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Redispatching Arrangements in Europe against the Background of the Clean Energy Package Requirements

CEER Report

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INFORMATION PAGE

Abstract

This document (C21-FP-52-03) presents the redispatching requirements laid out in Article 13 of the updated Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity,. The report provides a comparison of the advantages and disadvantages of market-based and cost-based mechanisms for redispatching and presents the reader with the actual implementation of redispatching regimes in three European countries (Germany, Spain and Switzerland).

Target audience

European Commission, energy regulators, energy suppliers, traders, gas/electricity customers, gas/electricity industry, consumer representative groups, network operators, Member States, academics and other interested parties.

Keywords

Redispatching, Clean Energy Package, electricity, market-based redispatching, cost-based redispatching

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Related documents

CEER Documents

- ACER-CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020: Electricity Wholesale Volume, November 2021.
- ACER-CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2019: Electricity Wholesale Volume, October 2020.

External Documents

- European Parliament and Council of the European Union. (2019). Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity. https://eur-lex.europa.eu/legal-content/EN/TXT/?toc=OJ%3AL%3A2019%3A158%3ATOC&uri=uriserv%3AOJ.L_.2019.158.01.0054.01.ENG
- European Parliament and Council of the European Union. (2016). Communication from the Commission on Clean Energy for All Europeans. https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1582103368596&uri=CELEX:52016DC0860

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EXECUTIVE SUMMARY

Background

Article 13 of the Regulation (EU) 2019/943 (Electricity Regulation) (requires EU Member States (MS) to use market-based mechanisms for redispatching, while also allowing the use of non-market-based mechanisms in specific cases.

Objectives and contents of the document

Against the background of these Electricity Regulation requirements, the paper sets out to shed some light on the different mechanisms for redispatching and to provide a rough comparison of both regimes, market-based and cost-based redispatching. The paper is complemented with the presentation of the actual implementation of redispatching regimes in three European countries (Germany, Spain and Switzerland).

The content of the paper is as follows:

- Introduction to the Electricity Regulation requirements for redispatching;
- Comparison of market-based vs. cost-based redispatching;
- Presentation of national case studies on currently applied redispatching regimes in Europe; and
- Conclusions.

Brief summary of the conclusions

Redispatching at the nodal level is required by zonal dispatching as zonal dispatching ignores or oversimplifies one or more system constraints. Therefore, the combination of the dispatch resulting from the zonal design and the redispatch happening at the nodal level can easily lead to Inc-Dec gaming[1] opportunities that rational agents will eventually exploit which can in turn lead to a sub-optimal outcome.

In order to overcome, or at least limit, the Inc-Dec gaming, two approaches are in principle possible:

- Cost-based mechanism of redispatching, which would be the best choice in zonal markets; or
- Avoid redispatching in the first place through the introduction of a market-based dispatch, compatible with the reality of the electricity system. This would imply a shift towards a nodal design (security-constrained economic dispatch), narrowing down cost-based regulation to conditions where *"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".*[2]

These conclusions are without prejudice to the main congestion management option presented in the Electricity Regulation based on a market-based solution – market-coupling – applied on bidding zones without structural congestions.

[1] For more information, see Chapter 3, page 10.

[2] Article 13(3) c) of Regulation (EU) 2019/943.

However, when fulfilling the criteria set out in Article 13 of the Electricity Regulation, one has the possibility to opt for a cost-based solution.

In addition, there is no requirement regarding the level of transparency with respect to the decision-making process and the final decision. In this context, it may be of interest and beneficial to all to strive for more transparency and a better understanding of the different regimes and their respective reasoning across Europe.

1 Introduction

Article 13 of the Regulation (EU) 2019/943 (Electricity Regulation) (requires EU Member States (MS) to use market-based mechanisms for redispatching. This means to select and financially compensate generation facilities, energy storage or demand response "*in order to…relieve a physical congestion or otherwise ensure system security*". However, this article also allows MS to use non-market-based mechanisms in four specific cases.

This CEER report on "Redispatching Arrangements in Europe against the Background of the Clean Energy Package (CEP) Requirements" aims to provide a presentation of the different approaches in European countries with respect to their redispatching mechanisms. It specifically looks into the details of market-based vs. cost-based mechanisms for redispatching. It presents the different regimes from a theoretical perspective, its advantages and drawbacks (Chapter 3) and how they are implemented in different countries (Germany, Switzerland, Spain) based on case studies (Chapter 4).

