Overview of EU Capacity Remuneration Mechanisms

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Contents

1. Introduction

This deliverable responds to the request of the Greek Regulatory Authority for Energy (RAE) for outlining the basic principles of a design for a Capacity Remuneration Mechanism (CRM) for the Greek Electricity Market. The following specific tasks are requested in the terms of reference of the regulator:

1. Documenting and assessing recent Capacity Remuneration Mechanisms that are implemented in Europe.

2. Documenting and assessing capacity auction rules / designs, in terms of competitiveness of the auction and preventing manipulation / non-competitive behavior, which is being implemented or has been implemented in practice internationally.

3. Recording the basic design principles of a Capacity Remuneration Mechanism for the case of the Greek electricity market.

Section 2 provides a discussion of the most basic elements of capacity remuneration mechanisms that are often encountered in practice. Such elements include the possible motivation for putting a CRM in place, the capacity demand curve for centralized capacity auctions, and reliability options. US capacity markets are briefly described at the end of the section.

Section 3 covers in more detail a number of European CRMs that have either already been put in place or that are currently being designed in the EU. The information in this section is based on the sector inquiries of the respective CRMs, and the CRM proposals are compared along the following dimensions: what are the justifications provided by the Member States for instituting a CRM, a broad outline of the CRM of each Member State, the roles and responsibilities of the market parties in the CRM, the rules of the capacity auction (in case one exists for the Member State in question), how the delivery of capacity is monitored, and how payments are determined.

Section 4 focuses on the design of capacity auctions for single-buyer CRMs. This section focuses specifically on the dilemma between sealed-bid and descending clock auctions. The material in this section is based on classical auction theory results as well as empirical evidence from the markets of ISO-New England, Colombia and (the considered capacity market of) Belgium.

Section 5 illustrates the possible application of a capacity auction on the a simplified model of the Greek market. The example is stylized, and serves towards illustrating the application of the first principles of section 2 to a simplified model of a possible future scenario for the Greek market. As required in the terms of reference, and in the absence of relevant data, the content is based on an assessment of the state of the art in capacity remuneration mechanisms, *not* a detailed simulation of the Greek electricity market.

Section 6 summarizes a number of relevant observations that emerge from the review of the state of the art.

2. Background

In this section we provide a high-level description of CRMs. We commence by tracing arguments that rationalize the introduction of CRMs in the academic literature. We then discuss certain important features of CRMs, including capacity auctions and the demand curves used in single buyer models of capacity auctions, the pay-for-performance attributes of CRMs, the role of reliability options, as well as the implementation of resource adequacy mechanisms in Europe and the United States.

2.1 Theoretical Underpinning of CRMs

There exists a long-standing theory on peak load pricing [3] which develops the main arguments of how the workings of an energy-only market can result in a long-run competitive equilibrium that replicates the outcome of a socially optimal capacity mix. The argument relies crucially on *scarcity pricing*, i.e. the notion that, for certain periods of market operation, it is the demand which sets the price. These scarcity periods are periods in which the production capacity of the system has been exhausted. The basic intuition of the argument can be understood by recognizing that the only way for peaking units to recover their long-run investment costs is through inframarginal rents during those periods when the entire capacity in the system has been exhausted. In these periods, the price elasticity of the demand side is crucial in driving up electricity prices and generating the required revenue for peaking units to remain financially viable in a competitive economic environment.

Scarcity pricing is not only important in theory, but also prominent in recent EU legislation. Article 20(3) of the European Parliament Clean Energy Package [22] and article 44(3) of the European Commission Electricity Balancing Guideline [19] refer to the potential role of a shortage pricing function as a requirement for Member States with identified resource adequacy concerns. There are a number of Member States where concrete measures for the implementation of scarcity pricing are underway, including Belgium [34], Poland and the UK [17].

The capacity remuneration mechanisms that are encountered in practice are motivated by an assumption that energy markets encounter difficulties in discovering efficient prices during scarcity periods. There are a number of points where the aforementioned theory of peak load pricing can stumble upon practical obstacles. (i) One is the exercise of market power. (ii) Another is the absence of reliability markets. (iii) The role of risk aversion is also relevant. (iv) Shortcomings in the EU energy market designs may also present obstacles in the appropriate valuation of capacity. We discuss these arguments in turn, inspired by specific scientific publications on each of these topics.

2.1.1 Market Power

Fabra [24] presents an interesting stylized analysis of the interplay between market power, price caps, missing money and the possible benefits of capacity mechanisms in a regime of price caps. Note, however, that the analysis ignores certain realistic elements of actual market operations (such as reserves, and therefore the potential benefits of scarcity pricing by means of operating reserve demand curves [26]).

After recalling the equivalence between socially optimal planning and a perfectly competitive energy-only market, Fabra proceeds to analyze how market power interplays with both the equilibrium level of capacity investment as well as consumer welfare. In proposition 2 [24], Fabra establishes that a dominant firm competing against fringe suppliers has an interesting in investing below the socially optimal level of capacity. The degree of equilibrium capacity depends on the price cap that is imposed on the market, with a larger price cap resulting in greater capacity investment. The total welfare in the case where market power is exercise is equal to the socially optimal welfare, however its partitioning between consumer and producer welfare depends on the price cap. From a consumer point of view, it is preferable to impose a price cap below VOLL, even if this implies investment in less than the socially optimal capacity.

Fabra then proceeds to establish that a capacity mechanism can stimulate investment. The analytical results suggest a price cap that is set at the level of the marginal cost of the marginal unit, and a capacity payment that fully recovers the scarcity rents that would be needed for stimulating the optimal level of investment in the system.

Although the model is stylized, it conveys the basic economic reasoning about the interplay between market power, price caps, capacity markets and consumer welfare. The analysis argues that the regulatory instruments and market failures can be disentangled: price caps can be employed for moderating the exercise of market power, while capacity markets can be put in place in order to restore missing money created by price caps and thus regulate the level of investment.

In this respect, it is interesting to note that, in the view of the Belgian regulator, the Clean Energy Package [22] regulation weakens the rationale for capacity markets, at least insofar as arguments related to price caps are concerned [37]. Article 10 of the Clean Energy Package foresees that there can be no maximum limit to the wholesale electricity price. Currently, there exists a technical bidding limit of 3000 €/MWh in the day-ahead market. Recent regulation has decided that the bidding limit increases by 1000 €/MWh every time that the market price reaches at least 60% of the bidding limit. This essentially lifts price caps, and puts into question whether price caps can be used as a valid argument moving forward for rationalizing the introduction of a capacity mechanism.

2.1.2 Absence of Reliability Markets

Joskow and Tirole [29] develop a quantitative framework for reasoning about reliability as a separate good from electrical energy, and proceed to use this framework in order to derive second-best conditions that a market must fulfill in order to deliver socially optimal outcomes. They then analyze how real markets may deviate from the conditions that characterize their second-best solution, and discuss how capacity mechanisms influence the market equilibrium under such non-ideal conditions.

Concretely, proposition 1 of [29] proves that the second-best optimum (second-best due to the fact that a certain subset of consumers are not able to react to real-time prices) can be implemented by retail and generation competition, provide that (i) real-time prices reflect the opportunity cost of generation, (ii) generation is used in rationing periods, (iii) load-serving entities face real-time prices, (iv) price-sensitive consumers face real-time prices, (v) price-insensitive consumers enroll to priority service contracts [6], and (vi) consumers are homogeneous.

Real markets may deviate from these ideal conditions in a number of ways. We have already discussed in the previous section how market power may induce the introduction of price caps, which in turn imply that real-time prices do not correspond to the opportunity cost of generation. During blackouts, excess generation may not be used due to system collapse. And until demand response aggregation markets mature, it is not possible to implement some form of priority rationing between retail consumers in conditions of scarcity.

Insofar as price caps are concerned, the authors demonstrate that the introduction of capacity payments can work towards restoring investment incentives. Interestingly, therefore, according to the analysis of Joskow and Tirole, the introduction of capacity mechanisms does rely on market power which induces price caps. It is not enough to simply rely on the argument of price-insensitive demand. Quoting from [29], "*Proposition 1 shows that price-insensitive customers alone do not create a rationale for capacity obligations.*".

2.1.3 Risk Aversion

Another rationalization for capacity remuneration mechanisms is the risk aversion of investors and the incompleteness of financial markets [31, 32]. Such arguments can be formalized quantitatively using coherent risk measures to represent risk aversion.

Market incompleteness in this context refers to the absence of markets for trading risk. Work by Smeers, Ehrenmann, de Maere d'Aertrycke, and Abada [12, 11, 1] establishes a quantitative framework for demonstrating that enriching financial markets with derivatives that allow agents to trade risk brings the market closer to an idealized complete market that trades Arrow-Debreu securities.

Capacity markets can be interpreted as one such means of trading risk. Given an appropriate choice of risk measures, one can establish that in a setting with risk-averse agents social welfare may be improved with the introduction of capacity markets [25]. Nevertheless, the accuracy of such results relies on an ability to accurately quantify the risk attitudes is a significant practical challenge.

Concretely, revenue streams from energy-only markets can be highly unpredictable. Capacity markets supplemented by reliability options essentially function as financial instruments that trade the cash flows in scarcity periods with more certain cash flows which reduce the risk exposure of both load serving entities as well as investors in generation capacity.

2.1.4 Shortcomings in EU Market Design

The incompleteness of financial markets which is discussed in the previous section is to be expected from *any* sector, not simply electricity. The ideal setting of a market that trades Arrow-Debreu securities can be understood as an intellectual construct rather than a viable market design proposal.

Nevertheless, the design of the short-term EU electricity market is also incomplete (in addition to the markets for financial hedging). These elements of market incompleteness are specific to the electricity sector, and there *are* practically viable market design choices that can be pursued which can contribute towards improving the ability of EU market design in better remunerating the right type of capacity in the right locations in a future that is expected to entail significant levels of renewable energy penetration.

Two prominent examples of market incompleteness that can be identified in the existing EU design include shortcomings in the pricing of transmission capacity [8, 21], as well as the absence of a real-time market for reserve capacity [34] (i.e. a market for settling balancing capacity imbalances, in the same way that we settle energy imbalances).

The challenges associated to the poor design choices for pricing transmission capacity are developed by Cramton [8], and are not repeated here. Instead, we briefly address the implications of the absence of an EU market for real-time reserve, and how it relates to the implementation of scarcity pricing based on operating reserve demand curves (ORDCs). In a nutshell, the introduction of ORDCs in real-time energy markets result in the computation of a *scarcity adder* which should be applied as follows [34]:

- as an adder to balancing prices
- as an adder to imbalance prices, and
- also used for settling balancing capacity imbalances, i.e. for putting in place a real-time market for reserve capacity.

The adder essentially uplifts balancing prices when the system is tight, and thus rewards flexible resources for providing much-needed energy to the system when the system is under stress. It also penalizes resources that stress the system in those periods, and sends a clear signal to flexible resources (including CCGTs, OCGTs, storage and demand response) to enter the market. The mechanism mitigates the risk that is associated to highly unpredictable energy price spikes, since scarcity prices occur with higher frequency and lower amplitude, thereby stabilizing the revenue stream of flexible resources. The mechanism is compatible with CRMs, and can also be combined with market power mitigation measures to as to maintain increases in balancing prices whenever the system is tight, even if market power mitigation controls are applied.

Recent analyses of the application of scarcity pricing in the Belgian market [35, 36] have established the ability of scarcity pricing based on operating reserve demand curves [26] to overturn the financial viability of flexible (combined cycle) capacity. A prerequisite for the conclusion of this analysis to be valid is for scarcity prices to back-propagate to forward energy and balancing capacity markets. The fact that the EU market design does not feature a real-time market for reserve capacity undermines this back-propagation, since the limited application of scarcity adders to balancing prices or imbalance prices is, according to analytical results [34], not sufficient for a full back-propagation of scarcity adders to forward (e.g. day-ahead) markets.

The absence of an EU real-time market for reserve capacity is a striking example of market incompleteness in the EU design. In its absence, there is a fundamental challenge in the appropriate valuation of balancing capacity. With the advent of renewable resources and the shift of value from energy to balancing capacity services, this market incompleteness shows its teeth by raising challenges for flexible resources that are characterized by high marginal costs (such as CCGT) to survive in a competitive economic environment, as also indicated by recent analyses of the Greek electricity market [5].

Another interesting challenge which is also particular to electricity markets is the presence of non-convexities related to the short-term operating costs of flexible units. Such non-convexities include include minimum load costs, startup costs, minimum up / down times, and other features that are specific to the unit commitment of thermal assets. The challenge of flexible thermal assets in recovering fixed short-term operating costs in the Greek electricity market are discussed by [5], and are not expanded further here. Whereas certain markets (such as in the US) rely on proxies of convex hull pricing [28] supplemented by non-uniform pricing / uplift payments in order to recover these costs, EU markets rely on uniform pricing and non-paradoxical acceptance in order to cope with the fact that equilibrium prices may not exist for recovering fixed costs related to the startup and operation of flexible thermal assets. The recovery of fixed short-term operating costs is therefore fundamentally a challenge in electricity market design and failure to recover such fixed costs contributes to missing money, though certain experts debate about the severity of this effect [8].

