Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan

David Newbery[1]
Energy Policy Research Group, University of Cambridge
24 March 2020

1. Introduction

The *Clean Energy Package* and *Regulation* (EU) 2019/943 (relevant extracts in Appendix C) argue that the default market design should be an Energy-Only Market (EOM), and that any Capacity Remuneration Mechanism (CRM) should only be introduced if it passes a series of hurdles, and then should be temporary and time-limited. This note takes the position that a requirement for an EOM is seriously problematic given the challenging decarbonisation targets increasingly adopted across the EU and in the UK, the requirement to massively increase renewables, and threats to phase-out or forego zero carbon nuclear power. Renewables require back-up, in amounts that are hard to predict even a year ahead, let alone over the life of the flexible plant required to be available. Relying on an EOM without longer term contracts that the private market is willing to offer will increase the cost of capital. As zero-carbon plant is very capital-intensive, this directly increases the cost of decarbonisation, at a time when public hostility to these costs is growing. However, there is a case for the EOM that needs to be examined before dismissing it as no longer fit for purpose, and this paper aims to set out some of the counter arguments.

Regulation (EU) 2019/943 lays out general principles for any CRM, of which perhaps the most important in set out in preamble at §45: "Capacity mechanisms should only be introduced to address the adequacy problems that cannot be solved through the removal of such distortions." Interpreting distortions in a wide sense, this would include failure to properly remunerate all the products needed to deliver security of supply, including such ancillary services as frequency and voltage response, reserves (primary, secondary, tertiary, defined by immediacy and duration) and other products such as ramping, black start, etc. The evidence from the development of these services in GB, and the importance attached by the Integrated Single Electricity Market (I-SEM) of the island of Ireland to DS3 (Delivering a Secure, Sustainable Electricity System) with its introduction of new ancillary services to manage increased wind penetration, demonstrates that the more generators can be motivated to invest in and provide these flexibility services, the smaller will be the "missing money" that the CRM is directed to meet.

However, this note argues that, while addressing all these market failures is a key first step, there remains the increasingly vexed problem of "missing markets" (Newbery, 2016),

---

[1] This document is an answer to the invitation received from the Andreas Tirez, Director at CREG, to provide feedback on CREG's public *Reaction to a consultation by the European Commission on the Belgium capacity remuneration mechanism*. I have benefitted from extensive and perceptive comments from Andreas Tirez and from François Boisseleau of Engie. I am currently a consultant to Engie, but am writing this in a personal capacity and it should not be taken as representing the views of Engie, CREG nor EPRG.

notably missing futures and insurance markets of a time span comparable to the tenor of financing new power stations. In a world of fluctuating policies towards carbon prices, emissions limits, nuclear phase-out or replacement, longer-term assurances in the form of long-term contracts or capacity contracts are the obvious solution, with the added benefit of reducing risk and hence the cost of capital. These problems are difficult enough in isolated island systems such as GB or I-SEM, but are even more complex in the meshed synchronised Continental network.

Perhaps the greatest uncertainty remaining now that the ETS has been partially reformed by the Market Stability Reserve is the ambiguity over nuclear life-extension (in Belgium)[2], phase-out (in France) or replacement with new nuclear (in GB). Thus in deciding the appropriate level of capacity needed to meet the Reliability Standard for Belgium it is necessary to determine whether France will in fact reduce its nuclear capacity in 2025: "described in the « *loi de transition énergétique* », namely a significant decrease in French nuclear capacity (from 59GW to 38 GW)[3] which is compatible with a French nuclear electricity production limited to 50% of total domestic generation." (Devogelaer, 2019). However, while the *loi de transition énergétique* was passed in 2015, the Multiannual Energy Programme (PPE) was presented by the French Government on 27 November 2018. The aim is to reduce the nuclear share to 50% by 2035 by closing 14 (a quarter) of its nuclear power stations. Apart from closing two nuclear stations in 2020, closures will not start until 2029. Coal plants will close by 2022, so the major nuclear phase-out is deferred.[4]

Finally, although "on 15 November 2018, a judgment of the General Court of the CJEU ("the General Court judgment") annulled the European Commission's July 2014 State aid approval of Great Britain's (GB's) CM[5] …" (BEIS, 2019, §10), the UK Government conducted a five-year review of its Capacity Market (CM) and found overwhelming support and justification for a CM. "The Government's view is that the CM's objectives remain well aligned and central to delivering the Government's energy priorities" (BEIS, 2019, §17).

2. Restrictions on the design of Capacity Remuneration Mechanisms

Regulation 2019/943 (Art. 22 §1f) requires the CRM to "ensure that the remuneration is determined through the competitive process;" which is most readily demonstrated by running a capacity auction, as in GB and the I-SEM. Indeed, the original market design on the island of Ireland that ran from 2007 until October 2018 had an administratively-determined capacity payment. The first I-SEM auction lowered the cost of meeting the reliability standard by a significant amount, demonstrating the power of auctions to reveal costs.

A key market imperfection or distortion that was the prime motivation for CRMs in the US is the failure of real time markets to reach the true scarcity price in stress periods. *Regulation* 2019/943 (Art. 10 §1-2) requires "… neither a maximum nor a minimum limit to

---

[2] endorsed in the Belgian interfederal Energy Pact (March 2018)

[3] Bracketed note added for clarification. "It has to be noted that when French nuclear capacity diminishes by 21 GW, the legally defined French security of supply criterium no longer is guaranteed. The construction of additional reliably available capacity in France then is necessary."

[4] See https://www.gouvernement.fr/en/multiannual-energy-programme-what-are-its-aims

[5] http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf

the wholesale electricity price. This provision shall apply, inter alia, to bidding and clearing in all timeframes and shall include balancing energy and imbalance prices, without prejudice to the technical price limits which may be applied in the balancing timeframe and in the day-ahead and intraday timeframes … NEMOs may apply harmonised limits on maximum and minimum clearing prices for day-ahead and intraday timeframes. Those limits shall be sufficiently high so as not to unnecessarily restrict trade, shall be harmonised for the internal market and shall take into account the maximum value of lost load." To reinforce the point that prices should reflect scarcity, *Regulation* 2019/943 (Art. 22 §2b) stresses the importance that the real time market should, if necessary, be assisted to reflect scarcity prices: "during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher." The idea of a capacity scarcity adder of the form adopted in the I-SEM and discussed below, is the logical solution to this failure. CREG (2020, §41 reproduced in Appendix A) refers to a similar scarcity adder used in Texas and termed the Operating Reserve Demand Curve (ORDC).

2.1 Missing futures markets as an argument for a CRM

However, the main argument for a CRM is not one of "missing money" but rather of "missing markets" (Newbery, 2016). Some of these missing markets are the extra ancillary service markets of DS3 on the island of Ireland, but the one relevant for a CRM is missing futures and insurance markets. Prospective entrants are interested in the value of their energy and other services, not over the lifetime of existing futures markets (only 2-3 years) but from the time of commissioning (2-4 yrs ahead for conventional technologies that meet the emissions requirements of *Regulation* 2019/943 (Art. 22 §4) to the end of the tenor of debt contracts (10+ years). The only counterparty carrying the credibility necessary to convince debt finance for long-term contracts is the Government, as the UK Government discovered when designing its Contract-for-Differences (CfDs) for renewables.

Even if companies are quite confident in their models and forecasting ability, banks are unlikely to share that same confidence. The point can be put more sharply, in that the argument for an EOM is that scarcity pricing will raise the average returns above the entry price when new investment is needed. That scarcity pricing will need to be forecast for the period 2-15+ years out from now. Scarcity prices are the tails of the distribution of spot prices, and as such prone to huge errors, as pointed out not just in the financial literature ("tail risk") but by Weitzman looking at the tails of climate change risk (Weitzman, 1998; Gollier & Weitzman, 2010). After the global financial crash, banks are more sober in their assessment of such tail risks, and would likely heavily discount revenues predicated on their frequency and value. This is relevant as CREG argues (Appendix A, §10 b) that "Due to the highly skewed revenue distribution, the P50-revenues for capacity used by Elia are strongly underestimating the true economic value of that capacity."

The counterargument can be put thus. Liberalised markets, like those for electricity, will respond to the need for an apparently missing market by either developing such a market or devising contractual alternatives. The history of futures markets evolving in the US is replete with such examples, including that they were a major stimulus to innovations in banking and the development of clearing houses with mark to market rules to insure against default (William, 1986).

In the present case, the central problem facing utilities considering generation investment is that of predicting future electricity, fuel and carbon prices over a reasonable fraction of the life of the plant. They face the risk that while their best estimate is one of an adequate return, there is a significant risk of poor returns that carry greater subjective weight than the "objective" expectation of high returns. On the other side of the market, consumers face the risk that future electricity prices might be on average acceptable, but the risk of high prices wiping out their processing profits outweighs the countervailing prospect of low prices delivering high profits. In short, both sides face asymmetric risks and would benefit from trade via hedging contracts. There is clear evidence for this in electricity-intensive large industries. The new nuclear power station at Olkiluoto in Finland was initially to be financed by long-term contracts with the pulp and paper industries, who manage forests with a comparable life-time to that of a nuclear power station.[6] (However, cost over-runs revealed the fragility of that contract).[7] In Belgium and many other countries there is little appetite for such long term contracts.

There was a different response to missing futures markets in the UK, where generation companies unbundled at privatisation moved as soon as legally permitted to buy retail companies (that in turn had to be spun out of the distribution companies), so that up-stream risks could be hedged with down-stream suppliers. High wholesale prices raised generation profits but damaged retailers selling to final consumers on fixed price contracts, and vice versa, so integration reduced the variability of their now aggregated profits.

There is no dispute that short-term anticipated price changes can be hedged by forward contracts in over-the-counter (OTC) and futures markets. Annual hydro variability with attendant price fluctuations can be hedged before weather conditions determine hydro volumes as futures markets work well for up to several years ahead, while announced nuclear outages can similarly be hedged. The more interesting question is whether the market can adequately respond to a sudden perceived risk of near-future shortages, as happened in the Winter of 2018 with nuclear outages. The evidence from many countries is in such cases, Governments, stimulated often by ill-in formed scare stories in the popular press, wish to be seen to be doing something. Whether it is an energy minister announcing to the press "Je me battrai pour chacque megawatt"[8] or whether it is setting up a task force or emergency committee to encourage action, and to what extent traders respond to this by forward hedging or would have done so without prompting is not the point. The evidence suggests that

[6] See https://www.building.co.uk/focus/nuclear-power-station-in-olkiluoto-finland-the-16-billion-watt-baby/3069771.article

[7] https://www.carbonbrief.org/new-nuclear-finlands-cautionary-tale-for-the-uk

[8] https://www.lecho.be/dossier/nucleaire/marghem-je-me-battrai-pour-chaque-megawatt/10053176.html

governments would prefer not to be back-footed in such cases and would prefer to be able to point to mechanisms that would more automatically deal with such shocks.

