absolute quantity determine the flexibility potential of the sector coupling options. The assumptions about demand development in Europe are based on the results from different demand models for the *Diversification Pathway* of the SET-Nav project [69,70]. This project investigated four different development paths for the strong decarbonization of the European energy system. The *Diversification Pathway* is characterized by comparatively high demand. Table 3 gives the annual demand for electricity, heat, and hydrogen in the year 2050 for Europe used as input for the *Enertile* model. In addition to the general inflexible electricity demand, the annual demand for the three examined flexibility options of electric vehicles, decentralized heat pumps in buildings, and district heating grids is listed separately. The hydrogen demand originates from industry and the transport sector and is supplied via electrolysis. Country-specific demand values are provided in Appendix B.

3.2.3. Generation potential for renewable energies

The main decision variables of the model include the expansion of the renewable technologies wind and solar. As described in Section 2.1, the electricity generation potential for RES is determined before optimization in a detailed calculation with high spatial resolution. The results of this calculation are regionally defined cost potential curves, which consist of potential capacity, annual specific costs, and full-load hours for individual expansion steps. Fig. 4 shows the aggregated cost potential curve for all modeled regions in Europe for the five solar and wind technologies considered. Good locations offer a high amount of full-load hours and consequently low specific generation costs. However, these conditions apply to only a limited number of locations and thus the resulting generation potential at low cost is small. When this potential is exploited, it is necessary to gradually move to inferior locations, which are characterized by less full-load hours and higher specific cost. As Fig. 4 shows, a larger potential is made available by increasing specific cost.

3.2.4. Techno-economic characteristics of investment options

The other main decision variables are the expansion and operation of conventional power plants for electricity and district heat generation and storage. These depend strongly on the techno-economic parameters of investment options. Table 4 shows the assumed techno-economic parameters for conventional power plants for the scenario analysis in *Enertile* for the year 2050. In order to calculate the annuity of capital costs, we use an interest rate of 7% for all technologies. This choice represents a middle ground between macroeconomic discount rates and business perspectives. However, it must be noted that the influence of the interest rate on the results of this study is limited. In the modeling, the interest rate influences market prices only if the cost of capital is relevant for additional investment decisions of the optimization algorithm. In the decisive model runs with varying flexibility options, almost all infrastructures are fixed by design. The only investment options available to the model for additional balancing of the system are gas-fired power plants to cover demand peaks. The capital costs of these plants are only relevant in very few hours, which reduces the influence of the interest rate on the results to a very low level. The capacity expansion of nuclear plants is set exogenously for each modeled country. Therefore, no costs for nuclear power are included in the table. CHP plants can be used to generate only electricity or for combined electricity and district heat generation. Their assumed techno-economic parameters are given in Table 5. Finally, Table 6 lists the assumed techno-economic parameters for district heating technologies including heat storages. The efficiency of the large heat pump in district heating depends on the hourly ambient temperature and is derived endogenously in the model.

4. Results and discussion

In the following, we discuss the results of the model-based analysis to examine the impact of flexibility through sector coupling.

4.1. Electricity generation and installed capacities

First, we present the scenario results for the electricity sector, since the generation mix determines the electricity prices, which are the main influencing factor for market values. The first optimized scenario is the

Table 6
Techno-economic parameters of district heating technologies in 2050.

Unit	Lifetime years	Investment $€_{2020}/kW_{th}$	Fixed O&M $€_{2020}/kW_{th}$	Efficiency %
Gas boiler	20	50	2.0	94%
Electric boiler	20	100	5.5	95%
Large heat pump	20	600	2.4	variable
Heat storage	20	22	0.0	99%

Table 5
Techno-economic parameters of CHP plants in 2050.

Unit	Lifetime years	Investment $€_{2020}/kW_{el}$	Fixed O&M $€_{2020}/kW_{el}$	Variable O&M $€_{2020}/MWh_{el}$	Electrical efficiency %	Efficiency CHP %
Combined cycle gas turbine CHP	30	730	30.0	2.7	33%	85%
Gas turbine CHP	30	950	30.0	3.0	48%	88%

