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Flexibility potential of aggregated electric vehicle fleets to reduce transmission congestions and redispatch needs: A case study in Austria

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ABSTRACT

Redispatch measures are a key instrument of the Central European electricity market design to prevent congestion of several transmission lines after the market clearing. In addition to generation rescheduling, demand-side flexibility can reduce this redispatch need. This paper mainly aims to analyse the flexibility demand application of electric vehicle fleets in the redispatch market. The developed European electricity market model minimises dispatch- and subsequently redispatch costs whilst using electric vehicle fleets as flexible demand. A novel modelling approach allows the integration of this flexibility into large-scale linear programming models without losing their essential parameters. This case study is examined in Austria with a remarkably high share of electricity from renewable energy sources and different market penetrations of electromobility. Results show that integrating this system as a redispatch measure leads to a reduced curtailment of renewable energies (up to 25%), whilst less additional thermal power plant usage is needed. Furthermore, redispatch cost and the associated CO_2 emissions are reduced by 3.3% to 13.9%. By contrast, using this flexibility as a market-based charging strategy raises CO_2 emissions and redispatch costs drastically by 186% if 2 million electric vehicles are considered. Especially with the high electrification rate of the transport sector, the provided flexibility potential significantly impacts the electricity market. Further efforts could address the influence of demand-side flexibility not only on redispatch within one control area but also on cross-border redispatch and counter-trading.

1. Introduction

The ever-increasing share of non-dispatchable variable renewable energy sources for electricity (RES-E), combined with the increasing electrification of the heating and transport sector, raises the amount of electricity transported over the transmission grid. Encouraged by the Paris Agreement [1] and the Green Energy for All Europeans' package with the Renewable Energy Directive (2018/2001/EU) [2], these developments will continue in the future. The number of congestion events and their magnitude and frequency has risen in the past years due to the increased power flow over the transmission grid [3].

The dispatch of the available generation units is largely determined by clearing the day-ahead (DA) electricity market, which includes the optimal generation schedules for all thermal power plants, RES-E and the usage of storage units. Therefore, the demand and supply curves are intersected. The latter is based on the short run marginal costs (SRMC) of the generation units, and the merit-order function within a perfectly competitive market [4]. Transmission line limitations within a bidding zone are disregarded during the dispatch, whilst cross-border capacities between bidding zones are explicitly allocated.

Therefore, congestions which are temporal overloads of a transmission line could occur. Congestions are favoured by a growing share of variable RES-E unequally distributed within a bidding zone, thereby allowing the flow of critical power. Additionally, the decarbonisation and electrification of the heating and transport sector lead to high overall electricity consumption. Particularly, electric vehicle (EV) charging events often occur simultaneously and do not correlate to electricity generation [5,6].

In addition to transmission line expansion as a long-term strategy, redispatch measures are also a key instrument of the Central European electricity market design. They can prevent congestion of several transmission lines after the market clearing. Congestions between bidding zones can be largely prevented during the dispatch. This is done through the explicit allocation of cross-border capacities. These capacities are calculated simultaneously with the market clearing through the principles of flow based market coupling (FBMC) [7]. This makes more cross-border transmission capacity available through an improved physical representation of the grid [8]. However, these methods are

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only used for trades between bidding zones. Redispatch measures must balance congestions that may occur within a bidding zone.

Such a balance is realised by modifying the power generation of several thermal power plants based on the instructions of the transmission system operator (TSO). A power plant will increase its power generation on one side of the congestion and reduce it on the other side to overcome this congestion. However, the number of these redispatch measures and, consequently the associated costs increased in the past years and may also continue to rise in the future [9,10]. Aggregated consumers can participate in the congestion management market to encourage active customer participation. These customers can adjust their demand to the actual local generation to reduce the power exchange on the transmission grid.

The model developed in this study uses aggregated EV fleets as flexibility to reduce transmission congestions within the redispatch. Additionally, the congestion management market allows the curtailment of RES-E as a redispatch measure. EVs are modelled as demand-side flexibility and not as bidirectional vehicle-to-grid (V2G) storage units, even if their use would provide increased potential. Using EVs as demand-side flexibility systems might obtain more acceptance amongst customers compared with their use as V2G units. Due to the cheaper charging infrastructure and because this phenomenon does not influence the vehicle warranty [11]. In addition, the battery is not burdened with additional charges and discharge cycles, thus influencing its lifetime. Furthermore,EV have high flexibility potential because they are not typically utilised for a large part of the day [6] and remain continuously available throughout the year in contrast to other technologies, such as heat pumps.

The core objective of this study mainly aims to model aggregated EV fleets as a temporal available flexibility and analyse their application in the redispatch market. Therefore, the following research questions will be answered.

(i) How can aggregated EV fleets, with different charging behaviours, be integrated as flexible demand into linear programming (LP) models?
(ii) How can technical limitations of the EVs and their charging infrastructure be considered?
(iii) What are the influences of customer integration as aggregated EV fleet demand-side flexibility on the redispatch market?
(iv) Can flexible demand reduce redispatch needs and RES-E curtailment?

This paper is organised as follows. State of the art is examined in Section 2. The methodology used is comprehensively described in Section 3. The aggregation model of the EVs and the demand-side flexibility functionalities is presented in Section 3.1, whilst the market-based dispatch and redispatch models are respectively introduced in Section 3.2 and Section 3.3. The results, including the used data sets for the different scenarios, are described in Section 4. The methodology and results are discussed in Section 5 and a conclusion is provided in Section 6.

2. State of the art

In this work, a congestion management system is integrated into the European electricity market model *EDisOn* by using the curtailment of RES-E and flexible EV demand [12]. Therefore, several different modelling approaches are used in combination.

2.1. Demand-side flexibility in electricity models

A European electricity market with a high share of RES-E highly depends on the actual, non-dispatchable generation of wind and photovoltaic (PV). An approach to overcome this variable generation issue is adjusting the demand to the actual generation by integrating flexibility. This integration into a fully renewable fundamental electricity market model compensates for imbalances, reduces the need for electricity generation of thermal power plants and decreases RES-E curtailment [13]. These positive effects of flexibility even persist if conventional power plants dominate the generation mix. Hence, the RES-E penetration is very low. Flexibility can still contribute to achieving environmental goals and lead to other price-setting marginal plants within Central Western Europe [14]. The used approaches integrate flexible demand into LP models as a demand that can be shifted by a specific time to a certain extent without considering the technical limitations of the EVs and the charging infrastructure that must be met.

Nodal hourly electricity prices for profit maximisation are used in [15]. Consumers are modelled as elastic demand to anticipate their willingness to reduce their electricity bills. They analyse the influence of nodal prices on the power peaks, peak-to-valley distance and energy exchange. The same authors use the potential of EVs and battery storage units to manage imbalances by the intermittent generation of wind farms [16]. The EVs adjust their charging demand based on hourly electricity prices for profit maximisation. These models use exogenous electricity prices, while the approach presented in this paper calculates the power plant generation schedules and further the DA prices. This is essential for an electricity market redispatch optimisation because the dispatch determines the available capacities for redispatch measures. Further, the redispatch costs are influenced by this.

The authors of [17] compare two different approaches to integrate this flexibility functionality into LP models, whereas [18] integrates this functionality as a price-sensitive demand into a mixed integer linear programming (MILP) unit commitment model. Several approaches for the integration of various technologies into expansion models are available. However, the integration of EVs in combination with flexible demand should be examined in the future because their importance will increase [19].

2.2. Electric vehicle models

Numerous studies deal with the optimal marketing of EV demand flexibility from the private perspective of individual market participants. They can maximise their economic benefits in electricity [20] and ancillary service markets [21]. The authors of [22] focus on their optimal bidding strategy considering four different types of EV users.

Moreover, these optimisations from the private perspective of EVs can be used to achieve system benefits. They can reduce frequency deviation, minimise local peak demand [23] and transfer electricity throughout the network whilst reducing grid operation costs [24,25]. The flexible charging of EVs can reduce overall system operating costs, RES-E curtailment [26,27] and CO_2 emissions [28]. These changes in the temporal distribution of EV charging events can be triggered by local price signals [29].

All these studies model EVs as bidirectional electricity storage systems in MILP [26,27], game-theoretic [23] and stochastic [24,25] models, but do not investigate their potential as flexible demand to reduce congestions in the LP electricity market models.

2.3. Electric vehicle system benefits

As described in the EV model section, EVs can be used for many applications. These lead to different benefits for the considered electricity system. At the local level EVs can be used for peak shaving [30–33] and valley-filling [31,34–36]. This can avoid the curtailment of RES-E [26,27,37]. Grid utilisation can be reduced by using EVs to transport electricity [24,25,38]. Further, they can improve the matching of generation and demand [39] and reduce peak loads [23]. A different use case for EVs is the provision of ancillary services and reserve provision [21,40–42]. Especially for fast frequency containment reserve and the even faster spinning reserve [43].