Similarly, the risks of high prices can be hedged with one-sided Contracts-for Difference (CfDs): in return for an upfront fee the CfD guarantees that prices will not exceed an agreed strike price—extensively used in some Australian states such as Queensland. As discussed below, this is almost the same as the specific form of a CRM known as a Reliability Option, and there is nothing to stop entrepreneurs or financial institutions offering such contracts to consumers, and in return, contracting with generators to deliver the power in high price periods at no higher than the strike price. Such CfDs are an apparently attractive way of dealing with "tail risk", also discussed below, where the viability of a generation investment relies upon a small number of very high priced hours that are unpredictable in frequency and extent. Without an obligation placed on suppliers there is little evidence of any customer willingness to sign such contracts.[9]

There are several observations to make about the ability of agents to respond to apparently missing futures markets. The first is that while large industrial companies may be willing to enter long-term PPAs to finance generation investment, there are few other takers. Retailers without a franchise that allows them to pass through contract costs to captive consumers (as was the case in GB before 1998-9) face the risk that their customers are footloose. If spot prices fall, new retailers can undercut contractually bound incumbents (as happened in Ireland when ESB was first subject to retail competition), and that limits the length of futures contracts they are willing to sign. Ofgem assumes that retailers will buy a rolling portfolio of roughly 18 months' duration when determining at what level to set the retail price cap.

If only short-term liquid futures markets exist, then how can investors hedge long-term risks comparable to the tenor of their debt obligations? One could argue that the investor could sell forward a multiple of its planned output for say two years ahead. If prices in two years' time fall, then these contracts will be in the money and will cover the cost of buying the next bunch of futures contracts and making up the shortfall in debt payments, and so on. It is in theory possible to replicate a 2*n* year contract by buying *n* 2-year contracts and rolling them forward. However, the credit risk of such a strategy massively outweighs its potential risk benefit (see for such an example the Metallgesellschaft scandal).[10]

To summarise, the problem is not that there are no futures and forward markets, only that their tenor is not matched to that needed to reassure financiers lending at an acceptable cost of capital. It has been argued that the correct market response is to recognise that the required hurdle rate (or required WACC) for investing in peaking plant or plant that could enter and alleviate the perceived future scarcity should, in a liberalised electricity market indeed be high, and that will affect the net Cost of New Entry (CoNE) used in capacity

[9] An exception might be Norway where periodic droughts lead to very high prices and industrial and commercial companies enter into forward contracts to hedge such risks, but domestic consumers, many of whom have spot contracts and face considerable price risk, are reluctant to do so. (Amundsen et al., 2005).

[10] E.g. at https://en.wikipedia.org/wiki/Metallgesellschaft

adequacy calculations discussed below. Without anticipating that discussion, it would seem perverse to step back and not create suitable hedging instruments (such as CRMs, or their more market friendly equivalent, long-term Reliability Option contracts) when the market shows a lack of ability or willingness to develop them. Again, in less critical markets less exposed to public scrutiny, markets may eventually deliver such contracts, but the history of financial innovation is measured in decades to centuries, while scarcity crises can arise at very short notice.

2.2 Missing insurance markets as an argument for a CRM

In addition to this missing futures market, there is a potential missing insurance market against regulatory and policy change. Massive renewables entry prompted by the *20-20-20 Renewables Directive* undermined the economics of the flexible conventional generation needed to infrequently back up such renewables. Carbon pricing and tax policies fluctuate, most recently in GB with its Carbon Price Support (a carbon tax on generation fuels) and the ETS *Market Stability Reserve* that has recently quadrupled the EUA price. Changing political commitments or hostility to nuclear power (e.g. the *Energiewende*) change future forecasts of capacity needs. Sweden's nuclear policy has fluctuated quite dramatically over the past 40 years.[11] A change in the tariff structure of embedded generation in the UK dramatically changed the kind of generation (small 10MW reciprocating engines connected to distribution networks to larger gas turbines connected to the transmission system). Faced with such policy instability and the lack of long-term hedging contracts, it is no wonder that there has been an investment freeze in several countries, followed by calls for CRMs. The UK's *Electricity Market Reform* was a response to just such a lack of needed generation investment (Newbery and Grubb, 2015; Grubb and Newbery, 2018).

It is often argued that missing risk markets do not solve the problem, as they merely transfer risk from one side (the utility) to the other side (whoever bears the risk, which in the case of a CRM, is normally the consumers). In short, there is an irreducible cost to this risk and it does not magically vanish through the risk shifting.

This claim is deeply flawed. The workhorse of utility regulation and portfolio valuation is the Capital Asset Pricing Model (CAPM). At its heart, this is based on expected utility theory, in which an equal probability of an increase or decrease in wealth of X is worth less than the certainty of enjoying X (see Newbery et al., 2019, Appendix E for a mathematical treatment). The cost of that risk can be measured by the risk premium r required to make the risky prospect $X+r$ have the same value or utility as the expected or certain value EX.

Figure 1 illustrates this. The utility of (or value placed on) consumption, $U(C)$, is plotted against different values of consumption. The risky choice is an equal chance of receiving 4 or 8 units of consumption at points **A** or **B**, a deviation of 2 from the mean, with expected value 6. The utility value of a certain level of consumption 6 shown as 42 but the average or expected utility is $\frac{1}{2}U(4)+\frac{1}{2}U(8) = 40 = U(5.528)$. The cost of risk in this case is

[11] See https://www.world-nuclear.org/information-library/country-profiles/countries-o-s/sweden.aspx

6 - 5.528 = 0.472, shown as the distance **MN**. If the risk is shared between two agents with equally likely outcomes **C** or **D**, then the deviation from the mean is halved, and each now has an expected utility of ½*U*(5)+ ½*U*(7) = 41.5 = *U*(5.877) and the cost of risk is now 0.123. However, there are two agents bearing this cost, so the total cost is twice this, or 0.246, which is half the cost of risk if just one agent bears all the risk.[12] More generally, in this quadratic approximation to the local shape of the utility function,[13] the total cost of risk divided equally among *n* equally placed agents is 1/*n* the cost of one similar agent bearing all the risk.

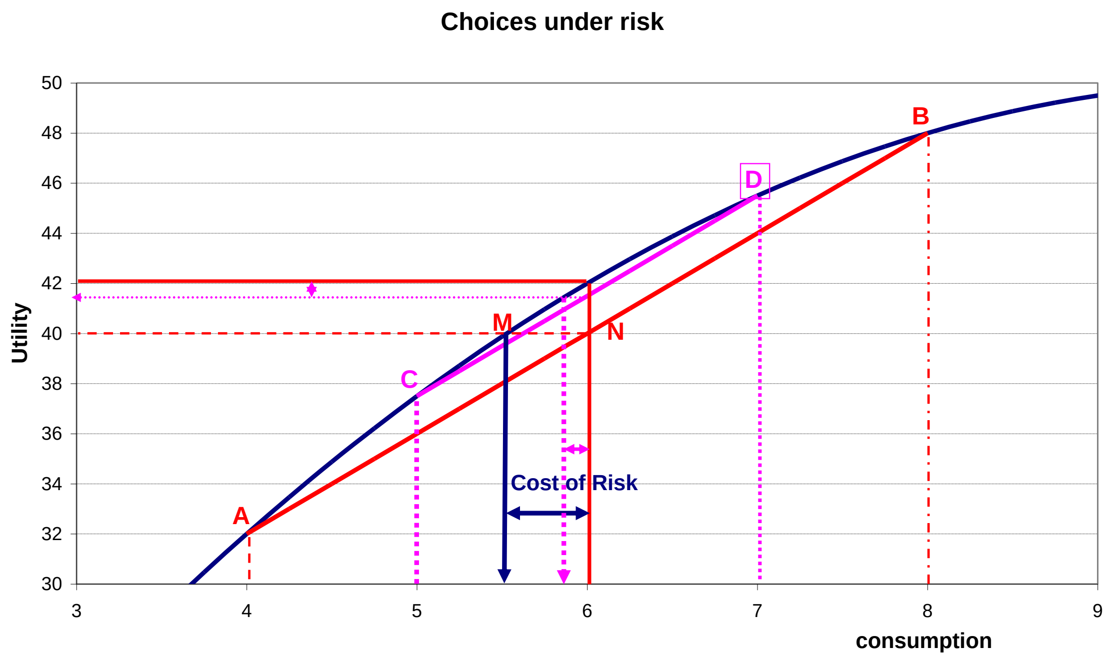

Figure 1 Illustration of cost of risk and risk premium
Note: The utility function is $U(C) = 10C - \frac{1}{2}C^2$

The implication is that placing all the risk of construction on the developer is potentially very large compared to spreading that risk over, for example, all 4.7 million Belgian households who enjoy electricity, and the remaining 70% of industrial, commercial and other consumers who consume higher amounts. This is not a fair comparison, however, as in the case of building power plants, the construction and operating risks are likely to have a low correlation with GNP, Government income and public sector net assets, and with the stock market. In short, they are largely idiosyncratic risks. That might suggest that they can be widely diversified through the stock market, but we again run into the problems of

[12] In utility terms the cost of risk is exactly halved, but as Newebry et al., (2019 Appendix E) shows, measured in consumption units the cost is only approximately halved, in this case to 52%. The other main message from CAPM is the cost of a risky project depends not on the absolute risk of the project but on its correlation with the existing portfolio. This is captured by the value of β, a key component of determining the WACC in utility regulation.

[13] This is equivalent to taking a second order expansion around the mean as in Appendix E, and ignoring higher order terms, which will only be valid for limited risks. Fat tails or extreme events would seriously invalidate this approximation.

asymmetric information and the perceived risk of political intervention. The problem is that the risks are not considered to be distributed around a known mean value. Especially with construction risk and even more for political risk, shareholders take the view that any financial proposal (particularly one coming from a company committed to such projects) is likely to have huge optimism bias.[14]

3. CREG's *Reaction* to DG Energy's consultation

CREG (2020) argues that an Energy-Only Market (EOM) combined with the current ENTSO-E proposals and *Regulation* 2019/943 should be able to provide adequate capacity and reliability in Belgium and that therefore there is no need for a market-wide capacity mechanism (CREG, 2020, §17, see Appendix A). Some of CREG's criticisms of ENTSO-E's approach are valid, but it does not follow that Belgium and other Member State do not need a CRM. The arguments that an EOM combined with current EU Directives and Regulations is adequate appears faulty. The Belgian Federal Planning Bureau and other studies[15] in addition to Elia (2019) argue that there is a need for new capacity by 2025, although this is disputed by other claims.