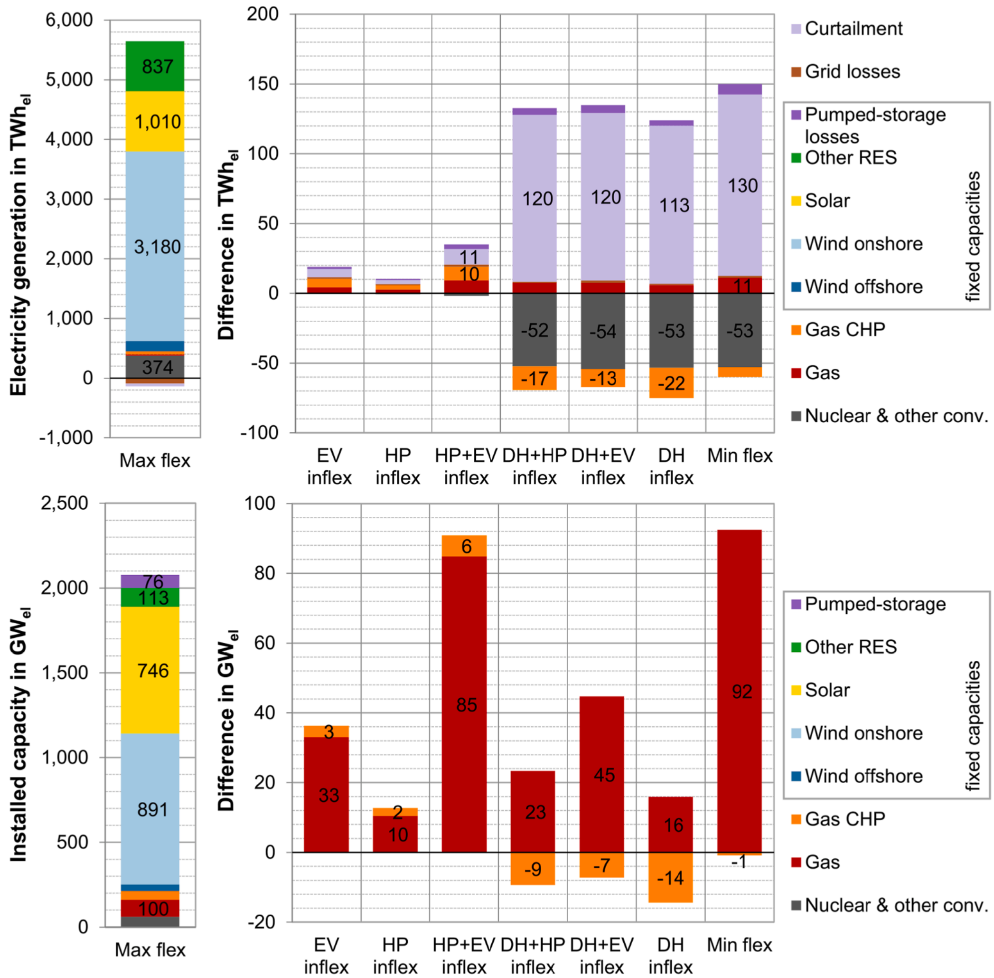

Fig. 5. Electricity generation (top) and installed capacities (bottom) in Europe in 2050 in the *Max flex* scenario and differences of the other scenarios relative to the *Max flex* scenario.

Max flex scenario, in which all three flexibility options are available. Based on this scenario, the resulting capacities of RES technologies, pumped-storages, and transmission grid connections are fixed in the subsequent scenarios with varying flexibility options (see Section 3.1). Due to the additional restrictions, these capacities and the electricity production of RES do not differ in the scenarios. Therefore, we present

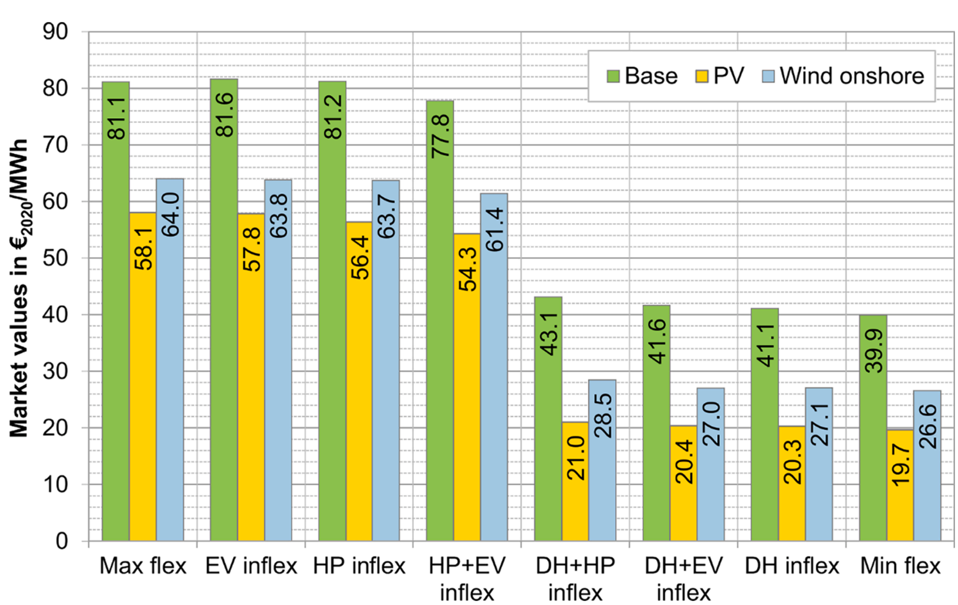

Fig. 6. Base price and market values for PV and wind onshore in Europe in 2050.