2.2 Capacity Demand Curves

As we discuss in further detail in the sequel, centralized capacity remuneration mechanisms rely on a capacity auction, e.g. an annual auction for the procurement of capacity one or four years ahead. The system operator can be thought of as the single buyer in this auction, while sellers correspond to entities that can contribute towards covering the adequacy needs of the system. Such resources include existing generation capacity, future generation capacity, demand response, storage, renewable resources, and interconnections, among others.

Original implementations of capacity mechanisms relied on inelastic demand curves for capacity, which resulted in a "bipolar" behavior of capacity prices depending on whether the system was temporarily short or long of the desired capacity target [8]. The idea of a downward-sloping demand curve, which is nowadays typically employed in capacity auctions, is to reduce the volatility of the capacity payments while aiming to cover, on average, the cost of building capacity and also allowing for a certain degree of mitigation on the exercise of market power in the capacity auction.

A prototypical design of a demand curve for capacity is discussed in [9], and presented in figure 1. In this figure $FC^{\star}$ corresponds to the cost of new entry (CONE), i.e. the fixed cost of a peaking unit. The capacity C_{min} corresponds to the minimum capacity that the system should be able to carry in order to keep loss of load expectation (LOLE) at the target reliability criterion of the system (e.g. 1 day in 10 years). The following additional three conditions are recommended by [9]:

- $SR(C_{min}) = 2 \cdot FC^{\star}$
- $SR(C_K) = FC^{\star}$
- $(C_{max} - C_K)/(C_K - C_{min}) = 3$

The last condition that fully defines the demand curve (and results in the parameter values of C_{min}, C_K, C_{target} and C_{max} indicated in figure 1) is the requirement that the average payoff along the demand curve for a random capacity which is normally distributed with a mean of $C_{target} = C_{min} + 0.94SD$ and a standard deviation of SD should be $FC^{\star}$. Here, SD is the standard deviation of the capacity and can be estimated from past observations. This assumption about capacity distribution implies that the level of capacity is lower than C_{min} with a probability of 17%.

In practice, the detailed design of the capacity demand curve may conform less to this recommended design. Nevertheless, among countries that implement a centralized CRM, there is a consensus in utilizing a downward sloping demand curve, and the CONE and target capacity level C_K are key parameters in the definition of the demand curve. The specific choices of various EU capacity markets in this respect are discussed in further detail in section 3.2.

2.3 The Pay-for-Performance Challenge

A challenging aspect of capacity markets is the fact that, in their simplest form, they involve no concrete commitment on behalf of the capacity providers. Consider the example of a "dog" unit [9] that is characterized by

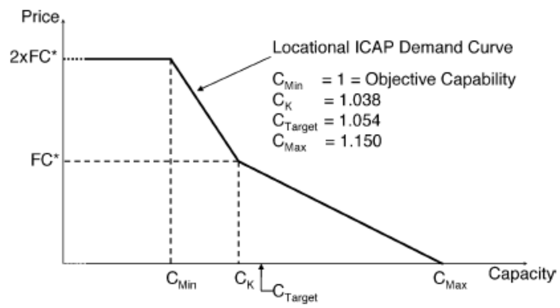

Figure 1: A typical shape of a capacity auction demand curve [9].

a very high marginal cost, and would not be economical to operate, even when market prices are very high. To fix concepts, let us consider a resource that, if retrofitted, would be able to run at a high marginal cost of 350 €/MWh, but if not retrofitted would require a prohibitively high marginal cost of 1000 €/MWh. Suppose that scarcity periods are considered to correspond to market prices of 120 €/MWh or more, and that there is a market price cap of 300 €/MWh in the energy market. If this unit participates in the capacity market without being retrofitted, it can recuperate a capacity payment. Come real time, and in conditions of scarcity, the unit faces the following payoff in the energy market:

$$(\lambda - C) \cdot p,$$

where λ is the market price, C is the marginal cost of the unit, and p is its output.

Suppose that the unit bids successfully in the capacity auction. If the unit is not retrofitted, it will not run unless the market price exceeds 1000 €/MWh, which would never occur due to the price cap of the market. This is despite the fact that this dog unit has been paid in the capacity market in order to be available during *all* scarcity periods. We refer to this as a pay-for-performance issue: the capacity market itself, if not supplemented by additional mechanisms, fails to achieve the fair outcome of only paying resources for performing, i.e. delivering energy, at scarcity periods when they are needed most.

It is interesting to reflect on what the unit provider would bid in the capacity market in this context. The resource owner would need to choose between honestly retrofitting its unit, or simply participating in the capacity market in order to collect opportunistic capacity payments. Suppose that the retrofit cost would correspond to 50,000 €/MW-y.

- If retrofitted, the generator would recover no extra profits in the energy market, because the price cap (300 €/MWh) exceeds its prohibitively high marginal cost (350 €/MWh). Thus, it would bid its retrofit cost.
- If not retrofitted, the generator would recover no extra profits in the energy market, because the price cap (300 €/MWh) exceeds its prohibitively high marginal cost (1000 €/MWh). Thus, it would bid 0 €/MW-y.

The perverse effect in this setting is that, even though the unit is uneconomic for this market[1], it is preferable for the owner to place an extremely competitive bid to the capacity market (0 €/MW-y), without any intention of ever retrofitting the unit or producing power during periods of scarcity. The origin of the distortion is a disconnect between the payment of the capacity market and an actual obligation to deliver power as promised by being successfully cleared in the capacity market.

2.4 Reliability Options

Reliability options have been proposed in a number of markets [33, 9, 10, 7], with early implementations in the design of the Colombian market [39]. Reliability options bundle a call option, referred to as a *reliability option*, to each unit that a capacity provider sells to the capacity market. This reliability option commits the capacity provider to a payment that is equal to the difference between the market price and the strike price of the call option, as indicated in figure 2.

In the presence of a reliability option, the payoff obligation of the dog unit employed in the previous example now becomes:

$$(\lambda - C) \cdot p - \max(\lambda - K, 0) \cdot x$$

where x is the capacity that the unit has sold in the capacity market, and K is the strike price of the call option[2].

[1] We assume in this discussion that the retrofit cost of 50,000 €/MW-y is already exceeding the cost of competitive capacity.

[2] Note that in the upcoming Belgian CRM design, the second term is not payable if a unit can establish adequately that it is in forced outage during a scarcity period, and declares this forced outage in advance [15].

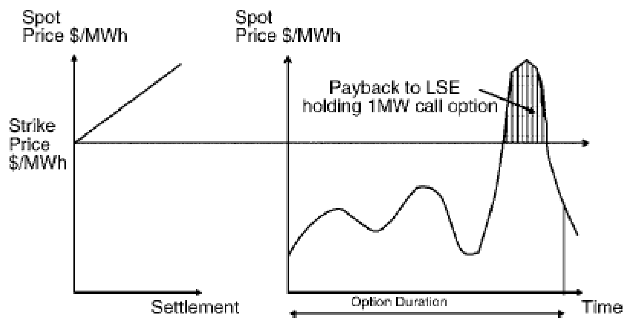

Figure 2: Payoff of reliability options from capacity providers to load serving entities. Source: Oren [33].

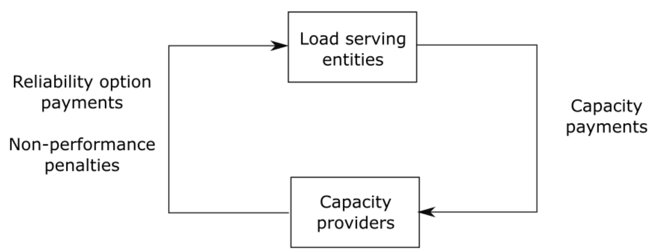

Figure 3: Cash flows in a typical capacity remuneration mechanism with reliability options.

Reliability options can be interpreted as risk sharing arrangements between load serving entities and capacity providers. Concretely, the reliability options are swapping the risky scarcity rents of capacity providers with the rather predictable capacity payment. Consumers are also protected from price spikes that are traded for the capacity payments. The cash flows of a typical capacity remuneration mechanism are presented in figure 3.

Note that the choice of the strike price of the call option is a relevant design parameter in this setup. At one extreme, a strike price of zero would correspond to a mandatory forward contract between load serving entities and capacity providers, which would arguably interfere excessively with the risk management practices of stakeholders, who may not be willing to hedge their entire supply / demand in a mandatory forward arrangement. Moreover, the lower the value of the strike price K, the larger the value of the reliability option, which creates significant cash flows when the trading of these options becomes mandatory. On the other extreme, an excessively high strike price invalidates the call option, since the option is rarely if ever exercised, and essentially becomes void. The typical practice is to set the strike price at or slightly above the marginal cost of peaking units in the market, so that the cash flow captured by the call option corresponds to the scarcity rents that would be earned by capacity providers when the capacity of the peaking unit is exhausted. It is the intention of the capacity market to hedge these risky cash flows by bundling reliability options with the capacity that is traded in the capacity market.

2.5 Resource Adequacy Mechanisms in Europe

Figure 4 presents the status of European capacity mechanisms based on fairly recent information sourced from ACER [2], as well as recent analysis by ADMIE [38]. A broad classification of capacity mechanisms can be summarized as follows [38]:

- Tenders for new capacity provide are targeted to newly constructed resources. Examples of this mechanism include Bulgaria and Croatia.
- Strategic reserve refers to capacity which is kept out of the energy and balancing capacity markets, and is only triggered under conditions of high system stress (as indicated, for example, by high day-ahead prices). Such mechanisms are in place in Germany, Belgium, Sweden, and Finland. Note, however, that strategic reserves dampen the scarcity signals of the market [35].
- Targeted capacity payments correspond to fixed prices that are determined by a regulatory authority and target selected technology types or newly built capacity. Such mechanisms are put in place in Spain and Portugal.
- Central buyer capacity auctions are based on the procurement of a target quantity of capacity which is procured through an auction. The quantity of procured capacity is based on adequacy computations of the system operator. Such mechanisms are in place in Italy, the UK, Ireland, Poland, the ISO-NE, MISO, NYISO, and PJM.
- De-centralized capacity obligations function by placing an obligation to load serving entities for securing a certain fraction of total system capacity so as to cover the demand of loads. There is no central auction

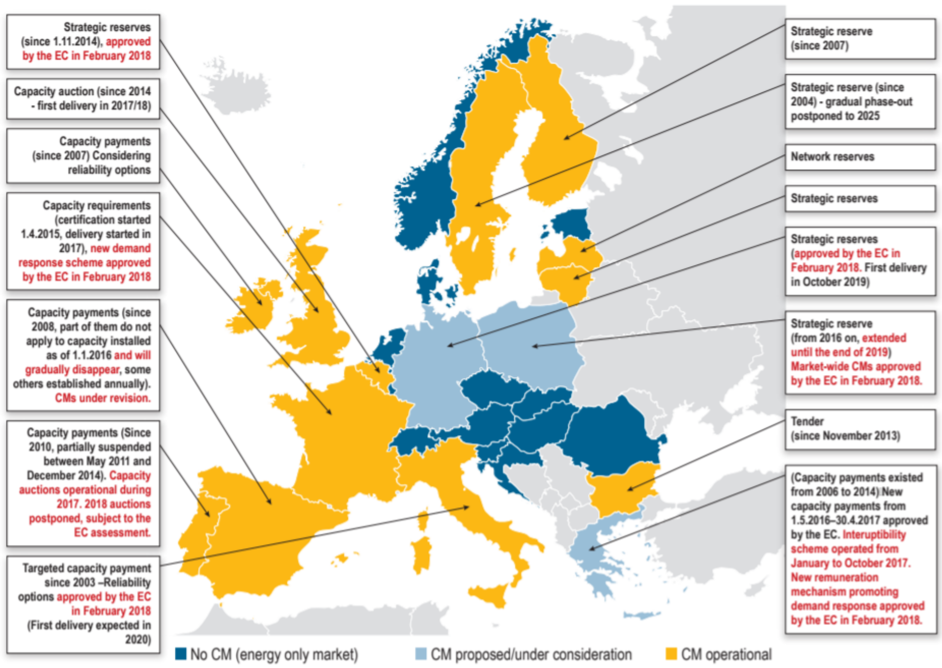

Figure 4: Capacity markets in Europe [2].

for the procurement of this capacity. Such mechanisms are put in place in France, Australia, CAISO, and SPP.

2.6 Resource Adequacy Mechanisms in the US

Since section 3 focuses on EU markets, we briefly summarize US capacity market designs at a high level in the present section. The information is sourced from [4].

