CREG

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Study

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Study on the implementation of a scarcity pricing mechanism in Belgium

carried out pursuant to Article 23, §2, second paragraph, of the Law of 29 April 1999 on the organisation of the electricity market

Non confidential

CREG - rue de l'Industrie 26-38, 1040 Bruxelles, Belgique
T +32 2 289 76 11 - F + 32 2 289 76 09 - www.creg.be

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INTRODUCTION

1. CREG has been working several years on the development of a scarcity pricing mechanism applicable to Belgium. Today, the design of the mechanism has been finalised and CREG considers that all elements are available to present and justify the design of the proposed mechanism to be applied in Belgium. Feedback of market participants on this study is expected and a workshop will be organised with that goal.

2. In order to achieve this goal, this study proceeds successively to:

    1) The presentation of the relevant legal framework

    2) The description of the reasons which have led to the examination of a scarcity pricing mechanism for Belgium

    3) A description of the chronology of the development of this mechanism in Belgium

    4) A presentation of the theoretical background

    5) The justification of the choices made for the proposed design

    6) A detailed description of the proposed design

    7) An estimation of the expected impact of the proposed design

    8) The justification of the legal compliance of the proposed design

    9) The provision of responses to Frequently Asked Question related to scarcity pricing mechanisms

3. The initial goal of the examination of a scarcity pricing mechanism was to address the concerns related to the profitability of CCGT units during the year 2014 and the announcement made that several of them may leave the market.

4. Today, with the energy transition, the system is undergoing fundamental changes linked to the introduction of renewables characterised by a lack of controllability, the inability (or the difficulty) to provide some ancillary services (reserves, inertia, voltage,..) and **low variable costs** (but important investments costs). As the remuneration coming from the short-term energy market may decrease due to this introduction of renewable resources, the remuneration coming from ancillary services and capacity will become critical.

5. Although these ancillary services came as by-product in a thermal system, this is much less the case in the new context where adequate (technology neutral) remuneration schemes compatible with the energy-only market design have to be developed.

6. With increasing amounts of electricity generation at low variable cost, solutions based on co-optimisation (energy, reserves, inertia,..) and in particular scarcity pricing mechanisms (a kind of co-optimisation of energy with the value of reserves on the basis of the “appetite” of consumers for reliability) will be more and more important for providing adequate price signals in short-term markets. These price signals are key in the functioning of energy-only markets for investment decisions.

7. Finally, given the existence of a Capacity Remuneration Mechanism (CRM) in Belgium, the implementation of the proposed scarcity pricing mechanism shall make sure that the expected revenues coming from short-term markets will materialise and shall provide increased incentives to make existing capacities available when most needed. Concerning T-1 capacity auctions, the existence

of a scarcity pricing mechanism should reduce the missing money issue and therefore should reduce the total costs of the procurement.

8. For the reasons mentioned above, the implementation of a scarcity pricing mechanism appears as a no-regret measure.

9. With this study, for the reasons explained in Chapter 2, it is proposed to implement, based on the process proposed in Chapter 10, a scarcity pricing mechanism as described in chapter 6 with the design justified in chapter 5.

10. The CREG considers that the consultation organised by ELIA in September 2020 on scarcity pricing is not adequate for the determination of a possible implementation of such a mechanism in Belgium. As it is the normal procedure, if a scarcity pricing mechanism has to be implemented, the CREG will consult market players when taking the decisions implementing the scarcity pricing mechanism. Additionally, the CREG will organise one-day virtual workshop with market players in order to discuss and exchange views on the design proposed in this study with stakeholders. Then, more "classical" or "mandatory" consultations will be organised at the occasion of the three Terms & Conditions decisions (for Balancing Responsible Parties – BRPs hereafter, aFRR Balancing Service Providers – BSPs hereafter - and mFRR BSPs) impacted by the implementation of a scarcity pricing mechanism

11. Recent work performed by the CORE[1], CREG's Consultant, are presented in the Annex of this study (4 papers).

12. The CREG expressly mentions that the present study does not settle the question of which national authority is competent to set up the scarcity pricing mechanism. This question is still being examined by the CREG.

13. This study was approved by the CREG's Board of Directors on 23 December 2021.

[1] Center for Operations Research and Econometrics of the UCLouvain

1. RELEVANT LEGAL FRAMEWORK

14. The most important legal requirements related to this study are recalled below.

1.1. 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 ("DIRECTIVE 944" HEREAFTER)

15. CHAPTER II GENERAL RULES FOR THE ORGANISATION OF THE ELECTRICITY SECTOR

Article 3 Competitive, consumer-centred, flexible and non-discriminatory electricity markets

1.Member States shall ensure that their national law does not unduly hamper cross-border trade in electricity, consumer participation, including through demand response, investments into, in particular, variable and flexible energy generation, energy storage, or the deployment of electromobility or new interconnectors between Member States, and ***shall ensure that electricity prices reflect actual demand and supply.***

This rule uses the term "reflect" and targets the principle (as obtained through a market mechanism maximising welfare or through continuous trade) and not a literal narrow interpretation corresponding to the intersection of the demand and offer curves. A market coupling with imports priced at the local price departs from this narrow interpretation.

1.2. REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL OF 5 JUNE 2019 ON THE INTERNAL MARKET FOR ELECTRICITY ("REGULATION 943" HEREAFTER)

16. Whereas:

(22) 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.

Prices should reflect needs for flexibility and demand response.

(23) ***While decarbonisation of the electricity sector, with energy from renewable sources becoming a major part of the market, is one of the goals of the Energy Union****, it is crucial that the market removes existing barriers to cross-border trade and encourages investments into supporting infrastructure, for example, more flexible generation, interconnection, demand response and energy storage. To support this shift to variable and distributed generation, and to ensure that energy market principles are the basis for the Union's electricity markets of the future, a renewed focus on short-term markets* ***and scarcity pricing*** *is essential.*

(24) 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.*

This whereas clearly indicates the importance of price reflecting scarcity. Note that scarcity pricing here does not distinguish scarcity bidding, by producers and consumers, and the recourse to a scarcity pricing mechanism. As explained in section 9.5 below, scarcity bidding by producers, if successful, is extremely difficult to distinguish from the exercise of market power.

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

As requested in Article 22, a scarcity pricing mechanism should be considered before a capacity mechanism. The fact that prices do not reflect scarcity, as requested for example by Whereas (24) above, can be considered as a distortion.

17. Article 3 Principles regarding the operation of electricity markets

*(a) prices shall be formed **based on demand and supply***

*(g**) market rules shall deliver appropriate investment incentives for generation, in particular for long-term investments in a decarbonised and sustainable electricity system**, energy storage, energy efficiency and demand response to meet market needs, and shall facilitate fair competition thus ensuring security of supply;*

With a scarcity pricing mechanism, prices are based on demand and supply (see section 8.3, 9.2 and chapter 4). As shown in sections 4 and 7.2 below, investment incentives are improved with a scarcity pricing mechanism, which is especially important for the energy transition.

Article 6 Balancing market

1. Balancing markets, including prequalification processes, shall be organised in such a way as to:

(a) ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response;

(c) ensure non-discriminatory access to all market participants, individually or through aggregation, including for electricity generated from variable renewable energy sources, demand response and energy storage;

…

*4. The settlement of **balancing energy** for standard balancing products and specific balancing products shall be **based on marginal pricing** (pay-as-cleared)…*

*5. The **imbalances** shall be settled at a price **that reflects the real-time value of energy**.*

The term “value” is mentioned here, which indicates that all essential components of the supply of electricity at a given location and time should be reflected in that price. An adequate valorization of reserves necessary for the reliability of the system is therefore required in the imbalance price.

Article 7 Day-ahead and intraday markets

*2.**Day-ahead and intraday markets shall**:*

*(d) **provide prices that reflect market fundamentals, including the real time value of energy, on which market participants are able to rely when agreeing on longer-term hedging products**;*

Same comment as above.

Article 10 Technical bidding limits

*1. **There shall be neither a maximum nor a minimum limit to the wholesale electricity price**. This provision shall apply, inter alia, to bidding and clearing **in all timeframes and shall include balancing energy and imbalance prices**, without prejudice to the technical price limits which may be applied in the balancing timeframe and in the day-ahead and intraday timeframes in accordance with paragraph …*

This paragraph forbid the implementation of a limit to the wholesale electricity price. A scarcity pricing mechanism, which provides an adder to the energy price resulting of the platforms is compliant with this requirement.

*4. **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.

***Article 20** Resource adequacy in the internal market for electricity*

1. …

3. Member States with identified resource adequacy concerns shall develop and publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures as a part of the State aid process. When addressing resource adequacy concerns, the Member States shall in particular take into account the principles set out in Article 3 and shall consider:

(c) introducing a shortage pricing function for balancing energy** as referred to in Article 44(3) of Regulation (EU) 2017/2195**;

This provision is very clear: a shortage pricing function, i.e. a scarcity pricing mechanism, should be considered for **the balancing energy** (i.e. the energy delivered by the Balancing Service Providers, or BSPs) and not for the imbalance (energy). More on this can be found in section 8.1 below.

Article 23 European resource adequacy assessment

5.The European resource adequacy assessment shall be based on a transparent methodology which shall ensure that the assessment:

*(e) **anticipates the likely impact of the measures referred in Article 20(3)**;*

This issue is mentioned in section 9.7 related to the interaction with a CRM.

1.3. COMMISSION REGULATION (EU) 2015/1222 OF 24 JULY 2015 ESTABLISHING A GUIDELINE ON CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

Article 41 Maximum and minimum prices

1. By 18 months after the entry into force of this Regulation, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single day-ahead coupling. The proposal shall take into account an estimation of the value of lost load. The proposal shall be subject to consultation in accordance with Article 12.

2. All NEMOs shall submit the proposal to the regulatory authorities for approval.

Where a Member State has provided that an authority other than the national regulatory authority has the power to approve maximum and minimum clearing prices at the national level, the regulatory authority shall consult the proposal with the relevant authority as regards its impact on national markets.

After receiving a decision for approval from all regulatory authorities, all NEMOs shall inform the concerned TSOs of that decision without undue delay.

By default, regulatory authorities are responsible/competent for the limitation of day-ahead clearing prices. Article 54 of the same guideline provides the same responsibility/competence for the intraday trade.

1.4. COMMISSION REGULATION (EU) 2017/2195 OF 23 NOVEMBER 2017 ESTABLISHING A GUIDELINE ON ELECTRICITY BALANCING ("BALANCING GUIDELINE" HEREAFTER)

18. Articles 4 to 7 of this Balancing Guideline have been replaced and the new articles are indicated in section 1.9 below.

Article 18 Terms and conditions related to balancing

1. No later than six months after entry into force of this Regulation and for all scheduling areas of a Member State, the TSOs of this Member State shall develop a proposal regarding:

(a) the terms and conditions for balancing service providers;

(b) the terms and conditions for balance responsible parties.

…

This provision of the Balancing Guideline indicates that the terms and condition for the balancing service providers and the terms and conditions for balance responsible parties are developed by each TSO individually. A direct consequence of this article is that these terms and conditions may not be the same as the terms and conditions of other TSOs provided that the general principles set in the Balancing Guideline are met.

3. When developing proposals for terms and conditions for balancing service providers and balance responsible parties, each TSO shall:

…

(b) respect the frameworks for the establishment of European platforms for the exchange of balancing energy and for the imbalance netting process pursuant to Articles 19, 20, 21 and 22;

…

4. The terms and conditions for balancing service providers shall:

…

(d) require that each balancing energy bid from a balancing service provider is assigned to one or more balance responsible parties to enable the calculation of an imbalance adjustment pursuant to Article 49.

This provision indicates the link between the balancing service provider and balancing responsible parties.

…

5. The terms and conditions for balancing service providers shall contain:

…

(i) **the rules for the settlement of balancing service providers defined pursuant to Chapters 2 and 5 of Title V;**

…

This provision clearly indicates that the terms and conditions related to Article 18 of the Balancing Guideline explicitly covers the way balancing service providers will be settled (i.e. the pricing rule). Combined with 18.1, this allows an unilateral implementation of country specific settlement rules, such as a scarcity component.

6. The terms and conditions for balance responsible parties shall contain:

…

(f) ***the rules for the settlement of balance responsible parties defined pursuant to Chapter 4 of Title V;***

This provision clearly indicates that the terms and conditions related to Article 18 of the Balancing Guideline explicitly covers the way balancing responsible parties will be settled (i.e. the pricing rule). Combined with 18.1, this allows an unilateral implementation of country specific settlement rules.

…

Article 30 Pricing for balancing energy and cross-zonal capacity used for exchange of balancing energy or for operating the imbalance netting process

1. By one year after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology to determine prices for the balancing energy that results from the activation of balancing energy bids for the frequency restoration process pursuant to Articles 143 and 147 of Regulation (EU) 2017/1485, and the reserve replacement process pursuant to Articles 144 and 148 of Regulation (EU) 2017/1485. Such methodology shall:

(a) ***be based on marginal pricing (pay-as-cleared);***

(b) define how the activation of balancing energy bids activated for purposes other than balancing affects the balancing energy price, while also ensuring that at least balancing energy bids activated for internal congestion management shall not set the marginal price of balancing energy;

(c) establish at least one price of balancing energy, for each imbalance settlement period;

(d) ***give correct price signals and incentives to market participants****;*

(e) take into account the pricing method in the day-ahead and intraday timeframes.

This article provides the requirements which have to be coordinated applicable to the pricing of balancing energy bids resulting from the frequency restoration process (mFRR – MARI – and aFRR – PICASSO) platforms.

CHAPTER 2 **Balancing capacity** Article 32 Procurement rules

…

2. Each TSO procuring ***balancing capacity*** *shall define the rules for the procurement of balancing capacity in the proposal for the terms and conditions related to balancing service providers developed pursuant to Article 18. The rules for the procurement of balancing capacity shall comply with the following principles:*

(a) the procurement method shall be market-based for at least the frequency restoration reserves and the replacement reserves;

(b) the procurement process shall be performed on a short-term basis to the extent possible and where economically efficient;

This article provides the principles for the procurement of balancing capacity (also referred as "reserves" in this study) to be followed when defining the terms and conditions related to BSPs developed pursuant Article 18 of the Balancing Guideline. These rules are national and shall comply with the two principles indicated above. These principles target the procurement of balancing capacity at the day ahead stage.

TITLE V SETTLEMENT CHAPTER 1 Settlement principles

Article 44 General principles

(1). The settlement processes shall:

(a) establish adequate economic signals which reflect the imbalance[2] *situation;*

If it refers to the local imbalance, this provision may be challenging to implement when implementing the EU balancing platforms. This concern disappears when the (global) imbalance situation is targeted.

(b) ensure that imbalances are settled at a price ***that reflects the real time value of energy****;*

This provision highlight the importance of prices reflecting the real time value of electricity, including, as an electric system requires reserves, the valuation of the costs of reserves. This provision also confirms that the regulator, which is responsible for the settlement of balancing responsible parties, is also responsible for the imbalance price formation.

[2] Note that a strict reading of this provision, on the basis of the definition of imbalance, which refers only to the imbalance of one BRP, makes this provision not applicable. We cannot imagine indeed that the signal will be different for all BRPs as their imbalance situation will be different.

(c) provide incentives to balance responsible parties to be in balance ***or help the system to restore its balance****;*

…

(f) ***avoid distorting incentives to balance responsible parties, balancing service providers and TSOs****;*

Settlement rules should not provide distorting incentives to Balancing Responsible Parties (BRPs), Balancing Service Providers (BSPs) and TSOs. This issue was examined carefully during the design of the proposed scarcity pricing mechanism (see Studies 4, 5 and 6 on market simulations).

(g) ***support competition*** *among market participants;*

(Fair) competition between market players located inside the bidding zone but also with foreign market players (through the balancing platforms) is key.

(h) ***provide incentives to balancing service providers to offer and deliver balancing services to the connecting TSO****;*

This provision is important as it can be shown (Studies **4, 5 and 6**) that the same remuneration/pricing for balancing responsible parties and balancing service providers, proposed as general rule in the development of a scarcity pricing mechanism, **provides the right incentives to balancing service providers to offer balancing services to the TSO**. To the contrary, a different remuneration or pricing applied to balancing responsible parties and balancing service providers (such as the Belgian Alpha) **may provide wrong incentives for not offering their whole capacity to the TSO** (and prefer self-balancing).

(i) ensure the financial neutrality of all TSOs.

*…****(3) 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****.*

This article shows the freedom provided to the TSOs (and NRAs) in the settlement process. In particular, this allows the addition of a scarcity adder (explicit mention of this possibility) for the settlement of balancing responsible parties. But other mechanisms may be envisaged, provided that they are approved.

CHAPTER 4 Imbalance settlement

Article 55 Imbalance price

…

4. The imbalance price for negative imbalance shall not be less than, alternatively:

(a) the weighted average price for positive activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

5. The imbalance price for positive imbalance shall not be greater than, alternatively:

(a) the weighted average price for negative activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

1.5. COMMISSION OPINION OF 30.4.2020 PURSUANT TO ARTICLE 20(5) OF REGULATION (EC) NO 2019/943 ON THE IMPLEMENTATION PLAN OF BELGIUM (COMMISSION OPINION HEREAFTER)

19. The view of the Commission on scarcity pricing mechanism related to the implementation of a capacity remuneration mechanism in Belgium can be found in the quote below:

The Commission is of the view that the 'alpha component' already exhibits certain characteristics of a scarcity pricing function. ***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 by ensuring that BRPs and BSPs face the same price for the energy produced/consumed,* ***as price differentiation may result in inefficient arbitrage from market players. The Commission also considers that the scarcity pricing function should be triggered by the scarcity of reserves in the system*** *and it should be calibrated to* ***increase balancing energy prices*** *to the Value of Lost Load when the system runs out of reserves. The Commission invites Belgium to consider amending its scarcity pricing scheme accordingly by no later than 1 January 2022.*

This opinion invites Belgium to consider a scarcity adder not only for BRPs but also for BSPs. In principle, even if a general disclaimer is mentioned at the end of the opinion, it would be rather surprising that the Commission recommends illegal measures. The above quote clearly link the scarcity adder to the balancing energy price, i.e. the price applied to the BSP.

1.6. COMMISSION DECISION OF 27.8.2021 ON THE AID SCHEME SA.54915 - 2020/C (EX 2019/N) BELGIUM – CAPACITY REMUNERATION MECHANISM

20. The invitation to consider the implementation of an improved scarcity pricing mechanism is re-iterated in paragraph (371) of this decision:

(371) Following a public consultation, the Commission adopted on 30 April 2020 an opinion on Belgium's implementation plan, pursuant to Article 20(5) of the Electricity Regulation101. In its opinion, ***the Commission found that Belgium should further improve the working of its balancing markets by amending its scarcity pricing scheme by considering applying the scarcity pricing function also to balancing service providers (BSPs) as mentioned in recital (62), but also recognised that several improvements have been recently implemented or are planned to be implemented****. As mentioned in recital (62), Belgium introduced a so-called alpha component in its imbalance pricing mechanism, implemented imbalance netting and is preparing for joining the Union balancing platform for aFRR and mFRR. …*

1.7. DECISION NO 01/2020 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS OF 24 JANUARY 2020 ("ACER DECISION ON BALANCING ENERGY" HEREAFTER) ON THE METHODOLOGY TO DETERMINE PRICES FOR THE BALANCING ENERGY THAT RESULTS FROM THE ACTIVATION OF BALANCING ENERGY BIDS

21. The approved methodology is described in the Annex 1 presented below:

*Annex I – **Methodology for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy** or operating the imbalance netting process in accordance with Article 30(1) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing*

Article 1 Subject matter and scope

*4. This pricing methodology is without **prejudice to the introduction of a shortage pricing function for balancing energy as referred in Article 20(3) of the Regulation (EU) 2019/943**, within the national terms and conditions related to balancing pursuant to article 18 of the EB Regulation*.

22. This statement clearly demonstrates that a shortage pricing function may be introduced for **balancing energy, i.e. to BSPs** (note that the whole decision **is about balancing energy**) with a reference to Article 20(3) of Regulation 2019/943 **where balancing energy and BSPs are targeted**. With other words, what can be introduced here in balancing is similar to what is indicated for adequacy but it is not indicated that this possibility is only offered if a country is facing adequacy concerns tackled by Article 20 of Regulation 943. More on this can be found in section 8.1 below.

This decision supports the fact that a scarcity pricing adder may be applied in the settlement of BSPs, as implicitly foreseen in Article 18 of the Balancing Guideline.

1.8. DECISION NO 18/2020 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS ("ACER DECISION ON IMBALANCE SETTLEMENT HARMONISATION" HEREAFTER) OF 15 JULY 2020 ON THE HARMONISATION OF THE MAIN FEATURES OF IMBALANCE SETTLEMENT

23. The details of the imbalance settlement harmonisation can be found in Annex 1 of that decision where Article 9 6 a allows a shortage pricing function for BRPs:

(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) 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.

With other words, what can be introduced here in balancing is not linked to the question of adequacy concerns tackled by Article 20 of Regulation.

1.9. COMMISSION IMPLEMENTING REGULATION (EU) 2021/280 OF 22 FEBRUARY 2021 AMENDING REGULATIONS (EU) 2015/1222, (EU) 2016/1719, (EU) 2017/2195 AND (EU) 2017/1485 IN ORDER TO ALIGN THEM WITH REGULATION (EU) 2019/943

24. Recently, several regulations have been amended by this Commission Implementing Regulation in order to align them with Regulation 2019/943. Issues related to the Balancing Guideline are presented below.

Article 4: Terms and conditions or methodologies of TSOs

1. TSOs shall develop the terms and conditions or methodologies required by this Regulation and submit them for approval to the Agency in accordance with Article 5(2), or to the relevant regulatory authorities in accordance with Article 5(3) within the respective deadlines set out in this Regulation…

…

7. Where TSOs fail to submit an initial or amended proposal for terms and conditions or methodologies to the relevant regulatory authorities or the Agency in accordance with Articles 5 and 6 within the deadlines set out in this Regulation, they shall provide the relevant regulatory authorities and the Agency with the relevant drafts of the proposals for terms and conditions or methodologies and explain why an agreement has not been reached. The Agency, all relevant regulatory authorities jointly, ***or the relevant regulatory authority shall take the appropriate steps for the adoption of the required terms and conditions or methodologies in accordance with Article 5, for instance by requesting amendments or revising and completing the drafts pursuant to this paragraph, including where no drafts have been submitted, and approve them****.*

This new paragraph (compared to the initial version) clearly assigns the task to the relevant regulatory authority (only one in case of Article 18) to take the appropriate steps for the adoption of the required terms and conditions **by requesting amendments, revising and completing the draft or including them where no draft has been submitted**. The possibility for an NRA to complete the draft of a TSO is explicitly mentioned.

Article 5: Approval of terms and conditions or methodologies of TSOs

1. Each regulatory authority or where applicable the Agency, as the case may be, shall approve the terms and conditions or methodologies developed by TSOs under paragraphs 2, 3 and 4. Before approving the terms and conditions or methodologies, the Agency or the relevant regulatory authorities shall revise the proposals where necessary, after consulting the respective TSOs, in order to ensure that they are in line with the purpose of this Regulation and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

2. The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by the Agency:

…

(f) the methodologies for pricing balancing energy and cross-zonal capacity used for the exchange of balancing energy or operating the imbalance netting process pursuant to Article 30(1) and (5);

…

4. ***The proposals for the following terms and conditions or methodologies and any amendments thereof shall be subject to approval by each regulatory authority of each concerned Member State on a case-by-case basis****:*

(c) ***the terms and conditions related to balancing pursuant to Article 18;***

This provision clearly indicates that CREG is sole responsible for the approval of the terms and conditions related to Article 18 of the Balancing Guideline, and in particular for the settlement rules applicable to BSPs and to BRPs.

…

(g) where appropriate, the additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity, administrative costs and other costs related to balancing with balance responsible parties pursuant to Article 44(3);

Article 6 Approval of terms and conditions or methodologies of TSOs

1. Where the Agency, all relevant regulatory authorities jointly ***or the relevant regulatory authority require an amendment in order to approve the terms and conditions or methodologies submitted in accordance with Article 5(2), (3) and (4) respectively, the relevant TSOs shall submit a proposal for amended terms and conditions or methodologies for approval within 2 months*** *following the request from the Agency or the relevant regulatory authorities. The Agency or the relevant regulatory authorities shall decide on the amended terms and conditions or methodologies within 2 months following their submission.*

This paragraph specifies the timing given to a TSO for submitting amended terms and conditions.

…

3. The Agency or the regulatory authorities where they are responsible for the adoption of terms and conditions or methodologies in accordance with Article 5(2), (3) and (4) ***may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals.*** *TSOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the Agency. The proposals for amendments to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 10 and approved in accordance with the procedure set out in Articles 4 and 5.*

The powers given to the NRA to require amendments to the terms and conditions are clearly indicated in this paragraph. This covers amendments related to settlement rules.

…

9. Where the approval of the terms and conditions or methodologies requires a decision by a single designated entity in accordance with paragraph 4 or competent regulatory authority in accordance with paragraph 5, the designated entity or competent regulatory authority shall reach a decision within 6 months following the receipt of the terms and conditions or methodologies. The period shall begin on the day following that on which the proposal was submitted to the designated entity in accordance with paragraph 4 or competent regulatory authority in accordance with paragraph 5.

This paragraph indicates that a regulator has six months for its decision.

Article 7 Amendments to the terms and conditions or methodologies of TSOs

…

2. Where a designated entity requires an amendment in order to approve the terms and conditions or methodologies submitted in accordance with Article 6(4) or the competent regulatory authority requires an amendment in order to approve the requirements submitted in accordance with Article 6(5), the relevant TSO shall submit a proposal for amended terms and conditions or methodologies or requirements for approval within 2 months following the request from the designated entity or

competent regulatory authority. The designated entity or competent regulatory authority shall decide on the amended terms and conditions or methodologies within 2 months following their submission.

…

4. The Agency or regulatory authorities or designated entities, where they are responsible for the adoption of terms and conditions or methodologies in accordance with paragraphs 2, 3 and 4 of Article 6, may respectively request proposals for amendments of those terms and conditions or methodologies and determine a deadline for the submission of those proposals. TSOs responsible for developing a proposal for terms and conditions or methodologies may propose amendments to regulatory authorities and the Agency. Proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation if applicable in accordance with the procedure set out in Article 11 and approved in accordance with the procedure set out in Articles 5 and 6.

2. DESCRIPTION OF THE REASONS WHICH HAVE LED TO THE EXAMINATION OF A SCARCITY PRICING MECHANISM FOR BELGIUM

25. The reason for the examination of the implementation of a scarcity pricing mechanism in Belgium[3] is related to the announcement made in 2014 of the mothballing of some CCGT units in Belgium when at the same time Belgium experienced a lack of generation capacity (several nuclear units, totalling a capacity of up to 4000 MW, were out of the market for several reasons).

26. Figure 2.1 below (from CREG's monitoring report) shows the operational profit of CCGT units in Belgium (with a hedging strategy combining the profit resulting from the day-ahead market and from the long-term market) for the recent years. The results for year 2014 are remarkable, given the lack of generation capacity indicated above.