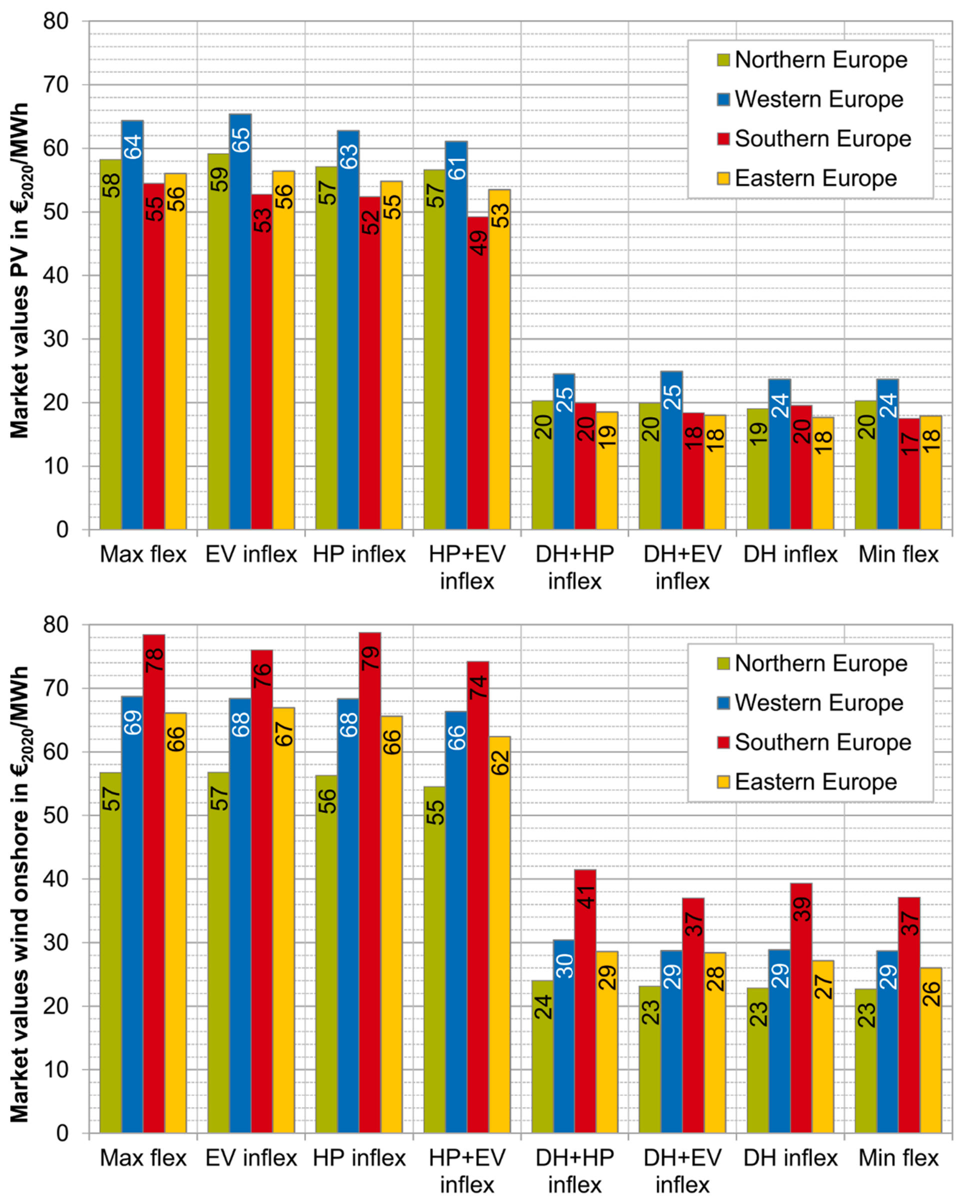

Fig. 7. Market values for PV (top) and wind onshore (bottom) in four European regions in 2050.

only the differences between the *Max flex* scenario and the other scenarios. Fig. 5 shows the electricity generation and installed capacities in Europe including grid losses, pumped-storage losses, and curtailment of RES.

In the *Max flex* scenario, the share of RES is very high (93.5%) due to the assumed CO_2 price of 250 $€_{2020}$/t. The most relevant RES is wind onshore due to the comparatively high generation potential at low generation costs: the installed capacity of 891 GW produces around 3,180 TWh of electricity in Europe. Wind offshore has only a small share with 171 TWh as it has higher generation costs and fewer potential locations (compare Fig. 4). Another important RES is solar energy with a capacity of 746 GW, which is used especially in southern countries like Spain and Italy, which have high generation potentials at low costs. Total solar energy production is 1,010 TWh, of which PV produces 662 TWh, rooftop PV 171 TWh and CSP 177 TWh. Other RES, including biomass, hydro and geothermal provide 837 TWh of electricity. Despite the high RES share of around 94% in the European electricity system, RES curtailment is relatively low: it amounts to 45 TWh in Europe, which corresponds to only 0.9% of total RES production. Nuclear power is mainly used in France and the United Kingdom (374 TWh). Fossil fuels except gas are almost completely removed from the electricity generation due to their high CO_2 costs. The installed gas capacity is 100 GW and this produces 22 TWh of electricity. The low utilization rate indicates that gas is rarely used to cover peak loads. Furthermore, gas is used in CHP plants to simultaneously cover part of the district heat demand. The installed CHP capacity is 52 GW and the plants produce 50 TWh of electricity. The pumped-storage capacity is 76 GW and the storage losses are 5 TWh. Due to the large share of variable RES generation the necessity of international balancing of supply and demand is high. This is evident from the high grid losses at 86 TWh.