This report does not intend to interfere with the concrete implementation work of Guidelines and Network Codes. Specifically, it will not deep dive into the methodologies according to Article 35 Capacity Allocation and Congestion Management (CACM) Regulation "Coordinated redispatching and countertrading", Article 74 CACM Regulation "Redispatching and countertrading cost sharing methodology" and their counterparts in the System Operation (SO) Regulation Article 76 "Methodology for coordinating operational security analysis". However, a short overview on the methodologies in question are provided in the report in order to provide a full picture of redispatching nationally and cross-border (see box in Chapter 2).

Finally, and even if this is not the topic of this report, it is worthwhile to recall that when considering different options for redispatching as congestion management tool, the application of a market coupling or market splitting on adequately defined bidding zones without structural congestions[3] (should also be considered as a primary option for the management of congestions[4].

2 Introduction to Electricity Regulation requirements for redispatching

"Redispatching" in the words of the Electricity Regulation means "…*a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical*

[3] See Article 14.1 of the Electricity Regulation: "Bidding zones shall not contain such structural congestions…").
[4] See Article 16.1 of the Electricity Regulation stipulating that "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.".

flows in the electricity system and relieve a physical congestion or otherwise ensure system security".

Article 13 of the Electricity Regulation lays out the legal basis for organising redispatching in Europe.

Paragraph (2) specifies that "…*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*." This is at the heart of the CEP requirement to establish market-based mechanisms for redispatch in Europe and is the origin of debates amongst scientists, regulators and politicians.

Taking into account the political debate in the drafting phase of the CEP and also imperfections of market-based mechanisms for redispatch, the following paragraph (3) of Article 13 also includes possible exemptions from the use of market-based mechanisms for redispatch:
"*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*[5] *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)*[6]."

The abovementioned exemptions point to the main challenges of market-based mechanisms for redispatching, namely a lack of competition and/or the predictability of network congestions.

Paragraph (6) then sets further boundaries with respect to non-market-based redispatch, in particular the safeguarding of priority dispatch of energy from renewable energy sources (RES) and Combined heat and power (CHP), whereas paragraph (7) defines general principles with respect to the financial compensation.

Article 13 does not specify who is responsible for issuing a decision on the chosen mechanism for redispatching. In most countries, the National Regulatory Authority (NRA) may be best suited to assess the preconditions for a market-based redispatching regime.

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[5] According to point (4) of Article 2 of Regulation (EU) 2019/943, "'congestion' means a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows". According to Article 25(1) of SO GL, "Each TSO shall specify the operational security limits for each element of its transmission system, taking into account at least the following physical characteristics:
(a) voltage limits in accordance with Article 27;
(b) short-circuit current limits according to Article 30; and
(c) current limits in terms of thermal rating including the transitory admissible overloads."

[6] According to paragraph (6) of Article 2 of Regulation (EU) 2019/943, "'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".

NRAs have pondered for which time span a decision for market-based or non-market-based redispatching regimes applies, or if they may even co-exist (in one market time unit it may be one or the other, depending on the circumstances).

The following text box provides a brief recap of the current implementation work based on CACM and SO Regulation requirements on cross-border redispatching. The aim of the text box is to give the reader a good overview before addressing market-based and cost-based redispatch.

Current implementation work based on CACM and SO Regulation requirements on cross-border redispatching (Art. 35, 74 CACM, Art. 76 SO)

Redispatching is one of the aspects included in the European target model pertaining to the optimisation of remedial actions.

CACM sees redispatching and countertrading as measures to cope with physical congestions, irrespective of whether the reasons for the physical congestion fall mainly outside a TSO's control area or not. Non-costly remedial actions shall be considered in the capacity calculation process, but they are not foreseen in the countertrading and redispatching optimisation process developed pursuant to Article 35 of CACM.

The scope of the management of remedial actions is widened in the SO Guideline (GL), where the main target is to ensure a secure operation of the system. To this extent, the Coordinating operational Security Analysis (CSA) methodology developed according to Article 75 of SO GL foresees a single optimisation run including both costly and non-costly remedial actions. Thus, it complements the optimisation run based on redispatching and countertrading resources proposed pursuant to Article 35 of CACM. The details of this single optimisation are defined at Capacity Calculation Region (CCR) level in the Regional Operational Security Coordination (ROSC) methodology to be developed in accordance with Article 76 of SO GL.

