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# An analysis of shortage pricing and capacity remuneration mechanisms on the pan-European common energy market

Yuting Mou [a,*], Anthony Papavasiliou [b], Katharina Hartz [c], Alexander Dusolt [c], Christian Redl [c]

[a] School of Electrical Engineering, Southeast University, Nanjing 210018, Jiangsu Province, China
[b] Department of Electrical and Computer Engineering, National Technical University of Athens, Greece
[c] Agora Energiewende, Anna-Louisa-Karsch-Str. 2, 10178 Berlin, Germany

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ABSTRACT

Various market design options have been implemented or proposed in order to address the missing money problem and facilitate the energy transition. In order to analyze the performance of energy-only markets, and energy markets supplemented by shortage pricing and/or capacity remuneration mechanisms, we develop a capacity expansion model for the European system. A number of market design scenarios are simulated until the year 2050. We consider a range of sensitivity analyses so as to understand the effect of various market design options on the performance of energy markets and their variants, as well as the effects of cross-border coordination. The findings of this paper indicate that capacity remuneration mechanisms are sensitive to numerous non-obvious design parameters and can sometimes lead to over-dimensioning, even if the effect on total cost can be less pronounced, whereas shortage pricing appears as a no-regret measure because price adders recede when there is abundant flexibility in the system.

## 1. Introduction

The European Union (EU) is implementing a consistent policy agenda for combating climate change and reducing carbon emissions. The European Council and the Parliament recently reached a provisional political agreement to raise the share of renewable energy in the EU's overall energy consumption to 42.5% by 2030 with an additional 2.5% indicative top up (Council of the EU, 2023). In the electricity sector, the increasing share of wind and solar capacities has a significant impact on the merit order (Koltsaklis et al., 2017), resulting in a revenue decrease for conventional generators. Concerns have thus been raised about the extent to which energy-only markets can support the energy transition by ensuring the right investment for guaranteeing security of supply, due to a shift in the merit order. The results from the European Resource Adequacy Assessment suggest that capacity mechanisms can contribute to avoiding adequacy risks (ENTSO-E, 2022). Various policy instruments have been proposed and/or adopted in various Member States (ACER, 2022) in order to cope with this evolution, including shortage pricing and capacity remuneration mechanisms.

Shortage pricing refers generically to the practice of setting price above the marginal cost of the marginal unit under conditions of high system stress. It is also referred to sometimes as scarcity pricing and can be implemented through elastic electricity demand as well as through interventions in the design of the reserve market (Stoft, 2002). We provide an overview of various approaches in Table 1, and we focus on shortage pricing through operating reserve demand curves (ORDCs) in our study.

Capacity remuneration mechanisms (CRMs) vary, and include capacity auctions (quantity based), capacity payments (price based), and decentralized capacity mechanisms. We collapse all of these designs under a generic year-ahead auction for capacity, where the buyer of the capacity is the TSO and the sellers of the capacity are the existing plants or potential new builds. CRMs are often accompanied by reliability options although we do not consider this aspect in our work. One appeal of CRMs is that they offer perceived risk mitigation to investors since the CRM auction provides a cash flow to investors of existing and potential future capacity (Cramton and Stoft, 2005; Joskow, 2008). The mechanism is sometimes viewed with caution in the regulatory world due to the fact that it creates challenges in precisely defining the capacity product, creating incentives for investors to deliver on their promise to build new capacity, deciding on administrative parameters (capacity credits, parameters of the capacity demand curve, and so on), and balkanization of the EU market design, to mention a number of concerns.

Although ORDCs and CRMs appear different, they both relate to the remuneration of capacity. It is often stated that CRMs target adequacy, and ORDCs target flexibility, but the two notions are interdependent

* Corresponding author.
*E-mail address:* yutingmou@seu.edu.cn (Y. Mou).

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**Table 1**
Overview of various approaches for implementing shortage pricing and the corresponding simulation scenarios, which are introduced in Section 2.3.

| Approach | Description | Country/System | Scenarios |
|---|---|---|---|
| 1 | In markets with a price-responsive demand, under conditions of tight system operation, the demand side sets the price in the energy market under tight conditions, while administratively determined prices are set when the supply and demand do not clear. | New Zealand | EOM |
| 2 | In markets where reserve and energy are auctioned off simultaneously through co-optimization, under conditions of tight system operation the reserve price (which is determined by an operating reserve demand curve) uplifts the energy price due to a no-arbitrage condition between energy and reserve. | PJM, SPP, MISO, ISO-NE, CAISO | ORDC-StatusQuo, ORDC-FullRollout |
| 3 | In markets where reserve and energy are auctioned off simultaneously, but without co-optimization, the outcome of the reserve market is approximated based on the amount of available reserve in real time and an operating reserve demand curve, in order to compute what would have been the equilibrium price of reserve in a co-optimization. This price of reserve is added to the marginal cost of the marginal unit, as computed in the real-time energy market. | ERCOT | Not simulated |
| 4 | In certain European markets there is a separation of settlements for participants that partake in the balancing market (balancing service providers, BSPs) versus participants that cause imbalances (balancing responsible parties, BRPs). This has led to various proposals for implementing approximations of scarcity pricing where the adder described in the third approach above applies only to BRPs. In our view, this is an imperfect implementation of scarcity pricing that should be avoided (Papavasiliou, 2020). | Proposed in Austria and Germany | Not simulated |
| 5 | In certain countries, operating reserve demand curves are only introduced in the day-ahead market. This, in our view, is also an imperfect implementation of scarcity pricing, since it would be necessary to back up the day-ahead design with a coherent real-time design (Papavasiliou, 2020). | Ireland and UK | Not simulated |

(Stoft, 2002; CREG, 2021) (for instance, investments in flexible capacity naturally contribute towards adequacy), but the two notions are not the same either. In article 44(3) of the Electricity Balancing Guideline,[1] a direct link is drawn between the two mechanisms. According to certain EU regulatory agencies, there is an interpretation that if a Member State wishes to establish a CRM, it should first attempt to implement a shortage pricing mechanism. This interpretation has sparked a debate among certain EU member states regarding the compatibility of these two mechanisms. Therefore, this study focuses on shortage pricing through operating reserve demand curves and capacity remuneration mechanisms, as well as their coexistence. The emphasis of our work on CRMs resonates well with the recent draft decision of the European Commission on electricity market design which refers repeatedly to flexibility mechanisms, peak load shaving products and capacity markets (European Commission, 2023).

### 1.1. Literature review

Shortage pricing based on ORDC is essentially the introduction of price-responsive demand curves for reserve, which are inserted in short-term energy markets. ORDCs have been analyzed in detail by Stoft (2002) and advocated by Hogan (2005). They have subsequently been adopted widely in U.S. electricity markets and attracted more attention in the EU markets in recent years. Papavasiliou et al. (2023) provide an overview of international shortage pricing mechanisms based on ORDC. The shape of the ORDC is analyzed in Zarnikau et al. (2020) for ERCOT and Cartuyvels and Papavasiliou (2022) for Europe, and the projected evolution of shortage prices as a function of increasing renewable energy penetration is analyzed in Bajo-Buenestado (2021).

Considering the notable differences between the European and U.S. markets, a series of studies are carried out in order to evaluate the possibility of implementing ORDCs in the European design. Papavasiliou and Smeers (2017) simulate the Belgian market over a period of 21 months and verify that the introduction of shortage pricing based on ORDCs can restore the economic viability of the majority of flexible units in the Belgian market. An analysis of the sensitivity of shortage pricing to a number of design choices and market conditions is analyzed in Papavasiliou et al. (2018). The study finds that value of lost load would have a minor impact on ORDC adders when capacity shortages are negligible whereas the restoration of nuclear capacity or removal of strategic reserve from the Belgian market would have a significant impact on ORDC adders.

Capacity markets predate shortage pricing based on ORDCs in the U.S., and were introduced since the late 1990s, including in PJM, NYISO, ISO-NE and CAISO. Spees et al. (2013) and Bowring (2013) report findings from these systems and identify several challenges to be addressed, such as the parameters that define the shape of capacity demand curves. Similar mechanisms are also implemented in several Member States of the EU (European Commission, 2017, 2018; Komorowska et al., 2020). Papavasiliou (2021a) provides a comprehensive overview of EU capacity remuneration mechanisms. Bhagwat et al. (2016) presents a survey of U.S. capacity market experts with the purpose of drawing lessons for the EU.

In addition to practical surveys, researchers have studied various design aspects of capacity markets (Stoft, 2002; Cramton and Stoft, 2005; Cramton et al., 2013). Cepeda (2018) assesses cross-border interactions, with a focus on the UK and French market. The results underline that the absence of cross-border participation could lead to significant social welfare losses. Nevertheless, the definition of the contribution of an adjacent market is a difficult design question. The impact of high renewable energy penetration levels on capacity markets is analyzed in Bhagwat et al. (2017). Cross-border interactions are revisited quantitatively in our study for the pan-European system in

[1] *"Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity pursuant to Chapter 5 of this Title, administrative costs and other cost related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority."*

a 30-year forward-looking scenario of large-scale renewable energy integration.

The literature on the comparison between shortage pricing and CRMs, or their co-existence, is relatively scarce. Petitet et al. (2017) compares shortage pricing with an increased price cap to a capacity mechanism using a system dynamics model, and applies the model to a hypothetical system. Three market design scenarios are considered, namely the energy-only market with a price cap of 3,000 €/MWh, shortage pricing with a price cap of 20,000 €/MWh, and a capacity mechanism. The study finds that: (i) in a risk-neutral setting, the energy-only market is not sufficient for reaching an acceptable level of loss of load expectation (LOLE), while shortage pricing and the capacity mechanism arrive at similar levels of load loss and social welfare, although the latter is very sensitive to the definition of the capacity target; (ii) in the case of risk averse investors, the capacity market outperforms the energy-only market and shortage pricing in terms of LOLE and social welfare, on the condition that the capacity target is well defined. A working paper by Cramton et al. (2021) models the entry and exit of individual units over 40 years, from 2020 to 2060, in PJM. The energy, reserve, and capacity markets are modeled in detail, including a model of the day-ahead market on an hourly basis and the real-time market on a five-minute basis. Both markets co-optimize energy and reserve. Price-responsive demand is considered, however there is no modeling of investment in demand response. Network constraints are ignored as well. Only the co-existence of ORDCs and CRMs is considered and there is no comparison of different market designs.

### *1.2. Research questions and structure*

The ongoing energy transition in Europe could be significantly influenced by various market designs, which have distinct impacts on the development of the power system. The analysis presented in our paper aims at addressing the following questions in the context of the pan-European market:

- Is the energy-only market poised to generate price signals that can support a transition from existing power systems to future power systems with deep renewable energy integration in a decentralized fashion by providing incentives for investment in sufficient flexibility resources?
- How is the energy market affected by the introduction of ORDCs and/or CRMs mechanisms?
- How do these mechanisms interact if implemented in a heterogeneous EU market design context?

In order to answer these questions, a capacity expansion model of the European power system is developed. In addition to simulating several market design scenarios with and without ORDCs and/or CRMs, a number of sensitivity analyses are conducted.

The remainder of this paper is organized as follows. The methodology applied in the study is described in Section 2, including model features, data sources and assumptions employed in the large-scale simulations. The main results and findings are discussed in Section 3. Section 4 presents the limitations of the study. The paper is concluded by summarizing main conclusions and policy implications in Section 5.

## 2. Methodology

In this section we describe the setup of the large-scale simulations of the EU market, including a summary of model features, data sources and the scenarios that we choose to simulate. In order not to disrupt the flow of the text, while maintaining clarity, we present stylized models in the appendix.

### *2.1. Model features*

In this section we describe the model that has been employed in the analysis. The overall modeling framework is presented in Fig. 1. We describe each component of the overall model in turn below.

