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Final report on Elia’s findings regarding the design of a scarcity pricing mechanism for implementation in Belgium

December 7, 2020

Executive summary

This report, based on an initial preliminary report that was publically consulted upon, presents Elia's findings in the context of the 2020 balancing incentive on scarcity pricing laid upon Elia by CREG regarding the design of a scarcity pricing mechanism for implementation in Belgium.

Assessment of the CORE study

A first and prominent objective of this incentive is to assess a study by UCL CORE titled 'Study on the general design of a mechanism for the remuneration of reserves in scarcity situations' (hereafter referred to as 'CORE study'). In this analysis, Elia in particular considers the circumstances in which market design evolutions take place. Hence, the analysis of the CORE study in this report investigates whether the proposals raised in the CORE study are compatible with the prevailing market design and are not obstructed by the boundaries set by the legal framework. These considerations are important, especially when targeting an implementation in the short- to mid-term future. Elia's starting point is therefore different from UCL CORE's perspective, whose aim is in the first place to identify implementation measures that result in the best possible scarcity pricing mechanism. The CORE study is largely inspired by the ORDC scarcity pricing implementation of ERCOT in Texas. Given the different objectives and perspectives of both reports, it makes sense that Elia's conclusion from its analysis in this report may differ from the conclusions of the CORE study. This does not detract from the merits of the CORE study, which has a different purpose.

The CORE study presents five scarcity pricing implementation measures. The first three measures focus on the integration of scarcity prices, i.e. so-called scarcity price adders, in the real-time market design. Measures four and five rather present approaches to improve the backward propagation of prices from real-time to earlier time frames.

Elia perceives a strong link and interdependency between the first and second scarcity pricing implementation measure considered in the CORE study in the sense that the one would not work properly without the implementation of the other. However, Elia's analysis identifies several issues that prevent a full implementation of the first and second scarcity pricing implementation measure considered in the CORE study. These issues result both from a market design compatibility perspective, as well as from Elia's preliminary legal assessment based on a legal note by an external law firm Liedekerke on the matter (cf. Annex I). Even if we would neglect the legal boundaries described in the legal note, it seems that the only possible way to fully implement the scarcity pricing mechanism envisaged in the CORE study in a way that avoids discriminatory and/or market distortive effects in a setting with European balancing platforms PICASSO and MARI, is through a harmonized and European-wide scarcity pricing implementation. However, such harmonized implementation is currently not on the European drawing board. Moreover and although not strictly necessary for a scarcity pricing implementation, an equalization of the real-time energy price among BRPs and BSPs at all times as prescribed in the first scarcity pricing implementation measure considered in CORE study, is not deemed achievable given the prevailing market design. In any case, such equalization does not seem desirable and even seems to be distortive.

The third scarcity pricing implementation measure considered in the CORE study, i.e. the removal of the alpha component in the imbalance tariff, is in Elia's view not deemed desirable and in any case also not essential for a scarcity pricing implementation (cf. infra on the alternative scarcity pricing proposal identified by Elia).

Finally, measures four and five presented in the CORE study seem useful to improve the backward price propagation and thereby contribute to an effective scarcity pricing implementation. However, feasibility assessments beyond the scope of this study are ongoing and/or these measures are to be seen rather as measures for the longer-term future.

Summarizing, Elia considers the CORE study as valuable in identifying potential building blocks when purely developing a scarcity pricing mechanism. However, Elia's analysis concludes that the design presented in the CORE study, and particularly the application of scarcity price adders on BSPs (both in energy and capacity prices) bounces with legal obstacles, is hardly compatible with the prevailing market design and would have discriminatory effects and potentially distort the good (European) market functioning. While the CORE study's design has several difficulties that cannot be overcome in the short to medium term, it nevertheless provides ingredients for alternatives that could be feasible.

'Omega component' as alternative scarcity pricing proposal: (Implementation) Feasibility

Based on the proposals raised in the CORE study and Elia's analysis thereof, Elia derives an alternative scarcity pricing proposal that is deemed feasible. This alternative proposal consists of the introduction of a scarcity component – further referred to as omega (Ω) component – in the imbalance price calculation. Importantly, the conceived scarcity component applies only on BRPs and is designed to apply in addition to the alpha component currently in place, since both components serve a different purpose. Moreover, the scarcity component applies only during negative to zero system imbalances in order not to obstruct appropriate balancing incentives. Finally, through the calculation methodology it is ensured that omega applies only during structural capacity shortages, is calibrated to VOLL and is based on a Loss of Load Probability (LOLP) estimation. An integration in prices directly applicable on BSPs is *not* foreseen.

The omega proposal is deemed compatible with the prevailing market design. Applying only on Belgian BRPs, the Belgian scarcity pricing mechanism that aims to be reflective of the scarcity situation in Belgium, as such applies directly to those market players (i.e. Belgian BRPs) that are responsible for their residual imbalances in relation to the overall system imbalance of the Belgian control zone market and therefore either alleviate or deteriorate the Belgian scarcity problem.

The omega proposal is also deemed compliant with the current legal framework, being conceived as an additional component in accordance with Art. 9(6)(a) of ACER's adopted methodology on Imbalance Settlement Harmonization.

Based on a preliminary assessment, an implementation of the omega proposal is deemed feasible by Q4 2022. An earlier implementation – to the extent it would be technically possible – is also not considered appropriate as by aiming for Q4 2022, the go-live of the scarcity component would be aligned with the foreseen timelines for implementation of PICASSO and MARI, which are an important factor in the calculation of the omega component. Reacting to the public consultation of Elia's preliminary scarcity pricing report, market parties indicate their support for this proposed timeline, if scarcity pricing were to be implemented at all. In summary, they request to maintain a realistic implementation track and to give priority to other ongoing market design evolutions, in particular the implementation of the MARI and PICASSO platforms, which already require a lot of resources from all involved parties.

Finally, it should be noted that this implementation plan is to be considered preliminary at this stage. A decision regarding the implementation of the proposed alternative is not yet made.

'Omega component' as alternative scarcity pricing proposal: Desirability

Beyond the fact that the omega component represents a feasible scarcity pricing implementation measure, it remains to be assessed whether this proposed – and in general any – scarcity pricing mechanism for Belgium, is desirable.

From the discussion presented in this report on what scarcity pricing actually is, for which this report goes back to the origins of scarcity pricing, it can be derived that scarcity pricing aims to be a solution for the missing-money problem. Although both academics and operational scarcity pricing implementations, generally implementing a capacity mechanism and scarcity pricing in parallel, agree on the fact that scarcity pricing cannot eliminate the missing money problem, it may help to reduce the missing money problem. However, this advantage is to be weighed against the complexity that comes with a scarcity pricing implementation. Design experience shows that the calibration of such mechanism is not straightforward and not a one-shot exercise. This calibration also seems especially sensitive to the capacity mix and the share of renewables therein.

It is to be noted that rather than particularly addressing adequacy in a way that it ensures a reliability standard to be met, a scarcity pricing mechanism appears to be instead more focused on ensuring that there is sufficient flexibility in the system. In the context of Belgium, one could wonder whether additional mechanisms specifically targeting flexibility development are needed. The results of Elia's 2019 Adequacy and flexibility study for Belgium 2020-2030[1] provide insights indicating that if the adequacy situation is solved, there should also be sufficient flexibility means installed in the system, thereby indicating that creating extra investment incentives targeting flexibility is not necessarily the key priority for market design evolutions. It is more a matter of ensuring that flexibility is made available in line with system needs in the operational time frames.

With respect to Elia's alternative scarcity pricing proposal, and by extension any other scarcity pricing mechanism, one should carefully consider to what extent this market design adaptation may raise market entry barriers. Indeed, even if scarcity price adders do not occur often, the threat alone may be enough to discourage market players from taking up the role of BRP.

In addition, the financing of a scarcity pricing mechanism is still to be assessed further as well. While a scarcity pricing mechanism integrated in energy prices can be designed such that it is self-financed, this would not be the case for a scarcity pricing mechanism that also remunerates available capacity. Elia's alternative proposal is designed such that it is self-financed, in a sense that BRPs being rewarded are financed by BRPs being penalized.

Based on the feedback received from stakeholders during the public consultation period related to aspects of desirability, it appears that there is no appetite for the implementation of a scarcity pricing mechanism in general. Market parties refer to the fact that scarcity pricing provides no (guaranteed) solution for adequacy, point out that there is no extra need for investment incentives for flexible capacity, express their believe that the real-time value of energy naturally takes into account the risk of scarcity already and argue that a scarcity pricing mechanism introduces risks and complexities.

Febeg, EFET and Nemo Link Limited are also not keen on the alternative omega proposal. Only Febeliec – on the condition that Belgium were to decide to implement a scarcity pricing mechanism for which they see at this stage no need – sees merit in the omega proposal, strengthening the price and investment signal towards BRPs to ensure system balance in their portfolios without direct extra cost for consumers.

Finally, it is to be noted that there is an explicit request from market parties to be involved in any further next steps considering the design and implementation of a scarcity pricing mechanism in Belgium.

[1] **https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/adequacy---studies/2019/20190628_elia_adequacy_and_flexibility_study_2020_2030_en.pdf?la=en**

Content

1. Introduction

This report is a deliverable in the context of the 2020 balancing incentive on scarcity pricing laid upon Elia by CREG. It bundles Elia’s findings on the implementation of a scarcity pricing mechanism for Belgium, respectively analyzing the proposals put forward in the CORE study[2], investigating own derived alternative proposals and drafting a preliminary implementation plan analyzing a possible implementation by the end of 2021. This final report takes into account the feedback received during the public consultation on a preliminary report organized in October 2020 when market parties were invited to provide feedback on Elia’s findings. Elia received four reactions during the public consultation period, namely from Febeg, Febeliec, EFET and Nemo Link Limited. Note that this report is accompanied by a separate consultation report, in which Elia provides an answer to all received comments.

More generally, this final report, taking into account the feedback received during the public consultation, adds to the ongoing considerations on the potential implementation of a scarcity pricing mechanism in the Belgian market.

This final report after public consultation was also preceded by two interactions with market parties via the Working Group Balancing of the Elia Users’ Group, including a dedicated workshop on the topic. When preparing this report Elia has also interacted with CREG and the researchers from UCL CORE. Notwithstanding potentially diverging views, Elia wishes to underline its appreciation for the discussions and exchanges that took place.

This document starts by providing a better explanation of scarcity pricing in chapter 2, elaborating on the origins of scarcity pricing, explaining its core concepts and analyzing the general objective of scarcity pricing, complemented by an overview of scarcity pricing implementations in other regions throughout the world. Chapter 2 is deemed an essential starting point and foundation for what comes later in the document, i.e. discussing and analyzing the design of a scarcity pricing mechanism to be implemented in Belgium.

Next, chapter 3 derives a framework for reviewing scarcity pricing implementation measures, specifically taking into account the Belgian and broader European context. On the one hand, in this framework, three general conditions are set out that are required to be fulfilled for an effective scarcity pricing mechanism, building on the explanations provided in chapter 2. On the other hand, the framework also considers the constraints defined by the prevailing market design and current legal context, which should be taken into account as well when assessing scarcity pricing implementation measures being considered for the short to medium term.

Chapter 4 then presents Elia’s analysis of the scarcity pricing implementation measures considered in the CORE study. In the CORE study, five measures are put forward. In chapter 4, for each of these measures, after an extensive explanation on what the measure exactly entails, its compatibility with the prevailing Belgian and European market design is evaluated. Moreover, each of the five measures is also assessed from a legal perspective. After a treatment of these five scarcity pricing implementation measures considered in the CORE study, an overall conclusion is provided.

After a detailed analysis of the CORE study, chapter 5 provides Elia’s first reflections on the financing of a scarcity pricing mechanism, distinguishing between measures that intervene on the remuneration of energy versus capacity.

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[2] The version of the CORE study that is analyzed can be consulted online: **https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986Annex.pdf**

Chapter 6 describes an alternative scarcity pricing proposal identified by Elia, building further on the analysis of the measures considered in the CORE study while specifically also taking into account the compatibility with the prevailing market design and the boundaries set by the current legal framework. As a result, Elia puts forward an alternative scarcity pricing proposal that is in the first place deemed feasible in today's setting. However, in addition to that and without taking position at this stage, Elia also formulates some open questions regarding the desirability of this – and in general any – scarcity pricing mechanism for Belgium in the second part of chapter 6, complemented by a short summary of the feedback received from market parties during the public consultation period.

Finally, notwithstanding the answer on the desirability of a possible implementation of Elia's alternative scarcity pricing proposal described in the previous chapter, a high-level preliminary implementation plan is elaborated in chapter 7. Note that the elaboration of such implementation plan at this stage does not imply that the mechanism will also be implemented. Further also note that only high-level estimations are provided, and hence that any eventual implementation may deviate from the indicative planning presented in this document.

2. What is Scarcity Pricing?

This chapter lays the foundations for further discussions on scarcity pricing in later chapters of this report, by first explaining what scarcity pricing actually is. A better understanding of the core concepts and purpose of scarcity pricing is essential in particular when assessing scarcity pricing implementation measures (cf. chapter 4 that analyzes the CORE study) and when formulating alternative scarcity pricing proposals (cf. chapter 6 that presents Elia's alternative scarcity pricing proposal).

Section 2.1 first elaborates on the theoretic origins of scarcity pricing, going in-depth into the academic literature on scarcity pricing, as it is also within this academic literature that the foundations of scarcity pricing lie. Next, section 2.2 explains the principles of the ORDC scarcity pricing implementation, often cited as the reference scarcity pricing implementation and the go-to implementation for scarcity pricing in US electricity markets. Section 2.3 then brings the discussion to Europe, elaborating on aspects of the EU regulatory context that are relevant in light of a scarcity pricing implementation in Europe and providing an overview of current EU scarcity pricing implementations. Section 2.4 assesses whether scarcity pricing can actually be a solution to the missing money problem, while also investigating whether scarcity pricing should not rather be seen addressing a flexibility problem. Section 2.5 concludes.

2.1 On the origins of scarcity pricing

To understand the origins of scarcity pricing, it is important to first grasp the fundamental theory underlying the energy only market (EOM) design and in particular how capacity is supposed to recover fixed costs under such EOM design. Therefore, section 2.1.1 starts by summarizing the peak load pricing theory. Next, section 2.1.2 explains the lack of free price formation as one possible driver for a missing money problem under the EOM design. Section 2.1.3 investigates how, in theory, scarcity pricing may be a solution for a missing money problem. Finally, section 2.1.4 describes the co-existence between scarcity pricing and capacity mechanisms as presented in academic literature.

2.1.1 Summary of peak load pricing theory

Since the beginning of the liberalization of electricity markets, the question of the ability of capacity to cover their fixed investment costs in the electricity market has been raised in academic literature, in particular, in case of peaking plants necessary to maintain system adequacy. Wholesale electricity markets with a pay-as-cleared price settlement allow generators to receive the market clearing price above their variable generation cost creating a rent that can contribute to the recovery of fixed costs. Based on the fundamental theory of 'peak load pricing'[3] that underpins energy only markets (EOMs), two types of rent are generally distinguished (cf. also Figure 1 below):

- Inframarginal rents, which are earned when the market clearing price is determined by the intersection of the demand with elastic supply, that is, the price set by other capacity with higher variable costs; and

[3] Boiteux, M. 1949. "La Tarification des demandes en point: application de la théorie de la vente au cout marginal." Revue Générale de l'Electricité 58 (August): 321–40; translated as "Peak Load Pricing." Journal of Business 33 (2) (1960): 157–79.

- Scarcity rents, which are earned when the market clearing price is determined by the intersection of the demand with the inelastic supply. In this case, the price is set at the level of Value of Lost Load (VOLL), i.e. the price level at which demand can be reduced when generation, import capacity and demand flexibility limits are reached.

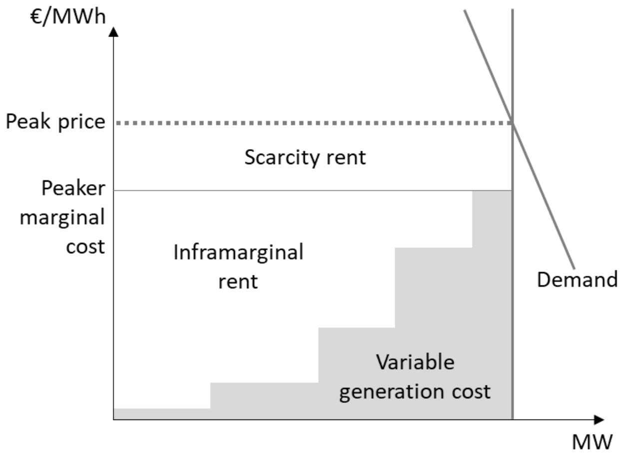

Figure 1: Illustration of peak load pricing theory with inframarginal and scarcity rents

The peak load pricing theory of Boiteux (1949) goes that a long-term equilibrium – insuring both adequacy and the optimal capacity mix (that is the appropriate amount of base/mid merit/peaking capacity) – can be reached only when these inframarginal and scarcity rents fully materialize. Hence, scarcity rents are critical both for peaking and baseload units to recover their fixed costs in EOMs. [4] However, such long-term equilibrium only holds if all underlying conditions are met, such as good market functioning, free market entry and exit, perfect competition, etc.

Also Stoft (2003) acknowledges that a competitive wholesale electricity market should allow both peaking and baseload plants to cover their fixed costs from short-run profits:

> *"In the long run, peakers and baseload plants must cover their fixed costs from short-run profits (inframarginal or scarcity rents)."*[5]

Stoft (2003) further concludes that an energy-only market that does not restrict prices from reaching the VOLL in scarcity events, should be expected to deliver the level of adequacy:

> *"Short-run competitive prices, which equal marginal costs, provide incentives for investment in generation technology, which lead to an optimal level and an optimal mix of generation technologies."*

Hence, it can be concluded that *at least in theory*, the mechanism can work and the EOM is able to 'discover' its own adequacy equilibrium, which may include an expectancy to experience loss of load during a certain number of hours. It is to be noted, however, that this adequacy equilibrium indeed corresponds to an economic equilibrium in terms of,

[4] Boiteux, M. 1949. "La Tarification des demandes en point: application de la theorie de la vente au cout marginal." Revue Generale de l'Electricité 58 (August): 321–40; translated as "Peak Load Pricing." Journal of Business 33 (2) (1960): 157–79.

[5] Stoft (2003), Chapter 2-2

for instance, loss of load expectation and that this may be different from a predefined reliability standard identified by authorities as a societal choice.

2.1.2 Lack of free price formation as driver for missing money

However, despite the sound theoretical foundations that underpin the EOM design as described in section 2.1.1, there is concern that there is missing money, i.e. that – for various reasons – scarcity prices are not (or insufficiently) met and investments are not recovered (and hence not done in the first place). The conclusion towards adequacy and cost recovery in the peak load pricing theorem only holds if also the theoretical underlying conditions are met.

Missing money is a crucial concept in this discussion, which can be defined as the amount of money investors lack to cover their total costs after having taken into account all revenues from the energy market (incl. ancillary services, flexibility).

One market failure jeopardizing the result of the peak load pricing theorem often indicated in economic literature is that there seem to be barriers that prevent the free movement of power prices at times of scarcity. These barriers include amongst others:

- The existence of explicit price caps:

Explicit price caps may clearly be an important barrier for free price formation. In particular when price caps are not calibrated to an appropriate level of VOLL, there may not be sufficient room to collect scarcity rents that are crucial to recover fixed costs.

However, it is to be noted that the day-ahead and intra-day electricity prices on the wholesale markets relevant for Belgium are only limited by the harmonized technical price limits, applied by the NEMOs. Moreover, decisions No 04/2017 and 05/2017 of ACER of 14 November 2017 foresee that these price limits are increased when certain market clearing price thresholds are reached. Therefore, the price limits are in fact dynamic and can be considered not to present explicit price caps that may limit free price formation for Belgium. Finally, also the maximum imbalance tariff in Belgium is set at a value well above the current intra-day maximum clearing price, thereby not obstructing free price formation either.

- Market power mitigation approaches, setting limits on bids and prices, thereby acting as implicit price caps:

The assumption of competitive wholesale electricity markets rarely holds in practice and various market power mitigation approaches may limit price spikes during the scarcity situations. Fabra (2018) formulates this as follows:

> *"The energy-only market paradigm relies on two key assumptions that are typically not satisfied in practice: free entry and no market power in the energy market. Once these are relaxed, the conclusion is unambiguous: relying on scarcity pricing[6] as a way to promote investments is not efficient."[7]*

[6] To avoid possible confusion, it is to be noted that scarcity pricing in the above-mentioned reference refers to the free price formation and prices rising to VOLL and not to scarcity pricing mechanisms as an administrative intervention in the energy market.

[7] Fabra 2018 - A Primer on Capacity Mechanisms

Of course, market power mitigation measures are fully justified to avoid market power abuse. However, they may prevent free price formation in case they are unable to distinguish market power abuse from genuine opportunity pricing – i.e. bidding at prices above short-run marginal costs – to the extent such behavior would be allowed at all, by ruling out both at the same time. Indeed, if the perceived threat of market power mitigation measures imposes such 'implicit price cap' on market actors, preventing prices to genuinely rise up to the VOLL, this would effectively present a market barrier and hence a driver for missing money problems. Note that by referring to these aspects Elia does not intend to cast an opinion on which market power mitigation measures are deemed appropriate or should be avoided.

When prices are prevented from moving freely, especially in periods of system scarcity, to prevent the exercise of market power through mitigation measures (e.g. by suppressing bids prices or threats on ex post investigations), scarcity rents do not materialize, which may lead to inefficient investment incentives provided by the energy prices:

> *"However, it is important to stress that such inefficiency is not created by price caps. Rather, inefficiencies are created by market power, which price caps are meant to mitigate. Maximization of consumer surplus calls for binding price caps (i.e. below consumers maximum willingness to pay) even if these lead to under-investment and thus lower consumption."*[8]

2.1.3 Scarcity pricing as solution for missing money problem?

Scarcity pricing as it is conceived by Hogan (2005) – the starting point for the mechanism as developed by the UCL CORE in the studies commissioned by CREG and in particular also the CORE study that is further analyzed in chapter 4 of this report – builds further on the theoretic foundations of the EOM design and aims to provide a solution to resolve an observed missing money problem. In this paper, Hogan notes that:

> "*The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. … Explicit price caps are not the usual means of restraining prices. A more likely constraint on generator revenues would arise from an offer cap on generators to mitigate market power."*[9]

Hogan further points out the absence of an explicit demand curve for operating reserves as a shortcoming of the EOM design, which – although it is not at the root of the problem of suppressed prices – de facto leads to price caps and missing money:

> *"The absence of an appropriate operating reserve demand curve is one of the difficulties in market designs that result in de facto price caps and missing money. With little explicit energy demand bidding and no recognition of an operating reserve demand curve, the pricing rules default to the most expensive generator offer. With mitigated offers, this can result in a generator running at capacity and price being set at the variable cost with no scarcity rent, even when reserves are reduced."*[10]

[8] Fabra 2018 - A Primer on Capacity Mechanisms

[9] Hogan 2005 – On an "energy only" electricity market design for resource adequacy

[10] Hogan 2005 – On an "energy only" electricity market design for resource adequacy

Therefore, to improve the EOM design, Hogan (2005) proposes to define and integrate a downward-sloping price sensitive demand curve for operating reserves in the market clearing process. This proposal for a scarcity pricing mechanism, is further described in detail in section 2.2.

However, it can already be concluded that the general objective of any scarcity pricing mechanism, as pointed out by Cramton (2017), is to produce a price that reflects the value of energy during scarcity even if generators offer their energy at marginal costs:

> *"Without scarcity pricing [mechanism], reserve and energy prices are apt to be too low during the critical periods of scarcity, because of rules that mitigate market power. Relying on the exercise of market power on the supply side to push prices higher during scarcity is a poor solution. With scarcity pricing [mechanism], a generator can offer at marginal cost, be efficiently dispatched in real time, and still receive a price that reflects its value in scarcity."*[11]

The end goal of the scarcity pricing mechanism, according to Hogan (2005), is to resolve the missing money problem such that there is no further need for additional resources adequacy programs such as capacity markets:

> *"In long-run equilibrium, there would be no missing money. Market prices would provide the needed incentives for loads and generation. … Since there would be no missing money, there would be no need for resource adequacy programs designed to provide the missing money. Both generators and loads would be hedged through the forward contracts."*[12]

2.1.4 Co-existence between scarcity pricing and capacity mechanisms

However, academic literature does not seem to consider scarcity pricing mechanisms as a substitute for capacity mechanisms. For instance Hogan (2005) – in the paper introducing the scarcity pricing concept – already stresses that scarcity pricing mechanisms and capacity mechanisms are not mutually exclusive:

> *"there appears to be nothing that dictates that an improved spot market design is mutually exclusive of an ICAP [Investment Capacity programs] approach."*[13]

Instead, academic literature supports the view that scarcity pricing mechanisms and capacity mechanisms serve different purposes: the system adequacy is ensured through the capacity mechanism, while the role of scarcity pricing is to improve the accuracy of the short-term price signals.

A scarcity pricing mechanism addresses only one condition for the EOM to induce adequacy, i.e. allowing prices to reflect the value of scarcity without interfering with market power mitigation measures. However, the other issues related to the investor risk, e.g. due to the lumpiness of capacity investment and the risk associated with relying on scarcity pricing for investment decisions, the absence of free entry and exit as well as the political intervention in the

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[11] Cramton 2017 - Electricity Market Design

[12] Hogan 2005 – On an "energy only" electricity market design for resource adequacy

[13] Hogan 2005 – On an "energy only" electricity market design for resource adequacy

generation mix, still exist. Therefore, economic literature often suggests reinforcing the investment signals provided by scarcity pricing mechanisms through explicit capacity mechanisms.

For example, among the observers of the EOM in Texas that exclusively relies on scarcity pricing to induce adequacy (cf. infra), Woo and Zarnikau (2020) consider that the adequacy incentive provided by scarcity pricing may need to be reinforced by capacity markets:

> *"Texas's energy-only market design may need refinements based on a consideration of the mechanisms discussed by Woo and Zarnikau (2019), potentially including capacity market, resource adequacy requirement, and reliability differentiation."*[14]

In a recent paper, Newbery (2020) points out that while scarcity pricing can address the short-term efficiency, it may not by itself provide a long-term hedging opportunity necessary for the development of new capacity, as the capacity markets do in for instance Great-Britain and Ireland:

> *"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"*[15]

2.2 ORDC scarcity pricing implementation

Although implementation details may differ (cf. infra), scarcity pricing implementations typically build further on the Operating Reserve Demand Curve (ORDC) scarcity pricing implementation as proposed by Hogan (2005) and which is at the basis of the current design of such mechanism in Texas' ERCOT market. In that paper, Hogan puts forward the idea of introducing an administratively determined demand curve for operating reserves that expresses the system operator's willingness-to-pay for specific levels of operating reserves, with a willingness-to-pay that rises to VOLL when operating reserve levels approach the minimum reserve level.

This concept of a scarcity pricing mechanism based on the ORDC has been further refined in Hogan (2013), suggesting a specific shape of the ORDC (cf. also Figure 2 for a graphical representation) consisting of two segments: a) a fixed requirement set at the minimum of contingency requirement valued at VOLL and b) the value of increment of operating reserves beyond this contingency requirement valued at VOLL multiplied by the probability of loss of load:

[14] Zarnikau Zhu Woo Tsai 2020 - Texas's Operating Reserve Demand Curve's Generation Investment Incentive

[15] Newbery 2020 - Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan

*"The key connection is with the value of lost load (VOLL) and the probability that the load will be curtailed or similar emergency actions taken. Whenever there is involuntary load curtailment and the system has just the minimum of contingency operating reserves, then any increment of reserves would correspondingly reduce the load curtailment. Hence the price of operating reserves should be set at the value of lost load net of any energy savings. At any other level of operating reserves, set to protect the system for events in the immediate future, the value of an increment of operating reserves would be the same VOLL multiplied by the probability that net load would increase enough in the coming interval to reduce reserves to the minimum level where emergency action would be taken to restore contingency reserves. Hence the incremental value of operating reserves would be the analogous to the product of the loss of load probability (LOLP) and VOLL, or LOLP*VOLL."*[16]

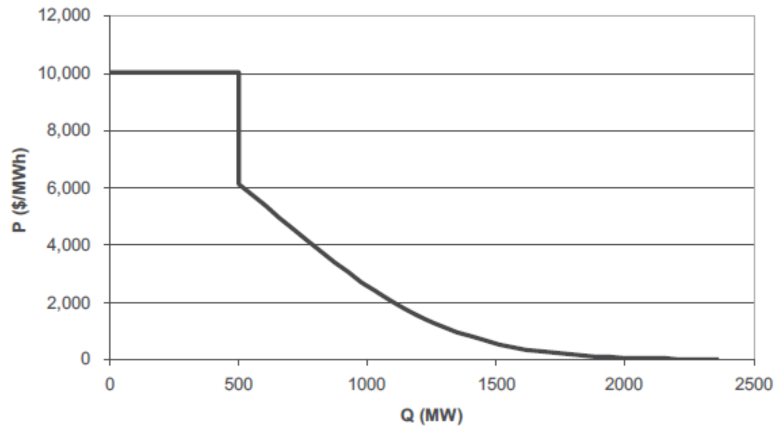

Figure 2: ORDC proposed by Hogan (2013)

In what follows, section 2.2.1 describes the general role of operating reserves in an EOM design and explains how the ORDC fits in. Next, section 2.2.2 explains how an ORDC influences the market clearing and thereby puts the scarcity pricing into practice. Section 2.2.3 finally provides an overview of some ORDC scarcity pricing implementations in US markets, elaborating both on the construction of the ORDC in several different markets and on a concrete use case of some design experiences with the ORDC in ERCOT Texas.

2.2.1 The role of operating reserves in an EOM design

Hogan (2005) mentions that the premise of an "energy only" market design does not mean that there should be nothing else than spot deliveries of electric energy with a complete absence of administrative features in the market. One of those administrative elements that does make sense also within the context of an EOM design, is the determination of the required level of operating reserves by the system operator to deal with possible contingencies, to protect against

[16] Hogan 2013 – Electricity Scarcity Pricing Through Operating Reserves

both involuntary load shedding and even other dangers such as a system collapse. This is not something against which the market would be able to fully protect itself. Essentially, such demand for operating reserves is to be added to the demand for electric energy at any moment and the installed capacity should foresee both.

From Hogan's perspective,[17] the system operator's demand for operating reserves typically includes a minimum contingency level, i.e. a minimum level that is needed to prevent catastrophic failure through a widespread and uncontrolled blackout in the system. Beyond this minimum contingency level, it is common sense that holding more operating reserves would be better – from the perspective that this would provide more flexibility to deal with possible contingencies, notwithstanding the negative effect this might have towards increased procurement costs for holding more operating reserves – but not crucial. For instance, when such higher level of operating reserves would use up resources to the extent that it leads to certain involuntary load shedding, it would be better to take the risk and accept a lower level of operating reserves. This lower level of operating reserves (provided it is above the minimum contingency level) may be sufficient to deal with possible contingencies and therefore not result in involuntary load shedding.

In Belgium and Europe in general, the legal basis to determine the required level of Frequency Restoration Reserves (FRR) – for the sake of simplicity here assumed equivalent to the more general terminology of 'demand for operating reserves' as used before – is set by Art. 157 of the System Operation Guideline (SOGL)[18]. This article on FRR dimensioning sets the minimum requirements regarding the level of FRR that should be ensured at all times within each Load Frequency Control (LFC) block. Hence, following these stipulations, TSOs are not allowed to accept a lower level of FRR than the one that respects these legal requirements. A higher level of FRR is possible though, but only if this follows from the FRR dimensioning rules set out in the LFC Block operational agreement, which is subject to regulatory approval.

Hence, a more general interpretation of the ORDC is that it determines an explicit value to each and every level of operating reserves that may be considered by the system operator, or observed in real-time. Indeed, while Hogan's perspective assumes some freedom in the level of operating reserves requested by the system operator, current practice in Europe provides no to at least considerably less such freedom. Instead however, an observed level of operating reserves still available in real-time may also be a good proxy to assess the scarcity condition, which – through the ORDC – can be translated into a value representative for the state of the system. As explained before, this ORDC valuation is supposed to be linked with VOLL and should reflect the loss of load probability associated to each level of operating reserves. These two elements combined – i.e. loss of load probability multiplied by VOLL – provides an estimation of a scarcity-reflective real-time energy price.

To summarize, a scarcity pricing mechanism can be defined as an administrative intervention to ensure that energy prices spike during scarcity events and reflect the value of energy without relying on supra-competitive bids of

[17] Note that this perspective is as such not compatible with the European rules on how to dimension balancing reserves as explained further.

[18] Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation

generators. Indeed, the correct valuation of real-time time energy should be reflected in the downward-sloping price-sensitive ORDC. As explained by Hogan (2005), it can be summarized as:

> *"The operating cost of the most expensive unit running is relevant when there is excess capacity. However, when capacity is short and generation supply is in effect fixed over the range, the demand curve for energy and operating reserve should set the price, and should be able to set the scarcity price at a high level."*[19]

2.2.2 The impact of the ORDC on market clearing

This section explains how the introduction of an ORDC influences the energy market clearing outcome, and hence how the ORDC may provide the scarcity prices that are crucial for generators to recover fixed costs. For illustrative purposes, it is assumed that energy and reserves are co-optimized in a centralized market clearing (which is in Belgium and throughout Europe currently not the case). Also, the illustrations show the energy and reserves supply curves as one and the same. In reality, some resources may bid to supply energy but not reserves and vice versa.

The illustration in Figure 3 below as provided by Hogan (2005) represents the situation of a normal "energy only" market clearing, i.e. without scarcity. Since there is sufficient supply available compared to the combined demand for energy and reserves, the market clearing price – determined by the intersection of the generation supply curve and the energy + reserves demand curve – is low.

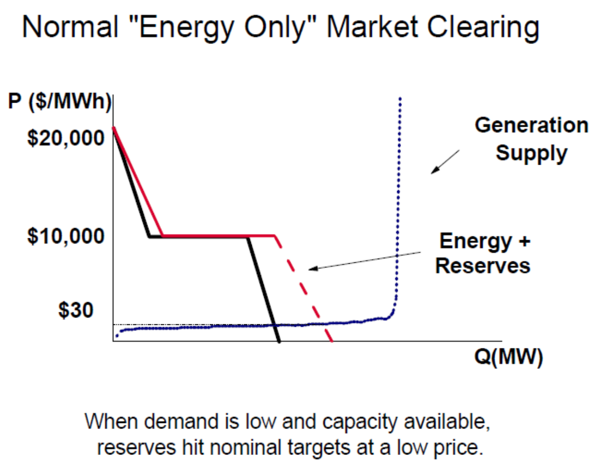

Figure 3: Normal "energy only" market clearing presented by Hogan (2005)

Figure 4 to the contrary, as also provided by Hogan (2005), illustrates the situation of a market clearing under (near-) scarcity conditions. From this illustration, it is clear that the elastic part of the supply curve is only just sufficient to cover the energy demand. However, when the demand for reserves – i.e. the ORDC – is added to the energy demand, the market clears at a higher price determined by the intersection between the ORDC and the inelastic part of the supply curve. Note that at this higher price level, part of the demand that is flexible is already reduced – following the elastic

[19] Hogan 2005 – On an "energy only" electricity market design for resource adequacy

shape of the demand curve, while also only a relatively small volume of operating reserves is contracted by the system operator. This volume of contracted reserve is smaller than under normal conditions as illustrated in Figure 3. The resulting high clearing price (i.e. 7000 $/MWh in this example) applies to suppliers who provide energy and almost this same price (net of the variable generation costs) applies also to suppliers who provide operating reserves.

