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Capacity Remuneration Mechanisms in the EU: today, tomorrow, and a look further ahead

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Abstract

In this paper, we discuss the implementation of Capacity Remuneration Mechanisms (CRM) in the European Union (EU). We first illustrate that the costs of CRMs in the EU are significantly lower than in the US. Next, we discuss how the Clean Energy Package (CEP) intends to limit the future role of CRMs. Two steps are introduced to check if CRMs are really needed: a European resource adequacy assessment and a national implementation plan to improve current electricity market design. In case residual adequacy concerns persist, the CEP also includes provisions to guide the design of a CRM. Last, we discuss the role of the consumer in securing resource adequacy in the future.

Keywords

Capacity remuneration mechanisms; Clean Energy Package; market design; active consumer.

1. Introduction[*]

Seminal works that were fundamental for the liberalization of power markets, such as Spot Pricing of Electricity by Schweppe et al. (1988), suggested that an energy-only market, when well-designed, could be sufficient to stimulate investment in power generation. However, in practice, there has never been a strong reliance on energy-only markets in the EU to stimulate investment. Roques (2021) shows that the large majority of investment in power generation in the EU has received at least some form of additional support on top of revenues from short-term power markets during the last decades. Two important examples are renewable subsidies and Capacity Remuneration Mechanisms (CRM).[1] Even though the optimal design of renewable subsidy schemes is an open issue, their introduction to reach ambitious climate and security of supply goals has been more or less accepted. On the contrary, CRMs continue to be controversial. Both their necessity and design continue to be debated among practitioners and academics.

When discussing security of supply, it is important to distinguish between resource adequacy and system reliability, jointly often referred to as security of supply (as depicted in Figure 1). Resource adequacy is about complying with an administratively determined margin by ensuring that enough resources are connected to the power grid and available at moments of peak demand. A resource adequacy assessment is typically done at least one or several years ahead of power delivery. If the results forecast shortages, this is typically used to argue in favour of a CRM to avoid that these shortages occur. When designing a CRM to address a resource adequacy concern, you do not only want to stimulate resources to be built or remain connected, but you also want them to be available when really needed. This issue is called the ‘’pay-for-performance’’ challenge.

System reliability is about making sure that supply equals demand in real time, without violating any security limits. The system operator typically enforces certain grid connection requirements and relies on ancillary service markets to assure system reliability. In practice, only system reliability matters but guaranteeing system reliability is conditional upon resource adequacy. If resources are inadequate, it can imply that the system operator has to implement rationing in real time to save the system from a blackout. System reliability is generally considered as a public good, while resource adequacy can potentially be a private good (Oren 2009).

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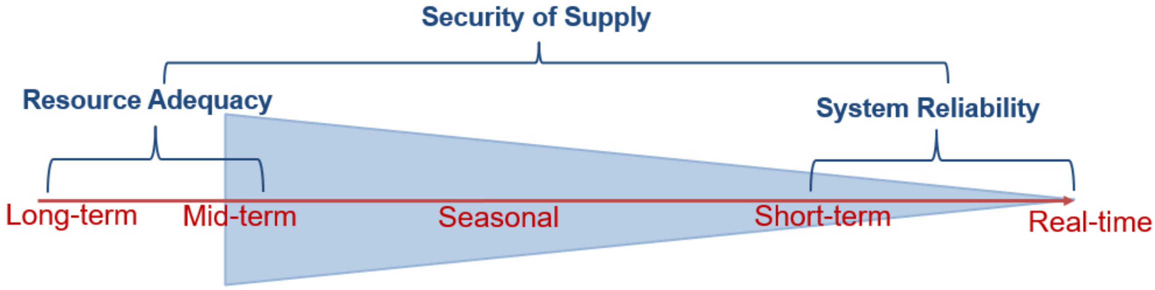
1 There is also a link between renewable subsidies and CRMs. It is often claimed that the introduction of the former is (partly) responsible for the need of the latter, as for example discussed by Cramton et al. (2013).

Figure 1: The link between security of supply, resource adequacy, and system reliability