#### *2.1.1. Cycles*

The overall simulation extends from the present to 2050, in 5-year blocks. Each 5-year block determines the amount of capacity that is built within that 5-year block, which is added to existing capacity that is decided so far by the model, and which serves as initial capacity for the next investment cycle of 5 years. The legacy capacities follow a predefined decommissioning trajectory based on the Ember study (Ember, 2022). For instance, there is a legacy capacity of 22.4 GW from hard coal, with approximately 13 GW being decommissioned in the first 5-year block, followed by an additional 2.4 GW in the second 5-year block, and so forth.

#### *2.1.2. Energy-only market and investment*

The backbone of the model is a standard capacity expansion model. This model is readily interpreted as a competitive long-term equilibrium, where investors decide on which technologies to invest, based on the profitability implied by the resulting mix of technologies in an ideally functioning energy-only market.

The investment criterion of the energy-only market model assumes that investors only decide to invest if the profit margin produced by the energy-only market covers their corresponding investment. Voluntary demand curtailment corresponds to price-responsive demand which is bid into the market at a price, whereas involuntary curtailment corresponds to inelastic demand which is assumed to be valued at a value of lost load which varies by Member State. In this setting, the only revenue that investors rely on is that of the energy market. Therefore, the unobstructed formation of shortage prices is an essential part of the workings of the energy market in order to signal an optimal mix of investment in the system.

The basic energy market can be augmented by the trading of reserve through operating reserve demand curves, and by capacity remuneration mechanisms through capacity demand curves. This can be done in a modular fashion in our setup, by adding on an ORDC, a CRM, or both, in a given Member State. The market coupling between Member States is based on a zonal transportation-based model that relies on available transfer capacities (ATC).

#### *2.1.3. ORDCs*

Shortage pricing through operating reserve demand curves is implemented by augmenting the energy market model with a reserve product, with the workings of how ORDCs contribute to shortage pricing being outlined by Hogan (2013). The increase of reserve prices under tight conditions is economically driven by a demand curve for operating reserve. Concretely, the TSO appears in the energy-reserve multi-product auction by a demand curve that quantifies the valuation that the TSO places in increments of reserve capacity. Existing hard reserve requirements employed by TSOs correspond to such ORDCs, simply price-inelastic ones. Stepped price-responsive ORDCs have been introduced in various US markets gradually over the past years. Hogan (2013) outlines a theory for deriving ORDCs that connects the valuation of reserve capacity to loss of load probability (LOLP) and value of lost load (VOLL). The ORDC formula under this framework can be summarized as follows:

$$VR(r) = (VOLL - MC) \cdot LOLP(r). \quad (1)$$

Here, $VR$ is the valuation for reserve, $r$ is the amount of reserve capacity, $VOLL$ is the value of lost load, $MC$ is a proxy of the marginal cost of the marginal unit in the system (for instance, the balancing market price), and $LOLP(r)$ is a function that maps available reserve $r$ in the system to loss of load probability.

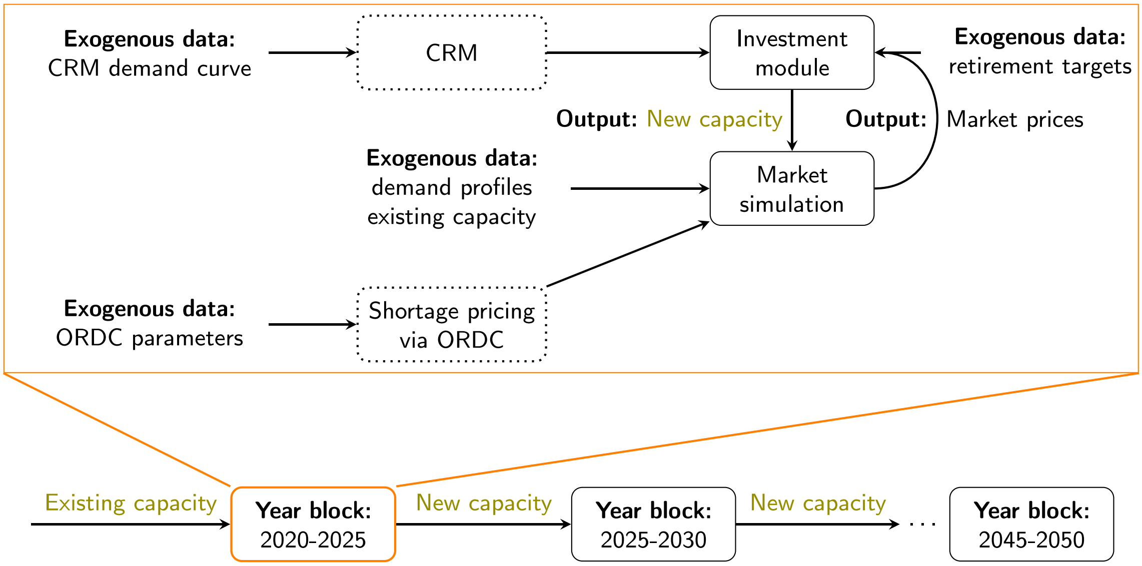


**Fig. 1.** Representation of the overall simulation framework that is employed in our analysis. As indicated in the lower part of the figure, the model proceeds in investment cycles of 5 years each. As indicated in the upper part of the figure, each investment cycle is represented as a standard capacity expansion planning model that has an economic interpretation as a competitive investment driven by a competitive energy market. The investment and market operation modules of a cycle are represented as an integrated interaction, as demonstrated from the mathematical models in Appendix B. This backbone can be augmented by the trading of reserve through operating reserve demand curves, and a capacity remuneration mechanism that is represented through a capacity auction.

The standard implementation of the design involves co-optimization of energy and reserve, both in real-time and in day-ahead markets (Hogan, 2013; Stoft, 2002). In our model, this mechanism is modeled by the introduction of a reserve product in the short-term market model, accompanied by a co-optimization of energy and reserve, where operating reserve demand curves are defined exogenously. In a market where energy is co-optimized with reserve, the way that the shortage pricing design through ORDCs functions is summarized as follows:

When the system runs tight, then the operating reserve demand curve (see Fig. 5 as an example) is only partially served. This implies that the price for reserve is essentially the ORDC evaluated at the amount of available reserve. Due to a no-arbitrage condition between energy and reserve, the profit margins in the energy and reserve markets must become equal, thus the price of energy becomes the marginal cost of the marginal unit uplifted by the price of reserve. Thus, whereas in an energy-only market without price-responsive demand we have a spike in energy prices only when the system runs out of capacity, in the case of ORDCs this increase in energy prices comes much earlier, when the system starts running out of capacity. We have added the KKT analysis in Appendix B.2 to further explain the rationale of price formation under shortage pricing with ORDC.

### 2.1.4. Modeling the real-time market

We model an idealized real-time market in our case study, which focuses on a single reserve product, and assumes a unique real-time price for energy, which is charged identically to BSPs (balancing price) and BRPs (imbalance settlement). The European balancing market does not actually adhere to this model, but rather distinguishes between the settlement of BSPs and BRPs. Moreover, there is no real-time market for reserve/balancing capacity in the European balancing market, nor is it foreseen in the upcoming pan-European balancing platforms for mFRR and aFRR. This issue has been analyzed extensively in Papavasiliou (2020), Papavasiliou and Bertrand (2021), where the authors present both an analytical model as well as an agent-based analysis for arguing in favor of a single real-time price for energy as well as the introduction of a real-time market for reserve in European balancing markets. The model developed in our study follows this assumption of a coherent real-time market design, and the representation of separate settlement for BRPs and BSPs or an incomplete market where reserve is not traded in real time is beyond the scope of our work. Separate work by the authors addresses questions related to the implementation of shortage pricing through ORDC in the European context, such as legal feasibility (Papavasiliou, 2020) and cross-border effects (Papavasiliou, 2021b; Papavasiliou et al., 2023).

It is worth noting that co-optimization of energy and reserve is not actually required for implementing shortage pricing based on ORDC. For instance, what has already been implemented in Texas (ERCOT, 2014), and what has also been proposed for the context of Belgium (Papavasiliou et al., 2019; CREG, 2021), is an ex-post application of an ORDC adder, as indicated in Eq. (1).

### 2.1.5. CRM design

We model the mechanism as an auction for generation capacity, which is decided in the investment module of Fig. 1. It generates a price signal that is payable from TSOs to potential investors for capacity that they plan to build. The introduction of this CRM introduces yet another revenue stream for investors, since units are now receiving payments by virtue of simply being built. Typical CRMs for European Member States are described in the various sector inquiries that have been conducted in the past for the approval of these mechanisms. We rely on these sector inquiries to the greatest extent possible. The shape of CRM demand curves has been debated extensively in the power system economics literature (Cramton and Stoft, 2005), as well as in empirical implementations (Papavasiliou, 2021a). The fine balance that one attempts to strike when calibrating these demand curves is to secure adequate investment in capacity while ensuring that the procured capacity is not excessive, especially given the uncertain conditions that unfold in the energy market after the CRM auction is concluded.

### 2.1.6. Sectoral interactions

Sectoral interactions are summarized in Fig. 2. The model consists of three coupled sectors, those of electricity, heat and hydrogen. By modeling the heat sector, we can represent extreme cold weather events by a higher demand for heat on certain days. In the hydrogen sector, combined cycle hydrogen turbines (CCHTs) or open cycle hydrogen turbines (OCHTs) convert hydrogen to electricity. When there is excess electricity, electrolyzers can convert electricity into hydrogen, which functions as another source of flexibility to facilitate the energy transition.

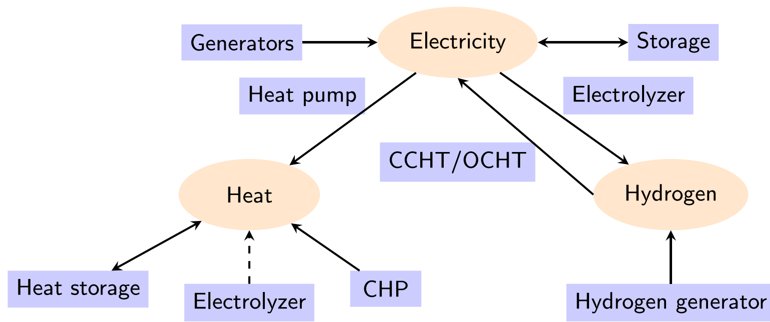


**Fig. 2.** There are three sectors, which are indicated in orange ellipses. Each sector has production or consumption assets, as well as couplings to other sectors that may result in uni-directional or bi-directional flow between the different sectors. The heat generated from electrolyzers is not considered in our study. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

### 2.2. Data sources and assumptions

The resolution of the model is one hour, and the horizon of each block in the capacity expansion planning problem is one year. Unit commitment and ramp constraints are not modeled, in order to ensure that the model can be solved within a reasonable run time. The risk-free rate in the model is assumed to be equal to 4.5% and carbon dioxide prices are assumed to increase from 90 €/ton in 2025 to 150 €/ton in 2050.[2] In the following, we describe major data sources and assumptions.

#### 2.2.1. Technologies

The technologies that are considered in the model include batteries, biomass, combined cycle gas/hydrogen turbines (CCGT/CCHT), combined heat and power (CHP), oil, open cycle gas/hydrogen turbines (OCGT/OCHT), lignite, hard coal, nuclear, hydro dams, pumped hydro, PV (rooftop and utility-scale) and wind (offshore and onshore). Generator data includes investment cost, variable operating and maintenance cost, fixed operating and maintenance cost, fuel cost, efficiency, emission factors and capacity in each Member State for milestone years, in particular from 2025 to 2050 in 5-year increments. Storage unit data includes investment cost, efficiency and capacity. Storage units are assumed to return to their initial state of charge at the end of each day. Interconnector data includes the countries being linked by each interconnector, as well as the corresponding capacity of the interconnector. Converter data includes linking carriers, efficiency and capacity. Time series data includes profiles for solar production, wind production, hydro dam inflows, the availability of different technologies and demand for electricity, hydrogen, and heat. These time series are provided in hourly resolution. Imbalance data is available in 15-minute, 30-minute or hourly resolution, depending on the specific Member State. The data sources for these technologies are summarized in Table 2.