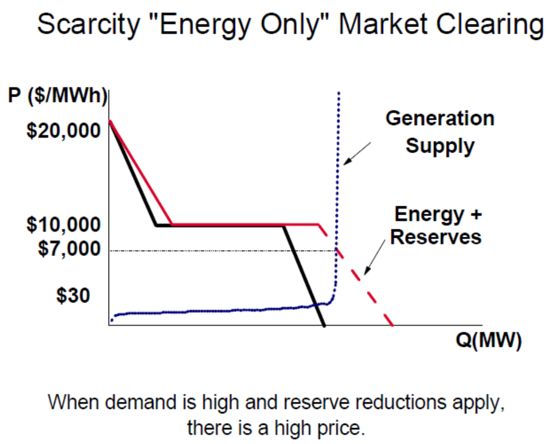

Figure 4: Scarcity "energy only" market clearing presented by Hogan (2005)

The main principle that can be derived from this example is that under the presented setup during (near-) scarcity conditions, the market clearing price is determined by the ORDC at a level significantly above the bid price of the most expensive generator running. Hence, there is no need for supra-competitive supply side bids that can be subject to market power mitigation measures. In the context of the peak load pricing theory, the remuneration at (near-) scarcity moments that leans towards VOLL are supposed to contribute considerably to the recovery of fixed costs. However, whether such scarcity pricing mechanism as conceived by Hogan is sufficient – by design and calibration – to eliminate the missing money problem and to guarantee a predefined reliability standard is far less obvious. This is further discussed in section 2.4. In what follows, first some international experience with scarcity pricing mechanisms is presented.

2.2.3 US scarcity pricing implementations

Since the conceptualization of the ORDC by Hogan (2005) and further refined by Hogan (2013), several US electricity markets have implemented different variations of an ORDC into their market design. The ORDC scarcity pricing implementation is well-suited for an integration in US markets that typically rely on integrated markets for energy and operating reserves. An implementation of a scarcity pricing mechanism in Europe in the first place needs to take into account a generally different market design and an ORDC as deployed in some US markets is mutatis mutandis not directly implementable. However, this will be discussed extensively and more in detail later in this report. In this section, the focus remains on the ORDC scarcity pricing implementation as conceived in the US.

From these US scarcity pricing implementations, it can be observed that ORDCs take different shapes and amplitudes. While single step functions are currently applied in PJM, ISO-NE, NYISO and CAISO, more dynamic shaped based on

Loss Of Load Probability (LOLP) are used in MISO, SPP and ERCOT. A graphical representation of ORDCs implemented in various US electricity markets is provided in Figure 5 below.[20]

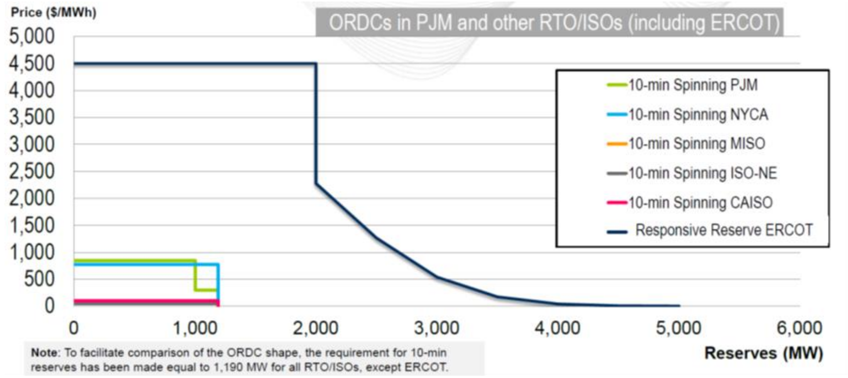

Figure 5: Graphical representation of ORDCs (Source: PJM (2018))

The difference in shape and amplitudes between ORDCs may be explained by different objectives that are pursued by the system operators, depending on the broader market design of their electricity market. In many US markets that have implemented an ORDC, scarcity pricing is not conceived as the sole driver for investment, which is rather the objective of capacity markets that are in place as well. Note that PJM, NYISO, MISO and ISO-NE all have a centralized CRM in place. CAISO and SPP do not have a formal capacity auction, but they do rely on a decentralized capacity obligation to address resource adequacy.

ERCOT in Texas is an exception in this respect, relying on the ORDC scarcity pricing mechanism as part of its "energy only" market design to sustain both short- and long-term signals of short-term scarcity, which must guide investment decisions in flexible generation capacity and demand-side resources. Therefore, in contrast to other ORDC implementations, ERCOT in Texas is currently the only US market where the scarcity pricing mechanism is based on an ORDC calibrated on VOLL and LOLP to be able to induce scarcity rents that are believed to be sufficient to provide system adequacy.

Use case: Design experience with ORDC in ERCOT

The ORDC scarcity pricing implementation of ERCOT in Texas is a good example to showcase some of the real-life design experiences with ORDC scarcity pricing mechanisms, as ERCOT relies entirely on the ORDC to provide both short-term signals to ensure efficient operations as well as long-term signals to provide system adequacy (cf. supra).

In June 2014, ERCOT implemented a scarcity pricing mechanism based on ORDC. The ORDC had two segments, as proposed in Hogan (2013): a flat segment price at VOLL at the level of 2000 MW corresponding to the minimum contingency requirement and a downward sloping segment calculated at the value of an increment of operating reserves equal to the VOLL multiplied by the LOLP.[21] The VOLL is estimated at 9000 $/MWh and the LOLP is

[20] Based on an illustration provided by PJM (2018) – Price Formation Education 4: Shortage Pricing and Operating Reserve Demand Curve

[21] Hogan 2013 – Electricity Scarcity Pricing Through Operating Reserves

calculated separately for different system conditions, resulting in 24 distributions that comprise 4 seasons and 6 time-of-day blocks.

The experience with the implementation of the scarcity pricing mechanism in Texas demonstrates that such a mechanism may require frequent re-calibration of ORDC parameters, as well as broader revisions of some elements of the mechanism and reforms of the electricity market design. Furthermore, several observers suggest that development of wind production in Texas may further undermine the efficiency of the scarcity pricing mechanism in reaching adequacy.

Frequent need to re-calibrate parameters of the ORDC

The evolution of the capacity mix, in particular the increase of variable wind production, requires adjustments and re-calibration of the ORDC. ERCOT periodically updates the ORDC's parameters of μ and σ, the mean and standard deviation of the hour-ahead errors in forecasting the level of available reserves used to calculate LOLP in the ORDC formula.

Kavulla and Gullen (2019) notice that some of these parameters have been recently revised to ensure that ORDC triggers price adders more frequently:

> *"As Texas adds more renewables, ORDC has been revisited. In early 2019, the PUCT approved several changes to market design. It directed ERCOT to phase in an increase in the standard deviation of the loss of load probability used to calculate ORDC primarily to account for increased uncertainty caused by intermittent resources ... In effect, this change will trigger ORDC price adders more frequently, without changing the minimum reserve level of 2000 MW."*[22]

However, changes in the parameters of ORDC calculation have been a subject of some controversy, as showcased by the discussions and opinions presented below. In addition to the statistical parameters of the hour-ahead errors themselves, the ORDC calculation has involved shifts to reflect risk aversion to lost load as ERCOT's reserve margin declined:

> *"On 01/17/2019, the PUCT ordered a "right shift" in the ORDC by 0.25 σ, which was implemented on 03/01/2019. A shift of an additional 0.25 σ is scheduled for early 2020."*[23]

The result of these shifts is shown in Figure 6 below.

[22] Kavulla and Gullen 2019 - 'Missing Money' and an off-ramp to the capacity debate

[23] Zarnikau Zhu Woo Tsai 2020 - Texas's Operating Reserve Demand Curve's Generation Investment Incentive

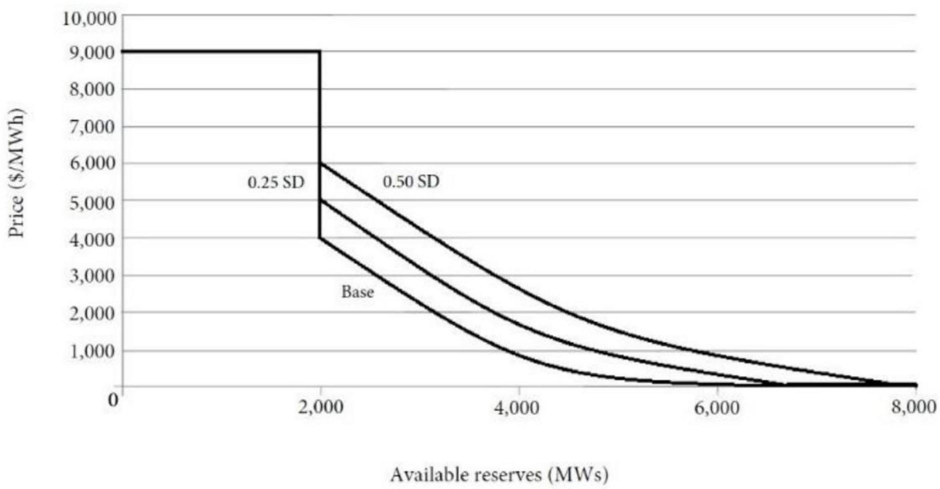

Figure 6: Effects of the shift in standard deviation on ORDC (Source: Zarnikau et al (2020))

Hogan and Pope (2017) consider such shifts reasonable to account for the fact that the distribution of errors is not normal and given that such shift represents a more conservative approach, i.e. making the ORDC function more "trigger happy":

> *"ERCOT calculates the mean (μ) and standard deviation (σ) of the historical CDF, which follows a normal distribution. The conservative measure would be to shift the mean of the CDF function by up to one standard deviation using a scaling value between 0 and 1 (0<s<1)."*[24]

However, Wakeland (2018a) considers such shifts are arbitrary and not justified by the increase of intermittent generation in Texas:

> *"A suggestion of multiplying the standard deviation (σ) used in the Electric Reliability Council of Texas'(ERCOT) Operating Demand Curve (ORDC) loss of load probability (LOLP) by a factor greater than 1.0 has been posited to solve the missing money argument. After the fact justification for this position has been given by the rational assumption that the increase in intermittent generation in ERCOT (mostly wind) has increased the LOLP but has not resulted in a corresponding increase in the σ used in the equation. No supporting data has been provided for this rational hypothesis."*[25]

Wakeland (2018b) further considers that there is a fundamental flaw in the approach implemented in ERCOT to calculate the ORDC because it is based on the distribution of hour-ahead forecasted level of reserves rather than real-time reserves:

> *"ERCOT makes a mathematical mistake in determining the LOLP used in its ORDC equation by applying a forecasted reserve level error distribution curve to the real-time reserve level […] The proper distribution to be*

[24] Hogan, W., Pope, S., 2017. Priorities for the evolution of an energy only electricity market design in ERCOT

[25] Wakeland 2019 - Does the Increase in Wind Generation in ERCOT Justify An Arbitrary Increase to its ORDC LOLP Calculation?

> *applied to the real-time reserve level would be the distribution of change in real-time reserve level over an hour."*[26]

He considers that this results in an under-estimation of the LOLP:

> *"The ORDC […] applies an hour ahead forecasted reserve level error distribution to the real-time reserve level, and it underestimates LOLP because it misapplies normal distribution probability methods at the finite limits of a system"*[27]

He further questions the approach of using multiple LOLP curves per day mentioning that "*additional significant problems are introduced by unnecessarily relying on six different LOLP curves a day*", but ERCOT is planning to change this current approach and introduce a single ORDC:

> *"ERCOT will also replace numerous loss of load curves based on season and time-of-day blocks with a blended curve for all seasons and hours."*[28]

Further need for reforms of the scarcity pricing mechanism and energy market design

Also Hogan and Pope (2017) have indicated a further need for improvement of the scarcity pricing mechanism in Texas. They point out that although the Texan ORDC approach is a great step forward to reflect the value of the system operator actions during scarcity in the electricity price, some system operator actions remain outside of the ORDC. In particular, the possibility of ERCOT to commit units out of market through Reliability Must Run (RMR) and Reliability Unit Commitment (RUC) mechanisms, resulting in the scarcity pricing underestimated by ORDC:'

> *"Including this non-market capacity in the ORDC determination of a market price distorts the underlying logic of scarcity pricing. There are at least two dimensions to the resulting price distortion in the ERCOT market. First, the scarcity price will be underestimated through the ORDC. Second, the incremental costs of the out-of-market capacity employed but seldom dispatched might be greater, even much greater, than the avoided costs of a reliability event, as estimated by ERCOT's VOLL."* [29]

To address this issue, they suggest accounting for the out-of-market commitments in the calculation of the operating reserves covered by ORDC and to *"decrease the operating reserves by the amount of the out-of-market commitments. This would be equivalent to decreasing the Real-Time Online Reserves by the amount of the capacity made available by the out-of-market action.*"

Hogan and Pope (2017) further indicate that the current scarcity pricing mechanism fails to reflect scarcity on locational level:

[26] Wakeland 2018, Fundamental Mathematical Errors in ERCOT's Operating Reserve Demand Curve and a Proposed Solution

[27] Wakeland 2018, Fundamental Mathematical Errors in ERCOT's Operating Reserve Demand Curve and a Proposed Solution

[28] Kavulla and Gullen 2019 - 'Missing Money' and an off-ramp to the capacity debate

[29] Hogan, W., Pope, S., 2017. Priorities for the evolution of an energy only electricity market design in ERCOT

> *"The current ORDC also does not price local scarcity in general. Therefore, if there is an adequate supply of reserves region-wide, but a shortage in a particular region, the ORDC will remain low."*[30]

One of the solutions to this issue they propose involves introduction of local reserve requirements with ORDC and a co-optimization between energy and reserves in real-time:

> *"Local reserve requirements, implemented day ahead and in real-time through co-optimization, would enable ERCOT to be better positioned to avoid committing additional units for reliability within the day."*[31]

In general, co-optimization between real-time energy and reserves is planned for introduction in the ERCOT market in 2023 (Zarnikau et al 2020). This will replace the manual addition of the reserve price adder. Current practice in ERCOT is to calculate reserve adders and add them "manually" to the real-time energy price. However, co-optimization would do this automatically:

> *"PUCT allowed for real-time co-optimization of energy and ancillary services markets. They had previously not been integrated."*[32]

Reduced efficiency of ORDC with development of wind

Observers, such as Zarnikau et al (2020) and Bajo-Buenestado (2019) point out that although the increased RES capacity and generation may justify adjustments of the ORDC, it is unclear if the improved scarcity pricing would outweigh the merit-order effect of RES in incentivizing market entry:

> *"In the longer run, we doubt revisions of the ORDC will provide an adequate solution. This is because the growth of solar and wind energy generation in Texas that is rich in renewable energy potential tends to constrain RTM prices through their merit-order effects."*[33]

> *"We also provide evidence that additional wind generation (resulting from an increase in installed wind capacity) has brought about lower ORDC prices and has increased the probability that these prices are equal to zero in Texas, which may further disincentive to increase generation capacity {especially dispatchable capacity that may be needed as a backup if the wind is not blowing."*[34]

Zarnikau et al (2020) consider that this may require additional mechanisms in Texas to induce adequacy, such as capacity mechanisms:

> *"Our findings' policy implication is that Texas's energy-only market design may need refinements based on a consideration of the mechanisms discussed by Woo and Zarnikau (2019), potentially including capacity market, resource adequacy requirement, and reliability differentiation."*[35]

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[30] Hogan, W., Pope, S., 2017. Priorities for the evolution of an energy only electricity market design in ERCOT

[31] Hogan, W., Pope, S., 2017. Priorities for the evolution of an energy only electricity market design in ERCOT

[32] Kavulla and Gullen 2019 - 'Missing Money' and an off-ramp to the capacity debate

[33] Zarnikau Zhu Woo Tsai 2020 - Texas's Operating Reserve Demand Curve's Generation Investment Incentive

[34] Bajo-Buenestado 2019, Operating Reserve Demand Curve, Scarcity Pricing and Intermittent Generation: Lessons from the Texas ERCOT Experience

[35] Zarnikau Zhu Woo Tsai 2020 - Texas's Operating Reserve Demand Curve's Generation Investment Incentive

Summary

This use case on the design experience with ORDC in ERCOT Texas is only presented for illustrative purposes. Elia does not wish to take position on the above design issues. However, for this report, the viewpoints expressed by observers of the ORDC scarcity pricing mechanism implemented in ERCOT illustrate that this approach triggers several questions in terms of precise design and calibration, and may result in choices sometimes perceived as being arbitrary.

Beyond the difficulties regarding the calibration and design of the ORDC scarcity pricing mechanism, this use case also shows that there are doubts on the adequacy effect of a scarcity pricing mechanism on the longer run with shifting capacity mixes, especially with rising shares of renewables in the system. Note that the latter point is especially relevant also in an EU and Belgian context.

To conclude from this use case, when considering a scarcity pricing mechanism for Belgium/Europe, it requires at least a sufficient underpinning of the choices made, ensuring that the scarcity pricing mechanism has the desired effect in relation to what is expected – and what can be expected realistically – from such mechanism.

2.3 Scarcity pricing integration in EU markets

Thus far, the discussion on scarcity pricing has focused mainly on the US electricity markets as this is where the origins of scarcity pricing lie and where the mechanism's design is also rooted in academic literature and debate. In this section, first some elements of the EU regulatory context that may be relevant in the context of scarcity pricing are discussed in section 2.3.1. Next, section 2.3.2 provides an overview of some (existing or planned) EU scarcity pricing implementations known to Elia.

2.3.1 EU regulatory context

Beyond various fundamental market design differences between EU and US electricity markets that need to be taken into account when implementing scarcity pricing in Europe, also the specific European regulatory context needs to be considered. This section reflects on some aspects of this European regulatory context that are relevant in the context of a scarcity pricing implementation.

2.3.1.1 European market power mitigation approach

As mentioned above, following academic literature the main objective of the administrative scarcity pricing mechanism is to ensure that the value of energy can rise during the scarcity events without the need for generators to bid above their marginal cost of their units. In the US, this need is justified by the market power mitigation approaches that apply market power tests during the clearing process of the day-ahead and real-time markets to determine if there might be a risk of market power exercise. Although there is no legal obligation to bid at cost, suppliers who fail the tests have their bids replaced with a reference level (generally cost-based bids), which is meant to approximate bidding under competitive conditions.

In Europe, the starting point is different. Market power mitigation is mainly conducted through ex-post investigations by NRAs under the competition policy or REMIT regulations, upon receiving specific signals or complaints. This leaves room for generators to bid above their short-term marginal cost (e.g. to include opportunity costs and to earn scarcity rent), unlike the US more systematic ex-ante market power screenings.

2.3.1.2 Back-propagation of real-time price signals

Price convergence between real-time and day-ahead (and earlier) markets is a result of a general trading arbitrage between these markets, and may be improved if there are no barriers to such arbitrages across different markets / time frames.

According to Isemonger (2006), one could distinguish approaches to ensure such arbitrage between so-called Explicit Virtual Bidding (EVB) and Implicit Virtual Bidding (IVB) and Physical Arbitrage (PA):

> *"While there are perhaps many ways to arbitrage prices between markets there are three principal methods, namely explicit virtual bidding (EVB), implicit virtual bidding (IVB) and physical arbitrage (PA)."*[36]

Following Isemonger (2006), Explicit Virtual Bidding means *"submission of bids for the financial purchase or sale of energy in the day-ahead and real-time energy markets without intending to physically consume or produce energy in real time. Rather the DA virtual position will simply be closed out with an automatic countervailing trade in RT as a price taker."* In the US markets in particular, explicit virtual bids play a role in ensuring arbitrage opportunities between day ahead and real time. Explicit virtual bidding does not exist as such in EU markets.

Again following Isemonger (2006), Implicit Virtual Bidding means *"piggybacking the virtual transactions onto existing physical transactions"*, for example, selling 300MW in DAM and producing 200MW in RT implies a pseudo-virtual sale of 100MW in DAM.

Smeers and Papavasilou (2019) seem to suggest that the European approach to portfolio bidding allows the Implicit Virtual Bidding but this may require the DAM bids to deviate from the marginal costs of the portfolio's physical resources and to be linked to the opportunity cost anticipating the value of the real-time market:

> *"Therefore, efficient day-ahead bids need not be linked to the physical characteristics of a resource, i.e. to its marginal cost, but rather to its opportunity cost. The fact that European day-ahead markets permit portfolio bidding provides market actors with significant flexibility to internalize such factors in their bids."*[37]

However, arbitrage between the day-ahead and the real-time balancing markets through such Implicit Virtual trades remains a regulatory "grey zone" in Europe from the point of view of the competition policy and market manipulation regulation. In particular, the REMIT regulation does not precisely define which cross-market transactions should be considered manipulative.

An important factor distinguishing the Explicit and Implicit Virtual bidding is the fact that Implicit Virtual bidding requires physical generation or consumption assets, while Explicit Virtual bidding is open for pure financial players. Chaves Avila (2014) considers that this limits the options for price convergence through financial arbitrage in the European context:

> *"In Europe, the short-term electricity markets (day-ahead, intraday and balancing) are markets restricted by regulations for physical delivery. They are open only to agents that consume and produce electricity or traders*

[36] Isemonger 2006, The Benefits and Risks of Virtual Bidding in Multi-Settlement Markets

[37] Smeers and Papavasiliou 2019, Study on the general design of a mechanism for the remuneration of reserves in scarcity situations

> *who buy or sell electricity for third parties. Therefore, pure financial arbitrage between markets is not allowed."*[38]

The discussion on explicit and implicit virtual bidding would be irrelevant for EU markets though, where it not for the formal day-ahead (and real-time) balance obligations that still exists in some EU countries. Indeed, given the European approach with portfolio bidding, participants could then choose to hold an open position. However, given formal balancing obligations, market participants are required to engage into Implicit Virtual Bidding (cf. infra). Pure financial arbitrage between day-ahead, intraday and real-time balancing markets is obstructed entirely by formal requirements for market participants to balance their schedules in the day-ahead. EFET (2020) consider that such requirements unduly limit trading opportunities:

> *"A number of jurisdictions maintain legal requirements for market participants to be balanced in DA. These requirements […] constitute a hindrance on portfolio optimisation and proprietary trading. Market participants must be free to optimise their full portfolio across all timeframes until the gate closure of the intraday market."*[39]

2.3.2 EU scarcity pricing implementations

While scarcity pricing mechanisms introduced in US electricity markets rely on the ORDC mechanism as conceived by Hogan (2005), the implementation of scarcity pricing in EU electricity markets require further design choices to be made. This is discussed in detail in subsequent chapters, which are specifically devoted to the design of a scarcity pricing mechanism for Belgium (and EU by extension). However, the fact that further design choices have to be made is also showcased by the difference in scarcity pricing implementations throughout Europe.

As far as it is known to Elia, the following countries have implemented (or plan to implement) a scarcity pricing mechanism:

- Great-Britain, since 2015, uses a Reserve Scarcity Function (RSF) to re-price the activation ("utilization") price of short-term operating reserves depending on system conditions. The RSF is based on VOLL and LOLP, which depends on the de-rated margin of the system. The reserve scarcity price is included in the calculation of imbalance prices along with the activation price of other accepted reserve bids, and therefore indirectly impacts the price of balancing energy;
- Ireland, in 2018 through its I-SEM market design, introduced administered Scarcity Pricing that works through the energy imbalance price;
- Poland, by 1 January 2021, plans to introduce a scarcity pricing mechanism. However, implementation details are not yet finalized.

Note that each of these countries has implemented a capacity market as well. Hence, also the EU experience with scarcity pricing seems to suggest that the capacity market and scarcity pricing serve a different purpose and one does

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[38] José Pablo Chaves Ávila 2014, European Short-term Electricity Market Designs under High Penetration of Wind Power

[39] EFET 2020, Towards an efficient intraday market design

not necessarily exclude the other. Furthermore, it is clear that scarcity pricing implementation details differ and that there is not one unique scarcity pricing implementation.

2.4 Can scarcity pricing be a solution to the missing money problem?

A general theoretical background of scarcity pricing was presented in section 2.1, while a more detailed description of the ORDC scarcity pricing implementation often cited as reference and used in US markets has been provided in section 2.2. Section 2.3 subsequently discussed the scarcity pricing integration in EU markets.

The question that is addressed in this section is whether a scarcity pricing implementation would in fact be able to resolve the problem it aims to address. Indeed, as also mentioned in section 2.1, the end goal of the scarcity pricing mechanism is to resolve the missing money problem.

2.4.1 Price-based versus volume-based mechanisms

Scarcity pricing mechanisms aim to increase real-time energy prices during system stress conditions. To the extent such extra revenues for the available resources are reflected in forward prices through backward propagation and are perceived as credible by investors, scarcity pricing may reinforce investment incentives.

However, a scarcity pricing mechanism relies on the energy market to translate the energy price signal into capacity investments (i.e. a price-based mechanism). Therefore, scarcity pricing cannot guarantee adequacy in the same way and as efficiently as a well-designed volume-based capacity mechanism. In other words, whilst volume-based mechanisms such as capacity markets, strategic reserves or targeted tenders are specifically targeted at ensuring system adequacy and seek to guarantee a volume based on a reliability standard, scarcity pricing mechanisms' primary objective is to ensure that spot market and reserve prices reflect accurately the economic value of electricity at times of scarcity, and thereby only indirectly contribute to system adequacy. For instance, more specifically:

- In a volume-based Capacity Remuneration Mechanism (CRM), the auctioned capacity volume is calibrated to meet the reliability standard, e.g. determined in terms of the average number of hours of Loss of Load Expectation (LOLE) per year, estimated from the Value of the Loss of Load (VOLL) and cost of new entry (CONE). The capacity market guarantees that the capacity required to attain this reliability standard is available each year.
- In a price-based scarcity pricing mechanism, the ORDC is calibrated to guarantee that in periods of operating reserve scarcity, the real-time price reflects the Value of Loss of Load (VOLL). The scarcity-reflective real-time price then contributes to the revenues of the available resources, and are thereby expected to provide a signal for optimal investment leading to a long-term capacity equilibrium not necessarily corresponding to a predefined reliability standard and/or ensuring it during each considered period.

In other words, while scarcity pricing may help to reduce the missing-money problem, it cannot guarantee by design to eliminate the missing money problem.

A particular issue is that scarcity pricing only focuses on the missing money problem from the perspective that there are barriers that obstruct free price formation (e.g. price caps) and therefore presents a solution to ensure that prices can rise towards the Value of Loss of Load under specifically specified scarcity conditions. However, scarcity pricing does not eliminate other aspects and market failures that are today inherent to the energy-only market and which put at risk adequacy. Amongst others the following problems still persist even with scarcity pricing being implemented:

- Boom & bust cycles

In an EOM design, investment cycles with moments of lower and higher adequacy (boom & bust) are a consequence of normal investment dynamics suffering from imperfect foresight and myopic behavior of investors and difficulties to overcome system shocks (compared to reacting to small changes). As scarcity pricing does not eliminate boom-bust cycles, very expensive scarcity pricing years would not necessarily correspond with years in which new investments take place.

Boom-bust cycles are also further reinforced by the lead times that some technologies have in getting capacity online.

Such boom-bust cycles in investments obviously can result in equivalent boom-bust cycles in the level of adequacy and energy prices, both system effects that should not be overlooked. Moreover, this means that by design, a scarcity pricing mechanism cannot guarantee the legally determined adequacy criteria in a continued fashion.

- Risk averseness of investors

Being a capital-intensive industry, with significant risks of stranded assets and long asset lifetimes, the power generation industry is confronted with risk aversive capital markets where infrequent revenue streams are difficult to secure in terms of financing and, if possible, in any case at a higher capital cost.

Especially investment decisions that rely on returns driven by the expected scarcity prices present significant risk for investors in the peaking plants. It is difficult to forecast the average returns over the lifetime of the plant that are driven by scarcity prices that by definition are much higher than normal price levels, occur rarely and are difficult to predict. Newbery (2020) considers that investments relying on scarcity prices would face significant "tail risk":

> *"…the argument for an EOM (energy only market) 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")."*[40]

2.4.2 International experience shows co-existence between scarcity pricing and capacity markets

From the international experience already discussed in section 2.2.3 it should be noted that almost all electricity markets that have implemented a scarcity pricing mechanism, also have some capacity mechanism targeting adequacy in place. In fact ERCOT in Texas is thus far the only exception, having implemented scarcity pricing with no other capacity mechanism in parallel. This seems to suggest that scarcity pricing mechanisms and capacity markets actually serve different purposes. The system adequacy is ensured through the capacity market, while the role of scarcity pricing is to improve the accuracy of the short term price signal inducing market participants to take actions to respond to the

[40] Newbery 2020 - Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan

real-time price signal ensuring the capacity providers that their availability at times of scarcity will be duly rewarded. As for instance stated by Independent Market monitor for PJM (2018) (underlining by author):

> *"Scarcity pricing for revenue adequacy is not required in PJM. … Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability."*[41]

As discussed in section 2.3.2, scarcity pricing mechanisms were also introduced or are planned to be introduced in several European countries (notably Ireland, UK and Poland). Also here, the scarcity pricing mechanism serves a different purpose than maintaining adequacy, since all these countries have also implemented a capacity mechanism. The complementary role of the scarcity pricing and capacity mechanism is underlined by the European Commission in its decisions.

As a first example, in its State Aid decision about the Irish capacity mechanism, the European Commission states in recital (107) (underlining by author):

> *"The Commission agrees that a capacity mechanism can be an effective instrument to reduce the uncertainty among investors about their returns. (…) Finally, the Commission welcomes that the authorities are in parallel taking steps to improve price signals in the electricity market by reforming the market framework so that prices will more accurately reflect scarcity situations. Moreover, the implementation of a system of Administrative Scarcity Pricing ('ASP') as described in recital (13) ensures that prices are high at times of scarcity and enhances the confidence of future capacity providers that their availability at times of scarcity will be duly rewarded."*[42]

As a second example, in its State Aid decision about the Polish capacity mechanism, the European Commission states in recital (149) (underlining by author):

> *"The Commission welcomes that the authorities are in parallel taking steps to improve price signals in the electricity market by reforming the market framework so that prices will more accurately reflect scarcity situations. In particular, the implementation of a system of administrative scarcity pricing as described in recital (16)(e) ensures that prices will be high at times of scarcity and enhances the confidence of future capacity providers that their availability at times of scarcity will be duly rewarded"*[43]

[41] Independent Market monitor for PJM 2018 – State of the Market report for PJM

[42] **https://ec.europa.eu/competition/state_aid/cases/267880/267880_1948214_166_2.pdf**

[43] **https://ec.europa.eu/competition/state_aid/cases/272253/272253_1977790_162_2.pdf**

2.4.3 Scarcity pricing rather a flexibility tool?

If scarcity pricing is not (generally) to be regarded as a solution to attain a predefined reliability standard, the question is where the most prominent added value of scarcity pricing lies. In any case, scarcity pricing ensures – if well calibrated – that the real-time prices reflect the value of capacity scarcity by explicitly expressing a system operator's real-time willingness-to-pay for operating reserves. Hence, targeting real-time prices and focusing on operating reserves, one should be aware in the design of a scarcity pricing mechanism that it is rather a flexibility tool providing investment signals especially to highly-flexible (i.e. reaction time ≤ 15mins) resources. This point of view is also expressed in the CORE study – which is analyzed later in chapter 4 as it proposed an implementation of scarcity pricing for Belgium – stating in section 1.1:

> *"Scarcity pricing is not a panacea. The mechanism is designed to reward short-run flexible capacity."*

When scarcity pricing functions in the first place as a flexibility tool, especially the following considerations should be taken into account:

- Not every balancing problem represents an adequacy problem

While resource adequacy problems result in real-time flexibility problems, not every real-time flexibility problem is also a resource adequacy problem. For instance, in a system with a winter peak (like Belgium) a forced outage of a generation unit in summer may deplete operating reserves significantly, but this does not constitute a genuine adequacy problem as sufficient capacity was obviously installed in the system to cover a summer load. Part of the capacity was simply not dispatched at all and hence also not contributing to the operational situation. Hence, a shortage of operating reserves does not necessarily mean that the system is approaching scarcity in terms of adequacy.

- Targeting long-term resource adequacy by providing investment signals to highly-flexible resources may be costly and therefore not cost-efficient

In case the scarcity pricing mechanism remunerates in particular highly-flexible capacity (notwithstanding backward propagation) such mechanism provides investment signals especially to these resources. However, it can be questioned whether it would be economically desirable to address resource adequacy issues (even if only partly) by stimulating particularly highly flexible, and therefore potentially more expensive, capacity. Slower reacting capacity (e.g. some generation sources or industrial processes participating as demand response) may require more time to react than 15 minutes, but they are as useful for dealing with resource adequacy problems that typically already manifest themselves in earlier time horizons like day ahead.

- In Belgium in particular, there is currently no anticipated need for extra stimuli for investments in flexibility

Despite an identified resource adequacy issue in Belgium as from winter 2022-2023 (and being exacerbated as from Winter 2025-2026 following the closure of all nuclear power plants), with respect to flexibility needs, in its recently published adequacy and flexibility study Elia concludes that in the years leading up to 2030, sufficient flexible resources will be available in the system to cope with the increased fluctuations between injections and offtake resulting from more volatile means of generation.[44] Hence, for the case of Belgium, there currently appears to be no need to provide further investment incentives to highly flexible generation capacity as long as the adequacy issue remains solved.

2.5 Conclusion

Stemming from US-inspired market mechanisms, it is Elia's understanding that scarcity pricing attempts to improve the energy only market (EOM) design in a way that scarcity prices can occur without having to rely on supra-competitive bids of generators. Scarcity pricing has been introduced particularly in US markets, characterized by unit-based bidding and ex-ante market power mitigation measures, to mitigate the lack of supra-competitive bids as a consequence of explicit and/or more importantly also implicit price caps. Under the European legal framework, with portfolio bidding and ex-post market power control, there appears to be at least some more freedom for market participants to engage into opportunity pricing, thereby potentially making an introduction of scarcity pricing less critical.

Furthermore, scarcity pricing is not able to eliminate by design the missing money problem and guarantee a predefined reliability standard. In essence, scarcity pricing is a price-based mechanism still relying on the energy market to provide investment signals. While scarcity pricing may fix the issue of free price formation to ensure scarcity rents can occur, it does not address other market failures inherent to the EOM design. The fact that scarcity pricing may serve a different purpose than targeting resource adequacy also seems to follow from international experience, as a scarcity pricing mechanism is often implemented in addition to other resource adequacy programs such as capacity remuneration mechanisms.

Finally, it is clear that there is no one such thing as scarcity pricing. Implementation details vary, both in the US through different ORDC scarcity pricing mechanisms but especially also across EU markets. The European market design as well as the European regulatory context differs considerably from the US context and therefore requires a tailored scarcity pricing implementation. Moreover, it should be noted that scarcity pricing mechanisms are an administrative intervention and require occasional re-calibration to be able to reflect actual market conditions and in particular the evolution of the power generation mix. On the latter aspect, some academics even question whether a scarcity pricing mechanism can actually be compatible with a system characterized by high levels of renewable energy sources and the corresponding merit-order effects this brings about.

[44] Elia – Adequacy and flexibility study for Belgium 2020-2030 (**https://www.elia.be/-/media/project/elia/elia-site/company/publication/studies-and-reports/studies/13082019adequacy-and-flexibility-study_en.pdf**)

3. Framework for reviewing scarcity pricing implementation measures

The objective of this chapter is to derive a framework for reviewing scarcity pricing implementation measures. Important in this respect is that a scarcity pricing implementation measure abides by the core principles of a scarcity pricing mechanism as explained in chapter 2 in order to qualify as a measure that contributes to an effective scarcity pricing implementation. Therefore, as a basis for evaluation, three fundamental conditions for an effective scarcity pricing implementation are presented in section 3.1. However, equally important is to consider the context in which a scarcity pricing implementation measure is to be implemented, which becomes even more important when targeting an implementation in the short- to mid-term future. In this respect, both the integration in the prevailing market design and the boundaries set by the current legal framework are to be accounted for. This is further described in section 3.2.

3.1 Three conditions for an effective scarcity pricing mechanism

To integrate a scarcity pricing mechanism in a market design, different implementation options exist. However, for a scarcity pricing mechanism to be effective – in line with the ORDC scarcity pricing implementation (cf. section 2.2) often cited as reference – generally the following three conditions need to be fulfilled.

