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On the role of electricity storage in capacity remuneration mechanisms

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ABSTRACT

In electricity markets around the world, the substantial increase of intermittent renewable electricity generation has intensified concerns about generation adequacy, ultimately driving the implementation of capacity remuneration mechanisms. Although formally technology-neutral, substantial barriers often exist in these mechanisms for non-conventional capacity such as electricity storage. In this article, we provide a rigorous theoretical discussion on design parameters and show that the concrete design of a capacity remuneration mechanism always creates a bias towards one technology or the other. In particular, we can identify the bundling of capacity auctions with call options and the definition of the storage capacity credit as essential drivers affecting the future technology mix as well as generation adequacy. In order to illustrate and confirm our theoretical findings, we apply an agent-based electricity market model and run a number of simulations. Our results show that electricity storage has a capacity value and should therefore be allowed to participate in any capacity remuneration mechanism. Moreover, we find the implementation of a capacity remuneration mechanism with call options and a strike price to increase the competitiveness of storages against conventional power plants. However, determining the amount of *firm* capacity an electricity storage unit can provide remains a challenging task.

1. Introduction

The substantial increase of renewable electricity generation in countries around the world brings along new challenges for the appropriate design of electricity markets. Due to the highly intermittent nature of solar and wind power, a certain amount of dispatchable capacity will likely also be required in the future, i.e., even under very high shares of renewables. At the same time, however, the reduced number of hours with scarcity and therefore price spikes leads to substantial risks for investments in this *firm* capacity.

Driven by such considerations, so-called capacity remuneration mechanisms (CRMs) have been implemented in several regions of the world as an extension to the energy-only market (EOM), in which capacity providers are solely compensated for the amount of electricity they sell on the markets. In the US, the earliest such mechanisms date back to the late 1990s. In recent years, also several European countries have started implementing different kinds of CRMs (Bublitz et al., 2019). All of these mechanisms typically aim to reduce the risks for new investments by offering capacity providers supplementary income on top of the earnings from selling electricity on the market. The additional generation, storage or demand side management (DSM) capacity may then in turn help to improve generation adequacy, i.e., avoid shortage situations.

Critical voices claim that CRMs are nothing but hidden subsidies to operators of conventional power plants while other alternative capacity providers, such as electricity storage or DSM, barely face any chance of successfully participating in these mechanisms. Formally, the European Commission requires full technology neutrality from any CRM to be implemented in Europe (European Commission, 2013). The situation is similar in the US, where the Federal Energy Regulatory Commission has recently directed grid operators to remove barriers that hinder storage from participating in wholesale energy, capacity and ancillary services markets and to define rules for their efficient remuneration taking into account physical and operational characteristics of such units (Sakti et al., 2018).

However, while most CRMs in Europe and the US generally allow the participation of storage and demand side units, the concrete rules applied differ substantially (Sakti et al., 2018; Usera et al., 2017). This is mostly due to the non-trivial question of whether and how much *firm* capacity such units can contribute to system adequacy. While conventional power plants can provide full power output throughout scarcity periods of whatever length, storage units are not able to do so due to

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their limited storage volume. The situation is similar for DSM, yet we exemplary focus on storage technologies in the remainder of this paper.

The rules defined for storage participation in a given CRM have a strong impact on the competitiveness of these technologies. For example, in the PJM[1] market area, storages are treated as conventional resources and therefore need to be available anytime PJM announces emergency conditions, no matter how long these situations may last (Chen et al., 2017; Usera et al., 2017). Consequently, storage operators need to fully manage the risk of their offers themselves and are subject to penalties if they fail to deliver their contracted capacity. Due to the energy-limited nature of electricity storage, this is a very rigorous requirement, basically excluding storages from participation in the CRM. Contrary, CAISO[2] requires contracted capacity of its CRM to deliver their full output for at least four consecutive hours and to do so over three consecutive days (Usera et al., 2017).

A different approach has been chosen in Ireland and the United Kingdom, where methodologies to determine derating factors for storage technologies based on adequacy metrics have recently been developed (National Grid, 2017; Single Electricity Market Committee, 2016; 2018). These factors mostly depend on the individual storage volume of a given unit and are subject to future adjustments. Applying derating factors essentially aims to base the remuneration on the capacity credit of storages, i.e., these units are only remunerated for the amount of *firm* capacity they are able to provide rather than for their *nameplate* (or *nominal*) capacity. Such an approach is also suggested by Usera et al. (2017), as it may help electricity storage to compete in CRMs as compared to treating them in the same way as conventional resources.

These examples show, that there still exists no consensus about the role of electricity storage in CRMs. While it is generally agreed that these technologies have some kind of capacity value, the specific rules of participation in CRMs may hinder them from being competitive against conventional resources. It is thus the objective of this paper, to delve into the question how the concrete design of a CRM may create a bias towards or against storage technologies and thereby affect the future technology mix as well as long-term generation adequacy.

The remainder of this paper is structured as follows. Section 2 provides an overview of the relevant literature and derives the research gap this paper aims to fill. In Section 3, a generic capacity auction mechanism is first set up and a rigorous theoretical discussion is then provided, which highlights how bundling a CRM with call options[3] and the choice of a storage derating factor may affect the competitiveness of storage units against conventional power plants. In order to illustrate and confirm the theoretical findings, a multi-period long-term electricity market model is applied and a number of simulations are run in Section 4. Ultimately, Section 5 provides a summary of the findings, draws conclusions and derives relevant policy recommendations.

2. Literature review and research gap

In the following, an overview of existing literature relevant for this article is provided. Although the article sets an explicit focus on electricity storage, some literature on DSM is also reviewed due to strong analogies between these technologies.

In a brief quantitative analysis, Schmitz et al. (2013) can show that excluding pumped storages from CRMs leads to a less efficient technology mix and ultimately welfare losses. The authors further provide a qualitative discussion on how the choice of CRM design parameters may create a bias against pumped storages. However, many of the parameters found to have an impact on pumped storages due to their capital cost intensity (contract duration, lag period, regional differentiation, market share) are much less relevant for novel storage technologies such as batteries.

Mays et al. (2019) very recently provided first evidence that bundling CRMs with call options has an asymmetric effect on different generation technologies and creates a bias towards resources with lower fixed costs and higher operating costs, i.e., peaker units. They conclude that current market structures might not be suitable to finance low-carbon resources, which are characterised by high fixed costs and near-zero operating costs. However, the authors use a rather stylistic setup and do not consider electricity storage, but only conventional and renewable generation technologies.

Another particularly relevant design parameter is the appropriate determination of so-called capacity credit metrics for storages. Different methods have been applied in this context, including approximations (Tuohy and O'Malley, 2009), dynamic programming (Sioshansi et al., 2014) and iterative algorithms coupled with Monte Carlo experiments (Borozan et al., 2019; Zhou et al., 2015, 2016). Yet, none of these contributions looks into the role of the derived capacity credits in the context of a CRM.

There exist, however, also a few studies investigating the interdependencies between CRMs and electricity storage or DSM, which we present next.

Lynch et al. (2019) set up a mixed complementary problem to model an electricity system with energy and reserve markets as well as a quantity-based capacity market. They use their model in a case study for Ireland and find that DSM has an inherent capacity value. The authors conclude that DSM should be eligible to participate in CRMs since welfare losses would occur otherwise.

Opathella et al. (2019) introduce a capacity market model including a capacity demand curve as well as electrical storage and apply the developed model in a case study for Ontario. In doing so, they find derating factors to be a crucial factor deciding on the competitiveness of electricity storage.

Teng and Strbac (2016) evaluate different multi-service business cases for bulk electricity storage. In doing so, the authors also rudimentally consider storage participation in a CRM by reserving capacity during the peak periods and assuming a fixed capacity remuneration. They find that the restrictions due to the CRM only marginally reduce storage profits from the other markets and conclude that a CRM can contribute to a profitable business case for storages.

Askeland et al. (2019) apply a linear complimentary model to analyze an EOM as well as a CRM in a European multi-country case study. The authors find that the CRM incentivizes substantial amounts of additional open cycle gas turbines, but also a little additional storage capacity as compared to the EOM. Moreover, they investigate the impact of different storage derating factors in the CRM and conclude that derating may lead to a substantial bias towards conventional power plants.

Khan et al. (2018) apply a hybrid electricity market model which uses optimization for short-term market operations and agent-based simulation of long-term investment decisions. The model is used to investigate an isolated and uncongested electricity market, which either relies on a pure EOM or has an additional CRM implemented. For both of these market designs, different settings with or without electricity storage and DSM are analyzed. The business case for storages is found to be better in the EOM setting than under a CRM, as scarcity prices allow for a larger arbitrage profit in this setting.

[1] Pennsylvania–New Jersey–Maryland Interconnection, a system operator in the US.

[2] California Independent System Operator.

[3] More precisely, real-world CRMs typically apply *tolling agreements*, which are a series of hourly call options with varying strike prices. However, given the non-availability of hourly resoluted projections up to 2050 in the literature, we assume constant fuel and carbon prices over the course of a year throughout this paper. In consequence, we also apply constant strike prices in a given future year. We therefore refer to *call options* rather than using the technically more correct term *tolling agreements*. This does however not diminish the validity of our results, but rather makes the analyses more concise. Please also note that while CRM typically have a long-term focus (i.e., multiple years), *tolling agreements* can also be used independently from a CRM and may then cover shorter time periods, e.g., one year.

In the context of the existing literature, the contribution of this paper is as follows. To start with, for the first time, a rigorous theoretical discussion is presented on why and how bundling a CRM with call options and the choice of a storage derating factor may affect the competitiveness of storage units against conventional power plants.

Moreover, a multi-period long-term electricity market model is applied and a number of simulations are run to confirm the theoretical results. This contribution is therefore also the first in the literature to quantitatively analyze the impact of bundling a CRM and call options with a strike price on the competitiveness of storage units. Last but not least, our simulation approach differs from those presented in the literature to date in several important aspects.

Firstly, we consider a region covering several interconnected European market areas. Like this, we are able to adequately take cross-border effects into account, an aspect that we regard essential in light of the ongoing strong increase in cross-border transmission capacity. In the existing literature, either only a single country is considered (Khan et al., 2018; Lynch et al., 2019; Opathella et al., 2019; Teng and Strbac, 2016) or an unlimited interconnection capacity between the modeled countries is assumed (Askeland et al., 2019).

Secondly, we model multiple investment decision, capacity auction and day-ahead market periods, which is important due to potential path dependencies and lock-in effects. Most of the literature only considers a single capacity auction period (Askeland et al., 2019; Lynch et al., 2019; Opathella et al., 2019; Teng and Strbac, 2016). Moreover, Opathella et al. (2019) and Teng and Strbac (2016) do not model endogenous investment decisions at all, while Askeland et al. (2019) use a greenfield approach instead of considering the existing generation fleets.

Thirdly, electricity storage is fully integrated into the investment module of our model by determining its maximum future arbitrage potential and deriving expected future profits. Despite the computational burden of this approach, we consider it the only possibility to have a real trade-off between different investment options, i.e., conventional power plants and storages. In contrast, Khan et al. (2018) only very rudimentally implement storage investments by considering historical profits rather than expected future profits as for the conventional power plant technologies. This is not only a strong simplification but also an inconsistent approach.

Fourthly, we also fully integrate electricity storage into the CRM module of our model by considering different storage derating strategies. This is an essential aspect as the literature suggests that the *nameplate* capacity of storage is not identical with the amount of *firm* capacity that this technology can provide. In contrast, Khan et al. (2018) use the rather basic approach of having the storages bid their full *nameplate* capacity.