We distinguish in the model between technologies that are competitive and technologies for which the available capacity is fixed exogenously. When capacity is invested competitively, the optimality conditions of the investment problem guarantee zero profit. This carries an economic interpretation: in competitive markets with endogenous long-run investment, profit margins are zero. On the other hand, capacity that is introduced exogenously may find itself earning strictly positive profits (investors would have built more of this capacity if the build were not constrained by the assumptions of the model), or strictly negative profits (the market price cannot support the underlying cost, and if investors were not forced to keep this capacity running, they would retire it). The classification of the technologies that are studied in the model between competitive or exogenous is outlined in Table 3. This is driven by our research objective, i.e., evaluating the impact of various market designs on the energy transition, with a focus on the investment of renewables and flexibility sources. More specifically, Battery, DR, CCHT and OCHT are categorized as competitive because these technologies are flexible and would be largely impacted by the market design. CCGT and OCGT can invest competitively only in 2025, but 15% of the capacity in 2030, 50% in 2035 and 100% in 2040 are converted into CCHT/OCHT. The motivation behind this assumption is to decrease the dependence of Europe on gas (Agora Energiewende, 2023). Biomass, wind, and solar are renewable energy technologies that play a crucial role in achieving net-zero emissions, therefore they are assumed to be competitive. Nevertheless, wind and solar are still benefiting from subsidies, and would be more viable in the future due to technological advances. Thus, we assume that they follow predefined trajectories until 2030 and start to invest competitively from 2035 onward (eEuropa Belgium, 2022). Solar power capacity increases from 268 GW in 2025 to 538 GW in 2030, while wind power capacity increases from 281 GW to 474 GW. Other technologies are assumed to follow investment trajectories that are determined from other studies (Ember, 2022, 2023). EV storage and electrolyzers are emerging technologies that are difficult to evaluate from the perspective of investment. Heat storage, heat pumps and CHP involve the heat sector, which is not modeled in detail, nor is it the focus of this study. Oil, lignite, hard coal and nuclear mostly follow a phase-out plan. Pumped hydro, hydro dams, and run-of-river technologies are subject to geographic constraints.

#### 2.2.2. Assumptions on demand response

Industrial demand response is modeled as price-responsive demand and can be shaved off when the energy prices are high. The cost of investing in industrial demand response is calibrated based on Piette et al. (2015), which is approximately 80 €/kW in 2025 and decreases slightly in future years. It is around 10% of the investment cost of the peaking technology (OCGT / OCHT) in the model. Industrial demand response potential increases over each 5-year block of the model, as indicated in Fig. 3. Industrial demand response is assumed to participate in the trading of reserve, and participate in CRMs with a capacity credit[3] of 65.0%, following the CRM design of Belgium (Elia, 2022), which corresponds to a service level of 8 h. The flexibility potential of electric vehicles is modeled separately as a storage resource. Heat pumps and electrolyzers, which act as indirect means of flexibility, are also modeled separately.

[2] We have tested a higher carbon price trajectory with an initial carbon price of 100 €/ton in 2025, which increases to 200 €/ton by 2050. The conclusions are largely unaffected.

[3] Capacity credits aim at quantifying the contribution of various technologies to meeting energy demands during peak periods. Similar terms include Effective Load Carrying Capacity (ELCC) for the PJM capacity market and De-Rating Factors for the UK capacity market.

**Table 2**
Summary of data sources for the study.

| Category | Subcategory | Source |
|---|---|---|
| Techno-economic parameters | Efficiency, Max hours of storage, Discount rate | ENTSOG (2020) |
| | Investment cost, FOM, VOM | Artelys (2022) |
| | Fuel price | ENTSOG (2020) |
| | Emission price | Agora Energiewende (2022) |
| | Emission factor | Koffi et al. (2017) |
| | VOLL | Cambridge Economic Policy Associates (2018) |
| Capacities | Hydro dam, Pumped hydro, Run-of-river, Oil | Ember (2022) |
| | Nuclear, DR potential, Interconnector, Electrolyzer | Ember (2022) |
| | Wind, Solar | eEuropa Belgium (2022) |
| | EV storage, Hard coal,Lignite | Artelys (2022) |
| Profiles | Demand | Artelys (2022), Ember (2022) |
| | Hydro dam inflows | Felice (2021) |
| | CHP production | Ruhnau et al. (2019) |
| | Availability of technologies | Agora Energiewende (2022), Renewables.ninja (2022) |
| Others | Imbalance data for calibrating ORDCs | ENTSO-E. Transparency Platform (2022) |
| | Capacity demand curves | European Commission (2017, 2018) |

**Table 3**
Set of technologies considered in the model, and classification according to whether or not they are invested in competitively and whether or not they are capable of offering reserve.

| Technology | Competitive or predefined? | Flexible? |
|---|---|---|
| Battery, DR<br>CCHT,OCHT | Competitive | ✓ |
| Biomass | Competitive | |
| CCGT,OCGT | Both | ✓ |
| PV, Wind | Mostly competitive | |
| EV storage, Oil<br>Pumped hydro<br>Hydro dam | Predefined | ✓ |
| Nuclear, CHP<br>Run-of-river<br>Electrolyzer<br>Lignite, Hard coal<br>Heat storage<br>Heat pump | Predefined | |

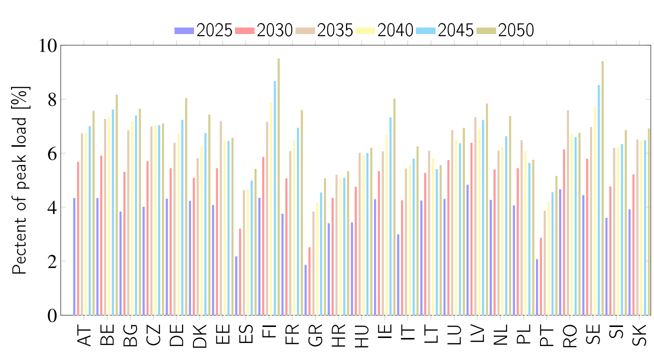


**Fig. 3.** Industrial demand response potential over the 5-year blocks of the model.

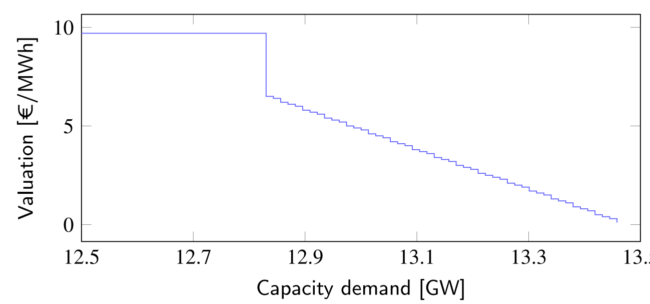


**Fig. 4.** CRM demand curve of Belgium of year 2025.

### 2.2.3. CRM demand curve calibration

The CRM demand curves of Ireland and Italy follow the shape provided in the sector inquiries of the European Commission (European Commission, 2017, 2018). For lack of data, other Member States in the model are assumed to follow the UK CRM demand curve. This implies that the valuation of the CRM demand curve drops to 0 €/MWh when the demand is 5% greater than the target capacity, which results in a loss of load probability equal to 3 h per year. We include indicatively the CRM demand curve of Belgium for 2025 that is used in our model in Fig. 4.

### 2.2.4. ORDC demand curve calibration

The calibration of ORDCs is based on the formula of Eq. (1), which indicates the shape of the ORDCs depends on the VOLL of the Member State that implements the design, as well as the distribution of imbalances in the Member State. We compute an adaptive ORDC, in the sense that we use the marginal cost of the marginal unit, as in Eq. (1), for adjusting the ORDC during each market clearing period. We use imbalance data from 2021 in order to estimate the parameters that are used for computing the loss of load probability function in Eq. (1). This imbalance increases over each 5-year block into the future, and the ORDC is adjusted correspondingly, namely by becoming wider but always coherent with system imbalance. We include indicatively the ORDC of Belgium for hour 2400 of 2025 that is used in our model in Fig. 5.

## 2.3. Scenarios

In order to propose simulation scenarios, we first summarize in Table 4 the state of play in the European market insofar the rollout

**Table 4**
A cartography of ORDCs and CRMs in the EU market. Columns in the table indicate concerned Member States. Green boxes (✓) correspond to Member States where the respective mechanism is already in place, while orange boxes (⋆) correspond to Member States where the rollout of the respective mechanism is contemplated.

| | AT | BE | BG | HR | CZ | DK | EE | FI | FR | DE | GR | HU | IE | IT | LV | LT | LU | NL | PL | PT | RO | SK | SI | ES | SE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ORDC | ⋆ | ⋆ | | | | | | | | ⋆ | ⋆ | | ✓ | | | ⋆ | | | ⋆ | | | | | | ⋆ |
| CRM | | ✓ | | | | | | | ✓ | | ⋆ | | ✓ | ✓ | | | | | ⋆ | | | | | | |

**Table 5**
Overview of simulation scenarios based on the rollout of ORDCs and CRMs. The suffix "StatusQuo" refers to that only Member States which already implement or consider the respective mechanism have the mechanism(s) in our simulations. Whereas "FullRollout" refers to that all EU countries implement the mechanism(s).

| Scenario | Name | Description |
|---|---|---|
| S1 | EOM | Ideal energy-only market, where price caps are set at the theoretical VOLL for each member state. |
| S2A<br>S2B | ORDC-StatusQuo<br>ORDC-FullRollout | Shortage pricing through ORDC, where energy and reserve are co-optimized. |
| S3A<br>S3B | CRM-StatusQuo<br>CRM-FullRollout | A capacity market is introduced on top of the energy market model. |
| S4A<br>S4B | ORDC+CRM-StatusQuo<br>ORDC+CRM-FullRollout | Energy and reserve are co-optimized and the capacity market is also introduced. |

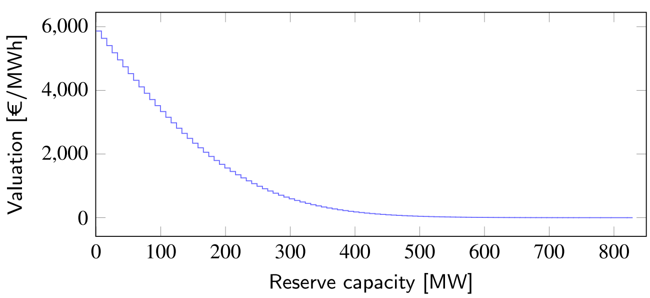


**Fig. 5.** ORDC of Belgium from hour 2400 of year 2025.

of shortage pricing and CRMs are concerned. Given this cartography, we provide an overview of simulation scenarios considered in the large-scale tests in Table 5.

In addition to the basic market design scenarios, we consider a number of sensitivity analyses that are inspired by various observations that emerge as our analysis unfolds. These sensitivity analyses attempt to test various specific market design questions, the robustness of the different designs, as well as questions that are motivated by contemporary evolutions in the European energy market. An overview of the analyses conducted in our study is presented in Table 6. They allow us to draw comparisons that shed light on the interactions of shortage pricing and CRMs, cross-border effects, and coordinated efforts to roll out these mechanisms. These aspects are discussed in further detail in the next section.

## 3. Results and discussion

### 3.1. Status quo versus EU-wide rollout of ORDCs and CRMs

In this section, we compare the results of the "StatusQuo" scenarios to the "FullRollout" scenarios, as well as a sensitivity run on the "FullRollout" scenarios that does not allow for cross-border trade in the capacity or reserve markets.