3.1.1 Condition 1: Identification of stressed conditions, translated into scarcity prices reflecting the expected Value of Loss of Load (VOLL)

This first condition is in fact the calibration of the ORDC itself. A valuation is given to any given level of – observed or considered – level of operating reserves. This level of operating reserves is then to be associated with a value that properly reflects scarcity conditions, and therefore requires an assessment in terms of loss of load probability. A loss of load probability that rises towards 100% is subsequently to be associated with a value that is equal to the Value of Loss of Load (VOLL).

For the case of Belgium, this aspect of scarcity pricing has been studied intensively over the past years by CREG and Elia, supported by the UCL CORE, with the objective to calculate scarcity price adders. Scarcity price adders can be seen as equivalent to an ORDC. In fact, the scarcity price adders are not fixed but depend on a certain level of operating reserves. Hence a scarcity price adder is equivalent to a value of the ORDC given a certain level of operating reserves.

On the study work in Belgium:

- In 2016, CREG, in collaboration with UCL CORE, published a report proposing a methodology to calculate scarcity price adders in a Belgian context, based on the ORDC approach developed by ERCOT in Texas.[45]

[45] **http://www.creg.info/pdf/Divers/Z1527EN.pdf**

- In 2018, based on this report, Elia applied the methodology to a concrete Belgian dataset to calculate and analyze scarcity price adders based on 2017 data.[46]
- Finally, as from October 2019, a parallel run is taking place to calculate scarcity price adders as defined in the work from CREG and UCL CORE for each quarter hour on a daily basis, published on D+1 basis on Elia's website.[47]

Although this calibration of the ORDC curve may be specific per region and although it requires several assumptions to be made and may even need periodic re-calibration (cf. section 2.2.3 on the ORDC design experience in ERCOT Texas), in general this first condition can actually be fulfilled regardless of the prevailing market design.

Note that this first condition is not in scope of this report's analysis of the scarcity pricing implementation measures considered in the CORE study (cf. chapter 4), as the CORE study rather focuses on the integration of a scarcity price adder into the market design. For the calculation of scarcity price adders, the CORE study builds further on previous study work (cf. supra). However, towards Elia's alternative scarcity pricing proposal and in the implementation plan, the topic of calculating scarcity price adders is picked up again, discussing the fine-tuning and future-proofing of the omega calculation methodology respectively in sections 6.1.5 and 7.1.

3.1.2 Condition 2: Integration of scarcity price adders into the real-time price

The second condition entails the integration of the ORDC, or equivalent scarcity price adders, in the real-time market design. This integration in the real-time price signal is essential towards an effective implementation of scarcity pricing, as it allows market players to act on these price signals and benefit from the real-time price that then becomes scarcity-reflective.

In many US markets, a single real-time energy price is applied both to settle the imbalances and to remunerate generators providing energy in real-time. Furthermore, energy and reserve capacity provision are often co-optimized by a single market and system operator. This means that an integration of the ORDC in this co-optimized settlement automatically ensures a scarcity-reflective real-time price signal.

In the EU target market design though, in the absence of US-style co-optimization of energy and reserves, integration of scarcity price adders into real-time prices does not occur automatically in a central manner. Moreover, in the EU target market design, there is no single real-time price signal (cf. infra).

3.1.3 Condition 3: Backward propagation of real-time price to earlier time frames

To complete the set of conditions to be fulfilled for an effective scarcity pricing implementation, the third and last condition entails the back propagation of scarcity-reflective real-time prices to forward and future markets. Such back

[46] https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/adequacy---scarcity-pricing/2018/2018_study_report_on_scarcity_pricing.pdf?la=en

[47] https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation

propagation is essential to induce investment triggers, knowing that investors primarily rely on stable long-term price prospects for own investments or to secure the necessary financing from credit providers at a sufficiently low cost.

3.2 Prevailing market design and legal context

In section 2.3.1, a couple of aspects concerning the EU regulatory context that are especially relevant in the context of a scarcity pricing integration have already been highlighted. However, also more fundamentally, any market design adaptation has to take into account the prevailing market design and has to comply with the boundaries set by the legal context. Of course, when targeting a market adaptation in the long-term future, one could afford larger degrees of freedom in this respect. However, based on the ambition as for instance expressed in the 2020 incentive on scarcity pricing to target a go live by the end of 2021, an implementation is rather to be envisaged in the short- to mid-term future. In this case, the prevailing market design and current EU legal context are very relevant and act as boundary conditions.

For instance, an ever more important European dimension characterizes the prevailing market design. This is especially the case for Belgium, being highly interconnected and integrated within this European context. Notably therefore, any scarcity pricing implementation measure has to consider the upcoming go-live of the European balancing platforms PICASSO & MARI. Whereas currently the activation of (both upward and downward) regulation capacity still heavily relies on a national merit order of available capacity, this will shift with PICASSO & MARI towards a European merit order of available capacity. The aim is to optimize the activation of balancing energy, by decoupling the supply and demand of balancing energy. For instance, in a setting with the European balancing platforms, balancing energy may be activated in France to cover for a Belgian need, when it is economically more interesting to do so and given there are no technical constraints (e.g. congestion) that prevent this action.

In the following chapter that present an analysis of the scarcity pricing implementation measures considered in the CORE study, the fit within the European context will be carefully examined. To that end, for each scarcity pricing implementation measure, dedicated sections will be devoted to an analysis of the compatibility of the measure with the prevailing market design (amongst others considering PICASSO & MARI) on the one hand, and a legal assessment of the measure on the other hand.

The legal assessments developed in this report are supported by and based on the analysis by the independent external law firm Liedekerke. Their note titled 'Legal aspects relating to the introduction of a "scarcity pricing" mechanism is Belgium' is added in annex to this report (see Annex I).

4. Analysis of scarcity pricing implementation measures considered in the CORE study

In this chapter, an analysis is presented of the scarcity pricing implementation measures considered in the CORE study.[48] Five measures are considered in the CORE study. The first three measures target a contribution to the second condition for an effective scarcity pricing implementation as described in section 3.1.2, i.e. to integrate scarcity price adders into the real-time price. The fourth and fifth measure rather aim to improve backward propagation, which is the third condition for an effective scarcity pricing implementation, as described in section 3.1.3.

In what follows, the five scarcity pricing implementation measures considered in the CORE study are treated sequentially. For each measure, an explanation is provided regarding what the measure entails, followed by a market design compatibility analysis and subsequently a legal assessment. Finally, each section concludes.

4.1 Step 1: Uniform pricing in balancing

4.1.1 What is it?

As a first measure towards the implementation of a scarcity pricing mechanism in Belgium, the CORE study considers to ensure a unique real-time energy price on which scarcity price adders can be applied. In essence, this measure can be divided into two elements:

- The first element concerns the implementation of a unique real-time energy price that at a specific moment applies to all, i.e. to BRPs and BSPs.
- The second element entails the integration of a scarcity price adder into the real-time energy price signal.

These two elements are treated sequentially in what follows. Note that for now, the focus is only on the remuneration of energy, not on the remuneration of capacity. This latter remuneration for capacity is dealt with by a next measure (cf. section 4.2).

4.1.1.1 Towards a unique real-time energy price

In line with the explanations provided in the CORE study, this measure aims at the implementation of a uniform pricing rule concerning all activated balancing energy bids and the equalization of the imbalance tariff to this uniform price, to ensure that all Balancing Service Providers (BSPs) that help resolving a balancing problem get the same price as the price to be paid by the Balance Responsible Parties (BRPs) causing the imbalance problem (i.e. the imbalance tariff).

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[48] The CORE study that is analyzed can be consulted on:
https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986Annex.pdf

The rationale as mentioned in section 3.1 of the CORE study is that *"…, there is no reason why the real-time market should differentiate the payment to the entities that cause imbalances from the entities that relieve imbalances*".

From this statement, Elia understands that the authors of the CORE study find the current multitude of real-time energy prices a shortcoming of the current market design, to the extent that a single real-time energy price would make more sense and should therefore be strived for. Also the European Commission refers to such consistent real-time energy price signal in its opinion on the implementation plan for Belgium, i.e. by on p.4-5 requesting to consider whether the scarcity pricing function should not apply both on BRPs and BSPs as a way to ensure "*that BRPs and BSPs face the same price for the energy produced/consumed, as price differentiation may result in inefficient arbitrage from market players*."[49]

Of course, as a secondary argument in view of scarcity pricing, Elia also understands that the integration of a scarcity price adder into only one single real-time energy price would be more straightforward. However this argument is not perceived to be the main driver for ensuring a unique real-time energy price. Indeed, it should be feasible to integrate the scarcity price adder in various real-time energy prices. In particular, previous study work performed by UCL, CREG and Elia has shown the feasibility to calculate different scarcity price adders, relating to different products.[50] Hence, the mere existence of various real-time prices should at least not be considered blocking for a scarcity pricing implementation.

It is Elia's understanding that, taking into account the current market design context with various balancing products, achieving a single real-time energy price as targeted in the CORE study applicable to both BSPs and BRPs at all times, practically requires the following modifications to the current market design:

- Modification 1: Implement per-product uniform pricing of activated balancing energy bids (BSP)
- Modification 2: Implement cross-product uniform pricing of activated balancing energy bids (BSP)
- Modification 3: Equalize at all times the imbalance tariff to the uniform price of activated balancing energy bids (BRP)

Note that there is also an important European dimension to this discussion with the planned implementation of the pan-European MARI (for the activation of mFRR) and PICASSO (for the activation of aFRR) balancing energy activation platforms in the coming years (cf. section 3.2).

Modification 1 is illustrated in Figure 7 below, in which a *per-product uniform pricing* towards BSPs of activated aFRR & mFRR balancing energy bids is demonstrated. In this example, all activated aFRR balancing energy bids are paid an aFRR product-specific uniform price of 20 €/MWh, whereas all activated mFRR balancing energy bids are paid 30 €/MWh. Note that the assumed pricing rule in this example is that all activated bids are paid the bid price of the most expensive activated bid.

[49] **https://ec.europa.eu/energy/sites/ener/files/adopted_opinion_be_en.pdf**

[50] Note in this respect the publication on Elia's website (**https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation**) of three scarcity price adders that are simulated based on the formulas conceived by UCL CORE. A 7,5 minutes, 15 minute and energy adder are differentiated. The main difference between these adders is the considered available margin, which is calculated as capacity that is able to react within 7,5 minutes and 15 minutes for the 7,5 minute and 15 minute adder respectively. Finally, the energy adder is calculated as a combination of the 7,5 and 15 minute adder.

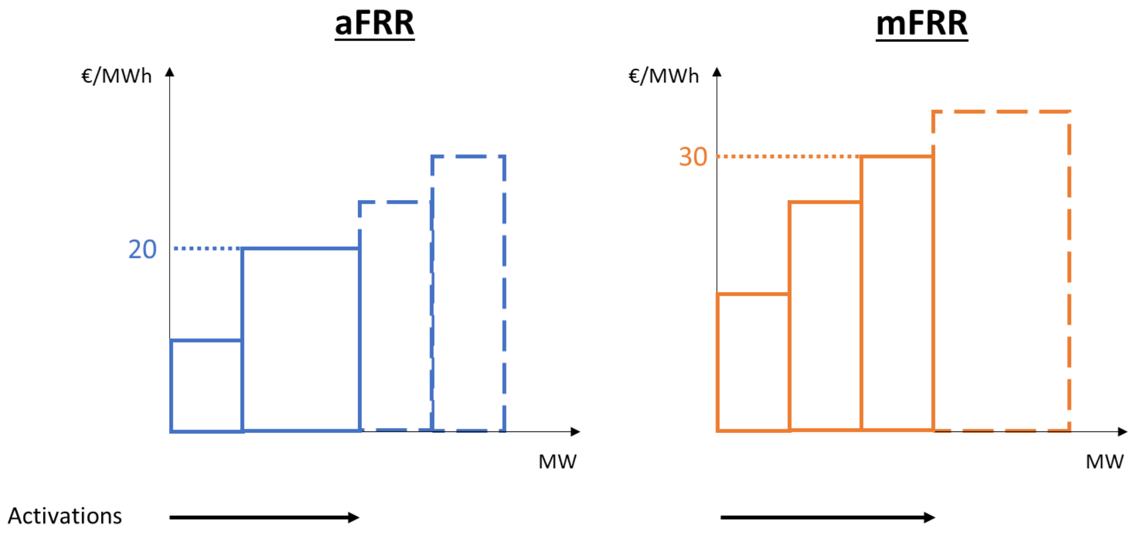

Figure 7: Illustration of per-product uniform pricing of activated aFRR & mFRR balancing energy bids

Modification 2 further requires a *cross-product uniform pricing*. Building on the example constructed in Figure 7, Figure 8 illustrates the cross-product uniform pricing towards BSPs of activated aFRR & mFRR balancing energy bids. This time, again assuming the same pricing rule as above, a uniform price of 30 €/MWh is paid to all activated aFRR & mFRR bids, compared to paying only 20 €/MWh to activated aFRR bids as would be the case with only per-product uniform pricing.

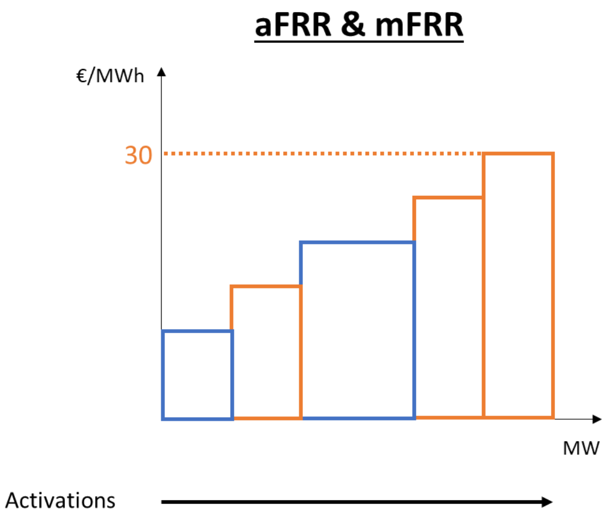

Figure 8: Illustration of cross-product uniform pricing of activated aFRR & mFRR balancing energy bids

Finally, modification 3 requires the *imbalance tariff applicable to BRPs to be equalized to the uniform price paid to BSPs* for the activation of balancing energy. From the example above, this means that the imbalance tariff would be equal to 30 €/MWh, in line with the uniform price paid to activated aFRR & mFRR balancing energy bids.

4.1.1.2 Integration of scarcity price adder in real-time energy price

Next to striving towards a unique real-time energy price (cf. previous section), this first measure of uniform pricing in balancing also consists of the integration of a scarcity price adder into the real-time energy price. If one unique real-time energy price applies at all times and for all (i.e. the subject of the previous section), then the integration of the scarcity price adder can be achieved unequivocally in this price.

If however, multiple real-time energy prices remain the way forward, the integration exercise of the scarcity price adder in the real-time price is less straightforward and has to take into account this specific context. Indeed, in case of multiple “real-time energy prices”, the integration of scarcity price adders can also be done in only one or only some of them, with possible spillovers to other real-time energy prices. Therefore, in the analysis that follows, the integration of a scarcity price adder in the real-time energy price signal is discussed secondly and is dependent on the most likely way forward defined regarding the proposed move towards a unique real-time energy price, in particular taking into account the compatibility of this unique real-time energy price proposal with the prevailing market design.

4.1.2 Compatibility with the prevailing market design

This section assesses to what extent the proposed implementation measure (i.e. uniform real-time pricing) is compatible with the prevailing market design, including the already foreseen – largely even imposed by European regulations – market design evolutions. In light of the first proposed scarcity pricing implementation measure, two questions arise:

- The first question is whether the striving towards a unique real-time energy price for both BRPs and BSPs at all times, specifically also taking into account the European dimension, is compatible with the current market design;
- The second question, of which the complexity depends to a certain extent on the answer to the first question, relates to the compatibility of integrating a scarcity price adder in the real-time energy price(s) from a market design point of view.

4.1.2.1 Towards a unique real-time energy price

In this section, the three necessary market design modifications to achieve a unique real-time energy price as identified before (cf. section 4.1.1.1), are assessed.

Modification 1: Implement per-product uniform pricing of activated balancing energy bids

The per-product uniform pricing of activated balancing energy bids is already in place, or at least being strived for, both on Belgian and European scale.

For what concerns the mFRR product, since February 2020, the settlement of mFRR balancing energy bids in Belgium applies uniform pricing[51], thereby having moved away from the earlier applied pay-as-bid approach. Such uniform (marginal) pricing methodology has also been confirmed for the European balancing platform for the activation of mFRR (MARI), with the decision of ACER on 24 January 2020 on the pricing on balancing energy.[52] Hence, uniform pricing of mFRR balancing energy bids is currently in place, and will remain applicable after the go-live of the MARI platform. A crucial difference though is that uniform pricing for now only takes into account bids from Belgian BSPs, while a European merit order of mFRR balancing energy bids (across uncongested areas) will be considered as from the go-live of the MARI platform to determine the uniform price.

Also for aFRR the longer-term target in Belgium is moving towards uniform pricing as from the moment sufficient liquidity will have developed. In any case, uniform (marginal) pricing will be in place as from the go-live of the European balancing platform for the activation of aFRR (PICASSO). This uniform (marginal) pricing methodology has been confirmed also for the platform for the activation of aFRR, in the same decision of ACER on 24 January 2020 on the pricing of balancing energy.

Modification 2: Implement cross-product uniform pricing of activated balancing energy bids

This second modification entails the additional step of applying uniform pricing across different balancing products. This development is not foreseen, neither in Belgium nor on European level.

On European level in particular, a per-product instead of cross-product approach is explicitly pursued (cf. supra, ACER decision of 24 January 2020 on the pricing of balancing energy). There are different good reasons from a market design perspective that support the view of having a different balancing energy pricing methodology for each balancing product:

- Balancing product characteristics are fundamentally different:

Fundamental differences are perceived between the various balancing products supporting the view of having a supply and demand curve per product. Activation triggers can be different. In Belgium for instance, long (> 15 minutes) imbalances are supposed to be covered by market parties (BRPs). Consequently, Elia does not contract slow reserves, i.e. reserves that cannot be fully activated within 15 minutes. The activation of these reserves are triggered rather by the BRP's own portfolio or another BRP's portfolio requirements. Fast (≤ 15 minutes) reserves are contracted and activated by Elia in Belgium. However, also within this reserve category differences exist. While aFRR reserve capacity is required to react on a 4 second basis with a full activation time of 7,5 minutes, mFRR reserve capacity is required to react with a full activation time of 15 minutes. All units or portfolios are not able to offer both type of products, so in practice, these are two separate markets with their own participants, merit orders, clearings and resulting investment signals for the ability to deliver on the different products. Considering that there should be only a single price for all

[51] However, note that currently in Belgium – as described in the Balancing Rules – the balancing energy bids corresponding to the mFRR Flex product constitute a second merit order list, that is used only when the merit order of bids corresponding to the mFRR Standard product and free bids has been exhausted.

[52] Decision No 01/2020 of the European Union Agency for the Cooperation of Energy Regulators of 24 January 2020 on the methodology to determine prices for the balancing energy that results from the activation of balancing energy bids

products because they are all delivering energy is an overly simplistic view. The balancing products are not as such a block of energy, they are defined by all their requirements, which are fundamentally different between aFRR and mFRR.

One consequence of the difference in balancing product characteristics is that the market clearing price for aFRR activated balancing energy bids is determined on a 4-second basis, compared to the market clearing price for mFRR activated balancing energy bids that is determined on a 15-minute basis. Equalizing the price of aFRR and mFRR activated balancing energy bids would thus require a rule to bring the market clearing prices on the same time scale, which is not straightforward and may not properly reflect actual market conditions.

- Balancing products do not (necessarily) solve the same problem

Different balancing products may be addressing a different problem. aFRR is typically activated in real-time, i.e. the signal is corrected every 4 seconds, to cover sudden power deviations via a load frequency controller. By contrast, the need for a possible activation of mFRR depends on the System Imbalance of the Elia LFC Block of at least the last 10 minutes and the level of activated aFRR. As decisions for activations of aFRR and mFRR are taken at different moments based on other decision criteria, both products may be activated differently. This is not to be considered as an inefficiency of the overall system but just the consequence of the fact that aFRR and mFRR are two totally different products, serving different needs as explained above.

- Upward and downward regulations may occur simultaneously within an imbalance settlement period (ISP)

Although maybe less relevant in a scarcity pricing context that considers mainly upward regulations to counter energy shortages, in reality it also often happens that upward and downward balancing energy are activated during the same quarter, i.e. the imbalance settlement period (ISP). This is especially true in a market where an efficient balancing design is in place to incentivize BRPs to be very close to the equilibrium. Therefore, in any case, there will always be a difference between the upward and downward price because the very definition of marginal pricing is different: for upward activation, it is the highest price of activated bids, whereas for downward activation, it is the lowest price.

- In a European context, prices may also differ because of cross-border congestions

With the go-live of the European balancing platforms, the prices for respectively aFRR and mFRR will be established based on a clearing algorithm that takes into account the available cross-border capacities. The direct outcome of the algorithm is a unique price for uncongested areas.[53] Equalizing the price of balancing energy bids across all BSPs in a multi-area market would impose some post-processing based on the individual results of each clearing. This is necessary already when just considering the requirement to have a per-product uniform price, but is especially problematic when a uniform price is required across various balancing products. Indeed, since aFRR balancing energy bids are cleared on a 4-second basis compared to the clearing of mFRR balancing energy bids on 15-minute basis (cf. supra), a border not congested during the mFRR timeframe (hence with a price for cross-border capacity equal to zero) but congested in the aFRR timeframe should end up being "congested" for both timeframes?

[53] For the sake of simplicity, we make abstraction of further complexities such as for instance the fact that there will be a different price for mFRR activated balancing energy bids in direct versus scheduled activation, which do not alter our conclusions.

Modification 3: Equalize at all times the imbalance tariff to the uniform price of activated balancing energy bids

From the discussion regarding modification 2, it follows that the prevailing market design does not foresee to have one balancing energy activation price that applies equally to all BSPs and to which the imbalance tariff applicable to BRPs can be equalized. In addition to that and more fundamentally in a European context, the role of the BRP and BSP are also explicitly defined differently in the Electricity Balancing Guideline (cf. also section 4.1.3.1 for a more in-depth legal assessment of the matter). While BSPs will be paid a cross-border uniform price for balancing energy (i.e. as from the European balancing platforms are live and in case there is no congestion), the imbalance tariff that applies to BRPs is and will remain based on the system imbalance and the corresponding necessary activations within each LFC area.

There is of course a clear link between the prices applicable to BSPs and BRPs, as the imbalance tariff – also already today – depends on the price of the balancing energy bids activated to satisfy the demand of the TSO responsible for the LFC area. For instance in Belgium, the imbalance tariff is set equal to the marginal price of upward or downward activation, depending on the state of the system. This means that, on the condition that modification 1 regarding the per-product uniform pricing is completed, the imbalance tariff in Belgium in case of a net negative imbalance corresponds with the uniform price of the most expensive activated upward reserve product.[54] This principle can remain in place also after the go-live of the pan-European MARI and PICASSO platforms, with imbalance tariffs becoming dependent on the uniform prices of the most expensive upward reserve product determined on these platforms instead of on (the Belgian) LFC area level.

However, since the necessary activations within a specific time interval might differ across LFC areas, so may the imbalance tariffs. For instance, the imbalance tariff in a LFC area where there was no need for mFRR activation should not be influenced by the mFRR price resulting from mFRR demand in other LFC areas in order to convey the right incentive to the BRPs to help the balance of their own area.

Consider for instance the following example. Assume that the Belgian and French LFC areas form an uncongested area. Belgium is 100 MW long, while France is 500 MW short. In the uncongested area therefore, 400 MW upward mFRR will be activated. However, the imbalance tariff in the Belgian LFC area should not be driven by such activation as no upward mFRR has been activated to cover the demand of the Belgian TSO. In such case, assuming no aFRR has been activated in Belgium either, the imbalance tariff will be based on the Value of Avoided Activation, in accordance with art. 10 of the Imbalance Settlement Harmonization methodology.[55] Setting the Belgian imbalance tariff at the price of upward mFRR would incentivize Belgian BRPs to take a long position, aggravating the Belgian LFC Block imbalance. In addition, would such behavior occur, this would not only cause much more volatile system imbalances, it would also increase Belgian’s reserve requirements. Indeed, the dimensioning of reserves is function of the system imbalances, and henceforth of the quality of the system balance.

[54] However, note that for the aFRR component, the volume weighted average price of the 4-second optimization cycles will be considered and hence not the highest price of all 4-second optimizations.

[55] Following the decision of ACER on 15 July 2020 on the harmonisation of the main features of imbalance settlement

Summary

To summarize on the first element (i.e. towards a unique real-time energy price) comprised in this first measure of 'uniform pricing in balancing' from a market design perspective.

● ***Modification 1*** *that entails the implementation of a* ***per-product uniform pricing of activated balancing energy bids*** *is* ***compatible*** *with the prevailing market design. This implementation is* ***foreseen and expected*** *to be completed in a couple of years.*

● ***Modification 2*** *that entails the implementation of a* ***cross-product uniform pricing of activated balancing energy bids*** *is considered* ***not compatible*** *with the prevailing market design. This implementation is not foreseen at Belgian or European level, nor is compliant with the European methodologies as approved by ACER. Moreover, several sound reasons underpin the difference in balancing energy price across the reserve products.*

● ***Modification 3*** *that entails the* ***equalization of the imbalance tariff to the uniform price of activated balancing energy bids*** *is considered* ***not compatible*** *with the prevailing market design. At fundamental level, the BSP is given a European-wide role, while the role of the BRP remains crucially associated to the LFC area. Therefore, the imbalance tariff that applies to the BRP depends in the first place on the situation within its LFC area, while the balancing energy price that applies to the BSP results from a European-wide optimization, combining the requests from all LFC areas and taking into account possible congestions. This means that the imbalance tariff cannot be guaranteed to be equal to the uniform price of activated balancing energy bids, as the necessary activations may differ per LFC area.*

To conclude, an evolution towards a unique real-time energy price as proposed in the first scarcity pricing implementation measure is not fully achievable given the prevailing market design. In addition, it is also not deemed desirable to strive for such unique real-time energy price.

4.1.2.2 Integration of scarcity price adder in the real-time energy price(s)

Given the above analysis and the fact that the way forward in terms of market design includes a multitude of so-called real-time energy prices (rather than one single real-time energy price), it seems inevitable to take into account this setting when assessing the integration of a scarcity price adder in the real-time energy price signal. However, in order to remain in line with the objective of the CORE study to impact all relevant real-time energy prices, the option assessed in this section is the market design compatibility of integrating a scarcity price adder into the pricing mechanism of the PICASSO and MARI European balancing platforms for both respectively the activation of (upward) aFRR and (upward) mFRR balancing energy. This way, though indirectly through the activations of the TSO, the scarcity price adder also impacts the imbalance tariff.

Although the CORE study does not elaborate on the way to integrate scarcity price adders into the real-time energy prices and in particular in the balancing platforms, Elia perceives that generally from a market design point of view, two approaches seem feasible. As discussed further below, the first approach identified by Elia is to pay a scarcity price adder to all activated Belgian BSP bids. The second approach identified by Elia is to apply a scarcity price adder to the Belgian BSP bids included in the Local Merit Order List (LMOL) submitted by Elia to the MARI/PICASSO platform and hence included in the activation price of the bid (irrespective of which TSO triggers its activation).

Although implementation details could allow for some further degrees of freedom when integrating a scarcity price adder into these platforms, it is our view that it will always be possible to categorize them into one of the two general approaches. At principles level, no other silver bullet solution appears available.

Approach 1: Scarcity price adder paid to activated Belgian BSP bids

In this first approach, which is illustrated by means of a simple example in Figure 9 below, the (Belgian) scarcity price adder is paid after the clearing of the platform and only to activated Belgian BSP bids. It is in general easy to implement and to ensure that only Belgian BSPs are receiving a remuneration by the scarcity pricing mechanism.

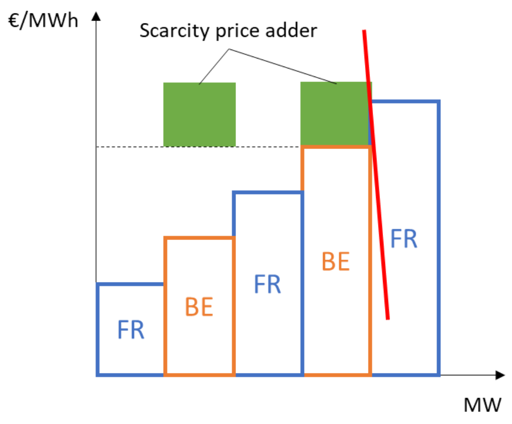

Figure 9: Scarcity price adder paid to activated BSP bids

However, since only Belgian BSPs are remunerated according to this approach, while also foreign BSPs may serve a Belgian need and thereby reduce the scarcity problem in Belgium, this could be considered as a discriminatory subsidy. Indeed, both foreign and Belgian BSPs are offering the same product and are in full competition to serve the same need.

Beyond the potential discriminatory character, this first approach may also distort competition, if no scarcity price adder is paid to available capacity, i.e. the subject of step 2 discussed in section 4.2. In other words, when there is no opportunity cost for being activated. In that case, assuming Belgian BSPs know they can count on the scarcity price adder when being activated, they may lower their bid price towards the platform to the extent that this lower bid price in combination with the scarcity price adder would still be sufficient to cover their initially targeted bid price. This means that the merit order could be influenced, as Belgian BSPs are in fact given a competitive advantage over foreign BSPs, who under this first approach, are never eligible to receive the Belgian scarcity price adder. Moreover, the lowering of the bid price by Belgian BSPs increases the possibility that Belgian BSPs are activated. Such activation may very well be triggered by a demand of another TSO and hence not be related to a demand of the Belgian TSO relating to a Belgian (scarcity) problem.

Approach 2: Scarcity price adder applied to the LMOL submitted by Elia to the platform

In the second approach (cf. Figure 10), the scarcity price adder is applied before the clearing of the platform, by applying a scarcity price adder on top of the Belgian BSP bids that are submitted to the platform.[56] This means that the scarcity price adder may change the merit order between the Belgian and foreign bids, as is also the case in the simple example

[56] For the sake of this theoretical analysis, we assume that the Belgian TSO is able to adapt the price of the bids from Belgian BSPs before they are sent to the platform. However, it has not been investigated whether a TSO will actually be allowed to do so, i.e. whether this is in line with the rules of the respective implementation frameworks.

shown in Figure 5 below, even to the extent that Belgian bids that would have been activated without the adder would not be activated anymore with the application of the scarcity price adder.

The scarcity price adder could here be seen as representing the opportunity cost of using the reserve capacity for energy activation. If the reserve capacity and energy (activations) were co-optimized, the scarcity value of capacity would be automatically accounted for in the optimization of the energy bids. In the absence of co-optimization though, the scarcity value of reserve capacity needs is added explicitly to the bid prices.

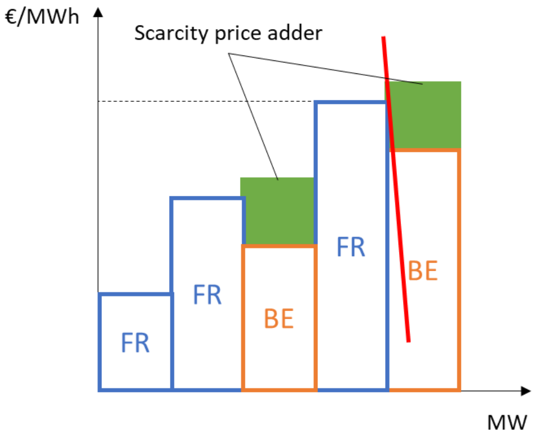

Figure 10: Scarcity price adder applied to LMOL

However, when considering this second approach, one should be aware also of the following considerations:

- In terms of financial impact, the Belgian scarcity price adder may increase the market clearing price for Belgium and the broader uncongested area. Furthermore, in case of congestion, the Belgian scarcity price adder may lead to spillovers to foreign TSOs through the congestion rent sharing:

As illustrated in Figure 11 below, because of the application of a Belgian scarcity price adder to Belgian BSP bids, the market clearing price for Belgium and the broader uncongested area increases. This is because the balancing platform performs a cross-border optimization and applies a pay-as-cleared pricing rule. In fact, all activated BSP bids benefit from the Belgian scarcity price adders, and all TSOs with a need within this uncongested area pay more for the service. There is no way to control that only Belgian BSP bids, or only BSP bids that alleviate the Belgian scarcity problem (i.e. the alleged reason for the scarcity pricing implementation), receive an additional remuneration.

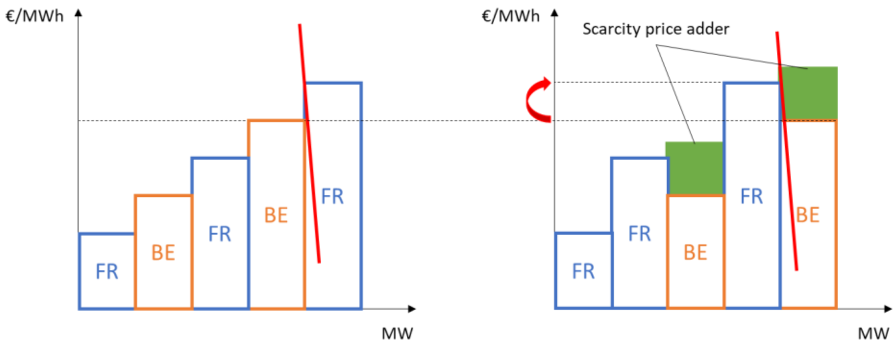

Figure 11: Scarcity price adder applied to LMOL may increase market clearing price

However, note that in line with the explanations above, an increase in the price of the service actually makes sense. In case of Belgian scarcity, proper economic incentives mean that Belgian capacity becomes more expensive, representing the opportunity cost of activating Belgian capacity.

More problematic in terms of financial impact though may be the impact on congestion rents and the associated split thereof. Building further on the example provided in Figure 11 above, the Belgian scarcity price adder increases the market clearing price for Belgium and the broader uncongested area. This means also that congestion rents on the border of this uncongested area would increase. Assume the extreme case in which all Belgian borders are congested. The Belgian scarcity price adder would increase congestion rents on all borders. As congestion rents are split equally across the TSOs at both sides of the border, this means that the Belgian scarcity price remuneration paid for in Belgium in fact spills over to foreign TSOs. Although the general objective of congestion rent sharing is to provide incentives for development of transmission capacity, the question is whether the addition of physical transmission capacity will contribute to alleviate the Belgium scarcity problem. Indeed, most often scarcity problems in Belgium coincide with scarcity problems in neighboring countries, most prominently considering France. In case of coincident scarcity between Belgium and France, increasing physical transmission capacity on the Belgian-French border will not increase import opportunities for Belgium, as France imports maximally itself (e.g. from Netherlands through Belgium to France or from Germany through the Netherlands and Belgium to France).

- In terms of competition, without behavioral change of Belgian BSPs, Belgian BSPs face a competitive disadvantage compared to foreign BSPs. With behavioral change of Belgian BSPs, competition is distorted compared to the outcome targeted by the introduction of a Belgian scarcity price adder.

Again consider the example provided in Figure 11 above, which compares the situation without application of the Belgian scarcity price adder (on the left of the figure) to the situation with a Belgian scarcity price adder (on the right of the figure). Without the Belgian scarcity price adder applied, two Belgian BSP bids are activated. However, with the Belgian scarcity price adder applied, only one Belgian BSP bid is activated. Indeed, through the increase of the Belgian BSP bid prices, Belgian BSPs are given a competitive disadvantage compared to foreign BSPs. Again, this makes sense since the scarcity price adder represents the opportunity cost for activating reserve capacity in Belgium. However, a Belgian scarcity pricing mechanism that applies a scarcity price adder to balancing energy bids of Belgian BSPS means that the opportunity cost related to scarcity in Belgium is reflected, while this is not the case for the opportunity cost related to scarcity in other European countries. In other words, the European merit order is disturbed when not all European countries implement a scarcity pricing mechanism and apply such a scarcity price adder. Moreover, this analysis assumes Belgian BSPs do not change their bidding behavior.