One of the more interesting comments by the Federal Planning Bureau (2017, p1) is that "First, it once again demonstrates the major impact a fair carbon price can have on the functioning and the profitability of the Belgian gas units. If the carbon price on the EU ETS market could trigger a switch in the merit-order between coal and natural gas, Belgian power plants will profit, run for more hours, export more electricity to the neighbours and overall would benefit in terms of increased inframarginal rents." Since that date the EU *Market Stability Reserve* has quadrupled the price of carbon (EUAs), and that has had a significant effect on the merit order and profitability of new gas generation. This is relevant to the statement in the abstract "Finally, the question of premature closure of currently existing Belgian gas-fired power plants that have not come to the end of their operational lifetime yet is investigated …" and later (Federal Planning Bureau (2017, p.2) "Finally, if we succeed in keeping the capacity of the current operational thermal flexible park online until after the complete phase-out of all the nuclear units, generation adequacy should be assured. It is when one (or more) of the current units decides to leave the system that adequacy can no longer be guaranteed …"

Belgium is strongly interconnected with her neighbours so obviously their capacity adequacy is also relevant to whether Belgium needs a CRM to address imminent problems of capacity adequacy. The German Federal Ministry of Economics and Energy (2019) argued

---

[14] CREG, in response to this argument, point out that "Risks can be traded and spread. More fundamentally, however, is the aspect of choice. With a CRM, the authorities are intervening and obliging every consumer to participate in the risky business of investment." The argument that there is an over-procurement risk is certainly the case and is discussed below and at length in Newbery and Grubb (2015). That is certainly an argument for an independent assessment of whether to run a CRM and if so the recommended capacity to procure. In the UK this is the task of the Panel of Technical Experts, but it could perhaps also be undertaken by the regulator, if so instructed by the government and consistent with any relevant Directives. The argument for intervening is the normal one that interventions are justified if they are the least-cost way of addressing a market failure.

[15] Cited in Devogelaer (2020)

that there is no adequacy concern assessed for Germany and little reason to be concerned about Belgium (while noting that the information and assessments about neighbours was inevitably less complete than for Germany). Thus "The capacity trend is also expected to decline sharply in France and in Belgium, where the announced phase-out of nuclear power by the end of 2025 is represented." (Federal Ministry of Economics and Energy, 2019, p.94), and later, "In Germany/Luxembourg, LoLP remains zero in the entire time span. This corresponds to a load balancing probability of 100 %. For Great Britain and to a much lesser extent also for Belgium, the sensitivity shows an increase in the LoLP in the year 2023." (Federal Ministry of Economics and Energy, 2019, p.195).[16]

The main dispute is about the amount of capacity to procure, how to estimate that, and whether the unaided EOM would deliver that amount (whichever it is). According to CREG,[17] the latest adequacy assessment (Elia, 2019) shows that the adequacy concern is decreasing. This is driven by increasing interconnection capacity and the massive increase of renewable capacity, mostly wind that is geographically dispersed. The results from the Elia adequacy assessment (Elia, 2019, Fig. 4-18, p. 138) show that the LoLE decreases in the EU-Base case[18] from 9.4 hours in 2025 to 6 hours in 2028 and 2030 (the EU-HiLo figures are for 2025, 10.5 hrs, 2028 6.9 hrs and 2030 6.2 hrs). For EENS (Expected Energy Not Served), the decrease is sharp, from 20 GWh in 2025 to 6.5 GWh in 2030 (in HiLo from 219 GWh to 6.3 GWh). In 2025 the non-viable gap (i.e. unable to cover its costs in the market) if all existing capacity remains is 2.4 GW (base, HiLo is 3.9 GW). If the EENS is valued at €10,000/MWh, the 2025 cost to consumers would be €200 million (Base) or €2.19 billion (HiLo). If the capital cost of a new CCGT is €700 million/GW, the base EENS would only pay for 330 MW. Whether or not these costs justify running a CRM is a calculation that should be left to the body charged with the adequacy assessment (in GB, the System Operator) ─ see §4.3.

3.1 Experience of CRMs in GB and I-SEM

Some of the elements proposed by ENTSO-E and in various Regulations might benefit from a study of existing CRMs. Both GB and I-SEM in the island of Ireland have introduced and successfully run capacity auctions, and their different approaches to the problem are also instructive. However, both have the advantage of being isolated from the synchronous Continental grid, for which cross-border flows are more problematic, and where interactions of different CRMs are more likely. Lambin and Léautier (2020) show that without the ability to control interconnector flows (i.e. within a meshed AC network) a country with an CRM

---

[16] However, there have been extensive criticisms of the apparent optimistic assumptions underlying this report. First, that the report assumes that 14 GW of as-yet unidentified capacity will be invested by utilities responding to market signals. Second, it expects some 7000 km of grid extension will be delivered on time by 2025 while on 1,700 km was delivered over the last 10 years, in a country which has found it very difficult to secure consents, to the extent that it has considered extensive and very expensive undergrounding. Finally, there is a paradox in arguing on the one had there is no adequacy issue in Germany in 2030 while at today continuously adding new capacity in different types of "strategic" reserves.

[17] in comments on an earlier draft of this note

[18] The EU-Base case is the best estimate (central scenario) while the low probability, high impact scenario is denoted as HiLo.

located next to a county with an EOM benefits at the expense of its neighbour and *vice versa*. The reason is that the CRM makes exporting to an EOM more profitable (the EOM will have higher stress hour prices), lowering the cost of the CRM, and undermining the security of the EOM by increasing dependence on uncertain imports. The authors conclude that within a meshed network CRMs should be harmonised as otherwise there will be a cascade of countries deciding to respond by introducing their own CRMs.

One issue that came out clearly in the GB capacity auction[19] was the importance of choosing how much of the gap to fill in the T-4 auction (for delivery 4 years hence) and how much to leave to the T-1 auction. In the first auction 1,600 MW of CCGT secured a capacity agreement, but its bankers would not finance it at the rather low clearing price (20% of net CoNE) and it then paid the (rather modest) penalty and relinquished its contract, leaving a very large apparent gap in the volume of new capacity to procure. In the event the failure to include interconnectors until later auctions made up the short-fall. The more that is left to the T-1 auction the better is the estimate of the capacity to procure, but the smaller the range of possible options that can be delivered in time. That said, no-one initially expected batteries to become such an important source of new capacity, deliverable quite quickly, while gas-fired small reciprocating engines (also popular, although mainly as a result of distorted incentives to connect to distribution networks) made up a large fraction of new capacity procured and can again be delivered rapidly.

Again, the T-1 auction is invaluable in keeping old plant on the system (effectively keeping them as a strategic reserve but without the apparent inefficiency of denying them access to other revenue streams).[20] The Panel of Technical Experts suggested that one low cost option would be to put in place timely arrangements for securing planning and connection consents at least system cost grid connection points that could be released closer to the time new plant is needed. While a CCGT can be commissioned within two years (and peaking plant much faster) it can take several years to acquire all these rights before starting to build.

One can dispute that all that is needed for an adequate investment signal is a real-time scarcity adder or the ORDC described in CREG (Appendix A, §43). While that can encourage short-term hedging contracts by addressing a potential short-run market failure (lack of full scarcity pricing), it does nothing to solve the missing futures/contract markets with a tenor of 14+ years discussed in the Introduction above. If the fear is of over-procuring, then keeping open options (such as contracting to prevent exit, or preparing new sites) and leaving more to a T-1 auction lower that risk. In the GB auction only new capacity secures long-term contracts (up to 15 years in GB, 10 years in the I-SEM) while existing capacity only receives a one-year contract, providing considerable flexibility if the amount of new capacity is modest and subsequent auction clearing prices are low, reflecting future adequacy.

As to whether the outcomes of these auctions was considered successful, in GB it appeared that the cost to consumers of the auction payments was almost totally offset by a

[19] The author was a member of the Panel of Technical Experts advising the Minister on the parameters chosen by the System Operator in its recommendations.

[20] But see footnote 27 below.

reduction in payments for wholesale electricity (Ofgem, 2017), reflecting the observation by the Competition and Markets Authority that the GB wholesale markets are workably competitive (CMA, 2016). There are potentially more serious problems in more concentrated markets, such as the I-SEM (see Teirila and Ritz, 2019), and much then depends on the efficacy of market power mitigation measures, to which a great deal of thought was given in the I-SEM (e.g. SEM, 2016 and subsequent documents on the I-SEM CRM design). Certainly the I-SEM auction lowered the annual cost of capacity procurement from about €575 million to €345 million, or by 40%.[21] Whether the auction clearing price could have been even lower with a more competitive market is hard to judge, but certainly there are local pockets of market power created by transmission constraints and the need to have adequate reserves to deliver in these constrained pockets.

Critics have pointed out that the GB auctions kept old coal on the system rather than lower-carbon gas generation or better still, demand side response. This is somewhat unfair as unlike the rest of the EU, GB has a high *additional* carbon price of generation fuels of £18/tonne CO_2. As these coal plants only run a few hours per year the cost of the emissions is greatly outweighed by the cost of replacement capacity. In short, carbon prices and the emissions restrictions of the *Clean Energy Package* can address such criticisms.

4. Reliability and the Value of Lost Load

The Value of Lost Load, VoLL, is particularly problematic and central to the Reliability Standard, normally measured by the Loss of Load Expectation (LoLE, in hours per year). The capacity to procure in the CRM auction must be sufficient to deliver this Reliability Standard. LoLE is related to the VoLL and the Cost of New Entry, CoNE theoretically and in practice by

$$\text{LoLE} = \text{CoNE}/\text{VoLL}. \qquad (1)$$

The GB CRM is based on assessments undertaken by the System Operator (e.g. National Grid ESO, 2019). The amount to procure is based on balancing the cost of Energy Unserved (or "Expected Energy Not Served" (EENS) or "Expected Energy Unserved" (EEU)) against the cost of reducing EENS by paying for more capacity. Equation (1) emerges from that calculation, but the cost of EENS also depends on the VoLL.

CREG argues that whether to have a CRM or an EOM should be decided by the "Principle of proportionality",[22] that is whether

[21] Compare the old SEM payments at https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-14-070%20ACPS%202015%20Decision%20Paper.pdf and the I-SEM results https://www.sem-o.com/documents/general-publications/T-1-2019-2020-Capacity-Market-Auction-Overview.pdf

[22] See https://www.creg.be/sites/default/files/assets/Consult/2019/2024/PRD2024PresentationTFCRM191104.pdf

$$\text{Cost of CRM} + \text{EENS}_{\text{CRM}} * \text{VOLL} < \text{EENS}_{\text{EOM}} * \text{VoLL}. \qquad (2)$$

This would be a special case of the formula to determine the amount of capacity K_t to procure at date *t*, which should minimise

$$\text{Cost of } K_t + \text{EENS}_{K(t)} * \text{VOLL}. \qquad (3)$$

Returning to the interpretation of equation (1), in both GB and I-SEM, CoNE is *net*, not *gross*, CoNE.[23] While that may not appear material for peaking plant that only operates during stress periods, even peaking plant may offer ancillary services. It would be misguided to discourage entrants from investing in suitably flexible peakers able provide such services. Further, Combined Cycle Gas Turbines (CCGTs) with a high gross CoNE might earn sufficient energy and other revenues to lower their net CoNE below that of peakers, and again it would be perverse to exclude these.