We can conclude that the applied simulation approach allows for the consideration of dynamic aspects and interdependencies in terms of time (multiple decision periods), space (multiple interconnected countries), technologies (different conventional power plants and types of storage) and markets (EOM and CRM) with an explicit focus on the development of the future technology mix as well as long-term generation adequacy. To the best of our knowledge, such an approach is unique in the literature available to date and highly suitable to investigate the role of electricity storage in CRMs.

3. Theoretical discussion on relevant design parameters

In this section, a theoretical discussion on CRM design and its impact on the competitiveness of electricity storage against conventional power plants is presented. For this purpose, a generic CRM is first set up (Section 3.1) and it is then shown that bundling a CRM with call options and derating of storage capacity are essential drivers for the competitiveness of storages. These two drivers are ultimately analyzed in more detail in Sections 3.2 and 3.3.

3.1. Generic capacity auction mechanism

CRMs are typically designed to maintain generation adequacy and ultimately avoid shortage situations by offering capacity providers income on top of the earnings from selling electricity on energy markets. Although mechanisms may vary substantially in the way the required capacity and the corresponding capacity prices are determined, all types of CRMs should in theory lead to similar outcomes.[4] Therefore, without loss of generality, we assume a so-called central buyer mechanism with reliability options in the following. Such mechanisms are currently used by the US system operator ISO-NE[5] (Byers et al., 2018) as well as in Italy (Mastropietro et al., 2018; Perico et al., 2018) and Ireland (Single Electricity Market Committee, 2015). In a central buyer mechanism, a regulator first determines the total amount of *firm* capacity to be procured in a centralized auction and other auction parameters. All successful participants of the auction are then rewarded with the marginal capacity price of the auction.

In order to ensure that sufficient capacity is actually available when needed, the regulator may impose capacity derating factors f^{derate} in the auction, e.g., based on historical availability data or technology-specific considerations. We assume in the following that storage units are generally eligible to participate in the capacity auction, however need to be able to provide *firm* capacity over a predefined discharge duration.[6]

Vazquez et al. (2002) propose combining the capacity auctions with financial call options, so-called reliability options. In exchange for the earnings through the fixed capacity remuneration provided in the auctions, the earnings from the energy markets are then reduced by setting a price cap p^{limit} on the market prices. If the electricity price rises above the price cap, the so-called strike price of the call option, the generators will have to return the peak energy rent, which is the difference between market price and strike price, to the regulator. Like this, electricity consumers are protected from unreasonably high prices while at the same time the capacity remuneration provides a more secure income to the generators which no longer have to rely on infrequently occurring price spikes. Typically, capacity providers will have to return the peak energy rent to the regulator anytime there is a positive difference between market price and strike price, regardless of whether they were able to produce in the given period or not. This reflects an *implicit* penalty for non-availability during scarcity periods, which is particularly crucial for electricity storage.

Imagine a multi-hour scarcity period with high market prices well above the strike price. Contrary to conventional power plants, storage units may then not be able to produce during the whole peak period, simply due to their limited energy content and consequently the storage running empty. Storage units may be exempt from the *implicit* penalty in such situations, as long as they were successfully providing their contracted capacity for the required discharge duration predefined by the regulator. This option implies that the risk of adequately derating storage capacity lies with the regulator. Alternatively, storage units may remain subject to the *implicit* penalty, even if their non-availability is caused by the storage running empty. Quite obviously, this latter option leaves a huge risk with the storage operators, basically excluding them from participation in the capacity auctions. This approach therefore

[4] For a detailed overview of different types of CRMs and their typical characteristics, please refer to Bublitz et al. (2019). Please note that apart from CRMs other instruments exist to address the *missing money problem*, e.g., tolling agreements. The expected payoff of a one-year tolling agreement is then comparable to the capacity price of a CRM, both of which describe a revenue per capacity unit and year.

[5] Independent System Operator New England.

[6] Although a typical design parameter, we refrain from considering an *explicit* penalty for non-availability during scarcity periods, since electricity prices typically rise substantially in such situations and thus, there exists already a strong incentive to be available.

seems not reasonable, if technology neutrality is to be achieved. Nevertheless, when looking at the impact of call options in more detail (Section 3.2), we consider both variants.

Let us further define that generators receive the remuneration of the capacity auction for a fixed amount of years n^{CRM}. Under the described assumptions, we can now derive bidding strategies of an economically rational generator for a new generation or storage unit p. For this purpose, the so-called difference costs DC_p need to be computed, which describe the delta between the income needed for an investment to reach profitability and the net present value if the unit was optimally operated on the electricity market. This relation is shown in Eq. (1). Please note that the difference costs are only positive in case of negative net present values, while for investments already profitable without additional capacity remuneration, it is rational to bid into the capacity auction at zero cost to maximize the chances of being contracted and receiving additional capacity remuneration.

The calculation of the specific net present value for a new generation or storage unit p is shown in Eq. (2), where c_p^{invest} denotes the total investment expenses, δ_p the construction time in years, c_p^{fix} the fixed expenditures for operation and maintenance per year, i the discount rate, n_p the investment horizon in years and $CM(p^{\mathrm{limit}})_{p,y}$ the annual contribution margins on the electricity market. Please note that the contribution margins depend crucially on the level of the strike price p^{limit} of the call option, as will be discussed in Section 3.2. Eq. (3) shows how the difference costs relate to the rational capacity bid price p_p^{CRM} for a unit p. Inserting Eqs. (2) and (3) into Eq. (1) and solving for p_p^{CRM}, we ultimately obtain the rational capacity bid price for investment option p as shown in Eq. (4).

$$DC_p = \max\left(-NPV_p, 0\right) \tag{1}$$

$$NPV_p = -\sum_{y=0}^{\delta_p-1} \frac{c_p^{\mathrm{invest}}/\delta_p}{(1+i)^y} + \sum_{y=\delta_p}^{n_p+\delta_p} \frac{CM(p^{\mathrm{limit}})_{p,y} - c_p^{\mathrm{fix}}}{(1+i)^y} \tag{2}$$

$$DC_p \overset{!}{=} f_p^{\mathrm{derate}} \cdot p_p^{\mathrm{CRM}} \cdot \sum_{y=\delta_p}^{n^{\mathrm{CRM}}+\delta_p} \frac{1}{(1+i)^y} \tag{3}$$

$$p_p^{\mathrm{CRM}} = \frac{\max\left(\sum_{y=0}^{\delta_p-1}\frac{c_p^{\mathrm{invest}}/\delta_p}{(1+i)^y} - \sum_{y=\delta_p}^{n_p+\delta_p}\frac{CM\left(p^{\mathrm{limit}}\right)_{p,y} - c_p^{\mathrm{fix}}}{(1+i)^y}, 0\right)}{\left(\sum_{y=\delta_p}^{n^{\mathrm{CRM}}+\delta_p}\frac{1}{(1+i)^y}\cdot f_p^{\mathrm{derate}}\right)} \tag{4}$$

We now apply a few additional simplifications to bring Eq. (4) into a more concise form.

(1) The contribution margins only depend on the respective technology and an option strike price, but are otherwise constant through all years under investigation – see Eq. (5a).
(2) The fixed costs are set as a percentage k_0 of the investment expenses – see Eq. (5b).
(3) Construction time and investment horizon are identical for all technologies – see Eqs. (5c) and (5d).
(4) Two additional constants k_1 and k_2 are defined, which are independent of the technology as long as assumption (3) holds – see Eqs. (5e) and (5f).

$$CM\left(p^{\mathrm{limit}}\right)_{p,y} = CM\left(p^{\mathrm{limit}}\right)_p \quad \forall p, y \tag{5a}$$

$$c_p^{\mathrm{fix}} = k_0 \cdot c_p^{\mathrm{invest}} \quad \forall p \tag{5b}$$

$$\delta_p = \delta \quad \forall p \tag{5c}$$

$$n_p = n \quad \forall p \tag{5d}$$

$$k_1 = \sum_{y=\delta}^{n+\delta} \frac{1}{(1+i)^y} \Bigg/ \sum_{y=\delta}^{n^{\mathrm{CRM}}+\delta} \frac{1}{(1+i)^y} \tag{5e}$$

$$k_2 = k_0 + \sum_{y=0}^{\delta-1} \frac{1}{\delta(1+i)^y} \Bigg/ \sum_{y=\delta}^{n+\delta} \frac{1}{(1+i)^y} \tag{5f}$$

Applying the simplifications of Eqs. (5a)–(5f) to Eq. (4) finally leads us to the much more concise form presented in Eq. (6).

$$p_p^{\mathrm{CRM}} = \frac{k_1}{f_p^{\mathrm{derate}}} \cdot \max\left(k_2 \cdot c_p^{\mathrm{invest}} - CM\left(p^{\mathrm{limit}}\right)_p, 0\right) \tag{6}$$

We can now see from Eq. (6) that the relation of investment expenses c_p^{invest}, contribution margins $CM(p^{\mathrm{limit}})_p$ and derating factor f_p^{derate} decides which technology option is able to bid the lowest capacity price p^{CRM}. To be more precise, there are essentially only these three drivers, on which ultimately the capacity auction outcome and in particular the resulting technology mix in the electricity market depends.

The investment expenses c_p^{invest} primarily depend on the specific technology p and cannot be directly influenced by the regulator of the capacity auction. However, particularly for emerging technologies, technological learning is likely to lead to substantial cost reductions in the future. For this reason, the simulation studies carried out later in this paper use dynamic investment expenses for all storage technologies.

Although the achievable contribution margins $CM(p^{\mathrm{limit}})_p$ largely depend on the respective technology, they can also be directly influenced by the regulator by implementing call options with a certain strike price on the electricity market. We will discuss the impact of this design parameter in more detail in Section 3.2.

The derating factors f_p^{derate} are technology-specific and particularly relevant for storage technologies. This parameter can be directly set by the regulator. More theoretical details on this design choice are presented in Section 3.3.

3.2. Impact of a combination with call options

Fig. 1 presents a stylized example of the day-ahead market in the future. In the first period $t_0, \ldots, t_1$, high feed-in of renewables results in a low price p^{low}, while in the subsequent second period $t_1, \ldots, t_2$, low feed-in from renewables and a lack of capacity leads to scarcity and high prices p^{high}. This is a situation as it may frequently occur in the future under ongoing strong expansion of renewables. For the described setting, Table 1 summarizes the contribution margins that a conventional power plant and a storage unit could make in different cases with and without a strike price.

A conventional power plant with total variable costs c^{var} would only

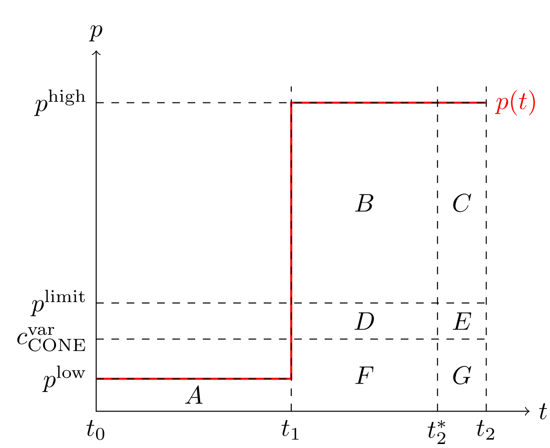

Fig. 1. Stylized example of the day-ahead market in the future with a low price period followed by a high price period.

Table 1
Contribution margin of a conventional power plant and storage unit in the stylized example with a low price period followed by a high price period (cf. Fig. 1).