Decentralized capacity mechanisms are implemented in the California ISO and the Southwest Power Pool. The New York ISO, PJM, ISO-New England, and Midcontinent ISO rely on centralized capacity mechanisms. The following information is extracted from [4] and summarizes a number of features of US resource adequacy mechanisms.

2.6.1 ERCOT

Procurement structure. ERCOT operates an energy-only market that primarily relies on scarcity pricing mechanisms.

Resource adequacy requirement. There is no explicit requirement. There exists a "target" reserve margin of 13.75%.

Time-line. This is not applicable in ERCOT, since there are no capacity auctions.

Price formation. ERCOT relies on an operating reserve demand curve adder and a reliability deployment adder. The adders depend on the Loss of Load Expectation and the value of lost load.

Market power mitigation. The system offer cap is set to 9000 $/MWh. There is a mechanism in place for reducing the offer cap if costs become excessive.

Resource obligations. Not applicable.

Performance incentives. This is not applicable in ERCOT, since there are no capacity auctions.

2.6.2 CAISO

Procurement structure. The CAISO applies a bilateral resource adequacy requirement, which can be met through bilateral contracts and self-supply.

Resource adequacy requirement. System requirements are set by load reserve obligations (most at a 15% reserve margin). Local and flexible requirements are determined by the ISO.

Time-line. There are yearly and monthly requirements.

Price formation. Backstop capacity is procured by the ISO via an auction, which is paid as bid.

Market power mitigation. The backstop procurement auction is subject to a soft offer cap.

Resource obligations. There are must-offer obligations which vary by capacity type but involve scheduling and bidding in the day-ahead and real-time markets.

Performance incentives. The performance incentives related to the resource adequacy obligations are average. An incentive mechanism assesses whether resources adhere to must-offer obligations. There are no established performance criteria.

2.6.3 SPP

Procurement structure. SPP implements a bilateral resource adequacy requirements. Procurement is organized through bilateral contracts and capacity can also be self-supplied.

Resource adequacy requirement. The planning reserve margin is set at 12%.

Time-line. The capacity procurement covers the peak summer season.

Price formation. There is no way to track the price formation due to the bilateral nature of the arrangements.

Market power mitigation. Market power mitigation cannot be applied to bilateral arrangements.

Resource obligations. Resource offer obligations cannot be applied to bilateral arrangements.

Performance incentives. There are no specific performance incentives implemented.

2.6.4 MISO

Procurement structure. There is a bilateral resource adequacy requirement put in place. Load serving entities may use bilateral contracts, or procure through a voluntary centralized Planning Resource Auction (PRA).

Resource adequacy requirement. There are system-wide and zonal requirements set, based on an LOLE study. The 2015 required reserve margin was set to 14.7%.

Time-line. There is an auction held immediately prior to the delivery year[3]. There is also a proposal for a 3-year forward auction for competitive retail states.

Price formation. There is currently a demand curve that is vertical at the resource adequacy requirement. There is furthermore a proposal for a sloped demand curve for competitive retail states.

Market power mitigation. Participants may self-schedule or submit 0$ offers in the planning resource auction. The offer cap is set at 2.7 times the zonal CONE.

Resource obligations. Awarded participants must offer their capacity in the day-ahead energy and reserve markets and the first post day-ahead residual unit commitment process every hour.

Performance incentives. Performance incentives are weak. MISO monitors must-offer obligations, however there is no formal incentive structure. Forced outages will reduce the capacity that is counted.

2.6.5 ISO-NE

Procurement structure. There is a centralized capacity market called the Forward Capacity Auctions (FCA).

Resource adequacy requirement. System and local requirements are set with an LOLE study.

Time-line. Auctions are held 3 years in advance, with additional auctions held annually and monthly.

Price formation. There is a sloped demand curve, which uses LOLE and CONE.

[3]Note that, despite the construction delay, the mere presence of the capacity mechanism contributes to a lower perceived risk by the investors.

Market power mitigation. There are minimum competitive offer prices. Any requests to exit from the mechanism are reviewed by market monitor (since they may induce a rise in the capacity prices of subsequent auctions).

Resource obligations. Resources must offer their capacity into the energy market and schedule their maintenance in agreement with the ISO.

Performance incentives. Performance incentives are strong. The new pay-for-performance design integrates performance into the capacity payment.

2.6.6 NY-ISO

Procurement structure. There is a centralized capacity market, called the Installed Capacity Auctions.

Resource adequacy requirement. System and local requirements are set with an LOLE study. The current reserve margin is roughly 17%.

Time-line. Auctions are held immediately prior to and during a 6-month capability period.

Price formation. There is a sloped demand curve, which depends on the capacity requirement and the CONE.

Market power mitigation. Market power tests determine when to impose offer floors and caps.

Resource obligations. Resources must schedule their resources, or bid them in the day-ahead market.

Performance incentives. Performance incentives are weak. There is no explicit performance mechanism, but forced outages reduce the capacity that is counted.

2.6.7 PJM

Procurement structure. There is a centralized capacity market, called the Reliability Pricing Model.

Resource adequacy requirement. There are system and local requirements, which are set with an LOLE study.

Time-line. The base auction takes place 3 years in advance. Incremental auctions are held up to the delivery year.

Price formation. A sloped demand curve is used, which is based on the system capacity requirement, the net-CONE, and demand reservation prices.

Market power mitigation. The minimum offer price is set at the net-CONE of the asset class.

Resource obligations. Awarded capacity must be offered into the day-ahead market.

Performance incentives. Performance incentives are strong. The new capacity performance product focuses on emergency events.

3. Cross-Comparison of EU Proposals

In this section we compare the different EU proposals along a number of relevant dimensions. The material in this section is a cross-sectional comparison among CRM proposals that have either been approved by the European Commission (Italy [21], UK [23], Ireland [20], France [18]), or will be subject to consideration in the immediate future (Belgium [16, 14]).

3.1 Why Have a Capacity Market?

The first axis of comparison aims at answering the question of why one should put in place a capacity market. This amounts to arguing that a market failure exists, and projecting a need for capacity. In the context of the EU state aid investigations, this also requires arguing that the Member State has taken steps towards addressing market failures before resorting to the CRM.

3.1.1 Italy

Identified need. Article 10 [21] explains that Italy is phasing out coal-fired power plants by 2025 and sets a target of covering 55% of its demand by renewable resources by 2030. The Italian LOLE target is 3 hours per year. The Italian TSO simulated three future years under various decommissioning assumptions, and using a two-step simulation that included an adequacy calculation (based on Monte Carlo simulation) as well as a market simulation. The simulations were verified by an independent auditor. The results show that in 2025 there could be an adequacy problem even in a base scenario with no closure of thermal plants.

Identified market failure. (i) Article 14 [21] makes reference to the public good character of reliability. (ii) Article 15 [21] makes reference to the inability of the market to coordinate transmission and generation investment, with the result that generation may be built in the wrong location. (iii) Article 16 [21] makes reference to a missing money problem, and mentions explicitly "the lack of sufficiently high prices during periods of scarcity". However, there is no explicit reference to price caps. Regarding the missing money problem, special emphasis is placed on the fact that the system will rely increasingly on renewables.

Measures in addition to CRM. (i) Article 18 [21] refers to the implementation of day-ahead market coupling. (ii) Italy has four intraday auctions, and is participating in the XBID project for cross-zonal intraday trading. (iii) There is a reform of the balancing market, which aims at more accurate imbalance pricing. (iv) Demand-side participation is being reinforced. In this respect, smart meters are also being rolled out. (v) Storage projects are underway. (vi) The internal network is being upgraded in order to avoid internal congestions. (vii) Interconnections with neighboring zones are being reinforced.

3.1.2 UK

Identified need. The LOLE target in the UK is three hours (article 90 of [23] and [31]). Figure 4 of [23] can be used for justifying the need for introduction of the measure. The idea is to calculate LOLE based on future demand projections and planned capacity installments. The study of LOLE in the UK case was performed by a number of organizations: (i) the UK department of Business, Energy and Industrial Strategy, (ii) National Grid (the UK TSO), (iii) the UK Department of Energy and Climate Change, (iv) Ofgem (the regulator). Article 93 [23] explains that there are assumptions about interconnector capacity that is coming online, and how it would be used in periods of peak demand.

Identified market failure. (i) Reliability is a public good, and therefore the optimal level of reliability cannot be expected to be delivered to consumers unless regulated. (ii) The missing money problem is related to shortcomings in the balancing mechanism[4] and the fact that hypothetically price caps could apply (although they are not present in the UK, see article 99 [23]). Related to the latter, there are concerns about market power mitigation in article 107 [23]. A third reason is reference in article 107 [23], related to hedging risk: reforms in cash-out prices are still risky compared to capacity payments.

Measures in addition to CRM. The UK argues that it has proceeded to the following actions: (i) Engaging demand response, e.g. through the installation of smart meters and time of use tariffs. (ii) Reform of imbalance settlement (referred to as "cash-out arrangements" in article 104 [23]). The

[4] "This is due to the fact that charges to generators who are out of balance in the balancing mechanism (cash-out) do not reflect the full cost of the balancing actions taken by the System Operator (such as voltage reduction)."

latter is achieved through a reserve scarcity pricing function, including a cost for disconnection and voltage reductions, and marginal pricing. (iii) Completing the internal energy market and increasing levels of interconnection.

3.1.3 France

Identified need. The inadequacy of the French system has been verified by studies performed by RTE (the French TSO), the Pentalateral Energy Forum, and ENTSO-E. RTE considered various scenarios for assessing adequacy: one in which all existing plants are maintained in operation (high thermal) and a low thermal scenario in which a number of thermal plants are closed down. Different weather scenarios were considered. The French LOLE target is three hours per year (article 106 of [18]).

Identified market failure. In article 101 [18], France argues explicitly that "Contrary to what the Commission appears to suggest, the French capacity mechanism was not designed to address any missing money problems". This however seems at odds with article 227 [18], which mentions that RTE estimates that there is a missing money problem. There is a reference in article 46 [18] to unpredictable peak demand due to the thermosensitivity of French electricity consumption. There is no explicit reference to price caps.

Measures in addition to CRM. Article 102 [18] explains that France is putting in place interconnection projects, reviews of tariffs that better reflect scarcity, and the development of demand-side response (including installations of meters).

3.1.4 Ireland

Identified need. The Irish and Northern Irish TSOs conducted adequacy assessments for 2017, 2020 and 2023. A follow-up study accounted for ancillary services incomes and was expanded to an annual analysis. The finding was that the reliability standard of 8 hours of LOLE could not be met in most of the years. The simulations account for the price cap of 3000 €/MWh. Figure 2 of [20] explains the simulated procedure, which combines a market simulation for determining which units are economically viable followed by an adequacy simulation which accounts only for the units that are indeed viable. The lack of adequacy is confirmed by a follow-up analysis with a higher price cap equal to the VOLL, which is 11000 €/MWh.

Identified market failure. (i) Article 15 of [20] refers to the missing money problem. (ii) The article also argues in terms of the public good nature of reliability. (iii) Article 16 [20] makes an additional interesting point which is the "bulkiness" of the investment: since the system is small in size, introducing a new flexible CCGT plant could represent a significant portion of the system fleet and could depress scarcity prices.

Measures in addition to CRM. The Irish market is highly concentrated. Nevertheless, in order to mitigate market power, dominant generators are obligated to offer "directed contracts" (article 13 [20]). Moreover, restrictions on generator offers are lifted, and the price cap is raised to the estimate of VOLL, equal to 11000 €/MWh. An administrative scarcity pricing function is introduced. Limitations are lifted in balancing market bids.

3.1.5 Belgium

Identified need. This issue is not discussed in the Belgian proposal.

Identified market failure. This issue is not discussed in the Belgian proposal.

Measures in addition to CRM. This issue is not discussed in the Belgian proposal.

3.2 How the CRM Works

A capacity remuneration mechanism is a set of institutions that extends well beyond the auction itself, but also aims at putting in place appropriate risk management mechanisms. In this section we describe the CRM that has been put in place in each Member State.

3.2.1 Italy

Mechanism overview. The Italian CRM is based on the auctioning of reliability options. The target quantity of reliability options is determined by the TSO, and corresponds to the target capacity that the system should carry. Awarded capacities are paid the value of the reliability options. They are then financially liable for the settlement of the reliability options. The auction is financed by charging retailers the difference between the capacity premium and the proceeds collected by the reliability options. Retailers are charged based on their contribution to peak load.

Shape of the demand curve. The demand curve used in the Italian CRM is presented in figure 5. The demand curve is designed using four points. The price of point A in the figure is the upper estimate of the cost of new entry of an OCGT unit (estimated for an OCGT at 75,000 - 95,000 €/MW-y). The capacity of point D in the figure is the capacity level that attains a zero LOLE (based on simulation). Point C corresponds to a price equal to the cost of new entry of an OCGT (lower estimate, approximately 50,000 - 70,000 €/MW-y) and a capacity target that ensures the LOLE target. The precise definition of point B is not provided (the price level is unambiguous, but the quantity level is not specified unambiguously in article 54 of [21]). Note that a different demand curve is used for each zone of the Italian system. The cost of new entry can be adjusted in future auctions.