With the loss of flexibility options, gas capacity and generation increase in all scenarios compared to the *Max flex* scenario. Without the possibility of load shifting from electric vehicles or heat pumps, there are more hours with peak loads requiring more flexible gas capacity. If only heat pumps are inflexible (*HP inflex*), gas capacity increases by 10 GW, whereas it increases by 33 GW if only electric vehicles are inflexible (*EV inflex*). The gas capacity required is higher for inflexible charging of electric vehicles than for inflexible operation of heat pumps, which is probably due to the overall higher electricity demand of electric vehicles. If both options are inflexible (*HP* + *EV inflex*), a substantial 85 GW increase of gas capacity is necessary. If both options are inflexible and do not allow load shifting, peak loads and therefore the required gas capacity are particularly high. If only one of the two options is flexible, it can compensate for the inflexible operation of the other option to a certain extent and reduce its peak load. If both are inflexible, this is no longer possible, resulting in more and higher peak loads overall. If in addition to this, district heating is inflexible, gas capacity rises by 23 GW (*DH* + *HP inflex*) or by 45 GW (*DH* + *EV inflex*). Without all three flexibility options (*Min Flex* scenario), the highest increase in gas capacity (92 GW) is necessary to balance supply and demand.

Furthermore, gas CHP capacity and generation rise between 2–6 GW and 3–10 TWh, respectively, if electric vehicles and/or heat pumps are inflexible (*EV inflex*, *HP inflex*, and *HP* + *EV inflex*). On the contrary, gas CHP is reduced if district heating is inflexible (*DH* + *HP inflex*, *DH* + *EV inflex*, *DH inflex*, and *Min flex*). CHP generation and capacity decrease by 7–22 TWh and 1–14 GW, respectively. The highest reduction occurs in the scenario in which only district heating is inflexible (*DH inflex*). As there is already a surplus of electricity production and high curtailment in all scenarios with inflexible district heating, there is no market potential for cost-efficient CHP in the electricity sector. Electric heating is no longer allowed and is completely replaced by gas boilers as the only cost-efficient alternative for district heating. For the same reason, nuclear generation decreases by around 53 TWh in these scenarios as the full-load hours of nuclear power decline.

In the other scenarios with fewer flexibility options, grid and pumped-storage losses are slightly higher than in the *Max flex* scenario, and most losses occur in the *Min flex* scenario, where no flexibility options are available. If flexibility options are unavailable, there is a higher utilization of the electricity transmission grid and pumped-storages to balance supply and demand. Moreover, RES curtailment increases with the loss of flexibility in all scenarios. In the scenarios with inflexible operation of electric vehicles and/or heat pumps (*EV inflex*, *HP inflex*, and *HP* + *EV inflex*), curtailment of RES is 3–11 TWh higher than in the *Max flex* scenario. If district heating is inflexible (*DH* + *HP inflex*, *DH* + *EV inflex*, *DH inflex*, and *Min flex*), curtailment is 113–130 TWh higher than in the *Max flex* scenario and corresponds to around 3% of overall RES production. This is because electricity-based technologies (large heat pumps and electric boilers) are not available for district heating. Consequently, the absolute electricity demand is lower without the electricity consumption of these two technologies. Therefore, in hours with high RES feed-in and low demand, the electricity surplus has to be curtailed. Overall, the changes in electricity generation are small in the scenarios with inflexible electric vehicles or heat pumps compared to the changes in the scenarios with inflexible district heating.

4.2. Market values of renewable energies

In the following, we present the market values of RES in the scenarios to analyze the effects of the different flexibility options. Fig. 6 shows the European base prices and market values for the *Max flex* scenario and the other scenarios sorted by descending values of base prices. The European market values for PV and wind onshore comprise all the countries with significant installed capacities. Market values for rooftop PV and wind offshore are not included, as these technologies are not available and cost-efficient in all European countries. In general, the market values of RES are much lower than the base prices, as their feed-in has the effect of reducing the market price due to their low marginal costs. In the investigated scenarios, the European market values for PV are always lower than those for wind onshore, even if PV has a smaller share in electricity generation in Europe than wind onshore (compare Fig. 5). In general, electricity prices are the main influencing factor for market values. In the scenarios, the high PV feed-in in 2050 lowers the electricity prices during the day. Countries with large PV feed-in are particularly affected, so that average electricity prices at midday are much lower than in the remaining hours. The feed-in of wind onshore is in average not strongly dependent on the time of day and therefore the market values are less affected. However, market values and their relation to one another are very country-specific and depend on the absolute generation of the respective technologies, the timing of their feed-in, and the simultaneous occurrence of low electricity prices.