#### 3.1.1. "StatusQuo" scenarios

The capacity mix under the base runs of "StatusQuo" scenarios is presented in Fig. 6 and only cross-border trade of energy is allowed in this scenario, but not reserve or capacity. The total capacity (and capacity mix) in the case of ORDC is almost identical to that of the EOM, whereas the CRM leads to a 1.4% increase in capacity relative to the ideal EOM, whereby peaking technology (mostly OCHT) is more heavily invested in.

We further break down the capacity mix according to the market design of each Member State. The capacity mix of EOM states is indicated in Fig. 7(a). As far as EOM Member States are concerned, the capacity mix seems to be largely unaffected by the choice of design. Nevertheless, demand response in EOM member states does decrease by 7.7%–7.9% in the presence of CRMs. Demand response is also slightly suppressed in CRM member states. This can be attributed to the fact that, in a CRM design, DR is at a competitive disadvantage relative to other resources which receive higher capacity credit in the market. This raises a question of appropriate choices for capacity credits of demand response in CRM designs. The total capacity increases in CRM Member States when a CRM is introduced. Concretely, capacity increases by 7.3% in CRM-StatusQuo and ORDC+CRM-StatusQuo relative to EOM. There is also a notable reshuffling in the wind capacity mix of the CRM states, even though total wind capacity remains relatively stable.

We note that the introduction of a CRM exerts downward pressure on energy prices in CRM states. More specially, the average energy price drops from around 60.7 €/MWh in EOM and ORDC-StatusQuo to around 56.8 €/MWh in CRM-StatusQuo and ORDC+CRM-StatusQuo. This relates to the fact that, in a competitive equilibrium, technologies break even in the sense that the sum of all their short-term profits should exactly cover their investment costs. In CRM states, part of these revenues are generated by a CRM auction, thus energy prices have to recede. The CRM signal charged after the fact to end users is not entirely representative of the instantaneous needs of the system, thus one may expect that demand response capabilities are mobilized to a smaller extent. This aspect is further discussed in Section 3.3. Comparing the average capacity price[4] in CRM-StatusQuo (1.448 €/MWh) to that in ORDC+CRM-StatusQuo (1.445 €/MWh), we find the coexistence of CRM and ORDC does not imply a significant impact on capacity market prices. This is because the ORDC prices are rather low due to the presence of abundant flexible technologies in the system. Instead, the coexistence of ORDC and CRM tends to slightly decrease average ORDC prices from 0.139 €/MWh in ORDC-StatusQuo to 0.128 €/MWh in ORDC+CRM-StatusQuo.

#### 3.1.2. "FullRollout" scenarios

The "FullRollout" scenarios correspond to a case where ORDCs and CRMs are rolled out over the entire European continent, i.e., they are

[4] It is calculated by taking the average of the capacity price in each five-year block of each CRM Member State.

**Table 6**
Overview of analyses conducted in our study.

| Analysis | Motivation | Comment | Section |
|---|---|---|---|
| Base case of “StatusQuo” scenarios | Comparison of EOM to ORDC, CRM, and ORDC+CRM | Cross-border trade is only allowed in the energy market, but not allowed in the reserve or capacity markets. | 3.1.1 |
| Base case of “FullRollout” scenarios | Value of EU-wide coordination | Cross-border trade in the reserve or capacity markets is limited to 70% ATC capacities. | 3.1.2 |
| Sensitivity: 70% availability of ATCs | What if neighbors cannot contribute to national ORDCs/CRMs? | Cross-border trade is not allowed in the reserve or capacity markets in the “FullRollout” scenarios. | 3.1.3 |
| Sensitivity: ATC=0 | What if Member States “close down” their borders in the future? | No cross-border trade is allowed in the energy, reserve or capacity markets in “StatusQuo” scenarios. | 3.2 |
| Sensitivity: DR capacity credit | How sensitive is the CRM design to this parameter | We consider how the results are affected by very low and very high capacity credits for demand response in “StatusQuo” scenarios. | 3.3 |
| Sensitivity: shape of CRM and ORDC demand curves | What if we get the calibration of CRMs/ORDCs wrong? | We change the width of the CRMs/ORDCs in “StatusQuo” scenarios to get wide and narrow curves. | 3.4 |

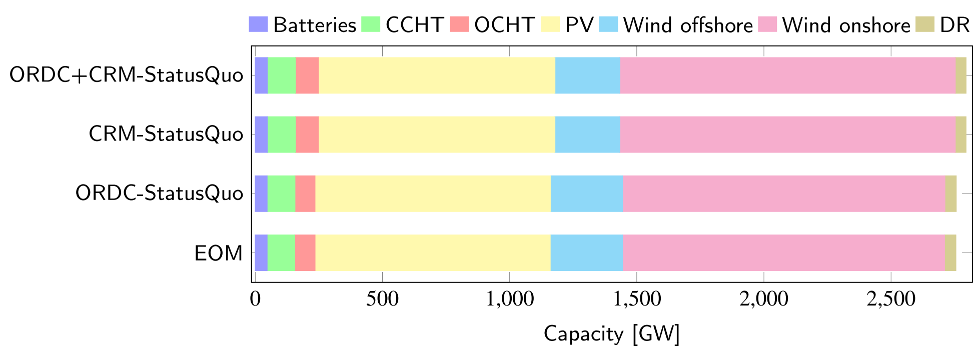


**Fig. 6.** Invested capacities under the base runs for the different “StatusQuo” scenarios until year 2050.

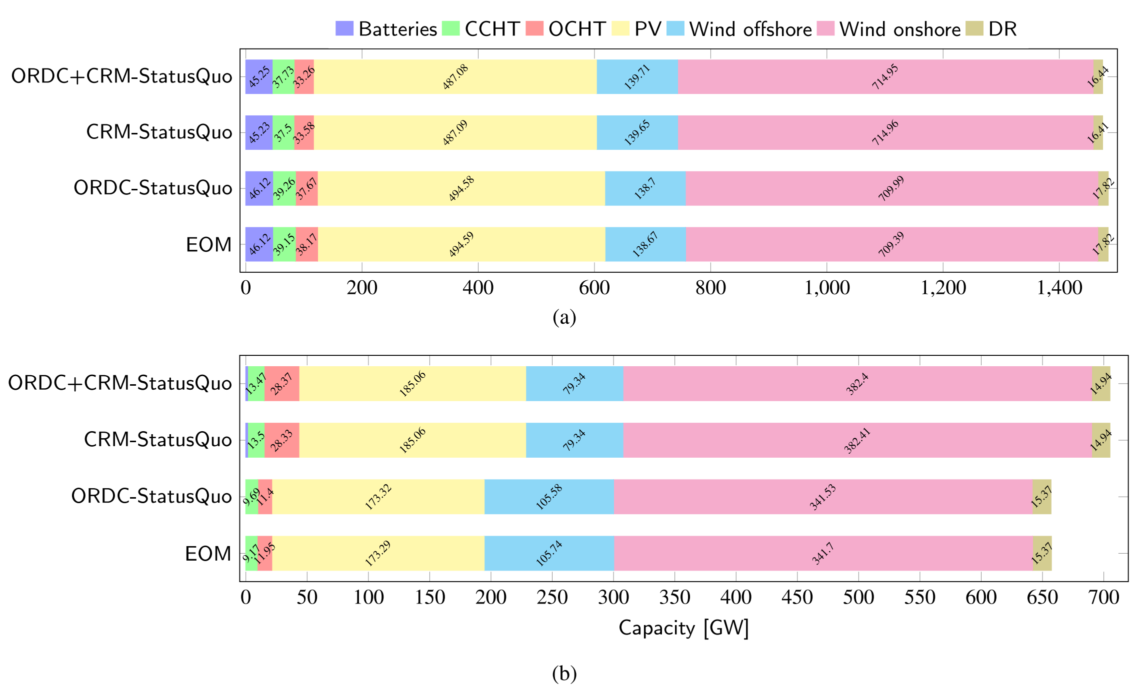


**Fig. 7.** Invested capacities in EOM (a) and CRM (b) Member States in “StatusQuo” scenarios.

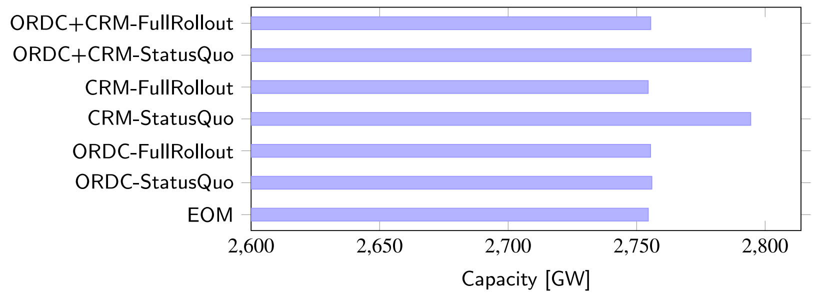


**Fig. 8.** Total invested capacities under the "FullRollout" scenarios with cross-border coordination of CRMs and ORDCs compared to a "status quo" implementation of CRMs and ORDCs ("StatusQuo" scenarios).

**Table 7**
Costs under the "FullRollout" scenarios without cross-border coordination (NoCB) of CRMs and ORDCs compared to "StatusQuo" scenarios. All values are in million € per day.

| KPIs | EOM | ORDC StatusQuo | ORDC FullRollout-NoCB | CRM StatusQuo | CRM FullRollout-NoCB | ORDC+CRM StatusQuo | ORDC+CRM FullRollout-NoCB |
|---|---|---|---|---|---|---|---|
| Investment costs | 183.79 | 183.82 | 184.12 | **185.02** | **186.56** | 185.03 | 187.44 |
| CO2 costs | 47.03 | 47.02 | 47.02 | 46.92 | 47.02 | 46.95 | 46.74 |
| Fuel costs | 663.83 | 663.82 | 663.80 | 663.87 | 663.68 | 663.84 | 662.88 |
| VOM | 28.13 | 28.19 | 28.37 | 27.99 | 28.33 | 27.97 | 28.38 |
| Total costs | 922.78 | 922.85 | **923.30** | **923.80** | **925.59** | 923.79 | 925.44 |

adopted by all Member States. We further assume cross-border trade of capacity and reserve is allowed and limited to 70% of the ATC capacities. The total invested capacity under the "FullRollout" scenarios with cross-border coordination of CRMs and ORDCs compared to the "StatusQuo" scenarios is presented in Fig. 8. We observe that the average ORDC price in ORDC-FullRollout drops to 0.02 €/MWh, and the resulting capacity mix is almost identical to EOM. The average CRM price in CRM-FullRollout drops to 0 €/MWh and the resulting invested capacity is almost identical to EOM. A design question is how much capacity should be assumed to be available in the network during peak demand periods of a given Member State so as to import qualifying capacity and reserve from a neighboring Member State. In the following we consider a case where there is no network capacity for trading reserve or capacity.

#### *3.1.3. "FullRollout" scenarios without cross-border trade in the capacity or reserve markets*

Table 7 presents costs under an EU-Wide deployment of CRMs and ORDCs, *without* cross-border trade (NoCB) of capacity or reserve. An EU-wide ORDC in ORDC-FullRollout-NoCB does not have a significant impact on costs. In contrast, an EU-wide CRM in CRM-FullRollout-NoCB increases investment costs by 1333 million € per year and total costs by 973 million € per year, while CRM-StatusQuo results in an increase of investment costs by 449 million € per year and of total costs by 372 million € per year. The results indicate a sensitivity of CRMs on an EU-wide deployment of the mechanism. In addition, if cross-border participation of CRM and ORDC is disabled, then we observe that the average ORDC price increases from 0.02 €/MWh in ORDC-FullRollout to 0.26 €/MWh in ORDC-FullRollout-NoCB. The average CRM price in CRM-FullRollout increases from 0 €/MWh to 1.86 €/MWh in CRM-FullRollout-NoCB.