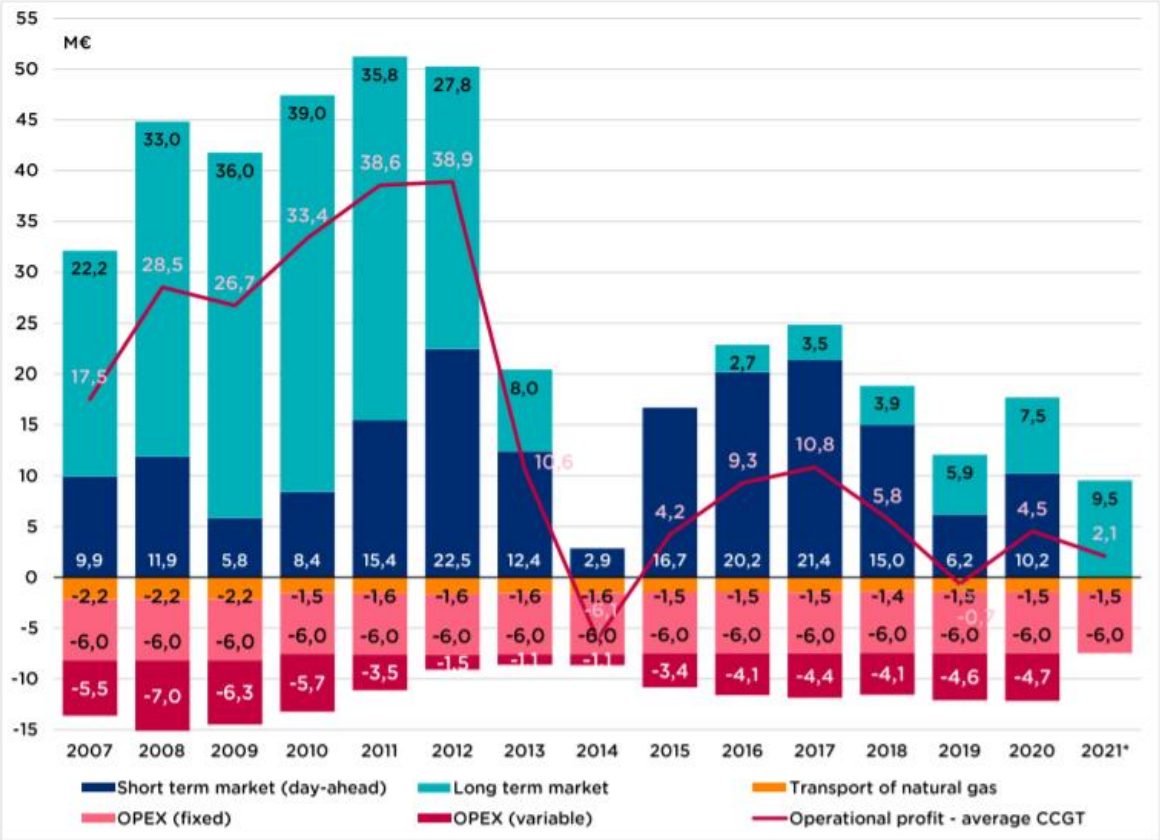

Figure 7 – Rentabilité d'exploitation par année de fourniture d'une centrale turbine gaz-vapeur (TGV) moyenne de 400 MW en Belgique avec un rendement de 50% et des coûts d'exploitation fixes annuels d'environ 7,5 MEUR. La centrale est couverte par des produits *Calendar*. Notez que les revenus à court terme sont multipliés par 90 % avant le calcul du bénéfice d'exploitation, pour tenir compte des indisponibilités.

Figure 2.1: Profitability of CCGT units in Belgium

[3] See CREG first NOTE (Z)160512-CDC-1527 on "Scarcity pricing applied to Belgium" http://www.creg.info/pdf/Divers/Z1527EN.pdf

27. The massive introduction of renewables with low variable costs contributes to the lowering of the average electricity price on short-term markets to levels that may put at risk the profitability of large-scale generation units (mainly CCGT) in pure energy-only markets even in the absence of excess generation capacity.

28. This lack of profitability observed in 2014 triggered the examination of scarcity pricing mechanisms.

29. Today, a continuing shift of value from the energy market (in the day-ahead time frame) to ancillary services and reserves is expected with the progressive implementation of the energy transition with renewable generation units with low variable costs. Additional revenues linked to ancillary services are becoming more and more important for the profitability of these units.

30. This shift of value alone is sufficient to motivate a scarcity pricing mechanism based on reserve demand curves which explicitly values reserve capacity. Such a mechanism reflects the value of reserves through reserve demand curves. Through implicit or explicit co-optimization of energy and reserves, it achieves a more accurate valuation of energy and reserves in conditions of scarcity. This improvement to the energy market design can be considered as a no-regret measure.

31. The improvement of the short-term price signal driven by shortage conditions motivates forward contracting that limits risk and induces investments which are key for system adequacy. In addition, the more even (regular) distribution of expected revenues can significantly limit investment risks.

32. Finally, the foreseen shutdown of nuclear power plants in Belgium – the nuclear phase out – constitutes another reason for improving the investment conditions in Belgium.

3. CHRONOLOGY OF THE IMPLEMENTATION OF A SCARCITY PRICING MECHANISM IN BELGIUM

33. CREG is studying the design of a scarcity pricing applied to Belgium since 2015. The various studies have been published on the English section of the CREG webpage. These studies include papers published by the CORE department of the Université Catholique de Louvain. Several incentives have also been given to Elia for the study, parallel testing and implementation of the mechanism.

34. The first note Z1527EN[4] published in May 2016 and the first study made by the CORE [Papavasiliou, 2017] (both documents will be referred to later in this text as "First Study" [CREG, 2016]) demonstrated that, on the basis of the simulation of the Belgian system made by the CORE, CCGTs would have been profitable again during 2014 with the implementation of a scarcity pricing mechanism.

35. On 29th June 2017, CREG took the decision[5] (B)658E/45 on a discretionary incentive applied to Elia which includes an incentive on a scarcity pricing mechanism targeting the determination of the volume of reserves available in real time and the simulation of the impact of a scarcity adder for the first 8 months of 2018.

36. The second note Z1707[6] together with the annex – second CORE study [Papavasiliou, 2018] - published in November 2017 (these two documents will be labelled later as "Second Study" [CREG, 2017]) indicated that, on the basis of simulations of the Belgian system in 2015 – 2016, in conditions of abundant capacity resulting from the restoration of nuclear capacity, the scarcity adder has a negligible effect on energy prices, which is compatible with the adaptive nature of the adder.

37. On 28th June 2018, CREG took the decision (B)658E/52[7] on 2019 ELIA incentives with an incentive on scarcity pricing mechanism targeting the determination of the formulas necessary for the computation of the proposed scarcity price adder and the publication, from October 2019 onwards, on Elia webpage, of the values of the scarcity adders computed in D+1 for the D day.

38. In December 2018, ELIA published its "Study Report on Scarcity Pricing in the context of the 2018 discretionary incentives" on its webpage, were the elements/formulas for the calculation of the scarcity adder were determined and computed for the year 2017. This study was made in the scope of the discretionary incentives defined by CREG for the year 2018.

39. The third note Z1986EN[8] published in September 2019, and its Annex, a third CORE study "Study on the general design of a mechanism for the remuneration of reserves in scarcity situations" [Papavasiliou, 2019], [Papavasiliou, 2021a] (referred later in the text as "Third Study" [CREG, 2019]) provided the fundamentals of the design proposed for Belgium, based on one energy adder applied to the balancing energy and two adders applied to balancing capacity, one for the mFRR and one for the aFRR. This design was chosen on the basis of simulations of the Belgian system of several alternatives (such as virtual trading and the co-optimisation of energy and reserves in day-ahead). In this study, the implementation of a real-time market for reserve capacity was considered as the lowest hanging fruit

[4] http://www.creg.info/pdf/Divers/Z1527EN.pdf
[5] https://www.creg.be/fr/publications/decision-b658e45
[6] https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1707EN.pdf
https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1707annex.pdf
[7] https://www.creg.be/fr/publications/decision-b658e52
[8] https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986EN.pdf
https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986Annex.pdf

in the Belgian market design: it is the easiest measure to implement, and it is expected to have a great effect on the long-run incentive to invest in flexible resources.

40. In October 2019, ELIA started the publication on its webpage of the values of the scarcity price adders calculated for the day before on the basis of real-time data[9].

41. On 21 November 2019, CREG took the decision[10] on 2020 incentive applied to ELIA which includes a component related to scarcity pricing targeting the study by ELIA of the mechanism proposed by the CORE, the proposal of an alternative, and a consultation of market players.

42. On 17 July 2020 CREG took the decision[11] on 2021 incentives applied to ELIA which includes a component related to scarcity pricing targeting the implementation by ELIA of a scarcity pricing mechanism for the 1st January 2022.

43. The fourth note Z2111EN[12] (referred later in the text as "Fourth Study" [CREG, 2020a]) was published in September 2020 and provided answers to Frequently Asked Question related to scarcity pricing mechanisms in general and to the mechanism proposed for Belgium.

44. The fifth study F2144EN[13] was published in November 2020 together with 4 additional studies delivered by the CORE ([Papavasiliou, 2021b], [Papavasiliou, 2021c], [Papavasiliou, 2021d], [Papavasiliou, 2021e]). This material will constitute the "Fifth Study"[CREG, 2020b] with four parts, one for each CORE document[14]. The Fifth Study provided a first description of the legal context applied to scarcity pricing, a justification of the proposed design on the basis of agent-based simulations and analytical calculations, the modelling of cross-border interactions related to a unilateral implementation of scarcity pricing in Belgium and further discussions on key elements of the design of a scarcity pricing mechanism. One of the design options examined in these papers (design D3) anticipated the ELIA Omega proposal (design D3 is very close to the ELIA proposal). The analysis and simulation performed by CORE demonstrated that design D3 was not able to efficiently back-propagate the real-time adder to the day-ahead reserve markets. Draft versions of 3 of these 4 papers were communicated beginning of July to ELIA.

45. On 7 December 2020, ELIA published on its webpage the final report on scarcity pricing delivered in the scope of its incentive on scarcity pricing: "Final report on Elia's findings regarding the design of a scarcity pricing mechanism for implementation in Belgium".

46. During 2021, the CORE, CREG's consultant, has continued its work on the mechanism in two directions: (i) two more scenarios D5 and D6, related to the current alpha component have been analysed [Bertrand, 2021]; (ii) a simulator of the Belgian market has been developed in order to tune the parameters of scarcity pricing and to evaluate the impact of the proposed mechanism. These recent works are referred to below as the "Sixth Study" and are presented in Annex.

47. In addition to that, extra analyses have been conducted by CREG on the consequences of a unilateral implementation of scarcity pricing in Belgium which are described in Section 5.5.

[9] https://www.elia.be/en/electricity-market-and-system/studies/scarcity-pricing-simulation
[10] https://www.creg.be/fr/publications/decision-b658e63
[11] https://www.creg.be/fr/publications/decision-b658e68
[12] https://www.creg.be/sites/default/files/assets/Publications/Notes/Z2111EN.pdf
[13] https://www.creg.be/sites/default/files/assets/Publications/Studies/F2144EN.pdf
[14] In the Annexes (4 papers) of CREG 2020b study

4. INTRODUCTION TO SCARCITY PRICING MECHANISM - THEORETICAL BACKGROUND

48. Before examining the theoretical background of a scarcity pricing mechanism, the general principles of "peak load pricing" as referred to by [Joskow and Thomas-Olivier Leautier, 2019][15] in energy only markets will be introduced.

49. Very often, the principle of "the marginal price rule" is referred to when mentioning the "classical" price rule of energy only markets. This is only one side of the coin, and the term "peak-load pricing" better reflects the way investment in generation may be profitable in energy only markets.

50. To understand the challenges of electricity pricing, it is useful to make a comparison[16] with other non-storable goods: "*One of the key insights from the microeconomics of electricity production is that the structure of wholesale power prices is similar to that of other non-storable goods for which demand varies significantly across time, for example, hotels rooms or plane tickets: the price is set close to the variable cost of production when capacity exceeds demand, while it is set by the value for the marginal consumer when demand is exactly equal to capacity. For example, the price for a room at the beach on Cape Cod is close to the cost of cleanup in the winter and goes much higher in the summer. This particular price structure is called "peak-load pricing" in the power industry. The main difference between electric power and other non-storable goods is the magnitude of the peak price: the summer price may be three to four times the winter price for a room at the beach, while the peak price for power may exceed 50 or even 100 times the off-peak price*."

51. In the same paper, the functioning of the peak-load pricing rule is further illustrated with a simple example. The simplest situation is characterised by a fully price-responsive electricity demand and a single production technology. This single generation unit is characterised by a variable production cost per unit c and a total capacity K. A useful concept to examine markets and price is the supply curve that traces the short-run marginal cost, that is, the cost of producing a marginal unit of a good for various quantities of this good when capacity is already built. In our example, the supply curve is L-shaped. Demand decreases as the price increases: hence inverse demand curves will be represented by downwards sloping line, depending of the hour of the year (blue lines in Figure 4.1 below).

[15] 2. Optimal Wholesale Pricing and Investment in Generation: The Basics 1 By Paul Joskow and Thomas-Olivier Léautier; https://economics.mit.edu/files/20742

[16] See the same reference

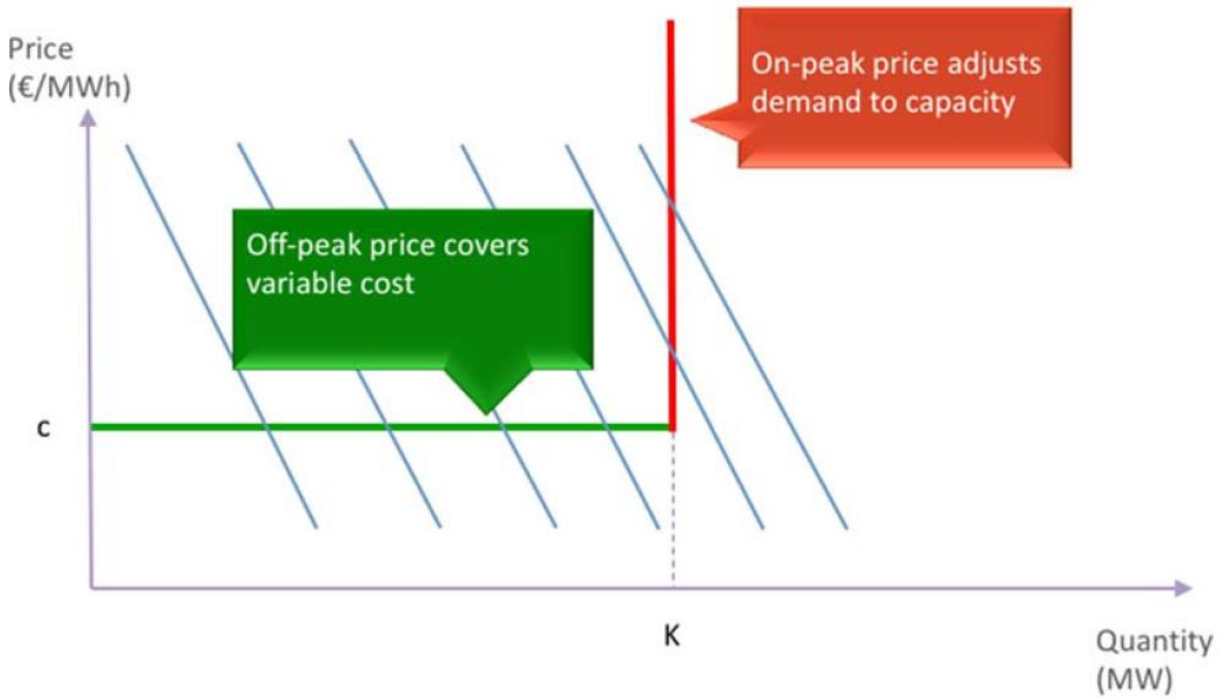

Figure 4.1: Demand curves and supply curve for a single generation technology. Source: Joskow and Léautier 2019, figure 2.4, page 24.

52. To understand the functioning of peak load pricing, the key is to separate two different configurations: off-peak, that is when production is lower than installed capacity, and on-peak when production and consumption are precisely equal to installed capacity. Off-peak, the price of electricity is equal to the cost of producing one additional megawatt-hour, i.e. the variable production cost c here (hence the "marginal price rule"). On-peak, on the right side of the picture, the price of electricity is equal to **the value (for the demand)** of the last unit consumed, the value of the marginal megawatt-hour that fully utilises the available capacity.

53. Total revenues coming from selling electricity for a generator is therefore the sum of the revenues coming from off-peak hours (left side of the picture) plus revenues coming from on-peak hours, on the right side of the curve. In the simple system presented above, fixed investments costs are only covered by revenues from on-peak hours, as the off-peak price is set at the variable costs of the single unit of the system (in practice, some revenues – the infra-marginal rent - may exist for non-marginal units)[17].

54. With the integration of renewables with low variable costs, the revenue stream coming from off-peak hours is decreasing and the revenues coming from on-peak hours will become more and more important.

55. It can be shown (same reference) that short term optimal prices based on the above described principles correspond to optimal generation capacity. Indeed, the capacity choice is a long-term investment decision; hence the long-term optimum is to maximise the average hourly long-term net surplus, which is the average hourly short-term net surplus minus the hourly capacity cost. If we consider adding a (marginal) megawatt of generation capacity, this additional installed capacity has no impact on the surplus made off-peak. Hence the analysis will be limited to on-peak hours (profit is coming only from these hours here). So, if generation capacity increases, the number of on-peak hours

[17] In practice, additional revenues may arise in day-ahead from the application of a flow-based market coupling where prices may differ from marginal activated bids and from the pricing rule applied to non-convex products.

will decrease, reducing the revenues coming from on-peak hours. If competition is perfect, producers build capacity until the last unit precisely breaks even, that is, until the average hourly marginal operating profit (coming from on-peak hours) is precisely equal to the hourly fixed cost. Since the marginal operating profit is equal to the marginal net surplus, the long-term equilibrium is also the optimum. So, in theory, optimal prices leads to optimal generation capacity. If the demand is non-elastic, it can be shown that the price for on-peak hours should be set at the VOLL.

56. The situation may be more complicated in practice, for several reasons (such as the existence of non-convexities in electricity markets [KOPERNIKUS PROJECTE 2021] and the risk aversion of investors.

57. Concerning the risk aversion issue, it should be stressed that for a risk averse investor, the pricing principle presented above may be far from ideal if the demand is non-elastic (vertical line) and the price is set at the VOLL only a few times over a period of ten years, which is more or less the current situation.

58. It will be shown in section 7.2 below of this study that a scarcity pricing mechanism can be seen as a way to smooth the revenue stream coming from on-peak hours, replacing a few spikes at a very high price by more regular spikes of lower magnitude.

59. Concerning scarcity pricing, the first paper[18] of William Hogan [Hogan, 2005] "ON AN "ENERGY ONLY" ELECTRICITY MARKET DESIGN FOR RESOURCE ADEQUACY" targeting adequacy concerns in energy only markets was published in September 2005. It is important to note here that the goal of the paper was adequacy and missing money issues and not the improvement of flexibility.

60. In 2013, William Hogan published the paper[19] on "Electricity Scarcity Pricing Through Operating Reserves"[20] [Hogan, 2013] which laid the basis of the design of a scarcity pricing mechanism based on operating reserves (approximately the equivalent to aFRR and mFRR in Europe) demand curves applied in real-time. With this paper, William Hogan proposes a solution for the implementation of a scarcity pricing mechanism which has been rolled out in Texas. The purpose of this article is to show that the price of energy and reserve in real-time should properly reflects real-time conditions (including scarcity). This would lead to investment in generators that would be available when scarcity occurs.

61. The permanent and reliable equilibrium between generation and demand requires the availability of reserves able to deploy quickly for compensating a sudden generation loss or a load change. These reserves have properties corresponding to a public good (there is no easy way to measure the usage of reserves by a given market player) which leads to a market failure - where self-organised markets will not lead to an efficient outcome. For this reason, reserves are procured by TSOs and charged to consumers through the tariffs. Rules of sharing these costs are also determined by the TSO.

62. Figure 4.2 below is sourced from the William Hogan 2005 paper, and illustrates the functioning of an energy-only market where the value of reserves is taken into account. On the left side, a classical energy-only market clears at a price determined by the intersection of the offer curve (blue) and of the demand curve (black). In order to ensure reliability of the system, generation capacity should not only cover the demand for energy, but also the need for reserves. This "augmented" demanded curve is displayed in red. Situations on the left typically represent conditions where the load is low compared to the generation capacity and the impact of the reserve requirements on the price (around 30 $/MWh in the graph), which moves from the intersection of the blue and black curves to the intersection of the blue and red curves, is rather small. On the right, a situation where generation capacity is scarce is

[18] https://scholar.harvard.edu/whogan/files/hogan_energy_only_092305.pdf

[19] https://scholar.harvard.edu/whogan/files/hogan_ordc_042513.pdf

[20] "Operational Reserves" are a subset of the installed capacity that is both available and standing by to produce energy on short notice. They correspond approximately to secondary and fast tertiary reserves in Europe.

presented. This time, the impact of the additional requirement related to the reserves is huge: the price without reserve requirements is still around 30 $/MWh, when the price taking into account the need for reserves jumps up to 7000 $/MWh in the example. The difference between the prices of 30 $/MWh and of 7000 $/MWh corresponds here to the energy adder which reflects the scarcity of the generation capacity of the system.

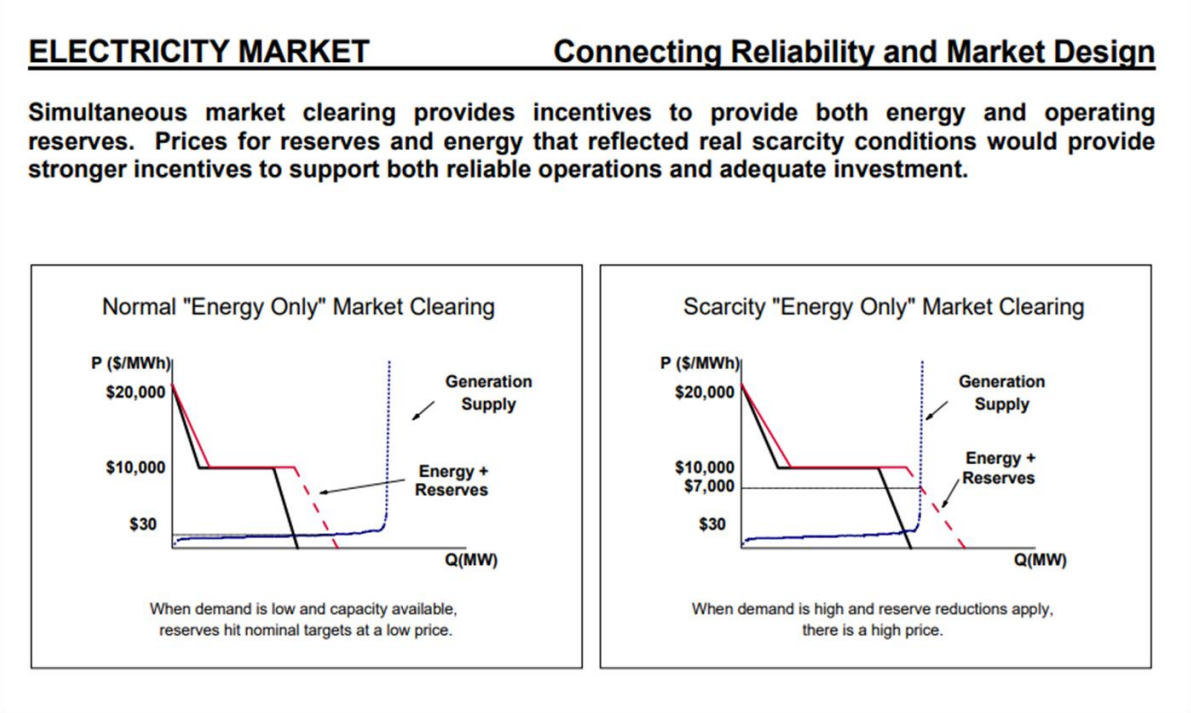

Figure 4.2 : Valuation of reserves in energy only markets

63. The principle of a scarcity pricing mechanism based on an operating reserve demand curve (ORDC) may be described as follows (see paper by William Hogan): when there is load curtailment (not a blackout) 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 reserves should be set at the value of loss of load (VOLL in short) during these periods.

64. At any other level of reserves above that minimum, set to protect the system from events in the immediate future, the value of an increment of operating reserves would be equal to the same VOLL multiplied by the probability that the net load would increase enough in the coming interval so as to reduce the reserves to the minimum level where load would be curtailed 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.

65. The following example (see Table 4.1) illustrates the inability of the current electricity market design to reflect real-time conditions of the system (especially reliability). To this aim, we compare two systems: the first one (Case 1) has only one CCGT unit while the other (Case 2) has two CCGT units. These CCGT units have a capacity of 200 MW and a marginal cost of 50 €/MWh. In both cases, the demand is assumed to be equal to 199 MW.

66. Currently, without a scarcity adder, the electricity prices are the same in both systems, even if the reliability of the situation with one unit only is very low. This illustrates the inability of the current design to reflect scarcity in the electricity prices because no matter the amount of reserve available in real-time, the electricity prices are the same. Therefore, in the current design, there is no incentive to invest in new capacity even though the system is tight.

67. With a scarcity pricing mechanism, a significant adder will be generated in the case with one unit only (Case 1), indicating that the value of reserves, and therefore of energy, is very high because the system is very tight (the loss of load probability –"LOLP"-- of the first case is indeed significantly higher than the one of the second case, where the amount of reserves is high). This will send a signal for investment in new capacities in the first system.

	Case 1	**Case 2**
Demand	199	199
CCGT1 production [MW]	199	99.5
CCGT2 production [MW]	Non-existent	99.5
Reserve in real-time [MW]	1	201
Probability of shortage in the next 15 minutes	High	Low
Price in the current situation [€/MWh]	50	50
Price with scarcity pricing [€/MWh]	$50 + (VOLL - 50) \cdot \boldsymbol{LOLP}(\mathbf{1})$	$50 + (VOLL - 50) \cdot \boldsymbol{LOLP}(\mathbf{201})$

Table 4.1: Illustration of the absence of valuation of reliability in the energy price

68. More information on the application of these principles can be found in the First Study made by the CORE of the Université Catholique de Louvain[21]. The estimation of the loss of load probability curve as a function of the volume of available reserves at a given time horizon is based on the distribution of the volume of reserves activated by Elia (mainly mFRR). Figure 4.3 shows the distribution curve (hourly data) of the volume of reserve activations made by Elia in 15 minutes from January 2013 until the end of September of 2014. This histogram is then transformed into a curve that represents the loss of load probability function of the volume of reserves available in the system (see Figure 4.4).