In the *Max flex* scenario, the base price is 81.1 €/MWh and the market values are 58.1 €/MWh for PV and 64.0 €/MWh for wind onshore. As all three flexibility options are available, the market values in the *Max flex* scenario are the highest in the scenario comparison. The market values for PV and wind onshore both decline compared to their values in the *Max flex* scenario, if single or multiple flexibility options are unavailable. Without any of the flexibility options in the *Min flex* scenario, the values are the lowest and fall by at least half compared to the *Max flex* scenario. The base price here is 39.9 €/MWh and the market values are 19.7 €/MWh for PV and 26.6 €/MWh for wind onshore. This clearly illustrates the effect of losing flexibility in the system. As a result, there are many more hours in which the feed-in of RES exceeds electricity demand, causing electricity prices of zero, RES curtailment, and sinking market values. Consequently, efficient sector coupling can significantly increase the market value of RES.

The three scenarios with inflexible operation of electric vehicles and/or heat pumps (*EV inflex*, *HP inflex*, and *HP* + *EV inflex*) show similar values to the *Max flex* scenario. If electric vehicles are inflexible (*EV inflex*), the market values show only minor differences compared to *Max flex* and decrease slightly. If heat pumps are inflexible (*HP inflex*), the market value for wind onshore again decreases only marginally, while the market value for PV declines by 1.7 €/MWh. This is because the inflexible operation of heat pumps does not allow load shifting to use excess PV electricity from the midday period. This results in high PV feed-in, which can ultimately lead to curtailment in case of negative residual load. As a result, electricity prices fall or even drop to zero and reduce the market value of PV. If both options are inflexible, the effect of reducing the base price and the market values is more pronounced, but still small overall. If only one of the load shifting flexibility options is unavailable, the other one can still postpone load and react to the situation in the electricity market. It can offset the inflexible operation of the other option to some extent and weaken the effect. Therefore, the impact of two inflexible options in combination is greater than the sum of the two individual effects. Nevertheless, the impact on RES market values of flexible charging of electric vehicles and flexible heating with electric heat pumps is unexpectedly low. The changes in these three scenarios are comparatively small, as is the case for electricity generation shown before (compare Fig. 5). Short-term flexibility through load shifting of charging or heating processes has only a minor influence.

The three scenarios with inflexible district heating (*DH + HP inflex*, *DH + EV inflex*, and *DH inflex*) have values very similar to the *Min Flex* scenario. The inflexible operation of district heating grids has a large effect and by far the greatest impact on market values in the scenario comparison. The market value for PV decreases from 58.1 €/MWh in the *Max flex* scenario to 20.3–21.0 €/MWh, and from 64.0 €/MWh to 27.0–28.5 €/MWh for wind onshore. The additional inflexible operation of electric vehicles (*DH + EV inflex*) or heat pumps (*DH + HP inflex*) does not have a significant effect on market values. These scenarios are dominated by the fact that electric district heating is unavailable. The loss of the possibility to change the total electricity load using electricity-based district heating in times of high RES feed-in leads to further curtailment as shown before in the electricity generation in Fig. 5. This consequently drastically reduces the market values.

Fig. 7 shows the market values for PV and wind onshore structured according to four different European regions: Northern, Western, Southern, and Eastern Europe (for allocation of countries see Appendix C). As mentioned before, the market values for PV are lower than for wind onshore in all scenarios. The only exception in this regard is Northern Europe with very low market values for wind onshore in comparison. The potential for wind onshore is higher than for PV due to the geographical location and weather conditions. Consequently, wind onshore production is quite high, leading to low market values. For similar reasons, the market values for wind onshore in Southern Europe are comparatively high, whereas the market values for PV are low. PV feed-in in southern countries is very high due to the high generation potentials at low costs, which reduces electricity prices during the day and leads to low market values. Since wind onshore production is rather limited due to the lower generation potential, the market values are less affected. Overall, the effects of the three flexibility options discussed above for Europe also occur in the European regions. Although the market values differ in the four regions, the decrease due to the loss of flexibility is comparable across all regions. As already shown, the scenarios with flexible district heating (*Max flex*, *EV inflex*, *HP inflex*, and *HP + EV inflex*) have significantly higher market values than the scenarios with inflexible district heating (*DH + HP inflex*, *DH + EV inflex*, *DH inflex*, and *Min flex*). Altogether, the impact of inflexible electric vehicles and heat pumps is negligible compared to the impact of inflexible district heating. In general, the same effects can be observed in individual countries (compare Appendix D).