### *3.2. Isolated operation versus cross-border coordination*

In the previous section, we observe that the contribution of neighboring Member States on covering the CRM demand of a given Member State can be important, but this raises the question of how much cross-border capacity we should assume is available during shortage incidents of a given Member State. In this section we consider an extreme case where Member States are not able to coordinate at all by setting the cross-zonal capacities of the network to zero, i.e., no cross-border trade of *energy*, *reserve* or *capacity* is possible in the "StatusQuo" scenarios. This pessimistic assumption is inspired by an aggressive withholding of ATCs in cross-border auctions, which in part triggered the 70% rule (European Commission, 2022).

The simulation results show that all cost terms increase significantly in the case of isolated operation, and that the number of Member States which exhibit involuntary load shedding increases from 6 in the base runs to 13. The investment in utility-scale PV and in flexible technologies (batteries, CCHT and OCHT) increases remarkably. One finding which is perhaps surprising is that CRM prices actually decrease when ATCs are set to zero, as indicated in Fig. 9. Concretely, we observe that CRM prices drop near zero (except Ireland with a notably wide CRM demand curve), which indicates that investments in this scenario are largely driven by the energy market. In isolated operation, assuming that CRMs are not over-dimensioned, then they do not interfere with the energy market. The energy market generates price signals that can cover investment costs, and missing money does not enter in the CRM auction, thus CRM prices tend to zero. On the other hand, we observe in Fig. 10 that average ORDC prices are largely insensitive to this assumption, since the system is already equipped with significant amounts of flexible capacity.

### *3.3. DR capacity credit*

We note in Fig. 7 that demand response can be affected adversely by the presence of a CRM, since a low capacity credit can create a non-level playing field for demand response resources. Whereas in the short run certain stakeholders argue that CRMs are an important factor for allowing for demand response "stand on its feet", the long-run effect of CRMs on demand response depend crucially on the awarded capacity credit, which is a non-obvious design parameter.

In this section we test the sensitivity of our results by analyzing how demand response investments are affected by increased or reduced capacity credits. We rationalize the choice of an 11% capacity credit for demand response by appealing to the Belgian CRM design (Elia, 2022), where we note that an 11% capacity credit corresponds to a service level agreement of 1 h of maximum continuous interruption. We achieve this in our model by imposing a constraint that the amount of demand response energy that can be activated at any hour of the year cannot exceed 50% of the total demand response capacity that is built in the model. This guarantees that any 1-kW slice of demand response capacity that is activated within a given time period can be

**Table 8**
Comparison of invested capacities in cases where demand response receives a capacity credit of 11%, 65% and 100%. All values are in GW.

| Technology | EOM | CRM-StatusQuo-65% | CRM-StatusQuo-11% | CRM-StatusQuo-100% |
|---|---|---|---|---|
| Batteries | 46.13 | 46.66 | 46.91 | 46.43 |
| CCHT | 108.83 | 110.73 | 111.57 | 110.99 |
| OCHT | 79.64 | 90.41 | **108.65** | 87.30 |
| PV | 924.79 | 930.15 | 931.55 | 930.16 |
| Wind offshore | 284.61 | 255.32 | **251.36** | 263.00 |
| Wind onshore | 1265.97 | 1318.76 | **1323.69** | 1302.94 |
| DR | 44.56 | 42.38 | **33.10** | **42.75** |
| Total | 2754.53 | 2794.39 | **2806.84** | 2783.58 |

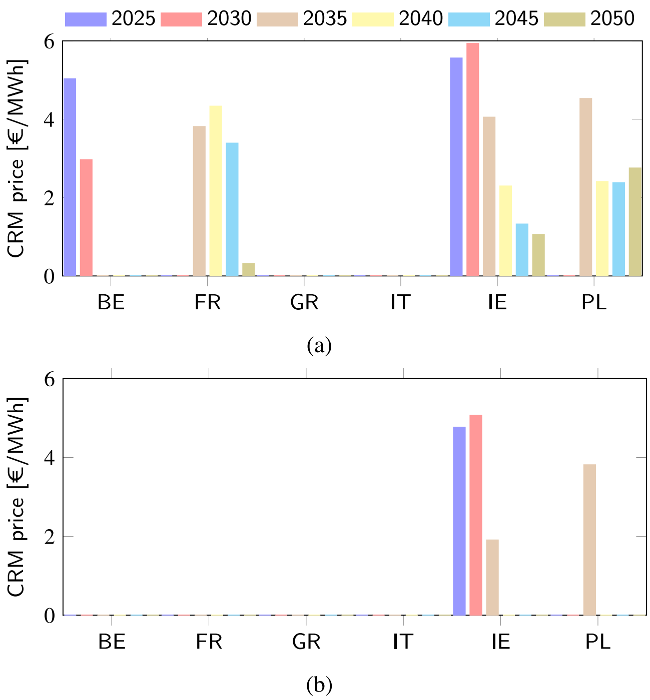


**Fig. 9.** CRM prices in the base case (a) and in the isolated operation case (b) under scenario CRM-StatusQuo.

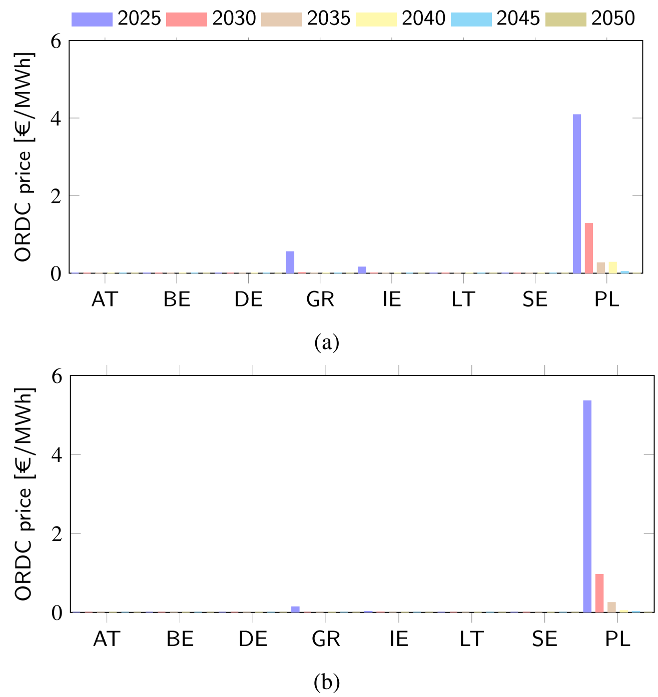


**Fig. 10.** Average ORDC prices in the base case (a) and in the isolated operation case (b) under scenario ORDC-StatusQuo.

set aside in the next period, since no more than 50% of the total demand response population is activated at any given hour of the year. Regarding the assumption of 100% capacity credit, we consider this best-case scenario in order to envelope our results, without having a good reason to believe that this would be a rational choice.

Table 8 compares the capacities that are built when DR receives a capacity credit of 65% (base case), 11%, and 100% respectively. We first analyze the case of reduced capacity credit for demand response. Note that there is a slight increase in overall capacity in the system, but more notably a significant change in the capacity mix of the system. Under the CRM design, the capacity of OCHT increases notably. There is also a notable shift towards on-shore wind and utility-scale PV, in the place of off-shore wind. Note that offshore wind requires 3 times the investment cost of OCHT. Note, finally, that there is a significant decrease in demand response capacity. Apart from the anticipated fact that demand response is disadvantaged in this setting, it is interesting to note how sensitive the results of the CRM design are to the choice of even a single parameter among the many that fully define the design.

We now comment on the results of the model in the case of 100% capacity credit for demand response. We observe that the total new invested capacity is only slightly higher if DR is given 100% capacity credit compared with CRM-StatusQuo-65%, and lower compared with EOM. This seemingly counter-intuitive result can be explained by the fact that (i) DR capacity is already built near its limit in all three of these scenarios, and thus (ii) even though slightly more capacity is built in CRM-StatusQuo-100% compared with CRM-StatusQuo-65% and less than EOM, it actually turns out to be more profitable. Moreover, (iii) in CRM-StatusQuo-100% the average capacity price drops from 1.82 €/MWh in CRM-StatusQuo-65% to 1.66 €/MWh in CRM-StatusQuo-100%.

### 3.4. Shape of CRM and ORDC demand curves

In order for CRMs to avoid interfering with the functioning of the energy market, in a single-zone setting it is required that the valuation of the CRM demand curve amount to 0 €/MWh at the level of target capacity. By contrast, various CRM demand curves in Europe are designed so as to slope linearly from the cost of new entry to zero at a level which is a fraction above the target capacity of the system. Although the motivation for doing so is clear, and relates to the desire of avoiding a “bipolar” behavior of CRM auction clearing prices (Cramton and Stoft, 2005), there is no clear economic justification for such over-dimensioning.

In this section, we consider the sensitivity of the results on the calibration of the CRMs. Concretely, we consider a case in which all CRMs of the CRM-StatusQuo scenario are replaced by the “Irish” calibration, i.e. their valuation lands at 0 €/MWh at 115% of target capacity. We

**Table 9**
EU-wide invested capacity and invested capacity in CRM Member States in scenario CRM-StatusQuo with wide and narrow CRM demand curves. All values are in GW.

| Technology | EU | | CRM states | |
|---|---|---|---|---|
| | Wide | Narrow | Wide | Narrow |
| Batteries | 48.09 | 45.83 | 2.78 | 0.32 |
| CCHT | 108.27 | 109.64 | 14.36 | 11.69 |
| OCHT | 103.62 | 84.66 | 44.49 | 20.70 |
| PV | 938.10 | 933.44 | 197.63 | 187.51 |
| Wind offshore | 245.15 | 270.17 | 69.76 | 88.91 |
| Wind onshore | 1332.52 | 1285.84 | 397.89 | 363.29 |
| DR | 44.67 | 43.89 | 16.08 | 15.61 |
| Total | 2820.41 | 2773.47 | 742.99 | 688.04 |

also consider another case in which valuation of all CRMs of the CRM-StatusQuo scenario lands at 0 €/MWh at the target capacity. The CRM price is quite sensitive to this assumption. Average CRM prices are 1.45, 2.38 and 1.05 €/MWh, respectively, in the three cases.

The installed capacities in the wide CRM and narrow CRM cases are presented in Table 9. It is worth noting that CRM Member States turn out to be very sensitive to the calibration of the CRM demand curves. Wide CRMs increase EU-wide capacity by 2.4% relative to EOM, and roughly double the over-sizing of the base CRM case (shown in Fig. 8). Narrow CRMs still increase EU-wide capacity, but only by 0.7%. Wide CRMs increase CRM Member State capacity (presented in Fig. 7(b)) by 13.1% relative to EOM. Narrow CRMs increase CRM Member State capacity by 4.7%.

We conduct a further sensitivity with respect to the width of the ORDCs. In order to draw a meaningful comparison to wide CRMs, we increase the width of the ORDCs by 15%. Although there is an increase in the average ORDC price from 0.14 €/MWh to 0.18 €/MWh, this change is clearly minor, and the mechanism is much less sensitive to the width of the demand curve relative to CRMs. This is further corroborated by the fact that the capacity mix of the system is almost identical in the case of the base ORDC or the wide ORDC.

## 4. Model limitations

Our analysis has ignored a number of real-world elements. We discuss the possible effect of such elements below.

**Detailed operational constraints.** In our analysis we have ignored unit commitment and ramp constraints, and generally the effect of day-ahead binary decisions which are irrevocable. This means that we overestimate the flexibility of the system at hand. Various metrics in our simulation can be affected by this simplifying assumption, such as the reported LOLE and the level of ORDC adders.

**Cyclic behavior of medium or long-term hydro storage.** We have assumed that storage units return to their initial state of charge at the end of each day. Although this assumption is not representative of medium or long-term hydro storage operations, it enables a decoupling of the model which delivers significant computational benefits. One remedy is to assume a trajectory for daily storage levels, which would require historical data for a reliable calibration.