3.2.2 UK

Mechanism overview. The UK conducts a centralized capacity auction. This has been in place since 2014.

Shape of the demand curve. The shape of the demand curve is presented in the middle panel of figure 5 of the present document. The curve, as in the Italian case, is defined by four points. Point A is based on a price cap which is intended to prevent the exercise of market power in the capacity market, with the appropriate price cap considered at 75 BP/kW. The quantity of point B corresponds to 95% of the target capacity. Point C corresponds to a price equal to the cost of new entry and the target capacity. Point D corresponds to a quantity which is equal to 105% the target system capacity.

3.2.3 Ireland

Mechanism overview. The Irish market implements a central buyer capacity mechanism based on reliability options. The design is largely similar to that of the Italian market. The mechanism was planned to be launched in 2018 for delivery of capacity effective 2022.

Shape of the demand curve. The Irish demand curve is depicted in the third panel of figure 5 of the present document. The demand curve is characterized by four points. The first is at a price of 150% of the cost of new entry. The second point is at the same price and at a quantity equal to 100% of the target quantity. The third point is at the same quantity but drops to 100% of the cost of new entry. The fourth point is at a price of zero and at 115% of the target capacity.

3.2.4 France

Mechanism overview. France relies on a decentralized capacity mechanism. Suppliers, large consumers and the system operator are required to furnish capacity guarantees in proportion to their contribution to system peak demand. Capacity guarantees are traded in a decentralized market. Capacity guarantees are issued by the system operator to owners of generation assets or demand response resources in proportion to their ability to contribute to peak system load. Certification commenced in 2015 for delivery in 2017, which is the first year when the measure applies. The decentralized nature of the mechanism resembles the decentralized capacity mechanisms that have been put in place in the California ISO and the Southwest Power Pool [4].

Shape of the demand curve. There is no demand curve described in the proposal for the French CRM.

3.2.5 Belgium

Mechanism overview. The Belgian auctions are planned to commence in October 2021 with first delivery of capacity planned for November 2025. The intention is to combine a capacity auction with reliability options.

Shape of the demand curve. The Belgian demand curve has yet to be determined. There are three points which seem to matter in the shape of the curve: (i) the minimum quantity which should be procured at a price cap, (ii) the quantity at which the target reliability is achieved, and (iii) the maximum quantity that could be procured. The shape of the demand curve may differ among Y-1 and Y-4 auctions. A minimum quantity shall be reserved for the Y-1 auction.

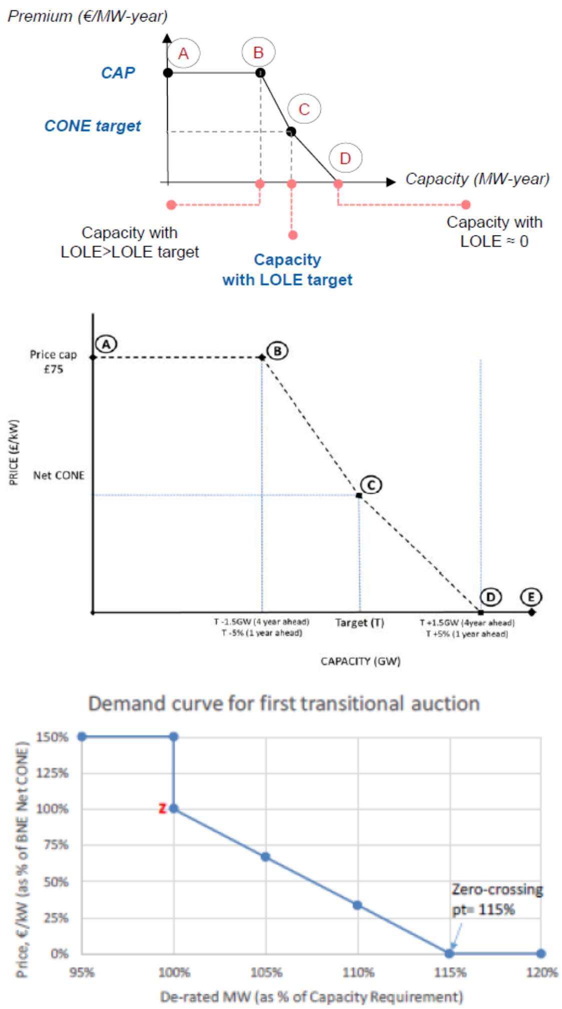

Figure 5: From top to bottom: Italian, UK and Irish demand curve.

3.3 Concerned Market Parties

In this section we discuss which market parties are affected by the mechanism. We also discuss special provisions that are foreseen for interconnectors and demand response participation.

3.3.1 Italy

General eligibility. Participation is voluntary. All existing and new capacity in the Italian system can participate, including demand response and storage. Refurbished capacity qualifies as new capacity. For planned capacity, it is necessary to furnish detailed plans of plant construction.

Ineligible resources. Resources that are benefiting from other support schemes should relinquish them in order to be eligible for participation in the CRM.

Treatment of interconnectors. The participation of cross-border capacity is pending on the implementation of cross-border balancing agreements.

Demand response. There is a simplified treatment of settlements for demand response providers. Demand response is liable for non-performance fees, like all other capacity providers. The TSO is entitled to disconnect demand response directly in case it does not follow dispatch instructions during scarcity periods.

3.3.2 UK

General eligibility. The UK allows existing and new generation capacity, interconnectors, storage and demand response to participate in the capacity auction. Resources need to exceed 2 MW to be eligible, and should be equipped with half-hour metering capability. Participation in the auction is not mandatory. For planned capacity, it is necessary to furnish detailed construction plans, as well as details of their expected capital expenditure. If plants opt out of the mechanism, or are not eligible due to other schemes, they contribute towards reducing the target capacity that would need to be bought in the capacity auction in order to deliver the target LOLE.

Ineligible resources. Resources that are already receiving support cannot participate. These include renewable resources, low-carbon technologies, experimental technologies such as tidal technology and so on.

Treatment of interconnectors. Imports through interconnectors (existing and new) are counted with a derating factor. The derating factor depends on an estimate of the reliability of the interconnector as well as the likely flows in periods of system stress.

Treatment of demand response. Demand response is allowed to participate in intermediate auctions before the main auctions, in order to stimulate investment in demand response resources.

3.3.3 Ireland

General eligibility. Eligible resources including renewable supplies, interconnectors, demand response, existing and new capacity, and storage. Conventional generation is required to participate in the CRM, whereas renewable resources are not.

Ineligible resources. There is no minimum bid size. Renewable Obligation Certificate holders cannot participate in the capacity auction.

Treatment of interconnectors. Interconnectors can directly participate in the auction. Generators located outside Ireland cannot participate directly.

Treatment of demand response. A percentage of capacity of the short-term auctions (one year ahead) is reserved for demand response providers, since it is more challenging for them to contract with consumers four years in advance. Bidding restrictions apply to demand response, although price caps do not. The derating of demand response providers is more flexible, i.e. they may be able to offer larger quantities in the auction. Demand response providers are not liable for reliability option difference payments.

3.3.4 France

General eligibility. Existing capacity, future capacity, and demand response can participate in the mechanism. Resources need to be certified by the TSO. Existing generation capacity must be certified three years in advance of delivery. Planned generation may be certified up to two months before delivery. Demand response may be certified up to two months before delivery. Participation in the mechanism is optional.

Ineligible resources. Certificates are only issued for capacity increments above 0.1 MW.

Treatment of interconnectors. Foreign capacity is not eligible to participate, see article 58 [18]. An amendment has been considered following stakeholder feedback where each border can issue interconnection tickets to foreign resources in an amount that corresponds to the capacity of the interconnector. These interconnection tickets can be auctioned off to foreign capacity providers, who can then sell their capacity certificates to the decentralized mechanism. Nevertheless, selling capacity to the French market does not preclude these resources from selling capacity to other markets.

Treatment of demand response. Demand response is eligible for participating in the mechanism. There is a different treatment between implicit and explicit demand response, which is discussed in article 15 and article 61 of [18], among others. Implicit demand response is delivered on the load serving entity side (by not consuming in peak periods) whereas explicit demand response is delivered on the capacity provider side (by registering demand response as a capacity provider which is eligible for certificates).

3.3.5 Belgium

General eligibility. Resources that are eligible include thermal units, aggregations, demand response, and foreign resources via interconnectors. There will exist a minimum power level that resources will need to exceed in order to be eligible, though this has yet to be determined. Each type of resource will have an associated availability factor, which will be estimated by the TSO for thermal resources based on historical forced outage rates, and for energy-limited resources it will be determined on the basis of how many hours of response the energy-limited resources commit to. If plants opt out of the mechanism, they may or may not be assumed to be available during scarcity periods, depending on whether or not they furnish closure notifications. By default, resources are not assumed to be opting out, and would need to opt out in the so-called prequalification procedure of the CRM.

Ineligible resources. It has yet to be determined if resources that are benefiting from other types of support will also be eligible to participate in the CRM.

Treatment of interconnectors. Neighboring capacities from the Netherlands, France, Germany and the UK will be allowed to participate in the Belgian CRM.

Demand response. There is no specific discussion about particular arrangements regarding demand response resources.

3.4 Auction Rules

This section discusses the rules and designs of the capacity auction in particular.

3.4.1 Italy

Auction format. A descending clock auction is conducted which consists of 21 rounds. At each round the same total capacity should be submitted, though the price can be reduced from one round to the next. Winning bids are paid a uniform clearing price.

Auction frequency. There are main auctions followed by secondary auctions. Secondary trading, based on a continuous trading mechanism, is allowed up to one month before delivery, but only for capacity within the same bidding zone.

Price cap. The price cap is dictated by an upper estimate of the CONE of OCGT, in the range of 90,000 €/MWy. In the first auctions with a very short lead time, existing capacity will not receive a price set by new capacity, if it is new capacity setting the price. The concern here is for owners of existing capacity who would bid new capacity without actually planning to build it, see article 79 [21].

Offer caps. Existing capacity will be capped at 25,000 - 45,000 €/MWy, which is the estimate of the Italian authorities for annual fixed operating costs of CCGT units. Caps for new capacity are at the estimate of the CONE, which amounts to 75,000 - 95,000 €/MWy.

Transmission constraints. The auction accounts for transmission constraints, and essentially produces a different capacity price for each Italian zone, similar to the day-ahead market.

3.4.2 UK

Auction format. The UK conducts a descending clock auction. Starting from a high initial price value, participants are asked to state how much capacity they are willing to supply at said price. The price is decreased following a regular schedule, until the auction discovers the lowest price at which demand equals supply. Winning bidders are paid a uniform clearing price.

Auction frequency. There is a four-year-ahead auction followed by a year-ahead auction. Demand may drop in between the two auctions, however. Capacity agreements can be traded in secondary markets.

Price cap. The UK market applies a price cap in its auction. As mentioned in article 50 of the UK proposal [23], the purpose of a price cap is to protect British consumers from abuse of market power by participants.

Offer caps. Article 63 [23] explains that bidders are classified between price makers and price takers. Price takers correspond essentially to existing capacity, while price makers correspond to capacity that has yet to be built. Price takers are not allowed to bid above a certain threshold, since they are not expected to incur building costs for rolling out new capacity. This threshold was set by the UK government to what they estimated as half of the cost of new entry, namely an overnight cost[5] of 25 GBP/kW. Exceptions to this rule are allowed for in article 64 [23], where certain high-cost existing capacities may furnish evidence of why they should be exempt from price-taker restrictions.

Transmission constraints. No specific provisions are foreseen for handling internal congestion.

3.4.3 Ireland

Auction format. The auctions are conducted as sealed-bid combinatorial auctions with a uniform clearing price. Exclusive bids apply, meaning that bids coming from a single resource are mutually exclusive.

[5]We use the assumptions of page 30 of [5] to convert this to a levelized cost. Concretely, assuming a WACC of 8%, a currency rate of 1.11 GBP/€, and an investment lifetime of 20 years, we use the following annual discounting formula for converting overnight cost OC to levelized cost $FC = (r \cdot OC)/(1-1/(1+r)^T)$, which implies $FC = 2,800$ €/MW-y.

Auction frequency. There are year-ahead and four-year ahead auctions held every year.

Price cap. The price cap is set equal to 150% of the CONE.

Offer caps. Existing capacity providers cannot bid above 50% of the CONE. Entities that wish to be exempt from the offer cap may submit an application to the regulatory authority. Demand response and new capacity are only subject to a bid cap of 150% of CONE.

Transmission constraints. Locational aspects matter. Although transmission constraints are not represented in the market clearing model per se, resources that are located in favorable parts of the system will be accepted at their bid price, even if out of the money, without being counted towards contributing to the capacity target of the TSO. This may result in the procurement of excess capacity above the reliability target of the TSO.

3.4.4 France

Auction format. There is no centralized auction foreseen in the mechanism.