Second, VoLL, required in all three equations, is particularly problematic if it is to be measured according to the ENTSO-E methodology. In GB the approach is more pragmatic. Having decided on a net CoNE of £49/kWyr,[24] and a LoLE of 3 hrs/yr, the implied VoLL was taken as £17/kWh, weakly justified by a stated preference survey with some very high industrial values and rather low consumer values (London Economics, 2013).

Basing the VoLL on the cost of disconnecting the least valued customers (as CREG suggests in Appendix A 18 §4) presupposes the ability to do so, which will be country-specific. In GB disconnections are automatically triggered when the frequency drops to 48.8 Hz, when each DNO is required to disconnect 5% of peak demand. As DNOs cover wide areas they have (at present) limited ability to target disconnections (although those who have obtained protection, such as hospitals, airports, etc. can avoid disconnection). One problem, perhaps peculiar to GB, is that disconnection automatically trips any embedded generation on the feeders disconnected, amplifying the loss of load (or reducing net load shedding). This (and frequency tripping) caused a larger loss of local generation in the GB black-out of 9 August 2019 than the original loss of grid-connected generation. While this particular loss of load was not due to inadequate capacity the lessons learned suggest the need for a larger reserve margin, which could influence the amount of capacity to procure (equal to peak load plus immediately available reserves).

If VoLL is to be directly measured, then system collapse or load shedding to avoid system collapse may have much wider impacts than personal inconvenience. Recent black-outs in GB and elsewhere have shown that critical infrastructure is often compromised. The GB black-out of 9 August 2019 resulted in the disconnection of 1.15 million customers and shed 931 MW for up to 44 minutes, with a loss of load of 521 MWh. Even taking the high value of £17,000/MWh, the apparent cost was less than £9 (€11) million. However, it occurred at 5pm on a Friday with consequential losses of electric train services that in turn

[23] Gross CoNE is required by ENTSO-E (2019).
[24] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/468203/Capacity_Market_-_parameters_0810.pdf

caused massive disruption on the railway network.[25] The overall cost of all these subsequent disruptions was substantially higher than the £9 million (which itself would have been much lower at some of the VoLLs adopted in Belgium by the Federal Planning Bureau for domestic consumers (€2,300 /MWh) and ACER (€5,500 /MWh) (cited by CREG, 2019 and reproduced in Appendix B).[26]

In Belgium matters are apparently handled better with implications for a lower VoLL. According to CREG "The fact that a load disconnection plan (a system defence plan) is economically efficient is mandatory according to article 11.6.b of *Regulation* 2017/2196 (establishing a Network Code on electricity Emergency and Restoration, or NC E&R).[27] In Belgium, this is already the case. The Belgian Minister of Energy approved on 19.12.2019 the system defence plan proposed by the Belgian TSO Elia according to the European NC E&R. The system defence plan includes the manual demand disconnection procedure in line with article 22 of the European NC E&R. The manual demand disconnection procedure affects only distribution grids with a connection of less than 30 kV to the transmission grids in primarily rural areas. Industrial and power plants are excluded in the manual disconnection procedure as well as the Brussels capital region, capital cities of the provinces and city centres of at least 50,000 inhabitants. Consequently, the manual disconnection procedure affects almost exclusively households. (Since it is technically not feasible to selectively disconnect consumers on distribution grids, small services (e.g. bakeries) and small enterprises in the concerned primarily rural area are also disconnected while – of course- high priority consumers like hospitals are excluded (though hospitals are not typically located in less than 30 kV rural areas)). Therefore, the approved manual disconnection procedure follows the requirement of art. 11 (6) by minimising the VoLL of manual demand disconnection and excluding the consumers with the highest VoLL e.g. industrial and power plants. In this sense, the Belgian manual demand disconnection plan is developed in order to minimise the overall costs of involuntary disconnection in order to guarantee system stability as well as adequacy."

If indeed VoLL is to be set at a relatively low level (compared to the GB back-estimate), and if the WACC for new entry is to be high (because of the absence of long-term CRM contracts) then the net CoNE will be also increased, perhaps substantially for plant with few running hours and for which the fixed capacity cost is the largest part. That in turn from equation (1) would imply an increased LoLE. Perhaps that is the correct answer, but before making that decision, the government will need to be advised of what that would mean in

[25] See https://www.ofgem.gov.uk/publications-and-updates/investigation-9-august-2019-power-outage

[26] Although CREG's presentation at https://www.creg.be/sites/default/files/assets/Consult/2019/2024/PRD2024PresentationTFCRM191104.pdf) indicates that VOLL is not yet known and considers a range of possible values from €20/kWh down to €5/kWh.

[27] At https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0054.01.ENG

practice. It is not impossible, and one of the surprises for Europeans is the high LoLE is many US states, which appear to be accepted as business as usual.[28]

Third, the events that precipitate a stress event are not necessarily simply calculated as independent outages of individual in-feeds according to the N-1 standard. With increasing renewables embedded in local networks, and voltage and frequency responsive generation that disconnects at set levels, and interacting control equipment increasingly deployed on networks, the SO has typically less visibility of and control over the impact of a single in-feed loss triggering voltage and frequency disturbances, as happed in the 9 August event. Consequential losses of generation can amplify the original disturbance, and this seems the case in several recent incidents in the I-SEM, where separate generating units in the same power station have sympathetically disconnected.

This point perhaps needs elaborating. The contribution that renewables can make to capacity adequacy is measured by (in GB) their de-rated capacity, or their equivalent firm capacity (EFC). As stress events are more likely in winter on cold days of peak demand, solar should be almost entirely de-rated, but wind often contributes more in winter than in summer in Northern Europe. Thus National Grid (2018) concludes that "For wind generation we assume an equivalent firm capacity (EFC) of 17 per cent. This assumes the same level of wind we have used in calculating the winter view." National Grid apparently undertook a separate analysis of extreme cold spells and de-rated wind a modest amount from the calculation based on all winter peak hours, in response to claims that a cold polar vortex could lead to a succession of cold windless days. The impact of such events will be country-specific, depending on their ability to shift supply and or demand via storage,[29] and the extent to which demand is cold-sensitive (France has many times the demand increase to degree days than GB as it has far more electric heating). The implication of increased renewable penetration is an increased demand for more flexibility, such as inertia and the ability to ride through higher Rates of Change of Frequency (RoCoF). This is clearly recognised in the I-SEM through its DS3 Programme discussed above, and also by CREG.

The I-SEM Reliability Option auction is in many ways superior to the GB CRM, in that it is a voluntary auction for in effect a one-sided Contract-for-Difference with a strike price set at above the variable costs of the most expensive generation unit (currently €500/MWh). Generators securing an RO sell at the market price, which, with a capacity adder can rise to the VOLL, and pay the difference between that market price and the strike price if they are generating, and otherwise they are obligated to pay the whole market price to replace their output. As such it provides a hedge for consumers who are protected against prices higher than the strike price.

[28] "The U.S. electrical grid has been plagued by ever more and ever worse blackouts over the past 15 years. In an average year, outages total 92 minutes per year in the Midwest and 214 minutes in the Northeast. Japan, by contrast, averages only 4 minutes of interrupted service each year. (The outage data excludes interruptions caused by extraordinary events such as fires or extreme weather.)" IEEE at https://spectrum.ieee.org/energy/policy/us-electrical-grid-gets-less-reliable . This is dated 2010 and matters may be improving, see NERC (2019) for more recent data.

[29] Some countries including the UK have special tariffs for off-peak electric heaters that store heat in the low demand hours for later use.

The other point about the I-SEM RO is that it is voluntary on participants, but exists to set an insurance hedge for consumers, as their wholesale buying price will be capped by the RO strike price. In effect the regulator is auctioning off a one-sided contract for difference to hedge consumers, overcoming the transaction cost of numerous consumers having to decide what that option is worth. Generators who think they can benefit more from selling opportunistically in the stress periods at the full uncapped price are free to do so and avoid the penalties from non-delivery (equal to buying back that amount in the spot market) but at the cost of foregoing the RO payment. Consumers are being offered a fair and explicit deal, in that in return for an up-front insurance premium (the RO payments) they are assured of prices never exceeding the strike price.

To summarise, CREG distinguishes between the VoLL_Low to be used for the reliability assessment, and the VoLL_high that would be the price earned in stress events and therefore more than enough to induce entry. But that ignores the heart of the problem that an expected future price in a small number of stress hours cannot, without a Reliability Option, be hedged over a long enough period to cover new investment, and as such is an inadequate basis to defend an EOM. While short-term futures markets can offer hedges against price spikes that can be sold by generators and increase their revenue, the problem is whether their future revenue from such options are bankable when it comes to financing new build. If so, then the EOM may be able to induce adequate entry, and the proof is in the willingness of funds to back such new entry at an acceptable cost of capital. What is an acceptable WACC and how this feeds through to an acceptable LoLE are interconnected, as noted above, and are essentially political judgements.

4.1. Evidence on the frequency of Loss of Load Events

Having made these points, though, it is noticeable that the actual frequency of Loss of Load events in the past appears much lower than the Reliability Standard would suggest. Part of the reason is the natural caution of System Operators (SOs) and/or Ministers when deciding on the capacity to procure, as they do not bear the cost of over-procuring, but they do bear the blame if there is a serious black-out with the kind of repercussions noted above. The evidence in GB is that either because the SO has numerous short-term measures in his back pocket (Max-Gen, emergency imports, voltage reductions, etc.) before getting to disconnections that we have not experienced many loss-of-load events. However, the past may not be a good guide to the rapid transition underway to a low-carbon electricity system with very different technologies connected in less visible ways to the networks.

4.2. Is a capacity adder a substitute for a CRM?

As to the main case for a system-wide capacity mechanism, the I-SEM Reliability Option auctions combined with their Pricing Adder (based as usual on the VoLL-SMP, but only gradually rising to the full value) seems to address the key point of missing futures markets for hedging for new entrants. Specifically, the market failure that the RO auctions addresses is that the shortfall from predicted market revenues needed to justify a new entrant's investment is better backed by a 10-year contract than just on the expected price forecasts of the company. If they are to borrow money from a sceptical lender, then the company forecast will be viewed as possibly biased, and will either be discounted or attract a high cost of borrowing (or a low debt:equity ratio). An auction-determined system-wide contract price carries credibility and avoids problems of asymmetric information.

