Commission de Régulation
de l'Électricité et du Gaz

CREG

Study

(F)1987
10 October 2019

Study on the best forecast of remedial actions to mitigate market distortion

drawn up pursuant to article 23, § 2, second paragraph, 2° 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

TABLE DES MATIERES

1 INTRODUCTION

1. The role of redispatching is being heavily discussed in the framework of the implementation of the European guidelines on Capacity Allocation and Congestion Management (CACM) and System Operations (SOGL), as well as in the scope of the implementation of the Clean Energy Package (CEP).

2. The ambitious targets set on capacities to be made available for cross-zonal exchanges in the CEP, with the help of re-dispatching, constitutes a radical change in the EU design which requires appropriate solutions for its implementation.

3. To this end, this concept note recalls the inefficiencies related to structural (frequent) redispatching and presents a short-term practical solution to minimize these inefficiencies within the given bidding zone configuration and the new legal framework.

4. In particular, this note illustrates the market impact of (curative) redispatching in terms of price and market distortion, competition and system security.

5. In contrast to other alternatives, the approach proposed in this note is expected to provide a more efficient market design, a better price formation and an improved system security. Furthermore, it should provide the basis for a fair and easier-to-implement allocation of redispatching costs.

6. Finally, the proposal made in this note constitutes the first "appropriate action" taken by CREG when identifying measures that may restrict the formation of price, as foreseen in Article 10, 5 of Regulation EU 2019/943 (see Chapter 3 below).

7. The initial trigger of the discovery of the price distortions put in evidence in this note was constituted by the differences in loop-flows patterns observed in the base case and in real time, also called "fake" loop-flows as mentioned in section 5.3.1 below.

Given that the changes introduced by the CEP to the European Target Model are so important, we cannot proceed to its implementation without carefully considering all implications. Therefore, all comments to this concept note and the proposed solution are welcome.

2 PROBLEM STATEMENT

8. Over the last years, the recourse to redispatching has increased in several countries in Europe. In Germany alone, redispatching costs raised from 130 M€ in 2006 to 1.000 M€ in 2016. The rise in redispatching cost can also be observed in other countries and is said to be linked not only to the large-scale integration of renewables in the market but also to the coincident decommissioning of conventional power plants. This has had an impact on congestion patterns and thus on redispatching volumes and costs. Overall flow patterns are changing and network developments are running far beyond.

9. With the implementation of the Clean Energy Package (CEP), there is high probability that the use of redispatching will further increase since the CEP incorporates the objective of a minimum 70% target on capacity made available for cross-zonal trade combined with the help of redispatching. There is a high probability that TSOs provide (see section 4.1) the defined commercial capacity targets in a virtual way (i.e. detached from the physical reality of the network in real-time), without anticipating and dealing with structural congestion already in the day-ahead capacity calculation phase, leaving all redispatching actions to be coordinated after the day-ahead market clearing.

10. Redispatching is done outside the (day-ahead) market by system operators and entails inefficiencies which propagate far beyond a specific bidding zone border. In the former legislative framework, the EC Regulation 714/2009, redispatching was only mentioned as a last-resort in case of residual congestions related to unlikely or temporary situations. The European Target Model incorporated in the former EC Regulation 714/2009 foresaw as solution for congestion management a market coupling between bidding zones which could be considered as copper plates. Structural recourse to redispatching linked to congestion inside bidding zones was avoided through the definition of appropriate bidding zones.

11. In contrast to the European Target Model, the Clean Energy Package (CEP) which entered into force in July 2019, foresees redispatching as a valid instrument for to help maximising interconnection capacities. Hence, regulators and system operators have to deal with the question how to include redispatching compliant with the CEP in the different methodologies for capacity calculation and allocation (CACM Guideline) and system operation (SOGL Guideline).

12. To ensure a proper implementation of the Clean Energy Package, we need to understand the intrinsic inefficient nature of redispatching in a zonal market coupling, and the different ways in which this inefficiency materializes. Only then may we be able to propose answers on how to minimize the impact of the redispatching-related inefficiencies.

13. It should be reminded that also the CEP states that appropriate defined bidding zones are the first best solution to deal with structural congestions (see 14.1 of Regulation EU 2019/943). Hence, every solution with structural redispatching should be evaluated against this first best solution of appropriate defined bidding zones.

2.1 REDISPATCHING IN A ZONAL MARKET DESIGN

14. A zonal system consists of copper plates (the "bidding zones") linked by cross-zonal transmission lines. And like copper plates, "ideal" bidding zones are characterised by an infinite internal capacity and therefore no - or only residual - internal congestions. A copper plate also implies a quasi-zero internal impedance, with the consequence that trades made between different parts of the copperplate only generate flows inside the copper plate and do not generate flows ("loop flows") outside the copper plate. In other words, adequate bidding zones should not contain structural internal congestions, and should not generate excessive loop flows. Congestions occur only on cross-zonal transmission lines.

15. The clearing prices of the bidding zone reflect the marginal value of consuming or generating electricity within the zone, while considering the transmission constraints between these zones. In such a market design, any (supposedly exceptional) internal congestions are solved by the TSO via redispatching actions inside the bidding zone.

16. This was more or less the situation described by the former EC Regulation 714/2009. In a nutshell, the EU target model was based on implicit auctions for energy and transmission capacity at the day-ahead timeframe between "adequately" defined bidding zones.

17. The problems linked to the interaction between redispatching and a zonal design have been extensively described in the literature (see references [1] [2] and [4]). This interaction and the related inefficiencies were at the origin of the famous California electricity crisis in 2002 and the crash of the Californian market[1].

[1] https://en.wikipedia.org/wiki/California_electricity_crisis

18. Structural[2] (frequent) congestions are considered as a reason for a zone split in the former and recast (CEP) electricity regulation. These structural congestions, which can be easily anticipated by involved (market) actor, due to their repetitive nature, constitute a key element of the inefficiency of the recourse to re-dispatching combined with a zonal design. This will be further explained below in the chapter on the inefficiencies of re-dispatching.

3 LEGAL CONTEXT LINKED TO THE CLEAN ENERGY PACKAGE, REMIT, CACM AND SOGL GUIDELINES

19. Relevant elements of the Clean Energy Package are recalled below. Text extracts are indicated in italic. Bold characters are from CREG. CREG comments are indicated with normal fonts.

20. On the 5th of June 2019, Directive (EU) 2019/944 of the European parliament and of the council on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (hereafter referred as the Directive) was published. General principles for the functioning of the internal market for electricity are provided and in particular on the price formation.

> *Article 2 Definitions*
>
> *The following definitions apply:*
>
> *…*
>
> *(6) 'structural congestion' means congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions;*
>
> *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 Article 3, 1. Clearly indicates that electricity prices should reflect **actual** demand and supply.

21. On 5 June 2019, Regulation (EU) 2019/943 of the European Parliament and Counsel on the internal market for electricity was published (hereafter referred to as the Regulation). This regulation

[2] Structural may be interpreted as frequent here. Article 13.3.d) of the regulation 2019/943 mention: "*the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding"* In addition, these congestions do not need to be located on exactly the same network element for constituting a structural congestion. Several lines on approximately the same path may constitute a structural congestion which splits the bidding zone in two parts. See also the Glossary at the end of the study.

is a recast of Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity.

22. The paragraphs below present the most important articles from the Regulation.

23. The Regulation also contains several provisions related to the determination of electricity prices and on the importance of the incentives for investments. Recital (22) indicates:

> *(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.*

24. Bidding zones with structural internal congestions do not allow that electricity prices are determined by demand and supply when supply is systematically redispatched (changed) after the price is fixed. This statement is supported by the recital (30) below, where the **problem of the price signal in relation with structural congestions is clearly identified**:

> *(30) To efficiently steer necessary investments, prices also need to provide signals where electricity is most needed. In a zonal electricity system, correct locational signals require a coherent, objective and reliable determination of bidding zones via a transparent process. In order to ensure efficient operation and planning of the Union electricity network and* ***to provide effective price signals for new generation capacity, demand response and transmission infrastructure, bidding zones should reflect structural congestion.*** *In particular, cross-zonal capacity should not be reduced in order to resolve internal congestion.*

25. Concerning the issue of the costs sharing, it is good to recall the following recital:

> *(31)… At the end of the implementation of such an action plan, Member States should have a possibility to choose whether to opt for a reconfiguration of the bidding zone(s) or* ***whether to opt for addressing remaining congestion through remedial actions for which they bear the costs. …***

Each MS has a responsibility regarding the costs it incurs to reach the 70% target as long as loop flows endured from bidding zones belonging to neighbouring MSs are below a certain threshold (range 0-30%-FRM).

26. Finally, in the following recital, the importance of economic signals and the market is re-affirmed:

> *(34) The* ***management of congestion problems should provide correct economic signals to transmission system operators*** *and market participants and should be based on market mechanisms.*

27. Article 3 of the Regulation shows the importance of prices formed on the basis of demand and supply, and clearly recommend **to avoid actions**[3] **which prevent** price formation on the basis of demand and supply. This article also signals the importance of appropriate investment signals.

> *Article 3 Principles regarding the operation of electricity markets*

[3] CREG considers that curative re-dispatching constitutes such an action.

Member States, regulatory authorities, transmission system operators, distribution system operators, market operators and delegated operators shall ensure that electricity markets are operated in accordance with the following principles:

(a) ***prices shall be formed on the basis of demand and supply;***

(b) ***market rules shall encourage free price formation and shall avoid actions which prevent price formation on the basis of 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;*

(…)

(j) ***safe and sustainable generation, energy storage and demand response shall participate on equal footing in the market****, under the requirements provided for in the Union law*

(…)

(m) market rules shall enable ***the efficient dispatch of generation assets****, energy storage and demand response;*

Paragraphs (a) and (b) above confirm what has already been indicated in the recital about the high importance of the formation of prices as resulting from demand and supply. This is a general principle which should be followed as breadcrumb ("fil d'Ariane" in French) when implementing the different articles of this Regulation. It can be shown [1] and [2] that market-based redispatching combined with structural internal congestions cannot provide the appropriate investment incentives requested in paragraph (g) and that demand and storage (j) are not compatible with cost-based redispatching (for which a cost cannot easily be defined) and so are not on an equal footing with generation.

28. Article 10 on technical bidding limits (see below) recalls the importance of the price formation on wholesale markets and of the importance of the role of the regulator on this issue. Bidding against a structural (which can be anticipated) congestion in the market coupling is a measure that restricts the price formation which should be tackled by the competent authority. When such a price restriction has been observed, **the competent authority shall take all appropriate actions** : this puts an obligation on the regulator to take all appropriate actions. In chapter 7 of this note, we propose an "appropriate action" to mitigate the impact of the recourse to curative redispatching on the day-ahead price signal.

Article 10: Technical bidding limits

…

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

*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.*

29. Article 13 on redispatching puts a strong emphasis on the use of redispatching and on market-based redispatching in particular.

> *Article 13: Redispatching*
>
> *1.The redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria. It shall be open to all generation technologies, all energy storage and all demand response, including those located in other Member States unless technically not feasible.*
>
> *2.The resources that are redispatched shall be selected from among generating facilities, energy storage or demand response* ***using market-based mechanisms and shall be financially compensated****. Balancing energy bids used for redispatching shall not set the balancing energy price.*

Here, the CEP sets a clear preference for market-based redispatching, with a financial compensation and with exceptions for the application of cost-based redispatching:

> *3.Non-market-based redispatching of generation, energy storage and demand response may only be used where:*
>
> *(a) no market-based alternative is available;*
>
> *(b) all available market-based resources have been used;*
>
> *(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or*
>
> *(d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8).*

The lack of effective competition and the presence of regular and predictable (i.e. structural) congestions constitute acceptable exceptions to the application of market-based redispatch. As with market-based re-dispatching, a compensation may also be due:

> *7. Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy. Such financial compensation shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:*

(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;

(b) net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.

The compensation of market players (redispatched down) for the loss of profit is clearly indicated here. The interaction of this sound principle with the existence of a zonal price means that market players may be paid for not producing.

30. The preference for bidding zone based on structural congestions, i.e. to manage structural congestions through a market coupling or splitting is indicated in Article 14 on the bidding zone review.

Article 14 Bidding zone review

1.Member States shall take all appropriate measures to address congestions. ***Bidding zone borders shall be based on long-term, structural congestions in the transmission network. Bidding zones shall not contain such structural congestions*** *unless they have no impact on neighbouring bidding zones, or, as a temporary exemption, their impact on neighbouring bidding zones is mitigated through the use of remedial actions and those structural congestions do not lead to reductions of cross-zonal trading capacity in accordance with the requirements of Article 16. The configuration of bidding zones in the Union shall be designed in such a way as to maximise economic efficiency and to maximise cross-zonal trading opportunities in accordance with Article 16, while maintaining security of supply.*

31. The implementation of the CEP will constitute in a mix of countries applying immediately the target of 70%, eventually together with derogations, and of countries going for an action plan. The CEP clearly indicates that the costs linked to the achievement of an action plan shall be borne by the Member State implementing an action plan. This paragraph has led to the proposal made in this note (see section 7 of this note below) of a stepwise implementation of re-dispatching actions, with a preventive redispatching in a first stage for internal congestions (see also Art. 16.4 of the CEP below) paid locally and residual curative redispatching actions organised at a broader level and with a sharing of costs[4].

Article 15: Action plans

(…)

3.The cost of the remedial actions necessary to achieve the linear trajectory referred to in paragraph 2 or make available cross-zonal capacity at the borders or on critical network elements concerned by the action ***plan shall be borne by the Member State or Member States implementing the action plan****.*

[4] The CREG does not see at this stage another approach of costs sharing guaranteeing compliance with this requirement of the CEP.