If no scarcity price adder is paid to available capacity, i.e. the subject of step 2 discussed in section 4.2, and assuming that Belgian BSPs can perfectly assess (or at least reasonably estimate) the occurrence and level of the scarcity price adder that would be applied to their bids before they are sent to the platform, the BSPs might change their behavior. Belgian BSPs might then have an incentive to lower their actual bid, knowing the scarcity price adder – which represents an additional income for them – is still to be added on top. Indeed, a Belgian BSP would be prepared to lower its bid price such that in the end, its bid price plus the scarcity price adder which is added by the Belgian TSO on top, again equals its original bid price. The result of such market distortive behavior would be that the merit order on the balancing platform returns to the situation without the implementation of a Belgian scarcity price adder. The alleged proper economic incentives in terms of reflecting the Belgian scarcity situation in the price of Belgian BSP bids would be undone. Essentially, one could wonder in this case what would be the point of a Belgian scarcity pricing implementation in the end.

- In terms of timing, this approach requires scarcity price adders to be determined before real-time.

Finally, this second approach requires Belgian scarcity price adders to be calculated before real-time, i.e. at the latest at the moment the bids are submitted to the platform. Although this is not necessarily a problem as forecasted information may be used to calculate scarcity price adders, it does go against previous study work regarding the calculation of scarcity price adders (cf. supra). Indeed, the current methodology[57] according to which scarcity price adders are calculated take into account real-time system conditions, meaning that scarcity price adders are only available (very) close after real-time. Furthermore, note that forecasts are made by market parties themselves as well, increasing the predictability of the scarcity price adder. Although in essence such predictability is not wrong, it is not desirable when it is primarily used to engage in market distortive behavior as described above, i.e. by lowering actual bids.

Summary

To summarize on the second element (i.e. the integration of a scarcity price adder in the real-time price(s)) comprised in this first measure of 'uniform pricing in balancing' from a market design perspective.

Neither of both general approaches to integrate a scarcity price adder in the European balancing platforms seems compatible with the prevailing market design:

*● While **approach 1** identified by Elia is easy to implement, it may be regarded as a **discriminatory subsidy** to Belgian BSPs while also foreign BSPs alleviate a Belgian scarcity problem. Moreover, in the absence of a scarcity price adder paid to standby capacity (cf. step 2 discussed below), predictability of the scarcity price adder may induce **market distortive** behavior by Belgian BSPs lowering their bid price, thereby further hampering fair competition between Belgian and foreign BSPs.*

*● **Approach 2** identified by Elia at first glance seems to provide sound economic incentives, increasing the price of Belgian balancing capacity at times of Belgian scarcity problems. However, through an increase of congestion rents, it leads to a **spillover from Belgium to foreign TSOs without clear direct contribution to alleviate the Belgian scarcity problem**. Moreover, the European **merit order is disturbed when only some countries implement a scarcity price adder** into their BSP bids and others do not. Also, in the absence of a scarcity price adder paid to standby capacity (cf. step 2 discussed below), **market distortive** behavior by Belgian BSPs is expected to occur insofar as the scarcity price adders are predictable. Finally, in terms of timings, approach 2 does not allow scarcity price adders to reflect real-time system conditions, since the scarcity price adders would have to be calculated upfront. This may increase predictability of the scarcity price adder and thereby further stimulate market distortive behavior by Belgian BSPs.*

To conclude, the integration of a scarcity price adder in all real-time energy prices paid to BSPs – and in the pricing methodology of the European balancing platforms MARI and PICASSO in particular – is, given the identified discriminatory and/or market distortive effects, not considered achievable for integration within the

[57] The currently methodology to calculate scarcity price adders, building on previous reports from UCL CORE, can be consulted on the following Elia webpage: **https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation**

prevailing market design. It seems that only a harmonized European-wide scarcity pricing implementation may be able to circumvent these problems.

4.1.3 Legal assessment

In this section, in part building further on the market design compatibility assessment presented above, the main legal framework is discussed and various legal obstacles are identified that would have to be overcome to fully implement the first scarcity pricing implementation measure as considered in the CORE study. Note that the legal assessments provided in this chapter to a large extent build further on an analysis by the independent external law firm Liedekerke. Their note titled 'Legal aspects relating to the introduction of a "scarcity pricing" mechanism is Belgium' is added in annex to this report (see Annex I).

4.1.3.1 Towards a unique real-time energy price

Modification 1 that entails a per-product uniform pricing of activated balancing energy bids is in line with the prevailing market design and in some instances even already fulfilled. Logically therefore, there are no legal obstructions identified to fully implement this first modification. Note in this respect that ACER has decided on 24 January 2020 on a per-product marginal pricing methodology for both the MARI and PICASSO European balancing platforms.[58] Consequently, at the latest as of the go-live of these balancing platforms, modification 1 will be fully implemented for Belgium.

Modification 2 that requires cross-product uniform pricing of activated balancing energy bids would go against this recent ACER decision of 24 January 2020. Moreover, a suggestion towards cross-product pricing was included in the feedback from stakeholders on the public consultation that was launched by ACER on 28 October 2019 regarding the pricing of balancing energy. ACER refuted this cross-product pricing suggestion, saying on page 10 in its *Evaluation of responses to the public consultation on the methodology to determine prices for the balancing energy that results from the activation of balancing energy bids* that "*such a cross-product pricing methodology would not respect the requirement for marginal pricing (pay-as-cleared) and would not properly reward flexibility*". Note that marginal pricing (pay-as-cleared) is required by Art. 30(1)(a) of the EBGL.[59]

Modification 3 requiring to equalize *at all times* the imbalance tariff to the uniform price of activated balancing energy bids (and hence goes beyond the logical link between the imbalance tariff and price of balancing energy bids that always exists and ensures consistency between these two price signals when required) contradicts with the fundamentally different role assigned to BRPs and BSPs in the EBGL. Art. 2 of this Guideline defines these roles as follows:

- *"'balancing service provider' means a market participant with reserve-providing units or reserve providing groups able to provide balancing services to TSOs;*

[58] Decision No 01/2020 of the European Union Agency for the Cooperation of Energy Regulators of 24 January 2020 on the methodology to determine prices for the balancing energy that results from the activation of balancing energy bids

[59] Regulation (EU) 2017/2195 establishing a guideline on electricity balancing is in this text referred to as 'the Electricity Balancing Guideline (EBGL)'

- *'balance responsible party' means a market participant or its chosen representative responsible for its imbalances"*

While there is an obligation following Art. 18(4)(d) of the EBLG that (own underlining) "*each balancing energy <u>bid</u> from a balancing service provider is assigned to one or more balance responsible parties*", this should not be interpreted as a general assimilation of the BRP and BSP into one single role. As described in what follows, the scope of BRP and BSP roles, as well as the responsibilities assigned to these roles, are different.

<u>Scope of the BRP and BSP</u>

Art. 17(2) of the EBGL clearly defines a local scope for the BRP, defining that (own underlining): *"Each balance responsible party shall be financially responsible for the imbalances <u>to be settled with the connecting TSO</u>"*.

By contrast, the role of the BSP has a broader European scope. Indeed, Articles 19, 20, 21 and 22 of the EBGL prescribe the rules for the establishment of European platforms for the 'exchange of balancing energy'. In accordance with Art. 2 (24) (own underlining): '*exchange of balancing energy' means <u>the activation of balancing energy bids for the delivery of balancing energy to a TSO in a different scheduling area than the one in which the activated balancing service provider is connected</u>*"

<u>Responsibilities of the BRP versus the BSP</u>

Beyond this difference in scope between the BRP and the BSP, various legal references also clearly separate the responsibilities of BRP and the BSP. This is to be interpreted in the sense that while a market player may take up the role of the BRP and the BSP at the same time, the responsibilities attached to each of these roles are different. Hence, a market player may also very well be only BRP or only BSP, meaning that it only has to take on the responsibilities associated with this role. Note that this is also observed in practice. Some market players take up the role of BRP without being BSP, and vice versa.

Some legal references further illustrate the separation between the BRP and BSP:

- Art. 19bis of the Electricity Act[60] states that *"Tout opérateur de service de flexibilité est tenu de confier à un responsable d'équilibre la responsabilité de l'équilibre de la flexibilité qu'il gère."* In this stipulation, 'opérateur de service de flexibilité' can be seen as the BSP, while 'responsible d'équilibre' refers to the BRP;
- Art. 15(2)(f) of Directive (EU) 2019/944 states that : "*Member States shall ensure that active customers are: … financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943."* In this stipulation, 'active customers' can be seen as a BSP;
- Art. 17(3)(d) of Directive (EU) 2019/944 states that: "an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943;" In this stipulation, 'market participants engaged in aggregation" can be seen as a BSP;

[60] The Federal Electricity Act of 29 April 1999 on the organization of the Belgian electricity market.

These legal references clearly show that the responsibilities of the BRP and the BSP complement one another. While the responsibility of the BSP is to unlock flexibility, the BRP has the end responsibilities for the imbalances that are caused within its perimeter (which go well beyond the aspect of flexibility).

Summary

To summarize on the first element (i.e. towards a unique real-time energy price) comprised in this first measure of 'uniform pricing in balancing' from a legal perspective:

● *The implementation of **modification 1** that entails the implementation of a **per-product uniform pricing of activated balancing energy bids** is **in line** with the current legal framework.*

● *The implementation of **modification 2** that entails the implementation of a **cross-product uniform pricing of activated balancing energy bids** seems to **face a legal obstruction** in the sense that such cross-product pricing approach would not be in line with the **marginal pricing (pay-as-cleared) as required in Art. 30(1)(a) of the EBGL**. Moreover, ACER has recently decided against cross-product pricing.*

● *The implementation of **modification 3** that entails the **equalization of the imbalance tariff to the uniform price of activated balancing energy bids** seems **incompatible** with the **fundamental difference in roles assigned to a BRP and BSP in the EBGL**. A BSP is given a European-wide role, while a BRP remains associated to the LFC area. Furthermore, also the responsibilities of a BSP are different from those from a BRP. Hence, the role of the BRP and BSP cannot be easily assimilated to a single role to which a uniform price applies at all times.*

To conclude, an evolution towards a unique real-time energy price applicable on both BRPs and BSPs as proposed in the first scarcity pricing implementation measure is not deemed realistic from a legal point of view and in any case seems to have to overcome several legal obstructions going beyond the Belgian framework alone.

4.1.3.2 Integration of scarcity price adder in the real-time energy price(s)

Free price formation

The integration of a scarcity price adder in the pricing methodology of the MARI and PICASSO European balancing platforms as assessed in section 4.1.2.2 first of all appears in contradiction with the principle that electricity prices must be freely determined by the market, without external intervention. This principle is set in on the one hand Regulation (EU) 2019/943[61].

In particular, Art. 3 of Regulation (EU) 2019/943 stipulates (among the "*principles regarding the operation of electricity markets*"):

> *"a) prices shall be formed on the basis of demand and supply*" and

[61] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) is in this text referred to as 'Regulation (EU) 2019/943'

> "*b) market rules shall encourage free price formation and shall avoid actions which prevent price formation on the basis of demand and supply*".

'Electricity markets' are defined as "*markets for electricity, including over-the-counter markets and electricity exchanges, markets for the trading of energy, capacity, balancing and ancillary services in all timeframes, including forward, day-ahead and intraday markets*".[62]

Recital (22) mentions accordingly:

> "*Core market principles should set out that electricity prices are to be determined through demand and supply. Those prices should indicate when electricity is needed, thereby providing market-based incentives for investments into flexibility sources such as flexible generation, interconnection, demand response or energy storage*".

On the other hand, also Directive (EU) 2019/944 of the European parliament and of the Council of 5 June 2019 on the common rules for the internal market for electricity and amending Directive 2012/27/EU (recast), sets this principle.

In particular, Art. 5(1) of this Directive stipulates:

> "*Suppliers shall be free to determine the price at which they supply electricity to customers. Member States shall take appropriate actions to ensure effective competition between suppliers*."

'Supply' is defined as "the sale, including the resale, of electricity to customers"[63] – thus not only sale to final customers[64], but also to customers who are not purchasing electricity for their own use (like a TSO buying power for balancing purposes).

Art. 3(3) and 3(4) also require from Member States to ensure that no undue barriers exist within the internal market and to ensure a level playing field, incl. through non-discriminatory treatment.

<u>Legal references regarding scarcity pricing</u>

Regulation (EU) 2019/943, referring to scarcity pricing as 'shortage pricing function', seems to authorize only one form of scarcity price, i.e. a scarcity price applying to BRPs.

Art. 20(3)(c) of Regulation (EU) 2019/943 requires that, if an adequacy resource concern is identified, Members States consider the introduction of a "*shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation (EU) 2017/2195*".[65]

The said Art. 44(3) of the EBGL reads (own underlining):

> "*Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity pursuant to Chapter 5 of this Title,*

[62] Art. 2(9) of Regulation (EU) 2019/943

[63] Art. 2(12) of this Directive

[64] As defined in Art. 2(3) of the Directive, i.e. "a customer who purchases electricity for own use".

[65] Note again that Regulation (EU) 2017/2195 is in this text referred to as 'the Electricity Balancing Guideline (EBGL)'

administrative costs and other costs related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority."

Summary

To summarize on the second element (i.e. the integration of a scarcity price adder in the real-time price(s)) comprised in this first measure of 'uniform pricing in balancing' from a market design perspective.

- *The application of a* ***scarcity price adder in the real-time price for balancing energy applicable to BSPs seems to be in contradiction with the principle of free price formation****, as stipulated in Regulation (EU) 2019/943 and Directive (EU) 2019/944.*
- *Regulation (EU) 2019/943 when talking about scarcity pricing refers to EBGL Art. 44(3) and thereby* ***limits the scope to a measure that applies on BRPs***

To conclude, the current legal framework seems to authorize only one form of scarcity pricing, i.e. a mechanism applying to BRPs. Several legal obstructions seem to hinder the integration of a scarcity price adder in the price applicable to BSPs.

4.1.4 Conclusion

This section concludes on the first scarcity pricing implementation measure considered in the CORE study, i.e. uniform pricing in balancing. This step includes on the one hand a proposed move towards a unique real-time energy price and on the other hand the proposal to integrate a scarcity price adder in the real-time price signal. Note again that this first step focuses entirely on the remuneration of energy, not capacity.

Towards a unique real-time energy price

Regarding the move towards a unique real-time energy price, it can be concluded that multiple real-time energy prices are foreseen from a prevailing market design perspective. Moving towards a unique real-time energy price goes against the prevailing view and does also not seem desirable. Moreover, equalizing the real-time energy price applicable to both BRPs and BSPs is not deemed realistic from a legal point of view as well, as there seem to be several legal obstructions that would have to be overcome to achieve one unique real-time energy price.

The ongoing evolutions on real-time, i.e. balancing, markets for the next years take as a starting point multiple real-time energy prices. The analysis of this chapter revealed that both from a market design and legal perspective this is not only a reality, but there also seem to be good reasons why multiple real-time energy prices are opted for.

However, the mere existence of multiple real-time energy prices should not obstruct the implementation of a scarcity pricing mechanism, as also illustrated by earlier previous study work performed by UCL, CREG and Elia, which has shown the feasibility to calculate different scarcity price adders, relating to different products.

Integration of scarcity price adder in the real-time price(s)

Regarding the integration of a scarcity price adder in the real-time energy price signal, this reality of the current way forward with multiple real-time energy prices is to be considered.

Both from a market design and legal point of view, the integration of a scarcity price adder in some of the real-time energy prices applied to BSPs is not deemed realistic, raising questions of potentially being discriminatory and/or inducing market distortive behavior of Belgian BSPs while a level playing field on European scale is being strived for. Therefore, it seems that a more harmonized approach towards scarcity price adders in the integrated European market design context may have to be strived for, as it seems to be the only true possibility to alleviate such concerns. However, as far as Elia can tell, a fully harmonized EU-wide scarcity pricing implementation is currently not on the drawing board.

Interestingly though, the current legal framework does seem to provide room for an integration of a scarcity price adder in the price applicable to BRPs, i.e. the imbalance price. This possibility will be further discussed in chapter 6 in which Elia's alternative scarcity pricing proposal is described.

4.2 Step 2: Real-time market for reserve capacity

4.2.1 What is it?

As a second measure towards the implementation of a scarcity pricing mechanism in Belgium, the CORE study considers to introduce a real-time market for reserve capacity.

In Elia's understanding, the idea of such 'market', as explained in the CORE study, is to remunerate resources also for the amount of reserve capacity they hold in stand-by in real-time. The rationale as mentioned in the CORE study in section 3.2 is that: ***"Even if these bids are not incurring additional costs for standing by …, they are offering value to the system by keeping the loss of load probability under check".*** To this end, the CORE study proposes to trade 'real-time reserve capacity'. By assigning this real-time reserve capacity a value equal to a scarcity price adder, it is ensured that a positive value for this product only arises in situations of (near-) scarcity. Note that different to step 1, here the focus lies on remunerating available capacity and not delivered energy.

Importantly, according to the CORE study, such real-time market for reserve capacity is not to be interpreted as a replacement of, but rather to be co-existing with, current processes such as the up-front procurement of balancing capacity by the TSO.

As a starting point therefore, in Figure 12 below, the basic working principles regarding the remuneration of up-front procured balancing capacity and in real-time activated balancing energy, are repeated.[66] When relevant and given the focus of scarcity pricing, the explanations are tailored to upward regulations to cover for energy shortages. Resources that expect capacity to be available in real-time and able to deliver on the specified service (e.g. aFRR or mFRR), may participate to the up-front balancing capacity procurement process, through which the TSO procures balancing capacity. Upon successful selection in this procurement process, this capacity is "reserved" to be available in real-time and is assigned a reservation fee. This reservation fee is thus determined up-front and remunerates capacity for being available for potentially delivering the energy. Subsequently, in real-time, the TSO may request the activation of this

[66] For the sake of the simplicity, no distinction is made between the different balancing capacity products. However, these basic working principles can be interpreted as applying similarly to the aFRR & mFRR balancing products, which are the most relevant balancing products that would be impacted by the introduction of a scarcity pricing mechanism as proposed in the CORE study.

reserved capacity. When capacity is activated, it receives a remuneration – i.e. the activation price – which is equal to the market clearing price for activated balancing energy bids (cf. discussion supra). The result is delivering energy into the system according to the specifications of the concerned reserve product. Hence, the activation price entails a remuneration of energy. For capacity that is reserved, the activation price applies on top of the reservation fee.

The upfront reservation of balancing capacity is a measure the TSO takes to ensure a minimum of liquidity on the balancing market, i.e. a minimum to comply with reserve dimensioning principles. However, the activation of balancing energy by the TSO occurs following a pure merit order principle in which energy bids issued pursuant to a 'reserved' capacity are competing with energy bids from 'non-reserved' capacity, also called 'free bids'. This merit order is today national, but will become cross-border following the implementation of MARI (mFRR) and PICASSO (aFRR).

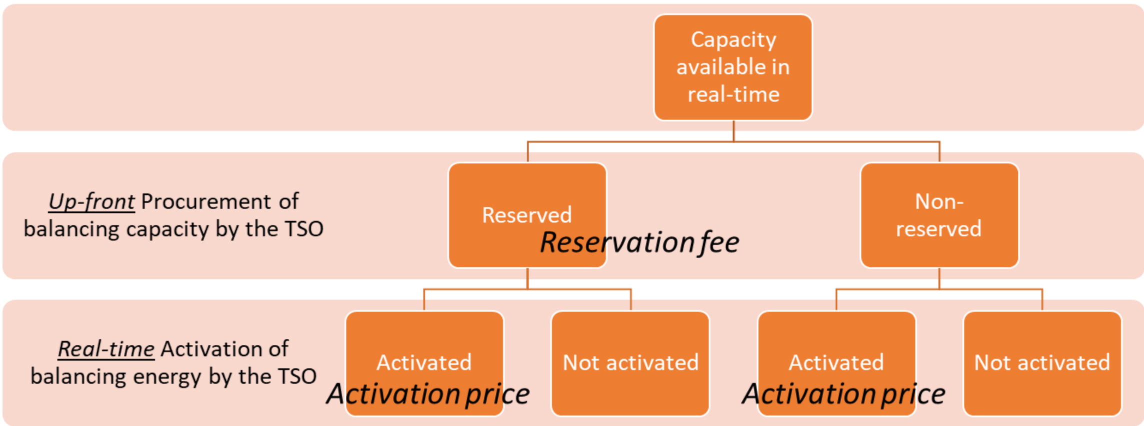

Figure 12: Balancing capacity procurement and balancing energy activation principles

It is Elia's understanding from the CORE study, that according to their market design perspective the above described working principles should remain in place and that the considered second scarcity pricing implementation measure entails the addition of certain elements to the current processes. As illustrated in Figure 13 below, the up-front procurement of balancing capacity remains unaffected by the second scarcity pricing implementation step as proposed in the CORE study. However, in real-time, an additional so-called 'real-time reserve capacity' product is introduced. The most prominent difference with the current way of working is that non-reserved capacity, i.e. capacity that has not been reserved by the TSO up-front, but is available in real-time to provide balancing energy, is eligible to receive the real-time reserve capacity price during moments of (near-) scarcity. As such, a capacity remuneration equal to the real-time reserve capacity price is assigned to non-reserved capacity based on real-time availability, i.e. without having received an activation signal from the TSO.

On the contrary, however, capacity reserved up-front by the TSO (that gets the reservation fee) that is activated in real-time by the TSO is required to pay the real-time reserve capacity price. The rationale, as indicated in the CORE study in section 3.2, is that reserved capacity pays back the activated capacity, which is consistent with their profit maximizing incentives: *"If generators are asked to be activated upwards, it is because they are getting a better payment from the energy market (even if they are depleting their reserve capacity and paying back for the capacity that they deplete) than they would receive from standing idle and not being activated upwards."*

The same kind of payback obligation applies to reserved capacity that is not available in real-time. For the amount of reserved capacity that is not available in real-time, they are bound to pay back the real-time reserve capacity price. In

Elia's understanding, such pay-back obligation would apply on top of any other unavailability penalty foreseen in the contract related to the procured aFRR/mFRR service.

In general, Elia considers that an important element of this second scarcity pricing implementation step is the monitoring of real-time availability of all capacity (i.e. to know who is standing by to receive the scarcity price remuneration), while currently in fact only the capacity that is reserved up-front by the TSO – and therefore has an obligation to be available in real-time – is being monitored.

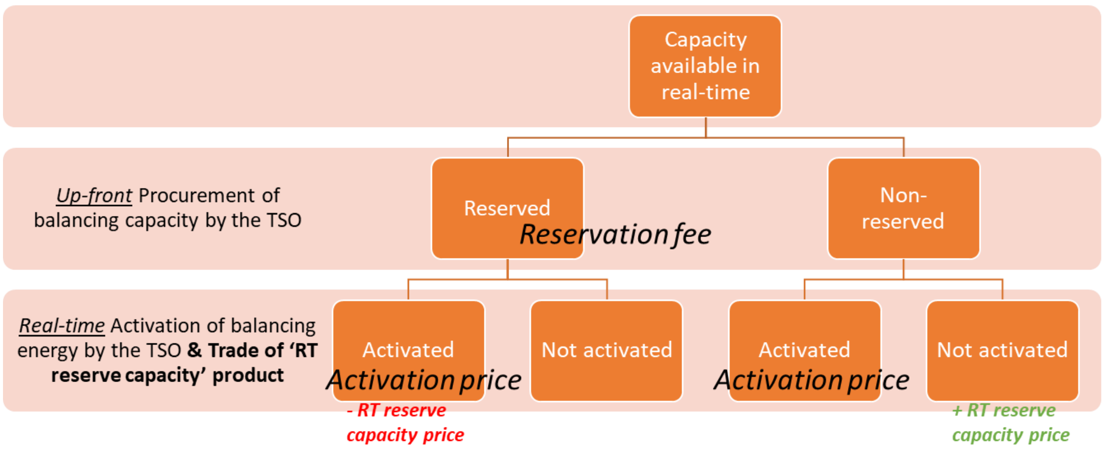

Figure 13: Balancing capacity procurement and balancing energy activation principles (including CORE's proposed addition)

Example for an installation of 100 MW able to offer mFRR balancing capacity

Let's illustrate these proposed working principles by means of a simplified example, building on the procurement and activation of the mFRR product. Assume an installation that is able to provide 100 MW of mFRR capacity. Further assume that there is near-scarcity in real-time, giving rise to a scarcity price adder of 500 €/MWh.

In line with the explanations above (cf. Figure 13), two phases are to be distinguished: on the one hand the up-front procurement of balancing capacity by the TSO and on the other hand the real-time activation of balancing energy by the TSO & trade of the 'real-time reserve capacity' product.

1. Up-front procurement of balancing capacity by the TSO

Suppose that the installation manages to sell 80 MW of mFRR capacity up-front, for which a reservation fee is paid. Assume the **reservation fee** amounts to 20 €/MW/h. The installation then receives **400 €** (= 80 MW * 20 €/MW/h * (1/4) h) for the reservation of mFRR capacity for one optimization cycle (assumed to be equal to 15 minutes or equivalently (1/4) h). Note that the reservation fee remunerates capacity.

2. Real-time activation of balancing energy by the TSO & Trade of 'Real-time reserve capacity' product

Suppose that towards real-time, the installation manages to make available the full 100 MW of mFRR capacity to the MARI platform, ready to be activated.

Suppose 90 MW of the installation is eventually activated by the MARI platform to provide the mFRR service. When then uniform price for activated balancing energy on the MARI platform is 60 €/MWh, it means that the installation receives a total **activation price** of **1350 €** (= 90 MW * 60 €/MWh * (1/4) h). Note that the activation price remunerates activated energy.

Now, given that there is near-scarcity, giving rise to a scarcity price adder of 500 €/MWh, additional revenue streams would apply as well to the concerned installation following the market design adaptations assumed in the CORE study regarding the introduction of a real-time market for reserve capacity.

As indicated before, the installation finally managed to offer 100 MW to the MARI platform, from which 90 MW was eventually activated. Assuming availability is monitored as the left-over capacity on the MARI platform, this means that 10 MW (= 100 MW – 90 MW) capacity is still available in real-time, i.e. to be activated additionally by the MARI platform if opportune. However, 80 MW was reserved up-front to be available in real-time. Following the proposal in the CORE study, this means that the installation has to buy back 70 MW (= 10 MW – 80 MW) at the rate of the real-time reserve capacity price, i.e. equal to the scarcity price adder of 500 €/MWh. Therefore, the installation has to pay a **real-time reserve capacity price** of **8 750 €** (= -70 MW * 500 €/MWh * (1/4) h). Note that the real-time reserve capacity price concerns a capacity remuneration/payment.

Figure 14 below explains these volume streams in a different way, building on the general illustration provided in Figure 13. Starting from 100 MW the installation is able to offer as mFRR capacity in real-time, the up-front procurement of balancing capacity by the TSO results in 80 MW being reserved and 20 MW non-reserved. In the end, all reserved capacity (i.e. 80 MW) and 10 MW of the non-reserved capacity is activated by the TSO in real-time.[67] Following the CORE proposal regarding the real-time market for reserve capacity, the installation receives the real-time reserve capacity price for 10 MW non-reserved and non-activated (and thus standby) capacity, but is required to pay back the real-time reserve capacity price for 80 MW reserved and activated capacity. In the end, the net result is the same as presented above: the installation has to pay back a real-time reserve capacity price of 8 750 € for 70 MW of 'missing' capacity.

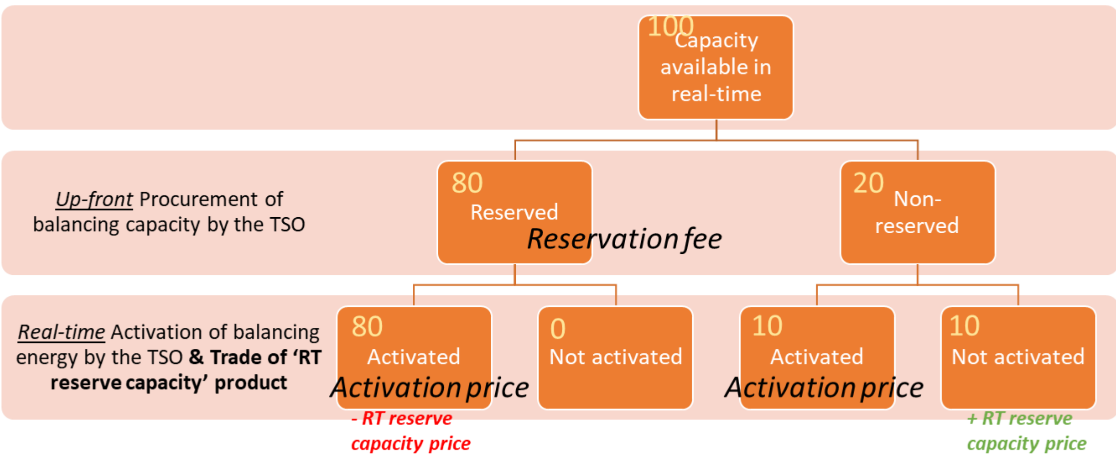

Figure 14: Example of balancing capacity procurement and balancing energy activation principles (incl. CORE's proposed addition) for an installation of 100 MW able to offer mFRR balancing capacity

[67] Note that here also other assumptions can be made with again the same outcome. For instance, if 70 MW is assumed to be activated from the reserved capacity (i.e. 80 MW), then 20 would be activated from the non-reserved capacity (i.e. 20 MW). In the end, the installation always needs to pay back a real-time reserve capacity price for 70 MW of missing capacity.

Considering the revenue streams until now, it seems as if the installation is losing money. Suppose that the activation price covers the installation's activation costs, the installation then still loses **8 350 €** (= 400 € reservation fee - 8750 € real-time reserve capacity price). However, a crucial element that is required to complement CORE's proposed real-time market for reserve capacity is a scarcity reflective real-time energy price, as discussed in the previous chapter, and has been omitted in this example thus far.

Neglecting for a moment the difficulties presented regarding the equalization of real-time energy prices and the integration of a scarcity price adder in this real-time price signal, assume a scarcity price adder is integrated in the activation price applying to mFRR providers. In this case, the installation would be entitled to an additional **scarcity price adder** of **11 250 €** (= 90 MW * 500 €/MWh * (1/4) h) for 90 MW of energy provided following an mFRR activation trigger. With this scarcity price adder on delivered energy, the installation finally realizes a net positive income of 2 900 € (= 11 250 € - 8350 €).

Let's continue on the same example, investigating the following questions:

- Is there a trade-off to be made between offering capacity during the up-front procurement process (which pays a reservation fee) and standing by in real-time (which pays a real-time reserve capacity price)?

To investigate this question, let's calculate the financial impact of one MW of capacity less being procured up-front, all other things equal.

Assuming the same reservation fee of 20 €/MW/h, the total reservation fee paid to the installation would reduce by **5 €** (= -1 MW * 20 €/MW/h * (1/4) h).

In real-time, suppose still 100 MW is offered to the MARI platform and 90 MW is activated. Hence, the activation price and scarcity price adder for energy provided remain unchanged. Only the remuneration in the context of the real-time market for reserve capacity as proposed in the CORE study changes. Compared to a 'missing' capacity of 70 MW in the original example, the missing capacity is now reduced to 69 MW (= 10 MW – 79 MW). Hence, the real-time reserve capacity price to be paid for the installation reduces by **125 €** (= 1 MW * 500 €/MWh * (1/4) h)).

In this example, it is better for the installation to have less capacity reserved up-front, as the reservation price (20 €/MW/h) is significantly lower than the real-time reserve capacity price (500 €/MWh). **In conclusion, yes the trade-off between offering capacity during the up-front procurement process and being available in real-time under the proposed market design by the CORE study, is relevant.**

Of course, in the end, some **equilibrium is expected to arise in which the reservation price and expected real-time reserve capacity price converge**. The latter price has to be estimated up-front. The expected price level will be influenced both by the expected height of the real-time reserve capacity price and the probability of such prices to occur in real-time.

- May there be an incentive to make less capacity available towards the balancing platform?

To investigate this question, let's calculate the financial impact of one MW of capacity less offered to the MARI platform, all other things equal.

Assuming 80 MW of mFRR reserve capacity procured up-front as in the original example, the reservation fee remains unchanged.

In real-time, suppose now 99 MW is offered to the MARI platform instead of 100 MW, while still 90 MW is activated. Again, the activation price and scarcity price adder for energy provided remain unchanged and only the remuneration in the context of the real-time market for reserve capacity as proposed in the CORE study changes.

Compared to a 'missing' capacity of 70 MW in the original example, the missing capacity now increases to 71 MW (= 9 MW – 80 MW). This gives rise to an additional real-time reserve capacity price to be paid of **125 €** (= -1 MW * 500 €/MWh * (1/4) h)).

In this example, it is unfavorable to make less capacity available to the MARI platform. **In conclusion, in particular when real-time availability is monitored on the balancing platforms, capacity is incentivized to be made available to the maximum possible extent to the balancing platforms.**

- May there be a preference not to be activated on the balancing platform?

To investigate this question, let's calculate the financial impact of one MW of capacity less being activated by the MARI platform of the installation, all other things equal.

Assuming 80 MW of mFRR reserve capacity procured up-front as in the original example, the resulting reservation fee remains unchanged.

In real-time, suppose still 100 MW is offered to the MARI platform but 89 MW is activated compared to 90 MW in the initial example. The activation price remuneration changes, but if we assume the activation price covers nothing more than the activation costs, there is no net financial impact. However, the scarcity price adder for energy provided changes. In particular, this remuneration decreases by **125 €** (= -1 MW * 500 €/MWh * (1/4) h). Additionally though, also the real-time reserve capacity price payment changes. Compared to a 'missing' capacity of 70 MW in the original example, the missing capacity now decreases to 69 MW (= 11 MW – 80 MW). This results in a real-time reserve capacity price payment reduction of **125 €** (= 1MW * 500 €/MWh * (1/4) h).

In this example, there is no net financial impact of less capacity being activated by the MARI platform. The lost scarcity price adder paid for activated energy is compensated by the scarcity price adder paid for real-time available capacity. Note that the same zero-sum result would apply when one MW of capacity more would have been activated by the MARI platform. **In conclusion, capacity is indifferent regarding the amount of capacity that is activated by the balancing platform in real-time, as there is no financial impact. Put differently, and in particular with marginal pricing in place, capacity has an interest to bid into the balancing platform at true marginal cost.**

From this example, it seems as if – at least in theory – the real-time market for reserve capacity as described in the CORE study, is well conceived. It can be expected to accurately reflect (near-) scarcity conditions through the trade of real-time reserve capacity that is valued at the rate of the scarcity price adder. Moreover, by remunerating stand-by capacity in real-time, resources are given an incentive to be available during (near-) scarcity conditions. Finally, the example also shows that capacity in the end would in fact be indifferent between standing by in real-time (and receive the real-time reserve capacity price) and being activated by the TSO in real-time (and then receive the scarcity reflective real-time energy price for being activated). However, a more thorough analysis of the real-time market for reserve capacity is presented in the next section, in which its compatibility with the prevailing market design will be assessed, also explicitly considering the current European context in which the electricity markets are developing nowadays.

4.2.2 Compatibility with the prevailing market design

The introduction of a real-time market for reserve capacity – considered in the CORE study as second scarcity pricing implementation measure – is currently not foreseen, not in Belgium and as far as Elia can tell also not in other European countries. What is foreseen in Belgium though, is an evolution towards more accurate close to real-time (i.e. day-ahead) dynamic dimensioning of reserve needs and tendering of balancing capacity by the TSO.[68] The day-ahead dimensioning exercise will take into account day-ahead predicted system conditions, including offshore and onshore wind power, photovoltaics, electricity demand and schedules of power plants and transmission assets. In terms of tendering process, at day-ahead procurement[69] is being strived for (compared to weekly/monthly/yearly procurement in the past) and fine granularity (i.e. 4h blocks). As such, this evolution should significantly improve both reliability and cost-efficiency of balancing procurement, incorporating close-to-real-time expected system conditions and therefore even already reflecting anticipated scarcity conditions in the reservation price of balancing capacity.