Auction frequency. The decentralized market operates on a continuous basis until delivery. Trades can take place over the counter or in organized exchanges.

Price cap. There is an implicit price cap of 40,000 €/MW implied by the fact that this value is an upper limit on the imbalance settlement value of load serving entities.

Offer caps. There are no specific offer caps foreseen in the decentralized trading of certificates. It is mentioned that suppliers who expect to have an oversupply of certificates should make them available in the market, though it is not clarified how this is enforced.

Transmission constraints. Internal congestion in the French grid is not discussed in the description of the CRM.

3.4.5 Belgium

Auction format. A sealed-bid auction will take place. The first two Y-4 auctions will be paid as bid, and the subsequent ones will be based on uniform pricing.

Auction frequency. There are year-ahead and four-year-ahead auctions taking place. Auctions will take place annually, effective October 1 2021 at the latest, and will conclude with the publication of the auction results on October 31 [14]. There will exist a secondary market, where capacity providers will be able to adjust their positions.

Price cap. There will be a price cap that will apply on all capacity categories, as well as a separate price cap that will apply for yearly contracts.

Offer caps. As in the case of price caps, offer caps will also apply globally (regardless of the length of the contract) as well as to capacities that seek annual contracts.

Transmission constraints. It is mentioned that grid constraints will be accounted for in the auction. These constraints correspond to power flow constraints, short-circuit current limitations, and spacing limitations, among others [14]. These constraints will be accounted for by applying combinatorial constraints on certain groups of offers in the CRM (in the spirit of mutually exclusive offers). It is not clarified how meshed networks are accounted for insofar as power flow constraints are concerned.

3.5 Delivery

The benefits enjoyed by a capacity remuneration mechanism are accompanied by corresponding delivery obligations. This section outlines the procedures that each country has put in place for monitoring delivery.

3.5.1 Italy

Delivery requirement. Capacity providers are expected to keep their availability above a certain ratio (e.g. 80%) for at least a certain fraction of a month (e.g. 75%). Failure to do so results in temporary suspension of capacity payments. If this non-delivery is systematic (e.g. three months in a row) the capacity payments of the last three months are returned to the

TSO, and the capacity rights of the capacity provider are seized and made available to the adjustment or secondary market.

Testing. No specific testing provisions are foreseen, although every technology has an associated availability factor.

3.5.2 UK

Delivery requirement. Resources that benefit from capacity payments are expected to produce power during periods of system stress. Such periods of system stress are indicated by "capacity market warnings". These warnings are issued at least four hours in advance. The delivery requirement is load following. This implies that, if the system requires 70% of the total capacity in order to cover demand, then capacity providers are only responsible for delivering 70% of their capacity agreement. Non-delivery penalties apply for resources that are not able to deliver. Penalties are payable on the month of non-performance.

Testing. Testing of generator availability may take place out of system stress periods. The motivation is to assess unit availability even during years where the system does not experience stress.

3.5.3 Ireland

Delivery requirement. Each technology has an associated availability factor, which is accounted for in the capacity auction. The availability factor is significantly lower for renewable resources. A secondary market exists for the reliability options. Delivery obligations are load following, meaning that they are adjusted pro rata to the demand in the system in periods of scarcity (e.g. during summer months when demand may be low but certain units may be on planned maintenance).

Testing. There is a pre-qualification procedure involved, in order to determine credible suppliers.

3.5.4 France

Delivery requirement. There are hours of peak-period consumption determined each year, based on day-ahead forecasts of the conditions of the following day. There is a distinction in the proposal between peak periods PP1 and PP2. These peak-period consumption days are announced by 10:30am the day before.

Testing. Random tests can be performed by the system operator, without notifying capacity owners in advance. No more than three tests can be performed per delivery period. Different renewable resources are characterized by different availability factors, see article 108 [18].

3.5.5 Belgium

Delivery requirement. Resources that have been cleared in the capacity auction will be monitored for timely delivery of their capacity. If they fail to make their capacity available on time, they will receive penalties in three forms: (i) penalty payments, (ii) reductions in the volume of their contracted capacities, and (iii) reductions in the duration of their contracts. Capacity providers will be subject to availability penalties if they fail to deliver during scarcity periods. The penalty applies to the difference between committed capacity and actually available capacity. Availability tests are triggered by so-called Availability Monitoring Triggers (AMT). These may correspond, for example, to the reference price (day-ahead price) exceeding a certain threshold.

Testing. Resources will be subject to random testing.

3.6 Payment Flows

3.6.1 Italy

Payments to capacity providers. Capacity providers receive the auction premiums.

Payments from capacity providers. Awarded capacities settle a reliability option by paying the difference between a reference price (defined as a function of the day-ahead and balancing price, see table 3 of [21]) and the strike price of the reliability option. The strike price is set at 125 €/MWh, which is the marginal cost of a peaking OCGT unit. For foreign capacities, the reference price is equal to the day-ahead price, due to the absence (for the moment) of cross-border balancing. The payback obligation is load-following: if a fraction of the capacity is needed in a scarcity period, capacity providers are only liable for a fraction of the payback.

Payments from load serving entities. Retailers are charged the difference between the capacity premium and the proceeds collected by the reliability options, in proportion to their contribution to peak load.

Length of agreement. In the initial auctions, existing capacity receives contracts of 1 year, while new capacity is contracted for 15 years. In the auctions of the full implementation phase, existing capacity is contracted for a delivery period of 3 years, and new capacity for a period of 15 years. Adjustment auctions are for a delivery period of 1 year.

3.6.2 UK

Payments to capacity providers. Capacity providers receive monthly payments that equal their capacity obligations times the price determined at the capacity auction. Payments are not uniform every month, but rather are profiled according to system demand, with capacity providers receiving higher payments during months with higher demand (i.e. during the winter).

Payments from capacity providers. No payments from capacity providers are foreseen, apart from non-delivery penalties.

Payments from load serving entities. Suppliers are charged based on their contribution to demand on winter weekdays between 4pm and 7pm, which coincides with peak demand in the system.

Length of agreements. The length of the agreements varies. The default length is one year, although for new investments it can extend up to 15 years. This has raised challenges for discriminatory treatment by various market parties, see for example article 117 [23].

3.6.3 Ireland

Payments to capacity providers. Capacity providers receive payments from the capacity mechanism.

Payments from capacity providers. Capacity providers are liable for settling the reliability options at the difference of the market price and a predetermined strike price.

Payments from load serving entities. Load serving entities are responsible for financing the mechanism, and are relieved from the part of the capacity auction which is covered by the reliability option payments. Load serving entities are responsible for financing the mechanism in proportion to their contribution to system demand in periods of stress.

Length of agreements. New capacity can acquire ten-year contracts, whereas existing capacity can only contract up to one year. Ten-year contracts require proof that at least a certain amount of funds will be invested.

3.6.4 France

Payments to capacity providers. Capacity providers earn payments from trading their capacity certificates, which are automatically granted to them after certification by RTE, with load serving entities which are required to procure these certificates.

Payments from capacity providers. No other payments are foreseen from capacity providers. It is not clear that the CRM application [18] explains what specific penalties would be foreseen in case of non-delivery by capacity providers.

Payments from load serving entities. Load serving entities are financially liable for imbalances in the possession of capacity certificates. Their responsibility for capacity certificates is proportional to their real-time metered contribution to system peak load, while the possession of capacity certificates is tracked by a registry that is updated by the TSO. Imbalances are settled at an imbalance price which varies, depending on whether the period in question exhibited scarcity or not.

Length of agreements. The capacity certificates are valid for one year.

3.6.5 Belgium

Payments to capacity providers. Capacity providers are entitled to a capacity payment which is determined by the price of the capacity auction.

Payments from capacity providers. Since capacity providers sell reliability options, they are liable for payments of the reference price minus the reliability option strike price, whenever the former exceeds the latter.

The appropriate reference price is considered by the Belgian TSO to be the day-ahead price. Capacity provides are also subject to penalties if they fail to deliver during scarcity periods.

Payments from load serving entities. The proposal does not identify who will finance the CRM.

Length of agreement. Contracts are by default offered for 1 year. For new entrants and certain other categories of technologies, longer contracts may be offered (1, 3, 8, or 15 years), however these longer contracts must be accompanied by a minimum level of investment that needs to be determined by the regulatory authority.

4. Capacity Auction Rules and Designs

The predominant auction formats that have been used in capacity mechanisms are simultaneous sealed-bid auctions and descending clock auctions. We summarize certain main results for each, as well as the existing state of play in terms of the utilization of these auction formats in practice.

Given the auction formats that have been adopted in practice, the relevant question becomes why one might prefer descending clock auctions relative to single-round sealed bid auctions. Ascending auctions (for sell of spectrum rights) have been used broadly in order to deal with complementarities of auctioned products that emerge frequently in frequency auctions [30]. In the case of power, complementarity seems to be less relevant. Clock auctions have been proposed in order to accelerate the convergence of descending auctions [30], but again this seems relevant in the case where complementarities matter. Empirical evidence [13] suggests that clock auctions offer opportunities for the exercise of market power, which led Colombia and ISO-New England to proposed moving away from clock auctions to sealed-bid auctions, see section 4.3.

4.1 Simultaneous Sealed-Bid Auctions

In a simultaneous sealed-bid auction, bidders submit a non-decreasing supply function which maps their asking price to increments of power. Although practical implementations of these auctions can involve more general specifications, we discuss here certain stylized results that are relevant for the basic setting of continuous inelastic demand.

Milgrom [30] reports a variety of interesting results regarding such auctions, but one which is worth pointing out relates to high-price equilibria. Concretely, it is shown that in a simultaneous sealed-bid auction with infinitely divisible goods and an inelastic demand, there exists a symmetric equilibrium which leads to a price that is equal to the ceiling of the auction.

We replicate the argument of [30], but rather on the supply side instead of the demand side. Concretely, we consider N symmetric suppliers with a true cost function that can be described as $C(q) = q + q^2$. We consider a market with unit demand. If all agents would bid truthfully an increasing supply function of $1 + 2q$, the market clearing price would be at the level where the output from each agent is equal, namely equal to $1 + 2/N$. As the number of agents becomes large, the price converges to 1.

Suppose that an agent considers that its competitors will all bid an intercept a and a slope b in the auction. Then the agent can adapt its own slope and intercept to achieve its target quantity. Assuming that the market will clear at the level of inelastic demand (1 unit), the market price as a function of the quantity that the agent will want to supply is expressed as $a + b \cdot (1 - q)/(N - 1)$, since when the agent in question supplies q, then its competitors are left with a quantity of $q/(N - 1)$ each in a symmetric equilibrium. This implies that the payoff of the agent in question can be expressed as

$$(a + b \cdot \frac{1-q}{N-1}) \cdot q - (q + q^2)$$

The first-order optimality conditions can be expressed as:

$$(a + b \cdot \frac{1-q}{N-1}) - \frac{b}{N-1} \cdot q - 1 - 2 \cdot q = 0$$

In a symmetric equilibrium, $q = 1/N$. Evaluating the above expression at this quantity fixes one equality that needs to be satisfied in equilibrium:

$$a + \frac{b}{N} - \frac{b}{N \cdot (N-1)} - 1 - \frac{2}{N} = 0$$

Assuming agents will bid their supply function $a + b \cdot q$ so as to lift the price to its ceiling R at $q = 1/N$, we can obtain the following condition for an equilibrium which results in the price ceiling R:

$$R = a + b/N$$

These two conditions result in the following values for the bid parameters:

$$a = R - (N-1) \cdot (R - 1 - \frac{2}{N})$$
$$b = N \cdot (N-1) \cdot (R - 1 - \frac{2}{N})$$

This result is reminiscent of hockey stick bidding in the Texas market [27]. The idea of hockey-stick bidding was for bidders to exploit uniform price auctions in energy by "sacrificing" their last increment of generation capacity at a very high bid price. In periods when the market price would exceed the true marginal cost of this increment but there would still be adequate capacity to serve demand, this incremental capacity would be out of the money even though it could have generated a profit. But in certain periods of scarcity, this increment would be pivotal. Even if this would occur infrequently, in such conditions the increment would set the clearing price, and generate infra-marginal rents for all lower increments which would make it worth sacrificing this increment in periods that did not correspond to scarcity.

4.2 Descending Clock Auctions

Descending clock auctions follow a predetermined decreasing price schedule. For every announced price, bidders submit a certain amount of capacity that they are willing to sell. As long as the offered capacity exceeds the demanded capacity, the price continues decreasing, until supply matches demand, at which point the auction pays a uniform price to all winning bids.

The results provided by Milgrom regarding simultaneous ascending auctions are summarized in section 7.2 of [30]. The main intuition of these results is discussed here.