2.4. Electric vehicle charging profiles

A realistic integration of EVs into models needs a detailed evaluation of specific characteristics, such as their charging and driving patterns, based on measurement data. Statistical analyses of real-world data, the temporal distribution of charging processes and their flexibility potential are performed in the Netherlands [44], Germany [45] and in the USA [6,46], which showed that a system-wide EV rollout increases demand at certain hours [6]. In addition to analysing measured data, simulating and predicting charging processes is possible. The charging behaviour is predicted with machine learning algorithms using user and charging infrastructure data sets by [47] and simulated using Monte Carlo methods [46].

2.5. Congestion management and redispatch

Congestion management in electricity markets is often associated with costs because intervention in the cost-optimal dispatch is required. In addition to costly methods that prevent transmission line congestions, using specific technologies, such as flexible AC transmission systems, is also possible to technically reduce the need for redispatch measures. A local system with local prices can contribute to reducing redispatch measures within Central Western Europe [48]. Whilst [49] shows the modelling of redispatch, the integration of FBMC in Northern Europe through regulation of thermal power plants is examined by [50]. This method considers several aspects of the grid topology within the European electricity market and reduces the necessary amount of redispatch measures. In addition to the integration into electricity market models, several approaches also focus on integrating congestion management into small power systems to show the influence of specific technologies or policies. The authors of [51] propose a method to model market-based congestion management in a power system with aggregated prosumer participation that performs redispatch. However, the prevention of congestion can still be realised by distributed nodes that only communicate with their neighbouring nodes despite the absence of a central planner [52]. Consumer surplus and cross-border capacity between bidding zones emerge if integrated preventive redispatch within the dispatch is used [53]. A collaboration of the four German TSOs can influence redispatch costs [54] and the RES-E curtailment [55]. However, a large rollout of bidirectional EVs within a power system [56], as well as a demand response system in combination with generation rescheduling can minimise redispatch costs [57]. These approaches demonstrate the high potential of different methods to reduce redispatch costs but were not analysed within an electricity market. Local electricity prices can be used for the redispatch costs based on the two-stage modelling of an electricity market model. In addition, the calculated schedules of the generation units imply their technical possibility to participate in the redispatch market.

2.6. European electricity market design

Since both dispatch and redispatch are modelled in this work, the definition of these terms is crucial. The dispatch of the available generation units is primarily determined by clearing the DA electricity market. On the DA market, electricity is traded anonymously for the following day. Cross-border trades between bidding zones require implicit allocation of cross-border capacities. These trades occur on the international power stock market or over the counter. The dispatch includes the optimal generation schedules for all thermal power plants, RES-E and the usage of storage units. Therefore, the demand and supply curves are intersected. The intersection directly results in the market clearing price for the respective hour. All market participants subsequently pay this DA price. The supply bids are based on the SRMC of the generation units, and the merit-order function within a perfectly competitive market [4].

During dispatch, transmission line limitations within a bidding zone are not considered. Hence, congestion could occur. To identify them in advance, the dispatch is forwarded to the TSO. The latter subsequently performs a load flow calculation to calculate any congestions of the transmission grid. Redispatch measures must balance congestions that would occur. Such a balance is realised by modifying the power generation of several thermal power plants based on the instructions of the TSO. A power plant will increase its power generation on one side of the congestion and reduce it on the other side to overcome this congestion. The corresponding power plants are financially equalised as if there had not been any redispatch measures. Aggregated consumers can participate in the congestion management market in Austria [58]. This should encourage active customer participation. They can adjust their demand to the actual local generation to reduce the power exchange on the transmission grid. A more detailed description of the European electricity market was carried out by [59].

2.7. Progress beyond state of the art

The potential of demand-side flexibility provided by EVs to reduce redispatch needs is evaluated in this paper using the European electricity market model *EDisOn* [12]. A detailed power plant fleet and a market clearing before the redispatch make it possible to consider the individual costs for regulating generation units and their availability. The contribution of this study is as follows.

(i) Implementation of aggregated EV fleets as demand-side flexibility into a generic EV model. A large number of the necessary calculations are conducted before the start of the optimisation considering the technical limitations as an LP model. Consequently, integrating this model into computationally intensive electricity market models is possible.
(ii) integration of the EV model in the dispatch and redispatch to investigate the influence on both optimisation steps.
(iii) Analysis of this congestion management approach in Austria, within the European electricity market, to consider simultaneity effects that might occur due to an extensive rollout of EVs and loop flows. A comprehensive view of congestion management in a real-world application is also provided.
(iv) Evaluation of the influence of this distributed flexibility on redispatch costs, CO_2 emissions and RES-E curtailment.

3. Methodology

A four-step optimisation model is used to analyse the influence of EVs that reduce redispatch needs (Fig. 1). This needs an optimised market-based power plant dispatch separated from the physical load flow. Additionally, the resulting local DA prices can be used within the redispatch. The EVs can participate as flexibility in a congestion management market by shifting their demand.

For this purpose, the existing European electricity market model *EDisOn* [12] was extended. The functionality of EVs (Section 3.1) and the redispatch model (Section 3.3) were added.

The first step of the model is aggregating the necessary input data. EVs are aggregated to a charging demand (CD) for each node. These CDs are characterised by a specific timeframe and electricity demand (Section 3.1). The nodes within Austria are aggregated based on their risk of congested transmission lines between them according to FBMC to model the market without physical limitations [8].

Hence, fewer nodes and transmission lines exist, but all power generation units exist in the dispatch. These generation units can no longer be precisely assigned to their geographical position (nodes) in the transmission grid. The correct cross boarder capacities are still included. Within Austria, the transmission grid is no longer modelled in sufficient detail. This may lead to congested transmission lines in Austria.

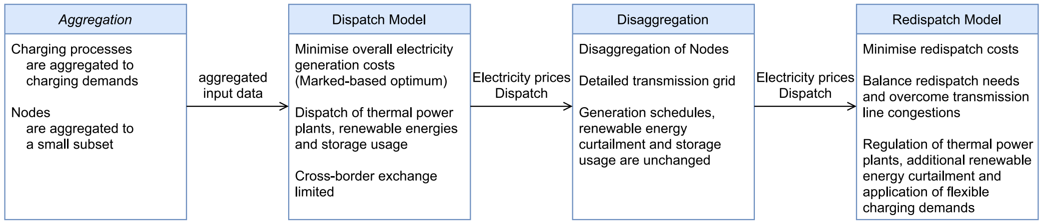

Fig. 1. Model overview.

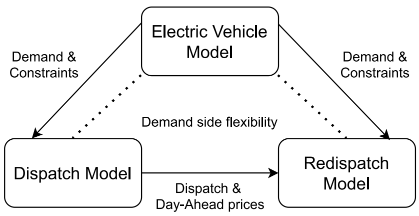

Fig. 2. Dependencies between the models.

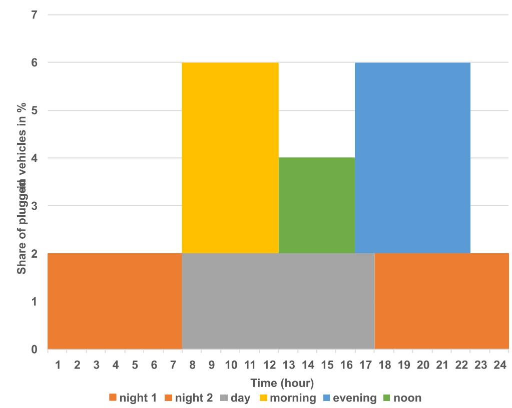

Fig. 3. Temporal distribution function of plugged-in vehicles.

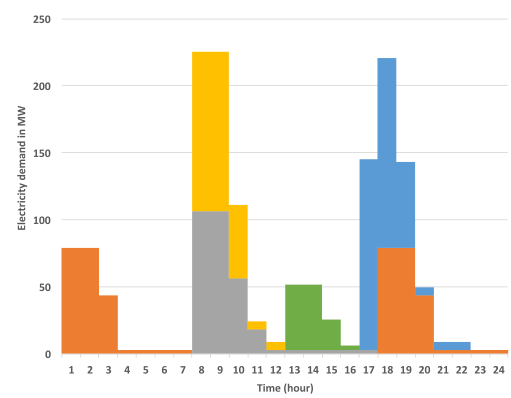

Fig. 4. Charging demand of 30 000 vehicles with all charging strategies.

In the following step, the generation schedule dispatch of all power plants within each node is conducted based on their SRMC by using the LP unit commitment European electricity market model *EDisOn* [12].

The previously aggregated nodes are disaggregated again after the market clearing to consider the physical limitations of the transmission lines. Hence, a detailed power plant fleet and the related transmission grid are modelled for Austria. The power plant usage remains unchanged compared with the one determined in the dispatch as the optimum of the market-clearing perspective. The last step of the optimisation involves preventing congestion by redispatch measures within Austria. Local DA prices are used, as derived from the market-clearing perspective, to calculate the redispatch costs of different generation units. Thermal power plant regulation and RES-E curtailment are associated with redispatch costs to ensure a profit compensation.