[21] see NOTE (Z)160512-CDC-1527 on CREG webpage

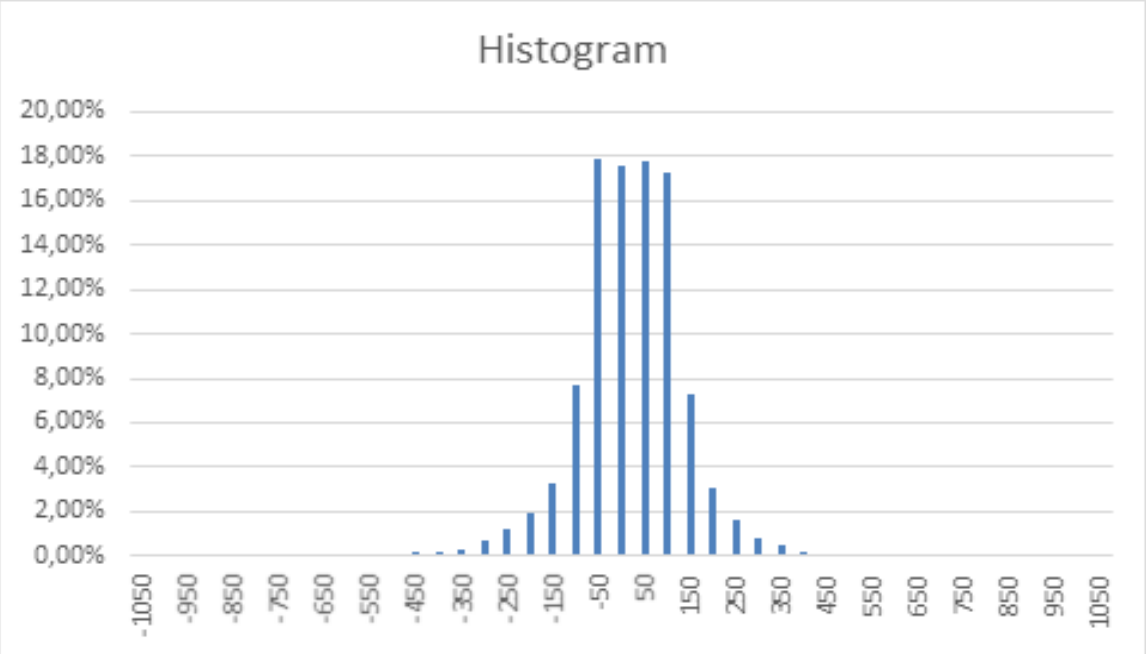

Figure 4.3: Distribution curve (hourly data) of the volume of reserve activations made by Elia

69. On this basis, the price adder curve, which is a function of the volume of reserves available in real time, is determined as the multiplication of the loss of load probability for a given level of reserves with the value of loss of load[22]. Figure 4.5 presents the computed adder for the balancing electricity prices as estimated by the CORE for the winter 2013/2014.

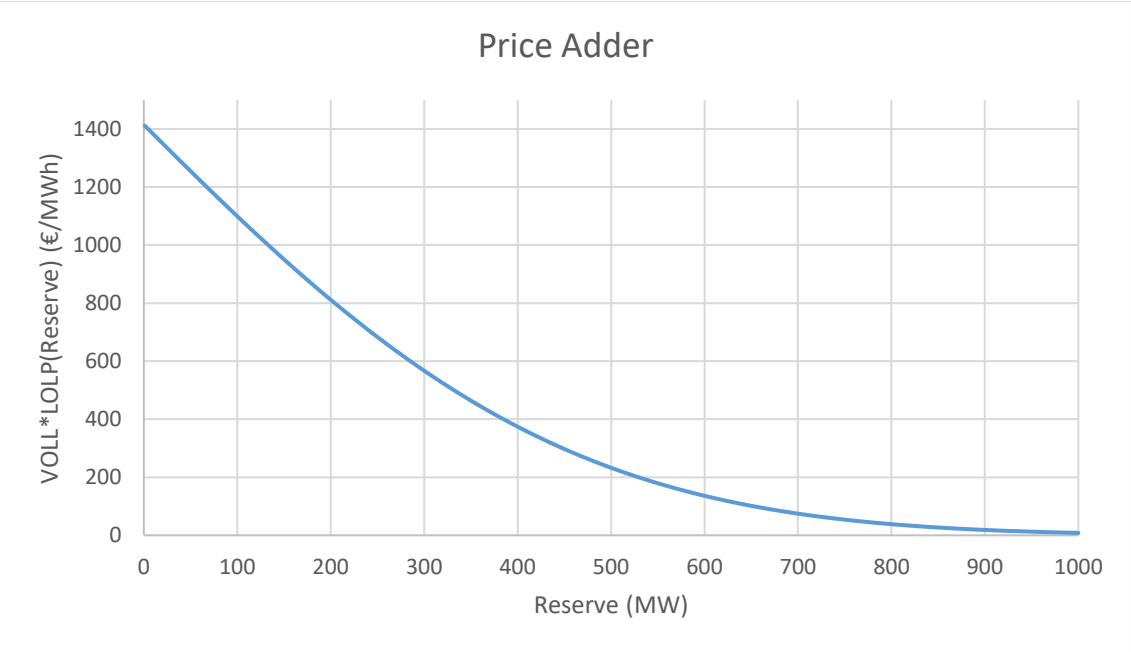

Figure 4.4: Loss of load probability curve

70. The idea with the scarcity adder is to replace infrequent and unpredictable very high price spikes by smaller, but more frequent scarcity signals, as shown in Figure 4.5.

[22] Based on a VOLL of 3000 €/MWh at that time

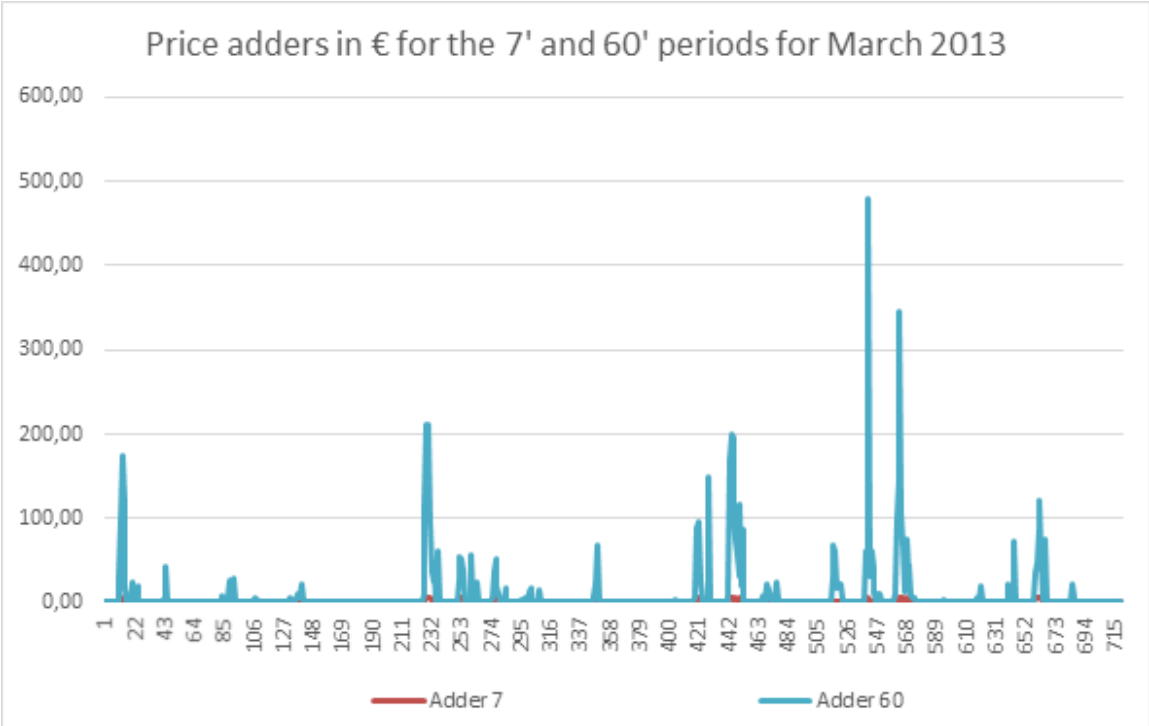

Figure 4.5: Price adders in € for the 7' and 60' periods

71. It is based on the assumption that, although it is difficult to forecast requirements for installed capacity many years ahead (as required by most CRMs), it is a comparatively easier task for a TSO to forecast operating reserve requirements and availability for the next instant or part of an hour.

72. In order to explain the benefits of a scarcity pricing mechanism, it is interesting to provide here the view of academics not directly involved in the developments of this mechanism, such as Peter Cramton, who has produced several papers on Capacity Remuneration Markets (CRMs), and Paul Joskow.

73. As indicated in [Cramton, 2017]: "*In broadest terms, regulators seek a market design that provides reliable electricity at least cost to consumers. This can be broken down into two key objectives: The first is short-run efficiency: making the best use of existing resources. (…) The second objective is long-run efficiency: ensuring the market provides the proper incentives for efficient long-run investment. This has proven to be the most challenging objective. In the simplest theory, efficient long-run investment is induced from the right spot prices. But this is complicated by the reliability requirement. Reliability requires a reserve to satisfy demand when supply and demand uncertainty would otherwise lead to shortage. In other industries, reliability is not an issue. Prices rise and fall to assure supply and demand balance, but in current electricity markets there is typically insufficient demand that responds to price, and consumers are unable to express a preference for reliability. Thus, there is a need in current markets for the regulator to determine how this preference for reliability is expressed. As we will see, one approach to reliability is to rely solely on spot prices but to include administrative scarcity prices at times when reserves are scarce. The preference for reliability is imbedded in the scarcity prices. Setting higher scarcity prices enhances reliability in providing stronger investment incentives. An alternative approach is to more directly coordinate investment with a capacity market, although this is best done as an addition to, not a substitute for, administrative scarcity pricing, since it is the scarcity price that motivates capacity to perform when needed.*"

74. Further in the same paper, it is indicated that "*In Texas (where the ORDC mechanism under consideration for Belgium is implemented), the high scarcity pricing motivates the forward contracting that limits risk and induces investment. The scarcity price is the key instrument for resource adequacy.*

One reason this may work well in Texas is substantial industrial load that makes the market for forward contracts more liquid."

75. On the importance of an adequate price signal for ensuring generation adequacy, we refer to Paul Joskow [Joskow, 2007] and [Joskow, 2019].

76. In [Joskow, 2007] , Paul Joskow highlights the new context linked to the increased penetration of renewables and the importance of an improved price signal for ensuring generation adequacy in the context of renewable energy integration: "*High penetration of intermittent generation with zero marginal operating costs creates challenges for wholesale market designs. And it is both intermittence and zero marginal operating cost that are important. To oversimplify, wholesale markets as they are now structured in the U.S. perform two related resource allocation functions --- short run and long run. First, they provide for the efficient real-time operation of existing generating capacity, clear supply and demand at efficient wholesale prices that represent the marginal cost of supply at any moment, and do so while maintaining the reliability of the system. Second, market prices and price expectations are supposed to provide efficient long run profit expectations and incentives to support efficient decentralized investments in new generating capacity and efficient retirements of existing generating capacity. Wholesale market designs in the U.S. that evolved since the late 1990s now do a reasonably good job supporting the first set of short run resource allocation tasks under most states of nature. However, they have been challenged in providing adequate financial incentives to support efficient entry (investment) and exit decisions consistent with reliability criteria established by system operators. That is, the short run price signals do not lead to long run price expectations that adequately incent efficient investment and retirement decisions. The disconnect emerges primarily as a result of energy and ancillary price formation during tight supply and other stressed conditions. Prices under these conditions do not rise high enough to reflect the scarcity value of the generation due to price caps, limited demand-side participation in the wholesale market, and out-of market actions by system operators during network security emergencies.*"

77. CREG shares the view that an increased penetration of renewables may lead to a price signal that will not allow efficient investment and retirement decisions in the markets.

78. From the same author [Joskow, 2019] we also find: "*Note that scarcity pricing is not a departure from the basic principle of short run marginal cost pricing. Rather, movements along the appropriate demand curve when capacity constraints are binding reflect consumer valuations of sudden reductions in available generating capacity (reliability) and represent consumers' short run marginal opportunity cost of having more or less generating capacity. While there may be few hours when capacity constraints are binding, energy prices would likely go to very high levels as demand is price-rationed and yield substantial revenue for all generators which would allow them to recover their capital costs in a long run equilibrium*".

79. On the issue of capacity markets, Paul Joskow indicates "*Capacity markets have been redesigned frequently as their imperfections have been revealed and efficient scarcity pricing will not be feasible without reforms of retail pricing. While the ongoing refinements to capacity markets have improved their performance, they too have been based on conceptual models for electric power systems which rely primarily on dispatchable generation. But, it is not at all clear how a capacity market mechanism can be implemented with intermittent generation at scale. Capacity payments are made based on performance commitments that require generators to be available to supply when the system operator determines they are needed. How would this work for intermittent generators that cannot predict whether and how much capacity will be available at a particular hour on a particular future date?*"

80. It is important to recall here the importance of decentralised investment decisions. The market, and not a central planner, should decide whether to invest or not: this is at the core of the liberalisation process, and price signals are the key instruments to reach this goal. More on this can be found in [Joskow, 2019] page 20: "*That is, "the market," rather than integrated resource planning by the vertically integrated utility, interest group interventions, plus regulatory oversight, would determine entry and exit decisions by decentralized owners of generating plants and lead to an efficient portfolio of generating capacity over time. Investors would bear the risks of changes in market conditions, construction cost overruns or construction efficiencies, etc., rather than consumers as was the case when all "prudent" generating costs were passed on to consumers through regulated rates. Decentralized entry of generating capacity based on market price signals, rather than regulated integrated resource planning, reflected one of the hidden goals of restructuring and reliance on competitive wholesale markets: get the interest group politics out of the regulated utility's entry, exit, and fuel supply decisions.*"

5. JUSTIFICATION OF THE CHOICE OF A SCARCITY PRICING MECHANISM AND OF THE PROPOSED DESIGN

81. The recourse to a scarcity pricing mechanism for restoring the profitability of generation units is based on (at least) two CREG's studies (the First Study[23] and the Third Study[24]) based on simulations of the Belgian system. These studies have also demonstrated that computed adders are equal to zero in the absence of scarcity in the system. See also the ELIA study[25] where the scarcity adder was computed for the year 2017 (see § 38).

82. The design proposed for implementation is based on studies made during the last 6 years. This determination of market design choices is based on models. Models provide a concrete basis for quantitative reasoning and argumentation. In their absence, it becomes extremely challenging to develop precise arguments about the economic rationale behind certain key market design choices (e.g. as they relate to the design of the balancing market). Furthermore, these models are approximations of reality and the fact that a given market design is able to meet its goal in theory, under certain modelling assumptions, does not provide a guarantee that this design will work as expected in practice. But at the same time, market designs options which are not able to meet their objectives when modelled have little chance to perform adequately in practice. With other words, market designs options identified as non-satisfactory in these studies should not be further considered for implementation as many issues may even worsen their implementation in reality.

83. The proposed design has been compared with other designs. In particular, the ELIA proposal (based on an Omega applied on BRPs) has been simulated.

84. In addition, choices made about the design are supported by "parallel runs" made by the TSO since October 2019 on Elia webpage.

85. Interested readers are invited to consult the numerous studies performed by the CORE on behalf of the CREG. The text below describing the different options and choices made is to a large extent "copy-pasted" from these papers.

5.1. A SCARCITY PRICING MECHANISM IS ABLE TO MAKE CCGTS PROFITABLE AGAIN

86. In the recent years, Belgium can be considered as an interesting test case for the design of scarcity pricing mechanisms as the availability of nuclear power plants exhibited huge differences during the recent years, alternating in a few months' time from periods with excess capacity to periods with a shortage in capacity. In order to demonstrate the proper functioning of a scarcity pricing mechanism, and achieving an adequate investment signal, it is important to show that the price signal is sufficiently high during scarcity periods and reverts to zero during periods with excess capacity.

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

[24] https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986EN.pdf
https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986Annex.pdf

[25] Study report on Scarcity Pricing in the context of the 2018 discretionary incentives Public version 20/12/2018 available on Elia webpage

87. The First, the Third and the Sixth Study have demonstrated that a scarcity price adder can make CCGT units profitable again.

88. The First Study demonstrated that the addition of a scarcity adder for the remuneration of flexible reserves is able to not only remunerate operating costs of CCGTs but also to remunerate investment costs of new CCGT units. The period analysed by the study - from January 2013 until September 2014 - has seen relatively deep negative Clean Spark Spreads.

89. The average adder for the duration of the study amounts to 6.06 €/MWh of generation reserve capacity. This is the average increase in revenues that can be expected, for example, by baseload units that produce a constant output if the adder fully back-propagates to forward energy prices. At that time, the way to ensure this back propagation was not yet clear: this mechanism – the recourse to a real-time market for reserves – is analysed in the Third Study and its efficiency will be checked in the Fifth Study.

90. This average value of 6.06 €/MW.h has to be taken with caution, as it is based on assumptions that have been refined today, and results of an open loop simulation with no market reaction, without demand participating in the mechanism and based on hourly data (15' data are used in today's simulations).

91. The important conclusions of this First Study are that a scarcity pricing mechanism was able to restore the profitability of CCGT units, to provide an adequate investment signal and improve adequacy conditions in Belgium.

92. The Third Study compared different design options (see the description of the different design options in section 5.3 below). A stochastic equilibrium model for quantifying the effects of these designs on the back-propagation of scarcity prices was used in this study. This model was applied on the period from September 2015 until March 2016, which was also the basis for the analysis presented in the Second Study.

93. This third study shows that, with the proposed introduction of a scarcity pricing mechanism and of reserve balancing capacity market in real-time, on the basis of the simulations performed, all generation units are either profitable or in the range of covering their investment costs.

94. The effectiveness of the back-propagation of the scarcity price signal will be further examined in section 5.4 below.

95. Finally, additional simulations of the Belgian system based on a more sophisticated model have been performed recently and are presented in the Sixth Study (see § 46 above). The aim of this study is to compare different variants of the ORDC (trade-off between security and operating cost) and analyse the impact that the mechanism would have on the Belgian market. The main results are presented in section 6 for the analysis of the different variants and section 7 for the mechanism impact.

5.2. IN PERIODS OF EXCESS CAPACITY, ADDERS ARE CLOSE TO ZERO

96. As indicated above, it is of utmost importance that the average value of the scarcity adders be close to zero in the absence of scarcity. The Second Study and ELIA computations made for the year 2017 support this statement.

97. As all nuclear units have been reintroduced in 2016 in the Belgian market, the situation has changed radically, and the absence of significant scarcity adders can be checked for that period.

98. The Second Study showed that for the period ranging from September 2015 to March 2016, the average adder over the duration of the study amounted to 0.3 €/MWh. This indicates that, under

conditions of abundant capacity resulting from the restoration of nuclear capacity, the ORDC adder has a negligible effect on energy prices, which is compatible with the adaptive nature of the adder.

99. In the 2018 ELIA "Study report on Scarcity Pricing in the context of the 2018 discretionary incentives"[26] it is indicated in page 58, as a summary of the main observations on the price adders calculated for the year 2017, that "*Despite the modest 2017 outcome in terms of scarcity price adders, the exercise has been useful. The results, and in particular the analysis of the four more extreme cases, reveal that the model behaves as it is expected to behave. Higher price adders are indeed reached in situations when margins get tighter and situations with large imbalances do not result in high price adders if, at the same time, reserves are not becoming scarce. Although the number of data points may be too limited to draw robust conclusions, and despite the fact that model is particularly tuned to balancing reserves and margins, the observed significant price adders occurred during (mainly evening) peak demand moments. This may suggest a link with moments also relevant for adequacy.*"

100. Finally, since October 2019, ELIA is computing[27] the three scarcity adders for the day before[28]. These parallel runs also demonstrate that, during periods of abundant capacity, scarcity adders are close to zero. In particular, published data for the year 2020 (October data seems to be missing) indicate that the average value of the adder is equal to 0 €/MWh[29].

5.3. CHOICE OF THE GENERAL DESIGN AND OF THE LOWER HANGING FRUIT

101. The objective of the Third Study on the general design of a scarcity pricing mechanism was to propose a general design for the implementation of a scarcity pricing mechanism based on the ORDC approach.

102. In particular, the following questions were to be answered for the definition of a design applicable to Belgium:

- Question 1: Do we need a market for reserve capacity in real time (in the balancing time frame), or can we just rely on the clearing of energy?
- Question 2: Do we require virtual trading?
- Question 3: Should energy and reserve be cleared simultaneously in the day-ahead market, i.e. co-optimised, or may reserve be cleared first?

Virtual trading and day-ahead co-optimization of energy and reserves are explained below.

103. Before answering to these questions, it is good to see how this mechanism is implemented in Texas, where the ORDC approach is followed. Currently, in Texas, there is an (implicit) real-time market for reserves (question 1) in the sense that market participants receive a real-time price for the real-time quantity of reserve capacity that they make available to the system. Regarding question 2, virtual trading of energy is allowed in Texas. Virtual trading is not allowed in the Belgian market. Regarding question 3, the Texas day-ahead market trades reserves and energy simultaneously in a multi-product auction.

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

[27] In April this year, CREG observed that the computation of the volume of mFRR reserves was too optimistic (linked to ARC available data).

[28] https://www.elia.be/fr/marche-de-electricite-et-reseau/studies/scarcity-pricing-simulation

[29] Even it should not change much for that period, its appears recently that the amount of available reserves were overestimated : see section 6.7 below.

104. The modifications of the current design corresponding to the three questions mentioned above will be examined in sequence from the least to the most disruptive steps, starting from the "standard" EU design (see Figure 5.3.1).

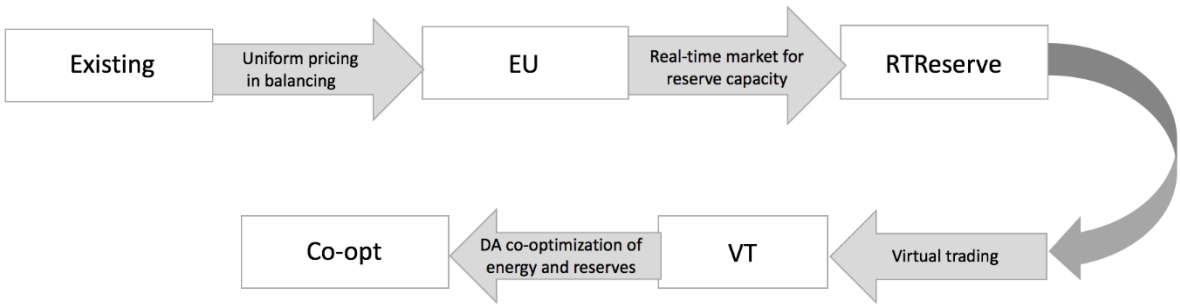

Figure 5.3.1: Chain of designs that has been considered

105. The EU model represents a first proxy of current Belgian market operations. The clearing of reserve precedes the clearing of energy in the day-ahead market. No virtual trading is allowed. There is no market for real-time reserve capacity. It is nevertheless assumed in this proxy that resources (free bids / reserves) that are activated in the balancing market are paid a uniform price[30], which is the price paid by resources that are causing the imbalances (in other words, that BRPs and BSPs are facing the same price). The rationale for the uniform pricing of activated real-time energy is that buyers and sellers of the same product should face the same price for the product that is being exchanged. In the case of real-time operations, the product in question is average energy during a 15-minute interval. It was also assumed in these models that balancing capacity reserves were procured[31] in day-ahead.

106. The EU-Inelastic model represents the second proxy of the Belgian market. In this model, it is assumed that at the end of a balancing interval, the units make their committed reserve capacity available, even if they have been activated during the interval for clearing an imbalance. This represents a strong requirement which constitutes the boundary of the current obligations set on BSPs in the current Belgian design.

107. The next step in this evolution considers the introduction of a real-time market for reserve capacity, and the resulting model is called "RTReserve".

108. Virtual trading is considered as the next modification and the resulting model is called (VT). This model is the evolution of RTReserve model where energy is traded freely (i.e. without the backing of physical assets) in the day-ahead time frame, which corresponds to a departure from the current practice of the Belgian market, at least in principle.

109. Virtual trading is the practice of allowing agents to trade energy in the day-ahead market, even if they do not own physical assets. 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. For example, if there is a sense by traders that day-ahead prices are over-valued compared to the expected value of electricity in real time, virtual trading would allow traders to sell energy in the day-ahead market (even if they do not own generating assets) and pay backfor that energy at the real-time price (assuming traders do not own physical assets, they cannot actually produce the power that they sold

[30] No Alpha component is considered here.
[31] This day-ahead procurement started in 2020.

in the day-ahead market, so the only way for them to honour their day-ahead trade is by buying back their position at the real-time price). The end result of this increased sale of electricity in the day-ahead market is to exert an downward pressure on day-ahead prices, and bring them closer to the average real-time prices. In this way, the expert knowledge of virtual traders about the expected real-time price contributes to the formation of day-ahead prices that are consistent with the average real-time prices. This contributes towards 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.

110. Some implicit virtual trading seems to exist for some players in the Belgian system. This implicit form of virtual trading may provide a certain degree of back-propagation of the price signal. Nevertheless, the compatibility of this behaviour with the current balancing obligations may be questioned, as balancing requests that all market participants shall strive to be balanced or shall help the electricity system to be balanced. Therefore, taking a position in the day-ahead market with the intention of keeping it open in real-time may raise some questions.

111. Finally, the introduction of co-optimization of energy and reserves in the day-ahead is considered. This leads to the model Co-opt.

112. Co-optimisation of energy and reserves in the day-ahead time frame corresponds to the simultaneous optimization of energy produced and reserves. The advantage of co-optimization compared to sequential optimization is that it automatically allocates optimally the capacity of the market participant between energy and reserve. Therefore, it avoids inefficient dispatch due to the wrong estimation of the opportunity cost by market participants.

113. Table 5.3.1 presents for the different design evolutions considered, from the right side of the table to the left (current design is on the right of the table), the profit results for the 8 CCGT units that were active in the market during the period of September 2015 till March 2016.

Unit/Design	Co-opt	VT	RTReserve	EU	EU-Inel
CCGT1	7.37	7.37	7.37	**2.59**	16.15
CCGT2	20.68	20.66	20.68	15.07	31.80
CCGT2	8.06	8.06	8.06	**2.64**	19.03
CCGT2	12.04	12.04	12.04	**3.84**	28.62
CCGT2	21.07	21.05	21.07	15.45	32.26
CCGT2	8.30	8.29	8.30	**2.66**	19.42
CCGT2	21.45	21.43	21.45	15.82	32.57
CCGT2	20.58	20.56	20.58	14.93	31.67

Table 5.3.1: Generator profits (€/MWh) for the designsconsidered in the comparison

114. As already indicated above, a stochastic equilibrium model for quantifying the effects of these designs on the back-propagation of scarcity prices is used in this study. The two EU envelope models, EU and EU-Inel, cover a wide range of generator profits. Therefore, the extent to which generator capacity after activation must correspond to reserve capacity committed in the day-ahead market can shift a unit from making losses to earning excessive profits. Removing this requirement altogether, which is the case in the EU model, places 4 out of 8 units in a non-viable financial position (they are not able to recover their investment costs which are estimated between 6,03 €/MWh and 8,66 €/MWh in the study).

115. The introduction of a real-time market for reserve capacity (RTReserve) restores 3 of these units to breaking even, and 1 of them to covering its investment costs comfortably. The introduction of

virtual trading and the simultaneous clearing of energy and reserve in day ahead only have a secondary impact on the profitability of the units under the risk-neutrality assumptions of the model used for executing this study. In addition, these measures seem to be much more difficult to implement. The co-optimisation of energy and reserve in the day-ahead market necessitates a modification of the Euphemia algorithm, which is not considered to be imminent, and may also necessitate certain adaptations in governance, since reserves are managed by the TSO and energy by NEMOs.

116. For the reasons mentioned in the paragraph before, the creation of (implicit) real-time markets for reserves, the design of which is not ruled by prescriptive EU laws for the moment, is considered as the lower hanging fruit for ensuring the back-propagation of the price adder to forward markets.

5.4. DOES THE PROPOSED DESIGN WORK PROPERLY? COMPARISON WITH ALTERNATIVE DESIGNS

117. This section will address the question of the good functioning of the proposed design and check if the back-propagation of the scarcity price signal is efficient. Other designs options (one of them being proposed by Elia) will also be examined at this occasion.

118. In the analysis of the Third Study[32], stochastic equilibrium has been used as the quantitative method of choice for representing the back-propagation effect of scarcity pricing quantitatively.