Firstly, it is important to distinguish ascending auctions from clock auctions. Both include rounds of bidding. The idea, in the case of selling an item[6], is to allow bidders to increment their offers. In certain formats (e.g. charities) the auction ends after a predetermined number of rounds. However, since the setting of predetermined rounds can be gamed (by waiting until the end of the auction to snipe[7] the sold items), in other formats (such as US auctions for spectrum) there are activity rules: (i) at the end of the auction bidders can react to the last submitted bid, and (ii) bidders cannot increase their bid for a certain product from one round to the next. In ascending auctions without a fixed number of rounds, the auction ends when no new offers are submitted for any items.

It is important to point out that ascending auctions are typically used for auctioning away multiple items (e.g. multiple frequency ranges in radio spectra). In such a setting, the interest in the multiple rounds of the auction is that it reveals to bidders how prices for bundles of items evolve, so that they may adapt their strategy accordingly. The items that are being auctioned off may typically be complements or substitutes. The rules that have been proposed for ascending auctions are better suited for selling away complements. The intuition of the results provided by Milgrom [30] relies on the definition of a "straightforward" bidding strategy. Under such a strategy, at every round of the auction, a bidder updates its bid for items for which it is not the highest bidder by submitting an offer at the lowest possible value, i.e. the standing high bid for the item plus a percentage which is defined as part of the definition of the ascending auction rules. Milgrom [30] provides results about hte existence of competitive equilibria and demonstrates that

[6] We will refer to ascending auctions in the context where an auctioneer sells an item to buyers, and descending auctions in the context where an auctioneer buys an item from sellers.

[7] Sniping refers to the practice of waiting until the end of the auction before submitting a bid which is as low as possible for buying an item, so that competitors do not have time to react to the offer.

straightforward bidding can achieve such equilibria when the items being auctioned off are substitutes. The problem with auctioning off complements is that this strategy is not guaranteed to be optimal for bidders as the auction evolves. Intuitively, the important property of substitutes is that if the price of one item increases, then an agent should increase its bid for a substitute item. In fact, in the case of complements, it can be shown that a competitive equilibrium may not even exist. These issues are clearly less relevant in the context of capacity auctions, where it is commonly the case that multiple items of a homogeneous good (capacity) are being auctioned off.

The motivation for clock auctions with uniform prices for homogeneous goods (which is the case fo capacity auctions) is to accelerate the auction, since in principle a simultaneous auction can require an excessive number of rounds until completion.

The aforementioned results are specific to a fixed inelastic supply. The introduction of price elasticity on the supply side (or an elastic demand curve in the case of capacity auctions) moderates market power. In the case of symmetrical agents, Milgrom [30] proves that an elastic supply side can result in non-zero equilibrium prices that are no greater than the Cournot prices, with Cournot prices being one possible equilibrium. In the limit where multiple agents are participating in the auction, the Cournot prices converge to competitive prices, thus the elasticity of supply serves towards steering the auction to a competitive outcome.

4.3 International Practices

International practices can broadly be classified as follows:

- Sealed bid auctions are used in Ireland, PJM, MISO, NYISO, and in Alberta, Canada [14].
- Multi-round descending clock auctions are used in the UK [31], Italy, Poland, New England and Colombia.

The Belgian TSO [14] claims that single-round sealed bid auctions are less susceptible to gaming. Interestingly, the aforementioned report cites ISO-New England and Colombia as cases in point, whereby the design evolved from descending clock auctions to single-round sealed bid auctions due to market power abuse. We summarize observations related to market power abuse in these two markets, and subsequently comment on the view of the Belgian TSO on the design of the Belgian CRM which is proposed for implementation by October 2021 [14].

4.3.1 ISO-NE

The Belgian TSO provides the following information about the transition of ISO-NE from descending clock auctions to sealed bid auctions in their Forward Capacity Auctions (FCA):

"*In FCA 9, the descending clock auction format would have provided information of strategic value to any bidder that was interested in setting a higher clearing price at the interface. Specifically, at the end of Round 3, participants were informed that the System-wide region had cleared at a price of $9.55/kW-month and that 1,154 MW was still competing at the New York AC Ties interface (equal to 1,054 MW). In this situation, any supplier would know that withdrawing 100 MW would stop the clearing price from falling further. Not surprisingly, 100 MW was withdrawn moments after Round 4 started at a price of $8.00/kW-month, setting a clearing price of $7.97/kW-month.*"

"*The descending clock auction format is sometimes touted over sealed bid formats because it provides auction participants with information about the value of a good. However, in the FCA, sellers do not receive any information that may be useful in establishing a competitive offer. Instead, the information learned through the auction process is primarily useful in determining when to leave the auction in order to set the highest price and receive the highest capacity revenue possible.*"

4.3.2 Colombia

The Belgian TSO provides the following information about the transition of the Colombian reliability auctions from descending clock auctions to sealed bid auctions [14]:

"*The CREG [Colombian Commission for the Regulation of Energy and Gas] has now held two capacity auctions using the descending clock auction format: the first in May 2008 and the second in December 2011. The 2008 auction ended early at the first point at which a large bidder could see that it had become pivotal and able to withdraw one of its offers to set a high capacity price. To avoid this happening again, in 2011 the CREG adopted measures to make this strategy harder by reducing the amount of information on demand and supply revealed to bidders during the auction. This was not sufficient, however, and the auctioneers abandoned the auction after the initial two rounds and effectively held a sealed-bid auction in its place. They subsequently recommended changing the auction format to a combinatorial clock auction followed by a sealed-bid stage to reduce the risk of this being* *repeated in the future"*."

4.3.3 Belgium

Insofar as the Belgian design is concerned, ELIA argues that the descending clock auction creates manipulation opportunities, without any advantages [14]. The Belgian design therefore seems to be converging towards a single-round auction.

The Belgian TSO aims at implementing a pay-as-bid remuneration for the first two years of the capacity auctions, and to then transition to a uniform price auction. The rationale is twofold: the goal of the initial pay-as-bid settlement is to limit infra-marginal rents for existing capacities, which will be competing with new entrants, while the transition to uniform pricing is driven by the fact that after a number of auction rounds the market participants will better develop an ability to predict the clearing price, and will tend to bid close to this price.

After the conclusion of each auction, the following information will be published: information related to total bid volume, total opt out volume, total cleared volume, and clearing price. Details about the granularity of this information are provided in section 6 of [14].

5. Illustration of the Designs on a Simplified Model of the Greek Market

In this section we illustrate the functioning of the different designs on a simplified representation of the Greek electricity market. We commence with a description of the model settings, and consider a short-term and long-term optimal capacity expansion scenario. We then describe the workings of a capacity auction under each of these scenarios, where the distinguishing feature of the long-term scenario is the entry of more new capacity. We clarify at the outset that due to the scope of the present study and lack of data, the goal of this section is not to represent a realistic analysis of the Greek electricity market. Instead, the intention is to describe the basic principles of the functioning of a capacity auction on a toy example that is inspired by the Greek capacity mix.

5.1 Model Settings

Supply side. We use the information in [5] for determining the system technologies and their installed capacity. Concretely, we consider 2250 MW of CCGT gas plants owned by IPPs, 1850 MW of CCGT plants operated by PPC, 1250 MW of open cycle gas and oil plants (which are maintained mainly as cold reserves), 4300 MW of lignite plants and 3020 MW of hydro plants. This amounts to a total of 12760 MW of dispatchable capacity. It is mentioned in [5] that "*the sum of reliable dispatchable capacity defined by taking into consideration outage probabilities (UCAP definitions according to the Grid Code) amounts to 10280 MW*". We translate this to an availability factor of 80.6% for each dispatchable technology. We assume an availability factor of 25% for RES-Trade.

The following variable costs are based on table 1 and table 5 of [5]. The fixed and capital costs used in the figure are based on table 5 of [5] as well as footnote 24 of [21]. We consider the "average price" values in the table as indicators of variable cost.

Note that the CCGT IPP technology is dominated in terms of both investment cost and variable cost by CCGT PPC.

Hydro generators can store water. We ignore this in our simplified model, and rather assume that they behave as resources with a marginal cost of 79.4 €/MWh, which is the historically observed price when hydro has been marginal in 2013. Although this value may to some extent be driven by strategic behavior [5], we simplify our analysis by fixing this value.

The supply side parameters are summarized in tables 1 and 2. Note

Table 1: The maintenance and investment costs assumed in the model. All values are in €/MWy.

Technology	Maint. cost (€/MWy)	Inv. cost (€/MWy)
Lignite	30,000	128,705
CCGT	21,000	71,297
OCGT	21,000	45,000
Hydro	5,500	181,692

Table 2: The supply side parameters considered in our model.

Technology	Maint. cost (€/MWh)	Inv. cost (€/MWh)	Ave. price 2013 (€/MWh)	Capacity (MW)
Lignite	3.4	14.7	40.4	4302
CCGT PPC	2.4	8.1	62.1	1824.2
CCGT IPP	2.4	8.1	76.6	2365.6
OCGT	2.4	5.1	80.9	1250
Hydro	0.6	20.7	79.4	3017.7
RES / Trade	N/A	N/A	25.0	4300

that maintenance and investment costs in the two tables are equivalent, and rather measured in different units. The units of measurement of table 1 for investment and maintenance cost are used in the derivation of truthful bids in the capacity auctions of sections 5.3 and 5.4. The units of measurement of table 2 for maintenance and investment cost are used in the optimal expansion model of section 5.2.

Demand side. We assume that the demand in the peak is 10000 MW, based on [5]. We assume that average demand is 5800 MW, based on dividing the committed GWh of table 1 of [5] by the number of hours in the year. We assume that D_0 moves from the peak demand of 10000 MW to a minimum level with a uniform probability. In order to arrive to the average load of 5800 MW, we assume a minimum demand of 1600 MW. Thus, the inelastic demand is expressed as $D_t = 10000 - \frac{10000-1600}{8760} \cdot (t-1)$.

Regarding VOLL, ACER [2] estimates a VOLL of 4240 €/MWh. Capros [5] (bottom of page 30) mentions a VOLL of 1600 €/MWh. On the other hand, if we assume a reliability target of 3 hours per year, which is typical in other EU CRM proposals, then the corresponding VOLL can be inferred from the following identity which should hold at the optimal expansion plan:

$$R \cdot VOLL = CONE$$

Table 3: Optimal capacity mix of the Greek market under the short-term and long-term scenarios.

Technology	Current	Short-term	Long-term
Lignite (MW)	4302	3871.2	3011.4
CCGT (MW)	4189.8	3770.8	4337.4
OCGT (MW)	1250	417.2	1232.3
Hydro (MW)	3017.7	3017.7	3017.7

where $R = 3/8760$ and $CONE = 5.1$ €/MWh is the cost of new entry of the peaking technology (OCGT), based on the Italian CRM report [21], see also table 2. This implies a VOLL of 14892 €/MWh. This value is quite close to the Belgian estimate of 13500 €/MWh. The results that are presented in the sequel correspond to this value.

Simulation settings. We consider a one-year simulation with hourly time step.

5.2 Optimal Mix

In this section we discuss the optimal mix of the Greek market under two hypothetical scenarios. One is a **short-term scenario** in which the current level of renewable resources remains in the system and 10% of the existing system capacity runs its lifetime. The other is a **long-term scenario** in which the amount of renewable resources in the system doubles, the system demand increases by 15%, and 30% of the existing system capacity runs its lifetime.

Insofar as the assumptions related to the technologies are concerned, we assume that lignite capacity cannot be expanded due to EU environmental objectives. We also assume that hydro capacity cannot be further expanded, but is also not diminished relative to current levels. Regarding CCGT technologies, we set the marginal costs of IPPs and PPC equal to each other and equal to the average marginal cost of table 2.

The evolution of the optimal system mix is presented in table 3. The corresponding price duration curves of the system are presented in figure 6. The short-term and long-term optimal expansion plans involve 1 hour and 5 hours of unserved load respectively.

For the existing condition of the system, we can compute the profit shortfall for each technology. The results are presented in table 4. In this illustrative model, only the CCGT-PPC units are able to recover short-

Figure 6: Price duration curve of the model under existing conditions, and under a short-term and long-term scenario with an ideal energy-only market.

Table 4: The profits and fixed costs for each technology given the current mix, as well as the resulting short-run net profits (SRNP) and long-run net profits (LRNP).

Technology	Profits (M€/y)	Maintenance (M€/y)	Investment (M€/y)	SRNP (M€/y)	LRNP (M€/y)
Lignite	658.4	129.1	553.7	529.3	-24.3
CCGT PPC	97.6	38.3	130.1	59.3	-70.8
CCGT IPP	11.6	49.7	168.7	-38.1	-206.7
OCGT	0	26.3	56.3	-26.3	-82.5
Hydro	0	16.6	548.3	-16.6	-564.9

run fixed maintenance costs. However, none of the technologies are able to recuperate their long-term investment costs.

5.3 Application of CRM to a Short-Term Scenario

In what follows, we compare the result of a centralized capacity auction to the outcome of the short-term optimal capacity expansion plan which is presented in table 3.