32. Market-based solutions providing efficient economic signal to the market participants still constitutes the reference for the management of congestions, as indicated in Article 16 below. CREG considers that redispatching does not belong to this category, as it may not be market based and does not provide an efficient economic signal.

> *Article 16 General principles of capacity allocation and congestion management*
>
> ***1.Network congestion problems shall be addressed with non-discriminatory market-based solutions which give efficient economic signals to the market participants and transmission system operators involved****. Network congestion problems shall be solved by means of non-transaction-based methods, namely methods that do not involve a selection between the contracts of individual market participants. When taking operational measures to ensure that its transmission system remains in the normal state, the transmission system operator shall take into account the effect of those measures on neighbouring control areas and coordinate such measures with other affected transmission system operators as provided for in Regulation (EU) 2015/1222.*
>
> *(…)*

Redispatching shall be used to reach the 70% target indicated in paragraph 16.8.

> *4.The maximum level of capacity of the interconnections and the transmission networks affected by cross-border capacity shall be made available to market participants complying with the safety standards of secure network operation.* ***Counter-trading and redispatch, including cross-border redispatch, shall be used to maximise available capacities to reach the minimum capacity provided for in paragraph 8****. A coordinated and non-discriminatory process for cross-border remedial actions shall be applied to enable such maximisation, following the implementation of a redispatching and counter-trading cost-sharing methodology.*

The implementation of the second part of this paragraph 4 may seem to be in contradiction with the importance of the price signal indicated in paragraph 1 above. Therefore, it is important to propose an appropriate design of redispatching rules combining both requirements. In addition, this paragraph indicates that cross-border redispatching has to be coordinated for cross-border remedial actions. No coordination requirement seems to exist for internal remedial actions.

Paragraph 16.13 below provides general principles for the sharing of redispatching costs. As a general principle, costs related to redispatching should be allocated in proportion to the loop flows and internal flows

> *13.When allocating costs of remedial actions between transmission system operators, regulatory authorities shall analyse to what* ***extent flows resulting from transactions internal to bidding zones contribute to the congestion between two bidding zones observed, and allocate the costs based on the contribution to the congestion to the transmission system operators of the bidding zones creating such flows except for costs induced by flows resulting from transactions internal to bidding zones*** *that are below the level that could be expected without structural congestion in a bidding zone.*
>
> *That level shall be jointly analysed and defined by all transmission system operators in a capacity calculation region for each individual bidding zone border, and shall be subject to the approval of all regulatory authorities in the capacity calculation region.*

Given that the CEP foresees redispatching as a valid instrument for helping maximising interconnection capacities, regulators and system operators have to deal with the question of how to include redispatching in the different methodologies for capacity calculation (CACM Guideline) and system operation (SOGL Guideline) in order to mitigate the already identified negative effects of this mechanism on the market and on competition (see below).

33. CACM Article 19 on Individual Grid Models stipulates that the IGM shall represent the **best possible forecast of transmission system conditions**, which is a very large and broad concept that includes all injections and extractions to the transmission network.

> *2. Each individual grid model shall represent the* ***best possible forecast of transmission system conditions*** *for each scenario specified by the TSO(s) at the time when the individual grid model is created.*

34. CACM Article 35 on redispatching and countertrade indicates that "only" actions of cross border relevance have to be coordinated and not all actions.

> *CHAPTER 3 Redispatching and countertrading Article 35 Coordinated redispatching and countertrading*
>
> *2.The methodology for coordinated redispatching and countertrading shall include actions of cross-border relevance and shall enable all TSOs in each capacity calculation region to effectively relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not. The methodology for coordinated redispatching and countertrading shall address the fact that its application may significantly influence flows outside the TSO's control area.*

35. REGULATION (EU) No 1227/2011 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 October 2011 on wholesale energy market integrity and transparency (referenced as REMIT below) stipulates the following in the recital section (bold letters are from CREG):

> *(4) Wholesale energy markets are increasingly interlinked across the Union. Market abuse in one Member State often affects not only wholesale prices for electricity and natural gas across national borders, but also retail prices to consumers and micro-enterprises. Therefore the concern to ensure the integrity of markets cannot be a matter only for individual Member States. Strong crossborder market monitoring is essential for the completion of a fully functioning, interconnected and integrated internal energy market.*
>
> *(13) Manipulation on wholesale energy markets involves actions undertaken by persons* ***that artificially cause prices to be at a level not justified by market forces of supply and demand, including actual availability of production****, storage or* ***transportation capacity, and demand****. Forms of market manipulation* ***include placing*** *and withdrawal* ***of false orders****; spreading of false or misleading information or rumours through the media, including the internet, or by any other means; deliberately providing false information to undertakings which provide price assessments or market reports with the effect of misleading market participants acting on the basis of those price assessments or market reports;* ***and deliberately making it appear that the availability of electricity generation capacity*** *or natural gas availability,* ***or the availability of transmission capacity is other than the capacity which is actually technically available where such information affects or is likely to affect the price of wholesale energy products****. Manipulation and its*

effects may occur across borders, between electricity and gas markets and across financial and commodity markets, including the emission allowances markets.

*This recital shows that actions which affect **or are likely to affect** the price of wholesale markets such as a wrong information about the availability of the transmission network or of a generation unit constitute a price manipulation. On this basis, the TSOs should inform concerned market participants that some of their generation units will have to be re-dispatched down, and on the basis of this information, market participants should refrain from introducing orders to trade in the day-ahead market coupling as they may not be able to run, as both **actions are likely to affect market prices.***

*(26) **National regulatory authorities should be responsible for ensuring that this Regulation is enforced in the Member States**. To this end they should have the necessary investigatory powers to allow them to carry out that task efficiently. These powers should be exercised in conformity with national law and may be subject to appropriate oversight.*

*(27) **The Agency should ensure that this Regulation is applied in a coordinated way** across the Union, coherent with the application of Directive 2003/6/EC. To that effect, the Agency should publish non-binding guidance on the application of the definitions set out in this Regulation, as appropriate. That guidance should address, inter alia, the issue of accepted market practices. Furthermore, since market abuse on wholesale energy markets often affects more than one Member State, the Agency should have an important role in ensuring that investigations are carried out in an efficient and coherent way. To achieve this, the Agency should be able to request cooperation and to coordinate the operation of investigatory groups comprised of representatives of the concerned national regulatory authorities and, where appropriate, other authorities including national competition authorities.*

Article 2 , Definitions For the purposes of this Regulation the following definitions shall apply:

(1) 'inside information' means information of a precise nature which has not been made public, which relates, directly or indirectly, to one or more wholesale energy products and which, if it were made public, would be likely to significantly affect the prices of those wholesale energy products.

For the purposes of this definition, 'information' means:

(a) information which is required to be made public in accordance with Regulations (EC) No 714/2009 and (EC) No 715/2009, including guidelines and network codes adopted pursuant to those Regulations;

(b) information relating to the capacity and use of facilities for production, storage, consumption or transmission of electricity or natural gas or related to the capacity and use of LNG facilities, including planned or unplanned unavailability of these facilities;

…

CREG considers that the need or the intention for deploying re-dispatching corresponds for the TSOs to an inside information as it relates to the use of facilities for production, storage, or consumption that may impact the wholesale electricity price.

(2) 'market manipulation' means:

(a) entering into any transaction or issuing any order to trade in wholesale energy products which:

*(i) gives**, or is likely to give,** false or misleading signals as to the supply of, demand for, or price of wholesale energy product*

…

Transactions which **are likely to give false** signals are considered as market manipulations. As internal congestions within a bidding zone prevent facilities for production, consumption or storage (if applicable) to physically inject electricity into the network, continuing to enter orders to trade these assets on wholesale energy markets after the need for re-dispatch became evident falls in this category.

or

(b) disseminating information through the media, including the internet, or by any other means, which gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of wholesale energy products, including the dissemination of rumours and false or misleading news, where the disseminating person knew, or ought to have known, that the information was false or misleading.

Dissemination of information by TSOs, other market participants or anyone else that is not justified by the actual supply and demand of wholesale energy products (including production and transmission) can be considered to be manipulative behaviour.

Article 4 Obligation to publish inside information

1. Market participants shall publicly disclose in an effective and timely manner inside information which they possess in respect of business or facilities which the market participant concerned, or its parent undertaking or related undertaking, owns or controls or for whose operational matters that market participant or undertaking is responsible, either in whole or in part. Such disclosure shall include information relevant to the capacity and use of facilities for production, storage, consumption or transmission of electricity or natural gas or related to the capacity and use of LNG facilities, including planned or unplanned unavailability of these facilities.

This article indicates that the information on the need for re-dispatching and consequently also the information on restrictions on the use of facilities for production/storage/consumption following the internal congestion, which is likely to affect the price, has to be published according to REMIT requirements as soon as available by the TSOs.

Article 5 Prohibition of market manipulation

Any engagement in, or attempt to engage in, market manipulation on wholesale energy markets shall be prohibited.

On this basis, we should deduce that a market participants, when informed by their TSO of a lack of transmission capacity and the need to redispatch some units down, should refrain from entering orders to trade that would aggravate the known congestion as this bidding behaviour is likely to distorts the market price.

Article 15 Obligations of persons professionally arranging transactions

Any person professionally arranging transactions in wholesale energy products who reasonably suspects that a transaction might breach Article 3 or 5 shall notify the national regulatory authority without further delay.

Persons professionally arranging transactions in wholesale energy products shall establish and maintain effective arrangements and procedures to identify breaches of Article 3 or 5.

This article places an obligation for the TSO to monitor/check if a curative redispatching down transactions has been implemented on an asset sold by a market participant in the day ahead market when knowing it may aggravate the congestion. This check could reveal manipulations.

36. COMMISSION REGULATION (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, referred hereafter as "SO GL", indicates in its Article 76 that all congestions detected in the base case, i.e. with no exchanges between control areas, have no cross-border relevance and should be tackled locally. If this may not apply for cross-zonal lines, this should at least apply for congestions observed on internal lines (as a few internal critical network elements may remain in the enduring CORE capacity calculation method).

Article 76 Proposal for regional operational security coordination

1.By 3 months after the approval of the methodology for coordinating operational security analysis in Article 75(1), all TSOs of each capacity calculation region shall jointly develop a proposal for common provisions for regional operational security coordination, to be applied by the regional security coordinators and the TSOs of the capacity calculation region. The proposal shall respect the methodologies for coordinating operational security analysis developed in accordance with Article 75(1) and complement where necessary the methodologies developed in accordance with Articles 35 and 74 of Regulation (EU) 2015/1222. The proposal shall determine:

(a) conditions and frequency of intraday coordination of operational security analysis and updates to the common grid model by the regional security coordinator;

(b) the methodology for the preparation of remedial actions managed in a coordinated way, ***considering their cross- border relevance as determined in accordance with Article 35 of Regulation (EU) 2015/1222****, taking into account the requirements in Articles 20 to 23 and determining at least:*

(i) the procedure for exchanging the information of the available remedial actions, between relevant TSOs and the regional security coordinator;

(ii) the classification of constraints and the remedial actions in accordance with Article 22;

(iii) the identification of the most effective and economically efficient remedial actions in case of operational security violations referred to in Article 22;

(iv) the preparation and activation of remedial actions in accordance with Article 23(2);

(v) the sharing of the costs of remedial actions referred to in Article 22, complementing where necessary the common methodology developed in accordance with Article 74 of Regulation (EU) 2015/1222. As a general principle,

costs of non-cross-border relevant congestions shall be borne by the TSO responsible for the given control area and costs of relieving cross-border-relevant congestions shall be covered by TSOs responsible for the control areas in proportion to the aggravating impact of energy exchange between given control areas on the congested grid element.

2.In determining whether congestion have cross-border relevance, the TSOs shall take into account the congestion that would appear in the absence of energy exchanges between control areas.

37. Congestions which appear with exchanges between control areas should be interpreted as having a cross-border relevance. On the basis of this interpretation, more congestions have to be coordinated than required by CACM. Nevertheless, article 76 above indicates that this should be interpreted in accordance with Article 35 of CACM. This definition also clearly indicates that congestions which appear without any cross-zonal exchange **are not cross-border relevant**. This corresponds exactly to congestions appearing in a (balanced) base case without any cross-zonal exchange (these congestions were referred a “pre-congestions” or non “congestion free base case”). These congestions do not have to be coordinated on this basis. Structural internal congestions fall very often in this category. All this supports the proposal we make in Chapter 7 below on the coordination of **residual curative redispatching only,** where structural internal congestions have to be tackled as much as possible (see below) before this coordinated process on a national/zonal basis**.**

4 INEFFICIENCIES LINKED TO REDISPATCHING

38. Redispatching means that system operators need to adjust the market outcome in order to ensure secure system operation. These adjustments are done outside the wholesale market. Cheap units dispatched on the basis of the wholesale market results are asked to regulate their production downwards, whereas more expensive units which had not been dispatched in the wholesale market, are asked to regulate their production upwards. These out-of-the-market adjustments are a source of inefficiency which results in additional costs for consumers.

39. The main concerns linked to structural curative (after the day-ahead market coupling) redispatching examined in this note are the suboptimal unit commitment decisions, discussed in section 4.1, the lack of efficiency, as presented in section 4.2, the market and competition distortion, discussed in Section 4.3, and the increased risk and uncertainties, discussed in Section 4.4.