In what follows, the compatibility of the real-time market for reserve capacity as put forward in the CORE study is analyzed in two consecutive steps. First, an assessment is made regarding such real-time market for reserve capacity in isolation (section 4.2.2.1). Secondly, further reflections are added regarding the complexities that arise from the introduction of a Belgian real-time market for reserve capacity in a cross-border setting (section 4.2.2.2).

4.2.2.1 Real-time market for reserve capacity in isolation

From the example developed in section 4.2.1, it is clear that the real-time market for reserve capacity relies structurally on several communicating vessels. In Elia's view, the mechanism might therefore be prone to inefficiencies. For instance, balancing capacity is in essence invited to arbitrage between on the one hand being procured by the TSO up front (and receive the reservation price) and on the other hand being available in real-time (and receive the real-time reserve capacity price, if non-zero). In the absence of any central co-optimization, such arbitrage depends crucially on the expectations of market participants regarding this real-time reserve capacity price and is therefore not necessarily perfect.

Moreover, the consequence of such arbitrage would nevertheless be an upward pressure on the TSO procurement cost for reserves as the reservation price now has to cover also any opportunity cost of not being able to receive the better real-time reserve capacity price.

More fundamentally though, it is clear from the example in section 4.2.1 that the real-time market for reserve capacity – which remunerates capacity – does not work properly without scarcity-reflective real-time energy prices. Without scarcity-reflective energy prices, activations are not properly valued compared to the remuneration that could be received by standby non-activated capacity. Consider for instance free bids as we currently know them in the prevailing market design, who would be eligible to receive the real-time reserve capacity price following the proposed working principles of the second scarcity pricing implementation measure considered in the CORE study. In order to make their activation worthwhile, the activation price should then cover both activation costs and the opportunity cost of no longer being able to claim the real-time reserve capacity price.

[68] More information on the dynamic dimensioning of reserves project can be found on Elia's website: **https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/balancing---balancing-services-and-bsp/2017/2017-study-report-dynamic-dimensioning-of-the-frr-needs.pdf?la=en**

[69] Since the end of September 2020, the day-ahead procurement of all balancing products (FCR, aFRR and mFRR) is a reality in Belgium.

Chapter 4.1 discussed the difficulties regarding the first measure, i.e. concerning the implementation of a uniform real-time energy price and the integration of a scarcity price adder in all real-time energy prices, both from a market design and legal point of view. Given the likely infeasibility of fully completing measure 1, it seems that the proposed real-time market for reserve capacity could only partially be implemented and may not work properly. This is a fortiori the case when considering an EU context (cf. next section).

4.2.2.2 Real-time market for reserve capacity in an EU context

The prevailing market design includes an important European dimension, in particular with the planned go-live of the MARI and PICASSO balancing platforms in the coming years. The European balancing platforms will essentially decouple the provision of, and demand for, balancing energy. For instance, Belgian balancing energy demand may be fulfilled by both Belgian and foreign BSPs, following an economic optimization (and considering cross-border congestions) by the balancing platform.

Therefore, in addition to the concerns raised in section 4.2.2.1, a crucial question regarding introducing a real-time market for reserve capacity in Belgium when considering the European balancing platforms, is whether foreign capacity that stands by and thereby reduces the Belgian scarcity problem, should not also be eligible to receive these real-time reserve capacity payments? Not treating Belgian and foreign capacity equally seems discriminatory. It might even be true that some foreign BSP bids are in fact better suited to alleviate the Belgian scarcity problem (e.g. because of a lower activation price) than some Belgian BSP bids that also stand-by (but at much higher activation prices).

Of course, given the decoupling between supply and demand of balancing energy on the European balancing platforms, it appears to be very difficult and probably even impossible to actually tell which capacity alleviates the Belgian scarcity problem based on information available in the MARI/PICASSO platforms. Moreover, a further complexity arises from the consideration of congestions. Indeed, when assessing whether foreign capacity stands by to alleviate a Belgian scarcity problem, one should also take into account whether its activation is actually possible given the available cross-border exchange capacity. Although this European dimension may be avoided when only Belgian BSPs would be considered eligible for a remuneration for stand-by capacity in real-time, this seems to be discriminatory in the same way as only integrating the scarcity price adder in the balancing energy remuneration of Belgian BSPs, as discussed in section 4.1.2.2 (cf. first approach identified by Elia).

The fact that the real-time market for reserve capacity relies structurally on the existence of scarcity-reflective real-time energy prices (as discussed in section 4.2.2.1) is especially problematic in an EU context. Indeed, as investigated in section 4.1.2.2, the integration of a (Belgian) scarcity price adder in the pricing methodology of the European balancing platform, i.e. in the pricing of BSP balancing energy bids, seems impossible to do in a non-discriminatory way and/or without inducing market distortive behavior.

Finally, a scarcity price adder on balancing capacity may compromise any future evolution towards cross-border procurement of balancing capacity. Jointly organizing a balancing capacity procurement (for exchanging or sharing reserves) with another TSO would require to harmonize the remuneration of the product. This would be hindered in case the Belgian BSPs have to include in their price the expected real-time reserve capacity price while other BSPs wouldn't. Indeed, a scarcity price adder on balancing capacity would clearly distort any cross-border market for balancing capacity procurement. Although such cooperation is not foreseen in the short-term, it could be beneficial in the future.

Summary

*To summarize on the **introduction of a real-time reserve capacity market**, considered as the second scarcity pricing implementation step in the CORE study. While in theory its working principles appear to be well conceived:*

- *Such real-time reserve capacity market **relies structurally on various communicating vessels**. In particular the inherent arbitrage between the reservation price (resulting from up-front procurement of reserve capacity) and the expected real-time reserve capacity price (resulting from real-time standby in case of (near-) scarcity), is key to the mechanism. As arbitrage is not necessarily perfect, the mechanism might be **prone to inefficiencies**. Moreover, such arbitrage is expected to put **upward pressure on the up-front TSO procurement cost for reserves**.*

- *In a European context, a Belgian real-time reserve capacity market **may be seen as discriminatory** when foreign capacity that stands by to alleviate a Belgian scarcity problem is not also eligible to receive a remuneration. However, a **non-discriminatory implementation is in any case deemed challenging** in a context with European balancing platforms, because demand and supply of reserve capacity are essentially decoupled on the European balancing platforms and because congestions also have to be considered when assessing real-time availability. This again triggers the thought that only a harmonized scarcity pricing implementation might truly be able to circumvent these EU complexities.*

- *Fundamentally, the real-time reserve capacity market **requires scarcity-reflective real-time energy prices**. Without this, the **real-time reserve capacity market may only partially be implemented** and the perceived communicating vessels do not work as they should, with **potential distortions** as a consequence. Chapter 4.1 already presented the challenges in implementing a scarcity reflective real-time energy price, which are especially problematic when considering a scarcity-reflective BSP price for balancing energy. Paying a scarcity price adder only to activated Belgian BSP bids may be regarded as discriminatory subsidy. Alternatively, if it would be considered to integrate a Belgian scarcity price adder in the European balancing platforms for activating BSP bids in a way that is not harmonized on a European level, this seems to give rise to important market distortive effects.*

To conclude, the introduction of a Belgian real-time market for reserve capacity is not considered achievable for integration within the prevailing market design. To our knowledge, it is currently also not foreseen in any other EU market.

4.2.3 Legal assessment

The legal assessment regarding the second measure on a real-time market for reserve capacity as considered in the CORE study particularly concerns the application of a scarcity price adder on BSPs. This aspect has already been discussed in more detail in section 4.1.3.2, where it is explained that the Regulation (EU) 2019/943 seems to authorize only one form of scarcity price mechanism, i.e. a scarcity price applying to BRPs. This follows from Art. 20(3)(c) of the above Regulation referring explicitly and solely to art. 44(3) of the EBGL. Hence, from a legal point of view, the introduction of a real-time reserve capacity market in Belgium – thereby remunerating BSPs for standby capacity – seems not to be allowed from a legal point of view.

In addition, since the second measure foresees a remuneration of standby capacity, it not perceived to be self-financed. This is in contrast to the first measure that concerns only energy prices and thereby may be designed such that there is no net financial cost, i.e. in line with the polluter pays principle. The reader is referred section 5 for some further reflections on the financing of a scarcity pricing mechanism. However, not being self-financed, the second measure in particular may raise questions regarding State aid. In indicative terms, a scarcity pricing mechanism applicable to BSPs *could* be a State aid subject to the European Commission's approval. If the mechanism is a State aid, its validity would have to be subject to the European Commission's appreciation, currently and until the end of 2021 as developed In the Guidelines on State aid for environmental protection and energy 2014-2020 ('EEAG').[70]

A final reflection from a legal point of view regarding this second measure is that the working principles of the real-time market for reserve capacity crucially rely on seemingly obvious financial transfers, not in the least between the BSP and the BRP. However, the current legal framework nowhere seems to enforce such transfers in a transparent and straightforward way. Rather, financial transfers between the BRP and the BSP seem to depend largely on contractual arrangements between individual market parties. Note that, as already elaborated upon in section 4.1.3.1, the EBGL makes a clear distinction between the role of the BRP and the BSP. While one market party may take up both roles at the same time, this is certainly not always (and not necessarily) the case.

Summary

To summarize on the ***introduction of a real-time reserve capacity market****, considered as the second scarcity pricing implementation step in the CORE study from a legal point of view:*

● *Regulation (EU) 2019/943 when talking about scarcity pricing refers to EBGL Art. 44(3) and thereby* ***limits the scope to a measure that applies on BRPs****.*

● *Not being self-financed and targeting an adequacy concern, the real-time reserve capacity market* ***may raise questions regarding State aid, requiring approval*** *by the European Commission.*

● *The assumed obvious financial transfers in particular between the BRP and BSP are not enforced in the current legal framework.*

To conclude, the introduction of ***a Belgian real-time market for reserve capacity is not deemed feasible from a legal point of view and may even raise questions regarding State aid.***

4.2.4 Conclusion

This section concludes on the second scarcity pricing implementation measure considered in the CORE study, i.e. the introduction of a real-time market for reserve capacity in Belgium.

The implementation of a real-time market for reserve capacity is not foreseen in Belgium, and as far as Elia can tell, also not in any other European country.

Although in theory the working principles of the real-time reserve capacity seem well conceived in the CORE study, various considerations hamper its achievability to be introduced in the prevailing market design. These considerations stem both from a market design compatibility point of view, as well as from a preliminary legal assessment.

[70] Communication from the Commission, 2014/C 200/01, Guidelines on State aid for environmental protection and energy 2014-2020, (225). The application period of those EEAG is extended until 2022.

Most prominently from a market design point of view, firstly the mechanism in isolation is deemed prone to inefficiencies, relying structurally on various communicating vessels. Secondly, considering the European context, a Belgian real-time reserve capacity market seems discriminatory when foreign capacity that stands by to alleviate the Belgian scarcity problem is not also eligible to receive a remuneration. At the same time, a non-discriminatory implementation may be difficult to achieve, potentially only to be solved by a harmonized European-wide scarcity pricing implementation. Thirdly, the real-time reserve capacity market may only partially be implemented when scarcity-reflective energy prices may not be achievable (cf. chapter 4.1). Such (Belgian triggered) scarcity-reflective real-time energy prices are especially problematic to achieve for BSP balancing energy activation bids in a context with European balancing platforms (cf. section 4.1.2.2). A partial implementation of the real-time market for reserve capacity might give rise to market distortive effects, valuing differently real-time standby capacity and real-time energy provision.

From a legal point of view, there seems today to be no room for a scarcity price applying to BSPs, which would make the introduction of a real-time market for reserve capacity in conflict with the current European legal framework.

Therefore, taking into account the above, the introduction of a Belgian real-time market for reserve capacity is not considered achievable for integration within the prevailing market design. Moreover, the only reasonable option for introducing a non-discriminatory and non-distortive real-time market for reserve capacity, may be a European-wide harmonized implementation thereof.

4.3 Step 3: Imbalance price = MIP (removal of alpha component)

4.3.1 What is it?

As a third measure towards the implementation of a scarcity pricing mechanism in Belgium, the CORE study considers to remove any administrative penalties on imbalances. In particular with respect to the Belgian situation, the CORE study in Figure 11 specifically mentions the removal of the alpha component as currently applied in the Belgian imbalance pricing mechanism.[71]

On the removal of administrative penalties on imbalances (like the alpha component), the CORE study mentions in section 3.3: *"The rationale of removing the administrative penalties is that a single product is traded in the real-time market (namely, real-time energy) and should be priced consistently between those who produce it (e.g. the entities that over-produce relative to their forward positions) and those who consume it (e.g. the entities that over-consume relative to their forward positions)."*

In Elia's understanding, this third step continues in the direction suggested by the first scarcity pricing implementation measure, i.e. towards a unique real-time energy price that applies to all.

[71] In the CORE study in Figure 11, reference is made to α_1 and α_2. However, in 2020 only a single, symmetrical α-component now applies, in accordance with the CREG tariff decision for the period 2020-2023: **https://www.elia.be/-/media/project/elia/elia-site/customers/tarrifs-and-invoicing/tariffs-and-invoicing/en/grille-tarifaire-2020-2023-onevenwicht-env1.pdf**

4.3.2 Compatibility with the prevailing market design

The removal of the alpha component in Belgium is not foreseen. To the contrary, in 2020, the alpha component has been revised in order to better reflect the current system conditions and has been part of CREG tariff decision for the period 2020-2023 (cf. footnote 71). In particular, the revision of the alpha component was triggered by the (planned) increase of installed renewable generation capacity (in particular offshore wind), resulting in an enlarged risk for substantial and persistent system imbalances within the Elia control zone.

In general, the alpha component is a dissuasive incentive incorporated in the imbalance settlement process to ensure that BRPs act in the interest of the overall balance in the system and in particular to avoid large and structural system imbalances that would otherwise lead to a future increase in reserve needs. The latter long-term beneficial effect seems not to be accounted for by the CORE study. Indeed, the alpha component puts downward pressure on future reserve needs and their consequent costs, thereby increasing overall social welfare.

The impact of the current alpha component on the imbalance tariff is shown in Figure 15 below. In case of a negative system imbalance, BRPs that are short have to pay the alpha component on top of the MIP (Marginal Price of upward activation), while BRPs that are long – and thereby help the system – receive the MIP plus alpha. In case of a positive system imbalance, BRPs that are short – and thereby help the system – pay the MDP (Marginal Price of Downward activation) minus alpha, while BRPs that as long only receive MPD minus alpha.

<table>
<tr><td></td><td></td><td colspan="2">System Imbalance</td></tr>
<tr><td></td><td></td><td>Positive</td><td>Negative or zero</td></tr>
<tr><td rowspan="2">Imbalance of the balance responsible party</td><td>Positive</td><td rowspan="2">MDP – α</td><td rowspan="2">MIP + α</td></tr>
<tr><td>Negative</td></tr>
</table>

Figure 15: Tariffs for maintaining and restoring the residual balance of individual BRPs

The alpha component is only assigned a value different from zero when the System Imbalance in the current Imbalance Settlement Period (ISP) in absolute terms exceeds 150 MW. Moreover, the exact value of the alpha component depends on the average of the absolute values of the system imbalance of the current and the previous ISP (cf. Figure 16 for a graphical representation). The exact formula that determines the alpha component can be consulted in the CREG tariff decision for the period 2020-2023 (cf. footnote 71). Note that the alpha component applies symmetrically for both negative and positive system imbalances. Further note that the alpha component is expressed by an S-shaped curves, which flattens out at a maximum value of 200 €/MWh.

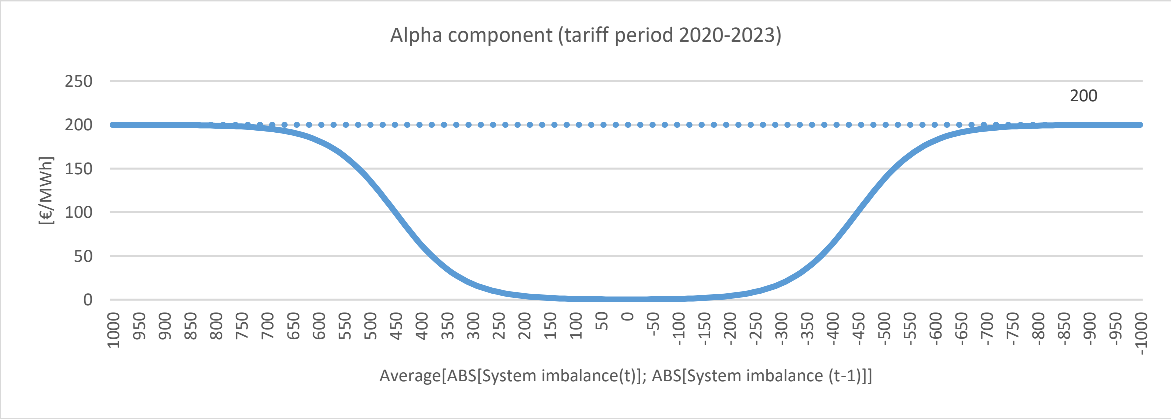

Figure 16: Alpha component (tariff period 2020-2023)[72]

According to Elia, the merits of the alpha component in Belgium should not be underestimated and it remains important to keep this imbalance tariff feature for the future given its positive effects in terms of incentive and downwards pressure on reserve needs.

To conclude, the ***removal of the alpha component integrated in the imbalance tariff applicable to Belgian BRPs****, considered as the third scarcity pricing implementation measure in the CORE study, is* ***not deemed desirable****. Removing the alpha component is believed to have a negative long-term impact on future reserve needs and their consequent costs.*

4.3.3 Legal assessment

The alpha component currently in place in Belgium applies exclusively to BRPs and is to be seen as a tariff component. Although from a legal perspective nothing would prevent removing the alpha component as proposed in the CORE study, this is not deemed desirable.

4.3.4 Conclusion

The removal of the alpha component and limiting the imbalance price to purely MIP in case of the LFC area being short, is not currently foreseen. To the contrary, the alpha-component has recently been revised and approved for the ongoing tariff period (2020-2023) in the context of changes in the power generation mix in Belgium, driven in particular by the (anticipated) increase of offshore wind generation capacity in Belgium over the coming years.

The alpha component has its own merits in terms of keeping the system imbalance under control and consequently putting downward pressure on the reserve capacity to be contracted (and the associated costs to do so). Hence, Elia

[72] Note as explained in the text that the alpha component is only assigned a value different from zero when the System Imbalance in the current Imbalance Settlement Period (ISP) in absolute terms exceeds 150 MW. Otherwise, the alpha component is equal to zero.

concludes that the merits of the alpha component should not be underestimated and concludes that its removal is not deemed desirable. From a legal perspective though, there is freedom to adapt or abandon it if required and if deemed desirable.

In this respect, rather than abandoning the alpha component, it might be interesting to investigate how it can co-exist with a scarcity pricing measure. Moreover, the alpha component can serve as inspiration for such scarcity pricing measure, being perfectly in line with the current legal and regulatory framework and applying only on BRPs. Art. 9(6) of ACER's adopted methodology on Imbalance Settlement Harmonization specifically foresees such additional components. The said Art. 9(6) reads (own underlining):

> *"The connecting TSO or connecting TSOs of an imbalance price area may propose in the Member State's terms and conditions for BRPs the conditions and a methodology to calculate additional components, to be included in the imbalance price calculation. In that case, this TSO or these TSOs shall propose one or more of the following additional components:*
>
> > *(a) a scarcity component to be used in nationally defined scarcity situations;*
> >
> > *(b) an incentivising component to be used to fulfil nationally defined boundary conditions;*
> >
> > *(c) a component related to the financial neutrality of the connecting TSO."*

Moreover, also the European Commission in its advice[73] on the Belgian implementation plan indicates that the current alpha component in Belgium may serve as inspiration, stating that: "T*he Commission is of the view that the 'alpha component' already exhibits certain characteristics of a scarcity pricing function.*"

In chapter 6, this alternative starting point is further considered for the design and implementation of an alternative scarcity pricing mechanism in Belgium. Also the co-existence of such scarcity pricing measure with the current alpha component is further investigated in that chapter.

4.4 Step 4: Virtual trading

4.4.1 What is it?

As a fourth step towards the implementation of a scarcity pricing mechanism in Belgium, the CORE study considers to introduce virtual trading, stating in chapter 4: "*The intended benefit of virtual trading is to exploit the "wisdom of the crowds" so as to permit day-ahead prices to converge to the expected real-time prices.*"

Virtual trading in US vs EU electricity markets

Virtual trading is a concept that originates from US electricity markets, currently in place in amongst others PJM, NYISO, ISO-NE and MISO. In these pool-based US electricity markets, participants are required to bid on the level of individual units in the day-ahead market. Virtual trading enlarges trading possibilities in US markets by providing the opportunity

[73] https://ec.europa.eu/energy/sites/ener/files/adopted_opinion_be_en.pdf

to submit bids that are not related to individual units, i.e. "virtual" bids. These virtual bids represent a financial purchase or sale of energy in for instance the day-ahead market, without the actual intention to physically consume or produce energy in real-time. Rather, the virtual bid is settled automatically in real-time by a countervailing price taker trade in real-time. Put differently, through a "virtual" bid, a trader is able to take an open position in day-ahead (e.g. selling something he is not able to produce or buying something he is not able to consumer), exposing himself with that open position (respectively a long/short position) to the real-time price.

In contrast to US electricity markets, EU electricity markets operate through power exchanges in which participants may bid on portfolio-level. In some EU electricity markets, market participants are required to hold a balanced portfolio position, i.e. in day-ahead, real-time or both. Such balanced position means that on portfolio level, the sum of planned injection and offtake of energy should be equal to the sum of planned demand for and sale of energy. The consequence of such balanced position at for instance the closure of the day-ahead market is that market participants without any physical assets would not be able to hold an open position beyond this day-ahead time frame.

Therefore, equivalently to the US implementation of virtual trading, in an EU setting the introduction of virtual trading can be considered as the removal of *all* – i.e. day-ahead and real-time – formal balance obligations of BRPs.

Benefit of virtual trading for Belgium

Currently in Belgium, BRPs have contractual obligations to submit balanced nominations in day-ahead and to take all reasonable measures to reach a balanced portfolio in real-time. This prevents market participants without physical assets to arbitrage beyond the day-ahead closing, i.e. in relation to intra-day and/or real-time prices. The introduction of virtual trading in Belgium (to be understood as the removal of both the day-ahead and real-time formal balance obligation) would in any case enlarge trading possibilities on Belgian electricity markets, by enlarging trading possibilities for market participants without physical assets.

4.4.2 Compatibility with the prevailing market design

An introduction of virtual trading for the Belgian market, i.e. the removal of both the day-ahead and real-time formal balance obligation, is currently not foreseen. However, in parallel to this study, Elia is currently performing a study regarding the weakening or removal of the day-ahead balanced position of BRPs in Belgium, in the context of another CREG balancing incentive titled "*Afschaffen of afzwakken van de day-ahead evenwichtsverplichting van de BRP's*".[74] Note that this could be seen as a first step towards virtual trading and could allow the system to benefit from already an important part of the virtual trading concept. A full implementation of virtual trading though, in line with the above explanations, would require also abandoning the real-time balanced position in Belgium. This aspect requires additional analyses and studies before it can be envisaged.

In what follows and provided that a comprehensive compatibility assessment is already being performed regarding an adaptation to the day-ahead balanced position in the context of another study, the focus here is the compatibility of

[74] A public consultation on this study was organized from Tuesday 22nd of September until Tuesday 20th of October 2020. The study that was subject to public consultation can be found on: https://www.elia.be/en/public-consultation/20200922-public-consultation-on-day-ahead-balance-obligation-of-brps

virtual trading with a market design that targets the implementation of scarcity pricing elements. The CORE study in Chapter 4 positions virtual trading as an element of a scarcity pricing implementation that aims to contribute to *"back-propagating efficient investment and operational planning signals to the day-ahead and earlier forward markets, thereby promoting short and long-term operational efficiency and effective risk management"*.

As already explained in section 4.4.1, it is true that the removal of all formal balance obligations in Belgium would increase trading possibilities, most prominently by providing market participants without physical assets to arbitrage beyond the day-ahead market closing. Although the added value of virtual trading on the backward propagation of prices from real-time to earlier time frames may not be proven as such, the enlargement of trading possibilities is expected to add to this positively.

However, two critical reflections are to be made:

- A relationship between the day-ahead and real-time price seems to exists already today:

Figure 17 below shows a graph composed by CREG, plotting the historical mean Belpex day-ahead market price and the positive/negative imbalance price. From this figure it is clear that since 2012 with the introduction of single pricing for imbalance tariffs, day-ahead and real-time market prices are strongly correlated.

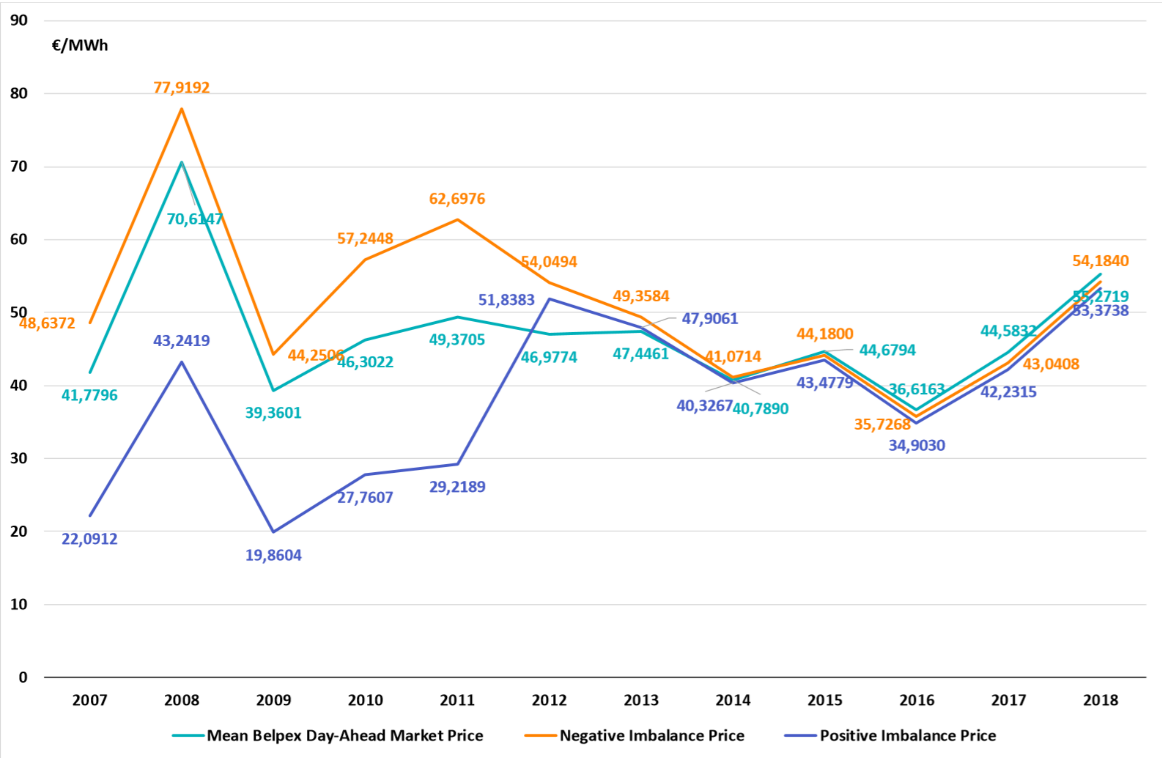

*Figure 17: Historical Belpex Day-Ahead Market and Negative/Positive Imbalance prices (Source: CREG monitoring report 2018, study (F)1958, **https://www.creg.be/fr/publications/etude-f1958**)*

The question is of course whether the real-time price is somehow following the day-ahead price as the likely same assets are setting the marginal price, or whether it is in fact a question of backward propagation, or a combination of both? In any case, the observation of a good relationship between both holds.

Backward propagation may be present on the Belgian markets already today, as the European approach to portfolio bidding allows arbitrage between the day-ahead and real-time timeframe at least to some extent, through what could be considered as 'implicit' virtual bidding.[75] Also the CORE study points out this aspect, saying that in the Belgian system with "*agents bidding portfolios as opposed to true physical assets, it can be argued that virtual trading is effectively allowed to a certain extent*". Indeed, for market participants with physical assets, it is possible to "piggyback the virtual transactions onto existing physical transactions", as stated in Isemonger (2006). For example, selling 300 MW in the Day-Ahead market and producing 200 MW in real-time, implies a pseudo-virtual sale of 100 MW in the Day-Ahead market.

On the discussion regarding explicit versus implicit virtual bidding, Isemonger (2006) further suggests that explicit virtual bidding should be preferred over implicit virtual bidding because implicit virtual bidding can bias the information of the system operator on the physical supply and demand and can even lead to reliability issues.

- Improved backward propagation of prices may not be sufficient to trigger new investments:

Although the introduction of virtual trading may and probably will improve the backward propagation of prices at least to some extent towards the day-ahead time frame, the crucial question is whether the scarcity reflective real-time price signal propagates back to liquid well-functioning forward markets with a sufficiently long-term maturity matching with investment lifetimes. While virtual trading may improve backward propagation towards day-ahead prices, any further backward propagation is not directly stimulated through virtual trading.

Regarding the discussion of backward propagation towards forward and future prices:

Firstly, perfect price propagation is often taken for granted, referring for instance to a theoretical model developed in Bessembinder and Lemmon (BL) (2002).[76] However, this theoretical link between the spot and forward price modelled by BL has been tested and has largely not been validated by the empirical literature.[77] Indeed its validity is conditional upon several specificities and assumptions that are not necessarily verified in practice. The robustness of the link assessed empirically between the spot price and the forward price is limited and the explanatory power of those empirical models is questionable. Authors often conclude that inefficiencies in the analyzed forward markets cannot be ruled out. Hence, perfect price propagation may not be achievable.

Secondly, while certain capacity investments require 10 to 15 year income stability, forward prices usually do not provide a more than three-year forward hedging horizon, which is short to build a business case for a significant investment. Newbery (2020) formulates it as follows: "*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.*"[78]

[75] A distinction between Explicit Virtual Bidding, Implicit Virtual Bidding and Physical Arbitrage is discussed in Isemonger 2006, The Benefits and Risks of Virtual Bidding in Multi-Settlement Markets

[76] Bessembinder H., Lemmon M.L. (2002). *Equilibrium pricing and optimal hedging in electricity forward markets*. The Journal of Finance 57(3) pp. 1347–1382.

[77] Cf. for instance Botterud A., Kristiansen T., Ilic M. (2009). *The relationship between spot and futures prices in the Nord Pool electricity market*. Energy Economics, Volume 32, Issue 5 and Lucia J.J, Torro H. (2008). *Short-term electricity futures prices: Evidence on the time-varying risk premium*. Working paper.

[78] Newbery D. (2020). *Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan.*

To conclude, although an ***introduction of virtual trading*** *– i.e. removal of both day-ahead and real-time balance obligation – is* ***currently not foreseen****, a study is ongoing regarding the weakening or removal of the day-ahead balanced position of BRPs in Belgium. This may be seen as a first step towards virtual trading in Belgium.*

In a market design that targets the implementation of scarcity pricing elements, virtual trading, although the benefits in backward propagation of prices may not be proven, can be expected to ***improve such backward propagation of prices at least to some extent towards the day-ahead time frame****. Besides, insofar as price convergence between the day-ahead and real-time prices would currently depend to some extent on 'implicit' virtual trading, it seems desirable to replace it with 'explicit' virtual trading, as this may lead to* ***more accurate information on the actual physical systems conditions****.*

However, one should be careful with subsequently concluding that virtual trading may lead to perfect price propagation and/or will trigger necessary new capacity investments. Perfect backward propagation from the day-ahead time frame towards forward and future prices may not be achievable. Moreover, the forward prices typically provide only a three-year forward hedging horizon, which is short to build a business case for significant investment projects.

4.4.3 Legal assessment

Also for the legal assessment of the weakening or removal of the day-ahead balanced position of BRPs in Belgium, to be considered as a potential first step towards virtual trading for Belgium, the reader is referred to the other Elia study.

However, there is one relevant legal aspect related to the introduction of virtual trading and its intended added value in the context of a scarcity pricing implementation to be discussed here. As discussed before, without (explicit) virtual trading, arbitrage beyond the day-ahead market closing depends on implicit virtual trades.

Such implicit virtual trades remain a regulatory "grey zone" in Europe from the point of view of the competition policy and market manipulation regulation. In particular, the REMIT regulation does not precisely define which cross-market transactions should be considered manipulative.

4.4.4 Conclusion

In the context of a market design that aims to implement scarcity pricing elements, the introduction of virtual trading is considered to be a useful addition. Although its benefits may not be fully proven, virtual trading does increase trading possibilities and as such may improve price propagation towards the day-ahead time frame.

Moreover, both from a market design and legal perspective, explicit virtual bidding is to be preferred over implicit virtual bidding that may (to some extent) be present in the current market design. Explicit virtual trading from a legal perspective has the advantage of making explicit that such cross-market transactions are allowed. From a market design perspective, explicit virtual bidding provides more accurate information regarding the actual physical system conditions, e.g. by not requiring a 'fictive' balanced position to cover for an actual open position as would be the case under implicit virtual bidding.

However, one should be careful in subsequently concluding that virtual trading would lead to perfect price propagation also to forward and future prices and/or is able to trigger the necessary longer-term capacity investment signals. Perfect price propagation may not be achievable, while forward and future electricity markets may not be able to provide a sufficiently long hedging horizon.

4.5 Step 5: Day-ahead co-optimization of energy and reserves

4.5.1 What is it?

As a fifth and last step towards the implementation of a scarcity pricing mechanism in Belgium, the CORE study considers a shift towards day-ahead co-optimization of energy and reserves. As indicated in section 5.2 of the CORE study: "*one major appeal of co-optimization is that it results in an automatic arbitrage between energy and reserve capacity, meaning that the output of a co-optimization model is such that agents are indifferent between allocating their capacity between reserve and energy*".

Day-ahead co-optimization is nowadays implemented primarily in several US electricity markets. The US electricity markets typically require a central dispatch approach to ensure a detailed treatment of generation units and the transmission network. Interactions between neighboring electricity markets are limited to even completely absent. Hence, electricity markets operated by means of day-ahead co-optimization of energy and reserves make perfect sense under such objectives.

The EU electricity market design on the contrary focuses rather on the integration of previously independent regions. Nowadays, these regions are highly interconnected. In the EU market design of today, the procurement of energy and reserves is separated.

Moving towards day-ahead co-optimization of energy and reserves in Europe as put forward in the CORE study, is considered to be highly disruptive in the current EU context. The disruptive character of this measure is also recognized by the CORE study. Given its unlikely implementation in the short to near-term future, a detailed analysis of what it requires to implement such day-ahead co-optimization of energy and reserves in Europe is out of scope of this report. Rather, the rest of this chapter focuses on a more high-level market design compatibility and legal assessment.

4.5.2 Compatibility with the prevailing market design

Not surprisingly, a rather disruptive move towards day-ahead co-optimization of energy and reserves as described in the CORE study, is currently not foreseen.

Nevertheless, "co-optimization" initiatives are being considered on European level. In accordance with Art. 40 of the EBGL, all TSOs developed a proposal for a methodology that aims at a co-optimized allocation of cross-zonal capacity to either a cross-border balancing capacity procurement or to the single day-ahead market coupling, depending on which process is expected to generate most value. This proposal includes also a different type of co-optimization, i.e. the co-optimization between balancing capacity bids and day-ahead market bids, which seems to be the type of co-optimization targeted in the CORE study. In accordance with ACER's decision of 17 June 2020 on the methodology for a co-optimized allocation process of cross-zonal capacity, the possibility for the co-optimization between energy and capacity will be assessed within 18 months as part of an implementation impact assessment for the Art. 40 methodology.