**Market imperfections and obstruction of price formation.** We have assumed an ideal energy-only market, which is allowed to set prices even during periods of shortage. In reality, and as we have observed recently with the natural gas crisis, price increases often result in intervention. This regulatory uncertainty is not represented in our analysis, which means that the EOM that we are modeling is an idealized version of an EOM without external intervention.

**Uncertainty in renewable energy generation.** Our study does not incorporate uncertainties in wind and PV production, and we adopt a single profile per technology per Member State. It is worth noting that, from a modeling perspective, it would be feasible to include multiple scenarios corresponding to different climate years in our study. However, doing so may present formidable computational challenges that need to be considered in future work.

## 5. Conclusions and policy implications

In order to analyze different electricity market designs for the energy transition, we develop a capacity expansion model of the EU power system. A number of simulations until year 2050 are conducted. In this section we summarize our findings into three categories and then present policy recommendations based on these findings. The full results are available in a detailed technical report.

**Findings related to the energy-only market, and how the energy market is affected by ORDC and CRM:**

**M1** Ideal energy-only markets alone can finance the needed investments in flexible generation in the energy transition. (Fig. 6 in Section 3.1.1, Fig. 8 in Section 3.1.2)

**M2** ORDC can achieve a similar capacity profile as EOM, and this result is robust to the shape of the ORDC. (Fig. 6 in Section 3.1.1, Section 3.4)

**M3** CRMs tend to procure excess capacity and decrease revenue streams from the energy market, although the impacts in terms of total cost are less pronounced due to the low capital cost of the excess capacity (Fig. 6 in Section 3.1.1 Fig. 7(b) in Section 3.1.1, Table 7 in Section 3.1.3).

**M4** Properly dimensioning CRMs (with their valuation becoming zero at the target capacity ) can result in CRMs not interfering with energy market cash flows. (Fig. 9 in Section 3.2)

**M5** Even a single change of parameter (e.g. the capacity credit awarded to demand response) can have a significant effect on the capacity mix that results from a CRM design. ( Table 8 in Section 3.3)

**M6** The cross-zonal contribution of neighboring zones to the CRM auction of a given Member State is a complex design parameter of a CRM, and CRM prices can be highly sensitive to this assumption. (Fig. 8 in Section 3.1.2, Fig. 9 in Section 3.2)

**Findings related to winner and loser technologies:**

**WL1** Demand response can be suppressed in the presence of CRMs, depending on the choice of DR capacity credit. ( Table 8 in Section 3.3)

**WL2** CRM can strongly increase investment in peaking plants (OCHT). (Fig. 7(b) in Section 3.1.1 and Table 9 in Section 3.4)

**Findings related to co-existence of ORDC and CRM:**

**CO** If properly calibrated, there is no noticeable impact on CRM prices when there is abundant flexibility in the system and ORDC adders are low. There is no noticeable result on the total amount of capacity installed (sensitive to the calibration of the CRM demand curves). (Fig. 8 in Section 3.1.2)

**Findings related to cross-border effects and EU-wide coordination:**

**CB1** CRM Member States tend to carry more capacity under a CRM design. (Fig. 7(b) in Section 3.1.1)

**CB2** The cross-border contribution of neighboring capacities to CRM auctions of Member States has strong effects on investment outcomes, however the availability of the network is a non-obvious choice of the CRM design. This suggests that an EU-wide coordination of this process can be valuable (Fig. 8 in Section 3.1.2).

Our analysis suggests that the ideal energy-only market is able to support the energy transition (M1), which resonates with observations that have emerged from U.S. markets (Bhagwat et al., 2016). CRMs are sensitive to numerous non-obvious design parameters (M5, M6) and can sometimes lead to over-dimensioning, even if the effect on total cost can be less pronounced (M3). If implemented, capacity demand curves should be dimensioned such that the valuation becomes zero at the target capacity (M4). Design parameters for CRMs should be estimated correctly, including target capacity, and capacity credits for demand response, storage, and renewable generation. If implemented in a subset of Member States, these States tend to carry more capacity (CB1) and cross-border contribution of neighboring States to CRM auctions impact investment outcomes significantly, which suggests that an EU-wide coordination of this process can be valuable (CB2). Shortage pricing appears as a no-regret measure because ORDC adders recede when there is abundant flexibility in the system (M2, CO).

Our analysis on CRMs can be informative in the context of the recent draft decision of the European Commission on electricity market design, which suggests an increased reliance on CRMs, dedicated CRMs for flexibility resources, peak shaving products, and various other policy measures. The results presented in this paper indicate that there are various non-obvious design parameters which can have a material impact on market equilibrium outcomes, including the shape of the CRM demand curves and capacity credits. A mis-specification of the former can potentially lead to excessive investments, while the latter can influence specific technologies and create an uneven playing field. Additionally, ensuring cross-border coordination is crucial in preventing oversizing and its associated implications.

## CRediT authorship contribution statement

**Yuting Mou:** Methodology, Software, Investigation, Data curation, Writing – original draft, Writing – review & editing, Visualization. **Anthony Papavasiliou:** Conceptualization, Methodology, Writing – original draft, Writing – review & editing. **Katharina Hartz:** Investigation, Data curation, Writing – review & editing. **Alexander Dusolt:** Conceptualization, Writing – review & editing. **Christian Redl:** Conceptualization, Writing – review & editing.

## Declaration of competing interest

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

## Data availability

Data will be made available on request.

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## Appendix A

In this appendix, we first describe the abbreviations used in our paper, and then present the models of the alternative market designs that we consider in a stylized fashion. We summarize notation in Appendix B.5. We also discuss the economic interpretation of these models and why they are a suitable starting point for our analysis. Further details, including cross-border interactions and sector coupling, are available in a technical report.

### *A.1. Abbreviations*

**aFRR** Automatic frequency restoration reserve

**ATC** Available Transfer Capacity

**BRP** Balancing responsible party

**BSP** Balancing service provider

**CAISO** California Independent System Operator

**CCGT** Combined cycle gas turbine

**CCHT** Combined cycle hydrogen turbine

**CHP** Combined heat and power

**CONE** Cost of new entry

**CRM** Capacity remuneration mechanism

**ERCOT** Electricity Reliability Council of Texas

**ISO** Independent System Operator

**ISO-NE** ISO New England

**KKT** Karush–Kuhn–Tucker

**LOLE** Loss of load expectation

**LOLP** Loss of load probability

**MARI** Manual Activated Reserves Initiative

**MISO** Midcontinent ISO

**mFRR** Manual frequency restoration reserve

**OCGT** Open cycle gas turbine

**OCHT** Open cycle hydrogen turbine

**ORDC** Operating reserve demand curve

**PICASSO** Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation

**PJM** Pennsylvania-New Jersey-Maryland

**SPP** Southern Power Pool

**TSO** Transmission system operator

**VOLL** Value of lost load

## Appendix B. Stylized market design models

### *B.1. Ideal energy-only market*

A stylized capacity expansion model which only involves the energy market can be formulated as follows.

$$\max_{x,p,d} \sum_{t\in\mathcal{T}}(V\cdot d_t - \sum_{i\in\mathcal{I}} MC_i\cdot p_{i,t}) - \sum_{i\in\mathcal{I}} IC_i\cdot x_i \tag{2a}$$

$$\text{s.t. } d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t\in\mathcal{T} \quad (\lambda_t) \tag{2b}$$

$$p_{i,t} \le x_i, i\in\mathcal{I}, t\in\mathcal{T} \quad (\mu_{i,t}) \tag{2c}$$

$$d_t \le D_t, t\in\mathcal{T} \quad (\nu_{i,t}) \tag{2d}$$

$$x,p,d \ge 0 \tag{2e}$$

We represent time periods as $t \in \mathcal{T}$ and technologies as $i \in \mathcal{I}$. The investment cost and marginal cost of technology $i$ are denoted as $IC_i$ and $MC_i$, respectively. The invested capacity of technology $i$ is represented by $x_i$. The production of technology $i$ to meet demand in period $t$ is represented by $p_{i,t}$ and it is limited by $x_i$, as shown in Eqs. (2c). The valuation of electricity by consumers is denoted by $V$. The demand for electricity in period $t$ is represented by $D_t$, and the amount served is given by the power balance Eq. (2b). This optimization model is equivalent to the equilibrium models (3)–(5), which capture the behaviors of various market participants.

Producer $i$ maximizes its profit at the energy market clearing price $\lambda_t$:

$$\max_{x_i,p_{i,t}} \sum_{t\in\mathcal{T}}(\lambda_t - MC_i)\cdot p_{i,t} - IC_i\cdot x_i \tag{3a}$$

$$\text{s.t. } p_{i,t} \le x_i, t\in\mathcal{T} \tag{3b}$$

$$x_i, p_{i,t} \ge 0, t\in\mathcal{T} \tag{3c}$$

Consumers maximize their net surplus at the energy market clearing price $\lambda_t$:

$$\max_{d_t} \sum_{t\in\mathcal{T}}(V-\lambda_t)\cdot d_t \tag{4a}$$

$$\text{s.t. } 0 \le d_t \le D_t, t\in\mathcal{T} \tag{4b}$$

Market clearing conditions:

$$d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t\in\mathcal{T}(\lambda_t) \tag{5a}$$

*B.2. Shortage pricing through ORDC*

In this section we further develop the stylized capacity expansion model of Appendix B.1 by introducing shortage pricing in the form of operating reserve demand curves.

$$\max_{x,p,d,r,dR} \sum_{t\in\mathcal{T}}(V\cdot d_t + \sum_{l\in\mathcal{LR}} VR_{l,t}\cdot dR_{l,t} - \sum_{i\in\mathcal{I}} MC_i\cdot p_{i,t}) - \sum_{i\in\mathcal{I}} IC_i\cdot x_i \tag{6a}$$

$$\text{s.t. } d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t\in\mathcal{T} \quad (\lambda_t) \tag{6b}$$

$$\sum_{l\in\mathcal{LR}} dR_{l,t} - \sum_{i\in\mathcal{I}} r_{i,t} = 0, t\in\mathcal{T} \quad (\lambda R_t) \tag{6c}$$

$$p_{i,t} + r_{i,t} \le x_i, i\in\mathcal{I}, t\in\mathcal{T} \quad (\mu_{i,t}) \tag{6d}$$

$$d_t \le D_t, t\in\mathcal{T} \quad (\nu_t) \tag{6e}$$

$$dR_{l,t} \le DR_{l,t}, l\in\mathcal{LR}, t\in\mathcal{T} \quad (\nu R_{l,t}) \tag{6f}$$

$$x,p,d,dR,r \ge 0 \tag{6g}$$

We use a set of segments $l \in \mathcal{LR}$ to represent the ORDC, with $DR_{l,t}$ denoting the reserve demand quantity and $VR_{l,t}$ denoting the reserve demand valuation of segment $l$ at period $t$. Compared with the EOM model, the objective function (6a) now includes a term which corresponds to the economic value that the TSO derives from procuring reserve, i.e., $\sum_{t\in\mathcal{T}}\sum_{l\in\mathcal{LR}} VR_{l,t}\cdot dR_{l,t}$. Note that the ORDC can be time-varying, and in fact it is time-varying in practice. A new market clearing condition (6c) is introduced for the reserve market, and the total available capacity of a plant is now split between energy and reserve, as indicated in constraint (6d).