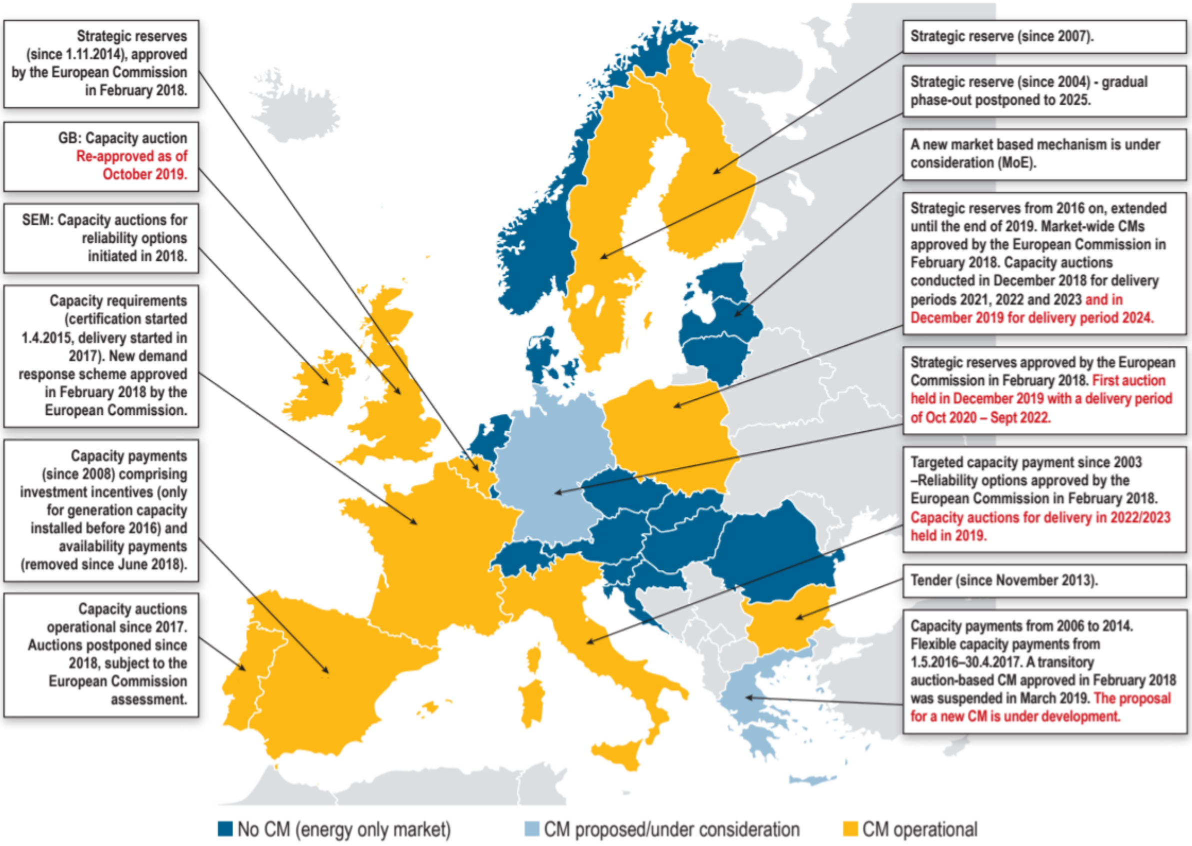
Throughout the years several arguments have been identified in favour of CRMs. The most important arguments revolve around the missing money and missing markets problems. Price caps, often serving as remedy to control market power as extensively discussed by Hogan (2013), is the most prominent reason for the missing money issue. Joskow (2008) adds that also administrative procedures implemented by system operators in emergency situations could lead to inadequate remuneration, and/or energy prices that are inefficiently low. A last example is the way transmission capacity is currently priced in EU electricity markets as discussed by Papavasiliou (2021). The most prominent missing markets are the missing market for long-term hedging instruments and the missing market for reliability. Regarding the former, revenue streams from energy-only markets can be highly unpredictable, while appropriate hedging instruments are not always available. Newbery (2016) discusses in-depth the issue with missing markets for risk allocation. Regarding the latter, many retail consumers are not subject to real-time prices and it is (often) not possible to implement some form of priority rationing in conditions of scarcity. Joskow and Tirole (2007) discuss that this implies that inconsistencies will arise between administrative reliability criteria and consumer preferences for reliability. Besides these two missing markets, there are also other examples, such as missing markets for certain ancillary services as discussed by Newbery (2016) and Papavasiliou (2021). Léautier (2019) and Meeus and Nouicer (2020) also list these arguments, but stress that the real reason that most countries go for CRMs is rather political than economic.

The remainder of this paper consists of three sections followed by conclusions. First, we describe the current state of play of CRMs in the EU. We also make a brief comparison with CRMs in the US. Second, we discuss how the Clean Energy for all Europeans Package will impact CRMs in the years ahead. Third, we look further ahead and focus on the role of the consumer in the discussions around resource adequacy. Lastly, we provide conclusions.

2. Today: state of play

Every year, the European Union Agency for the Cooperation of Energy Regulators (ACER) and the Council for European Energy Regulators (CEER) prepare EU-wide energy market monitoring reports. The wholesale electricity market volume includes an overview of the current state of play of CRMs in the EU. Figure 2 depicts in which countries CRMs are currently in place or where their introduction is expected. As can be seen from the figure, the situation is quite heterogenous. About half of the countries did not implement any CRM, while the other half did. The type of CRM implemented can take many forms. The most popular CRMs are strategic reserves, capacity payments, and capacity auctions awarding reliability options. The CRM in France is unique as it is the only decentralised mechanism in the EU. In France, suppliers, large consumers and the system operator are required to purchase capacity guarantees in proportion to their contribution to system peak demand. These capacity guarantees are issued to owners of generation assets or demand response resources in proportion to their availability at times when the system peak demand occurs.

Figure 2: CRMs in Europe in 2019. Source: ACER and CEER (2020). Note: Changes with respect to 2018 are printed in red