40. The impact of market power and gaming will even inflate the impact of these inefficiencies even more, as described in Hirth [1]. This problem arises when the congestion is structural such that market players can anticipate when they will be asked to regulate downwards or upwards and consequently adapt their bidding strategy to this. This worsens the congestion and inflates redispatching costs. A discussion or evaluation of the impact of market power and gaming in the case of structural redispatching is out of scope of this paper. In the rest of the paper we assume perfect competition, perfect foresight of all market participants and no market power. In case there is market power the inefficiencies will materialize even quicker and with more impact than without.

4.1 SUBOPTIMAL UNIT COMMITMENT DECISIONS

41. A proper market design allows optimal unit commitment decisions. It means that the production units selected should result in the lowest overall production cost or in the highest overall social welfare, depending on the objective function. This implies that dynamic effects such as start-up times, shut-down times, ramping constraints etc. can be taken into account with enough anticipation i.e. at the day-ahead stage when there is enough lead time between the moment of the decision making and the actual time of production.

42. Suboptimality arises when internal [5]congestions are ignored at the day-ahead stage. If redispatching decisions are only to be taken after the day-ahead market clearing, system operators will need to rely more on the activation of fast (or flexible) generators since the lead-time between the redispatching decision making and the actual time of production does not allow to significantly alter the schedule of the slow units anymore.

43. Hence, due to the presence of "slow" units, the overall production costs will be higher than when the presence of congestions is anticipated at the day-ahead stage and internalised in the day-ahead unit commitment decision.

44. The extent and impact of this problem depends on the production mix and on the location of the congestion. In a situation where cheaper but slow thermal power plants such as nuclear, coal and lignite co-exist with wind or solar at one side of the congestion with the more expensive but faster gas-fired power plants at the other side of the congestion, **more renewable generation may have to be curtailed for solving the congestion** that was not taken into account at the day-ahead market clearing stage. If the decision of re-dispatching down was taken earlier, before the day-ahead market coupling,

[5] Meaning of internal congestions in this note: internal congestions refer here to congestions located inside a bidding zone and provoked by exchanges internal to that bidding zone. See also the Glossary below.

slow thermal power plants would have been able to further reduce their generation output level, **allowing a higher generation from renewables**.

4.2 REDISPATCHING IS NOT EFFICIENT AND THE INFRA MARGINAL RENT IS KEPT

45. Participating in the day-ahead market coupling is voluntary, may be done on a portfolio basis, and the electricity delivered paid at the **zonal marginal price**. So, the first stage of a redispatching process, the dispatch, if part of the market coupling, is done in a market based way. Then, redispatching is paid at any node of the network on the basis of variable costs of production in the case of cost-based redispatching, or on the basis of bids in the case of a market-based approach. The existence of two different mechanisms with different pricing rules (one zonal, pay as cleared, the second nodal, at cost or bid based) creates (inefficient) arbitrage possibilities. In short, redispatching, when combined with a zonal price, is not efficient.

46. Production units which are redispatched downwards are remunerated (compensated according the CEP) for their opportunity costs. This opportunity cost corresponds to the profit they would have made by selling their energy in the day-ahead market coupling, being the difference between the day-ahead market clearing price and the variable cost of production or the bid price for being redispatched downwards. This difference is also referred to as the "infra-marginal rent". In contrast, units which are redispatched upwards do not have this opportunity loss since they had not been selected in the day-ahead market and hence did not make any profit in that day-ahead market. The upwards redispatching units are only remunerated for the variable cost of production or at bid price.

47. Cost-based redispatching is based on the assumption that a system operator or regulator can accurately assess the true variable operation cost of a production unit. This is difficult to do in practice. Furthermore, the concept of variable cost is hard to define in the case of demand response and storage.

48. Market-based redispatching tries to circumvent the problems of assessing the variable costs, especially when extending the scope towards demand response, storage and RES, by allowing production and demand units to introduce redispatching bids, with the volume and price being freely defined by the market player. The system operator then selects the combination of redispatching bids to minimize redispatching costs. The idea is that such a "market" for congestion bids will foster competition and reduce the costs related to redispatching.

49. From a market design perspective both cost-based and market-based redispatching remain inefficient because in both cases one may end up paying a producer even for not producing. The remuneration for downwards redispatched units, keeping the infra-marginal rent, if structural, is even contra-intuitive.

50. It creates a financial supporting mechanism for production units in export-constrained areas with a surplus of supply, providing producers the incentive to even invest more in those areas [6] thereby increasing the surplus of supply. At the same time, it provides a disincentive in unconstrained areas and in importing areas because the higher price is not paid there. The incentive to invest at the wrong location makes the congestion problem even bigger.

[6] See reference [1] and [2]

51. Both cost-based and market-based redispatching are prone to inefficient arbitrage in the case of structural congestions. Gaming aggravates congestion problems or may even create them where these were not present. However, the opportunity for gaming, in case of structural congestions, is even higher in case of market-based redispatching[7] than in case of cost-based redispatching.

52. Following the famous "Inc-Dec Game" applied by Enron between 2001 and 2002 and the collapse of the Californian electricity system in 2002, there is a rich scientific literature on this subject and on the aggravating effect of gaming in case of structural congestions: see [1] and [2]. California chose to shift from a zonal system to a nodal system to avoid that market players may arbitrate or game between the zonal market clearing price and the intrinsically nodal price of redispatching in case of structural internal congestion.

53. It is worth reading the paper of reference [1]. The perceived goal of this paper was to demonstrate, on the basis of a two-node simplified example that market based redispatching is very bad. CREG shares this view. But the examples used in the paper also clearly demonstrate that cost based redispatching suffers of the same flaws. The most recent version of the paper clearly shows the additional costs paid to producers due to re-dispatching in the case of cost based redispatching and in the case of market-based redispatching, when compared to a nodal or zonal (which is the same for the 2 node example used) solutions (sections 2.2 and 2.3): consumers pay more. The paper also shows the price distortion (section 4.3 where it is indicated that "the spot market loses its meaning as a lead or reference market"). Even in the case of cost based redispatching, the paper identifies the wrong incentive (support) given to producers in export constrained area (page 15, table 11 and in the Conclusions, with the "lack of locational incentive") and the aggravating effect of market based redispatching (compared to cost based). In sections 7, the difficulty to avoid "gaming" of the design even in the case of cost based redispatch is presented, if such a gaming can be detected. The problem linked to the anticipation of a (frequent, structural) congestion is clearly explained section 5.2) together with the possibility for TSOs to anticipate structural congestions.

4.3 MARKET AND COMPETITION DISTORTION

54. **As a rule repeated in the Clean Energy Package, electricity prices should reflect actual supply and demand.** This rule should also apply for the day-ahead market coupling, but unfortunately, this is not always the case in the presence of structural internal congestions. In a zonal market, production units are selected by the day-ahead market coupling on the basis of their position in the merit order curve for producing the next day and commercial exchanges between bidding zones are defined on the basis of the prices resulting from the day-ahead clearing.

55. Problems arise when these selected units face structural congestions: in that case, they are systematically redispatched down after the clearing of the day-ahead market coupling. This means that the market clearing price does not reflect the price of the true marginal generation unit as this is changed by the redispatching. The zonal price is determined by the cheaper units which are redispatched down, whereas the more expensive units redispatched up should determine the true zonal marginal price.

56. This practice, if frequent and related to high amounts of power, constitutes a serious bias to the price formation. In this case, electricity prices resulting from the day ahead market coupling are systematically depleted in comparison to the marginal price of the (more expensive) units that will

[7] In their paper [1], Hirth and Schlecht indicate, page 19, that "The existence – or more precisely, the anticipation – of a redispatch market leads market parties to submit spot market bids that increase the level of congestion"

effectively run in real time due to the internal congestion for meeting the agreed exchanges defined by the day-ahead market coupling. This price (and volume of exchanges: see below) distortion leads to inefficiencies in different ways.

57. Firstly, the financial compensation for the upwards and downwards redispatching results in a welfare loss and distributive effects. Producers are being remunerated outside the wholesale market to produce less or more than what resulted from the market clearing. This leads to an increase of costs and a loss and redistribution of welfare between producers and consumers. The extent of welfare loss depends on how much redispatching is needed, since the more redispatching, the more one deviates from the market clearing point where the welfare is maximized at the intersection of the demand and supply curves. In the case of structural congestions, the problem of welfare loss can be aggravated if market players start to anticipate if they will be redispatched upwards or downwards and adapt their bidding strategy to it. In the worst case, market players may be paid for resolving congestion that these market players caused themselves (e.g. by bidding *lower* than their true marginal cost).

58. **Secondly, redispatching distorts the results of the market coupling in term of prices and volumes.** In bidding zones with high amounts of redispatching, wholesale prices are artificially lower than they should be. Hence, in coupled markets, those bidding zones will import less from or export more to other bidding zones than they should do compared to the marginal price of the actually dispatched electricity generation units. Production units inside the other bidding zones face unfair competition with the artificially low prices of the import volumes from the redispatching-rich bidding zones. This results in a distortion of competition[8] between production units located in different bidding zones.

59. **Thirdly, market distortion also jeopardizes the business case for demand response.** If redispatching costs are paid by consumers through the grid tariffs, it means that the temporal variation of the wholesale price is attenuated. This jeopardizes the proper functioning of the market where price signals provide the right incentive for demand response, which is especially needed when evolving towards higher shares of renewables in the production mix. As indicated by Neuhoff 2019 [4], both the temporal and local dimension of price signals are needed for an effective use and full remuneration of local flexibility, which will reduce wind curtailment and conventional power generation.

60. **Overall, market distortion perverts the investment signals.** The effectively available volume of production capacity and the out-of-market compensations are not reflected in the market clearing price. As explained in [1] 2018, it leads to the day-ahead market price losing its meaning. In the long run (see [2]), this jeopardizes the functioning of the market where price signals should provide the right incentives for investment in new production capacity, network reinforcement and demand side management. A price signal reflecting the **actual** available supply, demand and transmission capacity is a necessary condition for having an efficient, liberalised market.

[8] 1. Due to its windfall profit nature, the support given by redispatching through the infra-marginal rent has some similarities with state aid for these producers. But this is out of the scope of this study.

4.4 INCREASED RISK AND UNCERTAINTY IN SYSTEM OPERATION

61. **Network management is governed by intrinsic uncertainties** such as those linked to the load forecasts, the renewable energy sources (RES) forecasts and the state of the network. To manage the risks associated with these uncertainties, TSOs adopt reliability margins and follow the N-1 criterion.

62. **Redispatching for solving structural congestion inside a bidding zone may constitute an additional source of uncertainty** for network management, leading to higher security margins, increased risk levels or higher costs for maintaining a given risk level.

63. **More uncertainty arises if redispatching is not anticipated in the capacity calculation phase.**[9] Redispatching alters the flows, so if structural redispatching is not taken into account in the load flow calculations of the common grid models exchanged between TSOs, there is a structural error and a systematic bias in the capacity calculations. Coordination is not adequate, and this is problematic because the main objective of capacity calculation is to calculate the maximum available commercial capacity while respecting the network constraints. If load flow calculations are systematically erroneous because structural redispatching is not properly taken into account, the result of the market coupling can never guarantee safe grid operation and TSOs will need to foresee additional remedial actions to cope with this uncertainty.

64. To conclude, **the manner in which redispatching is implemented in capacity calculation has an impact on the system security.** Today, TSOs do not systematically include the best-forecast of redispatching in the capacity calculation, leading to an erroneous image of the actual production and hence an erroneous image of the actual flows on transmission lines.

[9] This is also indicated in [1], 2018 paper: "Another consequence is that operation of the system gets significantly harder. The system operator gets a highly flawed picture of actual system condition and desired flows by market parties at the stage of the spot market. Since a redispatch market can only be opened after gate closure of any zonal trading, in the little time that remains for redispatch, the system operator has to cope with a large part of the dispatch changing.

5 IMPACT OF REDISPATCHING IN THE CENTRAL WEST EUROPEAN CAPACITY CALCULATION REGION

65. In this Section, we illustrate the impact of redispatching in terms of suboptimal unit commitment decisions, market price distortion and increased system uncertainty. These inefficiencies come in addition the costs of re-dispatching born by the consumers through the transmission tariffs. These impacts are illustrated by means of three examples from the Central West European market coupling (CWE).

66. Since 1 October 2018, the CWE market coupling consists of 5 bidding zones: the Belgian (BE), Dutch (NL), German/Luxembourg (DE/LU), Austrian (AT) and French (FR) bidding zones. All five bidding zones do apply redispatching for solving congestions. The annual volumes and related costs of redispatching per bidding zones are monitored and published by ACER in their annual market monitoring report. Detailed data on redispatching volumes and related costs are shared between the involved TSO and the involved regulator to monitor their need and reasonableness. Detailed redispatching data are not yet commonly publicly available with exception of the redispatching data of the DE/LU bidding zone (or the former DE/AT/LU bidding zone) for which a comprehensive data set can be found online[10][11].

5.1 IMPACT ON UNIT COMMITMENT DECISIONS

67. Within bidding zones, internal network constraints are not taken into account at the day-ahead stage in the day-ahead market coupling. This leads to inefficient unit commitment decisions, especially in poorly defined bidding zones. This phenomenon has been observed and quantified by Aravena 2017 [3] by means of a comparison of zonal NTC and zonal FB mechanisms with a nodal reference. Zonal congestion management mechanisms compared to nodal result in **additional costs estimated at 720M€/year for the CWE region**. These additional costs result mainly of suboptimal commitment decisions due to a lack of anticipation of internal constraints (64%).

68. The suboptimality arises from the fact that some production units such as nuclear, coal and lignite power plants have longer start-up, longer shut-down time and slower ramping rate than more flexible units such as gas power plants or wind turbines, and they may have constraints of minimal production capacity. If those slow thermal units are committed in the day-ahead market, it is technically more difficult to redispatch them than the more flexible units. Therefore, if congestions are not anticipated before the day-ahead market coupling, wind generators, which are more flexible, have to be curtailed because the committed coal power plants cannot operate below their minimal capacity. This entails large costs because of the wind feed-in tariffs have to be compensated and represent an important environmental cost.