Hence, in the first place a different type of co-optimization (related to the allocation of cross-zonal capacity) is being assessed in accordance with Art. 40 of the EBGL. In this assessment though, also the more ambitious co-optimization between balancing capacity bids and day-ahead market bids is considered. However, market parties already raised concerns on the potential impact of the latter type of co-optimization on Euphemia. There is for instance a clear request from market parties not to reduce functionalities of the algorithm to allow such co-optimization processes.

To conclude, a move towards ***day-ahead co-optimization of energy and reserves*** *for Belgium (and for Europe by extension) as described in the CORE study is* ***only foreseen as a possible addition to the co-optimization of the allocation of cross-zonal capacity for balancing capacity and for day-ahead energy****, in accordance with EBGL Art. 40.*

Feasibility assessments beyond the scope of this report are currently ongoing.

4.5.3 Legal assessment

Art. 40 of the EBGL requires all TSOs to propose a methodology for the co-optimization of the allocation of cross-zonal capacity for balancing and trading activities. While also a different type of co-optimization (i.e. between day-ahead bids and balancing capacity bids) was eventually included in the proposal by all TSOs, note that ACER states in the consultation report accompanying ACER's decision of 17 June 2020 on the methodology for a co-optimised allocation process of cross-zonal capacity:

> *"Since the linking of bids is not a legal requirement as a part of the co-optimised allocation process it was not introduced as a fixed requirement in this methodology to allow sufficient flexibility for implementing the co-optimised allocation process while taking into account the benefits of linking of bids."*

Considering the request from market parties during the public consultation, TSOs proposed (and ACER approved) to study, in accordance with Art. 13(2)(f) of the Methodology for a co-optimised allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves:

> *"level of linkage between standard balancing capacity bids in time and between products and between standard balancing capacity bids and day-ahead market bids;"*

Hence, unless the co-optimization between energy and reserve bids as proposed in the CORE study, is implemented in the context of Art. 40 of the EBGL concerning the co-optimization regarding cross-zonal capacity, it seems to Elia that there is no legal basis for TSOs to require NEMOs to facilitate such co-optimization.

4.5.4 Conclusion

Day-ahead co-optimization methodologies are currently under study in Europe in accordance with Art. 40 of the EBGL. While the scope of this article is restricted to a co-optimization of the allocation of cross-zonal capacity for the exchange of balancing capacity of sharing of reserves, another type of co-optimization is being considered alongside.

Note that unless the co-optimization between energy and reserve bids as proposed in the CORE study is implemented as an extension of Art. 40 of EBGL, there is no legal basis for such co-optimization.

Furthermore, although subject to an ongoing feasibility assessment beyond the scope of this study, the compatibility of such co-optimization – between energy and reserves, in line with the CORE study – with the prevailing market design and in particular the Euphemia algorithm currently in place for the day-ahead market clearing, is far from obvious. There is a clear request from market parties not to reduce other functionalities of the Euphemia algorithm to allow such co-optimization processes. It can be fairly assumed that this would not be a short to medium-term evolution within reach of the time horizon considered for a potential scarcity pricing implementation as studied in this report.

4.6 Overall conclusion

This section provides Elia's overall conclusion regarding the scarcity pricing measures considered in the CORE study.

Elia perceives a strong link and interdependency between the first and second considered scarcity pricing implementation measures. In particular, the real-time reserve capacity market (i.e. step 2) seems to not work properly without scarcity-reflective real-time energy prices (i.e. step 1). But also the other way around, some elements proposed in the step 1, i.e. the integration of scarcity price adders in the balancing energy price applicable to BSPs, seem to result in market distortive effects without the existence of a remuneration of real-time standby capacity, which is the second considered scarcity pricing measure. As a consequence, if some of the elements of the first and second scarcity pricing implementation measure cannot be realized, this jeopardizes the scarcity pricing mechanism envisaged in the CORE study, perceived to consist of a joint implementation of step 1 and 2.

Regarding the elements considered in these two first steps, several issues have indeed been identified that effectively prevent its implementation, both from a market design and legal point of view. For a moment neglecting the identified legal obstructions, from a market design point of view the only feasible way forward for a full scarcity pricing implementation as envisaged in the CORE study seems to be a fully harmonized European-wide scarcity pricing implementation. Without this, discriminatory and/or market distortive effects seem impossible to avoid. Moreover and although not strictly necessary for a scarcity pricing implementation, an equalization of the real-time energy price among BRPs and BSPs at all times as prescribed in the first scarcity pricing implementation measure considered in CORE study, is not deemed achievable given the prevailing market design. In any case, such equalization does not seem desirable and even seems to be distortive.

However, Elia believes that some of the elements described in the context of the first scarcity pricing implementation measure, further inspired by the discussion on the alpha component in light of the third proposed scarcity pricing implementation measure, may provide a feasible alternative starting point for a scarcity pricing implementation in Belgium. Important in this respect is that the scarcity pricing measure only applies to BRPs in order to be compatible with both the market design framework and avoids legal obstructions. Such alternative scarcity pricing proposal is further elaborated upon in chapter 6.

Finally, concerning the fourth and fifth scarcity pricing implementation measures that focus on improving backward price propagation, certain elements may certainly be useful in the context of a scarcity pricing implementation. However, these elements are subject to other ongoing studies (e.g. Elia study on the removal or weakening of the day-ahead balance obligation, feasibility assessment on EU-level regarding co-optimization) and/or should be seen more as measures for the longer-term future. However, it should also be noted that steps 4 and 5 are not considered crucial in the context of a scarcity pricing implementation, especially not since backward price propagation seems not completely absent in the current market design (particularly between real-time and day-ahead time frames).

5. First reflections on the financing of a scarcity pricing mechanism

The first scarcity pricing implementation measure considered in the CORE study concerns the integration of a scarcity price adder into the real-time *energy* price, while the second measure concerns a scarcity-reflective real-time *capacity* price. Having discussed both in the context of an analysis of the CORE study in chapter 4, this section elaborates on some reflections regarding the financing of a Scarcity Pricing mechanism.

5.1 Remuneration of energy

A Belgian scarcity price adder applied on energy prices can be designed in such a way that in the end it results in a zero sum game between BRPs and BSPs, following the polluter pays principle. In this respect, BRPs may receive or have to pay the scarcity price adder, depending on their imbalance position during (-near) scarcity moments. BSPs would receive the scarcity price adder when they are activated during (near-) scarcity moments.

However, two critical reflections can be made:

Firstly, although a scarcity price adder on energy prices in the end can result in a zero sum game, the volumes and flows – i.e. the 'turnover' of such remuneration – do increase. This may have an impact on its own on market players, for instance due to an increased perceived risk of having to pay the scarcity price adders. At worst, it may act as an increased entry barrier to the market if, for instance for BRPs, the risk would be deemed too high or hard to manage.

Secondly, in a European context with the MARI and PICASSO platforms in place but of course depending on the exact implementation of the Belgian scarcity price adder, it may be that the application of a Belgian scarcity price adder on energy prices results in a zero-sum game only on European level. From a Belgian perspective, this could mean that the adder is paid to foreign BSPs while it are Belgian BRPs that pay the adder. Although an alternative could be to pay the adder only to Belgian BSPs, thereby avoiding this spillover, such solution seems to result in the discriminatory effect that foreign BSPs are not eligible to receive the scarcity price adder while they may alleviate the Belgian scarcity problem in the same way as Belgian BSPs do. This aspect is further elaborated upon in section 4.1.2.2 when discussing the first approach identified by Elia.

A way to avoid spillover effects across European countries is to restrict the scope of the scarcity pricing mechanism to BRPs. For instance, a scarcity price adder only applicable on Belgian BRPs ensures that the impact of a Belgian scarcity pricing mechanism remains in Belgium. Note that restricting the scope of the scarcity pricing mechanism to BRPs only still keeps the interesting feature of being self-financed. Elia's alternative proposal presented in chapter 6 entails a scarcity pricing mechanism only on BRPs. The specific feature of applying only on BRPs is further discussed in section 6.1.2.

5.2 Remuneration of capacity

In contrast to a scarcity price adder applied on energy prices, a scarcity price adder paid to available balancing capacity is not a measure that is self-financed. These costs would have to be publicly financed somehow.[79] It is at this stage (neither in the CORE study) not further defined how the financing of this extra cost should be organized.

Note in this respect that in case such scarcity price adders would be financed by State resources (which may have to be interpreted broadly, e.g. also when it is financed through tariffs), this could raise questions regarding State aid and therefore require the European Commission's approval. Of course, this is only a premature and preliminary assessment, as much depends on the detailed modalities of the scarcity pricing implementation.

Moreover, as explained above, market participants are expected to arbitrage between the upfront reservation of balancing capacity (which pays a reservation fee) and being available in real-time (which pays the real-time reserve capacity price, i.e. a scarcity price adder). To the extent that market participants have an expected value for the scarcity price greater than zero, this opportunity cost will be priced in and therefore puts upward pressure on the TSO procurement cost.

[79] First estimations, included in CREG's Note (Z)1986 on p12 (point 50), indicate that "on average, loads would pay (5227/756) = 6,9 €/MWh if they do not participate in the mechanism" building on table 12 in section 6.4. of the CORE study.

6. Alternative scarcity pricing proposal

Following up on chapter 4 in which the CORE study – presenting a proposal for the introduction of a scarcity pricing mechanism for Belgium – was analyzed, this chapter presents an alternative proposal developed by Elia. This alternative proposal for a scarcity pricing implementation in Belgium builds further on elements already provided in the CORE study, while at the same time carefully considering the compatibility with both the prevailing market design and the boundaries set by the legal framework. Therefore, it is believed that the proposal elaborated in this chapter presents a feasible alternative for the implementation of scarcity pricing in Belgium. The (open) question on whether going forward with this alternative is deemed desirable is also discussed in this chapter.

Section 6.1 explains the 'Omega component' as alternative scarcity pricing proposal, while section 6.2 discusses its desirability.

6.1 'Omega component' as alternative scarcity pricing proposal

After a general description in section 6.1.1 setting the contours of the proposed alternative, the following sections zoom in on its main features. Several important characteristics of the proposed scarcity component are discussed in sections 6.1.2, 6.1.3 and 6.1.4. Next, the calculation of the scarcity component is detailed in section 6.1.5. Section 6.1.6 then discusses how the alpha and omega component will work together. Finally, section 6.1.7 provides some thoughts regarding backward propagation.

6.1.1 General description of the alternative

As an alternative proposal for the integration of a scarcity pricing mechanism for Belgium, Elia proposes a scarcity component integrated in the imbalance tariff. The imbalance tariff is the tariff applicable for maintaining and restoring the residual balance of individual Balance Responsible Parties (BRPs).[80]

The envisaged scarcity component – also denoted further as 'omega' (Ω) component – is to be interpreted as a scarcity component in the sense of Art. 9(6)(a) of ACER's decision of 15 July 2020 on the Imbalance Settlement Harmonization methodology (own underlining):

> *"6. The connecting TSO or connecting TSOs of an imbalance price area may propose in the Member State's terms and conditions for BRPs the conditions and a methodology to calculate additional components, to be included in the imbalance price calculation. In that case, this TSO or these TSOs shall propose one or more of the following additional components:*
>
> *(a) <u>a scarcity component to be used in nationally defined scarcity situations</u>;*
>
> *…"*

[80] The current imbalance tariffs for the period 2020-2023 can be found here: **https://www.elia.be/-/media/project/elia/elia-site/customers/tarrifs-and-invoicing/tariffs-and-invoicing/en/grille-tarifaire-2020-2023-onevenwicht-env1.pdf**

While the main features of the proposed scarcity component are described separately in more detail later, Elia's alternative scarcity pricing proposal is already summarized in Figure 18 below. The conceived omega component is proposed to be integrated in the imbalance tariff applicable to BRPs, but only applies during negative or zero system imbalances. Without scarcity pricing, this imbalance tariff would be equal to "MIP + α" (cf. link in footnote 80 for more details on the components that constitute the current imbalance tariff). With scarcity pricing, the maximum of the alpha and omega component would be considered as an addition to the Marginal Incremental Price (MIP), in case of negative or zero system imbalances.

		System Imbalance	
		Positive	*Negative or zero*
Imbalance of the balance responsible party	*Positive* *Negative*	MDP – α	MIP + max.(α;Ω)

Figure 18: Tariffs for maintaining and restoring the residual balance of BRPs (including a scarcity component also denoted as omega (Ω) component)

For instance, assume that for a specific Imbalance Settlement Period (ISP), i.e. a 15 minute period in the current setting, (near-) scarcity conditions give rise to an omega component equal to 500 €/MWh. Further suppose that during this ISP the system imbalance is negative (i.e. the Belgian control zone is short) and that alpha is equal to 200 €/MWh. In this case:

- BRPs who are short, i.e. hold a negative position, have to pay an imbalance tariff corresponding to MIP increased by the omega component, equal to MIP + 500 €/MWh[81];
- BRPs who are long, i.e. hold a positive position, receive an imbalance tariff corresponding to MIP increased by the omega component, equal to MIP + 500 €/MWh.

In other words, BRPs that are short/long during (near-) scarcity conditions and thereby deteriorate/alleviate the scarcity problem are punished/rewarded through the scarcity component integrated in the imbalance tariff. This means that the provided incentives towards the market, and particularly through the BRPs, to solve the scarcity problem are set in the correct direction via the omega component.

The calculation of the omega component incorporates elements to ensure that omega is tuned to apply during structural capacity shortage problems and is not already trigger by an exceptional event during one specific ISP. To this end, in the calculation of the omega component, a rule is included that omega has to be different from zero for two consecutive ISPs before it is assigned a value different from zero. Moreover, the omega component is calibrated to VOLL and based on a Loss of Load Probability (LOLP) estimation. The exact calculation methodology is further detailed in section 6.1.5.

[81] It is the omega component that applies, as in this example it is higher than the alpha component for this ISP and it is the maximum of both components that is considered following Figure 18.

6.1.2 Applicable on BRPs

Being integrated as a component in the imbalance price calculation in accordance with Art. 9(6)(a) of the ACER's decision of 15 July 2020 on the Imbalance Settlement Harmonization methodology, the proposed scarcity component is applicable on BRPs.

This is a deliberate choice, as the analysis of the scarcity pricing implementation steps considered in the CORE study (cf. previous chapter) made clear that both from market design as well as from legal perspective, a scarcity price adder applied on BSPs is not desirable or even impossible. Note in this respect especially section 4.1.3.2, in which a legal assessment was presented concluding that scarcity pricing seems only possible on BRP, as the legal basis for scarcity pricing set by Art. 20(3)(c) of Regulation (EU) 2019/943 refers to Art. 44(3) of the EBGL, stating that (own underlining): *"The additional settlement mechanism shall apply to <u>balance responsible parties</u>"*. Hence, scarcity pricing applied on BRPs is believed to be the only feasible way forward in the current and foreseen framework on the short and medium term.

In any case, Elia believes that – if a scarcity pricing mechanism is deemed desirable – it also makes sense to apply it (only) on BRPs. On the one hand, the BRP is responsible for its residual imbalances in relation to the overall system imbalance of the Belgian control zone. On the other hand, a scarcity pricing mechanism in Belgium aims to be reflective of the scarcity situation of the Belgian control zone. Hence, the application of a Belgian scarcity price adder on Belgian BRPs matches the actors capable and responsible for acting on the situation and is therefore logical. It is also perfectly compatible with the prevailing Belgian and broader European market design, where BRPs remain to be defined as acting within the perimeter of a control zone (unlike BSPs, cf. 4.1.3.1).

6.1.3 In addition to alpha

The alternative scarcity pricing proposal aims for a scarcity component in addition to the alpha component that is already integrated for several years in the imbalance price calculation (cf. footnote 80 for the current imbalance tariffs), as both components serve a different purpose:

- The *alpha* component incentivizes against large and persisting system imbalances (both negative and positive) that could otherwise lead to an increase in the requirement of upward reserves and/or a need to contract downward reserves.
- The purpose of the *omega* component is to incentivize market players to ensure sufficient capacity is available whenever the system approaches scarcity and the remaining margin becomes tight.

The distinction between the alpha and omega components can also be illustrated by means of the following case study of 12 December 2017 (cf. Figure 19 below). This case study stems from a report Elia already published in the context of the 2018 discretionary incentive on scarcity pricing, in which Elia applied a model developed by UCL CORE to calculate scarcity price adders to a historic dataset of 2017.[82] Of course, the market design has evolved meanwhile

[82] The study, titled *Study report on Scarcity Pricing in the context of the 2018 discretionary incentives*, can be consulted online: **https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/adequacy---scarcity-pricing/2018/2018_study_report_on_scarcity_pricing.pdf?la=en**

and for instance some products as mentioned in the figure such as 'ICH' do not exist as such anymore. Furthermore, also the calculation of the scarcity price adders is not exactly the same anymore as how they are nowadays calculated for the publication of scarcity price adders on D+1 basis on the Elia website.[83] Nevertheless, the underlying principles remain the same and for the sake of the illustration on how alpha and omega react to a situation, the case study is still relevant.

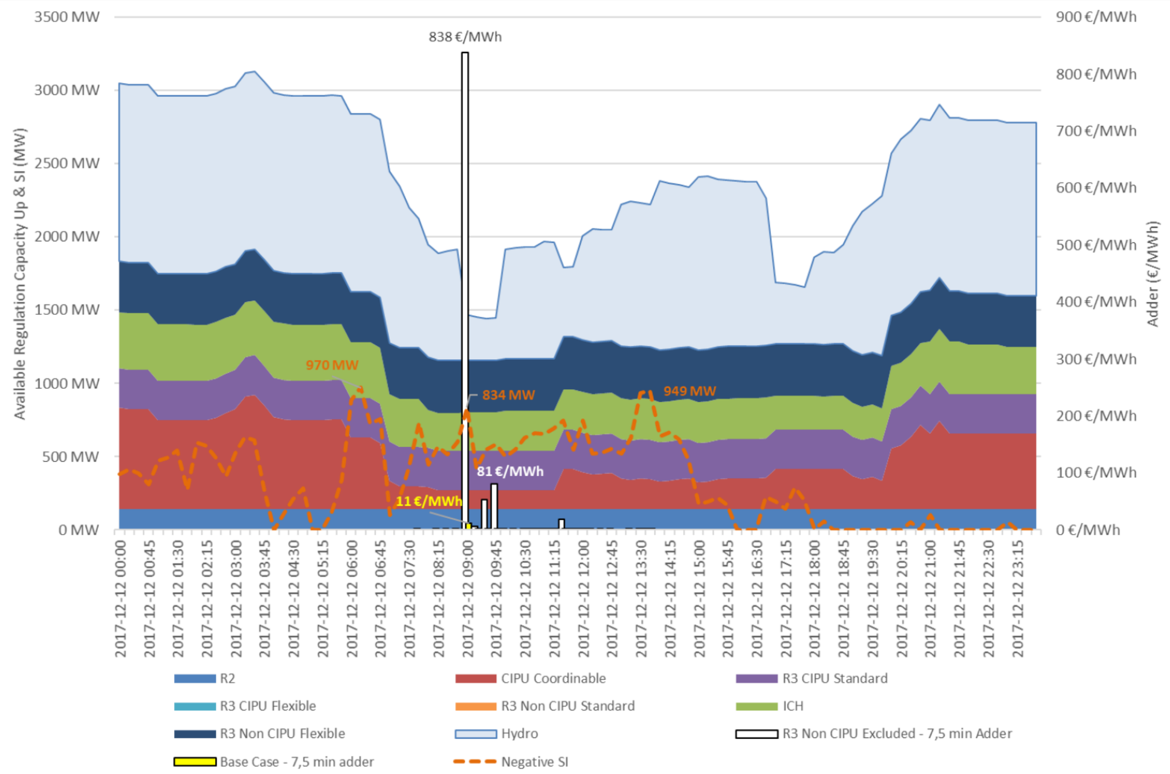

Figure 19: Case study for 12 December 2017

Figure 19 shows that significantly negative system imbalances occurred throughout that day, reaching peaks of -970 MW at 06:15, -834 MW at 09:00 and -949 MW at 13:45. The negative system imbalances seem to be explained mainly by a higher than forecasted load and lower than forecasted wind energy production for that considered day. However, only the peak at 09:00 – which was not even the most extreme system imbalance – triggered a considerable scarcity price adder. This is because this peak of negative system imbalance coincided with a reduced availability of upward regulation capacity, in particular explained by reduced hydro and free bid (i.e. CIPU Coordinable in the illustration) margins. The alpha component however applied throughout the day – non-zero between 07:00 and 16:00 – to incentivize against the persisting and often large negative system imbalance.

To summarize, while the alpha component acts against problems that cause (both positive and negative) large system imbalances, the omega component is only meant to apply during structural capacity shortage problems caused by a low remaining margin in the system. Note that a large negative system imbalance is not a necessary prerequisite for

[83] **https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation**

the omega component to apply. A zero or close to zero availability of upward regulation capacity by itself already triggers a considerable Loss of Load Probability (LOLP). The reader is referred to section 6.1.5 for a more in-depth explanation of the exact calculation of the omega component.

6.1.4 Applicable only during negative to zero system imbalances

A scarcity pricing mechanism is by definition asymmetric, as it wants to protect against shortages of available capacity, while it has no intention to also act against a surplus. Therefore, careful consideration is required when integrating a scarcity component in the imbalance tariff which aims to maintain and restore the residual imbalance of BRPs. Indeed, the scarcity component may not obstruct the appropriate balancing incentives. Therefore, Elia's alternative proposal includes an omega component that is applicable only during negative to zero system imbalances.

Such design avoids a potential problematic situation in particular cases with an omega while the system imbalance is positive, where BSPs are activated down by the system operator, while BRPs may get an incentive in the other direction, requiring even more downward activations. Although such situations may be rare, it is best to entirely avoid them in order to safeguard proper balancing incentives at all times. Moreover, especially because such situations are rare, this design choice is believed not to have an impact on the effectiveness of the scarcity pricing implementation.

Another interesting feature of the scarcity component, combining the fact that it only applies on BRPs (cf. section 6.1.2) and only during negative to zero system imbalances (cf. this section), it that it is at all times self-financed. This is in contrast to some elements included in the CORE study, such as the remuneration of standby non-reserved capacity analyzed in section 4.2. Since the scarcity component is self-financed, it does not seem to require state aid approval.

6.1.5 Applicable only during structural capacity shortages

The value for the omega component – in line with the alpha component – can be calculated (very) close after real-time, i.e. right after the end of the ISP. This ensures a proper evaluation of the real-time condition of the system, reflecting whether sufficient available capacity was eventually available in real-time.

The proposed calculation of the omega component corresponds largely with the formula to calculate the 'adder for energy' as detailed in section 7.1 of the CORE study, calibrated to VOLL and based on a LOLP estimation[84].

However, deviating from the proposal in the CORE study, for the proposed alternative mechanism it is deemed appropriate to incorporate a delaying/filtering effect to ensure that the omega component only applies during structural capacity shortages.[85] A volatile omega is to be avoided, as it might have a financial impact raising entry barriers for BRPs and/or might result in unnecessary negative/positive swings of the system imbalance. Specifically, the calculation of the omega component for a given ISP is equalized to zero if the omega component for the previous ISP was equal to 0 €/MWh.

---

[84] Building on historical imbalance data, in line with the description in section 1.3.2. of the CORE study

[85] Note that also today's alpha calculation includes such softening element, averaging values over two ISPs.

Additionally, as a further refinement of the proposal in the CORE study, it is foreseen that the omega component would be equalized to zero in case the Marginal Incremental Price (MIP) of the given ISP could become higher than or equal to VOLL. This is to ensure that the omega component does not become negative, reducing the imbalance tariff whenever it would become higher than VOLL by itself. Indeed, if the imbalance tariff for another reason goes up to VOLL or surpasses this value, omega has no role to play.

To summarize, for a given ISP, the omega component is calculated as:

$$\Omega_{ISP(t)} = \begin{cases} \mathbf{0}\ \boldsymbol{if}\ \Omega_{ISP(t-1)} = \mathbf{0}\ \text{€}/\boldsymbol{MWh} \\ \mathbf{0}\ \boldsymbol{if}\ \boldsymbol{MIP_{ISP(t)}} \geq \boldsymbol{VOLL} \\ \dfrac{\boldsymbol{T_1}}{\boldsymbol{T_1+T_2}} * \left[\left(\boldsymbol{VOLL} - \boldsymbol{MIP_{ISP(t)}}\right) * \boldsymbol{LOLP_{T_1}}\left(\boldsymbol{RemainingMargin^{T_1}_{ISP(t)}}\right)\right] + \\ \dfrac{\boldsymbol{T_2}}{\boldsymbol{T_1+T_2}} * \left[\left(\boldsymbol{VOLL} - \boldsymbol{MIP_{ISP(t)}}\right) * \boldsymbol{LOLP_{T_1+T_2}}\left(\boldsymbol{RemainingMargin^{T_1+T_2}_{ISP(t)}}\right)\right]\ \boldsymbol{otherwise} \end{cases}$$

Where:

- $T_1 = 7{,}5$ minutes, i.e. duration of the first part of the ISP;
- $T_2 = 7{,}5$ minutes, i.e. duration of the second part of the ISP;
- $VOLL =$ the Value of Loss of Load;
- $MIP_{ISP(t)} =$ marginal price of upward activation of the ISP, as established in the functioning rules of the market governing compensation for quarter-hourly imbalances that Elia has established in accordance with the Federal Grid Code, expressed in €/MWh;
- $LOLP_{T_1+T_2}(x) = \int_x^{+\infty} \frac{1}{\sqrt{2\pi}\sigma} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}$, i.e. the probability of incurring loss of load, given a specific Remaining Margin here denoted as x, expressed as %. A loss of load probability function is estimated for each season and for each 4-hour block, characterized by a mean (μ) and standard deviation (σ), which are parameters in the formula that are derived from historic system imbalance data from the past calendar year.[86] An example is provided in Table 1 below for the parameters that would apply during 2019, derived from historic system imbalance data of 2018. A graphical illustration of the calculation of $LOLP(x)$ is provided in Figure 20 below;
- $LOLP_{T_1}(x)$ is equal to the calculation of $LOLP_{T_1+T_2}(x)$, except for the fact that parameters μ and σ are now divided by 2;
- $RemainingMargin^{T1+T_2}_{ISP(t)} = SUM(R2+, I\ C, I\ C\ EnergyLimited, R3\ Std, R3\ Flex, Hydro) +$ $50MW\ assumed\ as\ fixed\ interTSO\ import +\ SI$, with $R2+, I\ C, I\ C\ EnergyLimited, R3\ Std, R3\ Flex$ derived from the available balancing volumes as published on the Elia website[87], expressed in MW;
- $RemainingMargin^{T1}_{ISP(t)} = 100\%\ of\ R2+\ + 50\%\ of\ SUM(\ I\ C, I\ C\ EnergyLimited, R3\ Std, R3\ Flex, Hydro) +$ $50\%\ of\ 50MW\ assumed\ as\ fixed\ interTSO\ import +\ 50\%\ of\ SI$, expresses in MW;
- $Hydro = Min[(P_{max} - P_{scheduled}); (T_1 + T_2) * Ramping\ Rate]$, calculated for each PHS units and summed

[86] The mean and standard deviation parameters will be updated each year, in order to consider the most recently available data.

[87] **https://www.elia.be/en/grid-data/balancing/energy-available-volumes-and-prices**

over all PHS units, expressed in MW;

- SI is the System Imbalance, equal to ACE minus NRV, as specified in the tariffs for maintaining and restoring the residual balance of individual BRPs (cf. footnote 80), expressed in MW.

Table 1: Example of μ and σ parameters used in the LOLP calculation that would apply during 2019 (based on historic system imbalance data of 2018)

Season[88]	Hour block[89]	μ	σ
WINTER	**1,2,23,24**	-31,12	151,18
	3-6	-25,73	120,8
	7-10	1,78	148,96
	11-14	-7,93	175,49
	15-18	-11,57	155,84
	19-22	1,93	148,5
SPRING	**1,2,23,24**	0,2	162,32
	3-6	-6,12	134,51
	7-10	17,51	154,62
	11-14	-2,59	209,74
	15-18	-24,71	192,89
	19-22	33,35	147,26
SUMMER	**1,2,23,24**	16,07	137,85
	3-6	11,46	105,7
	7-10	1,67	120,02
	11-14	-12,94	144,2
	15-18	3,62	154,75
	19-22	36,82	136,74
FALL	**1,2,23,24**	-15,78	146,45
	3-6	-25,87	124,24
	7-10	6,66	150,15
	11-14	0,27	183,08
	15-18	-16,73	158,52
	19-22	11,97	156,99

[88] **Winter** = December, January, February / **Spring** = March, April, May / **Summer** = June, July, August / **Fall** = September, October, November

[89] **1,2,23,24** = From 22:00 to 02:00 / **3-6** = From 02:00 to 06:00 / **7-10** = From 06:00 to 10:00 / **11-14** = From 10:00 to 14:00 / **15-18** = From 14:00 to 18:00 / **19-22** = From 18:00 to 22:00

Figure 20 shows graphically the calculation of the loss of load probability, based on a given LOLP function shown as an orange line, which is a normally distributed function characterized by a mean (μ, e.g. -31,12 MW in this example) and standard deviation (σ, e.g. 151,18 MW in this example) parameter.[90] The loss of load probability is equal to the areas in green, calculated as the integral of the LOLP function ranging from the remaining margin until +∞ and expressed as a percentage. As illustrated, a remaining margin of 100 MW results in a LOLP of 19,29%, while a remaining margin of 300 MW results in a LOLP of 1,43%. From this, it can be derived that a higher remaining margin corresponds to a lower loss of load probability. In other words, all things equal, a higher remaining margin provides more means to avoid involuntary load curtailment.

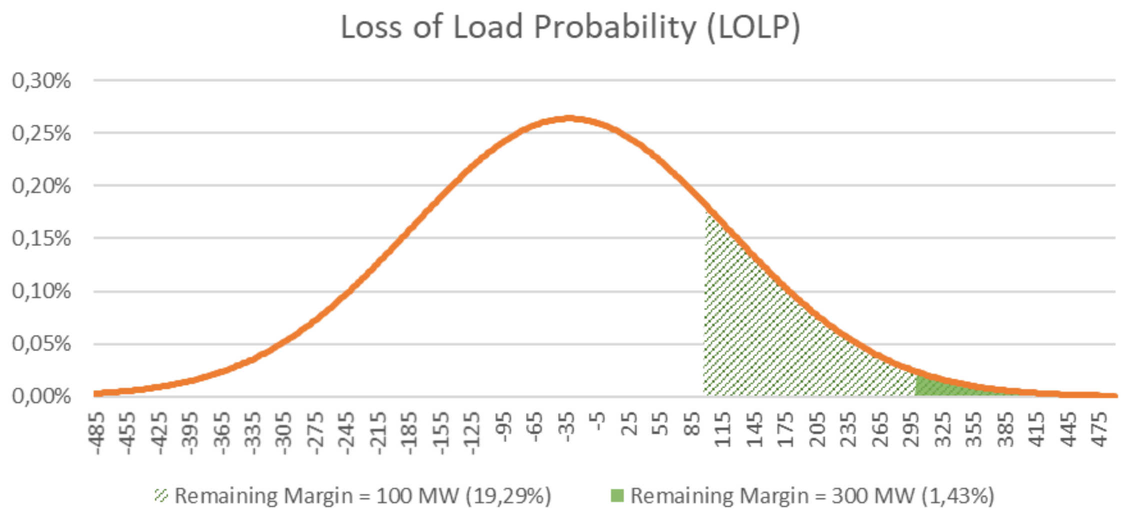

Figure 20: LOLP illustration (μ=-31,12 MW; σ=151,18 MW; Remaining Margin or x = 100/300 MW)

6.1.6 Alpha & omega

As discussed before, the alpha and omega component serve different purposes and are envisaged to operate side-by-side. Previous sections explained how the omega component is conceived, in addition to alpha, only during negative to zero system imbalances and calibrated to VOLL. This section puts the alpha and omega component side-by-side to explain how they are supposed to work together.

Figure 21 below illustrates the alpha and omega components in function of the system imbalance. Note that the left and right vertical axes are calibrated differently. The following observations can be made:

- As a first observation, note that while alpha depends solely on the system imbalance (note that in fact the average over two ISP's is considered), the system imbalance is only one element in the determination of

[90] Note that, deriving from Table 1, this is the LOLP function that would apply during 2019 in winter (i.e. December, January, February) each ISP from 22:00 to 02:00.

omega. Therefore, multiple parallel lines for omega are pictured in Figure 21, for various levels of remaining margin (excl. the system imbalance)[91]. For the same level of system imbalance, a lower remaining margin (excl. SI) triggers a higher value for omega.

- As a second observation, note that while alpha applies both during positive and negative system imbalances, omega only kicks in during zero to negative system imbalances. This has been discussed in section 6.1.4 before.
- As a third observation, note that alpha can rise to a maximum level of 200 €/MWh, while omega can reach a level equal to VOLL.

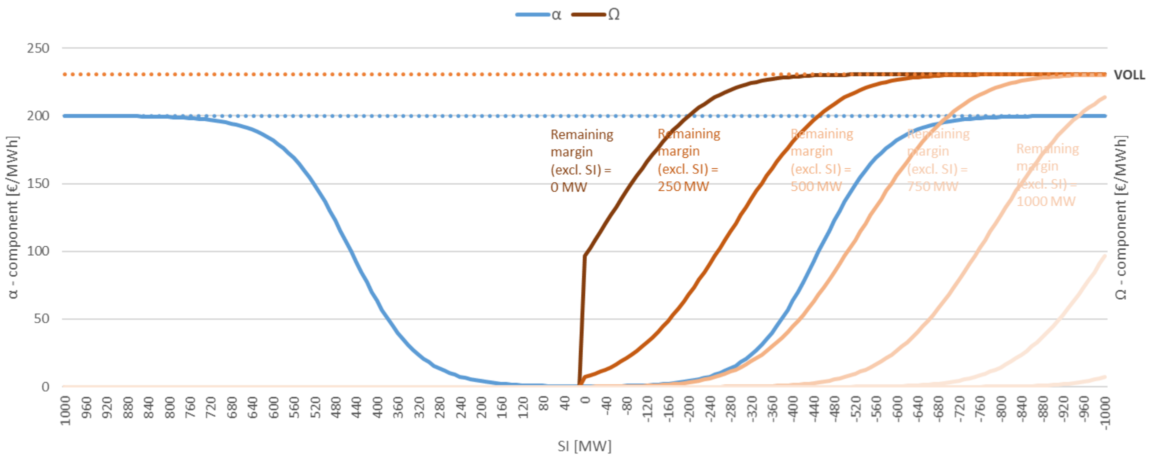

Figure 21: Alpha and omega component in function of the system imbalance[92] (left and right vertical axes not necessarily calibrated in the same way)

6.1.7 Backward propagation

Finally, for a scarcity pricing mechanism to be effective beyond real-time operational impacts, the impacted real-time price signal should propagate back to earlier time frames, such as day-ahead, forward and future prices in order to provide also long-term investment incentives. Note that in order to be a real incentive, the tenor of such markets should be sufficiently long. Newbery (2020) is critical on this aspect, stating that: *"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."*[93]

Although backward propagation is difficult to prove and probably cannot be assumed as currently being perfect (cf. supra), Elia observes that backward propagation is neither fully absent in the current market design (i.e. also without a so-called real-time reserve market as described in the market model put forward by the CORE).

[91] In Figure 19 denoted as "available upward regulation capacity"

[92] Note that in practice, both the alpha and omega component are calculated based on more complex formula's not considering the SI of one ISP as such (cf. supra). However, for the sake of illustration, this representation is deemed useful and relevant.

[93] Newbery D. (2020). Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan.