An overview of the electricity market model can be seen in Fig. 2. The block "Dispatch model" calculates the generation schedules and the DA prices. These results influence the available capacity for redispatch measures. The block "Redispatch model" performs the redispatch after the market clearing is done in the "Dispatch model" block. The model uses the DA price calculated in the dispatch. Available generation capacities for redispatch measures result from the previously calculated generation schedules. The flexibility potential provided by EV fleets (block "Electric Vehicle Model") can be included in both models. It is used to balance redispatch needs or for market-based charging strategies to minimise costs. The dashed arrows show the possible integration of the EV model into one of the optimisation steps of the market model, whilst the CD and their constraints are always considered.

The decision variables in the current study are always written in lower case, and exogenously defined constants are written in upper case.

3.1. Electric vehicle model

This section describes the EV model with a focus on the implementation of EVs as flexible demand into an LP unit commitment model. Macroeconomic models aim to maximise the social welfare of the overall system. Hence, business models and profit maximisation of individual market participants should not be considered. Otherwise, the welfare optimum could not be found. To achieve these goals, this type of European electricity market models are typically implemented as a unit commitment model [12].

Individual charging processes (CP) are aggregated to charging types (CT) such that the model can reasonably calculate the optimal dispatch or redispatch. Additionally, this strategy ensures that the technical limitations of the EVs and their charging infrastructure will be considered, and no restrictions emerge for the user.

It reduces the number of decision variables significantly. This is done based on a statistical evaluation of real-world charging events [44]. CPs with similar plug-in and plug-out times are summed up. These similarities can be described as a specific type of car user. Each CT describes a specific time slot within which a certain number of vehicles are connected to a charging station. For example, some EVs are used for commuting to work. These vehicles are charged at the workplace. The rectangular function of CT *day* in Fig. 3 describes this. The share of plugged-in EVs is larger than zero from 8 am to 5 pm (10 h). 2% of the considered vehicles are plugged in at each of these hours within the whole timeframe of 24 h. Consequently, this CT includes a total share of 20% $(10h \cdot 2\%/h = 20\%)$ of all EVs. This finding does not indicate that each vehicle connects to the charging station for the full timeframe but only the sum of the vehicles corresponds to this behaviour due to the aggregation.

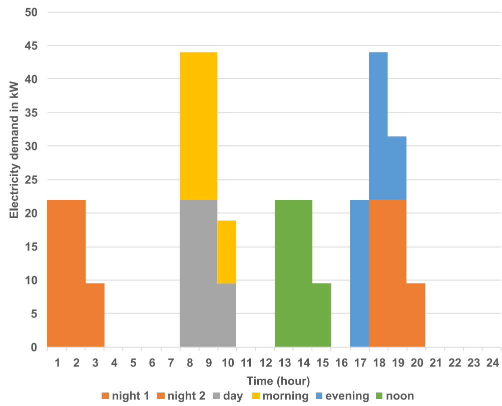

Fig. 5. Strategy *immediately*.

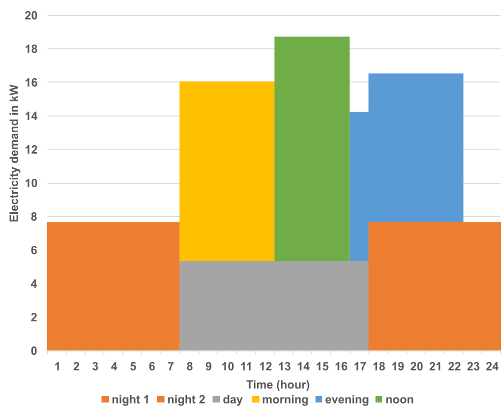

Fig. 6. Strategy *peak-shaving*.

Thus, the sum of all CTs defines the share of the considered EVs that are connected with the charging infrastructure at each hour. Hence, the sum of all CTs is 100%. The joint consideration of numerous vehicles within a CT reveals a similarity considering demand and flexibility potential (e.g. whether seven vehicles charge daily or one vehicle charges weekly).

The CTs are the temporal distribution of the plugged-in vehicles. These must first be converted into a concrete electrical demand. Charging strategies are used for this purpose. Three different charging strategies are used to calculate an electrical demand from the distribution function of the CTs described above.

(i) Strategy *immediately*: Charging with the maximum available power allowed by the vehicle and the charging infrastructure. The corresponding demand of one EV per CT charging with a nominal charging power of 22 kW can be observed in Fig. 5.
(ii) Strategy *peak-shaving*: Charging with a perfect smoothed demand over the entire plug-in time to prevent demand peaks (Fig. 6).
(iii) Strategy *partly peak-shaving*: Charging the same way as with the strategy *peak-shaving*, with the plug-in time reduced to 40%.

The multiplication of the CT distribution statistic with the considered number of EVs, their demand, based on statistical data (Section 4.2) and the charging strategies results in the overall CDs. Hence, several CDs (Γ) exist. Each of these CDs corresponds to one CT block and is the weighted sum of the three charging strategies (E.g. 70% *immediately*, 20% *partly peak-shaving* and 10% *peak-shaving*). In some scenarios, this CDs serve as model input and can be regulated (demand increase/decrease).

Fig. 4 shows the resulting CD for 30 000 EVs over 24 h. The electricity demand of a specific CD is always larger than zero (because of the partial use of the charging strategy *peak-shaving*) whilst the car is plugged in, which implies the flexibility potential for the model. The comparison of Figs. 3 and 4 shows that a CD only exists if EVs of the respective CT are connected to the charging infrastructure and the demand unevenly distributed due to a high proportion of the uncontrolled charging strategy *immediately*. The summation of individual CDs (D^{EV}) (e.g. Fig. 4) and their positive (d^{EV+}) or negative demand regulation (d^{EV-}) to an aggregated demand per node (d^{EV}) is described in Eq. (1).

$$d^{EV}_{t,n} = \sum_{\gamma \in \Gamma_n} D^{EV}_{t,\gamma} + d^{EV+}_{t,\gamma} - d^{EV-}_{t,\gamma} \qquad \forall t \in T, \forall n \in N. \tag{1}$$

An increase (2) and decrease (3) in demand are only possible when the CD is larger than zero, thereby implying that the EVs are connected to a charging station. The used EVs and the charging infrastructure limit the charging power. On the one hand, the upper power limit ($CAP^{EV\,max.}$) must not be exceeded. On the other hand, the charging power must not be lower than the minimum power ($CAP^{EV\,min.}$). These calculations are performed before the optimisation and therefore do not influence the model optimisation time; their implementation as LP models is also possible.

$$0 \le d^{EV+}_{t,\gamma} \le \left(CAP^{EV\,max.}_{\gamma} - D^{EV}_{t,\gamma}\right) \cdot \left(D^{EV}_{t,\gamma} > 0\right), \tag{2}$$

$$0 \le d^{EV-}_{t,\gamma} \le \left(D^{EV}_{t,\gamma} - CAP^{EV\,min.}_{\gamma}\right) \cdot \left(D^{EV}_{t,\gamma} > 0\right) \tag{3}$$

$\forall t \in T, \forall \gamma \in \Gamma.$

Moreover, these equations limit each EV's minimal, and maximal charging powers whilst the demand flexibility is in use. The electricity demand of each CD is always compensated whilst the vehicle is plugged in, which corresponds to the time frame during which a demand regulation is possible to avoid negative effects on the car owner. Eq. (4) ensures that the sum of up and down regulations over the entire 24 h DA optimisation step equals zero. Thus, demand flexibility influences the temporal charging power but not charged electricity in total.

$$\sum_{t=j\cdot 24+1}^{t=j\cdot 24+24} d^{EV+}_{t,\gamma} - d^{EV-}_{t,\gamma} = 0 \qquad \forall \gamma \in \Gamma, \forall j \in \left\{0, 1, \ldots, \frac{T}{24} - 1\right\}. \tag{4}$$

3.2. Dispatch model

The European electricity market model *EDisOn* [12] minimises the overall electricity generation costs of the entire system, which corresponds to the maximisation of social welfare. This model is an LP unit commitment model of the European electricity market implemented in MATLAB. The model calculates the minimal dispatch cost of all thermal power plants, RES-E curtailment, and storage units' utilisation. The RES-E generation technologies, namely PV, run-of-the-river hydroelectricity (RoR) and wind, are not dispatchable, and their generation profiles are exogenously defined. A reduced set of aggregated nodes $N^{disp.}$ is used in Austria to determine the optimal dispatch from an economic perspective. This set contains nodes that are connected via critical transport lines. Transmission lines within the new nodes in Austria are also aggregated; however, the absence of congestion of these lines is not guaranteed. Meanwhile, transfer capacities between the bidding zones are allocated within the optimisation. Fig. 7 shows the nodes and transmission grid used within the market-based dispatch.