4.3. Comparison of flexibility options

First and foremost, the amount of electricity demand caused by a flexibility option determines the general potential of that flexibility option. The total electricity demand for electric vehicles is 370 TWh in Europe (compare Table 3). The heat demand for buildings with heat pumps is 802 TWh. To cover this demand, heat pumps consume 295 TWh of electricity (implying an annual COP (Coefficient of performance) of 2.7 as an average for Europe). Electric district heating applications (large heat pumps and electric boilers) consume 188 TWh of electricity to cover part of the district heating demand (530 TWh). Even though total electricity demand from electric vehicles and heat pumps is much higher than the electricity demand for district heating, these two flexibility options have a much smaller impact on market values. This is because the degree of flexibility offered by district heating is much higher than that of electric vehicles and heat pumps. The demand of electric vehicles is either covered directly or indirectly via storages allowing load shifting within certain boundary conditions. The same applies to heat pumps, where the heat storage enables load shifting. In case of high residual load and consequently high electricity prices, charging and heating can be postponed to times with low or negative residual load and low electricity prices. However, the flexibility potential of load shifting is rather limited because it can only be shifted for a short period. District heating grids, however, have multivalent heating, meaning there are several alternative options to supply heat, and flexibility is further increased by the possibility of fuel switching. Hence, they can not only adapt directly to the situation on the electricity market, if a high level of RES feed-in occurs, but can increase or decrease the total electricity load through alternative supply options. Electricity-based heating technologies enable the integration of large quantities of renewable electricity over long periods. With the creation of additional electricity demand, the number of hours with curtailment and low electricity prices are drastically reduced and consequently the market values of RES increase. In case of a high residual load, on the other hand, district heating is provided alternatively by gas boilers and gas CHP or by using heat storages. If district heating is modeled as inflexible, the direct link to electricity generation is severed as electricity-based heating provides the actual flexibility for the electricity sector.

Due to sector coupling, the willingness to pay of other sectors becomes increasingly important in the electricity sector. In district heating, there is important competition between electricity and alternative heat supply using gas. The competitive price of gas plus the CO_2 price is therefore an important reference for the electricity sector in every hour. With flexible district heating, it is possible to change the total load because of the multivalent generation structure, while flexible operation of electric vehicles or heat pumps allows only a limited time shift of the charging or heating process. Consequently, the possibility to change the absolute demand for electricity has a greater impact on the market values of RES than flexibility in terms of time.

5. Summary and conclusions

In this paper, we examine the market values of renewable energy sources (RES) on the electricity market. We explore the effects of flexibility due to sector coupling using a model-based scenario analysis. We study three flexibility options in detail: electric vehicles, decentralized heat pumps in buildings, and multivalent district heating grids. For each of these options, we distinguish between flexible and inflexible operation in order to examine their impact on the market values of RES. For the analysis, we use the linear optimization model *Enertile*, which optimizes capacity expansion and hourly dispatch of power plants, renewable energies, cross-border transmission capacities, and storage facilities. The scenarios depict a highly decarbonized European energy system in 2050. We systematically vary the availability of the flexibility options in eight scenarios in order to isolate their influence on the market values. We calculate the market values of RES using the hourly marginal costs of electricity demand as electricity prices.

Our analysis shows that additional flexibility in the electricity sector due to closer interconnections with other demand sectors can significantly increase the market values of RES. The individual flexibility options examined in this analysis have different effects on the market values. The impact of flexible charging of electric vehicles and flexible heating with heat pumps is rather low. Flexible use of electric vehicles or heat pumps allows only a limited time shift of the charging or heating process, which has only minor influence on the market values. However, the flexible use of electricity in district heating grids has a much higher impact. Fuel switching due to the multivalent heating structure enables an immediate reaction to the current situation on the electricity market. The possibility of changing the absolute demand for electricity in direct response to the feed-in of RES has a particularly strong influence on market values as the occurrence of zero electricity prices can be drastically reduced. In summary, it can be stated that short-term flexibility via load shifting has only a limited effect, while the possibility of increasing electricity demand during times of high RES electricity generation has a significant and positive impact on the market values of RES.

The approach used provides interesting insights into the impact of sector coupling on the market values of RES. The high technological and hourly resolution is very well suited to mapping weather-dependent RES generation and for emphasizing the importance of flexibility in the energy system. This analysis considers a system with perfect optimization under the assumption of an economically perfect sector coupling between the electricity market, the heating market, and the market for hydrogen without distortions. It therefore represents the best possible result for the modeled energy system and shows the theoretical maximum effect of sector coupling. In reality, there will always be distortions due to forecasting errors, actor behavior, and imperfect regulation. Nevertheless, this type of analysis provides useful insights into where regulatory efforts to eliminate distortions in sector coupling can be particularly valuable.