In order to appreciate why shortage pricing has an effect on energy prices under conditions of scarcity, we can examine the optimality conditions of the co-optimization model.

$$0 \le d_t \perp \lambda_t - V + \nu_t \ge 0, t\in\mathcal{T} \tag{7a}$$

$$0 \le dR_{l,t} \perp \lambda R_t - VR_{l,t} + \nu R_t \ge 0, l\in\mathcal{LR}, t\in\mathcal{T} \tag{7b}$$

$$0 \le p_{i,t} \perp MC_i - \lambda_t + \mu_{i,t} \ge 0, i\in\mathcal{I}, t\in\mathcal{T} \tag{7c}$$

$$0 \le r_{i,t} \perp -\lambda R_t + \mu_{i,t} \ge 0, i\in\mathcal{I}, t\in\mathcal{T} \tag{7d}$$

$$0 \le x_i \perp IC_i - \sum_{t\in\mathcal{T}} \mu_{i,t} \ge 0, i\in\mathcal{I} \tag{7e}$$

$$0 \le \nu_t \perp D_t - d_t \ge 0, t\in\mathcal{T} \tag{7f}$$

$$0 \le \nu R_{l,t} \perp DR_{l,t} - dR_t \ge 0, l\in\mathcal{LR}, t\in\mathcal{T} \tag{7g}$$

Consider a situation of scarcity, i.e. a situation where the system is so tight that a certain portion of reserve demand cannot be fully covered. In such a situation, $dR_{l,t} < DR_{l,t}$ for some segment $l \in \mathcal{LR}$ of the ORDC. Condition (7g) then implies that $\nu R_{l,t} = 0$. The interpretation of this condition is that the "surplus" of ORDC segment $l \in \mathcal{LR}$ is zero. In other words, the price of reserve is equal to the valuation of this reserve segment. This specifically follows from condition (7b): since $dR_{l,t} > 0$ and $\nu R_{l,t} = 0$, we have

$$\lambda R_t = VR_l. \tag{8}$$

Let us now consider a generator which is "marginal", in the sense that it is the most expensive unit in the system and splits its available generation capacity between the provision of energy, with any leftover used to cover the demand of the TSO for reserve. For this unit, we have both $p_{i,t} > 0$ as well as $r_{i,t} > 0$. From condition (7d) we can conclude that the scarcity rent (i.e. the short-term profit margin) of this unit is equal to the price of reserve:

$$\mu_{i,t} = \lambda R_t. \tag{9}$$

But from condition (7c) we can conclude that the scarcity rent of this marginal unit is also equal to the difference between the energy price and the marginal cost of the unit:

$$\mu_{i,t} = \lambda_t - MC_i. \tag{10}$$

Since these profit margins are equal, the implication is that the price of energy and the price of reserve move in lockstep, with only the cost of the most expensive unit in the system separating them:

$$\lambda_t - MC_i = \lambda R_t. \tag{11}$$

An appeal of shortage pricing based on ORDC is that it results in a "well-behaved" energy price (i.e. an energy price that does not spike abruptly) even if the demand side is price-inelastic, as long as the ORDC has a smooth declining shape. This is due to the fact that the price of reserve is set by the segment of the ORDC which is only partially satisfied, $\lambda R_t = VR_l$, a condition which we already derived above from the optimality conditions of the problem.

Similar to the EOM model, this energy and reserve co-optimization model is equivalent to equilibrium models (12)–(15) below.

Producer $i$ maximizes its profit at the energy market clearing price $\lambda_t$ and reserve market clearing price $\lambda R_t$:

$$\max_{x_i,p_{i,t},r_{i,t}} \sum_{t\in\mathcal{T}}(\lambda_t - MC_i)\cdot p_{i,t} + \sum_{t\in\mathcal{T}} \lambda R_t\cdot r_{i,t} - IC_i\cdot x_i \tag{12a}$$

$$\text{s.t. } p_{i,t} + r_{i,t} \le x_i, t\in\mathcal{T} \tag{12b}$$

$$x_i, p_{i,t}, r_{i,t} \ge 0, t\in\mathcal{T} \tag{12c}$$

Consumers maximize their net surplus at the energy market clearing price $\lambda_t$:

$$\max_{d_t} \sum_{t\in\mathcal{T}}(V-\lambda_t)\cdot d_t \tag{13a}$$

$$\text{s.t. } 0 \le d_t \le D_t, t \in \mathcal{T} \tag{13b}$$

The TSO maximizes its net surplus at the reserve market clearing price $\lambda R_t$:

$$\max_{dR_{l,t}} \sum_{t\in\mathcal{T}} \sum_{l\in\mathcal{LR}} (VR_{l,t} - \lambda R_t) \cdot dR_{l,t} \tag{14a}$$

$$\text{s.t. } 0 \le dR_{l,t} \le DR_{l,t}, l \in \mathcal{LR}, t \in \mathcal{T} \tag{14b}$$

Market-clearing conditions:

$$d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t \in \mathcal{T} \quad (\lambda_t) \tag{15a}$$

$$\sum_{l\in\mathcal{LR}} dR_{l,t} - \sum_{i\in\mathcal{I}} r_{i,t} = 0, t \in \mathcal{T} \quad (\lambda R_t) \tag{15b}$$

### B.3. Capacity remuneration mechanisms

In this section, we proceed to extend the EOM model in order to account for a capacity remuneration mechanism. A CRM is represented in our framework with the introduction of a demand curve in the first stage of capacity procurement. This curve corresponds to a decreasing willingness to pay of the TSO for increments of generation capacity.

$$\max_{x,p,d,xd} \sum_{t\in\mathcal{T}} (V \cdot d_t - \sum_{i\in\mathcal{I}} MC_i \cdot p_{i,t}) + \sum_{l\in\mathcal{LC}} VC_l \cdot xd_l - \sum_{i\in\mathcal{I}} IC_i \cdot x_i \tag{16a}$$

$$\text{s.t. } d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t \in \mathcal{T} \quad (\lambda_t) \tag{16b}$$

$$\sum_{l\in\mathcal{LC}} xd_l - \sum_{i\in\mathcal{I}} x_i = 0 \quad (\lambda C) \tag{16c}$$

$$p_{i,t} \le x_i, i \in \mathcal{I}, t \in \mathcal{T} \quad (\mu_{i,t}) \tag{16d}$$

$$d_t \le D_t, t \in \mathcal{T} \quad (\nu_t) \tag{16e}$$

$$xd_l \le DC_l, l \in \mathcal{LC} \quad (\nu_l) \tag{16f}$$

$$x, p, d, xd \ge 0 \tag{16g}$$

We use a set of segments $l \in \mathcal{LC}$ to represent the CRM curve, with $DC_l$ denoting the capacity demand quantity and $VC_l$ denoting the capacity demand valuation of segment $l$. Compared with the EOM model, the objective function (16a) now includes a term which corresponds to the economic value that the TSO derives from procuring generation capacity, i.e., $\sum_{l\in\mathcal{LC}} VC_l \cdot xd_l$. A new market-clearing condition (16c) is introduced for the capacity market.

This model is equivalent to equilibrium models (17)–(20) below.

Producer $i$ maximizes its profit at the energy market clearing price $\lambda_t$ and capacity market clearing price $\lambda C$:

$$\max_{x_i,p_{i,t}} \sum_{t\in\mathcal{T}} (\lambda_t - MC_i) \cdot p_{i,t} + (\lambda C - IC_i) \cdot x_i \tag{17a}$$

$$\text{s.t. } p_{i,t} \le x_i, t \in \mathcal{T} \tag{17b}$$

$$x_i, p_{i,t} \ge 0, t \in \mathcal{T} \tag{17c}$$

Consumers maximize their net surplus at the energy market clearing price $\lambda_t$:

$$\max_{d_t} \sum_{t\in\mathcal{T}} (V - \lambda_t) \cdot d_t \tag{18a}$$

$$\text{s.t. } 0 \le d_t \le D_t, t \in \mathcal{T} \tag{18b}$$

The TSO maximize its net surplus at the capacity market clearing price $\lambda C$:

$$\max_{xd_l} \sum_{l\in\mathcal{LR}} (VC_l - \lambda C) \cdot xd_l \tag{19a}$$

$$\text{s.t. } 0 \le xd_l \le DC_l, l \in \mathcal{LC} \tag{19b}$$

Market-clearing conditions:

$$d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t \in \mathcal{T} \quad (\lambda_t) \tag{20a}$$

$$\sum_{l\in\mathcal{LC}} xd_l - \sum_{i\in\mathcal{I}} x_i = 0 \quad (\lambda C) \tag{20b}$$

### B.4. Coexistence of shortage pricing and CRMs

In this section we combine the models of Appendices B.2 and B.3 in order to demonstrate that shortage pricing can coexist with capacity mechanisms. We concretely consider a market model of the following form.

$$\max_{x,p,d,r,dR,xd} \sum_{t\in\mathcal{T}} (V \cdot d_t - \sum_{i\in\mathcal{I}} MC_i \cdot p_{i,t}) + \sum_{l\in\mathcal{LR},t\in\mathcal{T}} VR_{l,t} \cdot dR_{l,t} + \sum_{l\in\mathcal{LC}} VC_l \cdot xd_l - \sum_{i\in\mathcal{I}} IC_i \cdot x_i \tag{21a}$$

$$\text{s.t. } d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t \in \mathcal{T} \quad (\lambda_t) \tag{21b}$$

$$\sum_{l\in\mathcal{LR}} dR_{l,t} - \sum_{i\in\mathcal{I}} r_{i,t}, t \in \mathcal{T} = 0 \quad (\lambda R_t) \tag{21c}$$

$$\sum_{l\in\mathcal{LC}} xd_l - \sum_{i\in\mathcal{I}} x_i = 0 \quad (\lambda C) \tag{21d}$$

$$p_{i,t} + r_{i,t} \le x_i, i \in \mathcal{I}, t \in \mathcal{T} \quad (\mu_{i,t}) \tag{21e}$$

$$d_t \le D_t, t \in \mathcal{T} \quad (\nu_t) \tag{21f}$$

$$dR_{l,t} \le DR_{l,t}, l \in \mathcal{LR}, t \in \mathcal{T} \quad (\nu R_{l,t}) \tag{21g}$$

$$xd_l \le DC_l, l \in \mathcal{LC} \quad (\nu_l) \tag{21h}$$

$$x, p, d, dR, r, xd \ge 0 \tag{21i}$$

This model is equivalent to equilibrium models (22)–(25) below.

Producer $i$ maximizes its profit at the energy market clearing price $\lambda_t$, reserve market clearing price $\lambda R_t$ and capacity market clearing price $\lambda C$:

$$\max_{x_i,p_{i,t},r_{i,t}} \sum_{t\in\mathcal{T}} (\lambda_t - MC_i) \cdot p_{i,t} + \sum_{t\in\mathcal{T}} \lambda R_t \cdot r_{i,t} + (\lambda C - IC_i) \cdot x_i \tag{22a}$$

$$\text{s.t. } p_{i,t} \le x_i, t \in \mathcal{T} \tag{22b}$$

$$x_i, p_{i,t}, r_{i,t} \ge 0, t \in \mathcal{T} \tag{22c}$$

Consumers maximize their net surplus at the energy market clearing price $\lambda_t$:

$$\max_{d_t} \sum_{t\in\mathcal{T}} (V - \lambda_t) \cdot d_t \tag{23a}$$

$$0 \le d_t \le D_t, t \in \mathcal{T} \tag{23b}$$

The TSO maximizes its net surplus at the reserve market clearing price $\lambda R_t$ and at the capacity market clearing price $\lambda C$:

$$\max_{dR_{l,t},xd_l} \sum_{t\in\mathcal{T}} \sum_{l\in\mathcal{LR}} (VR_{l,t} - \lambda R_t) \cdot dR_{l,t} + \sum_{l\in\mathcal{LR}} (VC_l - \lambda C) \cdot xd_l \tag{24a}$$

$$\text{s.t. } 0 \le dR_{l,t} \le DR_{l,t}, l \in \mathcal{LR}, t \in \mathcal{T} \tag{24b}$$

$$0 \le xd_l \le DC_l, l \in \mathcal{LC} \tag{24c}$$

Market-clearing conditions:

$$d_t - \sum_{i\in\mathcal{I}} p_{i,t} = 0, t \in \mathcal{T} \quad (\lambda_t) \tag{25a}$$

$$\sum_{l\in\mathcal{LR}} dR_{l,t} - \sum_{i\in\mathcal{I}} r_{i,t} = 0, t \in \mathcal{T} \quad (\lambda R_t) \tag{25b}$$

$$\sum_{l\in\mathcal{LC}} xd_l - \sum_{i\in\mathcal{I}} x_i = 0 \quad (\lambda C) \tag{25c}$$