Case	Strike price	Risk of empty storage	Power plant	Storage unit
1	No	Regulator	$B+C+D+E$	$B+D+F-A$
2a	Yes	Storage operator	$D+E$	$D+F-A-C$
2b	Yes	Regulator	$D+E$	$D+F-A$

operate when the market price $p(t)$ exceeds its variable costs, i.e., in the period $t_1,\ldots,t_2$. The corresponding specific contribution margins of the power plant if no strike price is set (Case 1) and if a strike price is set (Cases 2a and 2b) can be calculated using Table 1 and are shown in Eq. (7), where $\Delta t = t_2 - t_1$.

$$\frac{CM^{\text{conv}}}{\Delta t} = \begin{cases} p^{\text{high}} - c^{\text{var}}, & \text{for Case 1} \\ p^{\text{limit}} - c^{\text{var}}, & \text{for Cases 2a/b} \end{cases} \tag{7}$$

A storage unit with round-trip efficiency η^{stor} could use the low prices in the period $t_0,\ldots,t_1$ to charge up to the maximum storage level and then discharge in the subsequent high price period $t_1,\ldots,t_2^*$. Please note that due to the limited storage volume as well as conversion losses, the unit can only sell electricity in a certain share of the high price period.[7] The maximum revenues of the storage unit are therefore lower than those of the conventional power plant.

The specific contribution margins of the storage if no strike price is set (Case 1) and if a strike price is set (Cases 2a and 2b) can again be calculated using Table 1 and are shown in Eq. (8), where $\Delta t = t_2 - t_1 = t_1 - t_0$. Please note, that, in case reliability options with a strike price are implemented, the margin depends on whether the storage operator (Case 2a) or the regulator (Case 2b) bears the risk of the storage running empty in a multi-hour scarcity period. In Case 2a, the storage operator would have to pay the difference between market price and strike price to the regulator during its non-availability in the period $t_2^*,\ldots,t_2$. Using $\Delta t^{**} = t_2 - t_{2^*} = \Delta t(1-\eta^{\text{stor}})$, this is essentially an *implicit* penalty of $pen = \Delta t(1-\eta^{\text{stor}})(p^{\text{high}} - p^{\text{limit}})$, corresponding to area C in Fig. 1. Contrary, in Case 2b, the storage operator is exempt from the *implicit* penalty and can therefore achieve a higher contribution margin.

$$\frac{CM^{\text{stor}}}{\Delta t} = \begin{cases} \eta^{\text{stor}} p^{\text{high}} - p^{\text{low}}, & \text{for Case 1} \\ p^{\text{limit}} - p^{\text{low}} - p^{\text{high}}(1-\eta^{\text{stor}}), & \text{for Case 2a} \\ \eta^{\text{stor}} p^{\text{limit}} - p^{\text{low}}, & \text{for Case 2b} \end{cases} \tag{8}$$

Whether a conventional power plant or a storage unit is better off in the given situation thus depends on different factors: the party bearing the risk of an empty storage, the absolute levels of p^{low}, p^{high}, c^{var} and p^{limit} (if applicable) as well as the storage volume $s^{\max}$ and round-trip efficiency η^{stor}. In systems with high shares of renewable electricity generation, it is reasonable to assume a lower price of $p^{\text{low}} = 0$ EUR/MWh$_{\text{el}}$.

Eqs. (7) and (8) ultimately lead us to Eq. (9), which shows the condition that needs to hold for the storage unit to gain a competitive advantage other the conventional power plant in the different cases. We can see that the condition for Cases 1 and 2a is identical and independent of the strike price level p^{limit}. Therefore, if the storage operator itself has to bear the risk of an empty storage and is then subject to an *implicit* penalty, the introduction of a strike price does not lead to a discrimination of any technology. However, setting p^{high} to the typical European day-ahead price limit of 3000EUR/MWh$_{\text{el}}$ and using a rather ambitious storage round-trip efficiency of $\eta^{\text{stor}} = 90$ %, we can derive that a storage unit would only be better off under very high variable costs of the conventional power plant $c^{\text{var}} > 300$ EUR/MWh$_{\text{el}}$ (in this specific setting). This is a rather unrealistically high value from today's perspective, but may well become true in the future, if carbon emission allowances reach a sufficiently high price level.

$$CM^{\text{stor}} > CM^{\text{conv}} \Leftrightarrow \begin{cases} p^{\text{high}}(1-\eta^{\text{stor}}) < c^{\text{var}}_{\text{CONE}}, & \text{for Cases 1/2a} \\ p^{\text{limit}}(1-\eta^{\text{stor}}) < c^{\text{var}}_{\text{CONE}}, & \text{for Case 2b} \end{cases} \tag{9}$$

If, however, a strike price is introduced and the regulator bears the risk of the storage running empty (Case 2b), the condition for the storage unit to be better off than the conventional power plant becomes dependent on the strike price level p^{limit}. Consequently, in this setting, storage units would benefit from the introduction of reliability options with a certain strike price. If the strike price is set equal to the variable costs of a new conventional power plant, i.e., $p^{\text{limit}} = c^{\text{var}}_{\text{CONE}}$, the contribution margin of storage units would always be at least equal, but likely higher, than that of conventional power plant.

As previously mentioned, leaving the risk of a storage running empty during a long scarcity period with the storage operator, would basically exclude this technology from participation in the capacity auctions. In the remainder of this paper, and in particular for the simulations carried out in Section 4, we therefore assume, that the regulator bears this risk and the storage operators are exempt from the *implicit* penalty.

3.3. The role of storage derating

A relatively simple way of determining derating factors for storage technologies is the definition of a minimum discharge duration requirement by the regulator. Using this approach, also storage units with a small storage volume can participate in the capacity auctions, yet are only remunerated for a certain share of their capacity. The relation between derating factor f_p^{derate} for technology p, achievable discharge duration $t_p^{\text{discharge}}$ at full capacity $c_p^{\max}$ and required discharge duration t^{required} is shown in Eq. (10). The achievable discharge duration can also be expressed using storage volume $s_p^{\max}$, maximum discharge capacity $c_p^{\max}$ and discharge efficiency $\eta_p^{\text{discharge}}$. Please note that the derating factor is limited to 1, since large storage volumes might otherwise lead to a storage unit being remunerated for more than its maximum discharge capacity.

$$f_p^{\text{derate}} = \min\left(\frac{t_p^{\text{discharge}}}{t^{\text{required}}}, 1\right) = \min\left(\frac{s_p^{\max} \cdot \eta_p^{\text{discharge}}}{c_p^{\max} \cdot t^{\text{required}}}, 1\right) \tag{10}$$

Fig. 2 illustrates the impact of varying the storage duration requirements t^{required} in a capacity auction. For this purpose, three

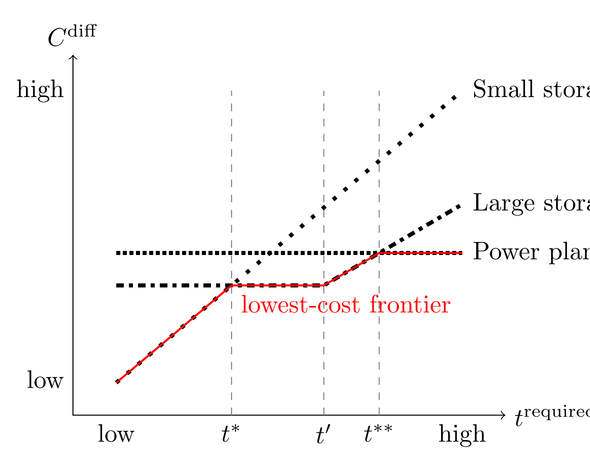

Fig. 2. Impact of different storage duration requirements on the difference costs of a conventional power plant, a small storage unit and a large storage unit in a stylized example.

[7] Assuming an empty storage in t_0, the share can easily be computed as $\Delta t^* = t_2^* - t_1 = \eta^{\text{stor}}(t_2 - t_1)$. Alternatively, it would be possible to discharge at lower capacity throughout the period $t_1,\ldots,t_2$. Since the prices are assumed constant during $t_1,\ldots,t_2$, this storage operation would lead to the exact same profit.

exemplary technologies and their respective difference costs C^{diff} are presented, namely a conventional power plant (e.g., an open-cycle gas turbine), a small storage unit (e.g., a lithium-ion battery) and a large storage unit (e.g., an electric thermal storage[8]). Please note that the stylized example assumes a situation in the future, where storage technologies have reached cost-competitiveness with conventional power plants.

In this setting, the conventional power plant has constant difference costs since it is not affected by the required storage duration. Contrary, the capacity of the small storage unit is already derated under relatively low storage duration requirements due to its limited storage volume. Increasing the storage duration requirements comes along with stronger derating, ultimately resulting in a constant linear increase of the difference costs. Due to its larger storage volume and consequently longer achievable discharge duration $t^{\text{discharge}} = t^{'}$, the difference costs of the large storage unit remain constant for storage duration requirements of $t^{\text{required}} \leq t^{'}$. Yet, for higher storage duration requirements, also the capacity of this technology is derated leading to a constant linear increase of its difference costs.

As a result, two tipping points regarding the lowest-cost technology to provide the required (equivalent) capacity can be observed in this specific setting (solid red line in Fig. 2). For storage duration requirements of $t^{\text{required}} \leq t^{*}$, the small storage unit is the best of the three available options. Increasing the requirements to $t^{*} < t^{\text{required}} \leq t^{**}$, the large storage unit becomes preferable. Finally, under even higher requirements of $t^{\text{required}} > t^{**}$, the conventional power plant is the cheapest option, since it is the only technology not affected by derating factors.

Apart from the described impact on technology choice, the choice of the derating factors also has another somewhat inverse effect. Since the total amount of *firm* capacity to be procured in the capacity auctions is typically predefined, stronger derating of storage technologies leads to a lower capacity contribution of these units and therefore a higher amount of *nameplate* capacity to be contracted in order to fulfill the desired *firm* capacity target. Thus, depending on the relation of the different technologies' difference costs, stronger derating of storages may indeed even lead to more storage investments being carried out despite the higher capacity prices bid into the auction. In the stylized example, the highest amount of small storage investments could therefore be expected for storage duration requirements marginally below t^{*}, and analogously for large storages at requirements marginally below t^{**}. Please note that this effect only occurs as long as the capacity demand is fixed and not price sensitive. In many US markets (PJM, ISO-NE, NYISO[9]) this is not the case as they apply downward-sloping capacity demand curves in their auctions (Byers et al., 2018).

4. Simulation study

In order to verify our theoretical findings regarding the impact of CRM design parameters on the competitiveness of storage, we now apply a multi-country long-term electricity market model to investigate these parameters in realistic and complex real-world settings. For this purpose, we first provide a brief introduction to the applied model (Section 4.1) and the necessary input data (Section 4.2). We then present developments under a European EOM, which serves as a benchmark (Section 4.3). Subsequently, we set up a number of additional simulations illustrating the impact of implementing capacity auctions with call options (Section 4.4) as well as different storage derating factors in these auctions (Section 4.5) on investments in storage units.

Please note that the applied model has an explorative rather than a normative character. Thus, by simulating system behavior that emerges from individual actors' decisions, we want to analyze which technologies *would* be successful in the capacity auctions and receive support to come into the market under a specific setting. In contrast, we explicitly do not investigate which technologies *should* be supported to achieve a certain goal targeted by the regulator.

4.1. Model overview and relevant extensions

PowerACE is an established agent-based simulation model developed for the analysis of European electricity markets in long-term scenario analyses. The initial model version is documented in Genoese (2010). Other previous applications of the model in different configurations include Bublitz et al. (2017), Keles et al. (2016) and Ringler et al. (2017). The model runs at hourly resolution (8760 h/a) over a typical time horizon from 2015 up to 2050. PowerACE covers different market segments with a focus on the day-ahead market and different types of CRMs.