Capacity auction bids. In order to compute what would be a truthful bid in the capacity market, we would like to compute the implied cost of being accepted in the capacity auction. As explained in previous sections, acceptance in the capacity auction implies an obligation to produce in stress periods, no matter what the price in these periods. Thus, there are two possible costs associated with this obligation: (i) fixed cost of having the capacity available, and (ii) any difference between energy prices and fuel costs in scarcity periods. The definition of the latter as peak periods implies that the second item is negligible. So the question is whether any fixed cost of having the capacity available is not recovered by the energy market[8]. To compute this, we use the price duration curve of the system in order to compute any shortfall. This results in the bids of the third column of table 5.

For the bid quantities of existing hydro, CCGT, OCGT and lignite, we assume that 90% of the current capacity is bid, since 10% of the capacity is assumed to run its lifetime, regardless of whether the owners of these assets are prepared to pay the required maintenance costs. For new technologies,

[8]The formal argument is provided in section A.3 of the appendix.

Table 5: The bids that would be submitted by different technologies in a centralized capacity auction for the short-term expansion scenario.

Technology	Bid quantity derated (MW)	Bid price no RO (€/MW-y)	Bid price with RO (€/MW-y)
CCGT existing	3,039	-5,128	-2,775
OCGT existing	907	18,672	21,025
Lignite existing	3,120	-137,615	-135,262
OCGT new	10,000	66,000	68,352
CCGT new	10,000	92,297	95,280
RES-trade existing	1,075	-200,000	-200,000
Hydro existing	2,432	-200,000	-200,000

we assume that a large quantity of each new technology may be potentially constructed, which we cap at 10000 MW.

The bid quantities should be derated by the availability factor α of each technology (because in order to be in a position to deliver α MW of capacity, the capacity provider should essentially have 1 MW built). Note that RES-Trade bids are assumed not to be eligible to bid in the auction since they are assumed to be already benefiting from other support schemes, and their (derated) capacity is added automatically to the supply offers as price-taking (very negatively priced) bids.

In order to understand the bid price of existing resources, let us consider for example the CCGT supplier. In estimating the short-term optimal plan, the CCGT supplier finds that its profits[9] are 26,152 €/MWy (see table 4). Since its maintenance cost amounts to 21,024 €/MWy, the CCGT supplier will bid the difference, i.e. -5,128 €/MWy. The precise computations are presented in section A.3 of the appendix.

For new technologies, the calculation for deriving bid prices is the same as existing ones, with the only difference that the investment cost is added to the maintenance cost. Especially in the case of CCGT technology, we adopt the optimistic assumption that the CCGT-PPC technology costs (i.e. the lower ones) would be accessible to interested new investors.

Including reliability options. The introduction of reliability options to the mechanism would imply that awarded capacities are bundling a reliability option to their capacity. Thus, when being successfully cleared in the capacity auction, they are not only liable for delivering the power in

[9]The computation of profits requires an assumption of the market price cap. We assume a price cap of 3000 €/MWh [37].

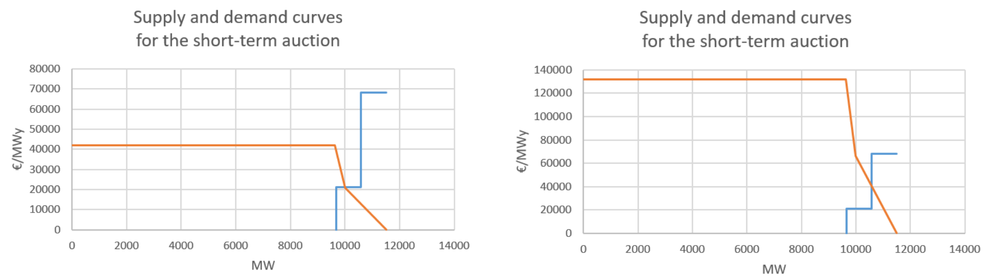

Figure 7: The supply and demand curves used in the short-term auction with $FC = 21,000$ €/MWy (left) and $FC = 66,000$ €/MWy (right).

scarcity periods, but also liable for a payment of the difference between a market price and a strike price. We use the marginal cost of the OCGT peaker, 80.9 €/MWh, as the relevant strike price in our analysis.

From the optimal solution of the capacity equilibrium problem (see section A.3), we conclude that each MWy of a reliability option implies a cash flow of 2,919 €/MWy. This implies that bid prices with reliability options are scaled by A_g for technology g (since each MWy cleared in the auction implies the sale of A_g MWy of reliability options, see also section A.3 of the appendix), yielding the truthful bid prices in the last column of table 5.

Capacity demand curve. We proceed next to apply the methodology of Cramton [9] in designing a demand curve for our model. We consider a CONE[10] of $FC = 21,000$ €/MW-y, based on the OCGT investment cost reported in table 1. The solution of the short-term expansion model of section 5.2 gives an optimal capacity of $C_K = 9999$ MW. We further have that $C_{min} = C_K/1.038 = 9633$ MW. Finally, $C_{max} = 1.15 \cdot C_K = 11499$ MW. The function is shown in figure 7.

Auction result. The result of the auction produces a clearing price of 21,025 €/MWy. The price is set by existing OCGT capacity, and a total of 9999 MW are cleared. As foreseen by the results of section A.3 of the appendix, this is consistent with the short-term optimal expansion plan

[10]The choice of CONE depends on the marginal technology that we wish to attract. If the target marginal technology is *new* OCGT capacity, then we can choose FC as the sum of the fixed cost of OCGT plus the value of the reliability options.

Table 6: The bids that would be submitted by different technologies in a centralized capacity auction for the long-term expansion scenario.

Technology	Bid quantity derated (MW)	Bid price no RO (€/MW-y)	Bid price with RO (€/MW-y)
CCGT existing	2,364	-33,651	-14,828
OCGT existing	705	-7,371	11,452
Lignite existing	2,427	-171,338	-152,515
OCGT new	10,000	46,886	66,000
CCGT new	10,000	46,886	66,000
RES-trade existing	2,150	-200,000	-200,000
Hydro existing	2,432	-200,000	-200,000

presented in table 3, where the optimal solution is to maintain 417 MW of existing OCGT capacity.

In the right panel of figure 7 we present the outcome that would have occurred if the CONE of new OCGT technology had been used for the demand curve, instead of the maintenance cost of existing OCGT technology. In this case, there would be a slight over-maintenance of OCGT capacity, with the capacity price becoming 40,744 €/MWy and the procured capacity amounting to 10573 MW.

5.4 Application of CRM Methodology to a Long-Term Scenario

We now repeat the procedure of section 5.3 in the long-term scenario, and focus on the extent to which the investments induced by the CRM are consistent with the outcome of a centralized expansion plan. The theory of section A.3 guarantees that the optimal expansion plan can be replicated, here why analyze the decentralized fashion by which this is achieved.

Capacity auction bids. In order to compute the capacity auction bids, we solve the capacity equilibrium model of section A.3 *given* the optimal expansion plan of the long-term scenario shown in table 3. The resulting bids are presented in the third column of table 6.

Including reliability options. From the optimal solution of the capacity equilibrium problem, we conclude that each MWy of a reliability option implies a cash flow of 23,353 €/MWy. The bids with the reliability options accounted for are presented in the last column of table 6. Note that the new

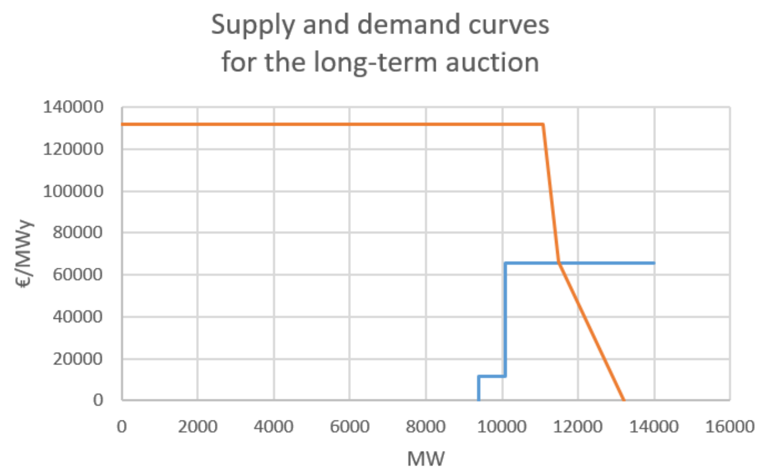

Figure 8: The supply and demand curves used in the long-term auction.

CCGT and new OCGT capacities have identical bids, which is consistent with the fact that the optimal mix comprises of both new OCGT and new CCGT capacity.

Capacity demand curve. We consider a CONE of $FC = 66,000$ €/MW-y, taking stock of the fact that new OCGT is the optimal capacity with the highest marginal cost in the optimal capacity mix. The solution of the long-term expansion model of section 5.2 gives an optimal capacity of $C_K = 11492$ MW. We further have that $C_{min} = C_K/1.038 = 11071$ MW. Finally, $C_{max} = 1.15 \cdot C_K = 13216$ MW. The function is shown in figure 8.

Auction result. The result of the auction produces a clearing price of 66,000 €/MWy. The price is set by new OCGT or CCGT capacity, and a total of 11492 MW are cleared. As foreseen by the results of section A.3 of the appendix, this is consistent with the long-term optimal expansion plan presented in table 3.

6. Conclusions

In this report we have provided a review of the literature on capacity remuneration mechanisms, with a specific attention to the CRM proposals that have recently been submitted, or are likely to soon be submitted, for approval to the European Commission. After approximately 20 years of experience with the implementation of CRMs throughout the world, a number of noteworthy patterns can be summarized.

- Centralized single-buyer capacity auctions seem to be a widespread option that is adopted in a number of markets (PJM, ISO-NE, MISO, Italy, the UK, Ireland, possibly Belgium, Colombia, to name some). With that being said, a considerable variation of resource adequacy measures can be encountered in practice.

- The bundling of capacity auctions with reliability options seems to be favored in practice, as a means of risk management.

- There exist noteworthy examples of capacity auctions that transitioned from a descending clock design to simultaneous uniform pricing.

- Demand curves in centralized capacity auctions are typically price-elastic, both in order to avoid a “bipolar” behavior of capacity prices [9], but also in order to counter, to a certain extent, strategic bidding behavior [30].

- The definition of procured quantities remains an important challenge [31].

- Scarcity pricing is an important step forward for CRMs. Scarcity pricing can co-exist with CRMs, however precedence matters. CRMs can introduce distortions to the energy-only market [31], therefore it is valuable to continue improving the design of the EU balancing, intraday and forward markets. The introduction of a real-time market for reserve capacity [34] is an important step in this direction.

A. Modeling Capacity Markets

In this section we present the underlying model for the results of section 5.

A.1 Notation

Sets
G: set of technologies
T: set of time periods
T^S: set of scarcity time periods

Primal variables
p_{gt}: production of technology g in period t
d_t: demand served in period t
x_g^+: new capacity of technology g
x_g^0: maintained capacity of technology g

Dual variables
λ_t: energy price in period t
μ_{gt}: scarcity rent of technology g in period t
ν_t: scarcity rent of loads in period t
$\gamma_g^{H/L}$: opportunity cost of additional / less new capacity for technology g
$\delta_g^{H/L}$: opportunity cost of additional / less maintained capacity for technology g

Parameters
C_g: marginal cost of technology g
V: value of lost load
D_t: maximum demand in period t
A_g: availability factor of technology g
$I_g^{+/0}$: investment / maintenance cost of technology g
$P_g^{H/L}$: minimum / maximum limit of new capacity for technology g
$M_g^{H/L}$: minimum / maximum limit of maintained capacity for technology g

A.2 Centralized Expansion Model

The centralized expansion model can be written as follows.

$$
\begin{aligned}
& \max_{d,p,x^0,x^+} \sum_{t\in T} V\cdot d_t - \sum_{g\in G}\sum_{t\in T} C_g\cdot p_{gt} - \sum_{g\in G}\sum_{t\in T} I_g^0\cdot x_g^0 - \sum_{g\in G}\sum_{t\in T} I_g^+\cdot x_g^+ \\
(\lambda_t): \quad & d_t - \sum_{g\in G} p_{gt} = 0, t\in T \\
(\mu_{gt}): \quad & p_{gt} \le A_g\cdot(x_g^0 + x_g^+), g\in G, t\in T \\
(\nu_t): \quad & d_t \le D_t, t\in T \\
(|T|\cdot\gamma_g^H): \quad & x_g^+ \le P_g^H, g\in G \\
(|T|\cdot\gamma_g^L): \quad & P_g^L \le x_g^+, g\in G \\
(|T|\cdot\delta_g^H): \quad & x_g^0 \le M_g^+, g\in G \\
(|T|\cdot\delta_g^L): \quad & M_g^- \le x_g^0, g\in G \\
& p\ge 0, d\ge 0
\end{aligned}
$$

The KKT conditions of the problem can be expressed as follows.

$$
\begin{aligned}
& 0 \le d_t \perp -V + \lambda_t + \nu_t \ge 0, t\in T \\
& 0 \le \nu_t \perp D_t - d_t \ge 0, t\in T \\
& 0 \le p_{gt} \perp -\lambda_t + C_g + \mu_{gt} \ge 0, g\in G, t\in T \\
& 0 \le \mu_{gt} \perp A_g\cdot(x_g^0 + x_g^+) - p_{gt} \ge 0, g\in G, t\in T \\
& |T|\cdot I_g^+ - A_g\cdot\sum_{t\in T}\mu_{gt} + |T|\cdot(\gamma_g^H - \gamma_g^L) = 0 \\
& |T|\cdot I_g^0 - A_g\cdot\sum_{t\in T}\mu_{gt} + |T|\cdot(\delta_g^H - \delta_g^L) = 0 \\
& 0 \le \gamma_g^H \perp P_g^H - x_g^+ \ge 0 \\
& 0 \le \gamma_g^L \perp x_g^+ - P_g^L \ge 0 \\
& 0 \le \delta_g^H \perp M_g^H - x_g^0 \ge 0 \\
& 0 \le \delta_g^L \perp x_g^0 - M_g^L \ge 0
\end{aligned}
$$

The latter set of conditions can be interpreted as an energy-only market model since it can be decomposed to (i) a set of generator profit maximization problems, (ii) a load profit maximization problem, and (iii) a market clearing condition for energy.