69. As a conclusion, if structural congestions appear, it is better to anticipate this congestion such that the day-ahead market can ensure an optimal unit commitment by taking all dynamic constraints into account.

[10] https://www.netztransparenz.de/EnWG/Redispatch
[11] It should be noted that the amount of redispatching is much lower in the other CWE bidding zones.

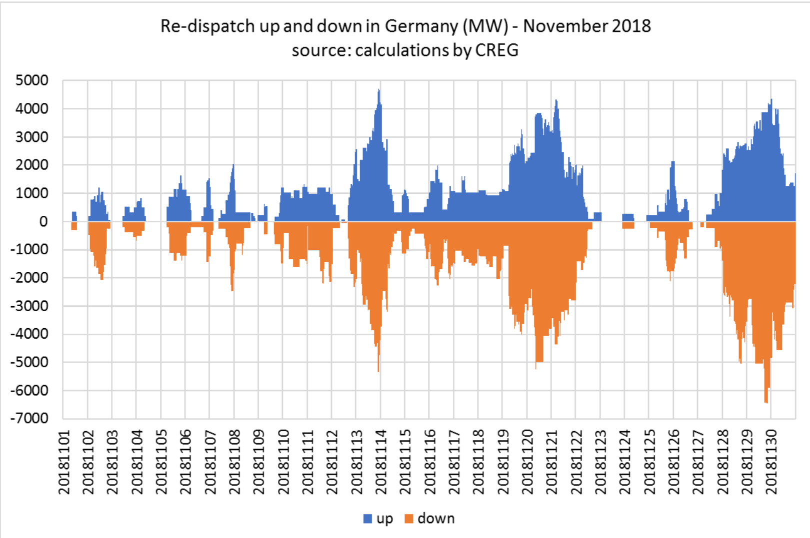
5.2 IMPACT ON WHOLESALE PRICES & COMPETITION

70. In the example below, we have used the detailed data publicly available on redispatching in the German bidding zone to illustrate the impact of redispatching on the German day-ahead wholesale prices.

71. This section establishes the evidence of the identification by CREG of policies and measures (here the functioning of market coupling with structural internal congestions) applied within their territory that could contribute to restricting wholesale price formation, as foreseen by Article 10.4 of Regulation 2019/943.

5.2.1 Methodology

72. German TSOs very frequently use significant volumes of redispatch to solve internal congestions. During certain periods, up to 4.000-6.000 MW is being redispatched down and up[12]. The figure below gives the redispatch up (+) and down (-) for November 2018.



73. By definition, redispatch downwards is being done by units that should produce on the basis of the outcome of the day-ahead market coupling, whereas the redispatch upwards is done by units that were not producing. What is important is that a downwards redispatch is being performed on a unit that has influenced the price formation on the day-ahead market. Indeed, the day-ahead price is established with the supply and demand curves reflecting the available capacities. The supply curve includes capacities that are willing to produce in real time, even if they would not be available in real-time because they will be redispatched downwards.

74. Hence, allowing a production unit to shift the supply curve to the right, even when it will be redispatched downwards after the market clearing, artificially lowers the day-ahead market clearing price.

75. If a TSO can predict in day-ahead on which units they will perform a downwards re-dispatch, then these capacities should be taken out of the day-ahead (and intraday) supply (or demand[13]) curve, because these capacities will not be available in real time. The reason is straightforward: the price

[12] The asymmetry of the curve (there is more redispatch down than up) is remarkable. Comments are welcome! More generally, asymmetric activation curves may bring additional difficulties to the sharing of re-dispatching costs.

[13] A generation unit can also be offered on the day ahead market through a demand bid.

formation should be done based on the actual available generation and transmission capacity[14]. Therefore, it is mandatory that TSOs use a best forecast of the actual available generation and transmission capacity.

76. The CREG simulated the German day ahead price during October 2018 until February 2019 (5 months) in the case the German TSOs would forecast in day-ahead all the downward redispatch in the German bidding zone. These capacities have been subtracted from the German day-ahead supply curve, with a shift to the left as a consequence. This shift leads to a higher price (see Figure 1 below).

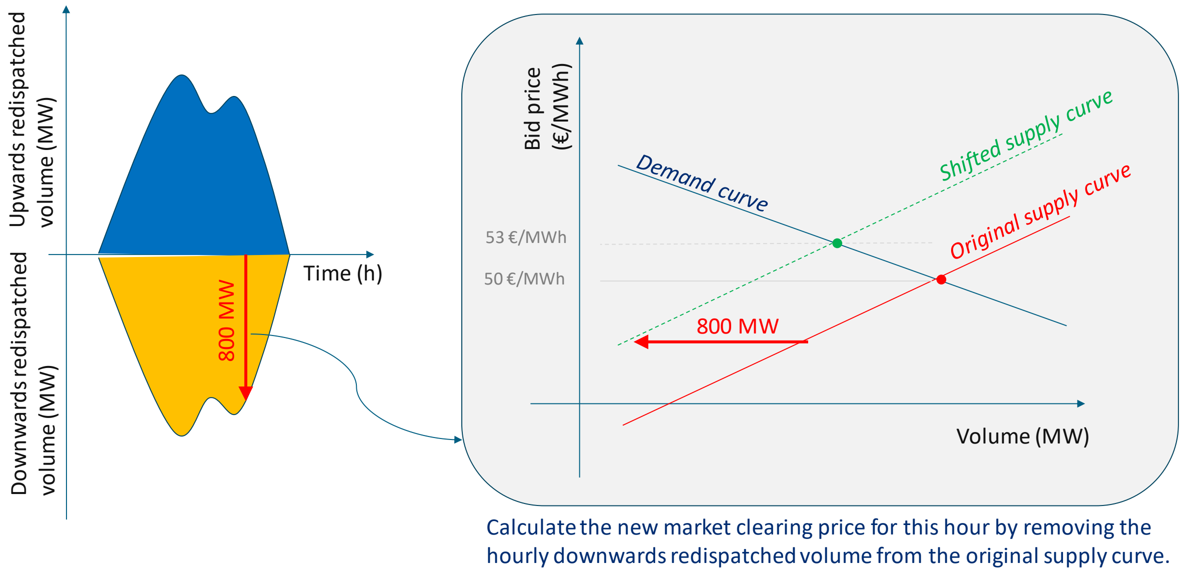


Figure 1: Wholesale prices are calculated based on the intersection of the demand curve and (shifted) supply curve. The supply curve is shifted to the left with the same volume as the volume of downwards redispatched units. The volume of exchanges (import/export) is assumed to be fixed.

77. We calculated the hourly German wholesale prices as the intersect of the shifted German supply curve and the German demand curve, given the historical German net export position. We used the historical net export positions **and do not consider the impact** of the increased German wholesale prices on the cross-zonal exchanged volumes. The results of our calculations **constitute an upper bound of the impact of redispatching on the German wholesale prices**, and a lower bound of the impact of redispatching on the volumes exchanged between the different bidding zones in the market coupling.

78. A higher market clearing price means that in situations where the German bidding zone was exporting, and this was generally the case, that bidding zone would have exported less to the neighbouring bidding zones which in turn would have put a downwards pressure on the German wholesale price. In order to have the exact impact of the shifted German production curve on German wholesale prices and exchanged volumes, one should simulate the removal of units redispatched down out of the merit order curve on the entire European market coupling with Euphemia, which is out of scope of this study.[15]

[14] See Recital 13 of the Regulation (EU) No 1227/2011 of the European Parliament and Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT Regulation)
[15] However, from a practical perspective, this theory could be tested by the involved TSOs and NEMOs.

5.2.2 Data set

79. We used the following three sets of hourly data: the German demand curve, the German supply curve and the downwards redispatched volume.

80. Data on the German demand and supply curves are obtained from EPEX SPOT. Data on the downwards redispatched volumes are retrieved from the German transparency platform.

81. The observed period covers 5 months, spanning from October 2018 to February 2019.

5.2.3 Results

82. The average German day ahead price would have increased on average by 6,15 €/MWh during these 5 months, which is a 10% price increase, if the capacities being redispatched downwards would not have participated in the price formation (this figure reaches 7,8€/MWh when only hours with re-dispatching are considered). This has an enormous impact and constitutes a serious price distortion.

83. The simulation was being done assuming the German net export position remained unchanged, thereby not influencing the dispatch of generation units in other countries. However, one could assume the German bidding zone would import more (export less) if downward redispatched units could not participate in the day-ahead (and intraday) price formation. If that effect were taken into account, the resulting German price increase would be lower, but then generation units in other countries would be able to produce more, clearly showing the distorted effect on the dispatch of units in other bidding zones than the German one.

5.2.4 Discussion

84. By not applying the best forecast on the available generation and transmission capacity, the day-ahead (and intraday) price formation is heavily distorted, leading to lower than normal prices in Germany and/or lower generation volumes in the neighboring countries. These distortions seriously affect competition with producers located in different bidding zones.

85. The increase of 6,15 €/MWh of the German wholesale price is explained by the fact that the bidding curve is shifted to the left by removing the production units which are expected to be downwards-redispatched. More expensive units are now selected in the market coupling process. They are able to set the price. This contrasts with the current situation where the cheaper units which are being redispatched down are able to set the price and more expensive units are being remunerated outside the market as upwards regulated capacity in the redispatching framework.

86. As discussed further in Chapter 6 below, the CREG is of the opinion that the price should be set by the actual available electricity generation capacity and available transmission capacity, in line with Recital 13 of the REMIT regulation. Generation units which are technically not able to generate electricity because the transmission capacity is not available, should not set the price.

87. Price formation should be done based on the actual available generation and transmission capacity. This implies that TSOs should use a best forecast of the actual available generation and transmission capacity.

88. Selling a good (energy) below production costs (when lignite prices are lower than gas) is very often associated to dumping practices.

89. The price distortion observed in the German bidding zones propagates, through the market coupling, to other bidding zones of the CWE region, and the Belgian day-ahead price which results

from the CWE FB market coupling is distorted. Volumes of energy exchanged between bidding zones are also distorted.

90. On the basis of the identification by CREG of a price distortion in Belgium resulting of the application of the CWE FB market coupling, the recently adopted Article 10.5 of Regulation 2019/943 provides the tool (the obligation) for the NRA for taking all appropriate actions for mitigating the observed distortion. The proposal made in section 7 below constitutes the first measures taken by CREG for mitigating the observed price distortion.

5.3 IMPACT ON LOAD FLOW FORECAST UNCERTAINTY AND ON SYSTEM SECURITY

91. We illustrate the impact of not anticipating redispatching on the quality of the load flow forecasts (as included in common grid models) by means of three small examples. These examples may not be representative for all time frames or for all bidding zone borders, but the aim is to show the possible consequences of the current approach to not anticipate the impact of redispatching in the load flow calculations which are used in the day-ahead capacity calculations.

5.3.1 Structural bias between forecasts and realized loop flows

92. Based on information from Elia grid operator, the Belgian TSO, loop flows in the day-ahead capacity calculation are structurally overestimated. Before the split of the DE/AT/LU bidding zone, the overestimation of loop flows on an annual average amounted to 630 MW[16]. Given that the forecasted loop flows in the day-ahead capacity calculation before the DE/AT/LU bidding zone amounted to 840 MW on average, it means that the loop flows are structurally overestimated by 75%[17].

93. Since loop flows reduce the available commercial capacity, it means that calculated cross-zonal capacities are structurally lower than would be the case with a better forecast of the loop flows. If the structural bias would be totally removed, the average loop flow value in the day-ahead capacity calculation would have been around 210 MW instead of 840 MW. All other things equal, the reference flows (Fref) on the cross-zonal CNECs at the Belgian-Dutch and Belgian-French borders would be 75% lower as well. For instance, the Belgian cross-zonal CNEC "PST Zandvliet", would have an average Fref of 150 MW instead of the current average Fref of 610 MW[18], providing 460 MW extra RAM[19] on that CNEC.

5.3.2 High number of pre-congested cases

94. CWE flow-based market coupling (FBMC) suffers from a high number of pre-congested cases. These are cases where the **zero-balanced base case is not congestion-free** meaning that the calculated flows on the critical network elements exceed the thermal limit in N-1 even before any cross-border exchanges has taken place. With other words, the N-1 security on the critical network elements is already violated by flows resulting from the exchanges inside bidding zones considered in the base case. Therefore, if one constructs the flow-based domain based on these load flow calculations, one obtains an empty flow-based domain and no cross-border exchange could take place. All the available cross-border and other network capacity is then being used to accommodate only domestic trade.

95. In the first years of CWE FBMC, this problem became apparent through the large number of LTA-violations. In 85% of the time, the small or empty flow-based domains needed to be systematically

[16] On average, loop flows are going from North to South through Belgium. Observed flows in the North to South direction are on average 630W lower than the flows expected at the day-ahead stage in the capacity calculation process. Figure provided by Elia (2018). See also CREG Study on the functioning and price evolution of the Belgian wholesale electricity market - monitoring report 2018 on www.creg.be/en/publications-available-english

[17] Forecasted loop flows in the day-ahead capacity calculation on the Belgian borders or published on the Elia website since 2017, see: www.elia.be/en/grid-data/interconnections/Loopflows

[18] Annual average calculated for 2018, considering only the time stamps where a CNEC of PST Zandvliet was active (661 hours)

[19] RAM = Remaining Available Margin [MW] is the network capacity offered to the European market coupling on a critical network element under contingency (CNEC).

increased through the LTA-inclusion patch in order to at least be able to cover the long-term allocated capacity. The LTA-inclusion provided a patch to partially mask this fundamental problem.