As shown in Fig. 3, various agents represent the associated market participants, such as utility companies, regulators and consumers. The electricity suppliers can decide on the daily scheduling of their conventional power plants and storage units (see Appendix A.1) as well as on the construction of new conventional generation or storage capacities based on expected future profits (see Appendix A.2 and A.3). Thus, the short-term and long-term decision levels are jointly considered and their interactions can be investigated. Ultimately, the development of the markets emerges from the simulated behavior of all agents. A model validation is provided in Ringler et al. (2017).

PowerACE has been substantially extended for the analyses of this paper. Firstly, a bidding algorithm for the participation of storage units in the day-ahead market has been developed, which is described in detail in Fraunholz et al. (2017). Secondly, the existing investment planning procedure has been modified from a national perspective to a cross-border perspective and storage technologies have been included as additional investment candidates (for details, see Fraunholz et al., 2019). Thirdly, storage technologies have been integrated in the modeled CRMs. For this purpose, in particular the two new parameters *price cap* and *required storage duration* were implemented. Please note that the described consideration of storage technologies in all relevant parts of PowerACE is challenging, as it adds a time-coupled component to the model.

4.2. Data and assumptions

Due to its nature as a detailed bottom-up simulation model, PowerACE requires substantial amounts of input data. Table 2 provides an overview of the data used in all simulations presented in the following as well as the respective sources. Please refer to Appendix B for details on the techno-economic characteristics of the different investment options as well as fuel and carbon prices. In the following paragraphs, additional assumptions are briefly described.

In order to adequately capture the variety of different electricity market designs in Europe, the regional scope of the applied version of PowerACE covers several European countries. We first run a benchmark simulation with a European EOM, which is then contrasted with several different configurations of national CRM policies, i.e., each of the ten countries is modeled under consideration of its current real-world market design[10] (see Fig. 4). Please refer to Table 3 for an overview of

[8] We base the characteristics of this technology on the concept presented by Siemens Gamesa (2019), which consists of a resistive heater for the charging process, volcanic stones as storage medium and a water steam cycle for the discharging process. Due to the large share of low-cost off the shelf components, we expect this technology to soon become one of the most cost-efficient large-scale electricity storage technologies available.

[9] New York Independent System Operator.

[10] For details on the different market designs see Bublitz et al. (2019). Due to the similarities of the different types of CRMs on an abstract level, the French mechanism is modeled using the central buyer implementation, although in reality, a de-central obligation mechanism is used in France.

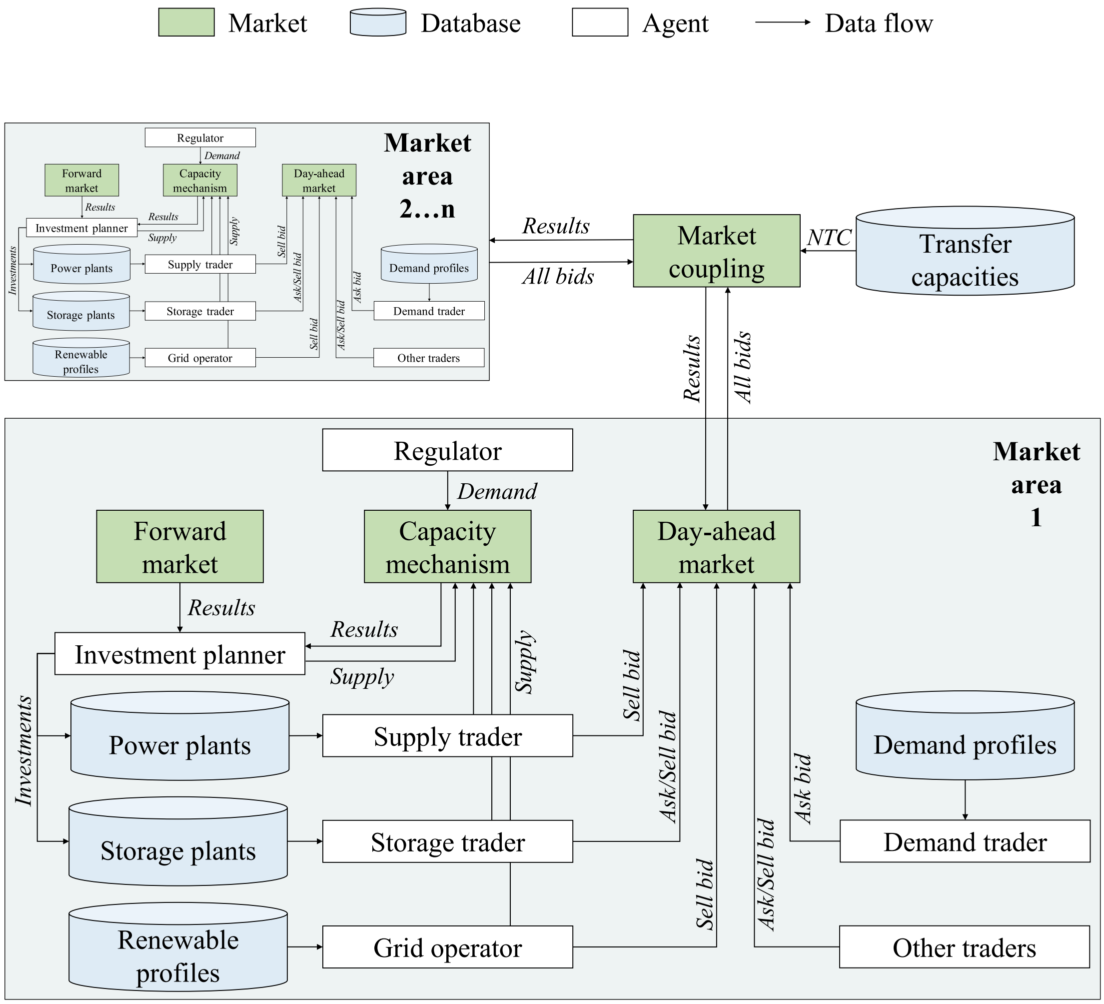

Fig. 3. Schematic overview of the electricity market model PowerACE. The focus lies on the short-term simulation of the day-ahead markets and long-term investment decisions under consideration of different capacity remuneration mechanisms as well as cross-border effects.

Table 2
Overview of the input data used in all simulations carried out with PowerACE.

Input data type	Resolution	Sources and comments
Conventional power plants	unit level	S&P Global Platts (2015), and own assumptions
Fuel prices	yearly	EU Reference Scenario (de Vita et al., 2016), and own assumptions (cf. Fig. 11)
Carbon prices	yearly	EU Reference Scenario (de Vita et al., 2016), scaled to reach 150 EUR/t_{CO_2} in 2050 (cf. Fig. 11)
Investment options	yearly	Louwen et al. (2018); Schröder et al. (2013); Siemens Gamesa (2019), and own assumptions (cf. Tables 8 and 9)
Transmission capacities	yearly	Ten-Year Network Development Plan (ENTSO-E, 2016)
Electricity demand	hourly, market area	historical time series of 2015 (ENTSO-E, 2017), scaled to the yearly demand given in the EU Reference Scenario (de Vita et al., 2016)
Renewable feed-in	hourly, market area	historical time series of 2015 (ENTSO-E, 2017), scaled to reach an overall renewable share in relation to electricity demand of 80% in 2050

the scenarios investigated with PowerACE in the following sections.

All simulations are carried out at an hourly resolution and cover the time horizon from 2020 to 2050. Please note that as the focus of this paper is on market design issues, we do not model the electrical grid in detail, but only consider limited cross-border transmission capacities, while intra-zonal restrictions are not accounted for. This corresponds to the concept of zonal pricing which is used for the real-world market clearing process in Europe.

Contrary to the model endogenous expansion planning, decommissioning of existing power plants is exogenously defined based on the respective age and technical lifetime of the generation units, which remain unchanged for all scenarios under investigation. For two exemplary countries, France and Italy, the remaining capacities until 2050 without additional investments are shown on a technology aggregated level in Fig. 5. As a reference, the peak residual demand[11] is also shown.

The developments of electricity generation from renewables and electricity demand are an exogenous input to PowerACE, which remains unchanged for all scenarios. Additional model endogenous investments in renewable technologies are therefore not considered. Moreover, DSM

[11] The peak residual demand is defined as the highest hourly electricity demand of the respective market area, which is not covered by renewable generation.

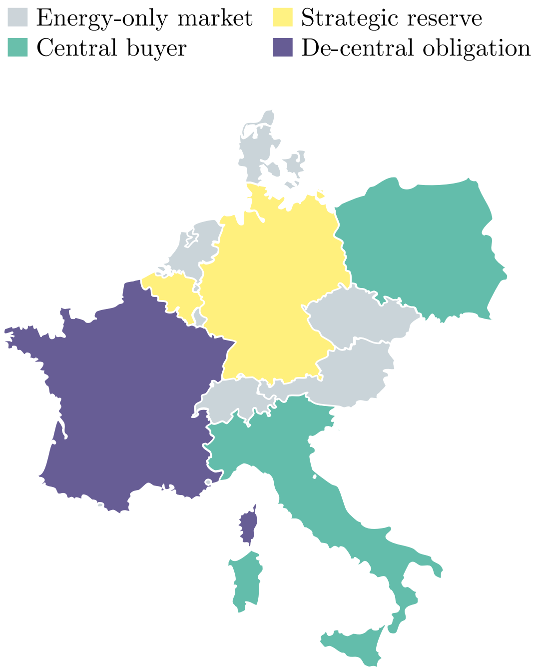

Fig. 4. Overview of the real-world electricity market designs implemented in the different countries covered by PowerACE.

renewable electricity generation, therefore rendering storage investments attractive. The capacity developments emerge from exogenously given decommissioning of power plants (cf. Fig. 5) and endogenous investment decisions of the different agents in PowerACE.[12]

In France, the first thing to notice is the sharp (exogenously given) decline of nuclear generation capacities within a rather short period of time (47 GW between 2028 and 2038). Consequently, we can observe substantial amounts of substitute investments, mainly in combined cycle (CCGT) and open cycle gas turbines (OCGT). Since these technologies have a typical lifetime of 30 years (cf. Table 8), once installed, they remain in the market until the end of the simulation period in 2050. As a result, only relatively few additional investments in storage technologies are carried out starting in 2040. This lock-in effect illustrates the high path dependence of the future technology mix. By using a dynamic multi-period model, we are able to properly take these effects into account. Ultimately, in 2050, we end up with 13.2 GW of new storages. Together with the 4.7 GW of pumped storage units, the total storage capacity in France makes up for some 24% of the total flexible, i.e., conventional plus storage, capacity installed.

In Italy, the picture is somewhat different than in France. Due to the huge initial overcapacities, new investments are only carried out starting in 2037, i.e., 10 years later than in France. By this time, investment expenses for storage technologies have already strongly declined as compared to today (cf. Table 9). In combination with the growing shares of renewable electricity generation towards 2050, this setting leads to some new conventional power plants, but also substantial investments in additional storage units. In 2050, a total of 23.4 GW of new storages is installed. Together with the 6.4 GW of pumped storage units, the total storage capacity in Italy makes up for some 56% of the total flexible capacity installed. This share is substantially higher than in France, which will be a highly relevant finding for the subsequent analyses on CRM design parameters.

Table 3
Overview of all scenarios investigated with PowerACE. In Section 4.3, a benchmark with a European EOM is analyzed. Section 4.4 focuses on the impact of different strike price levels in a CRM. Finally, Section 4.5 uses the most favorable strike price level for storages and then investigates varying storage duration requirements in more detail.