CREG (2020, §12, see Appendix A) argues "that the assessment of security of supply should be simulated in a realistic way. This implies that simulations should focus on real time LoLE rather than day ahead market LoLE." In GB the SO has to give four hours warning of a stress event after which failure to deliver will be penalised, and clearly this could happen considerably after the closure of the day-ahead market. In determining the capacity to procure, it is the actual LoLE and EENS that are modelled (by assuming outage probabilities, weather, etc.), rather than the forecast LoLE, and to that extent CREG is correct in how the required capacity should be determined.

The I-SEM Reliability Option deals with the vexed question of cross-border capacity eligibility, as it is properly seen as a hedge for domestic consumers, while allowing, and with the pricing adder, encouraging, spot and balancing markets to clear at the high prices signalling scarcity. It is then up to the National Regulatory Authority or the SO to assess the extent to which foreign generators can contribute to relieving that scarcity. Thus CREG (Appendix A, §12) also argues that "All available balancing reserves in Belgium and abroad should be taken into consideration." At §14 "Also, the winter reserves in Germany should be taken into consideration. In fact, the German regulator anticipates an increase of winter reserves from 6.6 GW to 10.6 GW by 2022-2023. These reserves are primarily used to stabilise the domestic electricity grid when there is a lot of wind production in the north that needs to be transported to the south. During periods of high wind, no capacity shortfalls are expected. So during periods of low wind, these capacities are largely available. These capacities can thus be used to address adequacy issues, considering that adequacy issues generally arise when wind generation is limited."

Both these external sources are indeed potentially valuable, but their contribution is hard to measure. Coupling EU balancing markets is still a work-in-progress, and the evidence from the I-SEM is not encouraging. Faced with a domestic potential shortage, SO's are reluctant to offer reserves (or even controllable interconnector capacity) to external claimants. Clearly ACER and ENTSO-E wish this to change and have worked continuously to achieve balancing integration since at least 2014. Using "spare" capacity abroad also makes sense and ought to be automatically available through day-ahead and intra-day markets at some price. Modelling their availability is harder as the quotation notes, depending on local wind and transmission constraints, and clearly a matter for Continent-wide integrated capacity studies that presumably ENTSO-E will coordinate. The difficulty may lie in which countries will be simultaneously bidding for them, and it would be imprudent for any one country to assume that all such capacity is available to them. Presumably access to strategic reserves will also depend on the circumstances under which they are made available.[30] Lambin and Léautier

[30] CREG argues (in a comment on an earlier draft) as follows. "Besides the direct impact of using out-of-market capacities, such as reserves, on the adequacy level, there is also an indirect impact via the increased profitability of assets in the market. The reason is that—by definition—out-of-market

(2020) are very sceptical of the value of strategic reserves, and note that they have the same trading disadvantages as an EOM, leading to pressure to replace them with a CRM.

The argument that at any moment in any country there may be adequate existing de-rated capacity just means that running an auction should lead to a zero price and no extra capacity entering. In short, as a CRM the I-SEM solution seems compliant with the various Regulations (see Appendix C Preamble para 50 and Art. 22 3(a)) and State Aids rules (and has been granted State Aid exemptions by the EC). It would seem to be an attractive model for other countries to follow.

4.3. How should scenarios be treated in determining the capacity to procure

Much of the dispute between CREG and Elia turns on whether the volume to procure is the best estimate (central scenario) of 2.2 GW or the low probability, high impact scenario (denoted as *HiLo*).[31] *Regulation* (EU) 2019/943 *Article 23*(5) requires that the amount to procure "(b) is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments; (c) contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address"; … (h) applies probabilistic calculations; (i) applies a single modelling tool; ...".

That would suggest that the amount to procure requires attaching probabilities to each scenario and then finding the capacity that minimises the expected cost. This is a non-trivial

capacity such as strategic reserves can prevent LoLE-hours (LoLE in real time, referred to as "LoLE_realtime"), without impacting market prices. As a result, the LoLE in real time, which is the only relevant LoLE when considering adequacy, will be lower than the number of hours the market cannot supply all demand ("market LoLE", in this document referred to as "LoLE_market"). This effect can be illustrated with a simple example. Assume there is a strategic reserve of 1 GW. The day ahead market cannot clear for 2 hours, with a curtailment of respectively 1 GW and 2 GW. So, the "LoLE_market" is 2 hours, during which the market price equals the market price cap (which is VoLL_high). In real time, the strategic reserves are activated, leading to only one hour with load shedding of 1 GW. The "LoLE_realtime" is only 1 hour. So, when there is out-of-market-capacity available, such as strategic reserves, the LoLE on the market ("LoLE_market") is higher than the LoLE in real time ("LoLE_realtime"). The LoLE_realtime is the only relevant parameter to assess whether the reliability standard is met."

[31] As CREG noted in a response to an earlier draft "In the HiLo scenario, Elia is using lower availability rates for nuclear capacity in France than France itself is applying. However, if France would agree on the availability rates, then it would follow that the derating of nuclear capacity should be adapted, leading to attributing less capacity certificates for the same nominal nuclear power capacity. This means that the offer of capacity certificates from other resources besides nuclear capacity will have to increase if the French CRM is to meet the reliability standard. This effect of having a higher offer from other capacities is ignored in the HiLo scenario. Moreover, according to *Regulation 2019/943*, a Member State can do its own National Resource Adequacy Assessment, as a complement to the European Resource Adequacy Assessment, but only by adjusting assumptions that are specific to its own country and not to other countries. Otherwise, coordination on the European level could fall apart and could lead to an overestimation of the need for capacity."

exercise. While one can attach moderately objective probabilities to loss of load events given the level of capacity and the individual scenario, at best there are only subjective probabilities to attach to the likelihood of each scenario. Faced with that difficulty, the GB Electricity System Operator's "decision on the target capacity to secure is made by a cost optimised Least Worst Regret (LWR) methodology." (National Grid ESO, 2019). Elia has two scenarios (Central and Hi-Lo) and several sensitivities (Elia, 2019, ch. 4 and fig 4.2). "It is important to stress that the new capacity is required for events beyond Belgium's control. In this case the 'EU-HiLo' scenario was combined with the 'CENTRAL' scenario for Belgium. The 'EU-HiLo' scenario is the one used to quantify the strategic reserve volume and is in line with the EC's State Aid approval of the current strategic reserve mechanism." (Elia, 2019, 4.1.4.) Elia then endeavours to assess whether the market will fill the gap(s) without a CRM and concludes not.

It would appear that Elia is not making a specific recommendation on the amount to procure in a CRM, as it is at an earlier stage of providing evidence to CREG and the EU on whether a CRM and/or Strategic Reserve is needed. That might explain the absence of a least-worst regrets or estimated expected least cost amount. However, at some stage, if Belgium does decide on a CRM, the amount to procure will have to be addressed, and a lack of clear guidance on how to do it is troubling.

5. **Conclusions**

Deciding on the most cost-effective way of delivering security of electricity supply in a country that is linked to a larger synchronised set of markets is not straightforward. While the guidance provided by the *Clean Energy Package* and *Regulation* (EU) 2019/943 is frequently helpful, it starts from the undemonstrated assumption that Energy-only Markets will normally provide adequate investment signals and incentives to deliver security, providing various listed market failures are rectified. Past private investment decisions in the relatively recently liberalised EU electricity sector have either been driven by long-term contracts (in the case of renewables) or by the emergence of low capital-cost highly efficient base-load Combined Cycle Gas Turbines (CCGTs), which, with favourable gas prices at various times, seemed attractive.

Early investment CCGT booms were predicated on a fairly stable regulatory and political environment, before climate change imperatives and debates on the future of nuclear power complicated the landscape. With high and growing renewables penetration underwritten by a series of Directives, the phase-out of coal, new emissions limits, the prospects for flexible plant like gas turbines have become more dependent on hard-to-predict shortage periods; in short, on the tails of future price distributions. Carbon prices quadrupled when the ETS *Market Stability Reserve* was finally enacted, but as its future remains uncertain, it will likely be difficult to convince now-cautious banks or fund managers to make long-term loans at acceptable interest rates unless with very low gearing. Equity funds may be hard to secure, given the recent performance of utility shares. Capacity payments, determined in competitive auctions, can reduce this future uncertainty and hence, by lowering investment risk, lower the cost of capital and the cost of meeting carbon targets.

That shifts the onus on to governments or their delegated advisors (usually System Operators) to determine the amounts of capacity to procure. This task is complicated by a number of factors, some of which are both large and politically problematic. Nuclear phase-out, attitudes to nuclear life extension and refurbishment, and to nuclear new-build all impact the likely available future capacity, in some cases relatively soon. Without clarity on these issues, the gap between future demand and likely available capacity could become very uncertain. While this is a new problem in some countries, older problems remain, such as determining the amounts of imports that can be relied upon in stress periods, de-rating renewables capacity for such periods, and forecasting the likely pace of efficiency gains and price-induced peak shifting that might emerge in four years' time.

There is some comfort in observing that if the market deems future capacity to be adequate with their forecast revenue streams, the capacity auction will clear at a low price, with little cost. There is the additional comfort that higher capacity targets and associated higher capacity auction prices have in competitive wholesale electricity markets (such as in GB) resulted in lower wholesale prices, so the capacity payments over-state the cost to consumers. However, in a meshed network, lower domestic prices will also benefit importing countries abroad. There is also the unattractive feedback that larger amounts to procure lead to lower wholesale prices, which amplifies the missing money and further increases auction clearing prices. Regulators such as CREG are therefore well-advised to scrutinise claims by System Operators and government ministries carefully, as they face the asymmetric risk of not paying for excessive procurement, but facing strong criticism if the lights go out.

The risk for consumers of overestimating the capacity need by TSOs and governments is also recognized by the European Commission in its report on CRMs:[32]

> (539) An important aspect in central buyer mechanisms – as in other volume-based mechanisms – is the need for a central body to estimate the required amount and type of generation capacity to attain the desired level of system reliability. While this minimises risks of insufficient provision of generation capacity, it risks leading to excess capacity if risk-averse central authorities set the targets for generation capacity at unnecessary high levels. This risk exists to some extent in every capacity mechanism type, however, and should be mitigated by links to a thorough and transparent adequacy assessment, and appropriate oversight of regulators or independent experts to verify the parameters set by governments and TSOs.
> (546) Some inefficiency may be unavoidable in any central buyer design, for example due to the complexity of carefully assessing all the design features, the dependence on central judgements by risk averse decision makers – though this can be reduced by including a role for the regulator or independent experts in the

[32] At https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf

process – and the need to centrally determine the required flexibility characteristics of capacity providers through the design of the capacity product.