### B.5. Notation

#### B.5.1. Sets

$\mathcal{T}$ Set of periods

$\mathcal{I}$ Set of technologies

**Table 10**
Invested capacity in each Member State in "StatusQuo" scenarios. All values are in GW.

| | AT | BE | BG | CZ | DE | DK | EE | ES | FI | FR | GR | HR | HU | IE | IT | LT | LU | LV | NL | PL | PT | RO | SE | SI | SK |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **EOM** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Batteries | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 42.62 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.57 | 0.00 | 1.93 | 0.00 | 0.00 | 0.00 | 0.00 |
| CCHT | 0.00 | 3.25 | 0.00 | 7.02 | 54.42 | 0.37 | 0.32 | 13.90 | 3.13 | 0.00 | 5.62 | 0.00 | 0.00 | 0.18 | 2.14 | 0.00 | 2.48 | 0.00 | 1.58 | 5.74 | 8.21 | 0.00 | 0.48 | 0.00 | 0.00 |
| OCHT | 0.00 | 2.60 | 1.74 | 5.27 | 26.15 | 0.76 | 0.91 | 7.57 | 3.01 | 6.75 | 1.04 | 0.00 | 0.00 | 1.08 | 3.17 | 0.76 | 1.08 | 0.66 | 6.64 | 1.52 | 3.62 | 1.80 | 1.57 | 0.00 | 1.96 |
| PV | 23.54 | 12.45 | 12.19 | 19.29 | 212.30 | 9.73 | 1.89 | 263.61 | 0.00 | 107.77 | 6.26 | 0.00 | 2.64 | 15.88 | 100.32 | 3.54 | 0.61 | 3.76 | 14.52 | 37.19 | 33.04 | 12.59 | 11.26 | 1.28 | 19.12 |
| Wind offshore | 0.00 | 0.00 | 0.00 | 0.00 | 5.93 | 0.00 | 0.00 | 18.86 | 0.00 | 76.93 | 17.76 | 13.28 | 0.00 | 0.00 | 101.28 | 0.00 | 0.00 | 0.00 | 0.00 | 28.81 | 5.25 | 0.00 | 16.51 | 0.00 | 0.00 |
| Wind onshore | 51.53 | 53.57 | 4.58 | 50.60 | 107.69 | 15.89 | 4.20 | 326.10 | 41.38 | 117.37 | 19.99 | 0.00 | 32.92 | 23.91 | 66.84 | 9.93 | 14.35 | 3.20 | 70.62 | 146.85 | 38.64 | 40.07 | 25.73 | 0.00 | 0.00 |
| DR | 1.05 | 1.75 | 0.78 | 1.23 | 7.10 | 0.48 | 0.13 | 2.03 | 1.43 | 9.59 | 0.62 | 0.40 | 0.94 | 0.79 | 5.88 | 0.27 | 0.08 | 0.21 | 2.69 | 3.23 | 0.46 | 0.48 | 2.33 | 0.22 | 0.39 |
| **ORDC-StatusQuo** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Batteries | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 42.62 | 0 | 0 | 0.03 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.57 | 0 | 1.93 | 0 | 0 | 0 | 0 |
| CCHT | 0 | 3.21 | 0 | 7.02 | 54.43 | 0.37 | 0.32 | 13.9 | 3.13 | 0 | 5.62 | 0 | 0 | 0.18 | 2.14 | 0 | 2.6 | 0 | 1.58 | 6.3 | 8.21 | 0 | 0.48 | 0 | 0 |
| OCHT | 0 | 2.57 | 1.75 | 5.26 | 26.29 | 0.63 | 0.9 | 7.57 | 3 | 6.75 | 1.03 | 0 | 0 | 1.09 | 3.17 | 0.88 | 0.85 | 0.53 | 6.64 | 0.99 | 3.62 | 1.79 | 1.51 | 0 | 1.96 |
| PV | 23.61 | 12.45 | 12.2 | 19.27 | 212.31 | 9.55 | 1.88 | 263.61 | 0 | 107.77 | 6.25 | 0 | 2.61 | 15.88 | 100.43 | 3.53 | 0.61 | 3.76 | 14.55 | 37.22 | 33.04 | 12.59 | 11.82 | 1.3 | 19.17 |
| Wind offshore | 0 | 0 | 0 | 0 | 5.77 | 0 | 0 | 18.86 | 0 | 76.93 | 17.76 | 13.28 | 0 | 0 | 101.3 | 0 | 0 | 0 | 0 | 28.65 | 5.25 | 0 | 16.46 | 0 | 0 |
| Wind onshore | 51.5 | 53.57 | 4.55 | 50.62 | 108.09 | 16.4 | 4.22 | 326.1 | 41.64 | 117.37 | 20.02 | 0 | 32.92 | 23.91 | 66.84 | 9.89 | 14.35 | 3.17 | 70.46 | 146.68 | 38.64 | 40.07 | 26.21 | 0 | 0 |
| DR | 1.05 | 1.75 | 0.78 | 1.23 | 7.1 | 0.48 | 0.13 | 2.03 | 1.43 | 9.59 | 0.62 | 0.4 | 0.94 | 0.79 | 5.87 | 0.27 | 0.08 | 0.21 | 2.69 | 3.23 | 0.46 | 0.48 | 2.33 | 0.22 | 0.39 |
| **CRM-StatusQuo** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Batteries | 0 | 1.4 | 0 | 0 | 0 | 0 | 0 | 42.22 | 0 | 0 | 0.03 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 2.01 | 0 | 0 | 0 | 0 |
| CCHT | 0 | 5.92 | 0 | 7.18 | 53.67 | 0 | 0.43 | 13.55 | 3.02 | 0 | 5.62 | 0 | 0 | 1.14 | 2.14 | 0 | 2.44 | 0 | 0.71 | 6.44 | 8.04 | 0 | 0.42 | 0 | 0 |
| OCHT | 0 | 0 | 1.75 | 4.34 | 24.87 | 0 | 0.76 | 8.32 | 1.96 | 19.89 | 1.04 | 0.05 | 0 | 0.74 | 3.17 | 1.04 | 0.97 | 0.34 | 4.85 | 7.7 | 3.39 | 1.8 | 1.54 | 0 | 1.87 |
| PV | 23.98 | 13.05 | 12.23 | 17.99 | 211.26 | 7.93 | 1.72 | 261.69 | 0 | 113.86 | 6.11 | 0 | 2.04 | 15.96 | 99.74 | 3.52 | 0.68 | 3.78 | 12.89 | 42.19 | 33.07 | 12.71 | 13.13 | 1.44 | 19.17 |
| Wind offshore | 0 | 0 | 0 | 0 | 1.94 | 0 | 0 | 19.48 | 0 | 52.97 | 17.8 | 13.28 | 0 | 0 | 101.73 | 0 | 0 | 0 | 0 | 26.37 | 5.16 | 0 | 16.59 | 0 | 0 |
| Wind onshore | 50.67 | 52.95 | 4.6 | 52.06 | 114.81 | 16.38 | 4.32 | 328.83 | 41.57 | 157.01 | 20.03 | 0 | 32.92 | 23.58 | 66.66 | 9.92 | 14.28 | 3.08 | 71.59 | 148.88 | 38.95 | 39.72 | 25.94 | 0 | 0 |
| DR | 1.05 | 1.41 | 0.78 | 0.91 | 7.1 | 0.48 | 0.13 | 2.03 | 1.31 | 9.22 | 0.62 | 0.4 | 0.94 | 0.7 | 5.83 | 0.27 | 0.08 | 0.21 | 1.74 | 3.61 | 0.46 | 0.51 | 1.98 | 0.22 | 0.39 |
| **ORDC+CRM-StatusQuo** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Batteries | 0 | 1.4 | 0 | 0 | 0 | 0 | 0 | 42.25 | 0 | 0 | 0.05 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | 0 | 0 | 0 | 0 |
| CCHT | 0 | 5.92 | 0 | 7.18 | 53.47 | 0 | 0.46 | 13.55 | 2.99 | 0 | 5.61 | 0 | 0 | 1.14 | 2.14 | 0 | 2.65 | 0 | 0.61 | 6.41 | 8.16 | 0 | 0.43 | 0 | 0 |
| OCHT | 0 | 0 | 1.73 | 4.34 | 25.07 | 0 | 0.72 | 8.33 | 1.99 | 19.9 | 1.07 | 0.05 | 0 | 0.74 | 3.17 | 1.12 | 0.76 | 0.26 | 4.95 | 7.73 | 3.26 | 1.83 | 1.54 | 0 | 1.87 |
| PV | 24.02 | 13.05 | 12.23 | 17.99 | 211.26 | 7.93 | 1.73 | 261.72 | 0 | 113.86 | 6.12 | 0 | 2.04 | 15.96 | 99.74 | 3.52 | 0.68 | 3.77 | 12.89 | 42.19 | 33.07 | 12.68 | 13.13 | 1.44 | 19.17 |
| Wind offshore | 0 | 0 | 0 | 0 | 1.94 | 0 | 0 | 19.54 | 0 | 52.97 | 17.8 | 13.28 | 0 | 0 | 101.73 | 0 | 0 | 0 | 0 | 26.37 | 5.16 | 0 | 16.59 | 0 | 0 |
| Wind onshore | 50.68 | 52.93 | 4.59 | 52.06 | 114.8 | 16.38 | 4.31 | 328.78 | 41.59 | 157.01 | 20 | 0 | 32.92 | 23.58 | 66.65 | 9.92 | 14.28 | 3.08 | 71.63 | 148.88 | 38.95 | 39.73 | 25.91 | 0 | 0 |
| DR | 1.05 | 1.41 | 0.78 | 0.91 | 7.1 | 0.48 | 0.14 | 2.03 | 1.31 | 9.22 | 0.62 | 0.4 | 0.94 | 0.7 | 5.83 | 0.27 | 0.08 | 0.21 | 1.74 | 3.61 | 0.46 | 0.54 | 1.99 | 0.22 | 0.39 |

$\mathcal{LR}$ Set of segments in ORDC

$\mathcal{LC}$ Set of segments in CRM demand curve

### *B.5.2. Parameters*

$V$ Valuation of consumers for electricity

$MC_i$ Marginal cost of technology $i \in \mathcal{I}$

$IC_i$ Investment cost of technology $i \in \mathcal{I}$

$D_t$ Load of period $t \in \mathcal{T}$

$VR_{l,t}$ Willingness to pay of ORDC segment $l \in \mathcal{LR}$ for period $t \in \mathcal{T}$

$DR_{l,t}$ Demand of ORDC segment $l \in \mathcal{LR}$ for period $t \in \mathcal{T}$

$VC_l$ Willingness to pay of CRM segment $l \in \mathcal{LC}$

$DC_l$ Demand of CRM segment $l \in \mathcal{LC}$

### *B.5.3. Variables*

$d_t$ Served demand of period $t \in \mathcal{T}$

$x_i$ Capacity investment of technology $i \in \mathcal{I}$

$p_{i,t}$ Production of technology $i \in \mathcal{I}$ for covering demand of period $t \in \mathcal{T}$

$r_{i,t}$ Reserve of technology $i \in \mathcal{I}$ for covering demand of period $t \in \mathcal{T}$

$dR_{l,t}$ Demand for reserve in period $t \in \mathcal{T}$ in ORDC segment $l \in \mathcal{LR}$

$xd_l$ Capacity demand of CRM demand curve segment $l \in \mathcal{LC}$

## Appendix C. Invested capacity in each member state

We present the invested capacity of each technology in each Member State in Table 10.

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