Section	Electricity market designs		Strike price[1]				Storage duration requirement[2]			
	European EOM	National CRM policies	n/a	none	high	low	n/a	low	medium	high
4.3	x		x				x			
4.4		x		x	x	x			x	
4.5		x				x		x	x	x

Abbreviations: CRM—capacity remuneration mechanism, EOM—energy-only market.
[1]This additional price limit on the day-ahead market only applies to capacity that has been successfully contracted in the capacity auctions and should not be confused with the general day-ahead price limit of 3000 EUR/MWh$_{el}$, which is valid for all participants of the day-ahead market.
[2]Storage units with shorter discharge durations than required may still participate in the capacity auctions, but are derated and are only remunerated for a certain share of their maximum discharging capacity.

is out of the scope of this paper and not taken into account, i.e., the electricity demand is completely static. Fig. 6 illustrates the assumed composition of the renewable electricity generation in France and Italy as well as the total yearly electricity demand.

4.3. Reference developments under a European energy-only market

As a benchmark for the subsequent analyses on CRM design parameters in Sections 4.4 and 4.5, we now present the simulated long-term developments under a European EOM. For this purpose, Figs. 7 and 8 depict the conventional power plant and utility-scale storage capacities in France and Italy from 2020 to 2050. We choose these two countries for further analysis, since they have implemented a CRM in the current real-world setting and face substantial increases in future

4.4. Capacity auctions bundled with call options

4.4.1. Scenario setup

Let us now move on to the introduction of national CRM policies (cf. Fig. 4) and more specifically the impact of bundling the capacity auctions with call options, which includes setting an additional day-ahead price limit for the capacity contracted in the capacity auctions. For this purpose, we set up three additional scenarios which we then compare with the European EOM scenario. An overview of the investigated scenarios is provided in Table 4. All variables and parameters not mentioned there remain unchanged in all scenarios under investigation.

In scenario *CRM-08*, no strike price is set, i.e., only the general day-

[12] Please note that Figs. 7 and 8 do not show the *electricity generation* but the *installed capacities*, i.e., despite similar capacity levels as compared to today, the conventional power plants face significantly lower running hours in the future due to the assumed strong increase in renewable electricity generation (cf. Fig. 6).

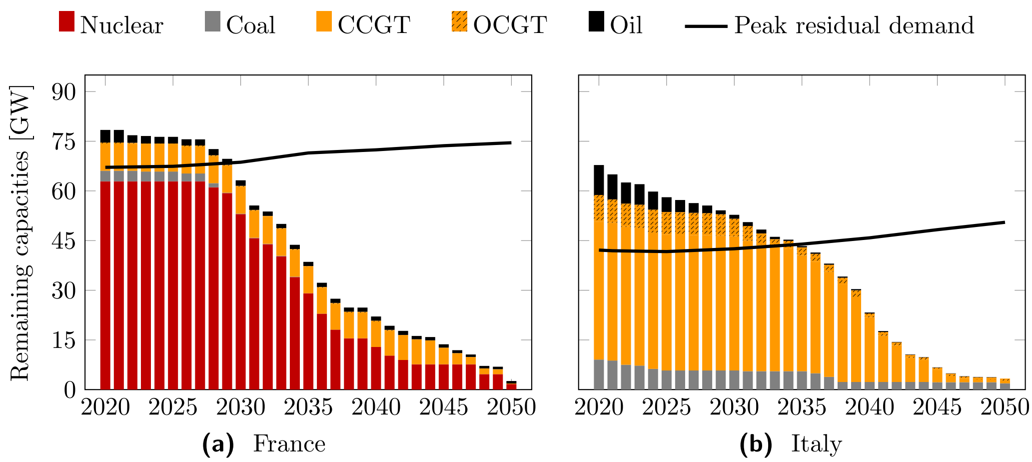

Fig. 5. Assumed conventional power plant capacities in France (a) and Italy (b) without additional new investments. Source: own illustration based on data from S&P Global Platts (2015), and own assumptions.

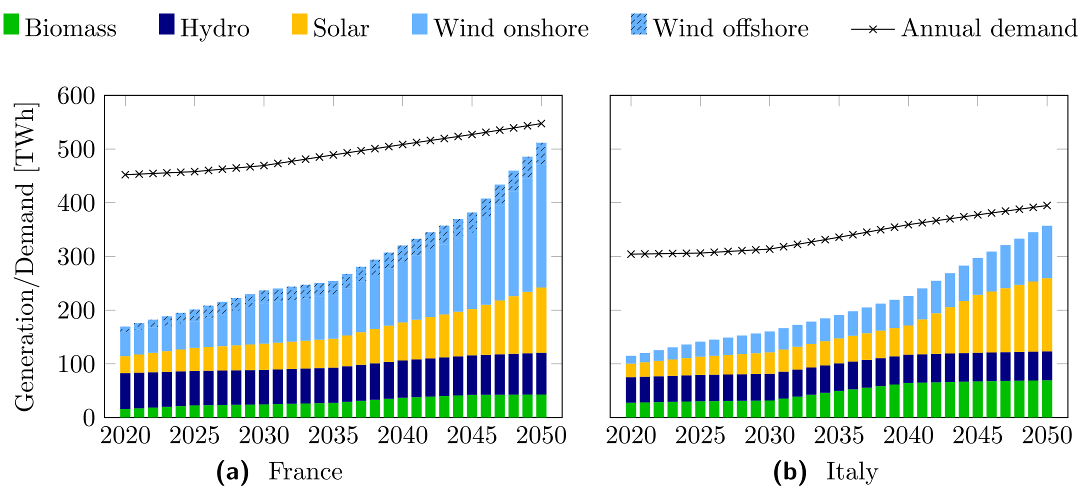

Fig. 6. Assumed renewable electricity generation and electricity demand in France (a) and Italy (b). Source: own illustration based on data from ENTSO-E (2017); de Vita et al. (2016), and own assumptions.

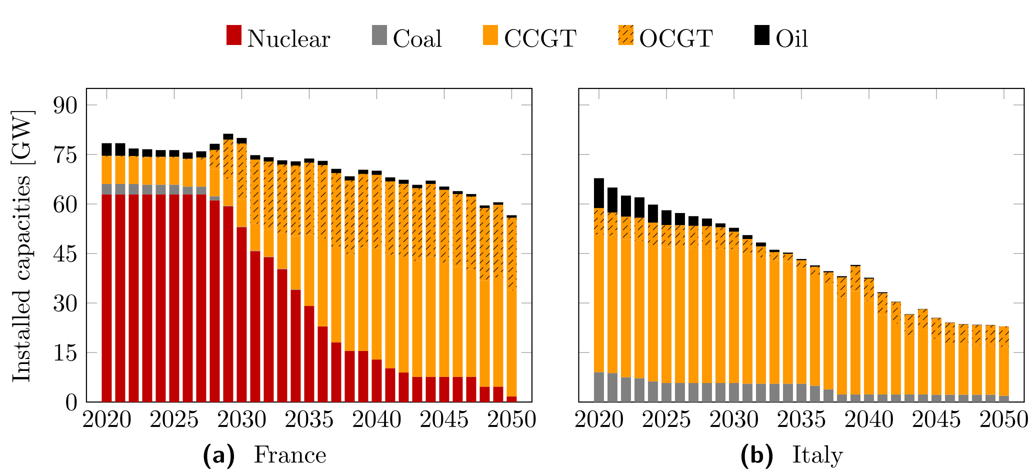

Fig. 7. Simulated development of the conventional power plant capacities in France (a) and Italy (b) under a European energy-only market design.

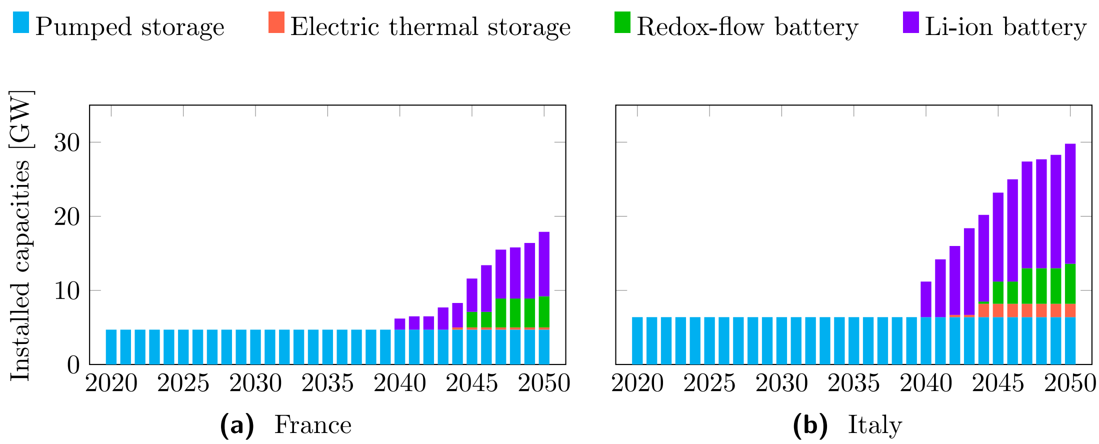

Fig. 8. Simulated development of the utility-scale storage capacities in France (a) and Italy (b) under a European energy-only market design.

Table 4
Overview of the investigated scenarios regarding capacity remuneration mechanisms with call options and different strike prices.

Scenario	Electricity market designs	Strike price[1]	Storage duration requirement[2]
EOM	European EOM	n/a	n/a
CRM-08	National CRM policies	none	8 h
CRM-08-limit_high	National CRM policies	$1.5 \cdot c^{var}_{CONE,y}$	8 h
CRM-08-limit_low	National CRM policies	$c^{var}_{CONE,y}$	8 h

Abbreviations: CONE—cost of new entry, CRM—capacity remuneration mechanism, EOM—energy-only market.
[1]This additional price limit on the day-ahead market only applies to capacity that has been successfully contracted in the capacity auctions and should not be confused with the general day-ahead price limit of 3000 EUR/MWh$_{el}$, which is valid for all participants of the day-ahead market.
[2] Storage units with shorter discharge durations than required may still participate in the capacity auctions, but are derated and are only remunerated for a certain share of their maximum discharging capacity.

ahead price limit of 3000 EUR/MWh$_{el}$ applies. Contrary, in scenario *CRM-08-limit_low*, we analyze the other extreme case, in which the strike price is set equal to $c^{var}_{CONE,y}$, i.e., the variable cost of a new entry conventional power plant (typically an OCGT) in the given year y.[13] In order to limit the interference with the market evolution in normal conditions, Vazquez et al. (2002) suggest to set the strike price at least 25% above the most expensive generator expected to produce. For this reason, in scenario *CRM-08-limit_high*, we also investigate the case of a higher strike price set at 150% of $c^{var}_{CONE,y}$.

In all described CRM scenarios, we assume that the regulator bears the risk of a storage unit running empty during a multi-hour scarcity period, i.e., the storage operator is not subject to an *implicit* penalty in such situations (see also the discussion in Section 3). Moreover, we set the required minimum storage duration to an intermediate value of 8 h for all scenarios. The impact of varying this parameter will then be analyzed in detail in the following Section 4.5.

4.4.2. Long-term capacity developments

For all described scenarios and the two countries under investigation (France and Italy), Fig. 9 shows the simulated development of the conventional power plant and utility-scale storage capacities between 2020 and 2050. Please note that in order to make the differences between the scenarios more clearly visible, the respective deltas of installed capacities as compared to the European EOM are illustrated rather than presenting the absolute capacity values. Consequently, the zero-line represents the installed capacities in the European EOM. We also integrate a solid black line indicating the sum of the storage capacity deltas as well as a dashed black line for the total conventional capacity deltas.

In France, we can observe that without implementing a strike price, the introduction of the French CRM mainly incentivizes more investments in gas-fired power plants (both CCGTs and OCGTs) as compared to the European EOM (Fig. 9, top left), while the total installed storage capacity remains relatively stable. It becomes obvious though, that storage investments are shifted to a later period, since the additional conventional power plants reduce their profitability. Results for Italy show similar trends (Fig. 9, top right).