119. However, the stochastic equilibrium framework encountered an immediate weakness from the outset during discussions with stakeholders: the model assumes a unique market for real-time energy, and therefore a unique price for balancing energy and for imbalance energy. This assumption contradicts the practice of using imbalance prices for BRP settlement that are different from balancing prices for BSP settlement. To put it differently: whereas stochastic equilibrium can be used for understanding the effect of certain market design choices on the back-propagation of reserve prices to forward markets, it cannot be used for assessing the validity of different mixtures of BSP and BRP settlement on this back-propagation. Therefore, an alternative model based on the representation of the balancing market as a Markov Decision Process (MDP) is used in the Fifth Study to compare the efficiency of different designs.

120. In this analysis, BRPs and BSPs are considered as agents that engage in trade in a balancing market, and develop trading strategies given different market design options. The MDP simulation framework is then used for providing tangible evidence for the behaviour that the analytical mathematical framework predicts. Six designs have been studied and compared:

121. (D1): This design corresponds to the default European design where the balancing price equals the imbalance price.

122. (D2): This design corresponds to the current Belgian design with an Alpha component. It is important to note that this design relies on imbalance penalties which depend on the level of system imbalance, which is not to be confused with the level of scarcity in the system. To clarify: a system that is exhibiting a very large negative imbalance is not experiencing scarcity if it carries abundant reserve at the moment in time when the large imbalance occurs. In (D2), the BRP price is different from the BSP price and is equal to the Alpha plus the BSP price.

[32] A. Papavasiliou, Y. Smeers, and G. de Maere d'Aertrycke, "Study on the general design of a mechanism for the remuneration of reserves in scarcity situations," UCLouvain Tech. Rep., 2019. [Online]. Available: https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1986Annex.pdf
A. Papavasiliou, Y. Smeers, G. de Maere d'Aertrycke, Market Design Considerations for Scarcity Pricing: A Stochastic Equilibrium Framework, The Energy Journal, forthcoming
https://ap-rg.eu/wp-content/uploads/2020/10/J26.pdf

123. (D3): This design foresees an adder reflecting scarcity on the imbalance energy only. This design corresponds approximately to the design currently proposed by ELIA with the Omega, but without the Alpha. Again, in this design, BRP and BSP prices are different.

124. (D4): This is the design currently proposed for the implementation of a scarcity pricing mechanism. This design relies on (i) a real-time market for reserve capacity, i.e. a Balancing Capacity market operated in the balancing time frame, (ii) the application of the scarcity adder to BSPs, and (iii) the application of the scarcity adder to the BRPs.

125. (D5): This is the design proposed by ELIA in its December 2020 report (the omega proposal). This design aims at including the scarcity adder to design (D2). Specifically, this design applies the maximum of the scarcity adder and the alpha parameter to the imbalance price. The price faced by BSPs is not modified.

126. (D6): This proposal is a mixture of design (D4) and (D5). It foresees (i) the creation of a real-time market for reserve capacity, (ii) the application of the scarcity adder to BSPs, and (iii) the application of the maximum of the scarcity adder and the alpha to the BRPs, as in design (D5).

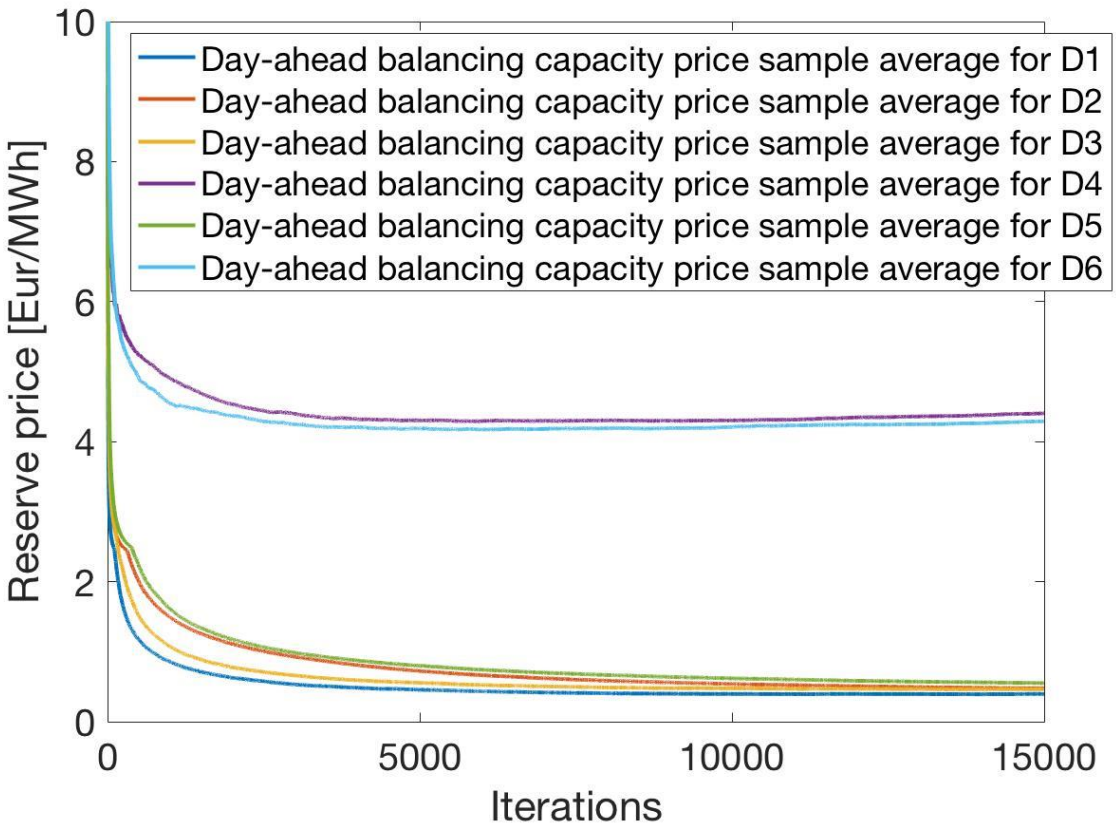

Figure 5.4.1: The evolution of the reserve price in the multi-agent simulation of [Papavasiliou, 2021d] and [Bertrand, 2021].

In figure 5.4.1, we present the evolution of the day-ahead balancing capacity price through the simulation. The horizontal axis in this figure represents rounds of learning by intelligent trading agents. For designs (D1), the reserve price sample average converges, with an increasing number of iterations, to a small value. This is anticipated by the analytical results (see Fifth Study for design (D1)-(D4) and Sixth Study for design (D5) and (D6)), because the opportunity cost for each agent in the day-ahead balancing capacity auction is equal to 0 €/MWh. For design (D2), (D3) and (D5), the reserve price sample average arrives slightly above the one resulting from (D1). For these designs, there is a trade-off between two effects. First, the imbalance price is higher than the balancing price, which creates an

opportunity cost (the BRP would request a non-zero payment in the day-ahead reserve market because it is losing the chance to do reactive balancing). Nevertheless, this opportunity cost is weakened by two effects: (i) while bidding in mFRR, a BSP is only activated if the price is higher than its marginal cost. On the other hand, while performing reactive balancing, a BRP has a certain uncertainty on the imbalance price. Due to this uncertainty, the BRP might activate itself when the price is lower than its marginal cost. This potential loss of money reduces the opportunity cost, (ii) the BRP only receives the adder if it is producing. This means that all the adders that arrive at imbalance prices lower than the BRP marginal cost do not create opportunity costs. Finally, under design (D4) and (D6), the day-ahead reserve price converges to a value which is close to the average real-time scarcity adder.

127. In conclusion, the simulations performed here, as well as the underlying quantitative analysis, expose the inability of market design alternatives (D2), (D3) and (D5) in back-propagating the value of reserve capacity in day-ahead markets. Moreover, they validate the ability of a real-time market for reserve capacity - designs (D4) and (D6) - to back-propagate the value of real-time reserve capacity to the day-ahead markets, while also preserving the incentive of agents to make their reserve resources available in the balancing market. With this real-time market for reserve capacity, agents will only sell reserve capacity in forward markets (i.e. day-ahead auctions) at the value that they would need to buy it back in real time. This is especially crucial, since it allows the value of reserve capacity to back-propagate into forward reserve auctions, and send the signal to investors that the market can support investments in reserve capacity.

128. These conclusions have been validated in the Fifth Study, which provides an analytical comparison of designs (D1)-(D4) and by the Sixth Study which analyses designs (D5) and (D6). The results of this analytical derivation of the properties of the 6 examined designs are presented below.

129. Under design (D1), it is always optimal for agents to bid their entire balancing capacity at their true marginal cost to the balancing auction. For agents with upward balancing capacity, the opportunity cost of bidding their capacity to the day-ahead reserve auction is zero. This is a pure strategy Nash equilibrium.

130. Under design (D2), in a system with independent and symmetric imbalances, it is optimal for agents to bid their entire balancing capacity at their true marginal cost to the balancing auction. For agents with upward balancing capacity, the opportunity cost[33] of bidding their capacity to the day-ahead reserve auction is zero. This is a pure strategy Nash equilibrium.

131. Under design (D3), it is optimal for a subset of agents to bid their entire balancing capacity at their true marginal cost to the balancing auction, whereas for a subset of the agents it is optimal to perform reactive balancing, and keep their flexible capacity out of the balancing auction. For agents with upward balancing capacity, the opportunity cost of bidding their capacity to the day-ahead reserve auction is less than or equal to the expected scarcity adder. This design is depressing the scarcity price in a number of ways: (i) agents who find it optimal to perform reactive balancingface an opportunity cost which is less than the scarcity price, (ii) the action itself of self-balancing is depressing balancing energy prices, and (iii) agents who find it optimal to bid their entire capacity to the balancing auction face an opportunity cost of zero for bidding reserve in the day ahead market.

132. Under design (D4), it is always optimal for agents to bid their entire balancing capacity at their true marginal cost to the balancing auction. Agents have an incentive to bid the expected scarcity adder in the day-ahead reserve auction. This is a pure strategy Nash equilibrium.

[33] This opportunity cost refers to the fact that successful bids in the day-ahead reserve auctions are required to bid at least the amount of day-ahead reserved capacity as balancing energy in the balancing market. This prevents them to perform reactive balancing and to receive the alpha.

133. Under design (D5), it is optimal for a subset of agents to bid their entire balancing capacity at their true marginal cost to the balancing auction, whereas for a subset of the agents it is optimal to perform reactive balancing, and keep their flexible capacity out of the balancing auction. For agents with upward balancing capacity, the opportunity cost of bidding their capacity to the day-ahead reserve auction is less than or equal to the opportunity cost of design (D3) which is itself lower than the expected scarcity adder. This design is depressing the scarcity price in a number of ways: (i) agents who find it optimal to self-balance face an opportunity cost which is less than the expected scarcity adder, (ii) the action itself of self-balancing is depressing balancing energy prices, and (iii) agents who find it optimal to bid their entire capacity to the balancing auction face an opportunity cost of zero for bidding reserve in the day-ahead market.

134. Under design (D6), it is always optimal for agents to bid their entire balancing capacity at their true marginal cost to the balancing auction. Agents have an incentive to bid the expected scarcity adder in the day-ahead reserve auction. This is a pure strategy Nash equilibrium.

135. In conclusion, designs (D4) and (D6) are the only designs that (i) maintain the incentive of agents to bid their entire flexible capacity to the balancing auction, while also (ii) providing an incentive to agents to back-propagate the expected scarcity adder to day-ahead reserve auctions. Nevertheless, design (D4) should be preferred to design (D6) because it is simpler and because it respects the law of one price[34] which states that since real-time energy is an uniform product it should have a single price. Therefore, on the basis of the different studies examined here, a proper implementation of scarcity pricing requires a real-time market for reserve capacity. No market design was found that did not settle real-time reserves and that is still capable of back-propagating scarcity (as efficiently).

The proposed scarcity pricing mechanism is able to achieve the backpropagation of the scarcity price signal.

5.5. DOES THE PROPOSED DESIGN DISTORTS INCENTIVES IN CROSS-BORDER SETTINGS?

136. Belgium will soon connect to the European cross-border balancing platforms MARI and PICASSO. For this connection, it is necessary that national designs do not distort market participant incentives. Specifically, the CREG wants to avoid having a design that incentivizes an expensive generator in Belgium to react if there is a cheaper generator abroad that can cover the imbalance (and cross-zonal capacities are available).

137. The incentives given by different designs in cross-border settings are currently analysed by the CORE and the CREG. In what follows, the initial conclusions of the analysis (based on analytical solutions) are presented. These results are illustrated on the following two-zone example (see Figure 5.5.1).

[34] Jevons 1879: The Theory of Political Economy "*In the same open market, at any moment, there cannot be two prices for the same kind of article.*"

138. In this example, additional components (such as a scarcity adder or an incentivising component - alpha adder) are placed on the balancing and imbalance price in zone B while it is assumed that zone A does not use any additional component (the imbalance price is equal to the balancing price).

139. In zone A, there is one generator with a cost of 100 €/MWh and a maximum capacity of 1000 MW. In zone B, there is one generator with a marginal cost of 200 €/MWh and a maximum capacity of 1000 MW. Generators 1 and 2 are owned by BRP1 and BRP2 that also have the role of BSPs. They can therefore decide if they prefer bidding their generator in the balancing platform or performing reactive balancing. Zone A is short of 50 MW while zone B is short of 700 MW. For the sake of simplicity, the example only considers mFRR with scheduled activation (and not aFRR nor mFRR with direct activation).

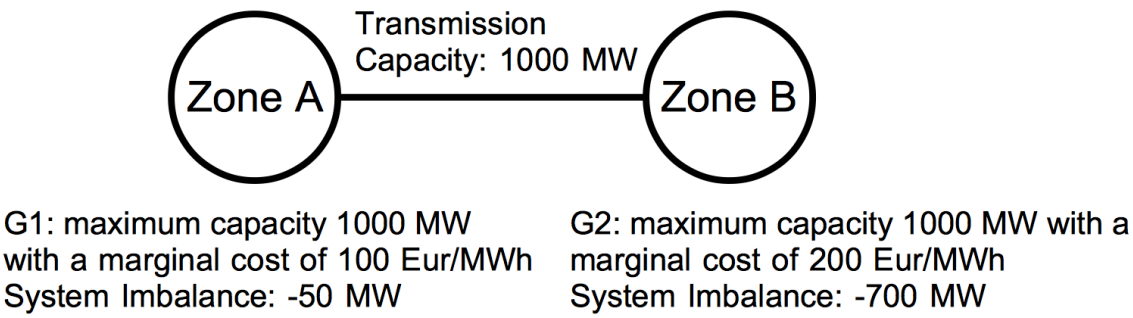

Figure 5.5.1: Example to illustrate the impact of different designs on the real-time dispatch in cross-border settings

5.5.1. No adder (D1)

140. If no adder is placed, there is an incentive for all market participants to bid all their capacity at their marginal cost.

141. In this design, generator 1 has an incentive to bid 1000 MW at 100 €/MWh. On its side, generator 2 has an incentive to bid 1000 MW at 250 €/MWh. MARI would dispatch Generator 1 for 750MW in order to cover the imbalance in zone A and zone B. The total cost of the system would be 750*100 = 75000 €.

5.5.2. Incentivizing components or scarcity adders applied on BRPs only (D2), (D3) and (D5)

142. With these designs, it has been shown that BRPs might have an incentive to react even though the balancing price is below their marginal cost.

143. In the example, let us assume that the incentivizing component (applied in zone B) grows linearly from 0 €/MWh at 200 MW to 200 €/MWh at 700 MW. Anticipating that generator 1 will be dispatched by the platform, BRP2 expects that the balancing price will be equal to 100 €/MWh and the imbalance price in zone B would be equal to 100 + α €/MWh. In order to maximize its profit, BRP2 performs reactive balancing until the imbalance price (100 + α €/MWh) reaches its marginal cost (200 €/MWh). This is obtained if the alpha is equal to 100 €/MWh which corresponds to a system imbalance of 450

MW in zone B. Therefore BRP2 performs 250 MW of reactive balancing[35]. The total cost of the system is 250*200 + 500*100 = 100000 €.

144. Incentivizing the reaction of BRPs when the balancing price is below their marginal cost prevents some offers that are part of the optimal dispatch to be cleared. The consequence is a decrease of the balancing price (also in neighbouring countries). This would therefore negatively impact BSPs from neighbouring countries and would raise questions about competition fairness.

5.5.3. Scarcity adders on BSPs and BRPs, no real-time market for reserves

145. In this design, BSPs have an incentive to bid all their capacity at their marginal cost minus the expected adder.

146. Let us assume that the expected adder in zone B is 200 €/MWh. In this situation, generator 1 has an incentive to bid 1000MW at 100 €/MWh as there is no adder in zone A. On its side, generator 2 has an incentive to bid at 0 €/MWh because if it is accepted, it will receive the adder of 200 €/MWh. Generator 2 is therefore dispatched for 750 MW. The balancing price in zone A is 0 €/MWh and the balancing price in zone B is 200 €/MWh. The total cost of the system is 750*200 = 150000 €.

147. As for the previous situation, the implementation of this design in zone B would reduce the profit of BSPs in zone A and raises questions on competition fairness.

5.5.4. Scarcity adders on BSPs, BRPs and a real-time market for reserve (D4)

148. In this design, market participants have an incentive to bid all their capacity at their marginal cost.

149. Let us assume that the system is tight in zone B and therefore the adder in zone B is 200 €/MWh. In this situation, generator 1 has an incentive to bid 200MW at 100 €/MWh as there is no adder in zone A. On its side, generator 2 has an incentive to bid at 200 €/MWh because it receives the adder no matter if it is accepted or not in the platform (real-time market for reserve). Generator 1 is therefore dispatched for 750MW. The balancing and imbalance prices in zone A are 100 €/MWh and the balancing and imbalance prices in zone B are 300 €/MWh. The total cost of the system is 750*100 = 75000 €. It can be observed that this design does not distort the real-time dispatch. As a consequence, it does not decrease the profit of BSPs in zone A.

150. Therefore, this design ensures a fair competition across borders[36].

[35] Notice that this is an optimistic view of reactive balancing because there is only one BRP per zone. In reality, as there are several BRPs, the profit of each BRP depends of the other BRP's behaviour. This may lead to coordination problems.
[36] The fact that BSPs in different zones do not receive the same price will be discussed in section 9.9.

The proposed scarcity pricing mechanism with a real-time market for reserves is the only design with adders or incentivizing components that preserves correct incentives for market participants. Therefore, it allows an optimal use of available balancing resources and reduces the costs for consumers.

5.6. THE IMPORTANCE OF A REAL-TIME MARKET FOR RESERVES

151. In electricity markets, the price of the commodity can only be settled in real time because it is in real time that the commodity is exchanged and that the real conditions of the system can be observed. There are also several forward markets (day-ahead, intraday, long-term markets) in which producers and consumers can hedge their exposure to risk. On the contrary, for reserve, there is currently only a forward market (day-ahead) but no real-time market.

152. One can therefore wonder what the day-ahead reserve price is reflecting and by which mechanism would this day-ahead reserve price reflect the real-time conditions of the system. In order to answer to this question, let us analyse how a bid in the day-ahead reserve market should be placed. The price of this offer can reflect all the variable costs (no investment costs, which are sunk costs) or the opportunity costs.

153. For the variable cost, this includes the start-up cost and must-run costs. There is no reason that these costs reflect scarcity in real time.

154. For the opportunity cost, by being accepted in the day-ahead reserve, the producers lose the opportunity of selling their energy in the day-ahead and intraday market as well as the opportunity to balance their portfolio (self-balancing/reactive balancing). Nevertheless, they are still able to sell their energy in the balancing market. Their opportunity cost (if we assume risk neutrality) is therefore the difference between their expected profit if they could sell their energy in all markets (day-ahead, intraday, balancing, reactive balancing) minus their expected profit in the balancing market.

155. The first observation that can be made is that, if the day-ahead and intraday market prices are aligned with the balancing market price, there is no reason to believe that there is an opportunity cost by not being able to sell in day-ahead and intraday. One could argue that, in the balancing market, there is a higher chance not to be cleared. This is indeed true in the merit order approach (only offers in the direction solving the system imbalance can be accepted) but will not hold true with the welfare maximization that will be used in MARI. Indeed, with a welfare maximization (i.e. counter-activations), a cheap upward offer will be matched with a more expensive downward offer even if the system is long because this matching increases the welfare. In conclusion, there is no reason to believe that a higher profit could be reached in the day-ahead or intraday market compared to the balancing market. Therefore, this does not generate an opportunity cost for the day-ahead reserve market.

156. We can also analyse the opportunity cost coming from the missing opportunity to perform reactive balancing. The opportunity cost would be coming from the fact that the imbalance price would be more favourable than the balancing price[37].

157. This can be seen historically in 2018 (as shown in ELIA study of December 2020), when the imbalance price was the marginal price of upward activation while the balancing price was paid-as-bid. In this situation, an opportunity cost can be generated (difference between the marginal price and the bid price of the market participant) but this opportunity cost does not reflect scarcity.

158. Currently, there are two main differences between the imbalance price and the mFRR price, the fact that the aFRR price can also set the imbalance price and the alpha component. For the fact that the aFRR can set a higher imbalance price than the mFRR price, there is no reason that this reflects scarcity. For the alpha component, it has been shown that it has no direct link to scarcity and that the backpropagation is limited (see section 5.4).

159. In conclusion, in the current design, there are no theoretical reasons supporting that the day-ahead reserve price reflects scarcity, if no real-time market for reserves is created.

[37] Note that differences in balancing and imbalance prices have been shown to have a negative effect on the European real-time dispatch in section 5.5.

6. DESCRIPTION OF THE PROPOSED DESIGN

160. In this chapter, we present the design we propose for the implementation of a scarcity pricing mechanism in Belgium. We foresee two different adders, a fast adder for reserve that can be fully activated in 7.5 minutes and a slow adder for reserve that can be activated in 15 minutes[38].

161. The chapter is structured as follows:

- Section 6.1 presents to which prices the different adders will be applied.
- Section 6.2 describes the choice of the value of lost load (VOLL) that we make.
- Section 6.3 presents the computation needed for obtaining the amount of reserve available in 7.5 and 15 minutes.
- Section 6.4 describes how we choose the parameters needed in order to compute the loss of load probability for a given amount of reserve available.
- Section 6.5 describes the settlement formula and provides examples.
- Section 6.6 indicates how the mechanism is financed.
- Section 6.7 refers to fine-tuning before implementation.

6.1. ADDER APPLICATION

162. This section describes how the prices will be defined in the different markets when a scarcity pricing mechanism is implemented.

6.1.1. Day-ahead energy

163. For the day-ahead energy price λ_E^{DA}, there is no change compared to the current situation. It is the clearing price obtained for Belgium from the Euphemia algorithm.

6.1.2. Day-ahead reserve

164. For the day-ahead reserve, the computation of the price remains also the same as currently planned. There are two prices for the two different reserve product (aFRR and mFRR):

- $\lambda_{R,aFRR}^{DA}$, the price for aFRR reserve capacity in the day ahead. This price is obtained from the reserve clearing performed by ELIA.

[38] It is noted that the Full Activation Time of FRR will change with the connection to the balancing platforms. See ACER decisions on aFRR and mFRR indicating that aFRR shall be fully deployed in 5 minutes and that mFRR shall be fully deployed in 12,5 minutes; https://extranet.acer.europa.eu/en/Electricity/MARKET-CODES/ELECTRICITY-BALANCING/Pages/06-aFRR-IF.aspx ; https://extranet.acer.europa.eu/en/Electricity/MARKET-CODES/ELECTRICITY-BALANCING/Pages/05-mFRR-IF.aspx

- $\lambda_{R,mFRR}^{DA}$, the price for mFRR reserve capacity in the day ahead. This price is obtained from the reserve clearing performed by ELIA.

6.1.3. Real-time energy

165. In Europe, there are 4 different prices for energy in real-time:

- $\lambda_{E,aFRR}^{RT}$, the price received by the aFRR reserve which is activated to produce energy. This price can change every 4 second based on the clearing of the PICASSO platform.
- $\lambda_{E,mFRRs}^{RT}$, the price received by the mFRR reserve for scheduled activation which is producing energy. This price is valid for the considered interval of 15 minutes.
- $\lambda_{E,mFRRd}^{RT}$, the price received by the mFRR reserve for direct activation which is producing energy.
- $\lambda_{E,BRP}^{RT}$, the price received by a BRP for its excess production (imbalance price). This price is valid for the considered interval of 15 minutes.

166. The idea of scarcity pricing is that the way these prices will be computed will remain the same. Nevertheless, a scarcity adder will be placed on top of these prices.

167. For the real-time energy price received by the aFRR reserve activated, it is currently foreseen that the price will be given by the PICASSO platform λ_{PIC}. With the introduction of scarcity pricing, an aFRR adder would be put on top of the price from the PICASSO platform[39]:

$$\lambda_{\mathrm{E,aFRR}}^{\mathrm{RT}} = \lambda_{\mathrm{PIC}} + adder_{aFRR}$$

where the adder is defined[40] as:

$$adder_{aFRR} = 0.5 \cdot \max(\mathrm{VOLL} - \overline{\lambda_{PIC}}, 0) \cdot LOLP_{7.5}(R_{7.5}) \; + 0.5 \cdot \max(\mathrm{VOLL} - \overline{\lambda_{PIC}}, 0) \cdot LOLP_{15}(R_{15})$$

where (i) λ_{PIC} is the 4-second price received by the BSP from the PICASSO platform. (ii) $\overline{\lambda_{PIC}}$ is the weighted average price of the four-second intervals in the fifteen-minute period. $\overline{\lambda_{PIC}}$ is used rather than λ_{PIC} in the second part of the formula in order to have the same adder for all BSPs.

168. For the real-time energy price received by the mFRR reserve activated, it is currently foreseen that the price will be given by the MARI platform λ_{MARIs} for scheduled activation and λ_{MARId} for direct activation. With the introduction of a scarcity pricing mechanism, an mFRR adder would be put on top of the price obtained from the MARI platform:

$$\lambda_{\mathrm{E,mFRRs}}^{\mathrm{RT}} = \lambda_{\mathrm{MARIs}} + adder_{mFRR}$$

$$\lambda_{\mathrm{E,mFRRd}}^{\mathrm{RT}} = \lambda_{\mathrm{MARId}} + adder_{mFRR}$$

where the adder is defined as:

$$adder_{mFRR} \; = \; 0.5 \cdot \max((\mathrm{VOLL} - \lambda_{\mathrm{MARId}}),0) \cdot LOLP_{15}(R_{15})$$

[39] Notice that this adder will only apply to upward activated aFRR. Indeed, if an aFRR bid is activated downward in situation of scarcity, it will not have to pay the adder.

[40] The definition of the different components of the adder will be defined in sections 6.2, 6.3 and 6.4.

λ_{MARId} is used for the computation of the adder for both the scheduled and the direct activation in order to have a unique adder. Notice that, from the platform organisation, it is guaranteed that the price for mFRR with direct activation is at least equal to the price for mFRR with scheduled activation.

169. For the real-time energy price received by the BRPs, the formula will be based on the prices from MARI and PICASSO. The precise formula is still in discussion currently and will be defined in the balancing rules. With the introduction of a scarcity pricing mechanism, the mFRR adder would be put[41] on top of the imbalance price λ_{I} (obtained from the formula defined in the balancing rules):

$$\lambda_{\mathrm{E,BRP}}^{\mathrm{RT}} = \lambda_{\mathrm{I}} + adder_{mFRR}$$

6.1.4. Real-time reserve

170. Currently, there is no market for real-time reserve in Belgium. As for the day-ahead reserve market, two adders would be introduced, an aFRR adder and an mFRR adder:

- $\lambda_{R,aFRR}^{RT}$, the price received by the aFRR reserve which is offering balancing capacity in real time (not contracted in day-ahead).
- $\lambda_{R,mFRR}^{RT}$the price received by the mFRR reserve which is offering balancing capacity in real time (not countracted in day-ahead).