As already indicated in section 4.4.2, a relationship between the day-ahead and real-time price signal seems to exist already today. Moreover, as an illustration, towards the end of 2018 system conditions were undoubtedly tight and the system margin (i.e. a key parameter sizing the level of omega) was under pressure. The period was characterized by very low availability of nuclear power plants, the weighted average price for balancing capacity rose to a multitude of its typical level. This is for instance illustrated in Figure 22 below for the mFRR reservation fee. Note that at that time mFRR capacity was procured by Elia through month-ahead auctions. While also other factors may be in play (such as possibly more expensive capacity offering), the prices could be interpreted as also reflecting the expected tight situation. Indeed, for an individual market actor offering balancing capacity to Elia takes away the option of using the same capacity to sell energy (as commodity) or to keep it for maintaining the own portfolio balance. This implies an arbitrage between offering balancing capacity month ahead and selling the energy/keeping the self-balancing option.

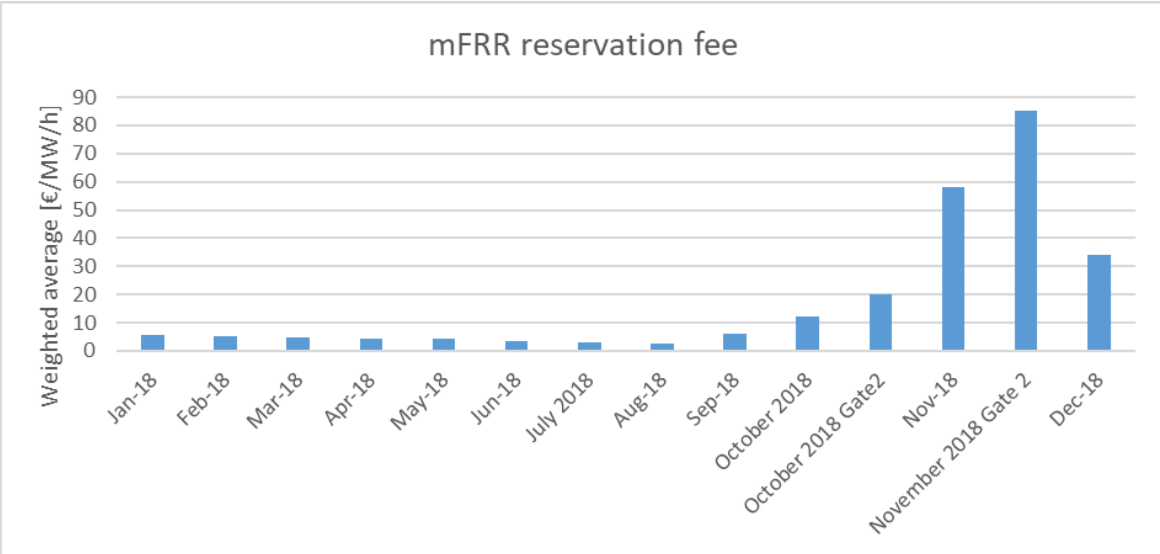

Figure 22: Weighted average mFRR reservation fee for 2018[94]

To summarize from the above observations, when the omega component is able to more properly reflect real-time (near-) scarcity conditions, this could very well be translated back also towards earlier time frames and in particular day-ahead, forward and future prices due to backward propagation which does not seem absent in the current market design.

Furthermore, note that the mFRR reservation fee applies to BSPs. Hence, the alternative scarcity pricing proposal as proposed on BRPs only, and therefore compatible with the prevailing market design and current legal framework, may also indirectly impact BSPs and thereby provide incentives to invest in new capacity.

[94] These prices are derived from the Elia website: **https://www.elia.be/en/grid-data/balancing/capacity-auction-results**

6.2 On the desirability of the 'Omega component' as alternative scarcity pricing proposal

The alternative scarcity pricing proposal put forward in section 6.1 of this chapter is in the first place a feasible proposal, starting from the CORE study and the conditions for an effective scarcity pricing mechanism, while at the same time also considering the prevailing market design and current legal framework. According to Elia, in the short to medium term and also in absence of any further harmonization of such scarcity mechanisms throughout Europe, a scarcity component applied through the imbalance tariff on BRPs is the only feasible and allowed way forward.

Beyond the question of feasibility though, Elia would like to explicitly raise a number of questions regarding the overall desirability of the proposed alternative – and by extension any – scarcity pricing implementation for Belgium.

It is to be noted that notwithstanding a number of critical reflections feeding the debate, at this stage Elia approaches the desirability yet as an open question being part of the more general consideration on the potential implementation of scarcity pricing mechanism for the Belgian market.

- ✓ *Most fundamentally, is there actually a problem to solve for which scarcity pricing is the solution?*
    - *More accurate, scarcity reflective real-time prices?*

Scarcity pricing mechanisms originate from the ORDC mechanisms that are conceived for US electricity markets. These US electricity markets typically operate through unit-based bidding and ex-ante market power mitigation measures, providing very limited to almost no room for opportunity bidding. By contrast, EU electricity markets allow portfolio-based bidding and only ex-post market power mitigation measures are in place. This may at least give some more freedom for genuine opportunity bidding without manipulation. Hence, the question is whether a scarcity pricing mechanism is crucial for EU electricity markets in order to induce scarcity rents, or whether it are not just other distortions or energy market failures that cause a missing money problem?

Furthermore, towards the end of 2018, market conditions were undoubtedly tight. At that moment in time (cf. Figure 22), weighted average mFRR reservation fees rose to a multitude of their typical level. Although it is difficult to tell what exactly were the underlying drivers for these elevated prices, it may well be that anticipated scarcity was one of the explaining factors.

- *Investment incentives for flexible capacity?*

While a scarcity pricing mechanism does not seem able to eliminate the missing money problem and neither guarantee a targeted reliability standard, it may provide additional investment incentives. However, by design fully triggered by flexibility issues in real time, scarcity pricing mechanisms are expected to in particular provide investment incentives towards flexible capacity. For the Belgian case, as long as adequacy can be guaranteed, there seems to be no need for additional flexible capacity in the system. This conclusion follows from Elia's 2019 adequacy and flexibility study for Belgium 2020-2030, stating that when solving the overall adequacy issue in any case also sufficient flexible resources will be available in the system to cope with the increased fluctuations between injections and offtake resulting from more volatile means of generation. (Balancing) market design should be such that those flexible capacities are used and made available efficiently. Hence, there seems to be no need for scarcity pricing to provide further investment incentives to highly flexible generation capacity, as long as the adequacy issue remains solved.

- ✓ *Secondly, insofar as there is a problem that needs to be solved, does this justify the additional complexity that comes with a scarcity pricing mechanism?*

The implementation of a scarcity pricing mechanism is an administrative intervention, requiring several assumptions to be made and parameters to be calibrated. Moreover, as design experiences with the ORDC mechanism show, this calibration is not a one shot exercise and subject of debate. It for instance also needs to consider changes in the capacity mix. These elements have for instance been discussed in the context of a use case on design experiences with ORDC scarcity pricing in ERCOT Texas, in section 2.2.3.

Also and especially for Belgium, which is a highly interconnected LFC area and which is embedded in a broader European market design and legal context, important assumptions will need to be made in the context of the introduction of a scarcity pricing mechanism. For instance, when determining the available upward regulation capacity as input to calculate the scarcity component for Belgium, it needs to be carefully assessed how much capacity at each moment in time is available abroad to be activated when the Belgian TSO needs it. These cross-border interactions become ever more important as from the go-live of the European balancing platforms MARI and PICASSO, which aim to decouple supply and demand of balancing energy towards a more efficient use of balancing energy on European level.

- ✓ *Thirdly, to what extent does the introduction of scarcity pricing raise market entry barriers?*

Elia's proposed scarcity component applies on BRPs. Although such measure is considered feasible from both market design and legal perspective, it is expected to raise entry barriers as it increases the financial risks to which BRPs are exposed. For instance, a BRP that is short during (near-) scarcity conditions is bound to pay the scarcity component, which may (cf. section 6.1.5) increase up to VOLL, as the LOLP approaches 100%. Hence, the scarcity component may discourage market players from taking up the role of BRP. Note that scarcity pricing indeed adds to the current situation as by design it targets more frequent price spikes through the administrative intervention of adding a price adder also – and particularly - during *near* scarcity situations.

- ✓ *Fourthly and summarizing regarding an overall assessment of the proposed scarcity pricing mechanism: How do you perceive the trade-off between increased entry barriers and/or a reduction of the missing-money and/or increased incentives to be available in real-time?*

Based on the previous open questions, it appears that there are several elements that should be considered in the overall evaluation of the introduction of a scarcity pricing mechanism. Therefore, this last question specifically aims to reflect on the trade-off between these aforementioned elements.

From the feedback received during the public consultation period, Elia observes that there is in general no appetite for the implementation of a scarcity pricing mechanism in Belgium. Market parties question the need for such mechanism. Febeg and EFET for instance argue that the real time value of energy naturally takes into account the risk of scarcity already. Febeliec – as does Febeg – opposes to the implementation of a scarcity pricing mechanism because it is not convinced that a scarcity pricing mechanism will be able to guarantee security of supply in the same way as a CRM could do. However, it is to be noted that Febeliec at the same time indicates that a CRM should be seen as a last resort measure and should be implemented under very strict conditions and for a clearly defined timeframe. Nemo Link Limited further points out the risks and complexities that come with a scarcity pricing mechanism, along with raising market entry barriers for BRPs.

Regarding the 'Omega component' as alternative scarcity pricing proposal, only Febeliec – on the condition that Belgium were to decide to implement a scarcity pricing mechanism for which they see at this stage no need – sees merit in the omega proposal, strengthening the price and investment signal towards BRPs to ensure system balance in their portfolios without direct extra cost for consumers. All other market parties (Febeg, EFET and Nemo Link Limited) oppose to the 'Omega component' scarcity pricing proposal.

7. Preliminary implementation plan

An analysis of the scarcity pricing implementation steps considered in the CORE study is presented in chapter 4. Subsequently, chapter 6 presents an alternative scarcity pricing proposal identified by Elia, considered to be the only feasible way forward for the introduction of scarcity pricing in Belgium in the short to medium term.

In this chapter, following also the requirements described in the incentive for 2020 laid upon Elia by CREG, an implementation plan is worked out regarding the alternative scarcity pricing proposal, i.e. towards the introduction of a Belgian scarcity component in the imbalance tariff applicable to Belgian BRPs, the so-called omega component. This measure is conceived as a first step towards the implementation of the scarcity pricing mechanism envisaged in the CORE study. However, the implementation of the further measures considered in the CORE study (i.e. on BSPs) seem to require an adaption of the current legal framework, following the assessment presented in chapter 4 based on the preliminary legal analysis by the independent external law firm Liedekerke attached in annex. Since it is impossible to assess the likeliness and timeline for adapting the current legal framework at this stage, these measures could not be included in the preliminary implementation plan presented in this chapter. Further note that as indicated in section 6.2, the development of such implementation plan does, at this stage, not imply that in Elia's view the desirability question regarding the actual implementation is already answered.

Several implementation tracks are identified. Section 7.1 first describes the omega calculation methodology revision track, aiming for a future-proof and robust calculation of the scarcity price component. Next, section 7.2 discusses the IT implementation track, in which several required IT developments are identified. Section 7.3 elaborates on the regulatory implementation track. Finally, a summarizing timeline is presented in section 7.3, presenting all identified tracks on a joint timeline.

It is to be clearly noted that the presented implementation plan is to be considered preliminary. First and foremost, this implementation plan is only relevant in case it is decided to implement the proposed alternative scarcity pricing proposal as described in chapter 6. This decision is not yet made and based on the feedback received from market parties during the public consultation period, there seems to be no appetite in general for the implementation of a scarcity pricing mechanism. Moreover, this implementation plan is based on high-level estimations and does not yet consider implementation bottlenecks (regarding resource, tools, etc.) as a result of other 'must do' projects for the coming years (e.g. MARI & PICASSO). However, in their feedback on the public consultation, market parties formulate a clear request to maintain a realistic implementation track and to give priority to other ongoing market design evolutions, in particular the implementation of the MARI and PICASSO platforms, which already require a lot of resources from all involved parties.

7.1 Omega calculation methodology revision track

The currently foreseen calculation methodology for the omega component builds on Elia's data sources, which focus on capacity that is available for activation by Elia within Belgium. For the part of the available upward regulation capacity that builds on capacity that Elia may activate in neighboring countries, such as for instance inter-TSO reserves, a fixed volume is currently assumed. However, with the foreseen go-live of the European balancing platforms and MARI over the course of 2022, this European dimension of available upward regulation capacity will become ever more important. A fixed volume assumption is no longer deemed the most appropriate way of working in such context.

Therefore, Elia believes it is crucial to set up a track to ensure the future-proofness of the omega component calculation and in particular to investigate and improve methodologies to determine the available upward regulation capacity appropriately, taking into account the capacity available for activation by Elia from the PICASSO and MARI platforms. Note that one complicating factor in this respect is the consideration of congestions, i.e. it is not sufficient that capacity is available abroad, also the available capacities on the interconnections need to allow an activation of this capacity to cover for a Belgian need.

Moreover, more generally, the current calculation methodology builds heavily on the Available Regulation Capacity source[95]. While this makes sense for a scarcity component that is provided for informational purposes only, it should be further verified whether this source should also be used for a component that will be integrated in the imbalance tariff. In this respect, it is especially important to work with validated and transparent data.

No work has been done regarding this track yet. However, the determination of such methodologies may already be initiated as of the moment the overall design choices have been confirmed, based on the known implementation details of the European balancing platforms. The question is rather – taking into account the planned go-live of the European balancing platforms in the near future – whether it is desirable, if it would appear to be feasible, to implement the scarcity component before the go-live of MARI/PICASSO. It seems appropriate to await the go-live of both MARI and PICASSO before launching the scarcity component, ensuring that it is future-proof from the start. This is further discussed in section 7.4.2.

Finally, it is to be noted that there is an explicit request from market parties – deriving from the feedback received during the public consultation period – to be involved in the omega component calculation methodology.

7.2 IT implementation track

Several IT developments are required towards a go-live of a Belgian scarcity component, applicable to Belgian BRPs. No detailed estimations have been made thus far, since the design of the scarcity pricing mechanism for Belgium is still under study. Note that therefore a period of 3 months is reserved in the summarizing timeline (cf. Figure 23 below) to account for such detailed workload estimations and a planning to be made, after the design choices are assumed final.

Of course, only these detailed estimations can lead to a final IT implementation track. Generally however, based on previous experiences, the following required developments can been identified, with indicative lead times:

- ✓ **Development for calculation of scarcity component & integration in imbalance price calculation**

A first important step entails the necessary developments to calculate the scarcity component. While it is assumed that this calculation can build further on the current processes to calculate scarcity price adders that are published on D+1

[95]This information can be consulted on the Elia website on **https://www.elia.be/en/grid-data/balancing/energy-available-volumes-and-prices**

basis on the Elia website[96], it is to be confirmed when addressing the implementation in more detail whether the transfer to the real-time would reveal unexpected issues to be also solved.

Besides some small modifications to the formula to bring the calculation in line with Elia's alternative scarcity pricing proposal and in particular the formula presented in section 6.1.5, more important will be the changes that result from the omega calculation methodology revision track described in section 7.1. This development is likely to require other input data to be used for the calculation. However, without having a view on the exact design of such future-proof and robust calculation methodology, it is very difficult to correctly estimate the IT development time for this task.

After the developments to calculate omega, another IT development is required to integrate this component in the imbalance price calculation methodology.

Once the design is final and "frozen", and a detailed planning has been made, a total lead time of **6 months** is estimated for this development.

- ✓ **Development for integration of scarcity component in 15-minute imbalance price publication**

The calculated scarcity component needs to be integrated in the 15-minute publication of the imbalance price, published on the following web page of the Elia website: **https://www.elia.be/en/grid-data/balancing/imbalance-prices-15-min**.

A lead time of **2 months** is estimated for this development.

- ✓ **Development for integration of scarcity component in 1-minute imbalance price publication**

On the Elia website, imbalance prices are not only published on 15-minute basis, but also on 1-minute basis, as non-validated values and only for informational purposes. The 1-minute values are published on the following web page of the Elia website: **https://www.elia.be/en/grid-data/balancing/imbalance-prices-1-min**. To remain consistent, Elia believes that the calculated scarcity component should also be integrated in the 1-minute publication.

A lead time of **2 months** is estimated for this development.

- ✓ **Development for adaptions to imbalance invoicing**

The scarcity component influences the imbalance price and therefore also has an impact on the imbalance invoicing, which requires a development before the go-live of the scarcity component.

A lead time of **3 months** is estimated for this development.

- ✓ **Development for transparency purposes**

The calculation of the omega component is the result of various individually calculated inputs, which are relevant and interesting on their own as well. Think about the remaining margin, which is in the current D+1 calculation constructed from the available regulation capacity (ARC) components and a calculated value for the margin available from pumped

[96] The 'adder energy' as published on **https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation**

hydro storage units[97]. Hence, a further IT development might be required to increase transparency (or even develop as such) the close to real-time input values that determine the omega component.

An (optional, i.e. depending whether such aspects would be identified in a detailed design) lead time of **2 months** is estimated for this development.

- ✓ **Dry-run of omega component calculation after go-live of PICASSO/MARI platforms**

Following up on the omega calculation methodology revision track described in section 7.1, it seems appropriate to foresee a dry-run of the omega component calculation after the go-live of PICASSO/MARI. This allows to verify if the changes to the calculation methodology that are made to appropriately account for the capacity available for activation on the PICASSO/MARI platforms, actually work out. Indeed, during the omega calculation methodology revision track, while the implementation details are expected to be known, no testing can take place until the platforms effectively go-live. This dry-run should be followed up from IT perspective, further developing IT processes where needed.

A lead-time of **5 months** is estimated for this development.

7.3 Regulatory implementation track

The regulatory implementation track covers the aspects of the implementation of the alternative scarcity pricing component requiring an approval by the relevant regulator, i.e. CREG and for the Terms and Conditions BRP also VREG.

The envisaged scarcity component 'omega' is to be seen as an additional component in accordance with Art. 9(6)(a) of ACER's adopted methodology on Imbalance Settlement Harmonization. The said Art. 9(6) reads (own underlining):

> *"The connecting TSO or connecting TSOs of an imbalance price area may propose in the Member State's terms and conditions for BRPs the conditions and a methodology to calculate additional components, to be included in the imbalance price calculation. In that case, this TSO or these TSOs shall propose one or more of the following additional components:*
>
> > *(a) a scarcity component to be used in nationally defined scarcity situations;*
> >
> > *(b) an incentivising component to be used to fulfil nationally defined boundary conditions;*
> >
> > *(c) a component related to the financial neutrality of the connecting TSO."*

Following this stipulation and in particular the fact that the additional component is "*to be included in the imbalance price calculation*", Elia judges that the scarcity component should be regarded as a tariff component and hence its introduction requires an evolution of the CREG approved tariffs. This is described further in section 7.3.1.

Next, this stipulation also mentions a required evolution of the terms and conditions for BRPs. This is discussed further in section 7.3.2.

[97] However, note that the calculation methodology might be adapted based on the revision track described in section 7.1. Nevertheless, transparency regarding the inputs in general is expected to remain relevant.

Finally, it remains to be investigated whether the above described evolutions will also trigger a required evolution of the balancing rules. This is described further in section 7.3.3.

7.3.1 Evolution of the tariff

It is our understanding from the description in Art. 9(6)(a) of ACER's adopted methodology on Imbalance Settlement Harmonization that the tariff should at least contain a description of the general characteristics of the omega component, summarizing when, where and how this component applies in the tariffs for maintaining and restoring the individual balance of BRPs. In addition, it is also deemed appropriate to include the more stable parameters that are used in the calculation of omega, such as the VOLL or the relevant reference to where it is determined for Belgium, in the tariff. Moreover, there should also be alignment between the tariff and the T&C BRP, which is further discussed in section 7.3.2.

Following Art. 12, §8 of the Electricity Act[98], the introduction and approval procedure for tariff proposals is the subject of an agreement between the CREG and Elia. Such an agreement has been concluded on 6 February 2018.

A legal basis for an evolution of the tariff in light of the introduction of a scarcity price component during the regulated period can thus be found in Art. 19 of this agreement:

> in Dutch:
>
> *"In geval van invoering van een nieuwe gereguleerde activiteit of van aanpassing van de bestaand gereguleerde activiteiten in de loop van de regulatoire periode kan Elia een geactualiseerd tariefvoorstel ter goedkeuring voorleggen aan de CREG.*
>
> *Het geactualiseerde tariefvoorstel gebruikt het naar behoren ingevulde ex ante rapporteringsmodel, zoals opgenomen in bijlage 1 van de tariefmethodologie."*
>
> or in French:
>
> *« En cas de création d'une nouvelle activité régulée ou d'adaptation des activités régulées existantes au cours de la période regulatoire, Elia peut soumettre une proposition tarifaire actualisée a !'approbation de la CREG.*
>
> *La proposition tarifaire actualisée utilise le modèle de rapport « ex ante » dûment complété, tel que contenu a l'annexe 1 de la méthodologie tarifaire »*

Taking into account the timings described in this agreement, the following steps, with (indicative) timings, need to be followed in the context of an updated tariff proposal:

- ✓ **Development of tariff proposal by Elia** → *2 months*
- ✓ **Organization of public consultation by Elia** → *3 – 6 weeks*

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[98] Federal Electricity Act of 29 April 1999 on the organization of the Belgian electricity market

✓ **Redaction of the consultation report and introduction of the proposal by Elia**	→ *4 weeks*
✓ **Questions from CREG**	→ *max. 20 calendar days*
✓ **Answers of Elia**	→ *max. 15 calendar days*
✓ **Notification approval/refusal by CREG**	→ *max. 63 days after receipt of proposal*
✓ **Publication of decision (if approval)**	→ *max. 3 working days after notification*

However, in case the tariff proposal is refused, the following additional steps need to be taken:

✓ **Demand to have a hearing by Elia**	→ *max. 3 calendar days after notification of refusal*
✓ **Hearing**	→ *max. 5 calendar days after demand*
✓ **Amended proposal by Elia**	→ *max. 15 calendar days after receipt of refusal*
✓ **Notification approval/refusal by CREG**	→ *max. 15 calendar days after receipt of amended proposal and max. 3 months after introduction of the initial proposal*
✓ **Publication of decision**	→ *max. 3 working days after notification*

To summarize, considering the above described process, a total lead time ranging from **5 months to 7,5 months** is to be expected for an evolution of the tariff proposal.

7.3.2 Evolution of T&C BRP

Art. 9(6)(a) of ACER’s adopted methodology on Imbalance Settlement Harmonization also explicitly mentions the T&C BRP, for what concerns the conditions and methodology to calculate additional components.

Hence, one option could be to include the detailed formula to calculate omega for each ISP in the T&C BRP. Moreover, in such case, Elia deems it appropriate that the T&C BRP would also define the methodology to determine the parameters used as input in the calculation of omega and that are updated on a regular basis. For instance, the mean (μ) and standard deviation (σ) parameters that define the LOLP function (cf. section 6.1.5) require an update each year. Rather than fixing the value of these parameters in the regulatory documents (which requires a yearly evolution of these documents), it is deemed more appropriate to embed only the methodology to calculate these parameters in the regulatory documents and hence to submit this methodology for validation.

However, note that in the current T&C BRP, a reference is already included in Art. 29 to the “Tariff for maintaining and restoring the individual balance of Balance Responsible Parties and the Tariff for external inconsistency”. Therefore, another option could be to include the above-mentioned conditions and methodology to calculate additional components rather in the tariff proposal. The T&C BRP then merely require the correct reference to the relevant passages of the tariffs.

Regardless of the option ultimately pursued, it will in any case be crucial to ensure the necessary alignment between the tariff and the T&C BRP.

To adapt the T&C BRP, the following steps, with (indicative) timings, need to be followed:

✓ **Development of request for amendment (RfA) to the T&C BRP by Elia**	*→ 2 months*
✓ **Organization of public consultation by Elia**	*→ 1 month (minimum duration in accordance with Art. 10 of the EBGL)*
✓ **Approval process (incl. the redaction of the consultation report & the introduction of RfA to the T&C BRP by Elia & the approval by the regulator)**	*→ 2 – 4 months*
✓ **Notification of the approved RfA to the T&C BRP to the BRPs**	*→ 1 month*
✓ **Entry into force**	*→ min. 14 days after notification (in accordance with Art. 10.1 of the BRP contract)*

However, in case of requests for amendment formulated by the regulator, a reiteration of the development of the T&C BRP and the approval process is required. This is expected to add an additional 2 – 4 months to the process.

To summarize, considering the above described process, a total lead time ranging from **6,5 months to 12,5 months** is to be expected.

7.3.3 Evolution of balancing rules

While the previous evolutions followed directly from the stipulations in Art. 9(6)(a) of ACER's methodology on Imbalance Settlement Harmonization, the balancing rules are not explicitly mentioned. However, note that Art. 27 of the balancing rules mentions a monitoring regarding the evolution of the tariff component alpha. Hence, a similar kind of monitoring may be required regarding the omega tariff component. Hence, an evolution of the balancing rules cannot be excluded.

However, Elia believes that this process can be done in parallel with the process for the evolution of the T&C BRP and will therefore not trigger any additional lead time.

7.4 Summarizing timeline

On the one hand, this section presents all above individually described implementation tracks on a summarizing timeline, presented in Figure 23 below and further described in section 7.4.1. In this respect, special consideration is given to the developments that can take place in parallel. On the other hand, section 7.4.2 discusses whether an implementation of the scarcity component by the end of 2021 is deemed feasible, taking into account in particular the summarizing timeline.

7.4.1 Summarizing timeline

An important parameter in the summarizing timeline is the start date, which requires a finalized design. Here it is assumed that the detailed design choices regarding the scarcity pricing mechanism for Belgium will be final by the end of Q2 2021, so that implementation can start based on confirmed design choices as of Q3 2021. This assumption is driven by the fact that in 2020, an incentive was ongoing (of which this implementation plan forms part) in which Elia assessed the design of scarcity pricing mechanisms for Belgium, based on a proposal from UCL CORE and own identified alternative proposals. After public consultation on Elia's preliminary findings, Elia has submitted its final report (i.e. this report) to CREG on December 7, 2020. Taking into account the necessary lead times to complete the omega calculation methodology revision track to ensure the future-proofness and robustness of the omega calculation, by the end of Q2 2021 a final design for a scarcity pricing mechanism to be implemented in Belgium is considered to be already quite ambitious.

The timeline for the omega calculation methodology revision track includes on the one hand a high-level estimation of the time required to develop the design principles of a future-proof and robust omega calculation methodology, which should be completed before the IT and regulatory implementation tracks can start. On the other hand, this track also includes an estimation of the time to be foreseen for a dry-run of the reviewed omega calculation methodology to verify its good functioning when the PICASSO and MARI platforms are effectively live and to allow the market to further familiarize with the concept. For this dry-run, there is a clear link with the IT implementation track, as necessary IT developments may follow from the dry-run process.

For the IT implementation track, only high-level estimated timings are provided. A preparation period is foreseen before actual IT developments can start for determining a detailed IT scope and planning. Again, this may influence the actual IT implementation track. The lead times indicated for the IT developments are based on previous experience and only provide high-level estimates.

Finally, the timeline regarding the regulatory implementation track determines specific processes including several minimum legal requirements, describing actions relevant for Elia (in yellow), Elia & market parties (in orange) and the regulator(s) (in blue). For all three identified documents that have to evolve, the process first consists of a development of a proposal, or Request for Amendment in case of the T&C BRP, by Elia and a public consultation of market parties afterwards. Next comes the drafting of the consultation report and the submission of a final proposal/RfA by Elia, followed by an approval process including the regulator(s). Finally, a decision is made and the changes apply. In case of an evolution of the T&C BRP, this final step includes a notification to BRPs, 14 days later followed by entry into force.

Note that the below timeline assumes that all three documents can be adapted in parallel. This would be most efficient from a timing point of view. However, if any of the documents is involved in another adaption process, this assumption may not hold anymore, with an expected impact on the overall timings. Note also that some time is already indicated for contingencies. These cover only a non-agreement on some aspects related to the scarcity component project that require an adaptation to the proposal and a reiteration of the approval process. Other elements such as for instance a delay caused by another project that also requires an evolution of the specified document, are not included. Note finally that no specific consideration is given to holiday periods in this summarizing timeline, which can of course have an impact on the lead times. For instance, it may be impossible to complete the approval processes during the summer months, or at least this could require more time to complete these processes. Likewise, organizing public consultations over typical holiday periods is to be avoided when reasonably possible.

7.4.2 End of 2021 implementation feasibility?

From the summarizing timeline presented in Figure 23 and further described in section 7.4.1, it can be concluded that a go-live of the scarcity component by the end of 2021 is not feasible.

Furthermore, concerning the regulatory implementation track in particular which is planned to start as from Q3 2021, several documents are perceived to evolve in parallel. Moreover, other evolutions of these regulatory documents may obstruct the timings as presented below. Note that regarding the T&C BRP, several other projects are ongoing that might also require an evolution of the T&C BRP over the course of 2021/2022, such as the MARI/PICASSO implementation, adaptations to Transfer of Energy (ToE) Day-Ahead/Intra-Day and/or adaptations to the day-ahead balance obligation.

Moreover, even if a go-live by the end of 2021 would have been feasible, it would have required the methodology to calculate available capacity to be activated in other European countries to change only some months after the scarcity component has been implemented, i.e. when the PICASSO and MARI platforms go live. Besides, such change in calculation would also have to be foreseen and described in the regulatory documents, thereby complicating its development further (with possible influence on timings) and blurring the transparency regarding the calculation of the scarcity component towards the market.

Finally, market parties insist on maintaining a realistic implementation track and to give priority to other ongoing implementation tracks, in particular regarding the implementation of the PICASSO and MARI platforms, which already require a lot of resources from all parties involved. In this respect, Febeg explicitly conforms that an implementation by the end of 2021 is not feasible.

To summarize, according to Elia, confirmed by the received feedback from market parties and notwithstanding the open question on the desirability of the implementation, an implementation of the envisaged scarcity component by the end of 2021 is not feasible, and is not the most appropriate option. Rather, Elia believes it is more appropriate to target a go-live of the scarcity component after the go-live of the European balancing platforms PICASSO & MARI. It is also requested by market parties to give priority to the implementation of PICASSO & MARI. Therefore, the current implementation plan foresees a go-live of the scarcity component by Q4 2022.

However, note that the implementation plan at this stage is still preliminary, pending a final decision on the implementation of the proposed alternative scarcity pricing proposal and subject to a feasible integrated planning taking into account also other 'must do' projects.

A go-live by Q4 2022, compared to the end of 2021 target suggested by CREG, would have the following advantages:

● *It means that only one methodology to calculate the scarcity component is to be included in the regulatory documents, which reduces complexity and improves transparency towards market parties.*

● *It ensures stability of the calculation of the scarcity component, not requiring adaptations at the go-live moments of the balancing platforms. Otherwise, multiple changes to the mechanism may be needed even during the first months of operation. This is not deemed desirable, especially not towards market parties who, besides getting accustomed to a new tariff component, would also have to anticipate multiple change to this component right after its introduction on top of the anyway already changing context due to the introduction of MARI and PICASSO.*

● *A go-live date of the scarcity component in Q4 2022 should allow some time to perform a dry-run of the calculation of the scarcity component. The correctness and robustness of the calculated scarcity component is deemed very* *important especially when this component is integrated in the imbalance tariff. Also, it allows the market to further familiarize with the concept, also with MARI and PICASSO already being up and running.*

In addition, it leaves some more time to finalize the design of the scarcity component at the beginning of 2021, allowing sufficient time to review the omega calculation methodology with respect to future-proofness and robustness. Such timing would also ensure market parties can be sufficiently involved in the discussions on such new mechanism.

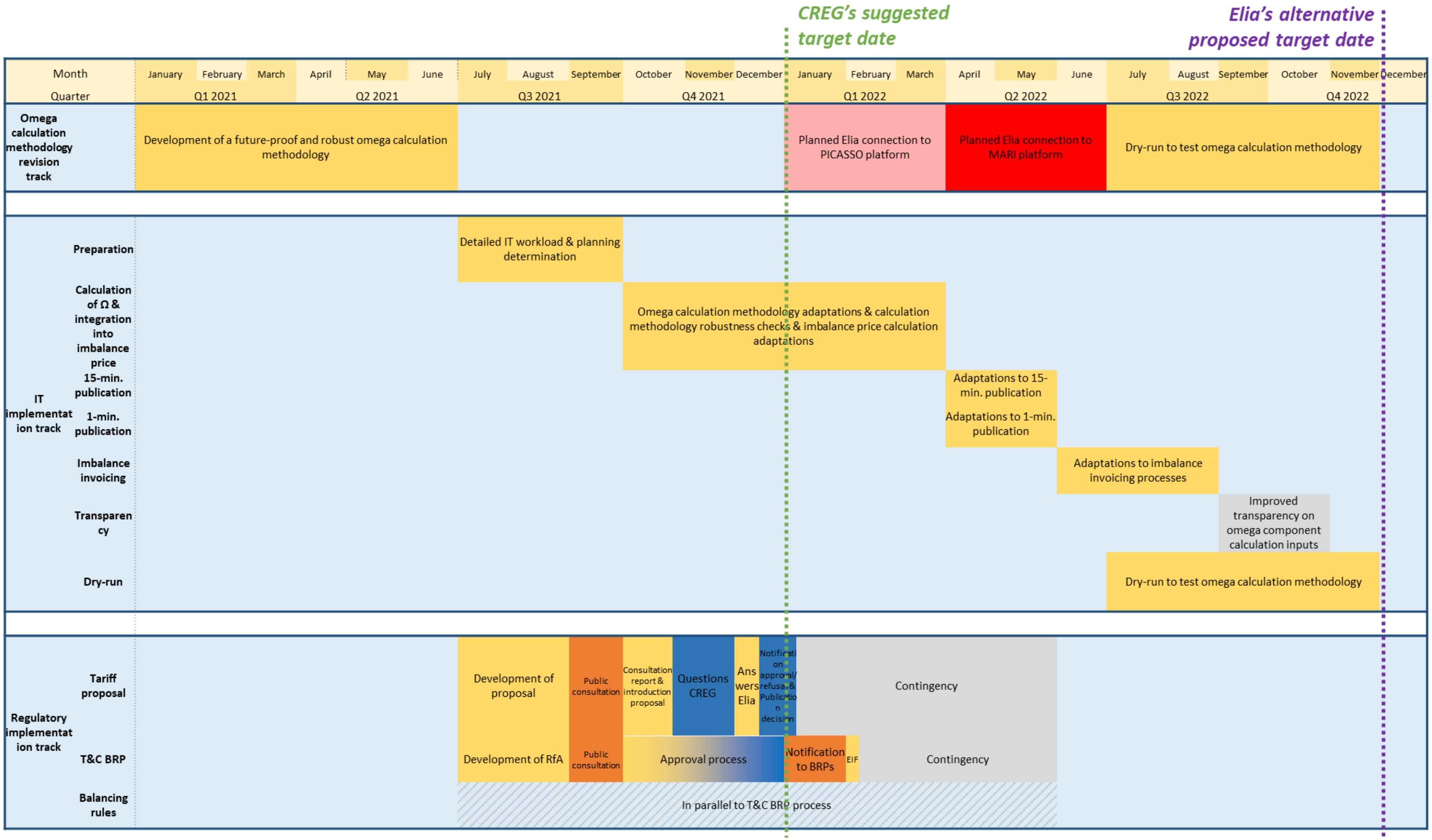

Figure 23: Scarcity component implementation plan (summarizing timeline)

Annex I: Legal aspects relating to the introduction of a “scarcity pricing” mechanism in Belgium by Liedekerke

Liedekerke wolters waelbroeck kirkpatrick

Legal aspects relating to

the introduction of a "scarcity pricing" mechanism in Belgium

From: Liedekerke (Damien Verhoeven and Lola Malluquin)

To: Elia

Date : 24 September 2020

Ref.: RERDAV2007

Executive summary

1. **The implementation of a "scarcity pricing mechanism**" (i.e. an administrative intervention in the energy market to ensure that real-time prices reflect the value of energy under stressed conditions) **is in principle excluded by EU law**:

   - It is an external intervention in price setting in contradiction with the core principle of EU energy law that electricity prices are freely determined by the market (set in both Electricity Regulation 2019/943 and Electricity Directive 2019/944) (I).