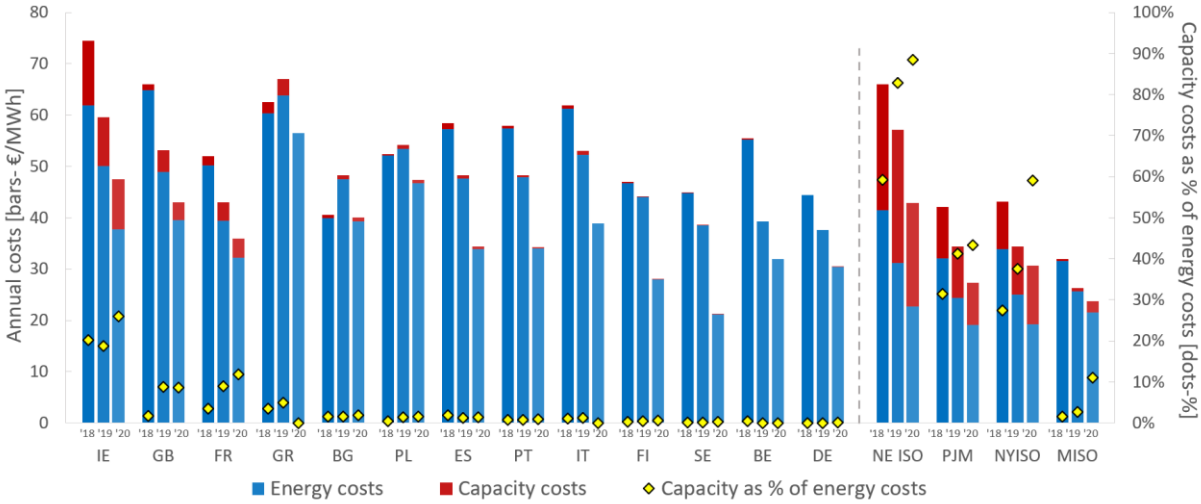


On the basis of the proposals for the introduction of CRMs submitted to the European Commission, Papavasiliou (2021) provides an overview of the rationale used in the different countries (Italy, the UK, Ireland and France) to justify the need for a capacity market. The most often cited are the missing money problem and the public good nature of reliability.

Figure 3 shows the cost incurred or forecasted to finance CRMs per unit of demand in the period 2018-2020 in those European countries that have such a mechanism. The energy costs are also included; and the capacity costs are shown as a percentage of the energy costs. For comparison, we added the same data for several US power systems with CRMs.[2]

2 For the European countries, the annual average day-ahead energy price is used. For the US power systems, the load-weighted average real-time energy price is used. The US costs are converted to euros using the average exchange rate in the respective year. For MISO, the capacity costs of Michigan are excluded. IE: Ireland, GB: Great Britain, FR: France, GR: Greece, BG: Bulgaria, PL: Poland, ES: Spain, PT: Portugal, IT: Italy, FI: Finland, SE: Sweden, BE: Belgium, DE: Germany, NE ISO: New England Independent System Operator, PJM: Pennsylvania-New Jersey-Maryland, NYISO: New York Independent System Operator, and MISO: Midcontinent Independent System Operator. Main sources: ACER and CEER (2020), All NEMO Committee (2021), GME (2021), ISO New England Inc. (2021), Monitoring Analytics (2021) and Potomac Economics (2021b, 2021a).

Figure 3: Annual energy cost vs costs of CRMs per unit of demand and capacity costs as a percentage of energy costs (%) for European countries and US power systems (euros/MWh) in 2018–2020. See footnote 2 for more information about the figure.



We highlight two findings from Figure 3 and add one important remark. First, in Europe, the relative costs differ substantially from one country to another. We also note that the countries with strategic reserves seem to have the lowest capacity costs, but it is hard to infer a causal relationship between the type of CRM and the resulting costs. Many other factors play a role, such as the level of interconnectivity of a country. This might explain the relatively higher costs for Ireland and Great Britain. Second, capacity costs are significantly higher in the selected US power systems, while energy prices are significantly lower. The costs of European CRMs, with the exception of Ireland and to some extent Great Britain and France, are currently negligible compared to their US counterparts. For example, the costs of the CRM in place in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection amounted to about 7 billion US dollars in 2019, while the total costs of CRMs in the EU was 3.9 billion euros in the same year (Monitoring Analytics 2021; ACER and CEER 2020). However, the capacity costs in the EU have been increasing by 73% compared to 2018 and are expected to increase further, especially because of anticipated high costs for the CRMs in Italy (2.8 billion for the period 2022-2023) and Poland (7.7 billion for the period 2021-2024). Lastly, an important remark to add is that costs as shown in Figure 3 are the gross costs of the CRMs, i.e. the money paid to the beneficiaries of the mechanism. Looking from a whole system perspective, the existence of a CRM, even when having a relatively minor cost, has an impact on prices in wholesale markets and can bring other important additional costs and benefits.[3]

3. Tomorrow: the impact of the EU Clean Energy Package

In 2019, the Clean Energy Package (CEP) was adopted. The CEP was the 4th legislative package addressing the electricity sector in Europe since the mid-1990s.[4] What is relevant for this paper is that the CEP also impacts the possibility to implement and the design of CRMs in EU Member States. We split this section into two parts. First, we discuss how the CEP limits the freedom of EU Member States in their choice to implement a CRM. Second, we explain

[3] Typically a reduction in average wholesale electricity prices is expected, as for example discussed in Komorowska et al. (2020). Höschle et al. (2017) provide a holistic analysis of the impact of CRMs on the remuneration of generation technologies including effects on wholesale electricity markets.

[4] For more background, please consult Meeus and Reif (2020) who discuss in more depth how the different EU energy packages have shaped European electricity markets in the last decades.

how the CEP impacts the design of the CRMs in case deemed needed to address residual resource adequacy concerns.

3.1 Limiting the (ab)use of CRMs

As also described in Meeus and Nouicer (2020), Regulation (EU) 2019/943 introduces a two-step procedure to verify whether there is a real resource adequacy problem in an EU Member State that justifies the need for a CRM. We first discuss the need for an EU-wide resource adequacy assessment, its potential benefits, and implementation. After, we discuss the alternative measures that can eliminate or at least reduce the need for a CRM.