These 2 prices can be computed as:

$$\lambda_{R,aFRR}^{RT} = adder_{aFRR}$$

$$\lambda_{R,mFRR}^{RT} = adder_{mFRR}$$

6.1.5. Article 55.4 of the Balancing Guideline

171. As the aFRR adder is bigger than the mFRR adder, there is a chance that the above mechanism does not respect article 55.4 of the Balancing Guideline (see section 1.4). This can be seen on the following example. If there is only an activation of one aFRR bid, the imbalance price (without adder) would be set by this bid price. If the aFRR adder is strictly higher than the mFRR adder, the aFRR price (including the adder) would be strictly higher than the imbalance price (including the adder) which would not respect article 55.4 of the Balancing Guideline.

A solution for this problem would be to bound the aFRR adder in order to respect article 55.4 of the balancing Guideline. Specifically, if the aFRR adder would make the design not respect article 55.4, the aFRR adder would be taken as the maximum value such as article 55.4 would be respected.

[41] It should still be decided if the adder will be applied no matter the Belgian system imbalance or only if the Belgian system is short. Nevertheless, this is a relatively minor point because it is difficult to imagine a situation in which the system is long and, at the same time, there is no upward reserve available (including cross-border).

6.2. VOLL DETERMINATION

172. The goal of introducing a scarcity pricing mechanism is to improve the efficiency of the price formation on the electricity markets. With scarcity pricing, the real-time electricity price reflects the system needs for capacity, namely the needs for energy, but also for reserves. Indeed, both energy and reserves are needed to have a robust electricity market.

173. For imbalance prices, the CREG, approved[42] the bidding limit at 13.500 €/MWh, proposed by the TSO. In its decision, the CREG stated that if the imbalance price would hit 13.500 €/MWh, the TSO can propose to increase this limit. The CREG will then investigate to what extent this price can be explained by real fundamentals of supply and demand or whether there are indications that market power was used. Simulations performed in the Sixth Study demonstrated that a value of 13 500 € resulted in lower total system costs (energy plus unserved energy; see § 188), which is an important element for the determination of the adder.

174. Therefore, the CREG used the current bidding limit for imbalance prices of 13.500 €/MWh as the VOLL for calculating the price adders. This value, together with the "old" reference of 8300 €/MWh was used in the previous studies presented above.

175. On the basis of recent developments, it appears that the VOLL of Belgium[43] has been set at 17340 €/MWh. This new value will be used in future simulations of the mechanism.

6.3. ESTIMATION OF THE AMOUNT OF RESERVE AVAILABLE IN THE SYSTEM TO COMPUTE THE ADDERS

6.3.1. Estimation of the amount of reserve available in 15 minutes

176. For the amount of reserve available in 15 minutes, we follow the proposition of ELIA in its 2020 report.

$$R_{15} = \mathrm{R2} + \mathrm{R3std} + \mathrm{R3flex} + \mathrm{IC} + \mathrm{ICEnergyLimited} + \mathrm{SI} + \mathrm{InterTSOImport}$$

where

- R_{15} is the amount of reserve available in 15 minutes.
- $\mathrm{R2}$ is the amount of upward secondary reserve.
- $\mathrm{R3std}$ is the amount of upward standard tertiary reserve.
- $\mathrm{R3flex}$ is the amount of upward flexible tertiary reserve.
- IC is the upward non-contracted capacity available by coordinable generators.
- $\mathrm{ICEnergyLimited}$ is the non-contracted upward imbalance energy available on generators with limited capacity.
- SI is the measured system imbalance.

[42] See CREG decision n°1806:
NL: https://www.creg.be/sites/default/files/assets/Publications/Decisions/B1806NL.pdf
FR: https://www.creg.be/sites/default/files/assets/Publications/Decisions/B1806FR.pdf
[43] See document on the CRM

- $\mathrm{InterTSOImport}$ is the import capacity available for Belgium. The way this capacity will be measured should be further discussed with ELIA.

177. Notice that, with the introduction of explicit bidding, we expect that the value of the terms IC, ICEnergyLimited will be shifted to R3std.

6.3.2. Estimation of the amount of reserve available in 7.5 minutes

178. For the amount of reserve available in 7.5 minutes, the proposition of ELIA is:

$$R_{7.5} = \mathrm{R2} + \rho * (\mathrm{R3std} + \mathrm{R3flex} + \mathrm{IC} + \mathrm{ICEnergyLimited} + \mathrm{SI} + \mathrm{InterTSOImport})$$

179. In theory, the only reserve that should be fully available in 7.5 minutes is R2. Nevertheless, it would be too restrictive to only consider R2 as available capacity in 7.5 minutes. Indeed, it is reasonable to think that the reserve that should be fully available in 15 minutes already starts increasing its output in the 7.5 first minutes.

180. ELIA has proposed in its 2018 report to consider that a given percentage (the ρ parameter) of mFRR resource can react in 7.5 minutes (the same percentage for every mFRR offers).

181. The assumption of ELIA is that half of the reserve available in 15 minutes would be available in 7.5 minutes ($\rho = 0.5$). The CORE (on proposition of the CREG) has used a different value ($\rho = 0.28$) except for the SI and the InterTSOImport for which ELIA's value has been kept ($\rho = 0.5$). This different parameter reflects the fact that, unlike aFRR activation, the mFRR activation is not made instantaneously after a change in the balance of the system. The CORE study has also demonstrated that the choice of this parameter has a strong impact on the adder value.

182. In theory, it should be possible to compute directly the amount of reserve available in 7.5 minutes for a specific generator. This possibility will be discussed with ELIA.

6.4. ESTIMATION OF THE LOSS OF LOAD PROBABILITY

183. The mean and standard deviation of the $LOLP_{15}(R_{15})$ distribution can be derived from the quarter-hourly system imbalances. In order to cope with differentiated system conditions, several distributions are considered in order to reflect this diversity and the mean and standard deviations are adapted to the season and to the moment of the day.

184. In principle, the parameters will be recalibrated every year using the system imbalance data of the previous year, or of the 3 previous years. An example of the parameters used by CORE in the Sixth Study are presented in Table 6.4.1.

Season	Hour block	μ_{15}(MW)	σ_{15}(MW)
Winter	1,2,23,24	29.00	160.25
Winter	3-6	25.93	134.12
Winter	7-10	6.77	165.30
Winter	11-14	44.00	190.88
Winter	15-18	56.95	169.15
Winter	19-22	3.99	144.29
Spring	1,2,23,24	7.74	145.75
Spring	3-6	27.05	128.75
Spring	7-10	-0.86	143.95
Spring	11-14	28.81	173.13
Spring	15-18	40.64	159.02
Spring	19-22	-7.44	127.18
Summer	1,2,23,24	14.54	134.15
Summer	3-6	27.89	111.75
Summer	7-10	0.86	130.06
Summer	11-14	28.98	151.59
Summer	15-18	27.60	144.17
Summer	19-22	-5.93	119.16
Autumn	1,2,23,24	11.62	151.34
Autumn	3-6	29.19	124.09
Autumn	7-10	-21.08	160.09
Autumn	11-14	-7.58	175.77
Autumn	15-18	-5.30	144.98
Autumn	19-22	-10.95	150.09

Table 6.4.1: System imbalance average (μ) and standard deviation (σ) per season and 4-hour block for 2015-2017 (from the Sixth Study of CORE).

185. In order to avoid IT requirements, the $LOLP_{7.5}(R_{7.5})$ distribution is estimated from the $LOLP_{15}(R_{15})$ rather than 1 minute imbalance data[44]. Two options have been considered in the Sixth Study of CORE: (i) two consecutive 7.5-minute imbalance increments are fully correlated; or (ii) two consecutive 7.5-minute imbalance increments are independent.

186. The impact of this design decision has been analysed by CORE in the Sixth Study. In order to compare the two options, the CORE realized a simulator of the Belgium market. Specifically, they model the different power plants in Belgium and simulate their operations based on historical infeed and demand.

187. Using this model, it is possible to observe how the different power plants will be committed depending on the choice of parameters used for the computation of the operating reserve demand curve, and consequently the scarcity adder. It is also possible to compute the operational cost for each delivery period as well as the scarcity adder.

188. In order to decide between the two options, the study proposes to compare the total system cost for the 2 different options (independent versus correlated) and choose the one with the smallest total cost. This total system cost includes: (i) fuel cost; (ii) fixed cost; (iii) activation cost; and (iv) shortage cost.

189. The authors have observed that considering independent 7.5-minute imbalance increments decreases the cost of operation by 0.8% compared to fully correlated imbalance increments.

[44] which corresponds to non-validated data https://www.elia.be/en/grid-data/balancing/imbalance-prices-1-min

190. Moreover, the study demonstrates that assuming independent 7.5-minute imbalance increments results in less risky cash flows. This is illustrated in Figure 6.4.1.

191. This figure shows the average value of the adder with respect to the level of risk aversion, where the risk measure is the conditional value at risk. More specifically, the graph represents the average adder with respect to the percentage of the best data excluded.

192. It can be observed that the case of correlated increments relies more on large spikes (the green curve reaches a small value quickly, which means that the largest part of the average adders is coming from rare events) compared to the case of independent increments, which relies on more moderate spikes (the blue curve decreases slowly). This is illustrated by the fact that, for the green curves, most of the average adder is obtained on the 2% most extreme hours, which is not the case for independent increments.

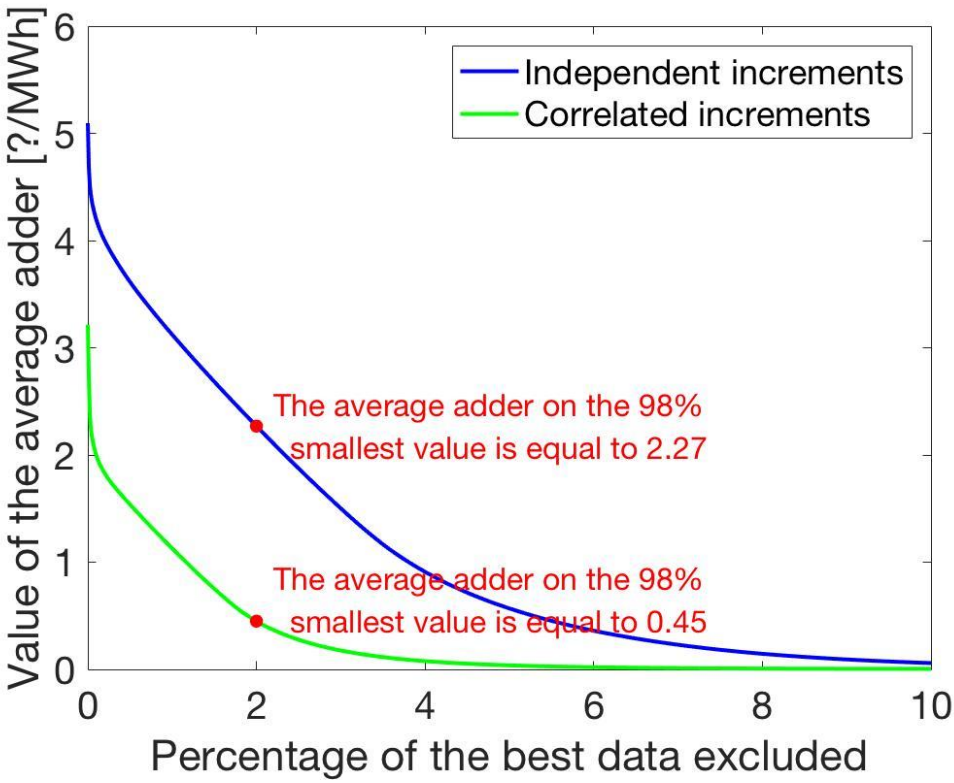

Figure 6.4.1: Value of the mean adder for different levels of risk aversion (Conditional Value at Risk).

193. In conclusion, we consider independent 7.5-minute imbalance increments. This means that $\sigma_{7.5} = \frac{\sqrt{2}}{2} \cdot \sigma_{15}$ where $\sigma_{7.5}$ is the standard deviation used for the LOLP at a 7.5-minute time frame and σ_{15} is the standard deviation used for the LOLP at a 15-minute time frame.

6.5. SETTLEMENT

This section describes the settlement faced by the different market participants and presents examples.

6.5.1. Formulas

194. The settlement for the different types of market participants is presented in Table 6.5.1.

195. The first column shows the pay-off of an aFRR BSP that (i) is cleared for $r_{7.5,g}^{DA}$MW in the day-ahead reserve market; (ii) is activated for $ra_{7.5,g}$MW in PICASSO; and (iii) provides $r_{7.5,g}^{RT}$ MW of reserve in real-time.

196. The second column shows the pay-off of an mFRR BSP that (i) is cleared for $r_{15,g}^{DA}$MW in the day-ahead reserve market; (ii) is activated for $ra_{15,g}$MW in MARI; and (iii) provides $r_{15,g}^{RT}$ MW of reserve in real-time. For the aFRR and mFRR BSPs, the day-ahead payoff is the revenue from the day-ahead reserve market (line 2). The real-time payoff can be decomposed as (i) the reserve imbalance (difference between the reserve provided in real-time and the reserve cleared in the day-ahead reserve market (line 4)); and (ii) the payoff for the activated energy (line 3).

197. The third column shows the pay-off of a BRP that (i) is cleared for p_g^{DA} MWh in the day-ahead energy market; and (ii) produces p_g^{RT} MWh of energy in real-time.

198. For a BRP, the day-ahead payoff is the revenue from the day-ahead energy market (line 1), and the real-time payoff (line 3) is the revenue for the BRP imbalance (difference between real-time production and schedules).

Market participants Pay-offs	aFRR BSP	mFRR BSP	BRP
Day-ahead Energy	0	0	$\lambda_E^{DA} \cdot \mathrm{p}_g^{DA}$
Day-ahead Reserve	$\lambda_{R,aFRR}^{DA} \cdot r_{7.5,g}^{DA}$	$\lambda_{R,mFRR}^{DA} \cdot r_{15,g}^{DA}$	0
Real-time Energy	$\lambda_{E,aFRR}^{RT} \cdot ra_{7.5,g}$	$\lambda_{E,mFRR}^{RT} \cdot ra_{15,g}$	$\lambda_{E,BRP}^{RT}(\mathrm{p}_g^{RT} - \mathrm{p}_g^{DA})$
Real-time reserve	$\lambda_{R,aFRR}^{RT} \cdot (r_{7.5,g}^{RT} - r_{7.5,g}^{DA})$	$\lambda_{R,mFRR}^{RT} \cdot (r_{15,g}^{RT} - r_{15,g}^{DA})$	0

Table 6.5.1: Settlement formula for different types of market participants.

6.5.2. Example settings

199. In the rest of the section, we present an example of settlement for three different types of market participants: (i) a producer which owns a generator for offering reserves, (ii) a wind farm park owner, and (iii) a demand response actor.

200. The prices in the different markets are presented in Table 6.5.2.

Market	Price
Day-ahead energy price	80
Day-ahead aFRR capacity price	6
Day-ahead mFRR capacity price	4
PICASSO price	120
MARI price	100
Fast adder (aFRR adder)	40
Slow adder (mFRR adder)	15

Table 6.5.2: Different prices in the example (reserve prices are in € per MW and energy prices are in € per MWh).

6.5.3. Example 1: generator offering reserves

201. The case of a market participant which has one generator with a maximum capacity of $50MW$ is considered. We also assume that the generator can offer a maximum of $15MW$ of aFRR reserve and $15MW$ of mFRR reserve (on top of the 15 MW of aFRR reserve).

In the day ahead, the market participant is cleared for (i) $15MW$ of aFRR reserve, (ii) $10MW$ of mFRR reserve, and (iii) $20MWh$ of energy.

In the balancing market, the market participant offers the rest of its mFRR capacity (5MW) as a free bid (this value is limited by the maximum capacity of the market participant).

In real time, the market participant (i) is activated for $12MW$ of aFRR (it is therefore providing 3MW of aFRR reserve in real-time), and (ii) is activated for $9MW$ of mFRR (it is therefore providing 6MW of mFRR reserve in real time).

The settlement for the market participant is presented in Table 6.5.3.

- For day-ahead energy, the payoff is coming from the selling in the day-ahead market.
- For day-ahead reserve, the payoff is coming from the selling of aFRR and mFRR reserve in the day ahead.
- For real-time energy, the payoff is coming from the activation of aFRR and mFRR.
- For real-time reserve, the payoff is coming from the reserve imbalance of aFRR and mFRR between real time and the day ahead.

Market	Formula	Pay-offs
Day-ahead energy	$\lambda_E^{DA} \cdot \mathrm{p}_g^{DA}$	$80 \cdot 20 = 1600€$
Day-ahead reserve	$\lambda_{R,aFRR}^{DA} \cdot r_{7.5,g}^{RT} + \lambda_{R,mFRR}^{DA} \cdot r_{15,g}^{RT}$	$6 \cdot 15 + 4 \cdot 10 = 130€$
Real-time energy	$\lambda_{E,aFRR}^{RT} \cdot ra_{7.5,g} + \lambda_{E,mFRR}^{RT} \cdot ra_{15,g}$	$(120 + 40) \cdot 12 + (100 + 15) \cdot 9 = 2955€$
Real-time reserve	$\lambda_{R,aFRR}^{RT} \cdot (r_{7.5,g}^{RT} - r_{7.5,g}^{DA}) + \lambda_{R,mFRR}^{RT} \cdot (r_{15,g}^{RT} - r_{15,g}^{DA})$	$40 \cdot (3 - 15) + 15 \cdot (6 - 10) = -540€$

Table 6.5.3: Settlement of the market participant in example 1.

6.5.4. Example 2: wind farm park

202. We consider the case of a market participant owning a wind farm park. We assume that the market participant bids its expected production of 30MWh in the day-ahead energy market, and that the realized production in real time is 40MWh.

203. The settlement for the market participant is presented in Table 6.5.4.

- For day-ahead energy, the payoff is coming from selling in the day-ahead market.
- For real-time energy, the payoff is coming from the energy imbalance.

Market	Formula	Pay-offs
Day-ahead energy	$\lambda_E^{DA} \cdot \mathrm{p}_g^{DA}$	$80 \cdot 30 = 2400€$
Day-ahead reserve	0	$0€$
Real-time energy	$\lambda_{E,BRP}^{RT}(\mathrm{p}_g^{RT} - \mathrm{p}_g^{DA})$	$(120 + 15) \cdot (40 - 30) = 1350€$
Real-time reserve	0	$0€$

Table 6.5.4: Settlement of the market participant in example 2.

6.5.5. Example 3: demand response

204. We consider the case of a market participant that provides demand response. We assume that the market participant can reduce its consumption by 2MW and that it is qualified for mFRR reserve.

205. We assume that the market participant is aware of its availability shortly before real-time, and therefore it submits a balancing energy bid at that moment (no capacity was offered in day-ahead). We also consider that its marginal cost is high and therefore it is not activated in real time. The settlement for the market participant is presented in Table 6.5.5. For real-time reserve, the payoff is coming from the mFRR reserve provided in real time.

206. A scarcity pricing mechanism creates the opportunity for “short notice” demand response to receive a capacity fee.

Market	Formula	Pay-offs
Day-ahead energy	0	$0€$
Day-ahead reserve	0	$0€$
Real-time energy	0	$0€$
Real-time reserve	$\lambda_{R,aFRR}^{RT} \cdot (r_{7.5,g}^{RT} - r_{7.5,g}^{DA})$	$15 \cdot (2 - 0) = 30€$

Table 6.5.5: Settlement of the market participant in example 3.

6.6. HOW IS THIS MECHANISM FINANCED?

207. Essentially, the mechanism is a market for (reserve) imbalances, so most of the net cash flow takes place in the day-ahead reserve auctions.

208. It should be stressed that, on the general introduction on the “peak load pricing” applied in electricity markets, a scarcity pricing mechanisms should be seen, when investments are needed, as a redistribution over time of revenues coming from exceptional events when demand exceed generation capacity (see section 4 above)..

209. The energy part of the mechanism (adder on imbalance price and balancing price) is automatically taken care of by the fact that the adder is applied both on the balancing price and the imbalance price. Thus, the mechanism will mainly result in cash flows and a re-distribution of benefits between BSPs and BRPs).

210. The costs of the procurement of reserve in day-ahead may increase. These costs are currently covered in ELIA tariffs “Tarif pour les réserves de puissance et le black start appliqué aux prélèvements” and this should not change with the implementation of a scarcity pricing mechanism.

211. The reserve part of the mechanism (market for reserve imbalances) is actually expected to create a (slight) cash surplus for the TSO, because when the system has more reserve than the DA requirement, the system operator buys back surplus reserve capacity at a lower adder and when the system is tight, the system operator collects payments for reserve shortage at a higher price adder. This remains to be validated with numerical simulations.

6.7. FINE-TUNING BEFORE IMPLEMENTATION

212. The current definition of the proposed design allows the determination of its impact on the missing money of generation units in Belgium and the assessment of resource adequacy in line with Article 23 of Regulation 2019/943.

213. The implementation of a scarcity pricing mechanism is expected end 2023, in principle after the connection of ELIA to the balancing platforms. In the interval, the design may undergo some minor changes in the coming months.

214. These changes may result from the consultations that will be organised and from the exact design related to the implementation of the PICASSO and MARI platforms and other changes related to balancing currently planned by ELIA (the move to explicit bids in the balancing time frame, …) or not planned (aFRR product definition and free bids,…).

215. Changes may also come from the fact that the model of the CORE (for comparing the different variants and assessing the impact of the mechanism) takes as input the ARC data. The CREG has recently realized that the ARC data may contain errors. Specifically, a certain percentage of the reserve in the ARC are not available. This can be observed on the data of April 21. For a period of 15 minutes, the most expensive offer has been activated (which indicate scarcity) but the scarcity adder computed by ELIA (based on the ARC data) was still equal to 0.

216. The way ELIA will operate and determine MARI requests on the basis of PICASSO activations together with the determination of the Belgian net position function of available cross-border capacities and of available bids, i.e. the behaviour of the TSO, may also have an impact on incentives provided to market players and so on the fine tuning of the design.

217. In particular, in order to meet the constraints of the new environment, recent studies presented in section 5.4 and 5.5 have been done in order to check if the proposed design will lead to the correct incentives for market players. This has been done for several design alternatives.

218. Finally, and as already indicated in § 184 above, it should be mentioned that the Loss of Load Probability function of the volume of available reserves in the system applied when the mechanism should go live will be based, depending on their availability, on updated data of observed system imbalances.

7. EXPECTED IMPACT OF THE PROPOSED MECHANISM

219. The implementation of scarcity pricing will have three main impacts: (i) increase the remuneration of flexible market participants, (ii) decrease the uncertainty for investors, and (iii) enhance the value of demand response. It will also correctly settle (i) contracted BSPs (in day-ahead balancing capacity market) that do not deliver the promised service, and (ii) BRPs that decrease the system reliability.

220. The expected impact of the mechanism has already been analysed in previous studies as presented in section 5.1. The First Study demonstrated that the addition of a scarcity adder for the remuneration of flexible reserves is able to not only remunerate operating costs of CCGTs but also to remunerate investment costs of new CCGT units. The period analysed by the study - from January 2013 until September 2014 - has seen relatively deep negative Clean Spark Spreads.

221. This is confirmed in the Third Study, which shows that, with the proposed introduction of a scarcity pricing mechanism and of reserve balancing capacity market in real-time, on the basis of the simulations performed, all the CCGTs are either profitable or in the range of investment costs.

222. The impact of the mechanism has also been tested in periods of abundant capacity (2016 in the Second Study and October 2019-now in the parallel runs of ELIA[45]). It has been observed that, in this situation, the adder is equal to 0 €/MWh.

7.1. LATEST COMPUTATION OF THE EXPECTED ADDER

223. In the Sixth Study, the CORE has implemented a simulator of the Belgian market in order to analyse different variants of operating reserve demand curves. In this section, we present the results for the parameters chosen in section 6.4.

224. The simulation spans the year 2018, when several nuclear power plants were on forced outage at the end of the year and when electricity imports reached record values around 5300 MW.

225. These simulations have been conducted under the following assumptions: (i) 10MW of demand response are available in the market for aFRR, (ii) the InterTSO import (available capacity for importing in real time) is assumed to be 50MW for the mFRR and 25MW for the aFRR, as proposed in the ELIA 2020 report, (iii) The VOLL is set at 13500€/MWh (iv) the percentage of mFRR reserve available in 7.5 minutes is equal to 28%, (v) the market simulator considers the day-ahead import of Belgium as being fixed to its historical value before optimizing the dispatch of Belgian generation units, and (vi) Belgium is considered as a copper plate, therefore internal flow constraints are ignored.

226. From these simulations, the expected aFRR reserve adder for 2018 is equal to 5 €/MWh and the expected mFRR reserve adder is equal to 0,22 €/MWh[46].

227. The CORE has also estimated the expected value of the Omega adder (presented by ELIA in its 2020 report on scarcity pricing). In order to only look at the difference between the adder formulas, the CORE uses the same dispatch as the one obtained in their simulator.

[45] Note that the results of parallel runs from ELIA should be taken with caution as they may be impacted by errors in the ARC data (see paragraph 215).

[46] Note that the results of the simulation should be taken with caution as they may be impacted by errors in the ARC data (see paragraph 215).

228. The only different feature between the Omega adder and the classical formulation of a scarcity adder is the introduction of a filtering process to "ensure that the omega component only applies during structural capacity shortages." This filter establishes "the omega component for a given ISP is equalized to zero if the omega component for the previous ISP was equal to 0 €/MWh". The application of the filter is not straightforward and has not been simulated by the CORE. On this basis, if the filter is removed, ELIAs formula is equivalent to the traditional formula and therefore the value of the adders is the same.

229. In fact, the problem with the ELIA proposal is not coming from the fact that the adder is not sufficient, but from the fact that (i) it does not ensure a proper back-propagation of this adder to forward reserve markets, as demonstrated in the Fifth Study. As mentioned in section 5.4, the reason for this insufficient back-propagation is the lack of real-time market for reserve, and. (ii) it has negative cross-border effects (see section 5.5).

The proposed scarcity pricing mechanism reduces the missing money

7.2. IMPROVEMENT OF INVESTMENT INCENTIVES

230. In addition to what has already been presented in the theoretical introduction to the mechanism, it is shown below that the implementation of scarcity pricing will improve the incentives for investors because it decreases the uncertainty they face.

231. This is illustrated in Figure 7.2.1, where we show the evolution of the adders in 2018 from the simulations of the Sixth Study. In this figure, it can be observed on the right part that the scarcity pricing mechanism generates many medium-size adders (below 100 €). This reduces the risk for the investors because they are not required to rely on very few high spikes (the current situation) but rather on many medium spikes.

232. This is confirmed by Figure 7.2.2, which shows that even if a market participant is missing the 10 biggest spikes, the average adder received would still be equal to 4.67 €/MWh.