96. Since the introduction of the 20% minRam requirement in April 2018, the number of LTA-violations has significantly decreased. However, the fundamental problem of (close-to) pre-congested cases remain. The problem is now partially being masked through the systematic use of an Adjustment for minRam (AMR) value to provide the minRam capacity.

5.3.3 High Flow Reliability Margins

97. Today, the forecast error between the day-ahead capacity calculations and the realized flows is translated into a Flow Reliability Margin (FRM) at CNE or CNEC level. It means that large forecast errors translate into large FRM-values as these margins are supposed to account for the uncertainty related to the forecast errors. Since the FRM is deducted from the available capacity for cross-zonal exchange, high FRM values reduce the commercial capacity. This unnecessary reduction of commercial capacity leads to the distortion of the price formation on the European power exchanges. As a consequence of the large loop flow forecast errors, we observe high FRM-values on the Belgian cross-zonal CNECs. As an example, the FRM of the CNEC “PST Zandvliet” is 256 MW, equal to 17% of the average thermal limit (or ‘Fmax’) of 1534 MW.

98. On top of the high FRM, there is another “safety margin” for handling with uncertainties, namely the number of PST tap positions which are reserved for dealing with unexpected flows close to real time. Today, one third of the Belgian PST tap positions are reserved for real-time operation. These tap positions cannot be used to optimize the flow pattern in the day-ahead and intraday capacity calculation or in the day-ahead coordinated security analysis.

5.3.4 Difficulty to assess the need of minRam derogations

99. In September and October 2018, German TSOs triggered the 20% minRam derogations for 20 hours, spread over 3 days, for system security reasons. CWE NRAs received data from German TSOs to monitor the justification of these 20% minRam derogations. The data comprised the load flows on the relevant network elements in the capacity calculation phase (“D2CF”), the load flow calculations in the day-ahead security analysis (“DACF”) and the real time flows. Each time, the load flows were available at the relevant CNE and CNEC levels for the network elements for which N-1 security violations had been detected.

100. The data revealed that reference flows in the D2CF base case were so high that they already triggered N-1 security violations even without accounting for any cross-zonal exchange (also called a pre-congested case as explained in section 5.3.2 above). The N-1 overloads on these internal lines amounted to 800 MW in the D2CF files. The N-1 overloads in the DACF files, i.e. after the coordinated security analysis, had shrunk to 300 MW. In real time, the N-1 overloads were close to zero.

101. A relatively small difference between the forecasts in D2CF, the forecasts in DACF and the realized flows may be attributed to several inputs such as the load forecast, RES forecasts and grid topology forecasts. The largest part of the observed discrepancy, however, is to be attributed to the inclusion (or not) of the redispatching in those load flow calculations.

102. If in real time a high amount of redispatching is used to assure N-1 grid security, and these redispatching actions are not included in the common D2CF, this significantly alters the load flow forecasts. Since the 20% minRam derogations are based on these D2CF forecasts, it is difficult for regulators to judge on the necessity of a minRam derogation for system security reasons if one knows

that the D2CF forecasts are so inaccurate and unrepresentative[20]. One may wonder how neighbouring TSOs assess the feasibility of a given minRam threshold if they face the same uncertainty.

5.3.5 System security at risk

103. System security is at risk due to a lack of anticipation of remedial actions in the grid models which lead to erroneous load flow calculations at the different stages.

104. With erroneous load flow calculations for the day-ahead capacity calculation, **TSOs cannot perform a proper system security analysis** in the capacity calculation phase. They can hardly check whether the commercially offered capacities are technically feasible and prepare remedial actions to cope with forecasted congestion. This may lead to increased conservatism in the capacity validation phase or to increased system security risks.

105. More generally, by allowing individual TSOs to postpone the decision-making on remedial actions towards closer to real time, real time flows can significantly deviate from what was foreseen in the common grid models. Because these deviations have not been coordinated amongst TSOs, they are referred to as **uncoordinated flows**. For neighbouring TSOs, these uncoordinated flows can put a large pressure on the system operators. System operators then need to cope with those uncoordinated flows within a short time span and with those remedial actions remaining available, having little or no information on how they will evolve in direction, magnitude and time.

5.3.6 Discussion

106. With the current 20% minRam framework in the CWE flow-based market coupling, the lack of an appropriate modelling of redispatching in the capacity calculation phase reduces the capacity for cross-zonal exchange in different ways. Firstly, loop flows are structurally overestimated. Secondly, high forecast errors, due to this structural overestimation, are translated in large FRM-values. And thirdly, it is difficult for TSOs to assess the feasibility of respecting a minRam threshold in the capacity validation phase or for regulators to monitor the justification of minRam derogations. Overall, there is a higher system risk due to a lack of anticipation of the impact of remedial actions.

107. With the implementation of the 70% minRam target of the CEP[21], reducing uncertainty in the capacity calculation phase will become of utmost importance to provide these commercial capacities in an efficient and secure way at reasonable cost.

108. The CREG is of the opinion that improving the load flow forecast accuracy in capacity calculation will help TSOs to offer that commercial capacity since, firstly, it reduces the structural overestimation of loop flows, secondly, it reduces the FRM-values and thirdly, it improves the accuracy for assessing N-1 grid security in the capacity validation phase. To put it the other way around, **if load flow forecast accuracy is not improved, this may jeopardize the effective implementation of the CEP targets by either less commercial capacity, or increased system security risks, or higher costs for guaranteeing system security.**

[20] The uncertainty may be as high as the minRam

[21] *CEP foresees a minRam threshold of 70% of Fmax as default value, though from 2020 to 2024 this 70% value may be replaced at Member State level by an intermediate value defined by an action plan introduced by this Member State.*

6 APPLICATION OF REMIT

109. In Section 5 we estimated that for the period of October 2018 to February 2019 the impact of redispatching in the German bidding zone on the German wholesale prices was 6,15 €/MWh on average, neglecting the impact on exchanged cross-zonal volumes. This is an enormous impact which threatens the integrity of the wholesale market. The structural downwards redispatch of lignite and hard coal units in Germany impact the competitiveness of generation units located in other price zones.

In this section, we therefore analyse this issue from a REMIT perspective.

6.1 REMIT LEGISLATION

110. The main objective of Regulation (EU) 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency, referred to as 'REMIT', is to safeguard the integrity of the wholesale market for the benefit of final consumers of energy.

111. The starting point for REMIT is the importance that prices set on wholesale energy markets reflect a fair and competitive interplay between supply and demand, and that no profits can be drawn from market abuse. In Recital 4, REMIT emphasizes that the concern to ensure the integrity of markets cannot be a matter for individual Member States and that strong cross-border market monitoring is essential for the completion of a fully functioning, interconnected and integrated internal energy market.

112. According to Recital 13 of REMIT, a manipulation on wholesale markets involves actions undertaken by persons that artificially cause prices to be at a level not justified by market forces of supply and demand, including actual availability of production, storage or transportation capacity, and demand. Forms of market manipulation include deliberately making it appear that the availability of electricity generation capacity (…), or transmission capacity is other than the capacity which is actually technically available where such information affects or is likely to affect the price of wholesale products.

113. Article 4 of REMIT obliges market participants (e.g. operators of concerned power plants or TSOs) to publish inside information and Article 5 of REMIT indicates that, any engagement in, or attempt to engage in, market manipulation on wholesale energy markets shall be prohibited.

6.2 DISCUSSION

114. CREG considers that the problems of price distortion related to redispatching are in the scope of the REMIT legislation. REMIT Recital 13 namely explicitly recognizes that market manipulation includes "**deliberately making it appear that the *availability of electricity generation capacity or transmission capacity is other than the capacity which is actually technically available where such information affects or is likely to affect the price of wholesale products***".

115. CREG considers that, in accordance with recital (13) ("actions undertaken by persons that artificially cause prices to be at a level not justified by market forces of supply and demand, including actual availability of production, storage or transportation capacity, and demand) and Art 2.2(a)(ii) of REMIT, TSOs, when facing congestions or problems for reaching the targets of the CEP in the base case, correctly inform the market and in particular **concerned producers of the units that will have to be re-dispatched down** (if they participate into the day-ahead market coupling) on the status, congested or not, of the network elements relevant for the transport of their energy, and also inform **the other TSOs** of their flows forecasts through adequate IGMs based on their best forecast of the transmission system conditions for the calculation of the day-ahead transmission capacity. A market outcome which does not reflect the actual availability of the transportation capacity is considered as delivering an artificial price in accordance with Article 2.2(a)(ii) of REMIT. By not providing correct information on the availability of transmission capacity, TSOs provide misleading signals to the market participants (see Article 2.2(a)(i) et 2.2(b)).

116. Market participants, informed by their TSO and knowing exactly which units are facing the identified congestions and the request for downwards re-dispatching, should refrain of offering these units which shall aggravate the congestion, in the day ahead market coupling in order to avoid price distortions.

117. Note that this operation is financially neutral for market participants as a compensation is foreseen by the CEP in that case. The only change is the moment when they are informed by their TSO of their downward re-dispatching.

7 PROPOSED SOLUTION

118. We propose hereafter a solution to incorporate redispatching in the market design in line with the Clean Energy Package, trying to mitigate as much as possible its identified price distortions and inefficiencies. This proposal constitutes the first action taken by CREG in application of Article 10.5 of Regulation 2019/943 having identified price distortions.

119. In the sections above, it has been shown that redispatching distorts market prices and competition between producers located in different bidding zones and increases system security risks. Both are especially true if redispatching is not anticipated and taken into account in the grid models at the day-ahead capacity calculation phase.

120. The extent of already identified market distortions is expected to further increase with the implementation of (curative) cross-border coordinated re-dispatching and with the ambitious targets set by the Clean Energy Package, unless fundamental changes are made in the way redispatching is taken into account in capacity calculation.

121. The solution we propose is to anticipate as much as possible the redispatching needed to solve structural internal congestion[22] early in the capacity calculation phase and to recourse to the activation of cross-zonal curative re-dispatching only when national/zonal resources are exhausted. The solution comprises three components. The first component is to include the best forecast of downwards redispatching in the base case of the capacity calculation, discussed in Section 7.1. The second component is to effectively apply preventively the corresponding downwards redispatching of production units when the probability of downwards redispatching exceeds a certain threshold, and to prevent that concerned producers bid in the day-ahead market coupling as discussed in Section 7.2. The third component is to deploy remaining local redispatching (very often more efficient in terms of impact – PTDFs) before resorting to available cross-zonal resources, as discussed in section 7.3. Combining these three components provides also clarity on how to allocate the redispatching costs according to the polluter pays principle and to the requirements of the CEP, discussed in Section 7.4. In Section 7.5. we compare the proposed solution with other options on the table. Finally, in Section 7.6 we revisit the questions regarding the implementation of the proposed mechanism from a legal perspective.

122. The starting point of the below described solution is the current situation of the CWE market coupling (CWE).

123. Concerning the geographical extension of the proposed measures, we consider that these measures should be applied on all bidding zones coupled with the Belgian bidding zone, in order to reduce the observed price distortion. The application of these measures in the CWE region, followed by the CORE region, when coupled, should constitute a practical first step. Note that the proposed measures only have an impact on bidding zones with structural internal congestions that may be anticipated at the day-ahead stage.

[22] It can be found in [1], 2018, that concerning re-dispatching markets, at the top of page 15, "However, the crucial assumption behind this outcome is that generators do not anticipate the redispatch market when submitting bids to the spot market. This is a plausible assumption if and only if congestion occurs completely unexpectedly. In a situation such as Germany's, where congestion occurs frequently (several lines are congested more than 20% of the time) and the situations can be easily predicted (as congestion is strongly correlated with wind generation), this seems to be a naïve assumption."

7.1 BEST-FORECAST OF REMEDIAL ACTIONS IN THE BASECASE

124. The CEP sets ambitious targets concerning the capacities offered to the market on the critical network elements. These capacities must be provided through a coordinated capacity calculation process. As stated in the ACER Recommendation on CEP implementation[23] (bold characters are from CREG), *"TSOs estimate the physical impact on a CNEC of the capacity offered for internal electricity exchanges in all bidding-zones and cross-zonal electricity exchanges outside the coordination area. This forecast is done when building a CGM,* ***which includes assumptions on the most likely impact of the electricity exchanges within and between bidding-zones****. Therefore, the capacity of a CNEC available for flows induced by internal exchanges in all bidding-zones and cross-zonal exchanges outside the coordination area is determined from the CGM.(…). One of the main purposes to establish the European-wide CGM is to ensure that all TSOs use the same assumptions about electricity exchanges within and between bidding-zones. This will ensure that capacity calculation, which is applied at CCR level (and is thereby not fully coordinated across CCRs), does not lead to inconsistent assumptions related to electricity exchanges, and thus ensures operational security".*

125. In this Section, we detail how to include the best-forecast of remedial actions in the coordinated capacity calculation process. As stated above, the objective is to ensure that the European-wide CGM includes assumptions on the most likely impact of the electricity exchanges within and between bidding zones and to have consistent assumptions related to electricity exchanges.

The rationale is that the remedial actions constitute a key part of the puzzle to make the load flow forecasts match with the physical reality of the grid. The inclusion of likely remedial actions will result in a more consistent and accurate load flow forecast[24]. This will provide for a more realistic and correct assessment of the available commercial capacities and/or the system security risks associated with providing these capacities. Eventually, improved load flow forecast accuracy will translate into smaller safety margins (e.g. smaller FRM). When translating this rationale into clear guidelines, however, some tricky questions arise.