3.2.1. Objective function

The objective function (5) minimises the overall electricity generation costs due to the generation (p_{th}), proportional to the SRMC and start-up costs (C^{start}) [60] of thermal power plants, RES-E operation and maintenance costs (O&M) (C^{RESE}), pumped hydro-power storage units (PHS) turbine O&M costs (C^{ps}) and not supplied energy (NSE) fee ($VoLL$). The RES-E O&M costs are proportional to RES-E generation

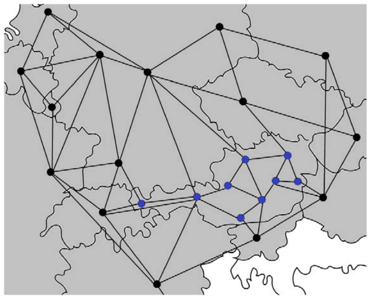

Fig. 7. Nodes and grid of the dispatch model.

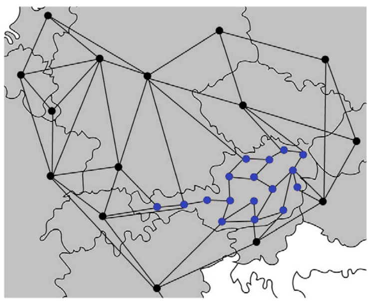

Fig. 8. Nodes and grid of the redispatch model.

(P^{RESE}) minus their curtailment ($spill^{RESE}$). PHS turbine O&M costs are proportional to the turbined electricity (p^{tu}).

$$\min_{p,str,spill^{RESE},p^{tu},nse} \sum_{t\in T}\sum_{th\in TH}\left(p_{t,th}\cdot SRMC_{th} + str_{t,th}\cdot C_{th}^{start}\right) + \sum_{t\in T}\sum_{ps\in PS} p_{t,ps}^{tu}\cdot C^{ps} + \sum_{t\in T}\sum_{r\in RESE}\left(P_t^{RESE} - spill_{t,r}^{RESE}\right)\cdot C^{RESE} + \sum_{t\in T}\sum_{n\in N^{disp.}} nse_{t,n}\cdot VoLL. \tag{5}$$

3.2.2. Constraints

The electricity demand (D_n) must be compensated in every aggregated node for each timestamp (6). The additional demand of EVs (D_n^{EV}) is implemented in accordance with (1) as a constant or a flexible demand. The demand compensation is done by thermal generation (p_{th}), PHS turbine generation (p^{tu}), storage discharging (p^{out}), RES-E generation (P^{RESE}) minus their curtailment ($spill^{RESE}$) and NSE (nse). The demand increases through PHS pump utilisation (p^{pu}) and storage charging (p^{in}).

The dual variable of this constraint (P_t^{DA}) provides the local DA price as an hourly profile. This price is used in the redispatch step to evaluate the cost of redispatch measures.

$$D_{t,n} + D_{t,n}^{EV} = \sum_{th\in TH_n} p_{t,th} + \sum_{ps\in PS_n}(p_{t,ps}^{tu} - p_{t,ps}^{pu}) + \sum_{st\in ST_n}(p_{t,st}^{out} - p_{t,st}^{in}) + P_{t,n}^{RESE} - spill_{t,n}^{RESE} - exch_{t,n} + nse_{t,n} \;:\; P_{t,n}^{DA} \qquad \forall t\in T, \forall n\in N_{ca}^{disp.}. \tag{6}$$

Thermal power plants are limited by a ramp rate and their technical minimal, and maximum capacities, which are implemented as a linear function to consider start-up costs [60]. The power generation of the RES-E technologies is represented by a yearly profile with hourly temporal resolution and their installed capacity per node. Storage units are power- and capacity-limited. Furthermore, pumped hydro storage units must follow an annual pattern to map a realistic operating behaviour as a long-term storage system.

The power exchange between the nodes (exch) is calculated using a power transfer distribution factor (PTDF) matrix. This method presupposes that the voltage angle between neighbour nodes is small; thus, a direct current (DC) approximation of the power flow can be used [61]. Matrix A is an incidence matrix, which describes which nodes are connected by a specific transmission line.

Based on this methodology, the susceptance ($B_{l_{AC}}$) of the lines is calculated (7). The resistance ($R_{l_{AC}}$) is negligible and the reactance ($X_{l_{AC}}$) is considered. Subsequently, the corresponding diagonal matrix (B_d) is formed (8) to calculate the PTDF matrix (9). This describes the relationship between the energy exchange between the nodes (exch), and the load flows over the transmission lines (flow) (10), (11).

$$B_{l_{AC}} = \frac{-X_{l_{AC}}}{R_{l_{AC}}^2 + X_{l_{AC}}^2} \approx -\frac{1}{X_{l_{AC}}} \tag{7}$$

$$B_d =: diag(B_{L_{AC}}) \tag{8}$$

$$PTDF = (B_d * A) * (A^T * B_d * A)^{-1} \tag{9}$$

$$flow_{t,l_{AC}} = \sum_{bg\in BG} PTDF_{l_{AC},n}\cdot exch_{t,n} \tag{10}$$

$$exch_{t,n} = \sum_{l\in L} A_{l,n}\cdot flow_{t,l} \tag{11}$$

$$\forall t\in T, \forall n\in N^{disp.}, \forall l\in L$$

The transmission lines and their transfer capacities are aggregated, and only the information regarding their spatial distribution is lost within the market-based dispatch. These lines are limited by their total net transfer capacities (NTC) [62].

3.3. Redispatch model

After the dispatch, model has minimised the overall electricity generation costs with an aggregated set of nodes $N^{disp.}$ and transmissions lines (Fig. 7), these nodes are disaggregated (Fig. 8) before performing the cost minimal redispatch in Austria. Thus, the differences between the market-based optimum and the actual physical power flows that may lead to congested transmission lines and must be compensated are analysed. The previously dispatched power plants are then assigned to the respective nodes using their existing generation schedules. The decision variables of the dispatch remain unchanged, as parameters, during the redispatch optimisation. The redispatch needs are balanced cost-minimal by new decision variables that adjust the generation of thermal power plants and additional curtail RES-E and use the EV demand-side flexibility.

3.3.1. Objective function

The modification of generation schedules to balance redispatch needs is associated with costs. Costs that arise due to the increase in thermal power plant generation must be compensated. The costs of a thermal generation increase ($C^{thRedis}$) as redispatch measure is the same as the local DA market price (P^{DA}). If the SRMC of the generation unit is higher than this price, then these costs must be compensated (12). The dispatch model is based on the merit-order function. Thus, the DA market price will be zero or even negative during periods with a remarkably high share of RES-E. Redispatch costs are also calculated for the curtailment of PV, wind and RoR ($C^{RESRedis}$) to ensure the economic participation in the redispatch market for RES-E from the operator viewpoint. These costs are either the fixed market premium ($P^{Mkt.Premium}$) for the specific technology or the local DA price (P^{DA}) if this is higher (13).

$$C_{t,th}^{thRedis} = max\left(P_n^{DA}, SRMC_{th}\right), \tag{12}$$

$$C_{t,n}^{RESRedis} = max\left(P_n^{DA}, P_n^{Mkt.Premium}\right). \tag{13}$$

The redispatch costs, that are minimised for Austria (14), arise from costs of thermal power plant generation schedule modification (generation increase: $p_{t,th}^{+Redis}$, generation decrease: $p_{t,th}^{-Redis}$) (15) and RES-E curtailment ($spill_{Redispatch}^{RESE}$) (16). EV demand regulation does not lead to additional costs.

$$\min_{C_{Redis_{th}}, C_{Redis_{RES}}} C_{Redis_{th}} + C_{Redis_{RES}}, \tag{14}$$

$$C_{Redis_{th}} = \sum_{t \in T} \sum_{th \in TH_{AT}} \left(p_{t,th}^{+Redis} \cdot C_{t,th}^{thRedis} - p_{t,th}^{-Redis} \cdot SRMC_{th} \right), \tag{15}$$

$$C_{Redis_{RES}} = \sum_{t \in T} \sum_{n \in N_{AT}} \left(spill_{Redispatch_n}^{RESE} \right) \cdot C_{t,n}^{RESRedis}. \tag{16}$$

3.3.2. Constraints

The demand compensation constraint (6) is expanded to (17) by the additional redispatch decision variables. This equation is only used within Austria because the redispatch evaluation is conducted in this location. In contrast to the market-based dispatch, all transmission lines and nodes are considered (N_{AT}). The nodes are still aggregated in all other countries; therefore, no local congestion management is necessary. Only redispatch measures within Austria will marginally change the power flow over their interconnectors. The generation schedules are taken over from the dispatch; thus, the redispatch regulation must be used if necessary.