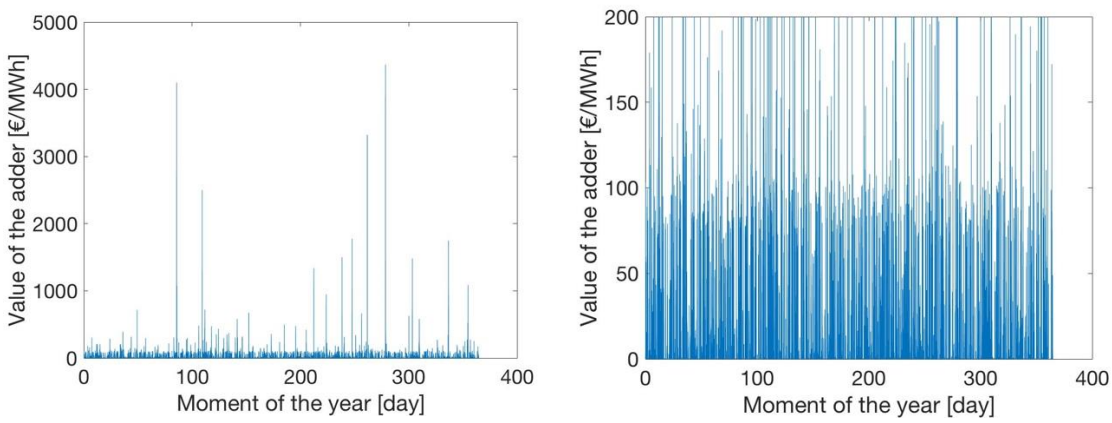

Figure 7.2.1: Values of the scarcity adder in the Sixth Study (left) zoom on medium adders (right)

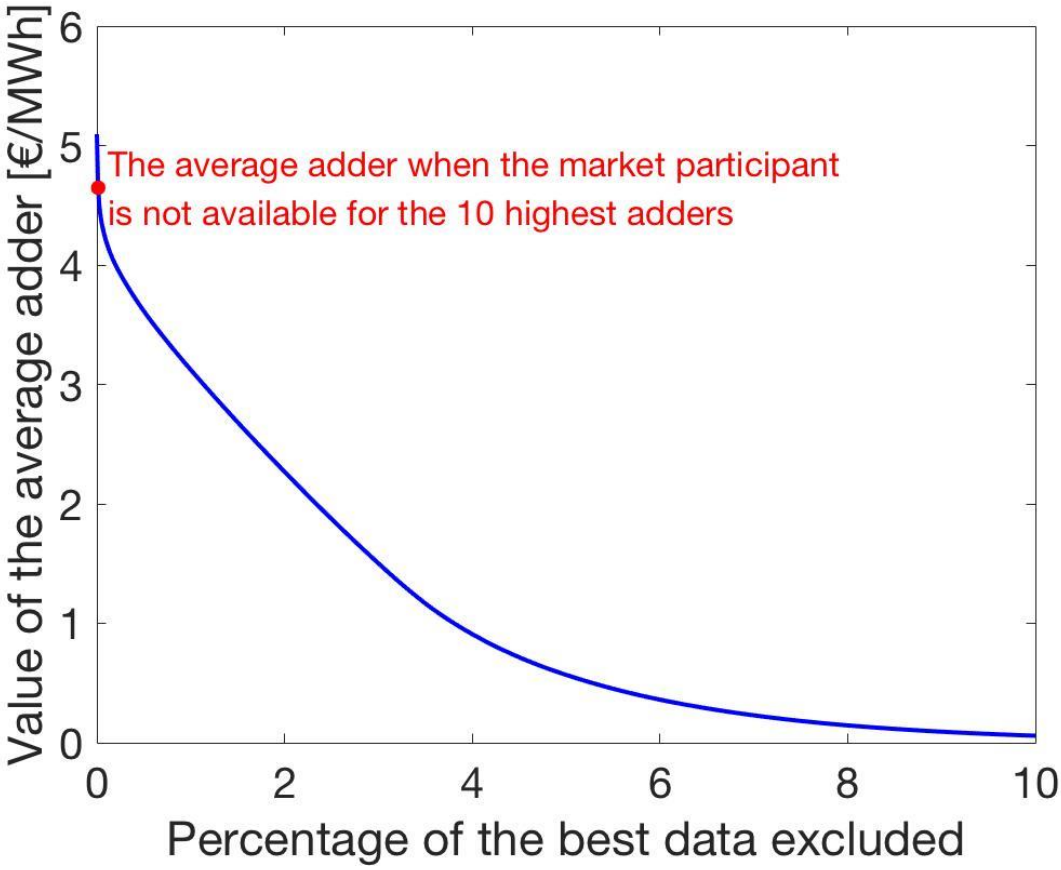

Figure 7.2.2: Value of the mean adder with respect to the percentage of the best data excluded.

The proposed scarcity pricing mechanism reduces the risk for investors

233. Scarcity pricing also improves the incentives for market participants to invest in the right technology. The reason is that scarcity pricing is a pay-for-performance mechanism. This means that market participants are remunerated when they are helping the system in periods of scarcity. This provides an incentive for market participants to invest in technologies that would be available when the system experiences scarcity.

The proposed scarcity pricing mechanism sends incentives for investing in technologies that help the system the most.

7.3. DEMAND RESPONSE ENHANCEMENT

234. In the current situation, the amount of demand response is relatively limited in the Belgian market. The offered volume of the bid ladder is very limited. There are two main reasons to explain this :

235. First, there is little interest for demand to actively participate in energy markets at levels below 500€/MWh. The problem for a demand response provider that places free bids in balancing is that it is only remunerated when decreasing its production. It is not remunerated for all the other periods (demand response is not cleared because it is too expensive), despite the fact that it provides security to the system.

236. Second, it is difficult to receive a capacity remuneration for mFRR in day-ahead due to the phase-out of the mFRR flex product. Indeed, the mFRR standard product requires being available during a complete day and being able to sustain activations for several periods in a row. This might be limiting for demand response (e.g. electric vehicles).

237. The introduction of a real-time market for balancing capacity would change this situation. With explicit bidding in mFRR (already foreseen by ELIA) and aFRR, consumers may introduce bids for consuming less at high prices representing their opportunity costs (e.g. 1000€/MWh) not being selected by the balancing platform but remunerated by the adder for providing reserve in scarcity situations.

238. Another advantage of the real-time market for reserve is that the demand response provider does not need to know in the day ahead at which hour it will be available. It is directly remunerated based on its availability in real time.

239. Finally, with the energy transition, the energy system is moving from a controllable generation mix supplying non-responsive demand towards a less controllable supply (ex. wind generation) feeding a more responsive demand. This transition calls for a new allocation, or a redistribution of the costs of an electric system (and in particular the cost related to ancillary services, such as reliability) between producers and consumers. Scarcity pricing provides a redistribution of costs inside the power system in favour of flexible demand .

The proposed scarcity pricing mechanism will stimulate demand response participation in the Belgian system.

7.4. REMUNERATION OF BSPS NOT DELIVERING THE SERVICE

240. Some market players plead "for a rebalancing of the risks between BRPs and BSPs and proposes that for contracted mFRR if the BSP is requested to activate mFRR but cannot deliver the whole volume, then only the volume supplied is remunerated instead of the volume requested as it is now."

241. It is indeed meaningful that BSPs not delivering the balancing energy they promise in the day-ahead should be penalized.

242. Nevertheless, settling BSP balancing capacity based on the quantity delivered rather than the quantity promised seems to be a deviation with respect to normal electricity market settlements. Indeed, in day-ahead or in intraday, market participants are remunerated based on the amount of energy they promise and not the amount they actually deliver in real time. It is unclear why the situation should be different in balancing markets.

243. Moreover, this proposal would introduce a different settlement of energy for contracted and non-contracted mFRR. This seems to prevent a fair competition between contracted and non-contracted bids. This is contrary to Article 44 of the Balancing Guideline requesting fair competition.

244. In fact, a real-time market for reserve would penalize BSPs not delivering the service in a "market-based" way. Specifically, a BSP contracted in day-ahead that is unable to deliver the service will have to buy back the missing reserve at the price of the real-time market for reserve. This solution is superior to fixed penalties because it is linked to risk that the BSPs are introducing to the system.

7.5. ALLOCATION OF THE RESERVE COST

245. Another interesting property from the proposed design is that it respects the "polluter pays" principle. Specifically, it is the one who creates the imbalance and therefore decreases the system reliability (less reserves available in real-time) that has to pay for the balancing capacity that it uses (at the price of the real-time market for reserve). On the other hand, the BSP that brings free bids is remunerated even if it is not cleared because it improves system reliability.

246. With the proposed design, bidding in mFRR is a hedge against the adder. Indeed, a BRP that would create an imbalance of 50 MW and has offered 50 MW to the balancing platforms does not incur any cost due to the scarcity adder (even though it is not cleared). BRPs are therefore not incentivized to keep their flexibility to balance their own portfolio. Notice that it would not be the case of a design in which an adder would only be applied to BRPs. Indeed, in this situation, a BRP has an incentive to balance its own portfolio in order to avoid being penalized by the adder (see section 5.4).

8. LEGAL COMPLIANCE OF THE PROPOSED DESIGN

247. The following sections examine the compliance of the proposed mechanism with the legal framework. Note that there are nearly no requirements related to the creation of reserve capacity markets in the balancing time frame, except some concerns related to state aid that are tackled in section 8.2 below.

8.1. AN ADDER ALSO FOR BSPS

248. A general recommendation resulting of the Consultant proposal is to apply[47] the same price (with a different sign), and therefore the same energy adder, for the energy supplied or withdrawn to BRPs and BSPs.

249. First, according to Article 18 of the Balancing Guideline, most of the requirements related to balancing are specified in national terms and conditions, provided that these terms and conditions are compatible with the development of the different balancing platforms currently implemented. These national Terms and Conditions (T&C) for BRPs and BSPs specify the actual settlement rules (prices, volumes, for BSPs and BRPs). This is the result of the chosen TSO-TSO model: every BSP/BRP always deals with its own TSO with respect to T&C. This legal framework allows national differences in the settlement for BRPs and BSPs, such as the Alpha for Belgium, and allows the implementation of a design where imbalance and balancing energy prices are equal (with a different sign).

250. Different prices for balancing energy (applied to BSPs) and for imbalance energy (charged on BRPs), linked to the presence of an Alpha component, is rather exceptional in Europe. Concerning the link between these two entities/concepts, at the origin, only BRPs existed and BSPs were created to allow more flexibility for the procurement by the TSO of reserves necessary to the system. But the concept of the BRP remains unchanged, meaning that this party is kept accountable for the imbalances it causes in the system. All market participants shall be responsible for the imbalances they cause in the system ('balance responsibility') and shall strive to be balanced or shall help the electricity system to be balanced (see Article 5.1, Regulation 943). This responsibility cannot be imagined without a strong link to a BSP that balances the energy consumed/produced by the BRP (see Article 18(4) of the Balancing Guideline). There is no obvious reason for having a different price applying to the supply side (BSP) and to the consumption side (BRP), and any differentiation may lead to inefficient (for the system) arbitrage possibilities.

[47] In practice, the current proposal may deviate slightly from this principle in order to comply with the existing legal framework – no cross product uniform pricing – and due to the fact that strictly speaking this principle only holds at a given moment and may not apply for products with different durations.

251. As an example, for the Netherlands, BRPs and BSPs face mostly[48] the same energy price[49].

252. Quick readings of some parts of the existing legislation may lead to the conclusion that a scarcity pricing adder can only be added to BRPs. Instead, as it will be shown below, this interpretation leads to inconsistencies indicating that this interpretation may not be the right one.

253. Article 44(3) of the Balancing Guideline clearly allows the application of a scarcity adder (to settle the procurement costs of balancing capacity) on the imbalance price charged on BRPs. This is confirmed by the ACER Decision 18/2020 on imbalance settlement harmonisation where Article 9.6 (a) allows a scarcity component to be used in nationally defined scarcity situations. Note also that this article clearly envisages a national implementation of this mechanism.

254. Article 20 (c) of Regulation 943 also makes a reference to a shortage pricing function in its section on resource adequacy (so targeting BSPs) as a measure to be considered when implementing a CRM: "introducing a shortage pricing function for balancing energy as referred to in Article 44(3)...". But this article clearly targets balancing energy and so BSPs, where Article 44(3) refers to imbalances, and BRPs. So, the reference to Article 44(3) should be understood as referring to the principle of a shortage pricing function itself, and not the balancing energy, which leads to a contradiction. So, this Article 20 (c) can more easily be read as "introducing a shortage pricing function ("also" for balancing energy) as referred to in Article 44(3)".

255. ACER Decision 01/2020 on balancing energy (so applicable to BSP) confirms this reading when indicating in Article 1 (4) that this pricing methodology (for BSP) is without prejudice to the introduction of a shortage pricing function for balancing energy (so for BSPs) as referred to in Article 20(3). Another interpretation should lead to a second inconsistency or contradiction.

256. The application of an energy adder to both BRPs and BSPs is considered in the Commission Opinion on the Belgian implementation plan when indicating that the scarcity pricing function should apply not only to BRPs but also to balancing service providers (BSPs): "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)".

257. Finally, the ACER Decision on imbalance settlement harmonisation indicates that the TSO may propose in the Member States' terms and conditions for BRPs the conditions and a methodology to calculate additional components, to be included in the imbalance price calculation, such as a scarcity component to be used in nationally defined scarcity situations.

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[48] The BRP/BSP price is mostly the same with some exceptions**: a**. Currently the BSPs (all of them: so providing aFRR and mFRR directly activated) receive the same marginal balancing energy price for the energy delivered to the TSO in that single ISP. The revenue of each BSP is thus equal to $Q_{BSP}xP_{ISP}$. Until the end of 2018, the pricing was slightly different because aFRR BSPs received the price equal to the marginally priced bid whereas mFRRda BSPs received a balancing energy price based on a specific pricing rule. These latter BSPs do not bid BE-bids but the price they received was set according to a price formula which lead to a BE-price roughly 200 EUR higher than the aFRR BE price in every ISP where mFRRda is activated (in Dutch this product is called 'Noodvermogen' and it is usually provided by large industries and only for a maximum of 20 ISPs per year). In the current regime the two pricing rules were merged into one: the first part (when aFRR is used) is based on the CMOL of aFRR (merit order price), the 2nd part is an mFRRda price adder on top of the aFRR price and now all the BSPs in NL receive this same price (so also aFRR BSPs receive the adder). This price rule is included in the Dutch grid code **b.** Regarding the price that BRPs pay for their imbalances, this is in general a single imbalance price (same for long and short imbalance BRPs) and is equal to the (single) price for BSPs as outlined above. Nevertheless, in some ISPs there is a dual imbalance price system having different prices for long and short imbalance BRPs. This happens in case the TSO must activate balancing energy in different directions (both positive/negative or upward/downward balancing energy in the same ISP). In order to incentivise BRPs in those ISPs as much as possible to stay close to their position (and not help the system) TenneT applies dual pricing. This happens in around 10-15% of ISPs per year.

[49] https://www.tennet.eu/fileadmin/user_upload/SO_NL/Imbalance_pricing_system.pdf

258. The elements presented above indicate clearly that scarcity pricing adders may be applied to the settlement of BRPs **but also to the remuneration of BSPs**.

8.2. DOES THE MECHANISM CONSTITUTE A STATE AID?

259. The issue of state aid is an important element when capacity remunerations are involved and it ought to be verified if it can trigger State aid scrutiny from the Commission.

260. Balancing capacities (aFRR and mFRR) are already procured in the day ahead by the TSO as ancillary service. What is new with the proposed mechanism is the creation of two balancing capacity markets for reserves in real time, where available reserves may be remunerated with a specific adder in scarcity conditions. As a consequence, this will have a re-distributive effect between BSPs and BRPs in real time and a net effect, an increase of the costs of the procurement of the reserves in the day ahead, when scarcity conditions are expected by market players. No impact is expected when capacities are abundant.

261. For a state aid to exist, four cumulative conditions must be fulfilled: the measure must (i) be funded through State resources and must be imputable to the State, (ii) confer an economic and selective advantage to certain undertakings, (iii) distort or threaten to distort competition, and (iv) be liable to affect trade between Member States.

262. Evaluating in details if these conditions are fulfilled or not is rather complex and goes beyond the scope of this study.

263. Informal contact with DG Comp indicated that there should be a priori no concern with the issue of state aid. Ultimately, it will be up to the Belgian State to decide whether to notify the measure to the European Commission.

8.3. DOES A SCARCITY PRICING MECHANISM CONSTITUTE A DEPARTURE FROM THE GENERAL LEGAL REQUIREMENT ENSURING THAT ELECTRICITY PRICES REFLECT ACTUAL DEMAND AND SUPPLY?

264. According to CREG, the answer to this question is obviously negative.

265. The simple explanation to this question is the following: The “old”, classical rule always applies. But the rule has to be adapted in order to cope with the massive introduction of renewables which may not provide reserves. In the past, the provision of reserves was a kind of side product always available in a system composed of thermal units. This is less and less the case today.

266. With the paradigm of an energy-only market, and for systems with a large contribution of units with a low variable cost and not able to provide reserves, a price signal based on the intersection of the offer price curve and the demand curve can no longer constitute an “all-inclusive” price for energy.

267. In an electric system, reserves are needed for ensuring reliability. Therefore, in order to get the price right, the energy price should be determined by the intersection of the offer curve and of the demand curve **augmented by the necessary volume of reserves**. Operating Reserve Demand Curves introduce price elasticity. With an ORDC mechanism, the demand curve for reserve (price versus volume) is determined on the basis of the (implicit) valuation of demand for reliability through the Value of Loss of Load and the Loss of Load Probability.

268. From a legal perspective, Article 3 of Directive 944 indicates that "*1. Member States shall ensure … that electricity prices reflect actual demand and supply* " and Article 3 of Regulation 943 stipulates that *"(a) prices shall be formed on the basis of demand and supply*".

269. It is important to indicate that these Articles do not provide that the electricity price is set at the intersection of the offer and demand curve, therefore not allowing to the demand side the addition of the **demand for** reserve capacity. Note that such a strict interpretation could lead to a situation where many features of the current EU design would be illegal.

270. Indeed, a strict or narrow interpretation of these provisions forbids the recourse to non-convex products reflecting technical limitations of generation units already implemented today[50], but also the implementation of co-optimization where the price reflects also "**demand for** the" transport capacity (through an implicit market coupling) or reserve (the proposed scarcity pricing mechanism constitutes a particular case of co-optimization).

271. A more general argument is that electricity auctions are fundamentally multi-product auctions. In their most general form, they trade energy, ancillary services, and transmission capacity. In this sense, scarcity pricing is fully compatible with "intersection of supply and demand". In fact, the adder is exactly the demand curve computed at the point of available real time supply. This multi-product auction point of view unifies many existing practices in electricity markets, e.g. the current trading of cross-zonal transmission capacity in day-ahead markets and the foreseen cross-zonal trading of balancing capacity in future EU day-ahead markets. The same principles should apply in real time.

272. In addition, Article 6[51] of Regulation 943 (related to balancing market) stipulates that "5. The imbalances shall be settled at a price that reflects the real-time value of energy." This is the electricity price paid by BRPs. In an electric power system, the fundamental components constituting the value of energy are the value of producing energy, the corresponding losses, the value of the transmission capacity and its associated reliability, the value of reserves, the value of inertia and the value of maintaining the voltage. This formulation indicates that all necessary components of the value of energy may/should be reflected in this imbalance price (in an energy-only design, the price of energy is deemed to be "all-inclusive"). A scarcity pricing mechanism providing a real-time adder pricing adequately the value of reserves in real time helps to fulfil this requirements.

273. The above elements indicate why valuing reserves in the electricity price is not only allowed but also requested if we want to comply with the provision referring to the real-time value of energy.

274. Finally, the proposed mechanism does not limit or cap bid prices in the balancing market as they are added on top of the resulting platform price. Of course, if the clearing price of the platform exceeds the Value of Loss of Load, the adder will be equal to zero (see formula of section 6.1 above).

CREG considers that the proposed scarcity pricing mechanism is legal

[50] Such a strict requirement (similar to a strict marginal pricing rule) is going too far and is only valid in a convex (with no block products) world. In a non-convex world, there may be some situations where there is no price which clears the market. An example of this is the recourse to Paradoxicaly Rejected Blocks, which should increase the welfare but do not allow the definition of a price, and are rejected for that reason.

[51] CREG is perfectly aware of the requirement related to Article 6 4. specifying that "The settlement of balancing energy for standard balancing products and specific balancing products shall be based on marginal pricing (pay-as-cleared)…" which may have led ACER to forbid a cross-product uniform pricing (Decision 01/2020) tackled in section 8.3 above

9. FAQ

275. As complement to the studies mentioned above, some elements/explanations of the proposed design are further provided and discussed below.

9.1. CO-OPTIMISATION

276. Article 40 of the Balancing Guideline foresees the implementation of a mechanism called co-optimisation where some freedom seems to be provided on how cross-zonal capacity shall be allocated to bids for the exchange of energy and bids for the exchange of balancing capacity or sharing of reserves in a single optimisation process performed for both implicit and explicit auctions.

277. In principle, a day-ahead co-optimisation of energy and balancing capacity reserves across several bidding zones should optimise at the same time the welfare related to energy bids and the constraints imposed by reserve requirements in the different bidding zones and by the available transmission capacities. This optimisation may require the identification of energy bids which may also provide reserve capacities. The optimisation process should then decide which part of the available transmission capacities should be used for the exchange of energy and which part should be kept for the exchange of reserves.

278. Prices produced by such a co-optimisation not only reflect the cost of energy and available transmission capacities, but also the constraints related to the procurement of reserves in the different bidding zones. This is perfectly compatible with Article 7 of Regulation 2019/943 specifying that "*2.Day-ahead and intraday markets shall: …(d)* ***provide prices that reflect market fundamentals****, including the real time value of energy, on which market participants are able to rely when agreeing on longer-term hedging products*"

279. Co-optimisation is not a totally new concept since today, the day-ahead market coupling may be considered as a co-optimisation of energy and transportation capacities (when the transmission capacity is scarce, local generation set the price, and not the common merit order).

280. The current implementation of the balancing guideline encompass some form of co-optimisation of energy and reserves in day ahead (Article 38 and 40 of the Balancing Guideline)

281. One of the effects of the penetration of a significant amount of renewable resources with low variable costs in the system is the depletion of the energy price: this is what is referred to as the "merit order effect" as shown in Figure 9.1.1[52]. This may have as consequence that the units providing reserves, may be pushed out of the system.

[52] https://ap-rg.eu/wp-content/uploads/2020/07/CEER2016.pdf

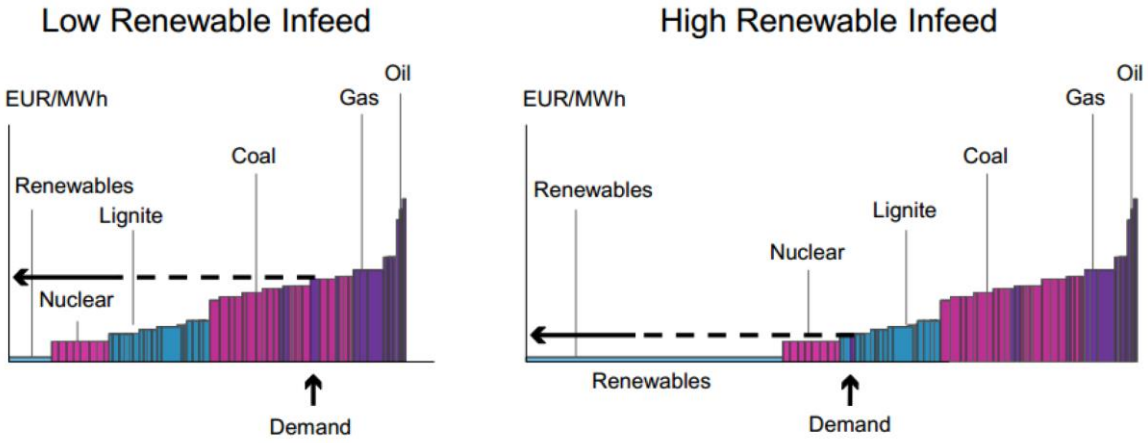

Figure 9.1.1: Illustration of the merit order effect

282. Co-optimisation of energy and reserves (see Art. 40 of the Balancing Guideline) in the day-ahead time frame and related pricing may allow a better integration of the value of reserves in the energy price. This issue can be illustrated the following way: with the low variable costs of renewables, energy-only electricity prices are depleted. If you co-optimise energy and reserve, and integrate the need for reserve in your co-optimisation, the system will keep the minimum and cheapest units providing reserves in the system. Being marginal for energy, these units will set the energy price.

283. The scarcity pricing mechanism proposed is based on a real-time co-optimisation of energy and reserves for which an implicit valuation of reliability for consumers (probability of curtailment x value of loss of load) is used. Indeed, reliability, and the value of reserves, are better evaluated in real time than one day or several hours in advance. Internalising the value of reserves in the price is clearly allowed by Article 6 on Balancing Market of Regulation 2019/943, which stipulates that : "*5. The imbalances shall be settled at a price that reflects the real-time value of energy*."

In the energy transition, solutions based on co-optimisation will be key in the pricing of short-term markets.

9.2. ARE SCARCITY ADDERS ARBITRARY COMPONENTS ADDED TO THE ENERGY PRICE?

284. Not really.

285. Scarcity adders allow the valuation of reserves in the energy price, as it will be explained below. As indicated in § 61 above, reserves have properties related to a public good, which is a market failure where some intervention cannot be avoided.

286. The reserve demand curve is partially[53] arbitrary (formula of the adder). Nevertheless, it is also the case in the day-ahead. In the day-ahead, the mFRR demand curve is equal to the auction bidding limit between 0 and the reserve requirement of 650 MW and 0 €/MWh above this reserve requirement.

287. The fact that the adder (real-time value of reserve) should also be applied to balancing and imbalance energy is not arbitrary. It is the direct consequence of a co-optimisation of energy and reserve in real time.

288. Let us first analyse what would happen in a simple implementation of a real-time market for reserve (without the co-optimization). Market participants would be remunerated for all their non-accepted bids in the balancing platforms at the real-time price for reserve. This would create an opportunity cost to market participants, while they bid in the real-time energy market. Indeed, they would not want to receive a lower profit than their expected profit from the real-time market for reserve.

289. This simple implementation would create difficulties for (i) market participants because they would have to estimate the real-time price for reserve (which depends of the amount of reserve available during the interval) 25 minutes before the beginning of the delivery interval (MARI gate closure time) (ii) regulators because it would be very difficult to differentiate proper reflection of the opportunity cost and application of market power.

290. The solution to these problems is to (implicitly[54]) co-optimize[55] energy and reserve in real-time. The idea of co-optimization is that the clearing algorithm would jointly optimize the welfare coming from energy and reserve. This clearing algorithm would allocate the optimal amount of energy and reserve for each offer and generate prices that would incentivize market participants to follow the obtained dispatch. A simplified[56] example of clearing algorithm for the co-optimization of energy and reserve is given below.

$$\max_{x_i, xR_i, x_{TSO}, xR_{TSO}} P_{TSO} \cdot Q_{TSO} \cdot x_{TSO} - \sum_i P_i \cdot Q_i \cdot x_i + PR_{TSO} \cdot Q_{TSO} \cdot xR_{TSO} \qquad (1)$$

$$x_i + xR_i \leq 1 \qquad (\mu_i) \qquad (2)$$

$$x_{TSO} \leq 1 \qquad (\mu_{TSO}) \qquad (3)$$

$$xR_{TSO} \leq 1 \qquad (\mu R_{TSO}) \qquad (4)$$

$$\sum_i Q_i \cdot x_i = Q_{TSO} \cdot x_{TSO} \qquad (\lambda) \qquad (5)$$

$$\sum_i Q_i \cdot xR_i = QR_{TSO} \cdot xR_{TSO} \qquad (\lambda R) \qquad (6)$$

$$x_i \geq 0 \qquad (\gamma_i) \qquad (7)$$

$$xR_i \geq 0 \qquad (\gamma R_i) \qquad (8)$$

$$x_{TSO} \geq 0 \qquad (\gamma_{TSO}) \qquad (9)$$

$$xR_{TSO} \geq 0 \qquad (\gamma R_{TSO}) \qquad (10)$$

[53] It has been proven in [Hogan, 2013] and in [Papavasiliou, 2017] that this formula would correspond to the optimal reserve valuation in a two-stage stochastic program.