7.1.1 Which congestions are concerned?

126. A first question is whether TSOs need to provide the best forecast of all remedial actions or not. One can distinguish between remedial actions for solving congestions provoked by exchanges internal to a bidding zones, (1) on network elements located inside the bidding zone and (2) on cross-zonal network elements or network elements located in other bidding zones and (3) remedial actions for solving congestions resulting of cross-border exchanges.

127. For the purpose of the inclusion of remedial actions in the IGM, an internal congestion (see also the Glossary) is a congestion which appears even without any cross-zonal exchange, given the expected electricity exchanges within a bidding zone. Given that the remedial actions needed to solve internal congestion (1) alter the "external" flow pattern, TSOs should apply the best forecast of remedial actions for solving internal congestions.

[23] https://www.acer.europa.eu/Media/News/Pages/Electricity-ACER-issues-a-Recommendation-for-implementing-the-70-minimum-margin-of-capacity-available-for-cross-border-trad.aspx , page 25

[24] Any remedial action resulting in a (partial) reduction of the generated loop-flows or a reduction of the internal flows is de facto going in the right direction and required to reach the ambitious targets set by the CEP. If the process is coordinated such that each TSO effectively and systematically applies these remedial actions to reduce internal flows and/or loop flows, the combined result of these actions will be in line with the CEP targets as well. Hence, this coordination on how to treat internal flows and loop flows in the capacity calculation phase, will improve transparency amongst TSOs and will improve consistency with the remedial actions needed in real-time.

128. For the second category of remedial actions linked to exchanges internal to a bidding zone (2) to be considered, being the remedial actions required to meet the minimum targets of capacity to be offered to the market (i.e. CEP targets) on cross-zonal network elements (or on network elements located in other bidding zones). Indeed, exchanges internal to a bidding zone generates loop-flows outside the bidding zone. In our view, TSOs should also include the best forecast of remedial actions for providing the CEP targets on cross-zonal and (remaining) internal critical network elements located in other bidding zones. In particular, TSOs should include the best-forecast of remedial actions needed to reduce the loop flows they generate over their neighbours below a given threshold.

129. Congestion resulting of cross-border trade (3) should in principle occur only very rarely since cross-zonal capacities are allocated through the cross-zonal market coupling. The latter should provide for an effective cross-zonal congestion management without the need for redispatching. Therefore, no anticipation of re-dispatching targeted at solving congestions resulting from cross-zonal trade should be included in the CGM.

7.1.2 Which type of remedial actions is concerned?

130. A second question is whether the best-forecast encompasses both costly and non-costly remedial actions. With costly remedial actions, one mostly refers to redispatching and countertrading. With non-costly remedial actions, one mostly refers to topological actions at the level of switching stations and phase shift transformers (PSTs).

131. Since the principle is to provide the best forecast of load flows, and load flows are determined by both costly and non-costly remedial actions, **both costly and non-costly remedial actions** best forecasts should be included in the base case. Systematically leaving out one of both types of remedial actions, will render the forecast of the other type less relevant. If costly remedial actions are not considered, the forecast of the non-costly ones will not be accurate or relevant and vice versa.

7.1.3 Best forecast in individual grid model versus common grid model

132. To address the question where and when to include the best forecast of remedial actions, we first summarize the approach currently adopted by CWE TSOs. Capacity calculations and coordinated security analyses are performed on the load flow calculations of the common grid model (CGM). The CGM is constructed in different phases:

1) **TSOs agree on a reference program** which defines the zone-to-zone commercial exchanges at the NTC-bidding zone borders and the bidding zone net exchange positions in the FBMC capacity calculation regions. Often, this reference program is the result of the market coupling of the previous day or – in case of a weekend day – of the previous week.

2) **Each TSO constructs its Individual Grid Model (IGM)** based on the forecasted load, forecasted RES production and must-run power plants production. To match the agreed reference program, TSOs apply a scaling factor on either the demand or on the production, whichever seems to be the most appropriate. In this phase, TSOs also need to include agreed remedial actions. They are free to also include other remedial actions. Today, it is not required that the IGMs are N-1 secure or that overloads are resolved.

3) **A merging entity merges these individual grid models into one CGM.** This designated entity may be one of the TSOs, the regional security coordinator or several TSOs taking turn. The merging entity checks for N-1 violations in the CGM and proposes remedial actions to TSOs to solve this N-1 violations.

4) **Each individual TSO has the chance to update its IGM based on the result of the CGM.** A TSO may decide whether to apply the proposed remedial actions in its IGM or not, or to apply other remedial actions. Again, it is not required that the updated IGMs are N-1 secure or that overloads are resolved.

5) **The updated IGMs are merged into a new CGM.** Depending on the capacity calculation region, TSOs may agree to maximize commercial capacities by coordinating non-costly remedial actions.

6) **The final CGM is used as an input for capacity calculation and is referred to as *the base case*.** To calculate the available commercial capacity for cross-zonal trade, the Net Positions in the CGM are brought back to zero by means of the Generation Shift Keys (GSKs). This hypothetical situation is referred to as the ***zero-balanced base case***. The corresponding load flows are the "zero-balanced reference flows" and denoted by Fref'. These zero-balanced reference flows are deducted from the network element thermal limit or *Fmax* to compute the available commercial capacity. Taken into account the flow reliability margin or FRM, the remaining available margin (RAM) is computed as follows: **RAM = Fmax – Fref' – FRM**. There are however three ways in which TSOs can adjust the calculated commercial capacity.

   a. CWE TSOs can increase or decrease the RAM-value by adding or subtracting a "**Flow Adjustment Value**" or FAV to model the impact of complex remedial actions. Today, this option is rarely used.

   b. CWE TSOs can increase commercial capacities to ensure firmness of the long-term allocated (LTA) capacities through the so-called **LTA-inclusion** process. This process virtually increases the day-ahead flow-based domain to cover the LTA-domain by increasing the RAM on a CNEC or by altering its power transfer distribution factors (PTDF). LTA-inclusion was expected to only be needed in 5% of hours, based on the parallel runs preceding the CWE FBMC go-live, but appear to be applied up to 85% of hours in 2016-2017.

   c. With the implementation of the 20% minRam, CWE TSOs introduced a third way to alter the calculated capacities and RAM-values are increased by means of an "**Adjustment for minRam**"-value (AMR) to reach the minRam target.

   The capacity increase provided through the FAV adjustment, the LTA-inclusion or the AMR adjustment, are incorporated as an accounting issue. The RAM provided to the market is calculated as **RAM = Fmax – Fref' – FRM + FAV + AMR**. There is no requirement for CWE TSOs to include the best forecast of remedial actions associated with the expected allocation of this commercial capacity.

133. The above description shows that today the responsibility for including remedial actions is mainly on the individual TSOs' level. TSOs have the opportunity to include remedial actions in three rounds. The first opportunity is when defining the initial IGM (step 2), the second one is when defining the updated IGM based on the result of the CGM after the merging process (step 4). The third one is in the updated CGM which serves as a basis for the capacity calculation (step 5).

134. CREG proposes a three-step solution for including the best forecast of remedial actions in line with the current process, being:

1) In the initial IGM, each TSO includes the best forecast of costly and non-costly remedial actions for solving N-1 security violations on its **internal lines**. This is done by means of internal remedial actions.

2) In the updated IGM (step 4 above), each TSO includes the best forecast of costly and non-costly remedial actions for ensuring the minRam[25] targets on the **critical network elements under contingencies** (CNEC)[26]. This covers costly and non-costly remedial actions that lower the loop-flows created on the neighbouring networks below a given threshold. This is done by means of internal remedial actions. *The result is that commercial capacities on the CNECs in the resulting CGM comply to the minRam target with no need for LTA-inclusion or AMR.*

3) TSOs inform market participants in accordance with REMIT requirements **that no transmission capacity is available** for units facing a congestion

4) At the end of the capacity calculation phase, TSOs coordinate **the remaining non-costly cross-border** relevant remedial actions to further **maximize cross-zonal capacities**. The result is that all non-costly remedial actions are coordinated given the most likely ('best forecast') grid situation. Hence, the result of this coordination phase will also result in a best forecast for these remaining non-costly remedial actions.

135. This approach, which forces each country to reduce as much as possible its negative impacts on neighbours[27], facilitates a sharing of costs in line with the CEP, where all costs for reaching the 70% target or the linear trajectory are borne by the responsible MS.

136. To improve forecast accuracy, it would be enough to include both upwards and downwards redispatching measures in the IGMs as fixed inputs along with the load and RES forecasts. However, to provide an effective solution to the problem of price distortion, this is not an adequate option. As we will discuss in the Section 7.2., we want downwards redispatched units to remain out of the market and upwards redispatched units to be selected through the market coupling process. This means that:

- Production units which are expected to be redispatched down, are not included in the IGMs. They do not contribute to the reference flows in the base case and they are not represented in the market coupling by means of GSKs.

- Production units which would normally be redispatched up to compensate for a downwards redispatching action, may now participate in the market. It means that they are represented in the IGMs the same way as other generation units participating in the day-ahead market, i.e. by means of a relevant reference generation output and a relevant GSK, as to obtain a balanced base case.

7.2 PREVENTIVE DOWNWARDS INTERNAL REDISPATCHING

137. In Section 7.1. we described the rationale behind and the process for including the best forecast of costly and non-costly remedial actions in the grid models determining the day-ahead capacity calculation. As the name suggests, including best forecasts of remedial actions improves the load flow forecast accuracy which in turn improves the accuracy of the calculated capacities and the associated

[25] 20% minRam in CWE today, 70% minRam or intermediate value of action plan from 01/01/2020 on.

[26] See section 7.1.1

[27] If the objectives of the different steps indicated above are not met, i.e. with internal congestions, with an available capacity lower than 70%, with an action plan, even after the optimisation of non-costly remedial actions, all these remaining congestions may have to be dealt with in the residual cross-zonal re-dispatching applied in a third step. If too frequent, this may jeopardise the residual character of the proposed cross-zonal re-dispatching and lead to inefficient arbitrage actions in all bidding zones concerned by the coordination of the cross-zonal redispatching. A specific, cross-zonal monitoring of the price formation and of the identified inefficiencies will have to be put in place. In addition, the cost sharing methodology should distinguish the costs of remaining remedial actions necessary for reaching the CEP targets which shall be borne exclusively by the concerned MS, and not on the basis of loop-flows / internal flows which are appropriate for residual cross-zonal re-dispatching.

system security assessments. It is, however, equally important that the process of best forecasts also leads to the objective of minimizing price distortion. To this end, we propose the use of preventive downwards internal redispatching[28].

138. Market participants informed by their TSOs of the absence of transmission capacity should not entering an order to trade when having no access to the transmission network.

7.2.1 Why preventive downward internal redispatching?

139. In Section 4 we explained that redispatching distorts the price signal because production units which are not technically able to produce electricity may take part in the price formation while units which are actually producing are remunerated outside the market. The impact of this price distortion is not restricted to the bidding zone applying redispatching. Besides the fact that the financial remunerations increase the grid tariffs, they also depress the wholesale price and hence alter the exchanged volumes and prices of the market coupling.

140. To minimize the impact of market distortion one needs to prevent that units which are likely to be redispatched downwards, may participate in the market coupling. This can simply be achieved by requiring TSOs to perform preventive downwards redispatching[29], i.e. before the day-ahead market coupling[30] and to inform concerned market participants before the day-ahead market coupling.

141. It should be noted that the CEP foresees a compensation for these units, which should not be financially impacted by the proposed solution.

142. TSOs only need to perform preventive redispatching on the downwards regulated capacities. The units which were formerly redispatched upwards and remunerated outside the market will now be selected in the market based on their price competitiveness. This way, those units contribute to a correct price formation.

143. Preventive downwards redispatching will reduce the total volume of redispatching since there will be no or less need for upwards redispatching after the day-ahead market clearing. Two reasons for that, as the price may be higher, the country should export less energy at cheap price coming from the north, and so less upward re-dispatching may be needed. In addition, it is proposed that the treatment of gas units located in the south should remained unchanged in the common grid model and the day ahead market coupling may decide that some them shall dispatched.

144. Preventive (before the day-ahead market coupling) redispatching also allow the maximisation of wind output, as less wind have to be curtailed due to the anticipation of structural congestions and the possibility, at that early stage, to further reduce the output of slow units (lignite), compared to a decision taken only a few hours ahead of real time.

145. The term internal redispatching is used to denote the difference with cross-border redispatching. This internal redispatching means that TSOs use production capacities inside the bidding zone when facing internal congestion or when generating too high levels of loop flows or internal line loading to meet the minRam targets.

[28] In this note, we use the term 'preventive' to denote redispatching actions taken *before* the day-ahead market clearing. The term 'curative' redispatching is used to denote redispatching actions taken *after* the day-ahead market clearing.

[29] It should be noted that this study only recommend the use of preventive redispatching as second best solution, in the scope of the implementation of the CEP, when a market splitting cannot be implemented in the presence of structural congestions.

[30] Reference [1], 2019 indicates that such an anticipation of re-dispatching actions seems feasible – see page 30 and 31 of 2019 version

146. The rationale to consider internal redispatching instead of cross-border redispatching is twofold. The first reason is to keep the impact on market distortion as much as possible confined to the bidding zone facing the above-mentioned issues of internal congestion, loop flows or domestic flows. As indicated in Section 4.3, market players will be able to anticipate redispatching if those problems are structural and subsequently start doing arbitrage or even strategic bidding or gaming. The second reason is that in general, it is topologically more efficient to solve those issues with internal measures. In the case of loop flows, internal redispatching is even the only way to have them reduced.