3.1.1 A European resource adequacy assessment

In recent years, ACER and CEER have been discussing the unjustified introduction of CRMs in several European countries in their annual market monitoring reports. For example, the latest market monitoring report observed that nine out of the thirteen countries that introduced a CRM (see Figure 1) did not demonstrate convincingly that they have a resource adequacy issue (ACER and CEER 2020). These countries are Bulgaria, Germany, Finland, Greece, Ireland (SEM), Poland, Portugal, Spain and the UK (Great Britain). ACER and CEER based their arguments on the 2019 Mid-term Adequacy Forecast (MAF) performed by the European Network for Transmission System Operators for Electricity (ENTSO-E).

Another issue is that some national adequacy assessments do not, or only to a limited extent, consider the contribution of interconnectors to (national) resource adequacy. In such cases, a Member State might perceive a resource adequacy issue while there is none. ACER and CEER (2020) state that four Member States, i.e. Austria, Latvia, Romania and Spain, as well as Norway, did not take the contribution of interconnectors to adequacy into account in their latest national adequacy assessments. Out of these four, Spain has a CRM in place. Hagspiel at al. (2018) estimate the benefits from regional cooperation for resource adequacy in the EU. They find that by cooperating, the need for firm generation capacity could be reduced by 36.2 GW (i.e., 6.4%), which translates into investment savings of 14.5 B€. Importantly, they stress that the distribution of the benefits (and costs) of cooperation is expected to be uneven among the Member States. These authors also find that cooperation has an impact on the capacity values of different technologies, i.e. how much a resource is expected to contribute at times of stress. For example, the capacity values of wind are in most cases positively affected by cross-border cooperation.

In response to these concerns, the CEP introduced the European Resource Adequacy Assessment (ERAA) whose outcome directly impacts the possibility to introduce a CRM in a Member State.[5] More precisely, according to Regulation (EU) 2019/943, ENTSO-E has to carry out an annual EU-wide resource adequacy assessment. The ERAA covers each year within a period of 10 years from the date of the assessment and is based on data provided by national TSOs. The methodology to conduct this assessment has been published by ACER in October 2020 (ACER 2020b). Importantly, the ERAA methodology ensures that in the assessment interconnections are explicitly modelled with a probabilistic consideration of the related cross-zonal capacity. Jointly with the ERAA methodology, ACER also published the methodology to calculate the reliability standard, based on the value of lost load and the cost of new entry for

5 Article 20 and 23 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124.

generation or demand response (ACER 2020a).[6] Previously, reliability standards had been widely diverging in form and underlying assumptions (Henriot and Glachant 2015). By comparing the results of the ERAA and the predefined reliability standards, resource adequacy concerns can be identified that are mutually comparable. On top of the ERAA, Member States can also continue to do national assessments with additional sensitivity analyses.[7] These national assessments shall have a regional scope and adequately consider the contribution of interconnectors. Member States shall not introduce CRMs where both the ERAA and the national resource adequacy assessment (if existent) have not identified any resource adequacy concern. If the national assessment comes to a different conclusion as the ERAA, a mediation process has been foreseen in which ACER will play a key role.

The purpose of the ERAA is to bring benefits to consumers by limiting the use of CRMs where they are unnecessary. However, there are open issues. One of them is whether Member States believe that they can rely on their neighbours during a multilateral shortage. Glachant et al. (2017) state that the national responsibility of each TSO for the continuity of supply in its own country and, at times, national distrust in neighbours, explain why solidarity is not always shown during emergency situations. Therefore, these authors suggested that in order to make an EU-wide approach to resource adequacy work, the TSOs involved in a multilateral shortage shall follow pre-established rules and pool the scarce available resources in order to minimise service disruptions and the impact on the most vulnerable consumers. And indeed, Houtman and Liakopoulou (2021) describe that rather stringent EU regulations were put in place to safeguard supply in the case of energy crises. More precisely, in 2017 the EU electricity Emergency and Restoration Network Code (ER NC, Regulation (EU) 2017/2196) was adopted. The ER NC sets out the rules for the management of the transmission system in case of emergency or blackout. After, in 2019, Regulation (EU) 2019/941 on risk-preparedness in the electricity sector was adopted as part of the CEP. Thus, the EU legislative framework is in place but the proof of the pudding is in the eating. Keyaerts (2016) describes the experience in the gas sector, which has had a longer tradition in cross-border crisis cooperation, from which some lessons can be learned. For example, the Sustainable Energy Security Package from 2016 as proposed by the Commission defined priority consumers, who are a strict subset of the protected consumers composed of households, essential social services and district heating. In case there is insufficient gas to supply all priority consumers in a Member State, mandatory solidarity requires that all other Member States send excess gas to help the Member State that has declared a state of emergency. Keyaerts (2016) explains that such definition helps to concretise the concept of “solidarity” by putting an upper limit on its volume and duration.

3.1.2 Measures to eliminate or reduce the need for CRMs

Regulation (EU) 2019/943 emphasises that if a resource adequacy concern is identified according to the previously described procedure, a Member State must develop a national implementation plan.[8] Only after the European Commission provides an opinion on the implementation plan, a Member State can introduce a CRM. The aim of this national

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[6] The term “reliability standard” can be confusing as in this context a reliability standard implies a minimum margin of available resources that can be relied on at all times. Non-compliance with the reliability standard indicates the presence of a resource adequacy concern. The term is not directly related to (real-time) system reliability as explained in the introduction of this paper.

[7] Article 20(1) and 24 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124.