$$D_{t,n} + d_{t,n}^{EV} = \sum_{th \in TH_n} P_{t,th} + p_{t,th}^{+Redis} - p_{t,th}^{-Redis} + \sum_{ps \in PS_n} (P_{t,ps}^{tu} - P_{t,ps}^{pu}) \tag{17}$$
$$+ \sum_{st \in ST_n} (P_{t,st}^{out} - P_{t,st}^{in}) + P_{t,n}^{RESE} - Spill_{t,n}^{RESE} - spill_{Redispatch_n}^{RESE}$$
$$- exch_{t,n} + NSE_{t,n} \qquad \forall t \in T, \forall n \in N_{AT}.$$

Unless the EV demand is regulated, Eq. (18) ensures that the sum of generated electricity within Austria is constant before and after the congestion management.

$$\sum_{n \in N_{AT}} d_{t,n}^{EV+} + \sum_{th \in TH_n} p_{t,th}^{-Redis} + \sum_{n \in N_{AT}} spill_{Redispatch_n}^{RESE} \tag{18}$$
$$= \sum_{n \in N_{AT}} d_{t,n}^{EV-} + \sum_{th \in TH_n} p_{th}^{+Redis} \qquad \forall t \in T.$$

All other control areas are restrictively aggregated as a sum for their thermal power plant generation (19). Consequently, these areas can compensate for the differing exchanges over the interconnectors created by congestion management in Austria. The exchanges with Austria are generally consistent with the one determined in the dispatch, but other transmission lines are possibly used.

$$\sum_{th \in TH_{CA_{Redis}}} p_{t,th}^{-Redis} = \sum_{th \in TH_{CA_{Redis}}} p_{t,th}^{+Redis} \qquad CA_{Redis} := CA \setminus AT. \tag{19}$$

The generation of the thermal power plants can be increased or decreased (20) based on the generation schedules in the dispatch. However, neither the limits of their technical capacity nor the power gradient may be exceeded.

$$p_{Redispatch_{th}}^{+} \geq 0; \qquad p_{Redispatch_{th}}^{-} \geq 0 \qquad \forall th \in TH. \tag{20}$$

The curtailment of RES-E as a redispatch measure (21) must consider the curtailment that was already performed in the dispatch.

$$0 \leq spill_{Redispatch_{t,n}}^{RESE} \leq P_{t,n}^{RESE} - Spill_{t,n}^{RESE} \tag{21}$$
$$\forall t \in T, \forall n \in N_{ca}.$$

The usage of the storage units, as well as NSE, remain unchanged as planned in the dispatch. Readjusting them within the redispatch is impossible. The nodes' exchanges are again calculated considering the new disaggregated transmission grid.

3.4. Model validation

The three developed models were validated separately. The power plant dispatch and the resulting DA prices of the dispatch model without demand-side flexibility and redispatch afterwards are compared with published electricity market data from the year 2013.

The redispatch model was verified without demand-side flexibility and with perfect foresight of the transmission grid already during the dispatch.

The EV model was verified for compliance with the implemented constraints.

A detailed explanation of the validation can be found in Appendix B.

4. Results

4.1. Input data

The fulfilment of the European national energy and climate plans (NECP) [63] by 2030 is assumed for all countries within the optimised area (AT, DE, NL, BE, LU, CH, CZ, Sl, PL, SK, HU, IT and FR) to investigate the potential of EV demand-side flexibility in an electricity market with a high share of RES-E. The NECP of Austria reveals that in balance, 100% of the yearly electricity demand is compensated by RES-E. The used *National Trends (NT) 2030* scenario provided by the European network of transmission system operators (ENTSO-E) is based on the fulfilment of these plans [64]. The used parameters can be found in Appendix C.

4.2. Electric vehicle data

The used CTs and subsequently the CDs of all EVs, described in Section 3.1 are based on the statistical evaluation of real-world charging events [44] in combination with statistical data. The charging strategies used are divided as follows: 70% *immediately*, 20% *partly peak-shaving* and 10% *peak-shaving*.

4.3. Scenarios

The optimisation is conducted as a rolling horizon optimisation with 365 24 h DA optimisation steps. The redispatch is optimised with a different number of EVs to demonstrate the influence of aggregated flexibilities as a congestion management compensation system. The cost-minimal redispatch is performed with 200 000 (*Scen. 200k*), 600 000 (*Scen. 600k*), and 2 000 000 (*Scen. 2M*) EVs as demand flexibility devices. Overall there are around 5 000 000 passenger cars in Austria. Thus, the electrification rate of Austria's private individual transport sector is 4%, 12%, and 40% [65]. Each transport electrification level is optimised with three different flexibility setups.

Firstly, the flexibility is optimised in the redispatch. Austrian law allows aggregated consumers to participate in the congestion management market due to the increasing share of RES-E and to encourage active customer participation. Hence, the EVs participate in the congestion management market to reduce redispatch needs (*Scen. Redispatch DSM*). Secondly, EVs do not actively participate in the electricity market. Demand-side flexibility can neither be used in the dispatch nor the redispatch (*Scen. no DSM*). Hence the summation of the CDs serves as additional inflexible demand. This scenario forms the "baseline" to analyse the effect of the other two scenarios. Thirdly, flexibility is available in the dispatch. Therefore, their CD will be adapted to the DA price (*Scen. Dispatch DSM*).

4.4. Redispatch electricity usage

The bars in Fig. 9 show the total amount of electricity used to operate redispatch without demand-side flexibility for all aggregated nodes. Negative electricity corresponds to a curtailment. Thus, PV, wind and RoR are only found herein. Positive electricity corresponds to a power increase and can only be executed by thermal power plants. Biomass power plants are also included; therefore, their use does not necessarily result in additional CO_2 emissions. Fig. 10 shows the influence of EV demand-side flexibility on this electricity usage with the same number of EVs. This flexibility can reduce the generation increase and raise the generation reduction of gas turbines at several nodes (e.g. *N 5* and *7*) as well as wind and PV curtailment. The *EV DSM* areas of the bars are identical in both directions due to the rebound effect associated with temporal demand shifts.

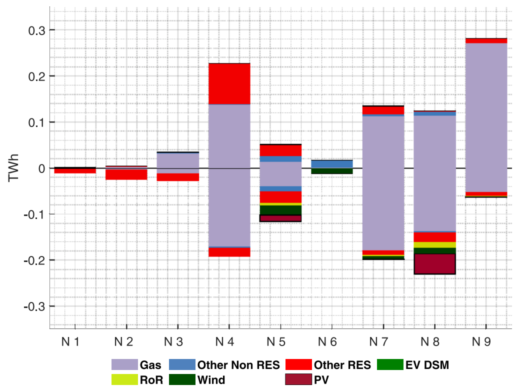

Fig. 9. Redispatch measures in the *600k - no DSM* scenario.

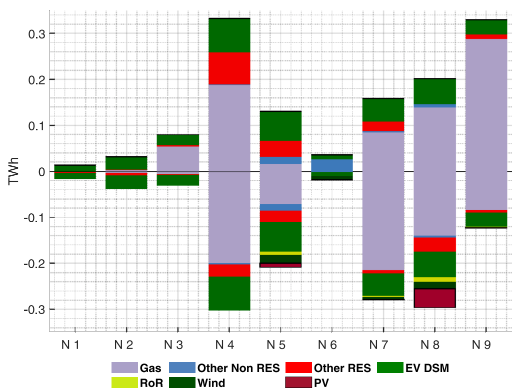

Fig. 10. Redispatch measures in the *600k - Redispatch DSM* scenario.

4.5. Curtailment of renewable energies

Fig. 11 shows that flexible demand as a redispatch measure leads to a reduction in RES-E curtailment regardless of the number of used vehicles. Reduced curtailment increases their economic profitability and thus raises possible investment incentives. The curtailment of RES-E always leads to a generation increase of thermal power plants due to the electricity equilibrium constraint (Eq. (18)). If curtailments in the dispatch and redispatch are considered together (Fig. 12), then the use of demand-side flexibility in the redispatch also leads to the lowest curtailments of RES-E. In the scenario *2M* the flexibility utilisation in the dispatch reduces the curtailment in the dispatch (0.04 TWh). However, the negative effects (an increase of 0.59 TWh) in redispatch compensate for this positive effect. If flexible demand is used in the dispatch, then the probability of transmission line congestion increases due to market-controlled charging. Thus, frequent interventions are necessary.

4.6. Redispatch costs

Demand-side flexibility in the redispatch causes significant costs savings (Fig. 13) in comparison to the scenario without EV flexibility. The costs are reduced from 59 million € to 57 million € by 3.3%, from 57 M€ to 53 M€ by 7.3% and from 56 M€ to 48 M€ by 13.9% in the *200k*, *600k* and *2M* EV scenarios. Flexible demand in the dispatch in the *200k* scenario does not cause additional costs. However, such demand increases the redispatch costs significantly in the *600k* and *2M* scenarios due to congestions caused by a high simultaneous EV charging demand. Two million EVs rise these costs from 56 M€ to 160 M€ by 186%. The redispatch costs per generation type for the scenario *600k - Redispatch DSM* (Fig. 14) show that a large part of the

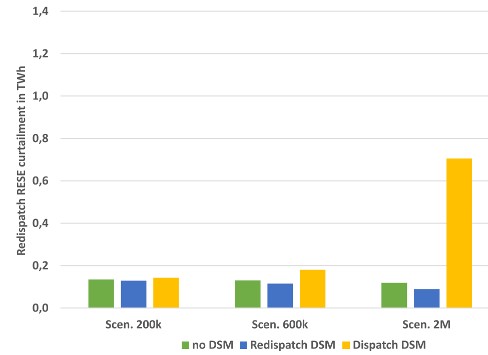

Fig. 11. Curtailment of renewable energies as redispatch measure.