If a high strike price at 150% of $c^{var}_{CONE,y}$ is implemented, somewhat more storage capacity is built in France as compared to both the situation under a European EOM and that under a CRM without strike price (Fig. 9, middle left). Contrary, in Italy, no such trend can be clearly identified (Fig. 9, middle right). We will come back to the reasons for this finding later.

Finally, under a low strike price at $c^{var}_{CONE,y}$, substantially more storages are built in France than in any other setting investigated thus far (Fig. 9, bottom left). Moreover, the investments in storages are also carried out a lot earlier, starting already in 2030 rather than only after 2040. The higher installed storage capacities in turn replace some later investments in OCGTs due to the lock-in effect. In Italy, the trend of building storages earlier than in the other settings is similar, yet does not lead to a stable higher amount of installed storages in the long run (Fig. 9, bottom right).

Summing up, we can conclude, that the findings of the simulations carried out generally stand in line with our theoretical discussion on the impact of implementing call options with a certain strike price in Section

[13] This stands in line with the way the strike price is determined in the recently implemented Italian CRM (Mastropietro et al., 2018; Perico et al., 2018). The Irish CRM also applies a similar methodology, in which the strike price is set a the maximum of two values: firstly, the fuel costs of a hypothetical reference peak generation unit and secondly, the variable costs of a reference demand side unit. This procedure is chosen to avoid discrimination against demand side management, which might face higher variable costs then a generation unit. Thus, under the Irish approach, typically a higher strike price than in Italy would evolve. For details please refer to Single Electricity Market Committee (2015).

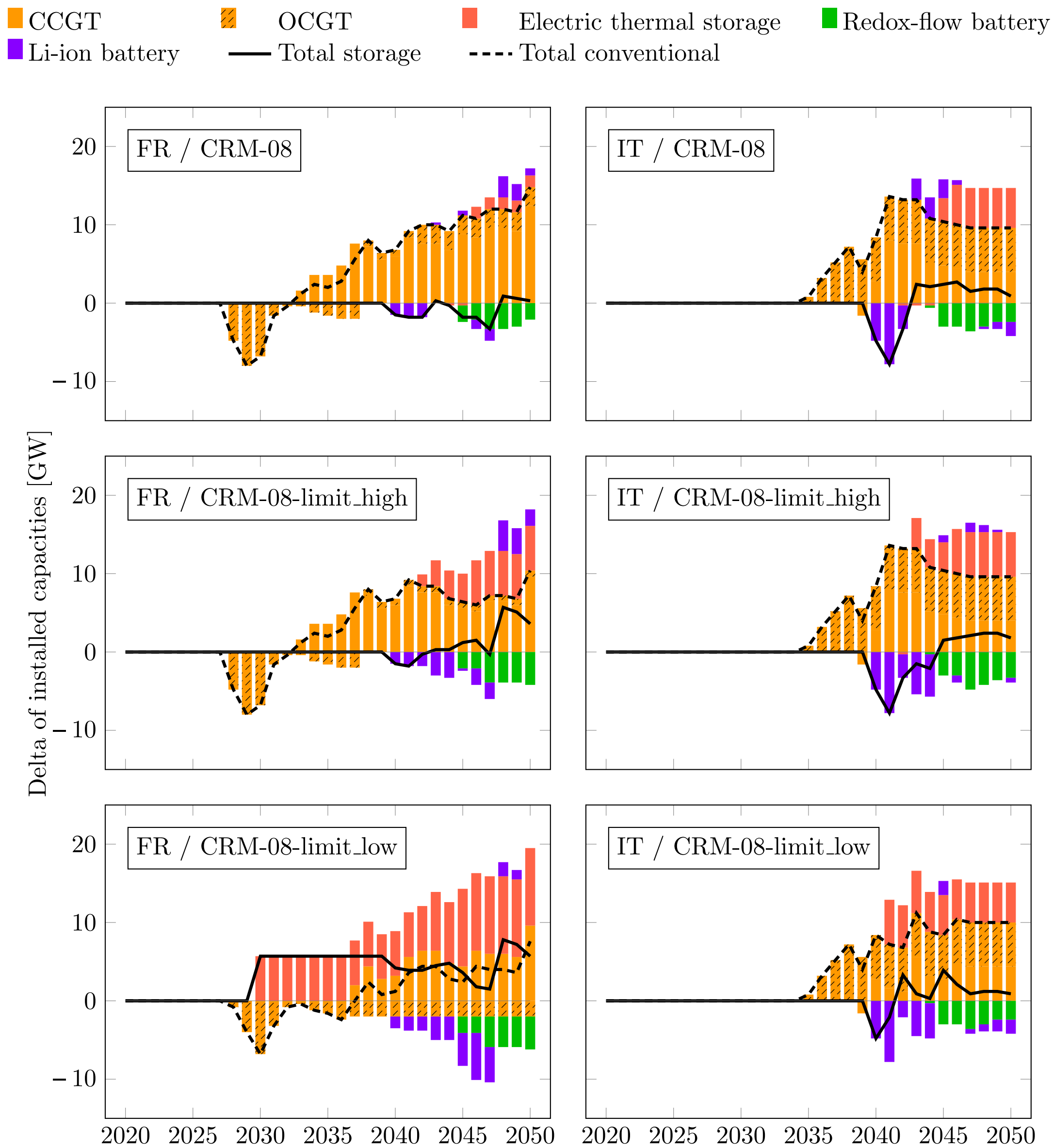

Fig. 9. Simulated development of the conventional power plant and utility-scale storage capacities in France (left) and Italy (right) under capacity remuneration mechanisms with different strike prices (from top to bottom: none, high, low). The values shown are the respective deltas of installed capacities as compared to the European energy-only market design.

3.2. We can therefore confirm that if a CRM without call options is implemented, an implicit bias towards conventional power plants exists, while a CRM with call options and a strike price increases storage profitability in direct comparison with conventional power plants.

However, the effect in the simulations is much more pronounced in France than in Italy. This can largely be attributed to differences in the structure of the initial power plant fleets. As shown in Fig. 5 and previously discussed in Section 4.3, exogenously defined decommissioning of power plants starts earlier and at a much sharper rate in France than in Italy. The dominating driver for storage investments in Italy are the achievable arbitrage profits due to low investment expenses for storages in the period beyond 2040. Consequently, both the introduction of the Italian CRM and the optional bundling with call options have a rather small impact. In France, however, due to the stronger decommissioning rate, investments are needed earlier, when storages are still rather expensive to build. In this particular situation, implementing a CRM bundled with call options can shift investments towards storage technologies.

It is also important to mention that in none of the analyzed settings does the implementation of a strike price lead to all conventional power plant investments being replaced by storage units. This is because a strike price only affects the technology choice in situations where high price periods follow low price periods (as in our stylized example presented in Section 3.2). If this situation is not given and storages are not able to charge at low or even zero cost, conventional power plants may remain the more profitable option to build, even if a strike price is implemented.

Our simulation results suggest that no straightforward answer can be given on whether an EOM or a CRM is more favorable for investments in storage technologies, but much depends on the country-specific drivers as well as the concrete design of the CRM. A CRM without call options has a rather small impact on storage investments as compared to an EOM, since lower revenues on the energy markets are compensated by the additional capacity remuneration. If call options with a strike price

Table 5
Generation adequacy indicators in France and Italy under a European energy-only market and capacity remuneration mechanisms with different strike prices.

Scenario	No market clearing [⌀ 2020–2050 in h/a]		Energy not served [⌀ 2020–2050 in GWh/a]	
	France	Italy	France	Italy
EOM	10.7	8.4	60.5	50.0
CRM-08	–	1.4	–	1.7
CRM-08-limit_high	1.6	1.8	3.7	2.7
CRM-08-limit_low	5.1	2.1	16.2	2.6

Table 6
Overview of the investigated scenarios regarding capacity remuneration mechanisms with different storage duration requirements.

Scenario	Electricity market designs	Strike price[1]	Storage duration requirement[2]
EOM	European EOM	n/a	n/a
CRM-04-limit_low	National CRM policies	$c^{\mathrm{var}}_{\mathrm{CONE},y}$	4 h
CRM-08-limit_low	National CRM policies	$c^{\mathrm{var}}_{\mathrm{CONE},y}$	8 h
CRM-12-limit_low	National CRM policies	$c^{\mathrm{var}}_{\mathrm{CONE},y}$	12 h

Abbreviations: CONE—cost of new entry, CRM—capacity remuneration mechanism, EOM—energy-only market.
[1]This additional price limit on the day-ahead market only applies to capacity that has been successfully contracted in the capacity auctions and should not be confused with the general day-ahead price limit of 3000 $\mathrm{EUR/MWh_{el}}$, which is valid for all participants of the day-ahead market.
[2]Storage units with shorter discharge durations than required may still participate in the capacity auctions, but are derated and are only remunerated for a certain share of their maximum discharging capacity.

are implemented, storage units gain a competitive advantage over conventional power plants in the capacity auctions. The additional capacity remuneration then leads to more storage investments as compared to an EOM. This effect is particularly important in countries with high capacity needs in the medium-term (2030–2040), where storage technologies are still rather expensive to build.

4.4.3. Impact on generation adequacy

An essential aspect when analyzing storage participation in CRMs is their ability to provide *firm* capacity. Although the model we apply for our simulations is deterministic, we can still draw some general conclusions on this issue by comparing the market outcomes in the different scenarios. For this purpose, Table 5 shows two relevant adequacy indicators for all scenarios investigated thus far. Firstly, we present the mean amount of yearly hours with no successful market clearing, i.e., the situations in which the available generation and storage capacity plus potential imports were not sufficient to cover the residual demand. Secondly, we show the respective average yearly amounts of energy not served in these scarcity situations.

In France, for both indicators we can clearly identify that in all CRM scenarios, generation adequacy is substantially higher than in the European EOM. This is a rather straightforward finding since capacity targets in France are implemented in these settings. We do observe, however, that scarcity situations only fully vanish, if no strike price is implemented and consequently comparably few storages are built. Apparently, some scarcity situations with longer durations exist, in which the required storage duration of 8 h is not sufficient. Since the introduction of a strike price has a rather small impact on the technology composition in Italy as described before, we can also see from Table 5 that the adequacy increases similarly in all CRM settings as compared to the European EOM. However, also in Italy some scarcity situations remain due to insufficiently large storage volumes.

In order to tackle the issue of storages running empty during scarcity periods, it is important to account for the energy-limited nature of storages in the capacity auctions. One way of doing so is to define a minimum discharge duration requirement and derate storage capacity accordingly, if a technology is not able to fulfill these requirements. The following section discusses this topic in more detail.

4.5. Storage derating in the capacity auctions

4.5.1. Scenario setup

We now stay with the CRM design determined as the most favorable one for storage investments, i.e., the setting with a low strike price set at $c^{\mathrm{var}}_{\mathrm{CONE},y}$. In order to investigate the impact of different storage derating factors, we re-use scenario *CRM-08-limit_low* from the previous section with a storage duration requirement of 8 h and run two additional simulations: *CRM-04-limit_low*, with a reduced requirement of 4 h and *CRM-12-limit_low*, with an increased requirement of 12 h.[14] These three scenarios are again all contrasted with the benchmark of a European EOM. Table 6 summarizes all scenarios and their respective characteristics. All variables and parameters not mentioned there remain unchanged in all scenarios under investigation.

In our model, regardless of the storage duration requirements, all storage technologies are allowed to participate in the capacity auctions, yet their contracted capacity is derated according to Eq. (10) if their storage volume is not sufficient to fulfill the requirements.[15]

4.5.2. Long-term capacity developments

Fig. 10 presents the simulated development of the conventional power plant and utility-scale storage capacities between 2020 and 2050 for all described scenarios and the two countries under investigation (France and Italy). As in the previous analysis focusing on call options, we illustrate the respective deltas of installed capacities as compared to the European EOM to emphasize the differences between the scenarios.