7.2.2 When applying preventive downwards internal redispatching?

147. The best forecast of remedial actions discussed in Section 7.1 serves as an input for selecting the production units for preventive downwards redispatching. **The selection should depend on the probability to accurately forecast which units will actually be required to be redispatched down, and which units will not be.** Downwards-redispatching units with a low probability for effectively being redispatched is inefficient since it entails direct costs and takes away capacity from the market. On the other hand, not applying preventive redispatching when the associated probability is high is also inefficient[31] because of the market price distortion and system security aspects described in this note. A sound trade-off must hence be made during the selection phase, based on the probability that the redispatching is needed.

148. TSOs should aim at improving the forecast accuracy of all independent inputs, i.e. load, RES production, cross-zonal exchanges and GSKs. These forecasts should be associated with information on their uncertainty interval. With this input, TSOs can compute the best forecast of the remedial actions and the associated probability by means of state-of-the art forecasting algorithms and artificial intelligence. TSOs should also provide all necessary data so third parties can do their own calculations (open data). This will provide the opportunity to assess and ensure that TSOs make use of the best-available algorithms for their forecasts.

149. Volumes of downward redispatching may be considered as adequate when the residual congestions after the day-ahead market coupling are not structural and cannot be predicted anymore with enough accuracy, hence avoiding inefficiencies during the last step of cross-zonal re-dispatching coordination (see Section 7.3).

7.3 RESIDUAL CURATIVE CROSS-ZONAL REDISPATCHING

150. After market clearing, coordinated curative remedial actions to solve residual, exceptional congestions to guarantee the firmness of the allocated day-ahead cross-zonal capacities may be needed. In our proposal, the use of cross-zonal redispatching is restricted for curative purposes, after the day-ahead market coupling, to solve residual, exceptional congestions when internal redispatching measures are depleted. This way, we try to avoid that cross-border remedial actions are never used in a structural way. The goal here is to avoid a system based on curative re-dispatching only, where all market players of all coupled bidding zones will systematically arbitrage between the day-ahead market and the re-dispatching mechanism and where the price signal of the different bidding zones may vanish.

151. The goal of a broad coordination of remedial actions across bidding zones is a reduction of costs of known, existing congestions. In order to fully grasp the importance of coordinating **residual** congestions only, it is good to recall that in bidding zones with structural or frequent congestions,

[31] This should not be considered as a general support to preventive redispatching as congestion management technique, which is inefficient compared to a market coupling: or splitting.

market players may anticipate the congestion and may enter into inefficient (for the system) arbitrage actions which will aggravate the already existing congestion. By bidding against a known congestion, they **increase** the need for re-dispatching up at the other side of the congested network element[32]. **Higher volumes** of redispatching will be needed due to this anticipation. In this case, if you coordinate the resolution of this structural congestion with resources located in other bidding zones, you will also allow the market players of these bidding zones to enter into inefficient arbitrage actions against the same structural congestion and further artificially increase that congestion, forcing more redispatching volumes to be activated for solving the congestion. The initial goal of minimizing total redispatching costs will be missed.

152. If those congestions appearing after the day-ahead market clearing are effectively residual and exceptional, because structural and likely congestions have been well anticipated before the market clearing, these remaining congestions could be solved within a single coordinated optimisation. This single optimisation would tackle all remaining congestions, both internal and cross-zonal, using all remaining available costly and non-costly remedial actions.

153. If the remaining congestions turn out not to have a structural or predictable character, one could defend a two-step approach where one makes first use of the available internal remedial actions (as it is done currently today) and only include cross-zonal remedial actions if the former are exhausted. This two-step approach would be necessary to mitigate as much as possible the risk of aggravated price distortion or gaming in other bidding zones that may result from anticipation by market players of their intervention for solving structural congestions located in another bidding zone.

154. This two steps approach may be necessary, as example, if the prediction of preventive re-dispatching is of poor quality and if only a part of the structural congestions is preventively eliminated.

155. Note that this proposal complies with the requirements of coordination of remedial actions set by the relevant articles of CACM and SO guidelines on the coordination of remedial actions of cross-border relevance (see at the end of Chapter 3 the section on SO GL).

7.4 WHO PAYS WHAT?

156. The legislative framework based on CACM regulation is clear on the fact that costs of remedial actions should be allocated according to the polluter pays principle. Translating this principle into a methodology which is supported by all stakeholders, however, is a daunting task since no party wants to pay more than deemed fair.

157. **We distinguish three types of costs**, in line with the proposed solution:

- Costs for preventive downwards remedial actions based on the best-forecast of remedial actions to ensure N-1 security on internal lines;
- Costs for preventive downwards remedial actions based on the best-forecast of remedial actions to ensure the minRam target on CNECs;
- Cost of curative remedial actions associated with paragraphs 144 and 145 above;
- Costs for curative remedial actions to ensure the firmness of the allocated cross-zonal capacities on CNECs during the day-ahead security analysis and consecutive intraday security analyses.

[32] Cost-based redispatching does not remove the incentive at the origin of this behaviour.

158. The first type of costs is simply to be borne by the involved TSO. The detected N-1 security violations are not or only marginally influenced by cross-zonal exchanges and hence it is not appropriate, effective or fair to share those costs amongst TSOs. Moreover, these costs could be avoided with an adequate BZ definition. In addition, the CREG wonders if an asymmetric pattern of re-dispatching actions allows a fair sharing of costs.

159. For the second type of costs we propose a two-step approach. In a first step one would determine the redispatching costs related to the reduction of loop flows below the threshold of 30%[33] minus the FRM, to be borne by the bidding zone which generates those loop flows. If necessary, for internal CNECs compliant with the new legislative framework[34] one would determine in a second step the redispatching costs related to the reduction of the domestic flows below that threshold, to be borne by the TSO being the owner of that line.

160. The third type of costs has to be clearly identified and borne by the MS not fulfilling its targets in line with the CEP.

161. The fourth type of costs are to be shared amongst TSOs based on a load flow decomposition with the same assumptions on nodal injections and extractions as used in the capacity calculation. Discussions on the stack order of polluting flows (loop flows) and acceptability thresholds are currently ongoing in the framework of the regional implementation of the CACM Regulation. Since the bulk of remedial actions are included in the capacity calculation and the accuracy of the capacity calculation is increased, the envelope of this third type of costs to be shared covers only residual congestions and should be relatively small.

162. Again, **the proposed order for determining and allocating costs is of utmost importance.** First, one addresses all costs related to managing internal congestions. Second, one addresses the costs related to free up the minRam capacities on CNECs (i.e. costs for reducing loop flows and in a second step, in case of internal CNECs, costs for reducing domestic flows). Third, already identified non fulfilment of the CEP at the end of the preventive stage should be attributed to the responsible MS. Fourth, residual congestions on CNECs which appear after the market coupling despite the coordinated capacity calculation and allocation process, are addressed.

163. Only this approach seems to guarantee that all (the majority of costs) linked to an action plan will be borne by the concerned Member State. As the amount of redispatching and cross-border redispatching costs may be huge[35], especially for reaching the objectives of the CEP, any viable method for the sharing of these costs should try as much as possible to reduce the amount of the costs to be shared, and to reduce the diversity of the sharing keys. This should ensure a reduction of the complexity of the cost sharing method and should increase its acceptance.

164. If, close to real time, uncoordinated flows trigger the need for remedial actions which had not been anticipated in the capacity calculation phase or in the coordinated security analyses, associated costs are to be borne by the TSO responsible for these uncoordinated flows. This could be traced by comparing the actual nodal injections and extractions with the ones considered in the common grid models. Such an approach would provide an extra incentive to TSOs to limit the uncertainty of the load

[33] The threshold of 30% for loop flows and FRM corresponds to a minRam of 70%. The threshold may be higher if a Member State adopts an action plan. In the latter case, the threshold will be (100% - minRam) with the minRam value being defined by the action plan.

[34] We assume that after two years of CEP entry into force, internal CNECs compliant with the ACER Decision 2019-01 will be exceptional.

[35] Total costs of redispatching linked to the implementation of the 70% rule may go far beyond the current figure of 1 billion € for the CORE Region. The sharing of costs between MS/NRAs linked to these huge figures may be extremely difficult to achieve.

flow calculations and to respect a harmonized and ambitious accuracy target, thereby increasing the precision of the individual and common grid models.

165. The question of the infra-marginal rents kept by market players when re-dispatched down (Regulation 2019/943 CEP Article 13.6) may also have distributive effects between bidding zones and complicates the discovery of a fair redispatching cost sharing solution.

7.5 COST BASED OR MARKET BASED RE-DISPATCHING?

166. It is said[36] that cost based re-dispatching reduces the risk that inefficient arbitrage done by market players aggravates existing congestions. Nevertheless, if we may share this view, the most fundamental inefficiencies of redispatching are valid for both the market based and the cost based approaches: redispatching distort market prices and the infra-marginal rent (the difference between the zonal price and the redispatching cost/bid) is kept by market players in both designs. CREG also recognises that cost based redispatching may hinder the participation of demand and storage in this mechanism. Note that the cost based downward re-dispatching of a given unit also starts with a payment based on bids in the day-ahead market, which is reduced by the variable costs or costs or bids of the quantities redispatched down.

167. It is proposed that only cost based remuneration of redispatching is applied as this reduce the risk linked to the aggravation of congestions compared to market based redispatching. Following the CEP, this cost-based approach may be justified in the case of structural congestions[37] or in the case of a lack of competition. The CREG wonders if the exemption of the obligation of a market based redispatching is also valid when the structural congestion is located in another bidding zone. What is important here is the structural, frequent character of the congestion and the possibility for market players to anticipate the request for redispatching leading to inefficient arbitrage between the day-ahead market and the redispatching. If the structural congestion is considered as a valid reason for preventing inefficient behaviour linked to market based re-dispatching inside a given bidding zone, the same rule should also be valid for bidding zones impacted by the same structural congestion through the implementation of a coordinated cross-zonal redispatching mechanism.

168. Finally, even if this is not directly linked with this proposal, an harmonisation of the different re-dispatching methods currently in place in the different MS should be achieved if we want a fair allocation of costs.

7.6 COMPARISON TO OTHER PROPOSED SOLUTIONS

169. Today, one of the proposed solutions on the table is to not include any redispatching action at all in the capacity calculation phase and to provide the bulk of commercial capacities for cross-zonal trade through the use of AMR values (see paragraph 7.1.3). It is also expected that with the ambitious targets set by the CEP, the size of the AMR will increase significantly. All remedial actions, both for internal and cross-border congestions, are coordinated once the results of the market clearing are known and the coordination is steered only towards minimizing the total envelope of redispatching costs XX. Afterwards, this envelope is shared between the involved TSOs according to the polluter pays (where the loop flows constitutes the pollution) principle, based on a load flow decomposition. The motivation for this approach is twofold. Firstly, to avoid that individual TSOs take unilateral decisions on remedial actions or include remedial actions which turn out to be obsolete once the results of the

[36] See [1]

[37] Note hate the fact that the structural congestion is located in another bidding zone is not relevant: what is relevant is the fact that market players may easily anticipate the need of being redispatched.

market clearing are known, and secondly, to minimize overall redispatching costs from a cost-efficiency perspective. A first underlying hypothesis of this proposed solution is that the uncertainty on the market results is so high, that one cannot appropriately anticipate remedial actions in the capacity calculation phase. A second underlying hypothesis is that minimization of the total envelope of redispatching costs is the right objective function[38]. A third underlying hypothesis is that load flow decomposition will allow effectively pinpointing the fair share of each TSO based on the polluter pays principle, and that this cost sharing is applicable to the requirements set by the CEP. This approach seems to ignore (see section 7.3 above) that the highest the volume of activated cross-zonal redispatching, the highest the possibility for market players in all coordinated bidding zones to anticipate the congestions (even if they are located in other bidding zones) and the highest the possibility of inefficient arbitrage (see [1] section 3.3 and 5.2) done by markets players between the re-dispatching mechanism and the zonal price.

170. **The solution proposed in this concept note fundamentally differs from the one described above.** Instead of postponing the decision on remedial actions until the results of the market clearing are known, we propose to anticipate and incorporate remedial actions as soon as possible. Instead of aiming at minimizing the total envelope of redispatching costs, we propose to aim at maximizing social welfare and efficiency by minimizing price and volume distortion. Instead of reducing redispatching costs through a global optimization process after the market clearing, we propose to reduce redispatching costs by reducing the need for upwards redispatching costs since those units now participate in the market and their costs are reflected in the wholesale price. Instead of allocating the cost of all remedial actions through a flow decomposition framework, we propose to clearly distinguish between remedial actions for managing internal congestion and loop flows from those for managing cross-border induced congestion. Note also that due to the price distortion (depletion), exports of artificially “cheap” energy from bidding zones with structural congestions will be higher with the other proposed methods without preventive redispatching, and so also the volumes to be redispatched[39]. So we propose, through a better zonal price, to reduce the exports of some bidding zones with structural congestions, **and by consequence also the volumes, and the costs of redispatching**.

171. **The underlying hypotheses are also fundamentally different.** The hypotheses of the solution proposed in this note is that TSOs are able and required[40] to forecast the need for remedial actions and to assess their associated probability, that anticipation is needed to improve the unit commitment by the day-ahead market, that preventive downwards redispatching comes at a cost but that this cost may be partially offset by a reduction of upwards redispatching costs, by **more energy will be produced by renewables** and reduced associated risks for gaming and most importantly , that **minimizing price and volume exchanged distortions is a necessary condition for short-term welfare maximization in a liberalized market** with less distortion of competition, correct price signals for investments in production, demand and network development.