The past 30 years of the evolution of liberalisation in EU electricity markets teaches us that institutional and regulatory developments are slow and often expensive. Each EU *Energy Directive* has been long in planning and delivery. Market coupling went live in NW Europe in 2014, but it took until 2018 for the I-SEM to be created and finally coupled. Transforming the electricity market on the island of Ireland took six years, cost the regulators well over €100 million (excluding all the adaptation costs of the energy companies), and is still evolving. Coupling balancing markets is still not complete, and there remain concerns that price zones are not necessarily of optimal geometry. Arguably they might (or should) be replaced by nodal pricing on the US Standard Market Design, which would considerably change the market design and regulatory requirements. Exactly how capacity adders should be set, invoked and managed in a meshed network in real time is still unclear, and will undoubtedly require experience and many adjustments to work well. It is notable that the experiments to date have been in electrically isolated systems like Texas and the island of Ireland.

In addition, while the current (since 1990) evolution of electricity markets started with surplus capacity and no pressing climate change or renewables targets, by now new investment is needed in zero-carbon generation and capacity margins in many countries are becoming tighter. The future of decentralised and increasingly volatile generation from renewables makes the task of measuring Equivalent Firm Capacity harder. It may be that ICT, local battery storage and digitalisation will make the demand side adequately flexible and improve reliability, but the business case and evidence for that hope is still lacking. While maintaining security of supply and reliability remain over-arching requirements, learning how best to maintain them may initially require higher payments to compensate for uncertainty than the long-run equilibrium cost, but that is the price of learning.

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

References

Amundsen, E., L. Bergman, N-H non der Fehr, 2005. The Nordic Market: signs of stress, *Energy Journal*, Special Issue on European Electricity Liberalisation, ed. D Newbery,

BEIS, 2019. *CAPACITY MARKET Five-year Review (2014 – 2019)*, at https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019

CMA, 2016. *Energy market investigation*, Competition and Markets Authority Final Report, 24 June, at https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

CREG, 2020. Reaction to the consultation organised by DG Energy (European Commission) on Belgium's market reform plan, at https://www.creg.be/sites/default/files/assets/Publications/Notes/Z2050EN.pdf

Devogelaer, D. 2019. Analysis of the CREG comments on the Elia A&F study, at https://economie.fgov.be/sites/default/files/Files/Energy/Mecanisme-remuneration-capacite-Note-E2-02-10-2019.pdf

Elia, 2019. *Adequacy and flexibility study for Belgium 2020-2030*, at https://www.elia.be/en/news/press-releases/2019/06/20190628_press-release-adequacy-and-flexibility-study-for-belgium-2020-2030

ENTSO-E, 2019. *Proposal for a Methodology for calculating the Value of Lost Load, the Cost of New Entry for generation, or demand response, and the Reliability Standard in accordance with Article 23 of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)* at https://consultations.entsoe.eu/entso-e-general/proposal-for-voll-cone-and-reliability-standard-me/supporting_documents/191205_Methodology%20for%20VoLL%20CONE%20and%20reliability%20standard_public%20consultation.pdf

Federal Planning Bureau, 2017. *Increasing interconnections: to build or not to build, that is (one of) the question(s)/ Addendum to the cost-benefit analysis of adequate future power policy scenarios*, at https://www.plan.be/uploaded/documents/201709280927450.Addendum_CBA.pdf

Federal Ministry of Economics and Energy, 2019. Definition and monitoring of security of supply on the European electricity markets Project No. 047/16(commissioned from Frauenhofer by the German Federal Ministry of Economics and Energy), at https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/definition-and-monitoring-of-security-of-supply-on-the-european-electricity-markets-from-2017-to-2019.pdf?__blob=publicationFile&v=9

Gollier C, Weitzman, M.L., 2010. How should the distant future be discounted when discount rates are uncertain? *Econ Lett* 107(3):350–35

Grubb, M. and D. Newbery, 2018. UK Electricity Market Reform and the Energy Transition: Emerging Lessons. *The Energy Journal* **39**(6) 1-24. https://doi.org/10.5547/01956574.39.6.mgru

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

London Economics, 2013. *The Value of Lost Load VoLL for Electricity in Great Britain; Final report for OFGEM and DECC*, July, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

National Grid, 2017. *Winter Outlook Report 2017/18* at https://www.nationalgrid.com/document/93916/download

National Grid ESO, 2019. *Electricity Capacity Report* at https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

NERC, 2019. *2019 State of Reliability*, at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

Newbery, D.M. 2016. Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors, *Energy Policy*, 94, 401–410. Doi: http://dx.doi.org/10.1016/j.enpol.2015.10.028

Ofgem, 2017. The impact of the Early Capacity Market Auction announcement on wholesale electricity prices and revenues. At https://www.ofgem.gov.uk/ofgem-publications/124340

Newbery, D.M. and Grubb, M., 2015. Security of Supply, the Role of Interconnectors and Option Values: insights from the GB Capacity Auction, *Economics of Energy & Environmental Policy*, **4**(2), 65- 81. doi http://dx.doi.org/10.5547/2160-5890.4.2.dnew

Newbery, D.M., M. Pollitt, D. Reiner and S. Taylor, 2019. Financing low-carbon generation in the UK: The hybrid RAB model, EPRG WP1926 at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2019/07/1926-Text_REV.pdf

SEM, 2016. *Integrated Single Electricity Market (I-SEM) Capacity Remuneration Mechanism Detailed Design Third Decision Paper*, SEM-16-039 at https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-039%20CRM%20Decision%203%20%28Updated%20pg%29.pdf

Teirila, J. and R. Ritz, 2019. Strategic behaviour in a capacity market? The new Irish electricity market design, *The Energy Journal*, Volume 40, Special Issue *The New Era of Energy Transition*, 105-126.

Weitzman M., 1998. Why the Far-Distant Future Should Be Discounted at Its Lowest Possible Rate, *Journal of Environmental Economics and Management*, 36(3), 201-208.

Williams, J., 1986. *The economic function of futures markets*, Cambridge University Press

Appendix A Extracts from CREG (2020)

10. The adequacy assessment should include an economic assessment of the likelihood of retirement, mothballing and new-build of generation assets. This economic assessment is of a major importance, as this should show whether or not, the markets will be able to anticipate or to solve an eventual adequacy concern, before introducing a capacity mechanism, which inevitably will create some market distortion. The CREG believes that the revenues for all types of capacities are underestimated due to some flaws in the methodology. Some major comments on this economic assessment, which were explained in its study (F)1957 (pages 16-31), are briefly listed :

    (a) The inframarginal rents simulated by Elia are heavily underestimating the inframarginal rents based on the current forward prices for 2020;

    (b) The revenues used are the median revenues (P50) of all simulations. Due to the highly skewed revenue distribution, the P50-revenues for capacity used by Elia are strongly underestimating the true economic value of that capacity. Moreover, CREG believes that using median revenues for the economic assessment and using average values for assessing the LoLE-reliability criterion is not consistent.

    (c) No scarcity pricing mechanism was modelled in the adequacy assessment, which could increase the profitability of existing generation units in Belgium (see also Chapter 2 on Proposed measures).

    (d) The economic viability assessment of CHP (combined heat and power units) has been conducted in a very conservative manner (no revenues for heat were considered, support schemes were not taken into account and its generation is only driven by heat demand, which reduces its availability, while CREG considers that at moments with an adequacy concerns (with power prices spiking up to 3,000 €/MWh or higher) CHP availability will no longer be driven by solely the heat demand and should thus contribute more.

    (e) The economic viability check should not only be conducted for capacity in Belgium, but also for other countries as these countries will also face the high prices in case of an adequacy concern in Belgium

    CREG considers that the current economic assessment, leads to an overestimation of the non-viable capacity in the Energy only market. This assessment needs to be improved.

11. Due to the use of median revenues, the impact of the removal of price caps (an obligatory measure imposed by the Regulation (EU)2019/943) is minimized. The potential of demand response, with prices spiking up to a multiple of the current price cap of 3,000 €/MWh, is underestimated in the adequacy assessment.

12. CREG considers that the assessment of security of supply should be simulated in a realistic way. This implies that simulations should focus on real time LoLE rather than day ahead market LoLE. The grid operator must take all possible measures to avoid involuntary disconnection in real time, including the use of balancing reserves

that are not required for balancing. All available balancing reserves in Belgium and abroad should be taken into consideration.

13. The adequacy assessment made by Elia indicates that Belgium still has available import capacity during periods of scarcity. During these periods, other countries will often quote the same high prices as Belgium. Market reaction to such high prices will not only happen in Belgium, but also in these other countries. This market reaction will contribute to solve an eventual adequacy concern.
14. Also, the winter reserves in Germany should be taken into consideration. In fact, the German regulator anticipates an increase of winter reserves from 6.6 GW to 10.6 GW by 2022-2023. These reserves are primarily used to stabilise the domestic electricity grid when there is a lot of wind production in the north that needs to be transported to the south. During periods of high wind, no capacity shortfalls are expected. So during periods of low wind, these capacities are largely available. These capacities can thus be used to address adequacy issues, considering that adequacy issues generally arise when wind generation is limited.
15. As already stated previously, CREG believes that the adequacy assessment is overestimating the adequacy concern and a complementary analysis should be conducted, taking into account the CREG- comments.

EOM adequacy assessment methodology

16. To implement a market wide capacity mechanism, Belgium has to show there is an adequacy concern in the EOM that cannot be solved through market measures, nor with strategic reserves. This adequacy concern should be expressed in LoLE and EENS (not in GW).
17. We will show that based on the current proposals by EntsoE and based on the European legislation, it is difficult to understand why the EOM would not be able to provide the necessary capacity to meet the reliability criteria in Belgium. Also, we will show the importance to adhere to the hierarchy set out in Regulation 2019/943 where the adequacy concern should first be assessed with a strategic reserve, which was not properly done in the Elia adequacy assessment.

18. The reasoning is as follows.
    1. EntsoE proposes to calculate the LoLE-target as follows: LoLE-target = CoNE[1] / VoLL[2].
    2. EntsoE proposes the CoNE to be the gross cost of new capacity (€/MW), namely the investment cost to build a new MW of capacity plus the cost to keep this capacity available. It does not take any revenues into account (CoNE is the so-called “gross CoNE”).

[1] Cost of New Entry
[2] Value of Loss of Load

3. EntsoE proposes the VoLL to represent the most likely cost of an adequacy outage, during which the different categories of consumers may be affected in different proportions.
4. The system defence plan has to be economically efficient (art 11.6.b of Regulation 2017/2196), implying that the consumers that will be first disconnected when there is an adequacy concern need to have a VoLL as low as possible. In this document, the VoLL of these disconnected consumers is referred to as VoLL_low. It is this VoLL that represents most likely the cost of an adequacy outage and thus LoLE-target = CoNE / VoLL_low. According to the Belgian defense plan, affected consumers will most likely be households in rural areas[3].
5. When there is an adequacy issue, the market price will go to the market price cap. According to European legislation, this market price cap cannot impede entrance of demand response to the market which implies that the price should be able to go as high as the highest VoLL of price-elastic consumers. In this document, this VoLL will be referred to as VoLL_high.