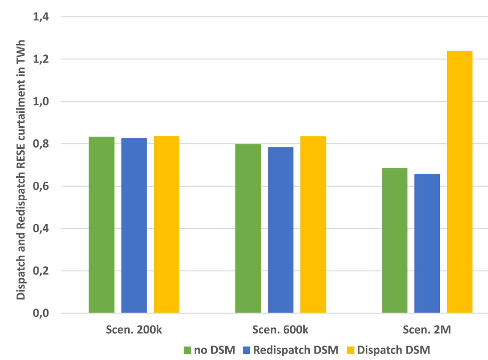

Fig. 12. Curtailment of renewable energies within the dispatch and redispatch.

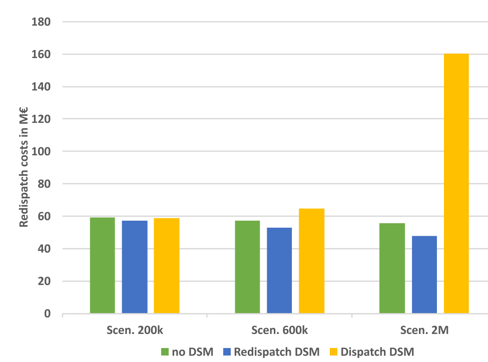

Fig. 13. Redispatch costs.

costs is incurred by thermal power plants and not by the curtailment of RES-E. These high redispatch costs of thermal power plants arise due to the use of the least expensive generation units during the dispatch. Therefore, only the respective marginal generation unit or pricier ones are available to balance redispatch needs.

The share of PV on the generation mix is remarkably high during summer due to the high penetration of PV with an installed capacity of 12 GW in Austria. The geographic distribution of PV systems is more even than that of other generation units (e.g. thermal power plants). These systems are almost always used in the dispatch due to their low SRMC, which reduces the local need for electricity imports. These systems also increase the consumption within their associated node and thus reduce the utilisation of the transmission grid, the need for redispatch measures and the associated costs.

4.7. CO_2 emissions

The necessity of redispatch measures and their provision by different technologies varies throughout the year, thus influencing the

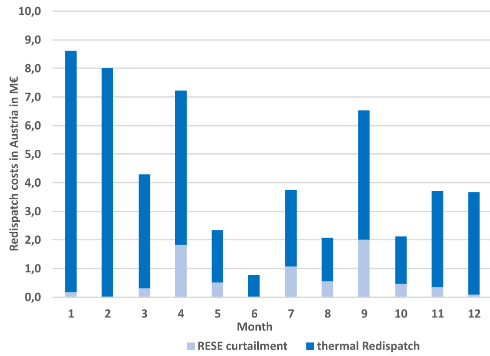

Fig. 14. Allocation of the redispatch costs.

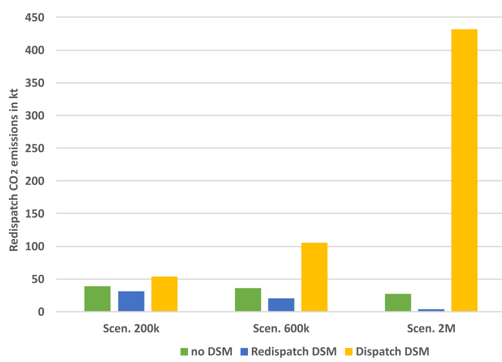

Fig. 15. Redispatch CO_2 emissions.

resulting CO_2 emissions. As a redispatch measure, flexible demand leads to a significant reduction in redispatch-caused emissions over the entire year in Austria (Fig. 15). Overall, these emissions are as follows; 31 ktons instead of 39 ktons and therefore 20% less for the *200k* scenario, 20 ktons instead of 36 ktons, which is 44% less for the *600k* scenario and 4 ktons instead of 28 ktons, which is a reduction of 85% for the *2M* scenario. By contrast, flexible demand during the dispatch leads to frequent congestion due to market-based charging and therefore increases emissions because thermal power plants are used to a high extent to overcome transmission line congestions (Section 4.5).

An increasing number of EVs leads to minimal RES-E curtailment, low CO_2 emissions and redispatch costs, if demand-side flexibility is used in the redispatch (*Scen. Redispatch DSM*) or not at all (*Scen. no DSM*). The overall electricity demand is increasing due to the larger number of EVs. Thermal power plants must compensate this increase if available RES-E is insufficient. Hence, additional thermal power plants are available for redispatch measures.

In contrast to RES-E curtailment, thermal power plant regulation reduces CO_2 emissions in the redispatch. Therefore, the CO_2 emissions in the redispatch decrease but are even high in the dispatch. The downward regulation of thermal plants in the redispatch leads to a refund of their SRMC in contrast to RES-E curtailment for which the market premium must be paid. Hence, redispatch costs are also significantly influenced by the varying electricity mix.

5. Discussion

The results show that the use of temporal flexible charging events significantly reduces redispatch costs (Section 4.6) in comparison to the scenario without EV flexibility. The costs are reduced from 3.3% to 13.9% in the three scenarios. Hence, the cost reduction increases significantly with the available EVs. If demand-side flexibility is used in the dispatch for market-based charging, the costs of the subsequent redispatch increase. Especially if a large EV fleet is considered, these costs rise by 186%. The demand of EVs and the cost savings from their participation in the congestion management market result in potential profits for the participants of less than one cent per kWh. Hence, from the customer‘s perspective, participation in the congestion management market is only reasonable if additional attractive conditions are provided (e.g. through different pricing models of charging tariffs at public charging points).

The use of demand-side flexibility to balance redispatch needs influences RES-E curtailment (Section 4.5). It reduces PV and wind curtailment (up to 25%) and decreases the generation increase of thermal power plants as a redispatch measure. This, moreover, leads to less CO_2 emissions. On the other hand, the use of this flexibility in the dispatch increases RES-E curtailment. Especially if a large EV fleet is considered. This influence exists regardless of the consideration. Both if the curtailment in redispatch and the total curtailment in dispatch and redispatch are considered together. This demonstrates that the demand increase in dispatch reduces curtailment. The additional curtailment in the redispatch compensates for this positive effect. Avoided RES-E curtailment leads to lower CO_2 emissions (Section 4.7). As a redispatch measure, flexible demand significantly reduces redispatch-caused emissions (up to 85%). Flexible demand during the dispatch leads to frequent congestion due to market-based charging. Hence, emissions rise.

The use of demand-side flexibility to reduce balancing needs leads to large demand shifts (Section 4.4). The total amount of electricity to be regulated during the redispatch increases due to the rebound effect of demand shifts. The associated regulation effort of the aggregators and the TSO requires a suitable IT infrastructure and standardised interfaces of the charging infrastructure. This establishes a congestion management market with low barriers for customers.

In summary, using demand-side flexibility as a market-based charging strategy leads to a significant rise in redispatch costs and CO_2 emissions. The use of demand-side flexibility in the redispatch, on the other hand, significantly reduces the need for redispatch measures, whilst the associated costs, CO_2 emissions and RES-E curtailment are reduced. This finding shows that the integration of demand-side flexibility, combined with RES-E expansion, can be an essential part of achieving the Green Energy for All Europeans‘ goals. It can reduce the need for redispatch measures and transmission grid expansion. However, the total amount of electricity to be regulated during the redispatch increases due to the rebound effect of demand shifts.

6. Conclusion

This paper proposes a novel method to integrate aggregated EVs as demand-side flexibility into the European electricity market, wherein the market-based dispatch and redispatch are optimised and analysed.

The described methodology allows the aggregation of charging events without losing the parameters necessary for the application as a demand-side flexibility system. Furthermore, compliance with the technical limitations of the vehicles and the charging infrastructure and the avoidance of restrictions for the EV users are ensured. However, the formulation as LP is possible because many of the necessary calculations can already be performed before the start of the optimisation. Therefore, integration is possible for large-scale and computationally intensive models, such as electricity market models. The dispatch model with subsequent redispatch is solved as a rolling optimisation with short time steps due to the model’s level of detail and size. Therefore, the theoretically possible optimum is approximated but corresponds to the realistic behaviour of DA electricity markets.