In both France and Italy similar trends can be observed. If we compare the settings with 4 h (Fig. 10, top) and 8 h (Fig. 10, middle) storage duration requirements, we can see a shift of investments from small li-ion batteries with 4 h discharge duration towards electric thermal storages[8] with 10 h discharge duration. The latter technology becomes the preferred option, as it is less affected by strong storage derating due to its larger storage volume. At the same time, the stronger derating of storages also leads to higher amounts of *nameplate* capacity to be contracted in the capacity auctions to fulfill the required *firm* capacity targets set by the regulator. This in turn leads to substantial amounts of additional gas-fired power plants (mostly CCGTs), but also to temporary phases with more storage investments carried out despite the stronger derating factor (see also Section 3.3).

[14] The range of 4–12 h for the storage duration requirement is chosen according to the properties of the implemented storage investment options (see Table 9). Moreover, for the CRM implemented in the UK a requirement of 4 h has recently been defined with derating applied for smaller storage discharge durations (National Grid, 2017).

[15] While this procedure is similar to the CRMs in Ireland and the UK, our approach of using linear derating is somewhat simplified as compared to the more advanced methods used in the real-world cases (National Grid, 2017; Single Electricity Market Committee, 2016).

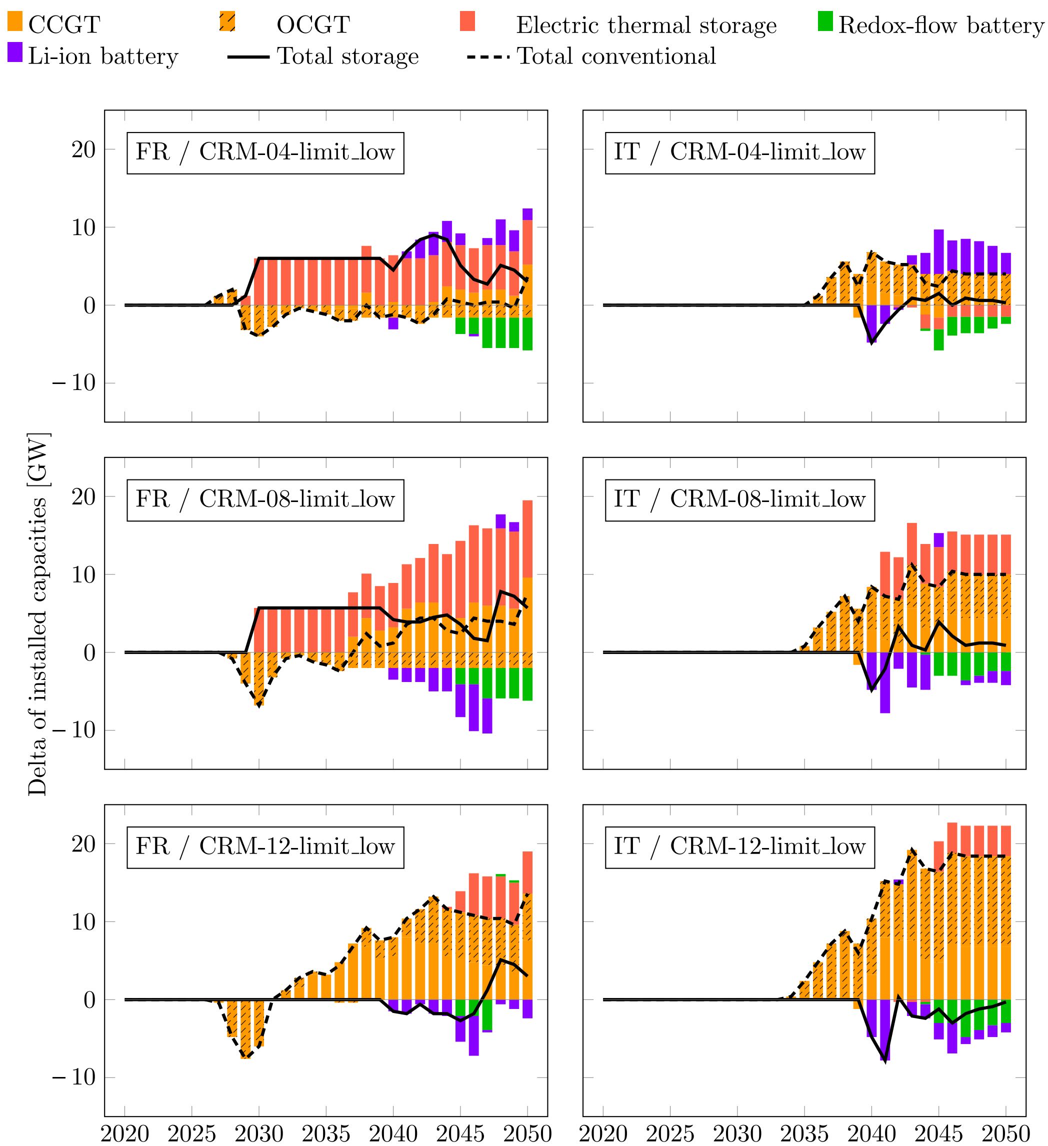

Fig. 10. Simulated development of the conventional power plant and utility-scale storage capacities in France (left) and Italy (right) under capacity remuneration mechanisms with different storage duration requirements (from top to bottom: 4 h, 8 h, 12 h). The values shown are the respective deltas of installed capacities as compared to the European energy-only market design.

Table 7
Generation adequacy indicators in France and Italy under a European energy-only market and capacity remuneration mechanisms with different storage duration requirements.

Scenario	No market clearing [⌀ 2020–2050 in h/a]		Energy not served [⌀ 2020–2050 in GWh/a]	
	France	Italy	France	Italy
EOM	10.7	8.4	60.5	50.0
CRM-04-limit_low	11.6	4.0	57.0	11.3
CRM-08-limit_low	5.1	2.1	16.2	2.6
CRM-12-limit_low	0.2	–	0.1	–

Moving on to the storage duration requirement of 12 h (Fig. 10, bottom), we can see that storage technologies are becoming a lot less competitive than in the other settings. Consequently, fewer storage investments are carried out and those that remain are built at a later phase of the simulated period. In this setting, the higher amounts of *nameplate* capacity to be contracted in the capacity auctions lead to a strong increase in CCGTs and OCGTs, but no additional storage investments.

These simulation results stand perfectly in line with what we would expect from out theoretical discussion of the impact of storage derating in Section 3.3. We can therefore confirm that stronger derating of storage technologies generally creates a bias towards larger storages and ultimately conventional power plants. However, we also find that the higher amounts of *nameplate* capacity to be procured in the capacity auctions may in some settings overcompensate this effect and even lead to more storage investments despite stronger derating.

Regarding the question whether an EOM or a CRM is more favorable for investments in storage technologies, we can confirm our findings from the previous section: While no straightforward answer to this issue can be given, it is rather the concrete design of the CRM that matters. The choice of the derating factors for storages is a strong driver deciding on whether more or less storage units are built than under a European EOM, and also which storage technology will be the dominant one. Moderate storage duration requirements are generally favorable for investments in small storages and may consequently lead to additional storage capacity under a CRM as compared to a European EOM. Higher storage duration requirements, i.e., stronger derating of storage capacity, makes small storages less attractive and shifts the technology mix towards larger storages or even conventional power plants. At the same time, stronger derating leads to higher *nameplate* capacity targets in the capacity auctions, which are then typically reached through additional large storage units or ultimately conventional power plants.

4.5.3. Impact on generation adequacy

As previously discussed, the choice of the storage derating factors does not only affect the future technology mix, but in consequence also the ability of a CRM to fulfill its major objective of ensuring long-term generation adequacy. In order to get insights on this issue, Table 7 presents the same two adequacy indicators as in the previous analysis of call options with varying strike prices.

In both France and Italy, we can see similar trends for the two indicators. Moderate storage derating leads to relatively high shares of storage units. Due to their limited storage volume, these units are not able to provide sufficient *firm* capacity to cover all peak demand periods. Consequently, scarcity situations can only be partly reduced (Italy) or even stay at a similar level as under a European EOM (France). This of course contradicts the actual goal of implementing a CRM in the first place.

If stronger storage derating factors are applied, fewer storage investments, but substantially more investments in conventional power plants are carried out. Since the conventional units are able to provide *firm* capacity at all times (neglecting forced outages), the scarcity situations vanish completely in this setting (Italy) or are at least reduced to a much lower level than in the European EOM setting (France). We can ultimately conclude that the appropriate choice of the storage derating factors in capacity auctions is essential in order to guarantee generation adequacy. At the same time, the resulting technology mix may be strongly affected by this design parameter.

5. Conclusion and policy implications

Both the theoretical discussion and the simulations carried out showed that there is no straightforward answer to whether an EOM or a CRM is the more beneficial market design for electricity storage technologies. Rather than the actual market design, much depends on the concrete specification of the CRM, which always creates a certain bias towards one technology or the other. We were able to show that bundling capacity auctions with call options and the choice of the storage derating factor are important drivers in this regard.

If storage units are not penalized for non-availability during scarcity situations caused by their storage volume running empty, they likely benefit from the introduction of call options with a certain strike price in direct comparison with conventional power plants. Contrary, if the storage units are indeed penalized even in these particular situations or if no call options with strike price are used, there exists a bias towards conventional power plants, as they do not face the risk of a storage running empty and can always provide *firm* capacity (neglecting forced outages).

We were also able to show that it is crucial to adequately estimate the *firm* capacity a storage unit can provide and to derive storage derating factors accordingly. Otherwise, the contribution of small storages may be overestimated, leading to issues regarding generation adequacy despite the implementation of a CRM.

At least to some extent, these results are also valid for DSM, which, much like electricity storage, is an energy-limited resource. However, each DSM technology differs regarding the underlying process, such that very individual restrictions need to be considered. Therefore a direct and general transfer of our results for electricity storage is not possible.

Overall, we can conclude, that the actual design of a CRM substantially impacts the future technology mix, even if all technologies are formally allowed to participate in the mechanism. The specification of the CRM may then in turn also have an impact on the goal of achieving long-term generation adequacy. More specifically, we could observe that electricity storage does indeed have a capacity value and should therefore be allowed to participate in any CRM, yet with its *nameplate* capacity adequately derated to reflect the *firm* capacity it can actually provide. Moreover, the simulation results suggest, that substantial need for investment in generation and storage capacity exists in Europe in the upcoming years due to decommissioning of old units.

Policymakers and regulators are therefore strongly recommended to design or re-specify their CRMs accordingly to allow for storage participation in an adequate manner. In this regard, the time to act is now. Otherwise, a lock-in effect may occur, i.e., once an undesired technology is built, it will likely remain in the system for a long time. While some European CRMs, e.g., Ireland and the United Kingdom, are already on the right path and have recently developed methods to determine storage derating factors, barriers are still very high in US markets like PJM, due to unnecessarily strict requirements (Chen et al., 2017; National Grid, 2017; Single Electricity Market Committee, 2016, 2018; Usera et al., 2017). Moreover, Ireland and Italy also combine their capacity auctions with call options and a certain strike price, which is generally favorable for storage units.

We are well aware that real-world CRMs are much more complicated than the simplified settings we have analyzed in our work and more research therefore needs to be carried out to confirm our findings. In particular, we refrain from modeling strategic behavior in the capacity auctions. To gain insights into this issue, it may be interesting to delve into the design and the auction outcomes of the different CRMs implemented around the world.