19. Based on these five points, the expected revenues on the EOM of new capacity will be more than sufficient to attract new capacity:

a. The necessary annual revenue for new capacity is by definition equal to CoNE, expressed in €/MW. This CoNE equals LoLE * VoLL_low
b. The expected market revenue of any available capacity during scarcity hours is the number of hours of scarcity (LoLE) multiplied with the market price during scarcity (= market price cap), which is VoLL_high, leading to an expected market revenue during scarcity hours is LoLE * VoLL_high

From (a) and (b) follows that the expected market revenue (= LoLE * VoLL_high) is (much) higher than the necessary revenue to attract new capacity (= LoLE * VoLL_low), since VoLL_high is (much) higher than VoLL_low[4]. Therefore, revenues that are needed to attract new capacity (= LoLE * VoLL_low) will be

---

[3] The Belgian Minister of Energy approved on 19.12.2019 the system defence plan proposed by the Belgian TSO Elia according to the European NC E&R. The system defence plan includes the manual demand disconnection procedure in line with article 22 of the European NC E&R. The manual demand disconnection procedure affects only distribution grids with a connection of less than 30 kV to the transmission grids in primarily rural areas. Industrial and power plants are excluded in the manual disconnection procedure as well as the Brussels capital region, capital cities of the provinces and city centres of at least 50.000 inhabitants. Consequently, the manual disconnection procedure affects almost exclusively household (Since it is technically not feasible to selectively disconnect consumers on distribution grids, small services (e.g. bakeries) and small enterprises in the concerned primarily rural area are also disconnected while – of course- high priority consumers like hospitals are excluded (though hospitals are not typically located in less than 30 kV rural areas)). Therefore, the approved manual disconnection procedure follows the requirement of art. 11 (6) by minimising the VoLL of manual demand disconnection and excluding the consumers with the highest VoLL e.g. industrial and power plants. In this sense is the Belgian manual demand disconnection plan is developed in order to minimise the overall costs of involuntary disconnection in order to guarantee system stability as well as adequacy.

[4] This regardless whether there are high volumes of demand response available or not.

supplied by the market because this market has a price of VoLL_high during LoLE-hours.
On top of that, one can assume that the new capacity will also earn revenues outside scarcity hours. This implies that the expected revenue from the market is LoLE*VoLL_high + revenuesWhenNoScarcity, which is even higher.

20. In addition, in the setting of an EOM with strategic reserves (EOM+SR), it is important to understand the impact of out-of-market capacity on the profitability of in-the-market capacity. The reason is that –by definition- out-of-market capacity such as strategic reserves can prevent LoLE-hours (LoLE in real time, in this document referred to as “LoLE_realtime”), without impacting market prices. As a result, the LoLE in real time, which is the only relevant LoLE when considering adequacy, will be lower than the number of hours the market cannot supply all demand (“market LoLE”, in this document referred to as “LoLE_market”).

21. This effect can be illustrated with a simple example. Assume there is a strategic reserve of 1 GW. The day ahead market cannot clear for 2 hours, with a curtailment of respectively 1 GW and 2 GW. So, the “LoLE_market” is 2 hours, during which the market price equals the market price cap (which is VoLL_high). In real time, the strategic reserves are activated, leading to only one hour with load shedding of 1 GW. The “LoLE_realtime” is only 1 hour. So, when there is out-of-market-capacity available, such as strategic reserves, the LoLE on the market (“LoLE_market”) is higher than the LoLE in real time (“LoLE_realtime”). The LoLE_realtime is the only relevant parameter to assess whether the reliability standard is met.

22. Therefore, the minimal expected market revenues of new capacity should be calculated as LoLE_market * VoLL_high. The necessary level for attracting new capacity to the market should be calculated as LoLE_realtime * VoLL_low. Both LoLE_market and VoLL_high are higher than LoLE_realtime and VoLL_low, respectively. This implies that the minimal expected market revenues of new capacity are more than sufficient for attracting new capacity.

23. Nevertheless, the Elia adequacy assessment concludes that the EOM cannot meet the reliability standard. To arrive to this conclusion, Elia ignores the important issues described above regarding the difference between LoLE in real time and LoLE on the market, and regarding the role of VoLL when disconnecting clients and when setting the market price cap. Also, the view by Elia that market parties would rely on the median value of spot prices, is showing a lack of understanding price formation on the forward market[33] and the importance of these forward prices[34] (instead of spot prices).

…

[33] price formation on the forward market: forward price = expected spot price + risk premium
[34] utilities hedge their assets on the forward market

34. Elia suggested a CoNE of at least 75.000 €/MW; other estimations are around 60.000 €/MW but can go as high as 100.000 €/MW or higher. The VoLL should be the likely cost of a forced disconnection, where mostly households are impacted. Given the VoLL estimations of households by the federal Planning Bureau (2300 €/MWh) and Acer (5500 €/MWh), this would lead to a LoLE-target that is most probable more than double the current LoLE-target.

…

2.1.1. The shortage pricing function ("ERCOT-like scarcity mechanism") improves the adequacy of the system

40. The statement made in the implementation plan seems to indicate that a shortage pricing function has nothing to do with adequacy, and only improve flexibility conditions. Of course CREG agree that the implementation of a shortage pricing function will improve the conditions for flexibility in Belgium. But the CREG is also convinced that the implementation of an "ERCOT-like scarcity mechanism" targets the adequacy of the Belgian system and the investment signal.
The objective pursued by CREG with the work done on shortage pricing was, from the beginning, the improvement of the investment conditions in the Belgium system, and therefore the adequacy of the system.

41. A first study on shortage pricing was performed by the Center for Operations Research and Econometrics (CORE) of the Université Catholique de Louvain (UCL) in 2015-2016. The text below is extracted from the note made by CREG (Z)160512-CDC-1527 in May 2016 on "Scarcity pricing applied to Belgium" accompanying the study. In this note, the objective and the trigger of the works on scarcity pricing are clearly indicated, together with the first conclusions of the study.
"Renewables are characterised by important investment cost, low fixed cost and variable cost close to zero. The massive introduction of large amount of renewable energy has led to overcapacity and has ***exacerbated the missing money problem*** *reflecting the difficulties of remunerating the marginal generation unit in an energy only market with a marginal pricing principle.*
This introduction contributed to the lowering of the average electricity price to levels that may put at risk the profitability of new large scale generation units (mainly CCGT) in pure energy only markets even in the absence of excess generation capacity…

This study was launched at the time when Belgium experienced a lack of generation capacity *(several nuclear units, totalling a capacity of up to 4000 MW, were out of the market for several reasons) and* ***where some CCGT were announced to be mothballed.***

A replacement/alternative to nuclear should indeed preferably come from the market, not from support schemes or even from open tenders for the remuneration (of investment and fixed costs) of alternative solutions."

Further in the text it is indicated that: "*ORDC (ie. the shortage pricing function) may be seen as* ***an alternative to CRMs****, ...*"

In the study results, it can be found that "The main conclusions of the study are…that the addition of a scarcity adder for the remuneration of flexibility (in the 7 min timeframe and 60 min timeframe) is able to not only remunerate operating costs but also to remunerate investment costs of new CCGT units."

Finally, it is stipulated in the Conclusions that "***The proposed adder provides a long term price signal enough to invest*** *in new CCGT units* ***or a transition towards a new energy system***." So the link with investment decisions required for the energy transition in Belgium and adequacy was clearly made by CREG from the beginning.

42. It is more difficult to comment on the exact goals pursued by ERCOT when implementing the ORDC mechanism. But more can be found on the link between a scarcity pricing mechanism, better price and adequacy in the literature. The text below is extracted from the note (Z)1986 of September 2019 published by CREG accompanying the publication of the third study made by the CORE. And in order to explain the benefits of a scarcity pricing mechanism, it is interesting to refer here the view of an academic not directly involved in the development of this kind of mechanism who has produced several papers on Capacity Remuneration Markets (CRMs), Peter Cramton12. Bold characters below are from CREG.

"*In broadest terms, regulators seek a market design that provides reliable electricity at least cost to consumers. This can be broken down into two key objectives: The first is short-run efficiency: making the best use of existing resources. (…)* ***The second objective is long-run efficiency: ensuring the market provides the proper incentives for efficient long-run investment****. This has proven to be the most challenging objective. In the simplest theory, efficient long-run investment is induced from the right spot prices. But this is complicated by the reliability requirement. Reliability requires a reserve to satisfy demand when supply and demand uncertainty would otherwise lead to shortage. In other industries, reliability is not an issue. Prices rise and fall to assure supply and demand balance, but in current electricity markets there is typically insufficient demand that responds to price, and consumers are unable to express a preference for reliability. Thus, there is a need in current markets for the regulator to determine how this preference for reliability is expressed. As we will see, one approach to reliability is to rely solely on spot prices but to include administrative scarcity prices at times when reserves are scarce. The preference for reliability is imbedded in the scarcity prices. Setting higher scarcity prices enhances reliability in providing stronger investment incentives. An alternative approach is to more directly coordinate investment with a capacity market, although this is best done as an addition to, not a substitute for, administrative scarcity pricing, since it is the scarcity price that motivates capacity to perform when needed.*"

The link between reliability, reserves and adequacy is clearly established here. The need for the implementation of a shortage pricing function before considering a capacity remuneration mechanism – as in the new Regulation (EU)2019/943 – is also clearly indicated in Cramton's text.

43. Further in the same paper of Peter Cramton, it is indicated that "In Texas13, the high scarcity pricing motivates the forward contracting that limits risk and induces investment. The scarcity price is the key instrument for resource adequacy. One reason this may work well in Texas is substantial industrial load that makes the market for forward contracts more liquid." So the link of an ORDC mechanism with adequacy is clearly established for Texas.

Appendix B ENTSO-E's Value of Lost Load and Cost of New Entry

ENTSO-E: Proposal for a Methodology for calculating the Value of Lost Load, the Cost of New Entry for generation, or demand response, and the Reliability Standard in accordance with Article 23 of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)

Value of Lost Load (VoLL): an estimation in EUR/MWh of the maximum electricity price that customers are willing to pay to avoid an outage, as referred in Article 2 of the Regulation (EU) 2019/943.

In order to evaluate the VoLL related to inadequacy for each category of consumers, the RA shall specify the characteristics of outages caused by inadequacy in terms of:
a. duration(s);
b. most likely period(s) of occurrence (hour, week day or week-end, season of the year);
c. pre-notification period3 (indicating if there is a pre-notification and, if there is one, how long it is).

When applying Capacity Mechanisms, Member States shall calculate a single estimate of the gross CONE for generation, or demand response, for their territory. That estimate shall be made publicly available. Member States may determine one estimate per bidding zone if they have more than one bidding zone in their territory. Where a bidding zone consists of territories of more than one Member State, the concerned Member States shall jointly determine a single estimate of the cost of New Entry for that bidding zone.