Further research is necessary with respect to the influence of the examined flexibility options on the hourly dispatch situation in the energy system. Analyses of the electricity price distribution and the occurrence of zero prices or their simultaneous occurrence in multiple countries could provide interesting additional insights into the different characteristics of the examined flexibility options. Future investigations should also consider the use of direct RES in district heating like biomass or solar and geothermal energy. Including these technologies reduces the potential share of electric district heating and its respective flexibility potential for the electricity sector. Furthermore, future analyses could focus on the indirect use of electricity by the conversion into synthetic fuels, such as hydrogen or e-fuels, as flexibility options. Due to their long-term storage properties and the flexible operation of electrolyzers and reconversion technologies, hydrogen and e-fuels could be competitive flexibility options. The combination of hydrogen and district heating by using hydrogen as a fuel for district heating could also provide additional potential for future highly decarbonized energy systems.

CRediT authorship contribution statement

Christiane Bernath: Conceptualization, Methodology, Software, Formal analysis, Investigation, Data curation, Visualization, Writing - original draft, Writing - review & editing. **Gerda Deac:** Conceptualization, Methodology, Software, Investigation, Writing - review & editing, Supervision. **Frank Sensfuß:** Conceptualization, Methodology, Software, Investigation, Writing - review & editing, Supervision.

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.

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Appendix A. Abbreviations

See Table 7.

Table 7
Abbreviation.

Abbreviation	Explanation
BEV	Battery electric vehicles
CHP	Combined heat and power
COP	Coefficient of performance
CSP	Concentrating solar power
DH	District heating
ENTSO-E	European network of transmission system operators for electricity
EU	European Union
EV	Electric vehicles
GHG	Greenhouse gas
HP	Heat pumps
NTC	Net transfer capacity
O&M	Operation and maintenance
PHEV	Plug-in hybrid vehicles
PtG	Power-to-Gas
PtH	Power-to-Heat
PtL	Power-to-Liquid
PtM	Power-to-Move
PtX	Power-to-X
PV	Photovoltaics
RES	Renewable energy sources
TYNDP	Ten-year network development plan

Appendix B. Annual demand for electricity, heat, and hydrogen in 2050 per country

See Table 8.

Table 8
Annual demand for electricity, heat, and hydrogen in 2050 per country.

Country	Electricity (TWh_{el})		Heat (TWh_{th})		Hydrogen (TWh)
	General	Electric vehicles	Heat pumps in buildings	District heating	
Austria	84.2	6.2	6.0	15.4	21.2
Belgium	114.3	8.1	33.5	7.7	58.6
Bulgaria	38.3	2.2	1.6	3.3	6.2
Croatia	18.6	0.9	4.7	2.0	0.6
Cyprus	5.7	0.2	0.6	0.0	0.1
Czech Republic	78.4	3.9	15.4	12.9	11.2
Denmark	46.5	5.9	1.7	13.7	0.2
Estonia	8.7	0.8	0.1	1.6	0.4
Finland	98.7	4.5	18.1	23.1	5.2
France	527.8	74.9	134.8	40.7	116.5
Germany	646.7	81.4	158.0	76.9	113.0
Greece	64.0	4.8	10.8	0.9	5.1
Hungary	52.8	2.1	8.9	7.3	9.3
Ireland	31.2	2.2	9.2	1.8	1.9
Italy	395.9	27.4	112.2	16.5	39.7
Latvia	9.5	0.5	0.2	2.7	0.0
Lithuania	13.8	0.7	1.0	2.6	4.3
Luxembourg	9.7	0.4	1.8	1.2	0.0
Malta	2.8	0.1	0.3	0.1	0.1
Netherlands	163.6	15.4	42.0	12.5	44.6
Norway	149.2	11.5	6.4	18.4	0.2
Poland	216.1	11.3	60.8	16.0	18.4
Portugal	66.8	5.7	4.9	0.4	5.9
Romania	73.9	4.5	1.9	6.6	17.9
Slovakia	38.9	1.4	6.6	7.6	7.3
Slovenia	17.2	1.5	1.1	1.8	0.0
Spain	328.2	14.1	31.7	3.8	23.0
Sweden	151.3	18.2	19.9	28.5	9.0
Switzerland	78.4	4.5	8.7	13.1	2.1
United Kingdom	429.8	53.8	99.4	90.6	34.7
Total EU 27 + 3	**3,961.1**	**369.2**	**802.1**	**429.7**	**556.7**

Appendix C. Definition of European regions

See Table 9.

Table 9
Definition of European regions as used in Fig. 7.

European region	Countries
Eastern Europe	Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia
Northern Europe	Denmark, Estonia, Finland, Ireland, Latvia, Lithuania, Norway, Sweden, United Kingdom
Southern Europe	Croatia, Cyprus, Greece, Italy, Malta, Portugal, Slovenia, Spain
Western Europe	Austria, Belgium, France, Germany, Luxembourg, Netherlands, Switzerland

Appendix D. Base prices and market values per country in the scenarios[1]

See Figs. 8–10.