[54] Explicit co-optimisation is not a short term option as it would require changes in the balancing platform clearing algorithms.

[55] Co-optimization is already a well-established principle in European markets. Indeed, Euphemia performs a co-optimization of energy and cross-zonal capacity. This has been shown to be superior compared to trading transmission rights and energy separately.

[56] We ignore complex bids (parent child, linking) and transmission constrains limitations .

291. The parameters of the model are:

- P_{TSO} is the price of the TSO demand in the balancing platform.
- Q_{TSO} is the TSO demand in the balancing platform.
- P_i is the price of bid i in the balancing platform.
- Q_i is the quantity of bid i in the balancing platform.
- PR_{TSO} is the TSO reserve valuation.
- QR_{TSO} is the TSO reserve demand.

292. The variables of the model are:

- x_{TSO} is the percentage of the TSO energy demand that is cleared.
- xR_{TSO} is the percentage of the TSO reserve demand that is cleared.
- x_i is the percentage of bid i that is cleared for energy.
- xR_i is the percentage of bid i that is cleared for reserve.

293. The variables between parentheses are the dual variables associated to the constraints:

- λ can be interpreted as the energy clearing price.
- λR can be interpreted as the reserve clearing price.

294. This optimization problem can be understood as follows. The objective function (Eq. (1)) corresponds to the maximization of Welfare (coming from energy and reserve). Eq. (2) states that the sum of the energy and reserve accepted from a bid cannot be higher than the bid size. Eqs. (3) and (4) state that the algorithm cannot accept more than the demand of the TSO for energy and reserve. Eq. (5) illustrates that the quantity accepted from the TSO energy demand is equal to the sum of the energy cleared on the producer's bids. Eq. (6) is equivalent to Equation (5) but for reserve. Eqs. (7)-(10) ensure that only a positive quantity from a bid can be accepted.

295. In order to analyse what clearing prices would be generated by the clearing algorithm, one can examine the optimality conditions (KKT conditions) of the optimization problem. A subset of these optimality conditions is presented in Eqs. (11)-(13).

$$x_i + xR_i \leq 1 \perp \mu_i \geq 1 \tag{11}$$
$$-P_i \cdot Q_i - \mu_i + \lambda \cdot Q_i \leq 0 \perp x_i \geq 0 \tag{12}$$
$$-\mu_i + \lambda R \cdot Q_i \leq 0 \perp xR_i \geq 0 \tag{13}$$

296. Using these conditions, let us analyse the situation of a producer that is partially cleared for energy. There are two different cases:

1) **The rest of the bid is cleared for reserve:** In this situation, x_i and xR_i are strictly positive. This means that Eqs. (12)-(13) become:

$$-P_i \cdot Q_i - \mu_i + \lambda \cdot Q_i = 0 \tag{14}$$
$$-\mu_i + \lambda R \cdot Q_i = 0 \tag{15}$$

By substituting μ_i, from Eq. (15) in Eq. (14) and dividing by Q_i, it can be obtained that:

$$\lambda = P_i + \lambda R$$

This illustrates that the energy price would not be set at the price of the marginal bid only. It would also include the reserve price. This shows the fact that if the agent is cleared for energy and reserve at the same time, its profit from both markets should be the same (if not, it would only be cleared in the most favourable one). Therefore, the energy price can only be equal at its energy bid price at which the reserve price is added.

2) **The rest of the bid is not cleared:** In this case, Eq. (11) gives that $\mu_i$is equal to 0. This implies that Eqs. (12)-(13) can be rewritten as:

$$\lambda = P_i$$
$$\lambda R = 0$$

In this situation, the reserve price is equal to 0. It is logical as part of the considered bid could provide reserve and does not. This means that the total welfare would not be improved if extra reserve would be available and therefore, the reserve price is equal to 0.

297. In conclusion, this illustrates that, in the proposed scarcity pricing mechanism, the adder on BSPs and BRPs is not arbitrarily decided. It is only an approximation of the prices that would have been obtained if the balancing platforms would run a co-optimization of energy and reserve in real-time (where reserves are implicitly valued by the appetite of consumers for reliability).

9.3. WHICH ARE THE DIFFERENCES BETWEEN THE US AND EU MARKET DESIGN?

298. The main difference between the US design and the EU design is the management of all transmission network constraints (congestions) in the day-ahead and real-time market mechanisms and the use of Locational Marginal Prices (LMP) applied at each node (substation) of the transmission system. Current US design also miss an intraday market with published prices.

299. Questions related to adequacy are zonal (covering a part of the area of an ISO) and scarcity price adders are the same for all the nodes of the same zone, as in Europe.

300. In both systems, reserves have properties related to a public good which correspond to a market failure where an administrative intervention is required. Therefore, in both systems, reserves correspond to ancillary services. Several EU designs already show some features of a scarcity pricing mechanism. And a scarcity pricing mechanism like the ORDC proposal is a way to address the market failure related to the public good property of reserves.

301. In both systems, as long as market power may be considered as an issue, this difficulty may prevent efficient scarcity bidding and a scarcity pricing mechanism is a way to circumvent this challenge.

302. Concerning real-time operations, the most important difference between EU and US markets is that most US markets implement a real-time market for reserve while it is not the case in Europe. Another important difference is the fact that real-time markets in the US are nearly always settled on a 5' basis, where in Europe a 15' settlement is the target. The longer duration of the European balancing market time interval provides additional possibilities of reactive balancing and self-balancing which require the provision of adequate incentives to market players.

303. Finally, Texas is not interconnected, or weakly interconnected with the rest of the US system, whereas Belgium is located in the centre of Europe with strong interconnections[57] and where the

[57] At the same time, it may be expected that in a situation of scarcity, the interconnections may be congested.

scarcity pricing mechanism should be implemented after the connection of ELIA to the MARI and PICASSO platforms.

9.4. WHERE IS AN ORDC MECHANISM IMPLEMENTED?

304. A comprehensive overview of the current status and foreseen evolutions of ORDCs in US markets is provided in (NYISO, 2019). For the moment, ORDC like mechanisms are implemented in several US ISOs (e.g. ERCOT, PJM, ISO-NE, SPP, CAISO and MISO). ERCOT was the first market to implement an ORDC based on the loss of load probability, and PJM recently followed suit, following a recent FERC order in May 2020. Among the ISOs which implement other types of ORDC, ISO-NE and MISO have received recommendations by their market monitor to transition to ORDCs based on LOLP and VOLL.

305. Potomac Economics is an independent company in charge of the monitoring of the functioning of the ERCOT wholesale electricity market. A lot of information can be found on their webpage, with a continuous monitoring of the functioning of the electricity markets.

306. Figures 9.4.1 and 9.4.2[58] below synthetize the impact of the energy adder on electricity prices. The meaning of the different components is explained as follows in the reports mentioned in the footnote: " *ERCOT real-time prices include the effects of two energy price adders that are designed to improve real-time energy pricing when conditions warrant or when ERCOT takes out-of-market actions for reliability. Although published energy prices include the effects of both adders, we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately here from the energy price. The operating reserve adder was implemented in mid-2014 to account for the value of reserves based on the probability of reserves falling below the minimum contingency level and the value of lost load. Taken together, an estimate of the economic value of increasingly low reserves in each interval in real-time is able to be included in prices. The reliability adder was implemented in June 2015 as a mechanism to ensure that certain reliability deployments do not distort the energy prices*."

307. Uplifts, a complement to the linear price to make market players indifferent, are related to the way non-convexities are tackled by the optimization algorithm. In the US, welfare maximization is considered as more important than a unique price (strict linear) as currently the case in Europe where some bids are "paradoxically" rejected, meaning that their acceptance increases the welfare but renders the determination of a price impossible.

308. These figures show that scarcity events occurred in August 2015 and in August 2019 and are related to summer consumption peaks related to cooling where system reserves are scarce. Average scarcity adders are around 1,41$/MWh for the year 2015, 0,27$/MWh for 2016 and 0,24$/MWh for 2017, 2$/MWh for 2018 and around 10$/MWh for 2019 (see below). Based on 2020 monthly data, we may expect that the 2020 adder was close to zero on average.

[58] https://www.potomaceconomics.com/document-library/page/4/?filtermarket=ERCOT : 2017 State of the Market Report and 2019 State of the Market Report

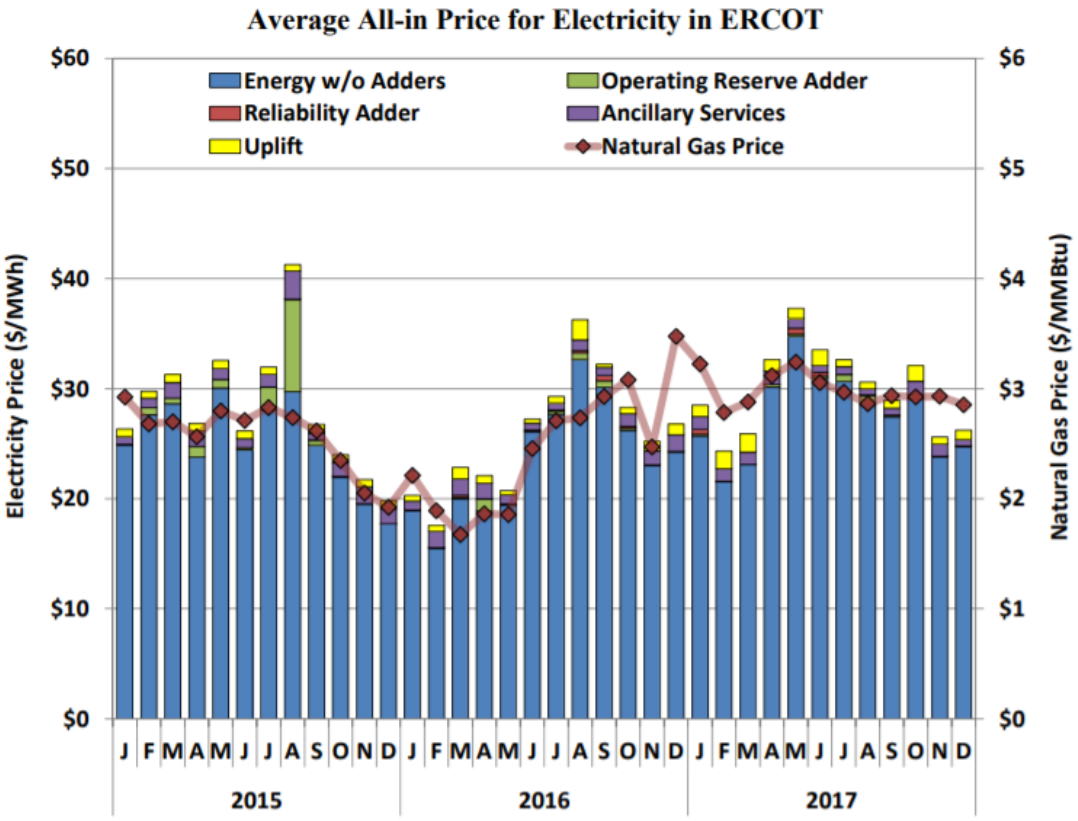

Figure 9.4.1 : Average All-in Price for Electricity in ERCOT from 2015 to 2017.

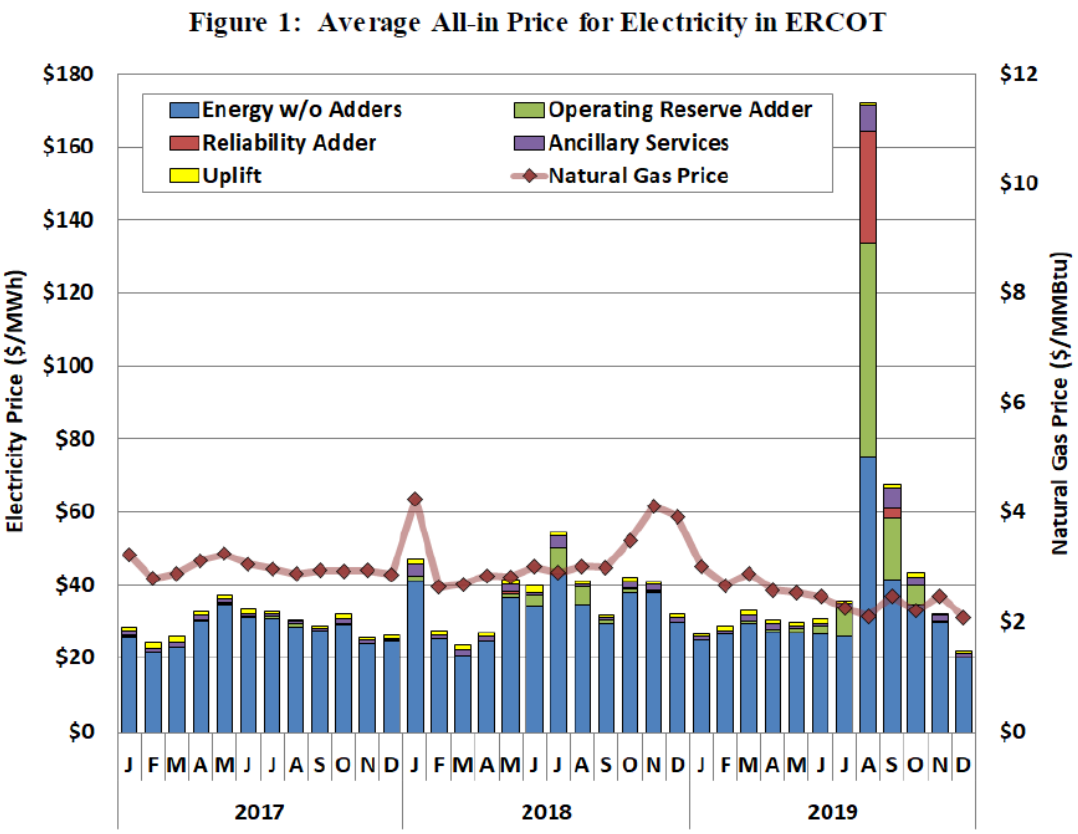

Figure 9.4.2 : Average All-in Price for Electricity in ERCOT from 2017 to 2019.

309. The same 2019 monitoring report indicates that "*The increase in shortage pricing was partly reflected in the higher contributions from ERCOT's energy price adders: $9.76 per MWh from the operating reserve adder and $3.55 per MWh from the reliability adder. Both of these values are significantly higher than the comparable values in 2018: $1.97 per MWh for the operating reserve adder and $0.08 per MWh for the reliability adder*".

310. The recent cold wave in Texas also triggered scarcity events and curtailments. Figure 9.4.3[59] illustrates the evolution of the prices in Texas. It is important to realise that two price adders exist in Texas, one for scarcity and one for reliability (see also Figure 9.4.4).

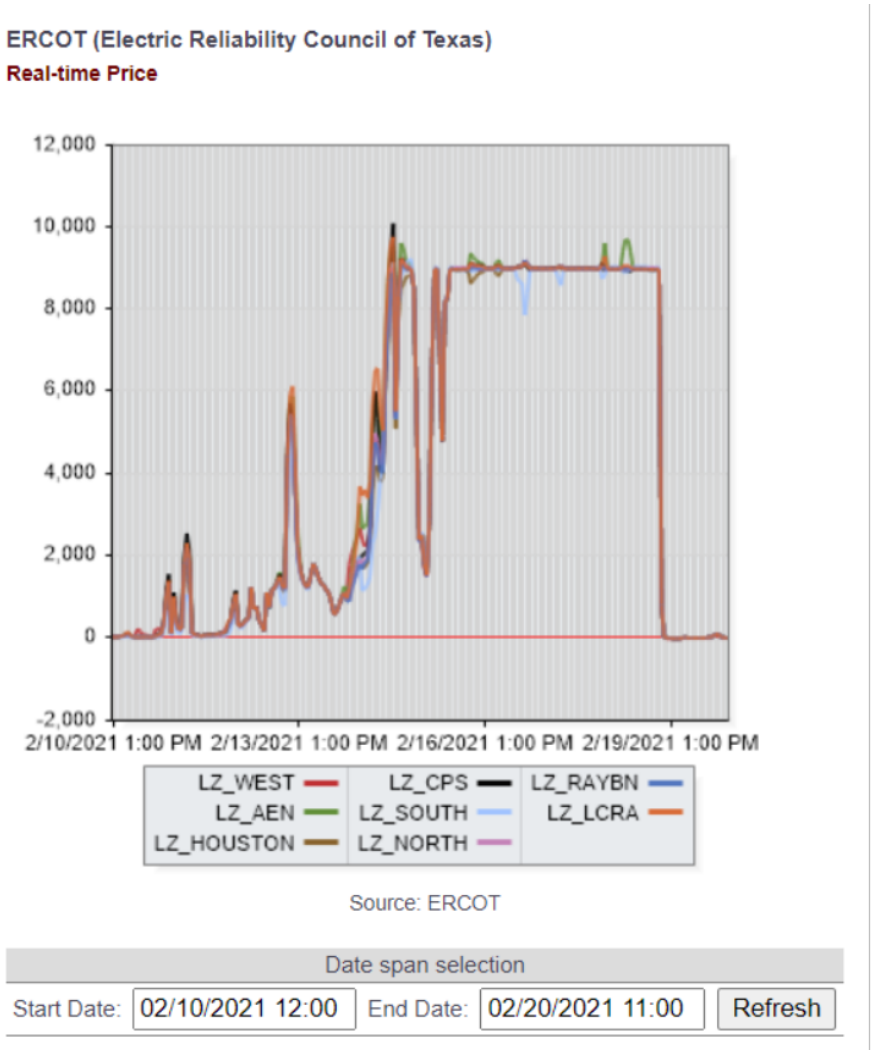

Figure 9.4.3: Real-time price during the cold wave in Texas.

311. Figure 9.4.4, provided by the ERCOT market monitor Potomac Economics for the month of February, shows the impacts of the two adders applied in Texas: the scarcity adder ("RS adder" in red) and a reliability adder ("RDP adder" in blue) similar to what may exist in Europe when prices are set at the maximum harmonised clearing price in the presence of curtailments. Daily average values of the scarcity adder rise three days before curtailments occur. During days with curtailments, the scarcity adder is significant but below the reliability adder.

[59] http://www.energyonline.com/Data/GenericData.aspx?DataId=4

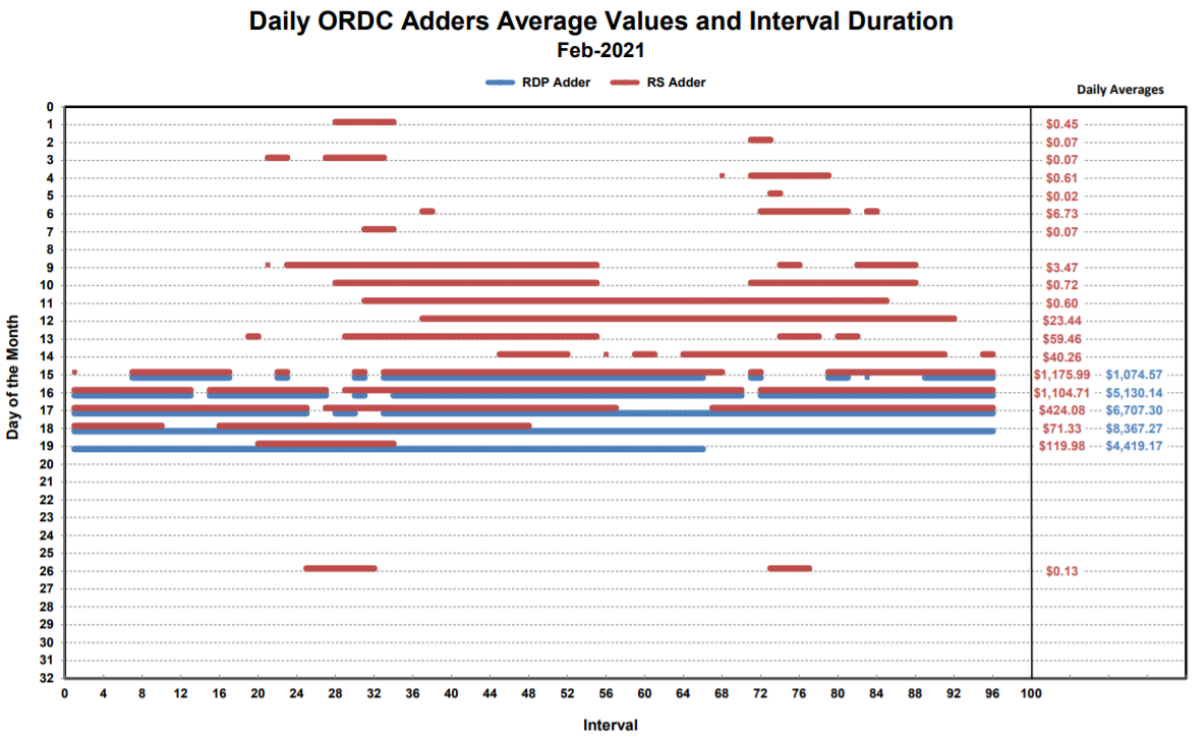

Figure 9.4.4: Daily ORDC Adders Average Values and Interval Duration

312. The cold wave in Texas was exceptional: associated probabilities as low as one event in one hundred years were mentioned in a recent web event[60]. Temperatures of 10°F lower than the ones observed in the 2011 cold wave were mentioned. Curtailments concerned 5 million people for 3 days, starting on the 15th of February.

313. The cold wave triggered several outages of gas power plants, of a nuclear power plant (partial) and of a few frozen wind turbines. Outages also concerned the availability of the gas transport system not designed to withstand such low temperatures on equipment or during production wells (for which winterization costs are very high), as there is nearly no gas storage in Texas. More than half of ERCOT's winter generating capacity, largely powered by natural gas, was offline due to the storm, an estimated 45 gigawatts (for a system of around 75 GW of installed capacity) according to Dan Woodfin, a senior director at ERCOT[61].

314. In the same web event mentioned in §312 above, Ross Baldick indicated that the Capacity Market versus Scarcity pricing issue is a red herring for the events in Texas. William Hogan indicated that, with or without a capacity Market, you need scarcity pricing, as with a capacity market you pay for capacity upfront that may not show up when needed, with the consequence of the provision of penalty schemes. According to Christian Zinglersen, current head of ACER, the problems arising from the Texas freeze were explained "*not least because of an acute gas supply shortage*"[62].

315. Finally, Peter Cramton recently published a paper[63] were the Texas crisis was analysed. In particular, it is indicated that "*ERCOT does not have a capacity market like the markets on the East Coast, PJM, NYISO, and ISO New England. A capacity market effectively enforces a target reserve margin. By contrast, ERCOT uses scarcity pricing to provide the incentive to invest in the ERCOT market. Scarcity pricing is set by the Public Utility Commission. Periodically, ERCOT engages independent*

[60] https://www.youtube.com/watch?app=desktop&v=hfxRKTdxIb4
[61] https://www.texastribune.org/2021/02/16/natural-gas-power-storm/
[62] https://www.euractiv.com/section/electricity/opinion/texas-power-outage-lessons-from-the-eu-regulators-perspective/
[63] Lessons for Peru from the 2021 Texas electricity crisis Peter Cramton 17 March 2021

experts to evaluate whether the scarcity pricing is providing sufficient incentives to invest in the ERCOT market. To date there have been no years where ERCOT has had insufficient capacity. The closing of several coal plants caused the reserve margin to be unusually low in 2019 at about 8 percent. Still there was no problem serving the summer peak load. Because of the strong performance incentives, the generators took steps to make sure their units were ready for summer 2019. Because of these efforts, there were no planned outages and forced outages were exceptionally low during the summer peak. A lack of a capacity market was not the problem. Texas had adequate resources to satisfy demand. This was confirmed in detailed study before the winter event. The problem is that nearly one-half of the resources were unable to produce energy, because of frozen gas lines and the lack of winterization sufficient for the 2021 storm. The problem was not resource adequacy. The problem was a lack of resilience to extreme cold" and that "Stronger interconnection does come with a cost—more federal regulation. To date, the Texas market has largely avoided FERC regulation. This has allowed the Texas market to be more innovative and improve more quickly than other markets. I believe FERC commissioners have understood the advantage of letting the Texas market develop without FERC regulation. If so, FERC's role in ERCOT may not substantially change with stronger ties. The political cost of FERC attempting to exert greater control would be large and the benefit likely negative. This would suggest FERC would continue a largely hands-off approach even with stronger interconnection."

316. Freezing temperatures also occurred in 2014 for PJM where a Capacity Remuneration Market was in place with similar consequences: 22% of the generation capacity was lost (see section 9.7 below). As a consequence, FERC, the US federal energy regulator, has recently approved a proposal of PJM for the implementation of an "ORDC like" mechanism.

317. Even if this is not directly linked to the existence of a scarcity pricing mechanism, very high prices (9000$) sustained during several days (price applied when some curtailment are made), the issue of a too large transfer of wealth from consumers to producers was raised. "Circuit breakers" were proposed to limit the duration when very high prices are applied in those circumstances. Values based on the cost of new entry may be considered. This issue will be further studied by CREG.

318. More can be found on the interaction between a CRM and a scarcity pricing mechanism in section 9.7 below.

9.5. DOES THE ADDER CONSTITUTE A MECHANISM FOR SOLVING ADEQUACY ISSUES OR FLEXIBILITY CONCERNS?

319. Both in fact.

320. Reserves are required for maintaining the reliability of an electric power system. In situations of scarcity, one may be tempted, before proceeding to curtailments, to reduce the amount of reserves necessary for the reliability of the system. This will have as a consequence that the system will transition to a less reliable state. Thus, the amount of reserves that can be deployed in real time is a good indicator of the conditions of adequacy of a system.

321. In the future, with the energy transition and the technological changes, we may also expect that the delineation between adequacy and flexibility will be less clear.

322. A scarcity pricing mechanism, as demonstrated in the studies made for CREG, reduces the missing money issue, if any, and improves investment conditions.

323. It is good to recall here the importance of decentralised investment decisions. The market, and not a central planner, should decide whether to invest or not: this is at the core of the liberalisation process, and **price signals** are the key instruments for reaching that goal. Investors would bear the risks of changes in market conditions, construction cost overruns or construction efficiencies, etc., rather

than consumers as it was the case when all "prudent" generating costs were passed on to consumers before liberalisation with vertically integrated resource planning.

324. A scarcity pricing mechanism improves the short-term signal providing an all-inclusive (including a better valuation of reserves) price signal and more frequent prices spikes (but less high). This encourages forward contracting and facilitates investment decisions.

325. The proposed mechanism should benefit reserves that are able to deliver on short notice (aFRR and mFRR) and so should reward flexibility in a technology neutral way. Thus, a scarcity pricing mechanism also improves flexibility conditions in a system (for the amount of reserves needed in the system).

326. The studies already published on the CREG webpage clearly show the built-in 'pay for performance' attribute of the scarcity pricing mechanism, which constitutes a notable difference between scarcity pricing and capacity mechanisms. The adaptive nature of the adder explains why a scarcity pricing mechanism constitutes a no-regret measure for the improvement of the functioning of the market.

327. On the basis of recent developments observed in PJM (see section 9.7 below), a scarcity pricing mechanism (ORDC like) may coexist with a CRM (even if there is no CRM in Texas where the ORDC mechanism was first implemented). Several academics, and the EU Commission[64], consider that in case of adequacy concerns, it is better to correct the price signal in a first stage and if the adequacy problem persists, to envisage a CRM in a second stage.