[8] Art. 20(3) of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124.

implementation plan is to improve the functioning of the electricity market and as a consequence eliminate or at least reduce the need for a CRM. We cannot discuss all the relevant market design elements in this paper, so we briefly illustrate three of them: the removal of wholesale price caps, the spatial granularity of electricity prices, and the introduction of a shortage price function for balancing reserves.

First, a lot of progress has been made in the EU regarding the removal of wholesale price caps. As described in Schittekatte et al. (2020), the Capacity Allocation and Congestion Management Guideline (CACM GL, Regulation (EU) 2015/1222) outlines that a methodology for EU-wide harmonised maximum and minimum clearing prices in the day-ahead and intraday timeframe had to be developed. Finally, in November 2017, ACER adopted the methodology stating that the maximum clearing price for the day-ahead market shall be 3000 €/MWh (ACER 2017a). The maximum clearing price in the intraday market was set at 9999 €/MWh (ACER 2017b). What is most important is that these price caps are not static. More precisely, the maximum day-ahead clearing price will increase by 1000 €/MWh if the clearing price exceeds a value of 60 % of the maximum clearing price in at least one market time unit in a day in an individual bidding zone or in multiple bidding zones. The maximum intraday clearing price will be amended in the event that the harmonised maximum day-ahead clearing price is increased above the maximum intraday clearing price. Regulation (EU) 2019/943 reiterates that there shall be neither a maximum nor a minimum limit to the wholesale electricity price. It is added that this provision applies, inter alia, to bidding and clearing in all timeframes and shall include balancing energy and imbalance prices. Therefore, it can be said that according to the EU legislation, there are no ‘true price caps’ blocking scarcity prices from occurring in EU electricity markets, but there are technical limits. However, in practice issues with bidding limits seem to persist in some Member States such as Spain and Portugal where, at least in 2020, there was still a bidding cap of 180.3€/MWh in place for the day-ahead and intraday market (Weik 2020).

Second, the way that the transmission network is considered in current EU wholesale markets is suboptimal. Currently, zonal pricing is applied in the EU, meaning that only the transmission elements between bidding zones are considered when trading electricity in wholesale markets. Bidding zones often equal national territories with a few exceptions. The current bidding zone configuration is a legacy from a time in which the networks within countries were well-developed, while networks between countries were often bottlenecks. In the last years, grid development did not catch up with the installation of new generation capacity, especially renewable generators. As explained by Pototschnig (2020), the result is that the current bidding zone configuration does not reflect grid conditions, leading to strongly increased costs for redispatch actions and limitations in cross-border trade. As described in more depth by Meeus and Schittekatte (2020), the CEP addresses this issue by requiring TSOs to offer at least a certain amount of cross-zonal capacity for trade (the so-called “70 %-rule”) and by introducing a novel governance for the bidding zone review. However, improvements are slow due to the option for a range of derogations. A real impact of these new measures on the pricing of transmission capacity can only be expected by 2025. It is hard to claim that improved pricing of transmission capacity in EU wholesale markets would lead to significantly more installed generation. But, at least investment in the right type of capacity in the right locations, including demand response, would be better incentivised. Especially in the context of integrating more renewables, this is an important development.

Third, scarcity in balancing reserves is not adequately reflected in prices. The concept of a shortage price function can address this issue. Currently, during those rare moments in which the balancing reserves are depleted, the balancing energy price should spike to the Value of Lost Load (VOLL) and administrative curtailments have to take place. A shortage price function does, is to provide a signal when the real-time balancing reserves are near depletion. More precisely, an administratively determined “scarcity price adder” is added to the balancing energy price. The adder equals zero when there are more than enough reserves and rises gradually to equal VOLL when the reserves are near to depletion. As such, the price spikes needed to recuperate the investment costs of flexible resources, able to support the system when in stress, become less infrequent and smoother. Scarcity prices also enable increased engagement of demand response. Ideally, demand response should set the scarcity price and the need for a calculated scarcity adder should fade with time.

A shortage price function, also known as an Operating Reserve Demand Curve (ORDC), has been in place since several years in a selection of US power markets such as those managed by the Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) (Papavasiliou and Smeers 2017; Hogan 2013). Since several years, a shortage price function has also been implemented in Great Britain (ACER and CEER 2016). In Belgium, currently, there is an extra price component in place that increases the imbalance price for Balance Responsible Parties (BRPs) when the system imbalance of the Belgian control zone increases (Belgian Energy Ministry 2020). In Poland a shortage price function, increasing the balancing energy prices at times of system stress, was proposed in its national implementation plan (European Commission 2020). The exact implementation of the shortage price function is not identical from one case to another. One discussion in the EU is whether to add the scarcity adder to the balancing energy price, to the imbalance price, or to both as in the US implementation (Elia 2020). Papavasiliou (2020) also notes that currently we are missing a real-time market for reserves in the EU, while such market is present in the US context. A real-time market for reserves is deemed necessary to correctly propagate the scarcity adder to the preceding wholesale electricity markets working in sequence.

A shortage price function can co-exist with a CRM, as is the case in PJM and MISO (Cramton 2017). In ERCOT, only an ORDC is in place without a CRM. The sustained outages in February 2021 in Texas due to unexpected cold temperatures led to a heated debate about its market design choices. Box 1 discusses this event in more depth.[9] There are important take-aways from this event that are also relevant for the EU and the discussion around capacity remuneration mechanisms. First, the energy crisis in Texas of February 2021 is not an argument for the need of CRMs; it is not proven that a CRM would have avoided the rolling black-outs. More crucial issues that were found to be contributing to the supply disruptions, and deserving careful consideration, are weatherisation standards and the coordination between the electricity and gas sector. Second, when introducing an ORDC, price setting rules during crises events have to be well-thought-out to mitigate adverse financial impacts on consumers and utilities. In the case of Texas, some observers argue that maximum prices were sustained for too long periods due to flaws in the design of the ORDC.