Moreover, in the simulations carried out, the storage derating factor has been determined by exogenously setting arbitrary required discharge durations rather than trying to choose optimal such values. It could therefore be a promising approach, to have the regulator agent determine adequate derating factors endogenously by implementing one of the methods from the literature (Borozan et al., 2019; Sioshansi et al., 2014; Zhou et al., 2015, 2016) into the simulation framework.

So far, we have focused on conventional power plants and short-term storage units. We could also extend our work by considering additional technologies like seasonal storage (power-to-X) or DSM to see whether the findings for short-term electricity storage also hold for these technologies. However, due to the large storage volume of power-to-X technologies, we expect its diffusion to mostly depend on the achievable reductions in capital expenditures rather than on the specific CRM design. As regards DSM, the issue lies mostly with the availability of the necessary process-specific data.

Finally, we have to mention that electricity storage has many additional benefits to just the provision of *firm* capacity and arbitrage trading as we assume it in our paper. As we neglect this aspect, we probably underestimate the storage diffusion potential as compared to a real-world setting with multiple revenue streams. However, this does not diminish the relevance of our results.

CRediT authorship contribution statement

Christoph Fraunholz: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Writing - original draft, Visualization. **Dogan Keles:** Conceptualization, Validation, Writing - review & editing, Supervision, Project administration, Funding acquisition. **Wolf Fichtner:** Conceptualization, Writing - review & editing, Supervision, Funding acquisition.

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. PowerACE model description

A.1. Day-ahead market simulation

PowerACE is structured into different market areas, in each of which multiple traders are active on the day-ahead market. All agents participating in the market first create a price forecast, for which the behavior of the other market participants is anticipated, and then prepare individual hourly demand and supply bids.

The bid prices for the supply bids are primarily based on the variable costs of the respective power plant. In addition, the price forecast is used to estimate the running hours of each power plant and to distribute the expected start-up costs accordingly. Further price-inelastic bids for demand, renewable feed-in and storage units are prepared by a single trader per market area, respectively. For details on the determination of the bid volumes for the storage units, please refer to Fraunholz et al. (2017).

Once all bids have been prepared, they are submitted to the central market coupling operator. In the market clearing process, supply and demand bids are matched across all market areas, such that welfare is maximized subject to the limited interconnector capacities between the different market areas. For a formal description and details of the market coupling and clearing see Ringler et al. (2017).

As a result, the information about which bids have been partly or fully accepted is returned to the different traders. Final outcome of the day-ahead market simulation is a market clearing price and corresponding electricity volume for each simulation hour and market area. Please note that situations may occur, in which the available generation and storage capacity plus potential imports are not sufficient to cover the residual demand. The market clearing price in the respective market area is then set at the day-ahead price limit of 3000 EUR/MWh$_{el}$.

A.2. Generation and storage expansion planning

In addition to the short-term decisions on the day-ahead market, the different utility companies modeled as agents in PowerACE can also perform long-term decisions on investments in new conventional power plant and storage capacities at the end of each simulation year. Contrary to the common approach of generation expansion planning with the objective of minimizing total future system costs, an actor's perspective is taken. Consequently, investments are only carried out if expected to be profitable by the investor agents. The expansion planning algorithm is introduced and described in detail in Fraunholz et al. (2019). A brief overview of the basic principles is given in the following.

In order to estimate the profitability of the different investment options, a model-endogenous long-term price forecast is first carried out. Using this forecast, annual contribution margins for all technologies are calculated and corresponding net present values are derived. These are ultimately converted to annuities to account for technology specific investment horizons.

For conventional power plant technologies, the contribution margins are calculated in a simplified fashion as the sum of call options on the respective hourly contribution margins. For storage technologies, the contribution margins correspond to their maximum arbitrage potential. Thus, in order to determine optimal hourly charging and discharging strategies based on the expected future prices, a time-coupled linear optimization problem is solved.

As previously mentioned in Appendix A.1, scarcity situations may occur in the model, if the available generation and storage capacities are not sufficient to cover the residual demand. The anticipation of the corresponding peak prices up to the day-ahead price limit of 3000 EUR/MWh$_{el}$ is an important driver for investment decisions, both in our model and the theoretical concept of the energy-only market.

The decisions of the different investors are primarily based on their expectations regarding future electricity prices. As these, vice versa, are influenced by the investment decisions of all investors in all interconnected market areas, a complex game with multiple possible strategies opens up. To find a stable outcome for this game, a Nash-equilibrium needs to be determined.

Therefore, the expansion planning algorithm terminates when all planned investments are profitable and at the same time none of the investors is able to improve his expected payoff by carrying out further or less investments, i.e., there is no incentive for any investor to unilaterally deviate from the equilibrium outcome. The different market areas are defined as the players interacting with each other and the planned investments are then distributed among the investors within each market area. Following this approach, it is possible to consider the mutual impact of investments in one market area on the electricity prices and consequently investments in the interconnected market areas.

A.3. Capacity remuneration mechanism

The following paragraphs briefly introduce the central buyer mechanism implemented in PowerACE, which follows closely the generic mechanism introduced in Section 3.1. For further details, please refer to Keles et al. (2016).

In the market areas with an active central buyer mechanism, annual descending clock auctions are carried out in order to contract a specific amount of *firm* generation and storage capacity. The auctions take place prior to the regular expansion planning as described above. Following this approach, it is possible to adequately consider the cross-border impacts of the capacity auctions.[16]

[16] If the capacity auctions were carried out after the regular expansion planning, the investors in the other market areas could only react to the auction results in the subsequent investment planning periods. However, since capacity auctions are typically carried out with a certain lead time, it seems more plausible to assume that all investors possess a priori knowledge about the auction results before deciding on their investments. Please note that also in market areas with an active central buyer mechanism, additional investments driven by expected revenues from the EOM are always possible. Consequently, all modeled countries are considered in the regular expansion planning algorithm.

For the auctions, the regulator first sets a targeted ratio between *firm* capacity and peak residual demand in the respective year, excluding imports. This ratio is an arbitrary value, which controls the desired level of generation adequacy and defines the amount of *firm* capacity to be procured in the auction. Since we only analyze deterministic cases in our simulations, we set the targeted ratio to 1.0, such that the residual load in the respective market area can always be covered by the domestically available conventional generation and storage capacity, without depending on electricity imports. Moreover, in order to analyze the impact of different mechanism designs, we have integrated the two parameters *price cap* and *required storage duration* as introduced in Section 3.1 into the modeled mechanism.

Next, the different utility companies provide capacity bids consisting of volume and price. While existing capacity is offered at zero cost,[17] the bids for potential new power plant and storage capacity are based on the respective difference costs. These are directly related to the regular investment planning procedure. Investments expected to be profitable even without additional capacity payments bid into the auction at zero cost. If the desired *firm* capacity is not yet guaranteed through these investments, additional bids of the technology with the lowest negative annuity, i.e. the best, yet not profitable investment option, are placed into the auction. The bid price of these additional investments is determined based on the additional income that would be needed to recover all cost related to the respective investment, the so-called difference costs.

For this contribution, storage technologies were integrated into the existing mechanism by using the concept of *firm* capacity. Thus, while conventional power plants can bid their full *nameplate* capacity in the auctions, storage units are derated according to the new mechanism design parameter *required storage duration* and can only bid their resulting *firm* capacity.

After receiving bids from all market participants, the auction is cleared and all successful participants are compensated with a uniform capacity price, which is paid to the existing power plants and storage units for one year and to new constructions for an arbitrary longer period.

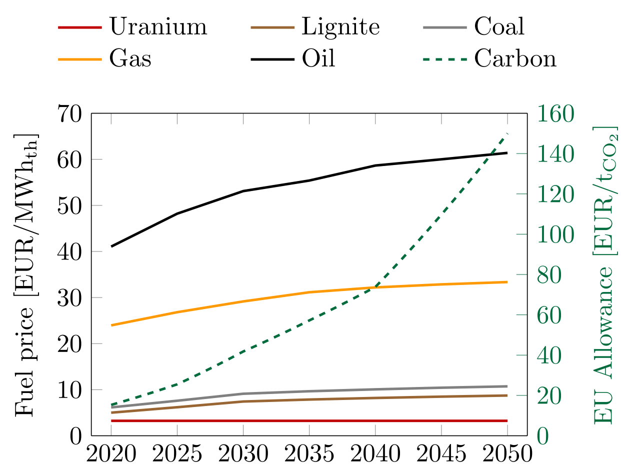

Fig. 11. Assumed development of fuel and carbon prices. Source: own illustration based on data from EU Reference Scenario (de Vita et al., 2016), and own assumptions.

Appendix B. Input data

Fig. 11 presents the assumed development of fuel and carbon prices over the time horizon of the simulation.

An overview of the techno-economic characteristics of the different investment options modeled in PowerACE is provided in Tables 8 and 9.

Table 8

Conventional power plant investment options modeled in PowerACE with their respective techno-economic characteristics. Source: Schröder et al. (2013); Louwen et al. (2018), own assumptions.

Technology	Block size [MW_{el}]	CCS	Net efficiency[1] [%]	Lifetime [a]	Building time [a]	Specific investment (2015–2050)[1] $\left[\frac{EUR}{kW_{el}}\right]$	O&M costs fixed $\left[\frac{EUR}{kW_{el}a}\right]$	O&M costs var[2] $\left[\frac{EUR}{MWh_{el}}\right]$
Coal	600	No	45–48	40	4	1800	60	6
		Yes	36–41			3143–2677		30
Lignite	800	No	43–47	40	4	1500	30	7
		Yes	30–33			3840–3324		34
CCGT	400	No	60–62	30	4	800	20	5
		Yes	49–52			1216–1078		18
OCGT	400	No	40–42	30	2	400	15	3

Abbreviations: CCGT—combined cycle gas turbine, CCS—carbon capture and storage, OCGT—open cycle gas turbine, O&M—operation and maintenance.
[1]Resulting from technological learning, the net efficiency is assumed to increase over time. Since conventional power plants can generally be regarded as mature technologies, it is further assumed that only the specific investments of the CCS-technologies are declining.
[2]Including variable costs for carbon capture, transport and storage, where applicable.

[17] In reality, existing capacity not able to operate profitably on the EOM would likely also bid with its respective difference costs. However, since we do not consider model endogenous decommissioning of power plant or storage capacity, investment expenses and fixed costs may be considered as sunk costs. Consequently, it is reasonable to assume that existing capacity would happily accept any additional capacity remuneration, regardless of how low it may be.

Table 9
Electricity storage investment options modeled in PowerACE with their respective techno-economic characteristics. Source: Louwen et al. (2018); Siemens Gamesa (2019), own assumptions.

Technology	Block size [MW_{el}]	Storage capacity[1] [MWh_{el}]	Round-trip efficiency[2] [%]	Lifetime[2] [a]	Building time [a]	Specific investment (2015–2050)[2] $\left[\frac{EUR}{kW_{el}}\right]$	O&M costs fixed[2] $\left[\frac{EUR}{kW_{el}a}\right]$
Li-ion battery	300	1200	85–95	20–30	2	3149–572	63–11
		3000				7643–1388	153–28
RF battery	300	3000	75–85	20–30	2	4206–892	84–18
A-CAES	300	3000	60–75	30	2	1095	22
ETES	300	1200	50–60	40	2	600	12
		3000				672	13

Abbreviations: A-CAES—adiabatic compressed air energy storage, ETES—electric thermal energy storage, O&M—operation and maintenance, RF battery—redox-flow battery.
[1]For RF batteries and A-CAES, a substantial share of the investment expenses is related to the converter units. Consequently, for economic reasons, only higher storage capacities of 3000 MWh_{el} are eligible as investment options for these technologies.
[2]Resulting from technological learning, round-trip efficiency and lifetime are assumed to increase over time for the emerging storage technologies. Analogously, specific investments and fixed costs for O&M are assumed to decline.

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