328. With the implementation of a CRM in Belgium, if this mechanism is able to make reserves available when needed, then the adders should be most of the time close to zero.

329. For Belgium, as explained in Chapter 2 above, it should be recalled that the examination of scarcity pricing mechanisms was triggered by adequacy concerns in the Belgian system and a wrong price/ investment signal.

330. Finally, one should also refer to the scientific literature (see Chapter 4 above) where a scarcity pricing mechanism is considered as key instrument for resource adequacy.

9.6. MARKET POWER, SCARCITY BIDDING AND THE ISSUE OF SUPRA-COMPETITIVE BIDS

331. It is generally accepted that bids in organised markets may reflect costs and opportunity costs, excluding sunk costs. The name of supra competitive bids sometimes refers to bids that may be submitted in order to reflect scarcity conditions.

332. On the basis of the general introduction provided on "peak load pricing" in Chapter 4 above, it should be noted already that supra-competitive bids are, in theory, not needed to ensure the profitability of generation units, as the recovery of investment costs also depend of the stream of revenues coming from the peak load pricing concept, i.e. the few hours when the demand exceeds the generation capacity.

333. These supra-competitive bids also raise the question of market power. Indeed, the goal of these supra competitive bids in an organised market is to increase the clearing price, when, precisely, the definition of market power can be formulated as " *Market power refers to the ability of a firm (or group of firms) to raise and maintain price above the level that would prevail under competition*". The exercise of market power leads to reduced output and loss of economic welfare". For PJM, market power is

[64] See Regulation 2019/943 Art. 20. 3. (c)

defined as the "*Ability to increase/decrease market clearing price above/below competitive price level*". In Europe, exercising market power can be considered as market manipulation as defined in REMIT and as further elaborated on in the ACER REMIT Guidance. In the context of supra-competitive bids, ACER considers the practice of keeping available generation capacity from being competitively offered on the wholesale electricity market without a technical, legal or economic justification as manipulative if competitively offering said capacity would have influenced the price, or the interplay of supply and demand. Concretely, in the context of market monitoring carried out by the CREG, market participants should for each market time unit be able to explain the value of each price component of which the total bid price is composed, and demonstrate that the methodology used to determine the price component produces consistent results in time.

334. Market power concerns are exacerbated in electricity markets and in the balancing time frame in particular by the fact that electricity can only be exchanged in real time, and that, for time considerations reasons, better deals or alternatives (there are few companies active in the balancing time frame) cannot be found. This facilitates the exercise of market power.

335. The treatment of market power by FERC, the US Federal Energy Regulatory Commission, illustrated the concerns raised by market power in electricity markets: "*It is the possession of market power (and therefore the potential to exercise it), not the actual exercise of market power, that triggers the need for mitigation… Once it is determined that an entity has market power, adequate mitigation of the potential to exercise market power becomes essential.*"[65] This leads to the application of mitigation measures in situations where market power concerns are detected, by capping certain bids for example. The treatment of market power is different in Europe, and is rather based on ex-post monitoring.

336. Market power is a concern in all market designs, and even if the solutions adopted to remedy this concern are different across the different designs (ex-ante mitigation in the US, ex-post scrutiny in Europe) the nature and characteristics of electricity are the same. Some insight can be found in a recent paper related to the recent implementation of an ORDC mechanism by PJM[66]: "*Physical withholding can be addressed by must-offer requirements. More controversial has been the policy of setting accompanying offer caps to foreclose economic withholding. It is difficult to distinguish between legitimate high-cost offers and the exercise of market power. The difficulties have been compounded by the faulty assumption that higher market-clearing prices, needed to reflect scarcity and provide better incentives in operations, require high energy offers from generators. The resulting dilemma has been how to separately identify price increases resulting from scarcity from the exercise of market power.*" And "*The ORDC substantially mitigates this problem of identifying economic withholding by providing a clear distinction between a scarcity price, from the ORDC, and energy offers that reflect variable generation costs. Under conditions of reserve scarcity, when operating reserves are reduced, low energy offers can be fully compatible with high market-clearing prices, for example because the generators on line and providing energy have limited ability to ramp quickly. Reserves are limited and the ORDC produces a high scarcity price. This scarcity component adds to the variable cost of energy and produces a high market-clearing price for energy. Hence, generators do not need to inflate their variable offers in order to achieve higher prices reflecting the scarcity value of their capacity. Generous offer caps would prevent material exercise of market power through economic withholding without creating a conflict for the ORDC. Likewise, if needed, offer caps could be provided for operating reserves as well as for energy. Hence an ORDC reduces the cost of using offer caps to mitigate generator market power. This is a natural and beneficial feature of the PJM ORDC reform proposal*."

[65] FERC Order on Rehearing re: the California MRTU market rules; paragraph 490.

[66] PJM Reserve Markets: Operating Reserve Demand Curve Enhancements William W. Hogan, Harvard University Susan L. Pope, FTI Consulting Inc. March 21, 2019

337. Three elements complicate adequate bidding in short-term markets in scarcity conditions:

- In both systems, and especially in Europe, where bids are not (in principle) capped at the entrance of an organised platform, nobody says how producers should reflect scarcity in their bids (sometimes called supra-competitive bids), as scarcity reflects the valuation, or the appetite of **demand** for reliability.
- It is extremely difficult for an NRA to distinguish between bids reflecting scarcity and the exercise of market power, which may be more acute in scarcity conditions. If these "supra-competitive" bids are successful, and able to influence the market price, this is precisely an indication of the exercise of market power and **there is a risk that the NRA recourse to a market power mitigation measure**.
- With the way short-term markets are organized, **there is a high competitive pressure on market players to bid at marginal price**.

338. The question of the treatment to be applied to these supra-competitive bids has recently triggered a new discussion between NRAs about the application of (some) price caps in the balancing time frame. The 19/1/2021, a price cap of 9.999 € has been introduced for balancing in Germany. Today, prices caps at 99 999€ are currently discussed.

339. As long as market power may be considered as an issue, these difficulties (risk of market power mitigation measures, the valuation of scarcity and the competitive pressure to bid at marginal price) may prevent efficient scarcity bidding and a scarcity pricing mechanism is a way to circumvent this tricky question.

340. As rightfully stated by FEBEG in its response to the Consultation organised by Elia on scarcity pricing [FEBEG 2020] when a scarcity pricing mechanism is implemented: "Hence, there would be no need for supra-competitive supply side bids that can be subject to market power mitigation measures".

9.7. INTERACTIONS WITH A CRM

341. In Belgium, where a Capacity Remuneration Mechanism (CRM) has been implemented, the following question was raised: If a CRM is in place, will consumers pay twice for adequacy if a scarcity pricing mechanism is also in place?

342. Scarcity pricing and CRM are compatible technically (according to the scientific literature) and linked legally (Articles 20 3. (c) & 23 5. (e) of Regulation 2019/943).

343. To address the question of the interaction of Scarcity Pricing and CRMs, the situation in the US where Capacity Markets are common, will be examined. Given the current developments in the implementation of a CRM in Belgium, no conclusions for Belgium will be made at this stage.

344. CRMs are common in the US, and some ISOs apply some form of shortage pricing.

345. PJM is, to some extent, the "champion" of CRM mechanisms which are implemented since 2006, leading to overcapacity[67]. From 2008 to 2017, generation capacity in PJM expanded by more than 15,000 MW despite essentially flat demand growth. Nearly all of this new capacity was in the form of new natural gas plants. As a result, reserve margins — the built-in cushion of excess capacity above peak demand — have soared. PJM's 2018 summer target reserve margin was 16.1%. The actual margin of excess power was more than twice that, at 32.8%, and the anticipated reserve margin for 2021, according to the North American Electric Reliability Corporation, is nearly 40%.

[67] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/54111666

346. Despite abundant capacities and a CRM, the 2014 polar vortex resulted, like in Texas this year, in many generator outages (up to 22%) from entities exceeding the design basis of their plants and difficulties facing the natural gas transportation sector. In addition, the 2018 cold wave indicated that the remuneration of standby reserves was not adequate.

347. For these reasons, an "ORDC like[68]" mechanism should be implemented in the coming months or years (the proposal has been approved by FERC in May 2020). The trigger for PJM[69] for improving the remuneration of reserve in short-term markets is the observed shift of revenues from the energy market to the capacity market.

348. The objective of shortage pricing is explained by PJM in two slides[70] presented hereafter:

Effective shortage pricing reduces the "missing money" problem

– **Rewards resources that supply energy and other essential grid services during emergency conditions**

– These resources collect additional revenues that go directly towards offsetting going-forward costs

As a result, shortage pricing mechanisms reduce reliance on the capacity market revenues to attract efficient resource investments

349. The importance of rewarding resources during emergency conditions is clearly indicated here. This statement makes clear that the PJM CRM does not meet that objective.

Why would we encounter shortage conditions even though we've met the capacity adequacy requirements?

Capacity adequacy is based on forecast assumptions that may not hold on any particular day or in any particular year. For instance:

- **Extreme weather conditions beyond those used to determine capacity requirements**
- **Higher than average generator outages**
- Greater than expected economic activity and consequent peak load growth
- Unexpected transmission outages that lead to more localized shortage

350. The need for a scarcity pricing mechanism even in the presence of a CRM is clearly indicated here for extreme weather conditions and higher than average generator outages. This slide confirms the analysis of the recent Texas crisis that the presence of a CRM in Texas should not have changed much (see also section 9.4 above).

[68] PJM design targets a better remuneration of reserves, in general, and not only the remuneration of reserves in scarcity conditions, which is the characteristic of the ERCOT ORDC approach. PJM justify his design the following way: "*The primary marginal cost associated with providing reserves is lost opportunity cost. Lost opportunity cost is the revenue that a resource foregoes in the Energy Market by not generating in order to provide reserves. Capacity market revenues are not intended to cover these costs. By capturing the lost opportunity cost in the reserve market clearing price, reserve markets also provide incentives for resources to lower their output and provide reserves instead of providing energy. Absent a payment for reserves, resources would not have the incentive to provide them because they could maximize revenues by providing energy instead*."

[69] Electricity market reform to enhance the energy and reserve pricing mechanism: Observations from PJM January 7, 2019 Isaac Newton Institute Cambridge University, UK Hung-po Chao, Ph. D. Senior Director and Chief Economist PJM Interconnection, LLC

[70] Price Formation Education 4: Shortage Pricing and Operating Reserve Demand Curve Patricio Rocha Garrido Lisa Morelli Laura Walter https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/price-formation/20180117-pm/20180117-price-formation-education-4.ashx

351. PJM studies indicated that the additional costs related to a better remuneration of reserves may be compensated, or not, depending on the scenario considered[71], by a reduction of the costs of the CRM which depends of the bidding behaviour of market players in the CRM market and of the reduction of costs of the uplifts (side payments remunerating producers in addition to the LMP price linked to non-convexities).

352. Finally, it is valuable to recall that the main consequences of the recent crisis in Texas on (residential) consumer bills, if any depending of the contract, is not related to the presence of a scarcity pricing mechanism but to the fact that, when loads are shed or curtailed, the balancing price is automatically set at its maximum of 9500 $/MWh.

Future adequacy assessments and capacity mechanisms should take the impact of the proposed scarcity pricing mechanism into account.

9.8. WHAT IS THE DIFFERENCE WITH THE ALPHA-COMPONENT?

353. In order to provide increasing incentives to BRPs for managing their imbalances within their portfolios, ELIA has put in place an imbalance price that is characterized by penalties when the system experiences large imbalances.

354. There is a clear incentive generated by the alpha component on BRP behaviour, so as to avoid being on the wrong side of the imbalance price in case of enduring (two times 15') large system imbalances. Therefore, the alpha component incentivizes agents to keep their flexible assets in order to balance their portfolio internally rather than offering it to the system. This is not optimal because it would be preferable that the balancing be performed by the cheapest unit available, which can be activated by the TSO following the platform outcome, rather than by generators activated by producers without coordination.

355. It is important to note that the alpha parameter is an imbalance penalty which depends on the level of system imbalance, which is not to be confused with the level of scarcity in the system. To clarify: a system that is exhibiting a very large negative imbalance is not experiencing scarcity if it carries abundant reserve at the moment in time when the large imbalance occurs.

356. It has been explained, in section 5.4, that applying the alpha penalty to the imbalance price does not provide sufficient back-propagation (design D2).

357. It has been explained in section 5.5, that an incentivizing component like the alpha would prevent obtaining an optimal dispatch at a European level (market players may not be incentivised anymore to bid at their marginal costs). Specifically, it may force expensive assets in Belgium to react

[71] PJM Price Formation Energy Price Formation Senior Task Force December 14, 2018 https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx

even though cheaper assets are available abroad and cross-zonal capacities are available. This creates unnecessary costs to Belgian BRPs that would pass them on Belgian consumers.

358. With the application of the new formula for the calculation of the alpha component since the first of January 2020, the average value of the alpha component for the year 2020 was 3,9 €/MWh[72] in case of positive imbalance and 4,4 €/MWh in case of negative imbalances. Note that the alpha for negative imbalance has risen to 7,4 €/MWh in 2021 (January-August). It should be noted that the future, or the need to keep an alpha component is currently examined by CREG with ELIA, given the complains forwarded by market players on this issue.

9.9. ISSUES RELATED TO THE UNILATERAL IMPLEMENTATION OF SCARCITY PRICING IN BELGIUM & DIFFERENCE IN TREATMENT OF NATIONAL AND FOREIGN BIDS

359. Scarcity pricing is a measure to be considered when resource adequacy issues have been identified, before the possible implementation of a capacity remuneration mechanism, as indicated by Article 20(3) c of Regulation 943, where a national implementation is foreseen. Similar to capacity market mechanisms, scarcity pricing can be applied nationally as a complement of the existing EU markets in day-ahead, intraday and balancing. Scarcity pricing can also be implemented on the basis of the Balancing Guidelines (Article 44 (3) and Article 18). From this we can conclude that scarcity pricing need not necessarily be applied within an EU-wide market design, but can be applied outside of it, as a complement to it.

9.9.1. Balancing energy

360. The current design of the scarcity pricing mechanism for Belgium foresees the application of an energy scarcity adder for the remuneration of the activation of bids from BSPs located in Belgium, and not to the remuneration of the activation of foreign BSPs coming from other bidding zones through the balancing platforms. This difference of treatment may raise some concerns about a possible discrimination of these foreign BSPs.

361. Concerning this difference of treatment, it is opportune to recall that in the balancing platforms, balancing energy bids are always settled locally, and bids of different bidding zones with the same price may be settled at different prices depending on local conditions. Moreover, it would be technically infeasible to apply the adder to BSPs of other countries because it is impossible to attribute the activation of a bid in a bidding zone to a request for energy in another bidding zone (except in the rather theoretical case of a two-zone example).

362. This difference of treatment is already present in the day-ahead market coupling. Even if a neighbouring country exports to Belgium, market participants in the neighbouring country will be paid at their local zonal price and not at the (higher) Belgian zonal price. This difference is due to the transportation costs, the cost necessary to make the energy available in the other bidding zone, and there is no discrimination here.

363. The same shall apply with the PICASSO and MARI balancing platforms, where, due to the global welfare optimisation and the limitations of the transmission system (NTC in a first stage), the remuneration of balancing energy bids (BSP) may differ in the different bidding zones. In addition, due

[72] CREG calculations based on ELIA published data.

to the approximation inherent to the NTC model and the separation of the balancing platforms, congestions may appear between two BZ for a platform and not for the other.

364. Moreover, it should be indicated that if scarcity pricing mechanisms are generalised across Europe, BSP remunerations will still differ as scarcity adders reflect different situations of scarcity and VOLL levels of the different countries.

365. This illustrates that the price difference that BSPs of neighbouring zones would face is not coming from the unilateral implementation of scarcity pricing. In fact, it is coming from the absence of co-optimization of energy and balancing capacity in real time in Europe.

366. Moreover, in the Sixth Study, the CORE has proven that out of the three following properties, only two can be true at the same time in a situation of scarcity. Indeed, in a normal situation the adder is equal to 0 and all can be true at the same time): (i) enforcing the network equilibrium conditions of an energy-only design (having the same price in different zones if there is no congestion), (ii) enforcing the balancing platform dispatch decisions, and (iii) implementing scarcity pricing (with the adder applied to BSPs and the real-time market for reserve).

367. As the second one (ii) is true by definition, as we use the output of MARI and PICASSO which do not run a co-optimization of energy and reserve, one has to abandon the first or the third property. In scarcity conditions, it seems preferable to abandon the first one because, if Belgium is in a scarcity situation, it is likely that import capacities in real time will be saturated. This means that the price in Belgium and in neighbouring countries will be disconnected anyway.

368. Moreover, imposing that the price would be the same in two neighbouring zones if there is no congestion is equivalent to forbidding the application of a shortage price function which is explicitly permitted by article 20 (c) of the Regulation 943. Indeed, the direct consequence of applying this shortage function to BSPs is to have different prices between neighbouring countries.

369. Finally, the implementation of the proposed scarcity pricing mechanism will not affect the functioning of the balancing platforms: bids transmitted to these platforms are unchanged and so the prices resulting from these platforms should not be modified. What the mechanism will do for Belgium is the addition of a scarcity adder in situation of scarcity.

9.9.2. Real-time market for reserve

370. Our implementation of scarcity pricing in Belgium will create a real-time market for reserve (see section 6.1). This real-time market for reserve will only be available for Belgian BSPs.

371. This follows the principle of a day-ahead balancing capacity market which only accepts offers of market participants from their own country. Moreover, the balancing capacity volume requirement in the day ahead is fixed at a national level.

372. The proposed application of a real-time market for reserve is simply the equivalent of Belgium putting a non-zero demand curve for balancing capacity in real time while other countries have a real-time demand for balancing capacity equal to 0 MW.

9.9.3. Incentives

373. It has been argued in ELIAs 2020 report that, in the case of a unilateral implementation of scarcity pricing in Belgium, Belgian BSPs might have incentives to bid under their marginal cost in the balancing platforms. This might be viewed as dumping because Belgian BSPs would be selected at the expense of foreign BSPs. The incentives brought by a unilateral implementation of scarcity pricing in Belgium have been studied by CORE and CREG in the Fifth and Sixth Study. Nevertheless, providing

correct incentives to market players dependon the behaviour of the TSO (concerning the use of manual FRR on the basis of aFRR activation) with the go-live of the balancing platforms.

374. Concretely, suppose that Belgium implements the mechanism, whereas neighbouring zones do not. How should the settlement exactly work out? And what could one expect in terms of balancing energy prices and day-ahead energy and reserve prices in neighbouring zones?

375. These questions are addressed using a stochastic equilibrium model in the Fifth Study and using a Markov Decision Process model in the Sixth Study. These methods are used in order to explain the mechanism by which agents arbitrage real-time prices against day-ahead prices. Thus, they provide a quantitative approach to explaining the back-propagation of energy and reserve prices in forward (e.g. day-ahead) markets when a change is introduced to the real-time market design (e.g. via the introduction of a scarcity adder).

376. A stylized two-zone example, i.e. Belgium and the Netherlands, is considered, with the two zones connected by a link of limited capacity. The market model features a missing market: the Dutch TSO does not trade reserve capacity in real time.

377. An underlying institutional concern of this analysis has been to understand how the proposed mechanism should interact with neighbouring BSPs and BRPs. According to the proposal analysed in the paper, the balancing platforms will produce a local zonal energy price for each BSP in the market. Zones which apply scarcity pricing settle their BRPs (and the associated BSPs of each BRP) according to the proposed scarcity pricing formulas, whereas zones which do not apply scarcity pricing are not affected.

378. Concretely, Dutch resources will pay the Dutch zonal price, and therefore they are not directly affected by the adder settlements. The fact that Dutch resources are being activated in order to address a Belgian scarcity incident is not at odds with the fact that these Dutch resources are supplying their balancing energy in the Dutch zone, and the balancing platforms produce a price for this balancing energy.

379. There is no need for violating the merit order of the balancing platform in order to arrive to the computed equilibrium outcome. If neighbouring Dutch BSPs are not exposed to real-time markets for reserve capacity in the Netherlands, they anyways would not internalize the cost of delivering this reserve in real time to their day-ahead reserve capacity auction bids.

380. This discussion underscores the importance of applying scarcity pricing for reserve imbalance settlements (equivalently, putting in place a real-time market for reserve capacity), and not limiting the application of the adder as an add-on to balancing/imbalance charges. Indeed, if scarcity adders would only be limited to add-ons on the balancing/imbalance price, then one could envision that Belgian BSPs might lower their bid price and that Belgian BRPs would react while the balancing price is below their marginal cost. They would therefore be dispatched at the expense of imported bids from foreign BSPs and would reduce the balancing price received by foreign BSPs (see section 5.5). This would raise a concern among foreign NRAs as a violation of the (common) merit order: if the scarcity adder is applicable and if the import potential is not fully used, then the perception is that Belgian BSPs and BRPs push away foreign BSPs. By contrast, the application of scarcity pricing, as it is intended, for settling not only real-time energy but also real-time reserve capacity, would eliminate the interest for Belgian BSPs to mark down their bids and for Belgian BRPs to react below their marginal cost. Indeed, whatever Belgian BSPs gain on the margin from providing balancing energy is balanced off from using up reserve capacity during activation. This explains why the implementation of the proposed scarcity pricing mechanism, with the creation of a balancing capacity market in real time, should not distort competition. What remains is the incentive for Belgian BSPs to internalize the real-time adders in their day-ahead reserve capacity bids, which would serve towards back-propagating real-time scarcity adders to day-ahead reserve prices in Belgium.

9.9.4. Money transfer to neighbouring countries

381. It has been argued by ELIA that the introduction of scarcity pricing can cause transfer of money from Belgium to neighbouring countries. The ELIA example is reproduced in Figure 9.9.1. Notice that this example considers only one type of reserve. Moreover, it assumes that no reserves have been contracted by the TSO in day-ahead which means that all the reserves are remunerated in real-time.

382. In this example, there is 700 MW of balancing capacity available in Belgium and 0 MW in France. From these 700 MW available, 300 MW are activated to produce energy: 200 MW of this energy to cover the system imbalance in Belgium and 100 MW to cover the imbalance in France.

383. The second example (Figure 9.9.2) is the same as the first one except that only 200 MW of balancing capacity are activated because there is no imbalance in France.

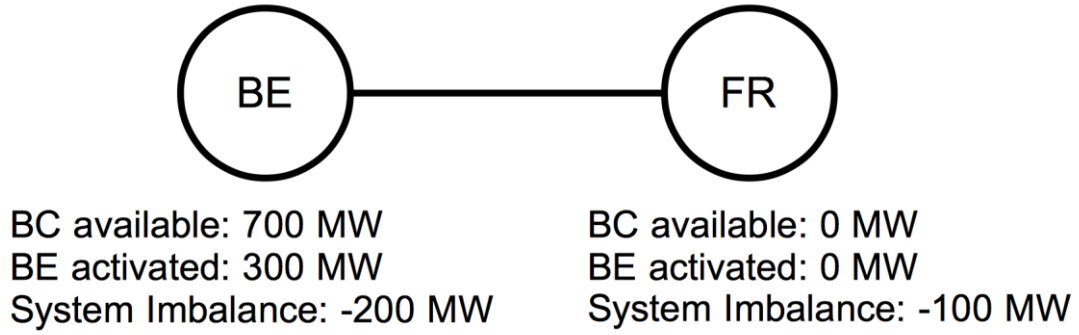

Figure 9.9.1: First example of balancing dispatch.

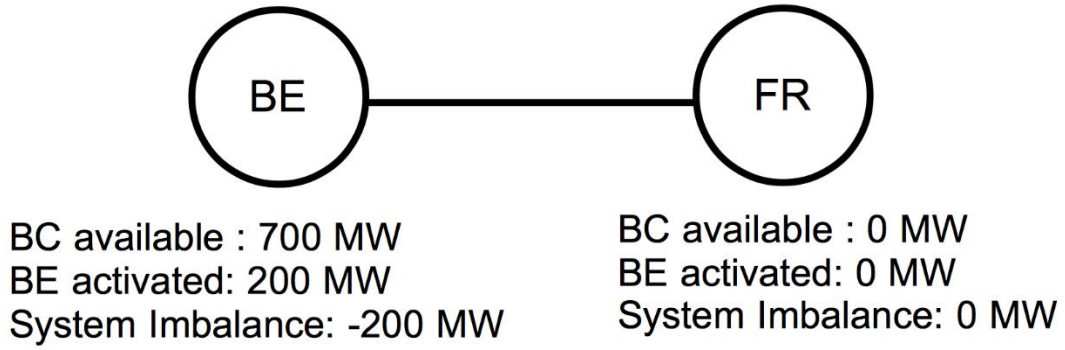

Figure 9.9.2: Second example of balancing dispatch.

384. The payments to the different actors, for the two examples, are summarized in Table 9.8.1 (where λ^B is the real-time energy price from the platform (it is also the price applied to BRPs because there is only one type of reserve) and λ^R is the scarcity adder). It can be observed that the fact that Belgian BSPs are activated to cover the need of France does not create an additional cost to the Belgian TSO because, even if these capacities were not producing, the Belgian TSO would have to remunerate them for the balancing capacity they offer to the system.

	BRP FR	BRP BE	BSP activated	BSP non activated	TSO
Example 1	$-\lambda^B \cdot 100$	$-(\lambda^B + \lambda^R) \cdot 200$	$(\lambda^B + \lambda^R) \cdot 300$	$\lambda^R \cdot 400$	$-\lambda^R \cdot 500$
Example 2	0	$-(\lambda^B + \lambda^R) \cdot 200$	$(\lambda^B + \lambda^R) \cdot 200$	$\lambda^R \cdot 500$	$-\lambda^R \cdot 500$

Table 9.9.1 Settlement for the two examples

385. It should also be observed that the situation where the adder is high in Belgium which means Belgium is experiencing scarcity (Belgium would need more balancing capacity) and where, at the same time, Belgium is exporting balancing energy seems relatively unlikely.

10. IMPLEMENTATION PROCESS

386. The implementation of the scarcity pricing mechanism shall in principle follow the rules prescribed by Article 18 of the Balancing Guideline, and in particular the Terms & Conditions related to the BRPs and the imbalance price, the BSPs for the supply of mFRR and the BSPs for the supply of aFRR.

387. In order to avoid too many consultations on the same issue (each decision mentioned above will proceed to a consultation of stakeholders that will cover, in addition to the modifications related directly to specificities of BRPs, BSPs mFRR and BSPs aFRR, the same scarcity pricing mechanism) which may constitute an unnecessary burden for stakeholders, it is the intention of CREG to organise a one day workshop on this study, in order to get the feedback and exchange views with stakeholders.

388. Ideally, on the basis of Commission request, the go-live of the scarcity pricing mechanism should occur the 1st of January 2022. For several reasons explained by ELIA in its study[73], this may not be feasible given the interaction with the implementation of the balancing platforms MARI and PICASSO. These projects may encounter some delay as some countries may ask derogations for the connection to a given platform.

389. The potential delays related to the implementation and the connection to the EU balancing platforms challenges the currently proposed design of the scarcity pricing mechanism if its implementation is to be considered in isolation, before the connection to the two platforms (it was considered that the mechanism should go in parallel with the implementation of the platforms).

[73] See ELIA webpage Final report on Elia's findings regarding the design of a ...https://www.elia.be › adequacy---scarcity-pricing

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For the Commission for Electricity and Gas Regulation:

Andreas TIREZ
Director

Koen LOCQUET
Acting President of the Board of Directors