The methodology that was used to implement demand-side flexibility is not limited to EVs but can also be easily adapted to integrate other coupled sectors through appropriate parameter selection. Hence, in addition to the electrification of the transport sector, integration as demand-side flexibility is possible in other sectors (e.g. heating or hydrogen). Several benefits are generated through the integration of demand-side flexibility in the redispatch. However, The total amount of electricity to be regulated during the redispatch increases due to the rebound effect of demand shifts. The associated regulation effort of the aggregators and the TSO requires a suitable IT infrastructure and standardised interfaces of the charging infrastructure. The use of cross-border flexibility would also substantially raise these IT requirements. The analysis builds on the widespread participation of EVs in the redispatch market, whereby it is not ensured that enough participants will allow externals to control the charging events of their vehicles. Nevertheless, the potential of distributed flexible demand within a market-based congestion management system in an electricity market with a high share of RES-E is demonstrated.

Redispatch costs are optimised within one control area, and adjacent areas are considered aggregated. Thus, cross-border redispatch is not evaluated to the full extent. Moreover, the redispatch costs and revenues from cross-border redispatch are not covered, but a qualitative analysis of these costs is possible. A holistic redispatch model would require a detailed power plant fleet of the entire market area, including all associated transmission lines. Generation units with identical SRMC can no longer be distinguished from each other due to the aggregation of the power plants before dispatch and subsequent disaggregation before redispatch. Therefore, their assignment to a specific node is no longer possible. This issue is irrelevant in the current study because a set of nine nodes is used in the dispatch to derive local price signals for the redispatch market.

The current study focuses on redispatch measures in Austria. Therefore, further efforts could address the effects on cross-border redispatch if the provided flexibility is used not only within one control area but in a European congestion management market. The redispatch model can be extended to allow the exact allocation and differentiation of power plants with identical bids in the electricity market (SRMC). This extension can be conducted by analysing these generation units, wherein their price bids are different due to slight variations of SRMC or strategic bidding behaviour. The integration of other sectors than private transport into electricity market models (e.g. heating and hydrogen as demand-side flexibility) can demonstrate the sector with the best performance for redispatch measures. Furthermore, flexibility can be used to participate in the ancillary service markets. In addition, EVs as V2G units, as well as decentralised battery storage units, which are installed in combination with PV systems, can also participate in the congestion management market. PV systems are not only used for temporal demand shifting but also as bidirectional electricity storage units due to the existing possibility of feeding these systems into the grid.

CRediT authorship contribution statement

Christoph Loschan: Writing – original draft, Editing, Conceptualization, Methodology. **Daniel Schwabeneder:** Writing – review & editing. **Georg Lettner:** Writing – review & editing, Funding acquisition. **Hans Auer:** Supervision, Writing – review & editing.

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

Most data used is public available. The data is referenced in the paper. Some data-sources are confidential.

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Table A.1
Model parameters and decision variables.

Sets		
L	Transmission lines	index: l_{AC}
N	Nodes	index: n
N_{AT}	Nodes in Austria	index: n
$N^{disp.} \subseteq N$	Aggregated nodes	index: n
CA	Control areas	index: ca
PS	Hydro storage units	index: ps
ST	Battery storage units	index: st
T	Time steps	index: t
TH	Thermal power plants	index: th
$RES-E$	Renewable energy sources	index r
Γ	Charging demands	index: γ
Parameters — Dispatch and Redispatch model		
A_n	Incidence matrix	(0;1)
B_l	Transmission line susceptance	Ω
B_d	Susceptance diagonal matrix	Ω
C^{ps}	PHS turbine costs	€/MWh
C^{RESE}	Renewable energy maintenance costs	€/MWh
C^{start}	Start-up costs	€
D_n	Electrical demand without EV demand	MWh
P^{RESE}	Renewable energy generation	MWh
R_l	Transmission line resistance	Ω
$SRMC$	Short run marginal costs	€/MWh
VoLL	Value of lost load	€/MWh
X_l	Transmission line reactance	Ω
Decision variables — Dispatch and Redispatch model		
d^{EV}	Demand of electrical vehicles	MWh
$exch_n$	Power exchange from/to n	MWh
$flow_{l_{AC}}$	Power flow over a AC transmission line	MWh
p^{in}	Charging	MWh
p^{out}	Discharging	MWh
p^{pu}	Pump mode	MWh
p_{th}	Electricity generation of th	MWh
p^{tu}_{ps}	Turbine mode	MWh
$spill^{RESE}$	Renewable energy curtailment	MWh
str_{th}	Start-up of th	(0;1)
nse	Not Supplied Energy	MWh
Parameters — Redispatch model		
$C^{RESRedis}$	RES-E curtailment costs	€/MWh
$C^{thRedis}$	Costs of increased generation	€/MWh
P^{DA}_n	Day-ahead price	€/MWh
$P^{Mkt.Premium}$	Market premium	€/MWh
Decision variables — Redispatch model		
p^{+Redis}_{th}	Increase electricity generation	MWh
$p^{-Redis}_{t,th}$	Decrease electricity generation	MWh
$spill^{RESE}_{Redispatch_n}$	Additional renewable energy curtailment	MWh
Parameters — Electric vehicle model		
$CAP^{EV min.}$	Minimal charging power	MW
$CAP^{EV max.}$	Maximum charging power	MW
Decision variables — Electric vehicle model		
d^{EV}_n	Demand of all EVs in n	MWh
d^{EV}_γ	Demand of charging profile γ	MWh
d^{EV+}_γ	Demand increase of charging profile γ	MWh
d^{EV-}_γ	Demand decrease of charging profile γ	MWh

Appendix A. Nomenclature

See Table A.1.

Appendix B. Model validation

The dispatch, redispatch and the EV model are validated separately to prove their functionality without interactions between the models.

The driving patterns and the assumptions regarding their electricity demand are listed in Table C.4.

Table B.2
Redispatch model validation.

Hour in h	Dispatch						Redispatch					
	Load in MW		RESE in MW	Power plant in MW			NSE in MW	RESE in MW	Power plant in MW			DC load flow in MW
	SW	SE	SW	N	SW	SE	SW and SE	SW	N	SW	SE	
1	0	960	960	0	0	0	0	960	0	0	0	466
2	450	450	800	0	100	0	0	800	0	100	0	0
3	400	400	600	0	200	0	0	600	0	200	0	0
4	1200	0	0	600	0	600	0	0	600	0	600	615
5	600	600	600	0	600	0	0	600	0	600	0	106
6	0	4600	2000	600	2000	0	2276	1263	461	0	600	1000
7	800	800	800	0	800	0	0	800	0	800	0	306
8	0	4600	2000	0	2000	600	2276	1263	461	0	600	1000
9	1000	2200	1000	600	1000	600	0	1000	585	1015	600	1000
10	900	900	900	0	900	0	0	900	0	900	0	406
11	1000	1000	1000	0	1000	0	0	1000	0	1000	0	506
12	1100	1100	1100	0	1100	0	0	1100	0	1100	0	606
13	0	600	0	600	0	0	0	0	600	0	0	15
14	0	5200	2000	600	2000	600	2876	1263	461	0	600	1000
15	0	4600	2000	600	2000	0	2276	1263	461	0	600	1000
16	1100	1100	0	600	1000	600	0	0	600	1000	600	0
17	1200	1200	1200	0	1200	0	0	1200	0	1200	0	706
18	0	4000	2000	0	2000	0	1676	1263	461	0	600	1000
19	1400	1400	1400	0	1400	0	0	1400	0	1400	0	906
20	1300	1300	1300	0	1300	0	0	1300	0	1300	0	806
21	1100	1100	1100	0	1100	0	0	1100	0	1100	0	606
22	900	900	900	0	900	0	0	900	0	900	0	406
23	700	700	700	0	700	0	0	700	0	700	0	206
24	500	500	500	0	500	0	0	500	0	500	0	6

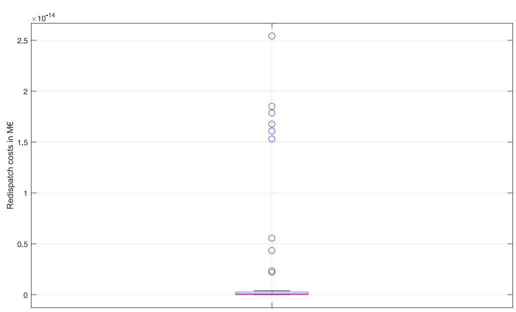

Fig. B.16. Validation — objective function of the redispatch model.

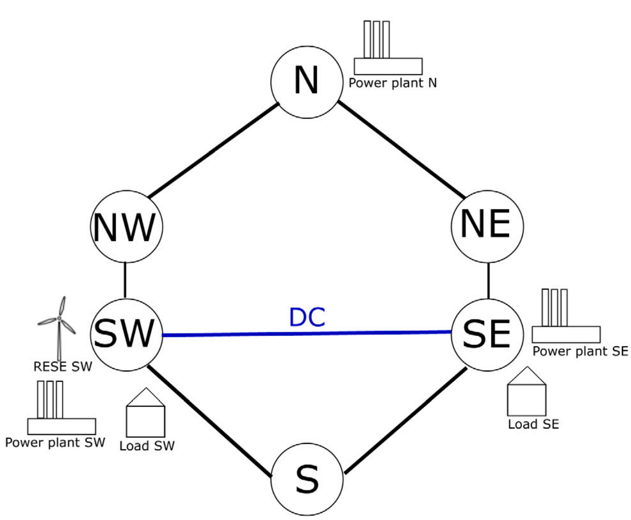

Fig. B.17. Setup of the redispatch validation model.