Appendix C Extracts from REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity (recast)

Preamble

(45) Before introducing capacity mechanisms, Member States should assess the regulatory distortions contributing to the related resource adequacy concern. Member States should be required to adopt measures to eliminate the identified distortions, and should adopt a timeline for their implementation. Capacity mechanisms should only be introduced to address the adequacy problems that cannot be solved through the removal of such distortions.

(46) Member States intending to introduce capacity mechanisms should derive resource adequacy targets on the basis of a transparent and verifiable process. Member States should have the freedom to set their own desired level of security of supply.

(48) Capacity mechanisms that are in place should be reviewed in light of this Regulation.

(49) Detailed rules for facilitating effective cross-border participation in capacity mechanisms should be laid down in this Regulation. Transmission system operators should facilitate the cross-border participation of interested producers in capacity mechanisms in other Member States. Therefore, they should calculate capacities up to which cross-border participation would be possible, should enable participation and should check availabilities. Regulatory authorities should enforce the cross-border rules in the Member States.

(50) Capacity mechanisms should not result in overcompensation, while at the same time they should ensure security of supply. In that regard, capacity mechanisms other than strategic reserves should be constructed to ensure that the price paid for availability automatically tends to zero when the level of capacity which would be profitable on the energy market in the absence of a capacity mechanism is expected to be adequate to meet the level of capacity demanded.

Article 10 Technical bidding limit

1. There shall be neither a maximum nor a minimum limit to the wholesale electricity price. This provision shall apply, inter alia, to bidding and clearing in all timeframes and shall include balancing energy and imbalance prices, without prejudice to the technical price limits which may be applied in the balancing timeframe and in the day-ahead and intraday timeframes in accordance with paragraph 2.
2. NEMOs may apply harmonised limits on maximum and minimum clearing prices for day-ahead and intraday timeframes. Those limits shall be sufficiently high so as not to unnecessarily restrict trade, shall be harmonised for the internal market and shall take into account the maximum value of lost load. NEMOs shall implement a transparent mechanism to adjust automatically the technical bidding limits in due time in the event that the set limits are expected to be reached. The adjusted higher limits shall remain applicable until further increases under that mechanism are required.

Article 11 Value of lost load

1. By 5 July 2020 where required for the purpose of setting a reliability standard in accordance with Article 25 regulatory authorities or, where a Member State has designated another competent authority for that purpose, such designated competent authorities shall determine a single estimate of the value of lost load for their territory. That estimate shall be made publically available. Regulatory authorities or other designated competent authorities may determine different estimates per bidding zone if they have more than one bidding zone in their territory. Where a bidding zone consists of territories of more than one Member State, the concerned regulatory authorities or other designated competent authorities shall determine a single estimate of the value of lost load for that bidding zone. In determining the single estimate of the value of lost load, regulatory authorities or other designated competent authorities shall apply the methodology referred to in Article 23(6).
2. Regulatory authorities and designated competent authorities shall update their estimate of the value of lost load at least every five years, or earlier where they observe a significant change.

Article 20 Resource adequacy in the internal market for electricity

3. Member States with identified resource adequacy concerns shall develop and publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures as a part of the State aid process. When addressing resource adequacy concerns, the Member States shall in particular take into account the principles set out in Article 3 and shall consider:
(a) removing regulatory distortions;
(b) removing price caps in accordance with Article 10;
(c) introducing a shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation (EU) 2017/2195;
(d) increasing interconnection and internal grid capacity with a view to reaching at least their interconnection targets as referred in point (d)(1) of Article 4 of Regulation (EU) 2018/1999;
(e) enabling self-generation, energy storage, demand side measures and energy efficiency by adopting measures to eliminate any identified regulatory distortions;
(f) ensuring cost-efficient and market-based procurement of balancing and ancillary services;
(g) removing regulated prices where required by Article 5 of Directive (EU) 2019/944.

Article 21 General principles for capacity mechanisms

1. To eliminate residual resource adequacy concerns, Member States may, as a last resort while implementing the measures referred to in Article 20(3) of this Regulation in accordance with Article 107, 108 and 109 of the TFEU, introduce capacity mechanisms.

2. Before introducing capacity mechanisms, the Member States concerned shall conduct a comprehensive study of the possible effects of such mechanisms on the neighbouring Member States by consulting at least its neighbouring Member States to which they have a direct network connection and the stakeholders of those Member States.
3. Member States shall assess whether a capacity mechanism in the form of strategic reserve is capable of addressing the resource adequacy concerns. Where this is not the case, Member States may implement a different type of capacity mechanism.
4. Member States shall not introduce capacity mechanisms where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern.
5. Member States shall not introduce capacity mechanisms before the implementation plan as referred to in Article 20(3) has received an opinion by the Commission as referred to in Article 20(5).
6. Where a Member State applies a capacity mechanism, it shall review that capacity mechanism and shall ensure that no new contracts are concluded under that mechanism where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern or the implementation plan as referred to in Article 20(3) has not received an opinion by the Commission as referred to in Article 20(5).
7. When designing capacity mechanisms Member States shall include a provision allowing for an efficient administrative phase-out of the capacity mechanism where no new contracts are concluded under paragraph 6 during three consecutive years.
8. Capacity mechanisms shall be temporary. They shall be approved by the Commission for no longer than 10 years. They shall be phased out or the amount of the committed capacities shall be reduced on the basis of the implementation plans referred to in Article 20. Member States shall continue to apply the implementation plan after the introduction of the capacity mechanism.

Article 22 Design principles for capacity mechanisms

1. Any capacity mechanism shall:
    (a) be temporary;
    (b) not create undue market distortions and not limit cross-zonal trade;
    (c) not go beyond what is necessary to address the adequacy concerns referred to in Article 20;
    (d) select capacity providers by means of a transparent, non-discriminatory and competitive process;
    (e) provide incentives for capacity providers to be available in times of expected system stress;
    (f) ensure that the remuneration is determined through the competitive process;

(g) set out the technical conditions for the participation of capacity providers in advance of the selection process;

(h) be open to participation of all resources that are capable of providing the required technical performance, including energy storage and demand side management;

(i) apply appropriate penalties to capacity providers that are not available in times of system stress.

2. The design of strategic reserves shall meet the following requirements:

(a) where a capacity mechanism has been designed as a strategic reserve, the resources thereof are to be dispatched only if the transmission system operators are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;

(b) during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher;

(c) the output of the strategic reserve following dispatch is to be attributed to balance responsible parties through the imbalance settlement mechanism;

(d) the resources taking part in the strategic reserve are not to receive remuneration from the wholesale electricity markets or from the balancing markets;

(e) the resources in the strategic reserve are to be held outside the market for at least the duration of the contractual period. The requirement referred to in point (a) of the first subparagraph shall be without prejudice to the activation of resources before actual dispatch in order to respect the ramping constraints and operating requirements of the resources. The output of the strategic reserve during activation shall not be attributed to balance groups through wholesale markets and shall not change their imbalances.

3. In addition to the requirements laid down in paragraph 1, capacity mechanisms other than strategic reserves shall:

(a) be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded;

(b) remunerate the participating resources only for their availability and ensure that the remuneration does not affect decisions of the capacity provider on whether or not to generate;

(c) ensure that capacity obligations are transferable between eligible capacity providers.

4. Capacity mechanisms shall incorporate the following requirements regarding CO2 emission limits:

(a) from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;

(b) from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity and more than 350 kg CO2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism. The emission limit of 550 g CO2 of fossil fuel origin per kWh of electricity and the limit of 350 kg CO2 of fossil fuel origin on average per year per installed kWe referred to in points (a) and (b) of the first subparagraph shall be calculated on the basis of the design efficiency of the generation unit meaning the net efficiency at nominal capacity under the relevant standards provided for by the International Organization for Standardization. By 5 January 2020, ACER shall publish an opinion providing technical guidance related to the calculation of the values referred in the first subparagraph.

5. Member States that apply capacity mechanisms on 4 July 2019 shall adapt their mechanisms to comply with Chapter 4 without prejudice to commitments or contracts concluded by 31 December 2019.

Article 23 European resource adequacy assessment

1. The European resource adequacy assessment shall identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demands for electricity at Union level, at the level of the Member States, and at the level of individual bidding zones, where relevant. The European resource adequacy assessment shall cover each year within a period of 10 years from the date of that assessment.
2. The European resource adequacy assessment shall be conducted by the ENTSO for Electricity.
3. By 5 January 2020, the ENTSO for Electricity shall submit to the Electricity Coordination Group set up under Article 1 of Commission Decision of 15 November 2012[35] and ACER a draft methodology for the European resource adequacy assessment based on the principles provided for in paragraph 5 of this Article.
4. Transmission system operators shall provide the ENTSO for Electricity with the data it needs to carry out the European resource adequacy assessment. The ENTSO for Electricity shall carry out the European resource adequacy assessment on an annual basis. Producers and other market participants shall provide transmission system operators with data regarding expected utilisation of the generation resources, taking into account the availability of primary resources and appropriate scenarios of projected demand and supply.

[35] 14.6.2019 L 158/87 Official Journal of the European Union EN (21)Commission Decision of 15 November 2012 setting up the Electricity Coordination Group (OJ C 353, 17.11.2012, p. 2).

5. The European resource adequacy assessment shall be based on a transparent methodology which shall ensure that the assessment:
   (a) is carried out on each bidding zone level covering at least all Member States;
   (b) is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments;
   (c) contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address;
   (d) appropriately takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;
   (e) anticipates the likely impact of the measures referred in Article 20(3);
   (f) includes variants without existing or planned capacity mechanisms and, where applicable, variants with such mechanisms;
   (g) is based on a market model using the flow-based approach, where applicable;
   (h) applies probabilistic calculations;
   (i) applies a single modelling tool;
   (j) includes at least the following indicators referred to in Article 25: — 'expected energy not served', and — 'loss of load expectation';
   (k) identifies the sources of possible resource adequacy concerns, in particular whether it is a network constraint, a resource constraint, or both;
   (l) takes into account real network development;
   (m) ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.
6. By 5 January 2020, the ENTSO for Electricity shall submit to ACER a draft methodology for calculating:
   (a) the value of lost load;
   (b) the cost of new entry for generation, or demand response; and
   (c) the reliability standard referred to in Article 25. The methodology shall be based on transparent, objective and verifiable criteria.
7. The proposals under paragraphs 3 and 6 for the draft methodology, the scenarios, sensitivities and assumptions on which they are based, and the results of the European resource adequacy assessment under paragraph 4 shall be subject to the prior

consultation of Member States, the Electricity Coordination Group and relevant stakeholders and approval by ACER under the procedure set out in Article 27.