[9] Besides the references provided, this box is a summary of a previous blog post of one of the authors (Schittekatte, 2021).

Box 1: The Texas freeze in February 2021

The power system covering more than 90% of the Texan territory is managed by ERCOT, the non-profit Independent System Operator (ISO). Unlike other US power systems and the power systems in many EU Member States, ERCOT does not have a CRM. Instead, Texas relies on an energy-only market with Locational Marginal Prices (LMPs) complemented with an ORDC mechanism.[10] At the peak of the Texas freeze of February 2021, more than 4.5 million customers, equalling more than 10 million people or about one out of three Texans, were left without electricity, some for several days. As demand reached unprecedented heights (>70 GW), about 45 GW of power generators were offline due to the freeze (S&P Global Platts 2021). There was never a real blackout, i.e. a complete collapse of the frequency, but due to the large shortfall of generation, rolling blackouts became multi-day controlled outages.

Scarcity prices did not manage to mobilize the generation capacity when needed. However, most experts agree that it is not a given that a CRM would have prevented the issue. For example, Recommendation 5-3 in the report about the event by six former Commissioners of the Public Utility Commission of Texas (PUCT) state "*The blackouts in February were not due to the lack of generation capacity within ERCOT, but rather to the failure of many generators to prepare their hardware and fuel supplies adequately for the Arctic weather; a capacity market would not have prevented this outcome*" (Wood III et al. 2021). This message is echoed by Busby et al. (2021) and Hogan (2021). The main reasons identified for the power crisis by these authors were forced outages of gas-fired power plants, and to a lesser extent coal-burning plants, a nuclear power plant, and wind turbines, due to fuel shortages and/or freezing equipment. There were issues with freezing of natural gas wells, gas storage, and gathering lines. Also, due to an important interaction between the gas and electricity systems, power outages at compressor stations led to low gas pressure, forcing more generation offline.

An important consequence of the outages, magnified due to the ORDC mechanism, were sustained high electricity prices. Littlechild and Kiesling (2021) describe that even though prices were clearing at lower levels, the wholesale price stayed at the price cap of 9,000 $/MWh from the evening of Monday 15 to the morning of Friday February 19, when ERCOT came out of emergency operations. The PUCT considered that prices have to reflect the load shedding and therefore they were set to 9,000 $/MWh. A few ten thousand consumers with real-time price contracts were exposed to these prices resulting in electricity bills of thousands of dollars for some. Busby et al. (2021) describe that multiple high-profile lawsuits are underway, challenging the resulting exorbitant electricity bills and utilities from being saddled with crippling debts. There was a so-called circuit breaker in place to go from the high price cap to a lower price cap when the net margin of the peak power plants were estimated to have reached a certain threshold. However, that lower price cap was determined to be equal to the maximum of 2,000$/MWh or 50 times a natural gas fuel index price. As gas prices were also peaking, the lower price cap superseded the high price cap and the high price cap was kept in place. Littlechild and Kiesling (2021) argue that there was no need to sustain such high price level as that maximum price level was chosen to incentivise the construction of sufficient new generation, and a significantly lower price would have sufficed to incentivise existing generation to make itself available for running. As such, the same authors state that problematic regulatory implementation of the scarcity pricing mechanism greatly exacerbated the consequences of the freeze.

[10] However, Botterud and Auer (2020) mention that it is important to note that ERCOT, like other US ISOs, has a backstop mechanism in place through the option of entering into so-called "reliability must run contracts", i.e. contracts that force individual generators to stay in operation for specific reliability purposes. Botterud and Auer (2020) interpret these contracts to be similar to strategic reserves as implemented in some EU countries.

3.2 Implementing a CRM to solve residual adequacy concerns

As a measure of last resort, the CEP allows a Member State to implement a CRM. However, certain design principles need to be respected.[11]

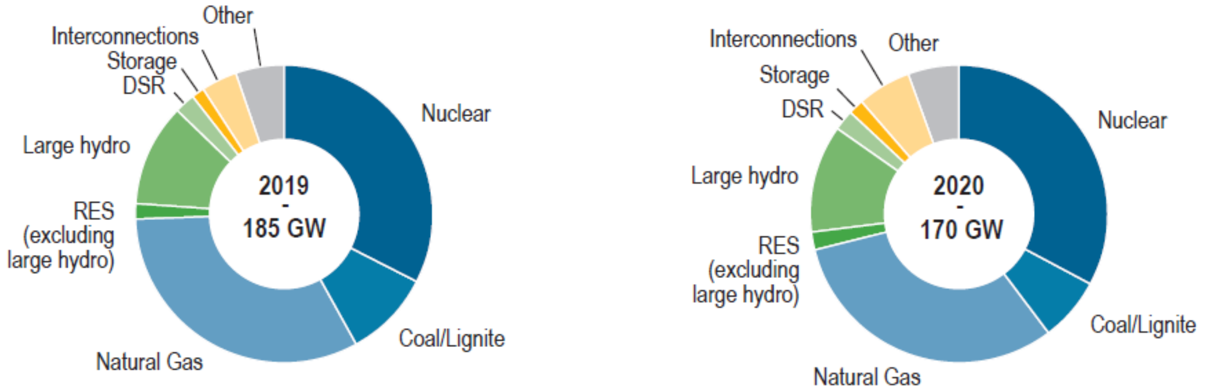
First, the default design of a CRM has to be strategic reserves. Strategic reserves refer to the remuneration of capacity that is kept outside of the electricity market and only used if the market participants do not offer enough generation to meet short-term demand. The Sector Inquiry on CRMs of the European Commission (2016) identified strategic reserves to be likely the most appropriate response when faced with a temporary adequacy issue because they can help to control the amount of existing capacity leaving the market. A strategic reserve is believed to keep market distortions at a minimum. However, to do so, three conditions need to be fulfilled that are also reflected in the CEP. First, the reserve has to be kept as small as possible. Second, the purpose of the mechanism is to prevent certain resources from leaving the market and not to promote new resources entering the market. Third, the contracted resources have to be held outside the market in standby to preserve market price signals and incentives for other resources to remain available. Experiences with strategic reserves have been gained in Sweden, Finland, Belgium, and Germany. Only in case a national assessment shows that a strategic reserve is not capable of addressing the resource adequacy concern, a different type of CRM may be introduced.