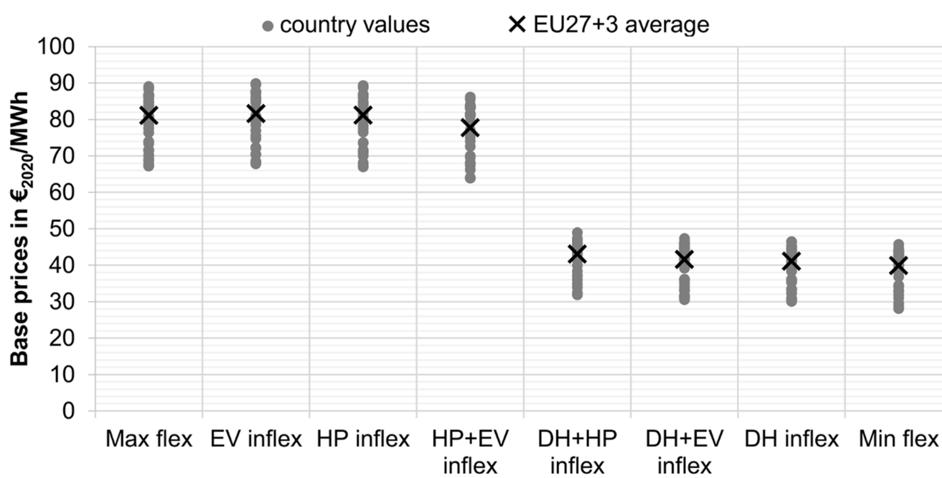

Fig. 8. Base prices - country values and EU27 + 3 average.

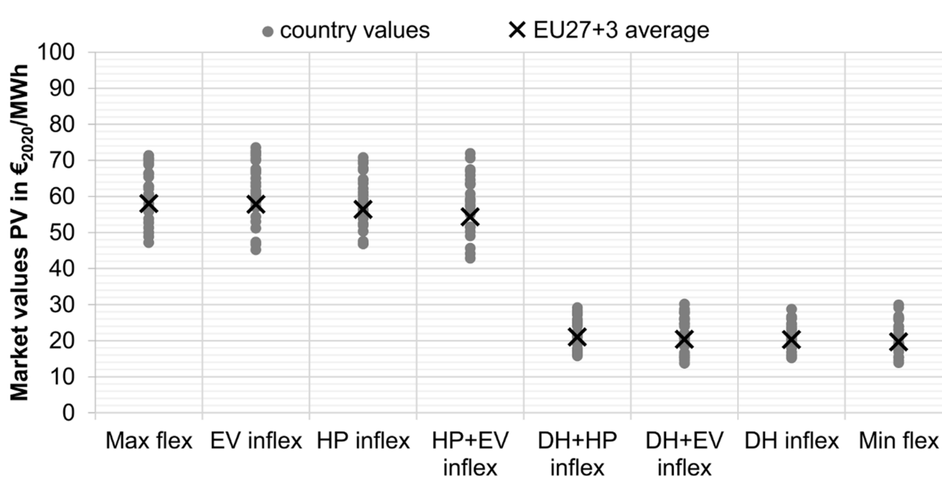

Fig. 9. Market values PV - country values and EU27 + 3 average.

[1] Malta is a special case and not included. Malta is an island completely separated from the EU and flexibility options do not influence the shown values, which are rather high and constant in the scenarios.

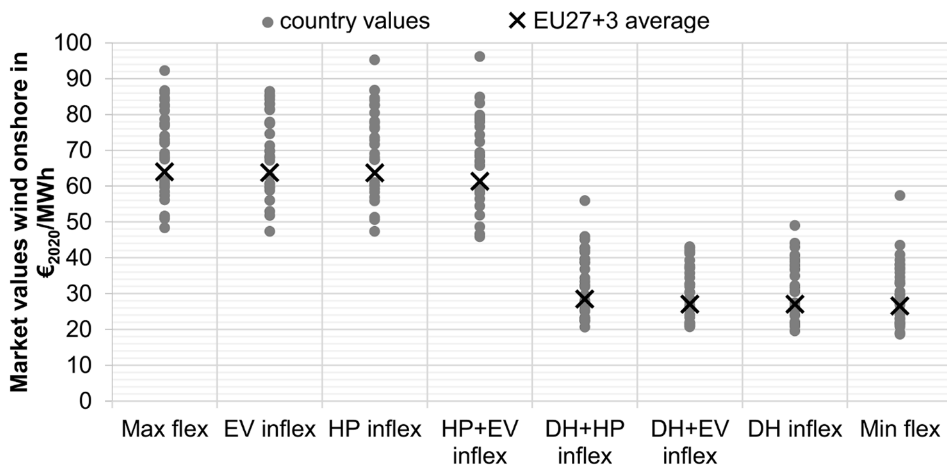

Fig. 10. Market values wind onshore - country values and EU27 + 3 average.

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