Concretely, the generator profit maximization reads as follows:

$$
\max_{p,x^0,x^+} -\sum_{t\in T} I_g^+\cdot x_g^+ - \sum_{t\in T} I_g^0\cdot x_g^0 + \sum_{t\in T}(\lambda_t - C_g)\cdot p_{gt}
$$

$$
\begin{aligned}
(\mu_{gt}): \quad & p_{gt} \leq A_g \cdot (x_g^0 + x_g^+), t \in T \\
(\gamma_g^H): \quad & x_g^+ \leq P_g^H \\
(\gamma_g^L): \quad & P_g^L \leq x_g^+ \\
(\delta_g^H): \quad & x_g^0 \leq M_g^H \\
(\delta_g^L): \quad & M_g^L \leq x_g^0 \\
& p \geq 0
\end{aligned}
$$

The load profit maximization reads as follows:

$$
\begin{aligned}
& \max_d \sum_{t \in T} (V - \lambda_t) \cdot d_t \\
(\nu_t): \quad & d_t \leq D_t \\
& d \geq 0
\end{aligned}
$$

The market clearing condition reads as follows:

$$
d_t - \sum_{g \in G} p_{gt} = 0, t \in T
$$

The collection of the generator profit and load profit KKT conditions, as well as the market clearing condition, coincides with the KKT conditions of the centralized expansion problem, thereby establishing the equivalence of energy-only markets and an optimal centralized expansion plan.

It is interesting to interpret the complementarity condition related to the build of new capacity (an analogous analysis applies for the maintenance of existing capacity). Concretely the following holds:

$$
A_g \cdot \sum_{t \in T} \mu_{gt} = |T| \cdot I_g^+ + |T| \cdot (\gamma_g^H - \gamma_g^L).
$$

The term $A_g \cdot \sum_{t \in T} \mu_{gt}$ corresponds to the scarcity rents earned by a technology. We can then interpret $A_g \cdot \sum_{t \in T} \mu_{gt} - |T| \cdot I_g^+$ as the profit margin of the technology in the energy market. The condition states the following:

- The profit margin of the technology is zero whenever the upper and lower limits in the expansion of the technology are non-binding.
- The profit margin of the technology can be positive whenever the upper limit in the expansion of the technology is binding (i.e. the technology is held back from being further expanded due to exogenous policy or technological constraints).

- The profit margin of the technology can be negative whenever the lower limit in the expansion of the technology is binding (i.e. the technology is held back from being further scrapped due to exogenous policy or technological constraints).

In order to rationalize capacity markets, we can consider the decomposition of the set of periods T between scarcity periods, T^S, and non-scarcity periods, $T - T^S$, where scarcity periods are characterized by $0 < d_t < D_t$. In such scarcity periods, the market price equals the VOLL, i.e. $\lambda_t = V$. We can then replicate the optimal capacity mix of the centralized capacity expansion model by exploiting the fact that, in a capacity market setting, the energy price is set to a price cap (as opposed to the VOLL), but in those same periods all generation capacity exhausted and demand may not be fully satisfied. The exact model (and the argument of why it can reproduce the same generation mix as an energy-only market) is developed in the next section.

A.3 Capacity Market Model

We now develop an equilibrium model of a capacity market, and discuss whether it can reproduce the same outcome as an energy-only market.

Generator profits in a setting with a capacity market can be expressed as follows:

$$
\begin{aligned}
& \max_{p,x^0,x^+} \sum_{t\in T^S} A_g \cdot \lambda^C \cdot x_g^+ - \sum_{t\in T} I_g^+ \cdot x_g^+ \\
& + \sum_{t\in T^S} A_g \cdot \lambda^C \cdot x_g^0 - \sum_{t\in T} I_g^0 \cdot x_g^0 \\
& + \sum_{t\in T-T^S} (\lambda_t - C_g) \cdot p_{gt} + \sum_{t\in T^S} (PC - C_g) \cdot p_{gt} \\
(\mu_{gt}): \quad & p_{gt} \leq A_g \cdot (x_g^0 + x_g^+), t \in T \\
(\gamma_g^H): \quad & x_g^+ \leq P_g^H \\
(\gamma_g^L): \quad & P_g^L \leq x_g^+ \\
(\delta_g^H): \quad & x_g^0 \leq M_g^H \\
(\delta_g^L): \quad & M_g^L \leq x_g^0 \\
& p \geq 0
\end{aligned}
$$

The KKT conditions of the generator profit maximization can be expressed as follows:

$$
\begin{aligned}
&0 \leq p_{gt} \perp -\lambda_t + C_g + \mu_{gt} \geq 0, g \in G, t \in T - T^S \\
&0 \leq p_{gt} \perp -PC + C_g + \mu_{gt} \geq 0, g \in G, t \in T^S \\
&0 \leq \mu_{gt} \perp A_g \cdot (x_g^0 + x_g^+) - p_{gt} \geq 0, g \in G, t \in T \\
&|T| \cdot I_g^+ - A_g \cdot \sum_{t \in T - T^S} \mu_{gt} - A_g \cdot \sum_{t \in T^S} (\mu_{gt} + \lambda^C) + |T| \cdot (\gamma_g^H - \gamma_g^L) = 0 \\
&|T| \cdot I_g^0 - A_g \cdot \sum_{t \in T - T^S} \mu_{gt} - A_g \cdot \sum_{t \in T^S} (\mu_{gt} + \lambda^C) + |T| \cdot (\delta_g^H - \delta_g^L) = 0 \\
&0 \leq \gamma_g^H \perp P_g^H - x_g^+ \geq 0 \\
&0 \leq \gamma_g^L \perp x_g^+ - P_g^L \geq 0 \\
&0 \leq \delta_g^H \perp M_g^H - x_g^0 \geq 0 \\
&0 \leq \delta_g^L \perp x_g^0 - M_g^L \geq 0
\end{aligned}
$$

Load profit maximization can be expressed as follows:

$$
\begin{aligned}
& \max_d \sum_{t \in T - T^S} (V - \lambda_t) \cdot d_t \\
(\nu_t): \quad & d_t \leq D_t \\
& d \geq 0
\end{aligned}
$$

The KKT conditions of the load profit maximization can be expressed as follows:

$$
\begin{aligned}
&0 \leq d_t \perp -V + \lambda_t + \nu_t \geq 0, t \in T - T^S \\
&0 \leq \nu_t \perp D_t - d_t \geq 0, t \in T - T^S
\end{aligned}
$$

Equilibrium in the energy market can be expressed as follows:

$$
d_t - \sum_{g \in G} p_{gt} = 0, t \in T
$$

The TSO profit maximization in the capacity market can be expressed as follows:

$$
MB(dx) = \lambda^C
$$

where $MB(\cdot)$ is the demand curve of the capacity market.

The capacity market equilibrium can be expressed as follows:

$$dx - \sum_{g \in G} (x_g^0 + x_g^+) = 0$$

We collect the KKT conditions of the profit maximization problems and the market clearing conditions into a single set of complementarity conditions, which constitutes the model of the capacity market. This equilibrium model is not a priori equivalent to any optimization problem, therefore there is no reason to expect that the resulting equilibrium can replicate the outcome of the optimal expansion plan. They key observation for establishing that this is the case is to observe that imposing a price cap on the energy market results in a model that resembles replacing the VOLL with the price cap, and then using the proceeds of the capacity market to replicate the scarcity rents of the conventional units. Concretely, we can state the following result.

Theorem 1. *Consider an optimal expansion plan* $(x_g^{+,\star}, x_g^{0,\star}, g \in G)$. *This optimal capacity expansion plan can be supported by a capacity market equilibrium given an appropriately chosen demand function for the capacity market.*

Proof. Given an expansion plan $(x_g^{+,\star}, x_g^{0,\star}, g \in G)$, we can infer the periods of scarcity as those periods for which $D_t > \sum_{g \in G} A_g \cdot (x_g^{+,\star} + x_g^{0,\star})$.

We need to establish that five sets of conditions are satisfied: the generator KKT conditions, the load KKT conditions, the optimality condition of the central buyer in the capacity auction, the energy market equilibrium, and the capacity market equilibrium.

For the load KKT conditions, we use the solution of the centralized expansion plan. Since the KKT conditions of the load profit maximization in the equilibrium model are a subset of the KKT conditions of the centralized problem (only applied to non-scarcity periods), the solution of the centralized expansion plan is guaranteed to satisfy these conditions.

For energy market clearing prices, we keep the energy prices of the non-scarcity periods equal to the energy prices of the centralized expansion problem, and set the energy prices of the scarcity periods equal to the price cap.

For the generator optimality condition, we keep the scarcity rents of the non-scarcity periods equal to those of the centralized expansion problem. The scarcity rents of the scarcity periods are "transferred" partially to the capacity payments. Concretely, whereas in the centralized expansion problem the scarcity payments in the scarcity periods are equal to

$A_g \cdot (V - C_g) \cdot x_g^+$ for new capacity (and correspondingly for maintained capacity), they become equal to $A_g \cdot (PC - C_g) \cdot x_g^+$ (and correspondingly for maintained capacity), with the difference being transferred to the capacity price. This difference is the same for all technologies, since it only depends on V, PC, and the number of scarcity periods.

For the optimality condition of the central buyer, we set $\lambda^C = MB(\sum_{g \in G} A_g \cdot (x_g^{+,\star} + x_g^{0,\star}))$. We therefore need to have chosen the demand curve $MB(\cdot)$ so that, at this level of capacity, it equals the missing money, as required by the optimality conditions of the generators in the previous paragraph.

□

The conclusion of this result is important, because it guarantees that an appropriately chosen demand function should be able to replicate the centralized planning outcome. This is what drives the results of section 5.3 and 5.4.

The truthful bids of the different technologies can be derived from a duality analysis of the following problem, which answers the question of what is the minimum cost at which a certain technology can make K units of capacity available (a similar analysis applies in the case of maintaining existing capacity):

$$\begin{aligned}
TC(K) \quad &= \quad \min_{p, x^+, x^0} I_g^+ \cdot x_g^+ - \sum_{t \in T} (\lambda_t - C_g) \cdot p_{gt} \\
(\mu_{gt}) : \quad & \quad p_{gt} \leq A_g \cdot x_g^+ \\
(|T| \cdot \gamma_g^H) : \quad & \quad x_g^+ \leq P_g^H \\
(|T| \cdot \gamma_g^L) : \quad & \quad P_g^L \leq x_g^+ \\
(|T| \cdot \psi_g) : \quad & \quad x_g^+ = K \\
& \quad p \geq 0
\end{aligned}$$

This total cost is a convex function of K. Its gradient is the truthful bid of a capacity provider in the capacity auction, and can be expressed as follows:

$$|T| \cdot A_g \cdot \psi = |T| \cdot (I_g^+ + \gamma_g^H - \gamma_g^L) - A_g \cdot \sum_{t \in T} \mu_{gt} \tag{1}$$

For an interior solution, we have $\gamma_g^H - \gamma_g^L = 0$. The introduction of a call option with strike price SP implies the inclusion of a term $A_g \cdot \sum_{t \in T} (\lambda_t - SP)^+ \cdot x_g^+$ in the objective function[11]. Thus, the term $\sum_{t \in T} (\lambda_t - SP, 0)^+$ is added to equation 1.

[11] Note that the derating factor that the system operator applies to the contribution of

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technology g in the capacity auction also applies to the awarding of reliability options for technology g. Thus, each MW of physical capacity of technology g implies an eligibility to bid A_g MW in the capacity auction and a sale of A_g MWy of a reliability option.

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