Second, the CEP prescribes that the CRM must be open to participation of all resources that are capable of providing the required technical performance, while the most polluting power plants reaching certain emission factor thresholds have to be excluded. Further, CRMs other than strategic reserves shall be open for cross-border participation.[12] When technically feasible, also strategic reserves must be open for cross-border participation. Figure 4 shows the capacity remunerated through CRMs in several European countries per type of technology in 2019 and 2020. Currently, demand-side response, storage, and renewables (excluding large hydro) only represent a minor proportion of the awarded remuneration. Also, the participation of interconnectors remains limited. More precisely, direct participation of interconnectors only took place in the British (6% for 2020), French (6% and 7% for 2019 and 2020 respectively), and the Irish (5% for both 2019 and 2020) CRMs.

[11] Article 21 and 22 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124.

[12] Article 26 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124.

Figure 4: Capacity remunerated through CRMs in several European countries per type of technology in 2019-2020. Data: Belgium, Bulgaria, France, Finland, Greece, Ireland, Poland, Portugal, Spain, Sweden and Great Britain. Source: ACER and CEER (2020).



In contrast, coal/lignite and natural gas power plants represent more than one third of the awarded capacity for both the years 2019 and 2020. To avoid subsidizing the most polluting power plants via CRMs, emission limits have been introduced in the CEP. More precisely, from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 gCO2/ kWh of electricity will be excluded from participation in the CRMs. From 1 July 2025 at the latest, the grandfather clause for older generators expires. Generation capacity that started commercial production before 4 July 2019 and that emits more than 550 gCO2/kWh of electricity and more than 350 kgCO2 on average per year per installed kWe will be excluded. Tranberg et al. (2019) calculate the lifecycle CO2 equivalent intensity per technology and country in the EU and find that coal-fired and oil-fired power plants emit significantly more than this threshold (respectively, 1160 gCO2/kWh and 1020 gCO2/kWh). Thus, these generation technologies will be excluded for a remuneration from CRMs from the predefined dates onwards. The average emission factor for natural gas-fired power plants was 513 gCO2/kWh without cogeneration and 475 gCO2/kWh with cogeneration. However, in several Member States the average gas-fired power plant emitted more than the 550gCO2/kWh threshold, meaning that only efficient gas-fired power plants will remain eligible to compete in a CRM. As required by the CEP, ACER (2019) published technical guidance on how exactly to calculate the emission factor per power plant.

4. A look further ahead: the role of the consumer

In the summer of 2021, ERCOT asked Texans to refrain from using air conditioning as unplanned outages and a heat wave collided. Instead of a rare extreme freeze as described in Box 1, the Texan power system was facing a more traditional summer peak (Reimann 2021). Fuelled by climate change, such extreme weather events are expected to repeat themselves more frequently all over the world. How to secure resource adequacy at an affordable cost in the future? [13]

One striking element when reading about the Texas freeze is the rudimentary way in which controlled load shedding is performed during a crisis, also called ‘rationing’. For example, homeowners on the same feeder as a critical facility, such as a hospital, were supplied during the entire freeze. Homeowners in other neighbourhoods were cut off for several days. Rudimentary load rationing plans are not unique to Texas, see for example the discussion in

[13] This section builds further on a previous blog post of one of the authors (Schittekatte, 2021).

Meeus and Nouicer (2020) about the Belgian rationing plan that led to a controversy in the media and a court case in 2014.

Even though load shedding is a measure of last resort, it cannot be denied that there is a lot of value in "smart crisis load curtailment" that better considers the consumer valuation for continued electricity supply. For example, it is well known that the VOLL is conditional upon the duration of load shedding, e.g. usually being without power for one hour is less than 24 times as bad as being without power for one day. Also, one can say that the VOLL is conditional upon how much "residual power" you can still consume, e.g. when your expected load is 4 kW, the VOLL per kW when being cut 3 kW is a lot lower compared to the VOLL per kW when being cut the full 4kW. By only applying these two rules of thumb, a lot of suffering can be avoided, i.e. each consumer being constraint in (part of) their consumption for short periods at times of crisis compared to a ''lottery'' with several consumers being in the complete dark for several days. Currently, with increased rollout of smart meters and smart grids, this should be possible and could also become economically feasible. As a reference, the economic losses of the power outages during the Texas freeze were estimated between $197.2 billion and $295.8 billion (The Perryman Group 2021). Even though smarter energy infrastructure would not suffice to completely avoid these losses, its cost is an order of magnitude less.[14]