172. CREG is not aware of the existence of simulations of market models based on generalised cross-zonal curative re-dispatching applied to coupled bidding zones. In particular, the impact of such an approach on the price signal in the different bidding zones, on the investment incentive, on competition, on the distribution of welfare between bidding zones and on the efficiency of the dispatch should be carefully monitored before going to a decision of implementation. For the implementation

[38] As already indicated, compensations (infra-marginal rents) increase the costs for consumers. The impact of the distribution of these costs on the different bidding zones is unknown. The question arise if these costs should also be minimised by the algorithm, and how.

[39] Note that this is a slippery slope: the more you have structural internal congestions, the more the prices are depleted, the more the bidding zone will export, and the more you will need redispatching.

[40] According REMIT and CACM Article 18

of a FB market coupling in the CWE region, two years of parallel runs were requested for changes which are less important than what is proposed today.

173. As indicated in this concept note, there is plenty of scientific literature supporting our analysis on price and market distortions and on the lack of adequate investment signals in the presence of structural redispatching. Our proposal tries to combine as much as possible the current zonal model (with “physical” congestions at the day ahead stage) with the requirements of redispatching set by the CEP, by mitigating the already identified negative impact of curative redispatching on the zonal price and on competition.

7.7 LEGAL BASIS FOR ACTION AND IMPLEMENTATION

174. As already indicated, Article 10.5 of Regulation 2019/943 constitutes a new driver for NRAs for addressing price distortions when observed. For CREG, the results provided by the CWE FB market coupling are distorted by the presence of structural internal curative re-dispatching in another bidding zone. These measures should apply on all bidding zones coupled to the Belgian bidding zone: ideally, this should extend at least to the CORE region.

175. In this section we investigate how the discussed proposal could be implemented in the current legislative framework constituted by the new Directive 2019/944 of the CEP, the new Regulation 2019/943, REMIT, CACM and SOGL.

176. To address this question, we recall the 3 main components of the proposed approach and the related cost sharing issue:

A. Before the day-ahead market coupling

1. Each TSO to include the <u>best-forecast</u> of their remedial actions in base cases and IGMs, CGM

2. Each TSO to informs market participants on the units which are likely to be redispatched down and market participants do not bid against a known congestion

B. After the day-ahead market coupling

1. Remaining internal congestions are solved by curative re-dispatching
2. All TSOs to coordinate the remaining non-costly and costly RA to solve non-structural, unexpected congestions appearing after the day-ahead market clearing.

C. Costs sharing proposal

177. CREG considers that the following elements should be used as legal basis for the implementation of the different steps of the proposed approach.

Legal framework	**A.1**	**A.2**	**B.1&2**	**C**
Directive 2019/944 Article 3, 1 on price formation	X			
Regulation 2019/943 Recital 31 on cost sharing			X	X
Regulation 2019/943 Article 3 on principles of electricity markets	X	X		
Regulation 2019/943 Article 10, 3,4 and 5 on mitigation of price distortion	X	X	X	
Regulation 2019/943 Article 13, 2 and 7 on compensation and redispatching		X		X
Regulation 2019/943 Article 15, 3 on cost sharing with action plan			X	X
Regulation 2019/943 Article 16, 1 on the price signal	X	X		
Regulation 2019/943 Article 16, 4 on the use of redispatching			X	X
Regulation 2019/943 Article 16, 13 on cost sharing			X	X
REMIT Regulation 1227/2011, recital (13) on manipulation and price distortion	X	X		
REMIT Regulation 1227/2011, Article (2) on definition of inside information and market manipulation	X	X		
REMIT Regulation 1227/2011, Article (4) on the obligation to publish inside information	X			
REMIT Regulation 1227/2011, Article (5) on the prohibition of market manipulation		X		
REMIT Regulation 1227/2011, Article (15) on obligations of persons arranging transactions	X			
CACM Art. 19: Individual grid model	X			
CACM Art. 35: Coordinated redispatching & countertrading			X	
CACM Art. 74: Redispatching & countertrading cost sharing				X
SOGL Art. 76: Regional operational Security Coordination	X	X	X	

178. The first component of the solution (A.1), i.e. the principle of inclusion of the best-forecast of RA in the IGMs before and during the CGM process, could be implemented through the Common Grid Model Methodology according to CACM Article 19, with the objective to comply with the numerous articles addressing the price formation of the CEP and with REMIT obligations.

179. The second component of the solution (A.2) is supported by REMIT, with the goal to fulfil the many articles related to the price formation.

180. The implementation of the second part of the proposed solution (B1&2), is currently under discussion in the scope of the implementation of CACM and SO GL requirements. In particular, the implementation of the fourth component (B2) of the proposed solution, i.e. coordination (optimisation) of costly and non-costly RA after the day-ahead market clearing to solve residual congestions, fits in the framework of the methodologies to be established in accordance to CACM Art.35 and SOGL Art.76.

181. The implementation of the cost sharing should be based on relevant Article of CACM, taking into account the new requirements of the CEP.

8 CONCLUSION

182. Over the last years, the recourse to redispatching has increased in several countries in Europe. The rise in redispatching costs is said to be linked not only to the large-scale integration of renewables in the market but also to the coincident decommissioning of conventional power plants.

183. Redispatching means that system operators need to adjust the market outcome in order to ensure secure system operation without congestions, and to change the dispatch, or “redispatch” of these generation units. These adjustments are done outside the wholesale market. Cheap units dispatched on the basis of the wholesale market results are asked to regulate their production downwards, whereas more expensive units which had not been dispatched in the wholesale market, are asked to regulate their production upwards.

184. With the implementation of the Clean Energy Package (CEP), the use of redispatching will further increase since the CEP incorporates the objective of a minimum 70% target on capacity made available for cross-zonal trade combined with the help of redispatching. There is a high probability that TSOs provide (see section 4.1) the defined commercial capacity targets in a virtual way (i.e. detached from the physical reality of the network in real-time), without anticipating and dealing with structural congestion already in the day-ahead capacity calculation phase, leaving all redispatching actions to be coordinated after the day-ahead market clearing.

185. This concept paper discusses important inefficiencies linked to redispatching, such as price, market and competition distortion and uncertainty and illustrated the impact of these inefficiencies on the German wholesale prices and on the load flow forecasts used in the common grid models by the TSOs in their capacity calculation process.

186. A big distortive impact on the day-ahead price formation resulting from the extensive use of redispatching within the German bidding zone has been identified. For the period of October 2018 to February 2019, the impact of redispatching in the German bidding zone is on average an absolute reduction of up to 6,15€/MWh of the German wholesale price, or a relative reduction of 10% of the wholesale price of electricity. Such an enormous impact on wholesale prices alters the volumes exchanged between bidding zones and the market clearing prices in the entire European Energy Market and distorts the prices that are required for fair competition and right investment signals.

187. The reduction of 6,15€/MWh of the German wholesale price is explained by the fact that cheaper units which are not allowed to produce electricity because of structural congestion, bid in the market and set the price. This study develops why a “best forecast” approach is necessary to mitigate this distorted price formation. The reason is straightforward: the price formation should be done based on the actual available generation and transmission capacity, without taking into account units that will most probably be re-dispatched down for reason of network congestion. Therefore, it is mandatory that TSOs use a best forecast of the actual available generation and transmission capacity leading to a better coordination of capacity calculation processes between TSOs.

188. For the period 2016-2017, the average forecast error of the loop flows on the Belgian borders amounted to 630MW, a relative error of 80%. Small errors linked to intrinsic uncertainties of load and renewable forecasts are unavoidable, though a 630MW structural bias in loop flow forecasts, explained by the fact that the load flow calculations today do not incorporate the best forecast of remedial actions, is not unavoidable and definitely not acceptable.

189. The extent of market price distortion and the impact on load forecast uncertainty is expected to only further increase with the implementation of the Clean Energy Package, unless fundamental changes are made in the way redispatching is taken into account, and implemented.

190. The legal framework of the proposed solution (see Chapter 7) is based on CACM, on the Regulation 2019/943, on REMIT and on SO GL. In particular, this proposal or action (in accordance with the wording of article 10.5 of Regulation 2019/943) provides a first answer to the obligation set on regulators foreseen in that article when policies applied within their territory that could contribute to indirectly restricting wholesale price formation have been identified.

191. This study proposes to mitigate the impact of inefficiencies linked to redispatching by anticipating and incorporating redispatching as soon as possible in the capacity calculation process. The proposed solution consists of including the best forecast of remedial actions (mainly redispatching and the position of phase shift transformers) for managing internal congestion first in the individual grid models, followed by the best forecast of remedial actions for ensuring minRam compliance. Preventive downwards redispatching is then done before the day-ahead market coupling, based on the associated probability. This way, units which have high probability to be redispatched down, do not participate in the market while some of those which are now being upwards regulated and remunerated in the redispatching framework, will now participate in the market. This solution not only improves the forecast accuracy of the calculated capacities important for system security assessment, but significantly reduces distortion of the wholesale prices and the distortion of competition. Zonal prices and, as a consequence, volumes of energy exchanged better reflect demand and supply in the different biddings zones. For some bidding zones with structural congestions, exports volumes will be reduced and so the volumes and costs of re-dispatching.

192. The most fundamental difference of the proposed solution compared to other ones being discussed, is that this proposal tries to address the problem of suboptimal unit commitment decisions (more renewable should be able to produce when the TSOs anticipates internal structural congestions), market (price and volume) and competition distortions, and of uncertainty associated with redispatching, elements which are considered to be fundamental for an efficient market operation and network management.

193. The approach proposed also allows for a more straightforward cost-sharing solution of redispatching since the need for curative redispatching for ensuring firmness of the allocated cross-zonal capacities is significantly reduced. Only residual and exceptional curative redispatching actions remain, with relatively small associated costs to be shared.

194. The goal of this proposal is, given the new legislative framework, to mitigate as much as possible the negative impact of redispatching and in particular the price distortions inherent to this mechanism. A better price formation is the key for an effective and fair competition and for providing the right investment signal.

9 GLOSSARY

In the context of this concept note, the following definitions are used:

An **Internal congestion** is congestion which appears even without any cross-zonal exchange, given the expected electricity exchanges within a bidding zone. Internal congestion can be detected in a zero-balanced IGM or CGM.

A **cross-border induced congestion** is congestion on critical network elements which results from cross-zonal exchanges because the assumptions made during the capacity calculation phase were erroneous and the security margins (e.g. FRM) not enough to cover the forecast error. It can only appear after the results of the day-ahead market coupling are known and can be detected during the coordinated day-ahead security analysis.

A **structural congestion** is defined in Regulation 2019/943 as a *congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions* - in the framework of this note- is a congestion which can be anticipated with a certain probability once the best-forecast of the other grid model inputs (load, RES, reference programme) is known. Structural congestion (in the framework of a bidding zone review) adds to this character of anticipation, a criterion on frequency of occurrence (e.g. 10% of hours).

A **residual congestion** – in the framework of this note – is a congestion which could not have been anticipated based on the best-forecast. A residual congestion appears in case of an unexpected, rare or extreme event.

An **internal remedial action** is a remedial action activated by a TSO on one of the assets inside its control area, used for solving internal congestion or ensuring compliance with the CEP targets on cross-zonal capacity. The requesting and activating TSO are the same. A **cross-zonal remedial action** is a remedial action which is requested by one TSO to solve an internal congestion or ensuring compliance with the CEP targets on cross-zonal capacities, activated on an asset outside its control area. The requesting and activating TSO are not the same.

Coordination of remedial actions in the capacity calculation phase is the detailed description of the roles, responsibilities, timing, objectives and expected results on the inclusion of remedial actions in the common grid model and capacity calculation processes.

Coordination of remedial actions in the regional security analysis phase is the detailed description of the roles, responsibilities, timing, objectives and expected results on the inclusion of remedial actions in the updated common grid model and regional security analysis processes.

The **best-forecast** is the scenario having the highest probability to occur. It can be based on a deterministic approach or on a probabilistic approach. In the latter case, one does not only have the best-forecast, but also the associated probability. The quality of the best-forecast is assessed through analysis of the forecast errors. The forecast errors should be statistically fully random, i.e. not contain any information of pattern. These best-forecasts (and associated probabilities) could be provided to TSOs by third parties specialized in statistical tools such as artificial intelligence and benchmarked to ensure neutrality.

Preventive redispatching is a redispatching action decided before the day-ahead market coupling stage.

Curative redispatching is a redispatching action decided after the day-ahead market coupling stage.

Probability-based selection of remedial actions for preventive downwards redispatching can be done in two ways. With a probabilistic forecast, the probability of the downwards redispatching action can be assessed and used as a selection criterion (e.g. probability of 80% or more). With a deterministic forecast, one can use a simpler though less accurate approach such as selecting a certain percentage (e.g. 50%) of the best-forecast of downwards redispatching actions.

10 REFERENCES

[1] Market-based redispatch in zonal electricity markets, Inc-dec gaming as a consequence of inconsistent power market design, Version 2018-11-13, Lion Hirth and Ingmar Schlecht, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3286798 and 2019: https://www.econstor.eu/bitstream/10419/194292/1/Market-Based-Redispatch-in-Zonal-Electricity-Markets.pdf

[2] The effect of counter-trading on competition in electricity markets, Justin Dijk and Bert Willems, Energy Policy39(2011)1764–1773

[3] Analysis of renewable energy integration in transmission constrained electricity markets using parallel computing, Ignacio Aravena, Thesis, September 2018 https://dial.uclouvain.be/pr/boreal/object/boreal:203018

[4] Benefits of local prices for the power market, presentation made at the FSR in January 2019, Karsten Neuhoff

For the Commission for Electricity and Gas Regulation:

Andreas TIREZ
Director

Koen LOCQUET
Acting President of the Board of Directors