   - It incorporates a "price-adder" in wholesale prices, thus sets a minimum price limit in contradiction with Regulation 2019/943, esp. Art. 10(1) that prohibits external influence on wholesale market prices (incl. balancing energy prices). The prohibition of scarcity pricing mechanisms is confirmed by the recitals of the Regulation, stressing that prices reflecting scarcity should form naturally from the market, whereas price caps should be removed (II).

2. **As an exception** (set in Art. 20(3) c) of Regulation 2019/943)**, Members States may apply a** "shortage pricing function" (i.e. a **scarcity pricing mechanism**) ***to BRPs* in order to cover the costs related to balancing**, when an adequacy concern is identified.

   No other exception is created to introduce scarcity pricing mechanisms: neither in Regulation 2019/943, nor in Directive 2019/944 (PSOs taking the form of supply price interventions are only allowed for final customers, i.e. in circumstances not relevant in the case of scarcity pricing mechanisms).

   Any other form of scarcity pricing mechanism seems thus not allowed (III).

3. **A scarcity pricing mechanism *applied on BRPs only* should be self-financed and, hence, will in principle not be interpreted as involving State aid (in absence of intervention of State resources).**
   Conversely, a scarcity pricing mechanism *applied (i.a.) on BSPs* (irrespective whether the service is sourced by generation means or demand-side management), (provided that it would be technically possible to design it and) **provided that it is financed by State resources, risks to be viewed as an illegal form of "aid for generation adequacy" according to the current EEAG** (IV).

1. This note further expands on the legal aspects that must be taken into consideration in the context of the possible introduction of a "scarcity pricing" mechanism in the Belgian electricity markets.

For this purpose, a "scarcity pricing mechanism" is understood as an administrative intervention in the energy market to ensure that real-time prices reflect the value of energy under stressed conditions.

Such a mechanism can have many different designs. Two of those would be:

- to apply a "price adder" to all real-time prices, which (in the European market) include:
    - the balancing price applicable to balancing responsible providers ("BRPs"), i.e. the imbalance tariff;
    - the balancing energy price paid by the TSO to balancing services providers ("BSPs");
    - the reservation price paid by the TSO to BSPs;
    - the price paid[1] to standby non-contracted reserves.
- to apply a price adder only on the imbalance tariff paid by the BRPs.

Based on the analysis below, we however conclude that only the second design, i.e. a scarcity pricing mechanism on BRPs, is allowed under the current EU legal framework.

[1] This price would not be applied currently in Belgium, but could be applied in the context of a scarcity pricing mechanism depending on the selected design.

I. PRINCIPLE OF MARKET-BASED ELECTRICITY PRICES

2. A scarcity pricing mechanism appears in first instance in contradiction with the principle that **electricity prices must be freely determined by the market**, without external intervention.

This principle is set in both the Electricity Regulation (No. 2019/943)[2] and the Electricity Directive (No. 2019/944)[3].

3. ***Regulation -*** Art. 3 of the Electricity Regulation stipulates (among the "principles regarding the operation of electricity markets"):

> *"a) prices shall be formed on the basis of demand and supply"* and
> *"b) market rules shall encourage free price formation and shall avoid actions which prevent price formation on the basis of demand and supply".*

'Electricity markets' are defined as *"'markets for electricity, including over-the-counter markets and electricity exchanges, markets for the trading of energy, capacity, balancing and ancillary services in all timeframes, including forward, day-ahead and intraday markets"*[4].

Recital (22) mentions accordingly:

> *"Core market principles should set out that electricity prices are to be determined through demand and supply. Those prices should indicate when electricity is needed, thereby providing market-based incentives for investments into flexibility sources such as flexible generation, interconnection, demand response or energy storage".*

4. ***Directive –*** The Electricity Directive contains the same principle of electricity prices freely determined by the market.

Art. 5(1) of the Directive stipulates:

> "*Suppliers shall be free to determine the price at which they supply electricity to customers. Member States shall take appropriate actions to ensure effective competition between suppliers.*"

'Supply' is defined as "the sale, including the resale, of electricity to customers"[5] – thus not only sale to final customers[6], but also to customers who are not purchasing electricity for their own use (like a TSO buying power for balancing purposes).

Art. 3(3) and 3(4) of the Directive also require from Member States to ensure that no undue barriers exist within the internal market and to ensure a level playing field, incl. through non-discriminatory treatment.

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[2] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).
[3] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).
[4] Art. 2(9) of Electricity Directive.
[5] Art. 2(12) of Electricity Directive.
[6] As defined in art. 2(3) of the Electricity Directive, i.e. "*a customer who purchases electricity for own use".*

5. ***Contradiction of SP with EU principle –*** A scarcity pricing mechanism implies an external intervention in price setting (as a consequence of an administrative regime) and thus prevents the formation of purely market-based prices.

A scarcity pricing mechanism is therefore in contradiction with one of the core principles of EU energy law: market-based electricity prices. It could thus only be implemented as an exception to the principle, provided such an exception is admissible.

6. ***No impact of an action on the demand curve? -*** Scarcity pricing mechanisms can use an artificially created demand curve, calibrated in such a way that prices raise when capacity becomes scarce. This is a "less invasive" intervention in price setting than acting directly on prices, since it leaves a scope for the market to operate. In our opinion however, it remains an external intervention in price setting[7] which is in principle forbidden: prices are not formed on the basis of the market, but on the basis of an administratively modified demand curve to better reflect scarcity. The modification of the demand curve is, by definition, not the consequence of actual demand. It can be viewed as a price adder, *c.q.* an indirect intervention in price setting.

This conclusion is *slightly* subject to interpretation, which could be impacted by the modalities of a scarcity pricing mechanism. Still, a scarcity pricing mechanism, as long as it is developed as an external intervention in price setting as a consequence of an administrative regime, is opposed to prices that are only the result of demand and supply.

In other words: as long as we speak of a scarcity pricing mechanism as defined for the scope of this opinion, it seems in contradiction with the core principle of market-based electricity prices. The fact that the mechanism would be based on a "demand curve" makes no difference as long as that demand curve is artificial and not the result of untouched market demand.

Additionally, the creation of an artificial demand curve would not be compliant with the prohibition of price-limits in wholesale markets and the duty to identify and eliminate measures restricting wholesale price formation (see the next section).

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[7] See *mutatis mutandis* the regime of maximum price for protected household customers in implementation of Art. 20 § 2 of the Electricity Act: the price is not capped at a predetermined level, but depends on the lowest commercial prices available and hence fluctuates with the market. In its opinion on the Belgian "implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures" referred to in Art. 20(3) of Regulation 2019/943, the EU Commission stressed that, despite following the market prices, this regime is a form of price regulation (Commission Opinion of 30.4.2020 pursuant to Article 20(5) of Regulation (EC) No 2019/943 on the implementation plan of Belgium, Brussels, C(2020) 2654 final (https://ec.europa.eu/energy/sites/ener/files/documents/adopted_opinion_be_en_0.pdf), p. 2 and 5:

> *"Belgium applies public interventions in the price setting for the supply of electricity to energy vulnerable household customers, [...]. The tariff is based on the lowest commercial tariff in the zone with the lowest network tariff and thus follows the evolution of market prices. [..]. Belgium commits to comply with Article 5 of Directive (EU) 2019/9441 (hereinafter "Electricity Directive") regarding market-based supply prices. [...] the Commission notes that the public intervention in prices applied in Belgium falls under Article 5(3) to (5) of the Electricity Directive, namely public interventions in the price setting for the supply of electricity [...]".*

II. PROHIBITION OF PRICE-LIMITS ON WHOLESALE MARKETS

7. Regulation 2019/943 contains a more specific prohibition of external influence on market prices, applicable to wholesale prices. This prohibition is also a limit to take into account in the context of the introduction of a scarcity pricing mechanism.

A scarcity pricing mechanism can indeed be viewed as a minimum limit (i.e. a floor) to wholesale electricity prices: the price incorporates the (administratively determined) "price-adder" and hence could not fall below the electricity price increased by that price-adder.

8. ***Prohibition of price-limits -*** Art. 10(1) of the Regulation 2019/943 precisely prevents Member States from applying such minimum limits to wholesale electricity prices, including balancing energy and imbalance prices:

> *"1. **There shall be neither a maximum <u>nor a minimum limit</u> to the <u>wholesale electricity price</u>. This provision shall apply, inter alia, to bidding and clearing in all timeframes and shall <u>include balancing energy and imbalance prices</u>**, 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."*[8]

Please note that "wholesale markets" is defined as including any power supply except to final customers lower than 600 GWh/year[9], as well as transport contracts.

9. ***Prohibition for TSOs to influence wholesale prices -*** According to Art. 10(3) of Regulation 2019/943, TSOs cannot change wholesale prices:

> "*Transmission system operators shall not take any measures for the purpose of changing wholesale prices".*

We understand that this provision applies to measures *other* than maximum or minimum limits to prices (which are already forbidden by Art. 10(1)).

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[8] Art. 10(2) of Regulation 2019/943 stipulates:

> "*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".*

[9] Art. 2(64) of Electricity Regulation defines 'wholesale energy market' as "wholesale energy market as defined in point (6) of Article 2 of Regulation (EU) No 1227/2011 of the European Parliament and of the Council"(i.e. REMIT).

Art. 2(6) of REMIT defines 'wholesale energy market' as "*any market within the Union on which wholesale energy products are traded".*

Art. 2(4) of REMIT defines 'wholesale energy products' as:

> *" the following contracts and derivatives, irrespective of where and how they are traded:*
> *(a) contracts for the supply of electricity or natural gas where delivery is in the Union; [...]*
> *(c) contracts relating to the transportation of electricity or natural gas in the Union;*
>
> *Contracts for the supply and distribution of electricity or natural gas for the use of final customers are not wholesale energy products. However, contracts for the supply and distribution of electricity or natural gas to final customers with a consumption capacity greater than the threshold set out in the second paragraph of point (5) [i.e. 600 GWh per year] shall be treated as wholesale energy products".*

10. ***Duty to identify and eliminate measures restricting wholesale price formation -*** More generally, measures contributing to restricting wholesale price formation must be identified and then eliminated or, if not possible, their impact on bidding behaviour must be mitigated (Art. 10(4) and (5)):

> *"Regulatory authorities or, where a Member State has designated another competent authority for that purpose, such designated competent authorities, shall identify policies and measures applied within their territory that could contribute to indirectly restricting wholesale price formation, including limiting bids relating to the activation of balancing energy, capacity mechanisms, measures by the transmission system operators, measures intended to challenge market outcomes, or to prevent the abuse of dominant positions or inefficiently defined bidding zones.*
>
> *5. Where a regulatory authority or designated competent authority has identified a policy or measure which could serve to restrict wholesale price formation it shall take all appropriate actions to eliminate or, if not possible, to mitigate the impact of that policy or measure on bidding behaviour. Member States shall provide a report to the Commission by 5 January 2020 detailing the measures and actions they have taken or intend to take".*

The duty to identify and eliminate *existing* measures restricting (even indirectly, or even if they could contribute to restrict) wholesale price formation seems to confirm the prohibition to implement *new* measures of this nature, which would be included in Art. 10(1).

Art. 10(1) of Regulation 2019/943 thus seems to prevent, as a principle, the introduction of any scarcity pricing mechanism applied to (or interfering on) wholesale markets.

11. ***Scarcity prices freely determined by the market -*** This interpretation is also supported by the Recitals of the Regulation 2019/943. Recital (24) in particular seems to confirm that the reflection of scarcity in pricing should come automatically, as a result of a well-functioning market, unaffected by i.a. external measures restricting price formation.

Moreover, Recital (24) specifies that in order to allow for scarcity prices to be formed naturally on the market, administrative caps should be removed.

The expression "scarcity *prices*" used in this Recital does not refer to an administrative intervention in the energy market (as opposed to the expression "scarcity pricing *mechanisms*" used in the rest of the present note). On the contrary, it here refers to prices "naturally" reflecting the value of scarcity, without external intervention.

A difference is made in Recital (24) between:

- the wholesale markets, where only "*scarcity pricing without price caps"* (i.e. prices resulting directly from the market) are allowed, and
- the retail markets, where prices to SMEs and household customers, as final customers, can be affected by price regulation (within the narrow limits set by Art. 5(3) and (4) of Directive 2019/944).

Recital (24) stipulates:

> "*Short-term markets improve liquidity and competition by enabling more resources to participate fully in the market, especially those resources that are more flexible. Effective scarcity pricing will encourage market participants to react to market signals and to be available when the market most needs them and ensures that they can recover their costs in the wholesale market.* ***It is therefore critical to ensure that administrative and implicit price caps are removed*** *in*

> *order to allow for scarcity pricing. When fully embedded in the market structure, short-term markets and scarcity pricing contribute to the removal of other market distortive measures, such as capacity mechanisms, in order to ensure security of supply. At the same time,* ***scarcity pricing without price caps on the wholesale market*** *should not jeopardize the possibility of offering reliable and stable prices to final customers, in particular household customers, small and medium-sized enterprises (SMEs) and industrial customers.*

In short, Recital (24) does not envisage the introduction of administrative minimum pricing on wholesale markets. It confirms the prohibition of introduction of such measure, as "non market-based".

12. Recital (25) also emphasizes that broad deviations from market principles are not consistent with the aim of achieving market-based processes and should thus be replaced by more targeted measures[10].

13. Note that it is unclear whether *all* intervention in wholesale prices would be forbidden as a principle. Art. 10(3) stresses that "*transmission system operators shall not take any measures for the purpose of changing wholesale prices*". This could be interpreted in the sense that the State or the regulatory authority could take such measures, provided:

- that they do not take the form of maximum or minimum limits to prices (forbidden in Art. 10(1));
- that the principle that prices are market-based (Art. 3) is taken into account, so that State intervention must be limited.

14. Anyhow, scarcity pricing *mechanisms* (understood as "an administrative intervention in the energy market to ensure the real-time prices reflect the value of energy under stressed conditions", i.e. an "artificially influenced price") – as opposed to scarcity prices resulting *from the market* (without external alteration) – do not seem to be compliant at least with the principles set by Regulation 2019/943.

III. LIMITED POSSIBILITY TO INTRODUCE SCARCITY PRICING MECHANISMS

15. A scarcity pricing mechanism is thus difficult to reconcile with Regulation 2019/943, especially Art. 10(1), and could only exist based on Art. 20(3) c) of Regulation 2019/943 through a scarcity pricing mechanism ("shortage pricing function") applied to BRPs.

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[10] Recital (25): "*Without prejudice to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union (TFEU), derogations from fundamental market principles such as balancing responsibility, market-based dispatch, or redispatch reduce flexibility signals and act as barriers to the development of solutions such as energy storage, demand response or aggregation. While derogations are still necessary to avoid an unnecessary administrative burden to certain market participants, in particular household customers and SMEs, broad derogations covering entire technologies are not consistent with the aim of achieving efficient market-based decarbonisation processes and should thus be replaced by more targeted measures.*"

III.1. Art. 20(3) c) of Regulation 2019/943: scarcity pricing mechanism on BRPs

16. Regulation 2019/943 authorizes one form of scarcity pricing mechanism, applied to BRPs.

Art. 20(3) c) requires that, if an adequacy resource concern is identified, Members States consider the introduction of a "*shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation (EU) 2017/2195*".

The said Art. 44(3) reads:

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

In other words: Member States may, when an adequacy concern is identified, apply a scarcity pricing mechanism ("shortage pricing function"), provided:

1) the mechanism applies to BRPs

2) it takes the form of an "additional settlement mechanism", separated from the imbalance settlement (i.e. the invoicing of energy volumes)[11] to settle the "the procurement costs of balancing capacity [...], administrative costs and other costs related to balancing"[12].

A scarcity pricing mechanism having those two features, i.a. *applicable **to BRPs***, would thus be authorized by the Regulation 2019/943, as an exception, in case of an adequacy problem, in order to cover other costs related to balancing than energy.

No such exception is created for scarcity pricing *applying to all real-time prices, incl. prices paid **to BSPs***.

17. ***Link between Art. 10(1) and 20(3) c): uncertainty without impact -*** The link between Art. 10(1) and Art. 20(3)(c) of Regulation 2019/943 is not clearly made.

According to a first interpretation, Art. 20(3) c) is best understood as an exception to Art. 10(1) when an adequacy resource concern is identified. Being an exception, it should be

[11] See art. 2(8) and 2(9) of Regulation 2017/2195:

> *(8) 'imbalance' means an energy volume calculated for a balance responsible party and representing the difference between the allocated volume attributed to that balance responsible party and the final position of that balance responsible party, including any imbalance adjustment applied to that balance responsible party, within a given imbalance settlement period;*
>
> *(9) 'imbalance settlement' means a financial settlement mechanism for charging or paying balance responsible parties for their imbalances;*

[12] It can be argued that the mechanism should be sized in such a way that it cannot give rise to incomes exceeding the balancing costs. Regulation 2017/2195 does not define what exactly is covered under the notion of "costs related to balancing". Understood broadly, those costs can include the costs incurred by BRPs to make sure that capacity is available/flexible enough in times of scarcity (thus investment costs).

construed restrictively as authorizing only mechanisms applying to balance responsible parties in order to cover the costs related to balancing.

According to a second interpretation, the possibility to set an additional settlement mechanism based on Art. 20(3) c) is not an exception but a possibility outside the scope of Art. 10(1). Such possibility could be explained if we consider that imbalance tariffs applicable to BRPs would not refer to wholesale prices. It could be assimilated to a (virtual) supply to the final customer who caused the imbalance (i.e. the BRP or the client who designated the BRP), or viewed as a mere grid tariff, outside any market.

Conversely, balancing energy prices paid to BSPs are prices for the supply of electricity to the TSO, who is not a final customer. They are therefore included in wholesale markets and, hence, subject to the prohibition of scarcity prices set in Art. 10(1).

In any event, the qualification of the link between Art. 10(1) and 20(3) c) of Regulation 2019/943 does not make an actual difference:

- The possibility of scarcity pricing mechanism applied to BRPs as stated in Art. 20(3) c) is a possibility, irrespective of whether it is a deviation from Art. 10(1) or a possibility outside the scope of Art. 10(1).

- The principle remains that supply prices have to be market-based and any deviation from this principle is of restrictive interpretation.

III.2. The Regulation fully harmonized the matter and excludes any other form of scarcity pricing mechanism than on BRPs

18. Under a strict interpretation, Regulation 2019/943 has fully harmonized the possibility to introduce scarcity pricing mechanisms, by

- ruling out minimum limits on wholesale prices incl. balancing prices (Art. 10(1)),
- except in case of adequacy concerns, where only a scarcity pricing mechanism on BRPs can be considered (Art. 20(3) c)).

In our opinion, this interpretation is the only possible one (see also III.3).

A Regulation fully harmonizes the topics that it regulates and does not leave space for implementation *c.q.* margin for the Member States. When confronted to a problem of adequacy, the member States would have no other choice than to consider the forms of remedies listed in Art. 20(3) c) and, if they are not sufficient, to implement a capacity mechanism taking into account the conditions in Art. 21sq.

Beside the text of Art. 10(1) and 20(3) c) of the Regulation, this analysis is reinforced by:

- The economy of the Regulation which establishes the free determination of prices by the markets as a core principle, and the consequence that any deviation from this principle has to be restrictively interpreted;

- Art. 5 of the Directive, that also states the principle of free determination of the prices by the market (Art. 5(1)) and only provides for a (very limited) derogation possibility for supply prices to some categories of final customers, i.e. vulnerable customers, or household and SMEs (Art. 5(3) and 5(6)). A contrario, for wholesale markets, no deviation from the free price setting is authorised.

III.3. No additional ground to regulate wholesale prices (e.g. as PSO based on the Directive)

19. In line with the aforesaid, we stress that we do not identify any other legal ground that would empower the Member States to regulate wholesale electricity prices.

20. Both the Electricity Regulation and the Electricity Directive establish the principle of free price setting by the market. The Regulation only sets an exception for scarcity pricing mechanisms on BRPs (Art. 20(3) c)) whereas the Directive only sets an exception for the supply to some categories of final customers (Art. 5(3) and (6)).

Conversely, we do not see any legal ground for any other form of scarcity pricing mechanisms (applied on wholesale markets).

This is confirmed by Recital (22) of the Directive, which states that the only way to regulate prices is through a possibility that is not applicable in the present case:

> *"Public interventions in price setting for the supply of electricity should be carried out <u>only as</u> public service obligations and should be subject to specific conditions set out in this Directive".*

21. ***No scarcity pricing mechanism as PSO* –** A scarcity pricing mechanism could not be introduced as a public service obligation.

Art. 9(2) of the Directive conditionally authorises the Member States to set public service obligations on undertakings operating in the electricity sector, i.a. in order to ensure the security of supply, which can take the form of price regulation measures.

A scarcity pricing mechanism is an external intervention in supply prices. Those mechanisms are indeed precisely designed with the aim to influence supply prices, to better reflect the degree of scarcity than what the market is able to reflect[13].

At first view, a scarcity pricing mechanism could be considered as a public service obligation (i.e. artificially raising prices in times of scarcity) imposed on undertakings operating in the electricity sector in order to ensure the security of supply (e.g. by triggering investments in flexible capacity).

However, this possibility is excluded by the Directive: <u>a scarcity pricing mechanism cannot be introduced as a public obligation (and thus cannot be introduced outside the hypothesis of Art. 20(3) c) of the Regulation, i.e. on BRPs</u>).

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[13] The balancing energy price paid by TSOs to BSPs is a supply price: the BSP sells electricity to the TSO. A scarcity pricing mechanism on the prices paid by BSPs would in any case at least be an *indirect* intervention in the supply prices: it would have an indirect effect on the (supply) prices of other European BSPs as well as on the rest of the wholesale supply market.
The question whether an imbalance tariff paid to TSOs by BRPs should be (partly) considered as a supply price (since the TSO resells the energy that it bought from the BSP to the BRP) is less easy to solve. However, it does not matter, since scarcity pricing mechanisms on BRPs are authorised by the Electricity Regulation.

Art. 9(2) last sentence of the Directive reads indeed:

> *"Public service obligations which concern the price setting for the supply of electricity shall comply with the requirements set out in Article 5 of this Directive".*

As explained above, Art. 5 sets as principle that supply prices (i.e. the price of any sale of electricity) are freely determined by the market, whereas exceptions allowing public interventions in price setting are (according to the Directive) conditionally authorised only for supply to some categories of final customers.

In other words, the Electricity Directive (Art. 9(2) j° 5) excludes a public intervention in price setting for wholesale markets (other than those authorised by the Regulation).

This conclusion is in line with the core principles of both the Regulation and the Directive, as well as with our interpretation of Art. 10(1) of the Regulation.

It is also confirmed by Recitals (22) and (23) of the Directive[14].

In the present case, it means that any other form of scarcity pricing mechanism than on BRPs is not allowed.

III.4. Confirmation through ACER's methodology on imbalance settlements?

22. ACER adopted on 15 July 2020 a methodology for the harmonisation of the main features of imbalance settlement, pursuant to art. 52(2) of Regulation 2017/2195[15].

Art. 9(6) of Annex 1 of this methodology could be viewed as a confirmation that a scarcity pricing mechanism would only be possible if applicable *to BRPs*.

Art. 9(6) of this methodology authorizes TSOs to apply three different forms of additional components to calculate the imbalance price, incl. a scarcity component (to be used in scarcity situations) or an incentivising component (e.g. to ensure balance):

> *"The connecting TSO or connecting TSOs of an imbalance price area may propose in the Member State's terms and conditions **for BRPs** the conditions and a methodology to calculate **additional components**, to*

[14] *"(22) Member States should maintain wide discretion to impose public service obligations on electricity undertakings in pursuing objectives of general economic interest. [...]. Nevertheless, public service obligations in the form of price setting for the supply of electricity constitute a fundamentally distortive measure that often leads to the accumulation of tariff deficits, the limitation of consumer choice, poorer incentives for energy saving and energy efficiency investments, lower standards of service, lower levels of consumer engagement and satisfaction, and the restriction of competition, as well as to there being fewer innovative products and services on the market. Consequently, Member States should apply other policy tools, in particular targeted social policy measures, to safeguard the affordability of electricity supply to their citizens. **Public interventions in price setting for the supply of electricity should be carried out only as public service obligations** and should be subject to specific conditions set out in this Directive. A fully liberalised, well-functioning retail electricity market would stimulate price and non-price competition among existing suppliers and provide incentives to new market entrants, thereby improving consumer choice and satisfaction.*

(23) Public service obligations in the form of price setting for the supply of electricity should be used without overriding the principle of open markets in clearly defined circumstances and beneficiaries and should be limited in duration".

[15] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Pages/Annexes-to-the-DECISION-OF-THE-AGENCY-FOR-THE-COOPERATION-OF-ENERGY-REGULATORS-No-18-2020.aspx, Annex 1

be included in the imbalance price calculation. In that case, this TSO or these TSOs shall propose one or more of the following additional components:

(a) ***a <u>scarcity component</u>*** *to be used in nationally defined scarcity situations;*

(b) ***an <u>incentivising component</u>*** *to be used to fulfil nationally defined boundary conditions;*

(c) a component related to the financial neutrality of the connecting TSO."

This can be viewed as a confirmation that scarcity mechanisms can only be applied *to BRPs*.

This is in line with Art. 20(3) c) of Regulation 2019/943 that refers to Art. 44(3) of Regulation 2017/2195 (that "*shall apply to balance responsible parties")* as only possibility to introduce a scarcity pricing function.

III.5. Doubts of the Belgian State in the implementation plan

23. In the context of the implementation plan filed for Belgium as a consequence of Art. 20(3) of Regulation 2019/943, the Belgian State seems to share at first view that a scarcity pricing mechanism can only be applied to BRPs, and that the possibility of an extension to BSPs needs further examination. The European Commission did not take position on the matter from a legal point of view. To our best knowledge, the Belgian State did not perform yet this further examination.

24. ***Implementation plan -*** In the implementation plan filed for Belgium to the European Commission on 25 November 2019, the Belgian State mentioned the possibility to integrate scarcity pricing in the Belgian market, based on CREG's initiatives. The Belgian State however stressed that, from a legal perspective, a scarcity pricing mechanism seems only possible if applied on BRPs (taking into account the applicable EU provisions). It reserved the possibility to extend the scope of such a mechanism to BSPs, but this is subject to a legal assessment:

> *"From a legal perspective, Art. 20.3 of Regulation (EU) 2019/943 requires scarcity pricing to be considered in case of identified resource adequacy concerns. More precisely, a shortage pricing function for balancing energy is put forward and explicit referral to Art. 44(3) of the Electricity Balancing Guideline is made.* ***The explicit referral to balancing energy on the one hand and on the other hand the precise scope of Art. 44(3) of the Electricity Balancing Guideline <u>explicitly referring to the Balancing Responsible Parties</u> (BRP) <u>triggers questions on the boundary conditions for the design of scarcity pricing mechanism</u>. For instance, <u>it remains to be assessed whether scarcity price-adders on the Balancing Service Providers (BSPs) could be conceived in this framework</u>.*** *Note that the alpha-component already present in the Belgian imbalance pricing mechanism relates to balancing energy and applies to BRPs (cf. infra)."*

25. ***Opinion of the European Commission -*** In its opinion on the Belgian implementation plan of 30 April 2020[16], the European Commission invited Belgium to assess whether a scarcity pricing function should apply not only to BRPs, but also to BSPs, stressing the advantages of this solution for security of supply.

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[16] Commission Opinion of 30.4.2020 pursuant to Article 20(5) of Regulation (EC) No 2019/943 on the implementation plan of Belgium, Brussels, C(2020) 2654 final (https://ec.europa.eu/energy/sites/ener/files/documents/adopted_opinion_be_en_0.pdf), p. 5: "*The Commission, however, invites Belgium* ***to consider whether*** *the scarcity pricing function should apply not only to BRPs but also to balancing service providers (BSPs). This may support security of supply* [...]"

The Commission hereby merely underlines the factual advantages of an extension of a scarcity mechanism to BSPs, but does not assess whether this would be legally valid under EU law. On the contrary, the opinion invites Belgium to examine this point. It further contains an explicit reservation as to the compatibility of any measure mentioned in the plan with EU law: *"The Commission's position on this particular notification is without prejudice to any position it may take on the compatibility of any national implementing measure with EU law".* The opinion is not a legal analysis, and is merely building upon the Belgian State's proposal backed up by CREG.

26. ***Amended plan -*** In the amended implementation plan of 22 June 2020[17] (taking into account the EC's opinion), the section re: scarcity mechanism is not modified. The Belgian State maintained its reservation, from a legal perspective, as to the compatibility with EU law of a scarcity pricing mechanism applying to BSPs, and its intention to further examine the question. This confirms at least that the Belgian State believes such compatibility is far from obvious. The previous analysis demonstrated that only a scarcity mechanism applying to BRPs is allowed, the EU-framework forbidding other forms of prices regulation.

IV. COMPLIANCE WITH STATE AID RULES

27. ***Premature assessment -*** Depending on its design, a scarcity pricing mechanism *could* be a State aid subject to the European Commission's approval.

The *actual* existence of a State aid (and if it is the case, whether the aid is acceptable) can however not be assessed yet: this is depending on the detailed modalities of a scarcity pricing mechanism, which are undefined at this stage.

The following elements are therefore merely indicative.

IV.1. Scarcity pricing mechanism on BRPs: no State aid?

28. We understand that a scarcity pricing mechanism applied on BRPs, in implementation of Art. 20(3) of Regulation 2019/943, would consist in a price-adder on imbalance tariffs.

As we understand it, such a mechanism would be self-financed (by the BRPs) within the "closed envelop" of balancing costs: a scarcity price adder integrated in the imbalance tariff that some BRPs get because of a long position during (near-) scarcity conditions, is paid by other BRPs that have to pay the scarcity price adder because they are short. The net result is that the BRPs in total have to pay the same or more than what (other) BRPs receive in total, if the scarcity price adder applies only during zero to negative system imbalances. .

In presence of such a financing by the market, a scarcity pricing mechanism on BRPs would most likely *not* qualify as a State aid, (i.a.) due to the absence of intervention of State resources.

[17] https://economie.fgov.be/sites/default/files/Files/Energy/Belgian-electricity-market-Final-implementation-plan-CRM-22062020.pdf.

This conclusion is however subject to a slight uncertainty, because the interpretation of the condition of implication of State resources gives rise to rather unpredictable case-law[18].

IV.2. Scarcity pricing mechanism on all real-time prices: State aid risk

29. As explained above, a scarcity pricing mechanism on all real-time prices (i.e. applicable to both BRPs and BSPs) – provided that it would be technically possible to design it - seems not allowed by EU energy law. The State aid question is therefore not applicable, because such a mechanism cannot be developed.

30. If this element is ignored, a scarcity pricing mechanism on all real-time prices raises questions on State aid level, especially for its application to BSPs.

With the possible exclusion of the State resources, the other criteria of State aid are a priori met (i.e. conferring an advantage to economic undertakings, being selective and having an effect on trade / distorting competition). A scarcity pricing mechanism applicable to BSPs would indeed:

- lead to prices that are higher than prices based on “normal” demand and supply (thus conferring an advantage to those benefitting from that raise);
- benefit only flexible capacity, to the exclusion of other forms of electricity generation;
- give an advantage only to national BSPs, thus affecting foreign BSPs.

31. ***Inclusion of State resources? -*** Whether it would be a State aid will thus depend mostly on the way the mechanism is financed. If financed by State resources, the mechanism would likely qualify as a State aid.

Whether the mechanism is financed by “State resources” is however a delicate question whose answer depends on the specifics of the mechanism, that are not known yet.

In case of scarcity pricing mechanism on all real-time price, there is at least a risk of qualification as State aid.

32. ***Non-compliance with EEAG? -*** If the mechanism is a State aid, its validity would have to be subject to the EC’s appreciation, currently and until the end of 2021 as developed in the Guidelines on State aid for environmental protection and energy 2014-2020 (‘EEAG’)[19].

The EEAG do not directly consider the hypothesis of a scarcity pricing mechanism on BSPs as one of the discussed forms of state aid. This could be because such mechanisms are not allowed by EU law (see above).

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[18] I.a. a measure adopted by a public authority and favouring certain undertakings or products does not lose the character of a gratuitous advantage by virtue of the fact that it is wholly or partially financed by contributions imposed by the public authority and levied on the undertakings concerned (CJEU 22 March 1977, *Steinike & Weinlig*, 78/76, ECLI:EU:C:1977:52, paragraph 22).

[19] Communication from the Commission, 2014/C 200/01, *Guidelines on State aid for environmental protection and energy 2014-2020,* (225). The application period of those EEAG is extended until 2022.

Depending on its modalities and goal, a scarcity pricing mechanism applicable to BSPs (irrespective whether the service is sourced by generation means or demand-side management) could however be viewed as an "aid for generation adequacy" in the sense of section 3.9 of the EEAG[20]. This will probably be the case, since the existence of an adequacy concern is a condition for a shortage pricing function (according to Art. 20(3) of Regulation 2019/943).

If qualified as an aid for generation adequacy, a "balancing energy price" paid to BSPs for the capacity activated in times of scarcity seems contrary to § (225) of the EEAG, stating that:

> *"the aid should remunerate solely the service of pure availability provided by the generator, that is to say, the commitment of being available to deliver electricity and the corresponding compensation for it, for example, in terms of remuneration per MW of capacity being made available. The aid should not include any remuneration for the sale of electricity, that is to say, remuneration per MWh sold".*

Furthermore, a generation adequacy measure should be proved to be necessary to achieve generation adequacy, proportionate and designed so as to minimize negative effects on competition and trade. Especially, the measure should comply with §§ (232) and (233) of the EEAG, which stipulate:

(232) The measure should be designed in a way so as to make it possible for any capacity which can effectively contribute to addressing the generation adequacy problem to participate in the measure, in particular, taking into account the following factors:

(a) the participation of generators using different technologies and of operators offering measures with equivalent technical performance, for example, demand side management, interconnectors and storage. Without prejudice to the paragraph (228), restriction on participation can only be justified on the basis of insufficient technical performance required to address the generation adequacy problem. Moreover, the generation adequacy measure should be open to potential aggregation of both demand and supply;

(b) the participation of operators from other Member States where such participation is physically possible in particular in the regional context, that is to say, where the capacity can be physically provided to the Member State implementing the measure and the obligations set out in the measure can be enforced;

(c) participation of a sufficient number of generators to establish a competitive price for the capacity;

(d) avoidance of negative effects on the internal market, for example due to export restrictions, wholesale price caps, bidding restrictions or other measures undermining the operation of market coupling, including intra-day and

[20] According to § (19) 34) and 36) of the EEAG,

- 'generation adequacy' means a level of generated capacity which is deemed to be adequate to meet demand levels in the Member State in any given period, based on the use of a conventional statistical indicator used by organisations which the Union institutions recognise as performing an essential role in the creation of a single market in electricity, for example ENTSO-E;
- 'generation adequacy measure' means a mechanism which has the aim of ensuring that certain generation adequacy levels are met at national level.

balancing markets.

(233) *The measure should:*

(a) not reduce incentives to invest in interconnection capacity;

(b) not undermine market coupling, including balancing markets;

(c) not undermine investment decisions on generation which preceded the measure or decisions by operators regarding the balancing or ancillary services market;

(d) not unduly strengthen market dominance;

(e) give preference to low-carbon generators in case of equivalent technical and economic parameters".

In other words, provided that a scarcity pricing mechanism applicable (i.a.) to BSPs is financed by State resources and is qualified as an "aid for generation adequacy", it would most probably be viewed as an illegal State aid (according to the current guidelines of the European Commission).