One can think even further. Currently, decisions about resource adequacy are made centrally. A minimum reliability standard is administratively determined, and the regulator assesses whether the standard is respected or whether intervention is needed. This task is becoming increasingly challenging. With consumers investing in solar PV, battery packs, electric vehicles, smart thermostats, etc. the asymmetry of information increases between the regulator and consumers. With risk-averse decision makers, this asymmetry of information will lead to increased costs, while costs to guarantee power at all moments are already rising due to ambitious decarbonisation goals and a higher frequency of extreme climate events. One way of reducing this asymmetry of information is by letting consumers individually decide about their reliability level, solving the so-called missing market issue for reliability. Ideas on how to implement such reliability market are not new.[15,16] Inspired by examples of quality differentiation in other deregulated industries, a seminal paper by Chao and Wilson (1987) discusses priority service, with different levels of guaranteed electricity supply corresponding to different prices. Other papers further discuss these ideas and work out related proposals such as capacity subscriptions by Doorman (2005) and service priority tiers for appliances by Papalexopoulos et al. (2013). Digitalisation might make these proposals implementable soon. One could also interpret a reliability market at retail level as a more refined implementation of the decentralised capacity such as currently in place in France.

However, a complete privatisation of resource adequacy might be a too radical change, with new risks for vulnerable consumers. A compromise could be a hybrid electricity investment

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[14] For example, Eurelectric and E.DSO (2021) estimate the costs of installing smart meters plus the modernisation, digitalisation, automatization and increasing the resilience of all distribution grids in the entire EU27+UK to be €175-205 billion in the period between 2020 and 2030. In 2020, the EU27 plus UK counted more than 500 million inhabitants versus less than 30 million inhabitants in Texas.

[15] A "missing market for reliability" and a "reliability market" are also slightly confusing terms as (system) reliability remains centrally managed and is a public good; what is really marketed is individual (priority) access to electricity supply at times of system stress.

[16] As discussed in Gerard and Papavasiliou (2019), real-time electricity pricing could in theory achieve the same goal in a more efficient manner. However, the advantage of priority service and related approaches is simplicity. With real-time prices, consumption decisions would have to be made at every market time unit interval. Also, priority service and related approaches allow for a more predictable consumer response, a development favoured by grid operators. On the other hand, depending on the implementation, privacy can be a major concern for priority service when implemented via direct load control.

model in which a centralized resource adequacy planner intervenes when no minimum reliable electricity supply can be guaranteed for all consumers. The minimum reliable supply level would imply a significantly looser reliability standard as is in place today. Consumers that want more protection would then need to invest in physical backup or contract that extra protection via a retailer. This would require the retailer to make sure to have access to sufficient contracted capacity at events of system stress and have in place a procedure with the relevant system operator(s) to identify their retail clients. Some people might prefer to have their own backup or to (jointly) invest in a microgrid as a local energy community. Moving away from centralised resource adequacy management is not necessarily an asocial idea in the sense that it would benefit wealthy consumers, while it would disadvantage poorer consumers. All consumers could be better off than when they would be charged for the over-procurement of capacity in fully centralized CRMs, accounting for every possible event with no consumer involvement nor choice.

5. Conclusions

In this paper, we discuss the implementation of Capacity Remuneration Mechanisms (CRMs) in the EU. We summarise the conclusions as follows.

Currently, about half of the EU Member State have a CRM in place. The precise type of mechanism differs from one country to another. In comparison to the situation in the US, the overall costs of these European CRMs remain limited. However, the capacity costs in the EU are growing year by year. For example, relative expensive mechanisms in Italy and Poland are anticipated in the near future. Importantly, one cannot forget that the existence of a CRM, even when having a relatively minor cost, can lead to distortions in other market segments and as such may lead to additional costs.

In the short run, the Clean Energy Package has the clear objective to keep the use of CRMs limited in the EU and not go down the same road as the liberalised US power systems (with the exception of ERCOT). Therefore, two steps are introduced to check if a CRM is really needed in a Member State that wants to introduce a mechanism: a European resource adequacy assessment and a national implementation plan to improve current market design. Regarding the latter, one of the important innovations several Member States are experimenting with is a shortage price function for balancing reserves. The crisis in Texas in February 2021 should not discourage from the use of a shortage price function, but its implementation details need to be decided upon carefully. In case a CRM is justified, strategic reserves with strict participation rules are the preferred option.

In the longer run, we might need to reconsider how we treat resource adequacy; resource adequacy has so far always been considered a public good, administrated by the regulator. Due to climate change, future power systems may increasingly be confronted periods of exceptional high demand for electricity and challenging supply conditions, e.g. freezes and droughts. At the same time, the information asymmetry between the regulator and consumers is increasing with the adoption of behind-the-meter technologies. Accounting for every possible event, while at the same time having a lack of insight in the reliability needs of consumers, would lead to the over-procurement of capacity in fully centralized CRMs and thus unnecessary high charges for consumers. Academics have argued that resource adequacy can potentially be a private good. Several variants of priority service, with different levels and durations of guaranteed electricity supply corresponding to different prices, have been proposed in the literature since more than three decades. Implementation in practice did not follow and the missing market for reliability has always been one of the arguments in favour of CRMs. However, time has come to start implementing these concepts as they can avoid that CRM costs start getting out of control.

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