Table C.3
Cost parameters of the market model.

Parameter	Value	
CO_2 price	100	€/t
VoLL	10 000	€/MWh
Wind/PV O&M costs	0.1	€/MWh
RoR O&M costs	0.01	€/MWh
PHS turbine costs	1.0	€/MWh
$P_n^{Mkt.Premium}$	60	€/MWh

Table C.4
Electric vehicle parameters.

Parameter	Value	
Driving pattern	13 900	km/a
Electricity demand	20.0	kWh/100 km
Electricity demand per year	2 780	kWh
Electricity demand per week	53	kWh
Nom. charging power	22	kW
$CAP_{\gamma}^{EV min.}$	1	kW
$CAP_{\gamma}^{EV max.}$	22	kW

Table C.5
Scenario overview.

Demand-side flexibility	Electric vehicle fleet size	Scenario name
Not in use	200 000 600 000 2 000 000	*200k - no DSM* *600k - no DSM* *2M - no DSM*
Dispatch (market-based charging)	200 000 600 000 2 000 000	*200k - Dispatch DSM* *600k - Dispatch DSM* *2M - Dispatch DSM*
Redispatch (reduce redispatch needs)	200 000 600 000 2 000 000	*200k - Redispatch DSM* *600k - Redispatch DSM* *2M - Redispatch DSM*

B.1. Dispatch model

The validation of the dispatch model is performed without redispatch after the market clearing. The EV model is not implemented; hence, demand-side flexibility provided by EVs is impossible. The

Table C.6
Generation unit parameters.

	Efficiency in %	Emissions in t/MWh	Prim. energy price in €/MWh	O&M costs in €/MWh	Min. load in %	Gradient in %/min	Start-up costs in €
Gas-1	34.0	0.20196	24.9	1.6	35.0	3.0	68
Gas-2	45.15	0.20196	24.9	1.6	35.0	6.0	43
Gas-3	56.3	0.20196	24.9	1.6	35.0	9.0	25
Coal-1	36.5	0.34524	15.5	3.3	43.0	1.0	70
Coal-2	43.25	0.34524	15.5	3.3	43.0	2.0	50
Coal-3	50.0	0.34524	15.5	3.3	43.0	4.0	42
Lignite-1	36.0	0.3636	4.0	3.3	43.0	0.5	70
Lignite-2	40.5	0.3636	4.0	3.3	43.0	1.0	50
Lignite-3	45.0	0.3636	4.0	3.3	43.0	2.0	42
Oil-1	32.0	0.27	73.8	3.3	35.0	1.0	70
Oil-2	35.0	0.27	73.8	3.3	35.0	2.5	70
Oil-3	38.0	0.27	73.8	3.3	35.0	4.0	50
Other Non-RES	35.0	0.2	24.9	3.3	1.0	4.0	36
Other-RES	46.0	0	10.0	0	0	4.0	0
Biofuel	0.46	0	10.0	0	0	4.0	0
Nuclear	33.0	0	1.7	9	50.0	5.0	21
RoR	100	0	0	0	0	0	0
Wind	100	0	0	0	0	0	0
PV	100	0	0	0	0	0	0
PHS	86.0	0	0	0	0	0	0
HS	86.0	0	0	0	0	0	0
Battery	90.0	0	0	0	0	0	0

electricity generation from 2013 is compared with published electricity market data from the *Yearly Statistics and Adequacy Retrospect* report from 2013 published by ENTSO-E. This validation of the *EDisOn* model can be found in [12].

B.2. Redispatch model

The redispatch model is verified in two independent methods. Firstly, node/transmission line aggregation influence in the dispatch on the redispatch is shown. For this purpose, the redispatch model is verified without demand-side flexibility of EVs either during the dispatch or the redispatch. The nodes' and transmission grid aggregation before the optimisation is skipped. A perfect foresight of the transmission grid utilisation is provided during the dispatch. The remaining parameters and the data set are the same as used in this paper. The objective function and the main constraints of the redispatch model focus on Austria and not on the entire electricity market as in the dispatch. The model can regulate thermal power plants in all countries and change the power exchange between bidding zones.

The perfect foresight prevents any congestion in Austria during the dispatch. Hence, the redispatch costs of Austria should never be positive. These costs should be negative because the model allows changes in the cross-border exchanges, but the electricity balance should be constant. Austria could decrease the generation of considerably expensive thermal power plants and increase the generation of cheap ones to maintain a balanced overall generation. These less expensive power plants were not used during dispatch because the objective of the dispatch is not the cost minimisation for one control area but the overall system. Thus, generation units in Austria may generate and export some electricity from more expensive generation units to their neighbouring countries than they would to cover the demand of Austria.

The results show that the redispatch is not negative or zero at every optimisation step as expected but positive at 61 days of the year and negligibly small in the scale of 10^{-14} (Fig. B.16). The highest positive redispatch cost is $2.542 \cdot 10^{-14}$ € and, therefore, an acceptable calculation error.

Secondly, the validation of the redispatch model was conducted using a small test model, with an exogenously defined dispatch and DA price (Fig. B.17). The parameters of the dispatch and the resulting values after the redispatch are listed in Table B.2. A power decrease through redispatch measures is marked red, while an increase is marked green. The AC transmission lines between the nodes N, NW, NE, SW and SE have an NTC capacity of 395 MW. The AC transmission lines between nodes SW, S and SE are limited to 329 MW, while the DC transmission line has a capacity of 1000 MW. All AC transmission lines are modelled with the same susceptance. Hence, an easy verifiable load flow is generated. The DC line is not used until the capacity of the AC lines is insufficient (utilisation price of 0.05 €/Mwh). The power plants at node *N* and SE have an installed capacity of 600 MW, while the one in Node SW has a capacity of 2000 MW. The RES-E at Node SW is only curtailable but cannot increase the generation. Power increase/decrease of each power plant leads to the same costs/revenues, while RES-E curtailment is free of charge.

In the test model, there are two possibilities for the AC load flow from one node to every other node. Since the susceptance of the transmission lines is the same, the load flow over these two routes is divided inversely proportional to the number of transmission line segments. The load flow can be easily replicated in hour 1 since no redispatch is necessary for that hour. Due to the location of generation and demand, 960 MW must be transferred from the SW node to the SE node. Hence, 4/6 of the AC load will flow from node SW via node S to node SE. 2/6 of the AC load will flow from Node SW via Node NW, Node *N* and Node NE to Node SE. Since the line from node SW to node S is limited to 329 MW, only 329 MW will flow through it. Due to the calculated distribution of the load flow, only half of it will take the route via node S ($\frac{2/6}{4/6}$). Hence, 494 MW (329 + 165) are transported via the AC lines, and the remaining 466 MW via the DC line. In hour 6, the line capacities are insufficient to transport the generation in nodes SW and *N* to the load in node SE. Thus, the generation in node SW is curtailed from 4000 MW to 1263 MW, and the capacity of the DC power is utilised to the maximum of 1000 MW. The generation in node SE is increased to 600 MW (max. capacity) as the demand is located there. Generation in node *N* is increased to 461 MW. This means that the line from node *N* to node NE is 100% utilised. Further generation increase is not possible due to congestion. This results in 2276 MW NSE. These results can be found in Table B.2.

B.3. Electric vehicle model

The EV model is verified for compliance with the implemented constraints used in the dispatch model without redispatch after the market clearing. The electricity demand is proven to be compensated if demand-side flexibility is used. Furthermore, the restrictions regarding the minimal and maximum charging powers comply.

Appendix C. Scenario dataset and parameters

The parameters for the scenarios are taken from the *NT 2030* scenario of the ENTSO-E. This scenario is based on the fulfilment of the NECP [64], which includes a power plant fleet with different types of generation units. Their essential parameters are listed in Table C.6. The NECP of Austria indicates that in balance, 100% of the yearly electricity demand is compensated by RES-E; therefore, CO_2 emitting power plants are only used to a minor extent. The overall electricity demand of each country includes the progressing electrification of the coupled sectors of heating, cooling and transport. The EV demand according to the respective scenarios is subtracted from the *NT 2030* electricity demand considering this previously assumed EV demand. Therefore, the total electricity demand of Austria is maintained compared with the ENTSO-E specifications.

The SRMCs are essential parameters to dispatch models with a significant impact on the resulting DA prices and the generation mix. These parameters are calculated based on fuel costs, efficiency, emission factor, O&M costs and CO_2 price. The cost parameters of the dispatch model are listed in Table C.3.

An overview of the scenarios, the number of EVs in use, and their demand-side flexibility is provided in Table C.5.

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