The wider scope introduced pursuant to SO GL significantly affected the implementation process of the redispatching.

In all CCRs, except for Core and South East Europe (SEE), the redispatching and countertrading methodologies pursuant to Article 35 of CACM were submitted in 2018 and approved by National Regulatory Authorities (NRAs) between late 2018 and early 2019. The implementation started shortly after, but the process was frozen when the EU Agency for the Cooperation of Energy Regulators (ACER) approved the CSA methodology in June 2019, foreseeing the joint optimisation of costly and non-costly remedial actions. The TSOs implemented this new requisite in the ROSC methodologies that were submitted in late 2019/early 2020 and approved by the relevant NRAs in late 2020/early 2021.

In the SEE CCR, the countertrading and redispatching methodology was referred to ACER, which adopted a decision in July 2019, aligning the optimisation concept to the requisites included also in the CSA methodology. The ROSC methodology was referred to ACER as well and a decision was taken in December 2020, along with the methodology for Core.

Core CCR followed a slightly different path. The initial submission of the countertrading and redispatching methodologies pursuant to Article 35 of CACM was not finalised by the Transmission System Operators (TSOs) in 2018. The European Commission (EC) granted more time and the first draft was submitted only in 2019. Upon request by the Core NRAs, ACER extended the time for the NRAs to adopt a decision until March 2020. Nevertheless, eventually the NRAs decided to refer the matter to ACER, along with the Core ROSC methodology. ACER decided on both methodologies at the same time in December 2020.

Following the approval of the ROSC methodologies, the implementation of redispatching towards the European target model restarted. In the most complex CCRs (e.g. Italy North, Core and SEE, where redispatching plays a significant role), a full optimisation process is expected to enter into force no earlier than 2025-2026 (developing a single run with both costly and non-costly actions is challenging from a computational point of view, since the process includes both linear and integer variables). A simplified approach is expected, but it will not be implemented before about three years from date of publication of this paper. In the meantime, simplified coordinated approaches developed on a voluntary basis are in place for cross-border redispatching and countertrading, complementing the schemes adopted at national level.

3 The theory: Comparison of market-based vs. cost-based redispatching

Redispatching means that the TSO intervenes in the original schedules (i.e. nominations by market participants to the TSOs) by demanding specific power plants to ramp down while ramping up other power plants to relieve a congestion and/or ensure system security.

A certain level of redispatching is an integral and residual part of the European target model. It ensures the coherence of the zonal model by correcting local and transitory deviations from the “copper plate” model that grounds the zonal system, while avoiding inefficient investment in power grids. Therefore, MS need to establish rules for dealing with redispatching.
The correct delineation of bidding zones is not within the scope of this paper.

Given that redispatching can be considered as a 'necessary evil’, one should consider what the most appropriate procurement mechanism(s) are. There are basically two options to organise redispatching, which both have various names:

- Cost-based mechanisms for redispatch, cost-based redispatching, regulatory obligation, administrative redispatch[7], or
- Market-based mechanisms for redispatching, market-based redispatch, competitive procurement, local flexibility markets for redispatching.

Common to both options should be the guiding principle that they should not distort wholesale energy markets, i.e. the outcome of those markets shall not be influenced by the subsequent redispatch actions of TSOs.

[7] All these terms can be subsumed under the term “non-market based redispatching”

The two different options for redispatching, cost-based and market based, are compared below. When redispatching is compared with a split of the bidding zone at the level of the structural congestion[8], redispatching induces inefficiencies.

Notably, redispatching at the nodal level is required by zonal dispatching as zonal dispatching ignores or oversimplifies one or more system constraints. Therefore, the combination of the dispatch resulting from the zonal design and the redispatch happening at the nodal level can easily lead to Inc-Dec gaming opportunities that rational agents will eventually exploit leading to a sub-optimal outcome.

The Inc-Dec game results from inefficient (for the society) arbitrage possibilities stemming from the trading of the same energy in two separate, subsequent mechanisms/markets valuating the same energy on different spatial dimensions, i.e. the day-ahead market coupling where the energy is valued without considering internal congestions (zonal market) and a re-dispatch mechanism/market where the energy is valued taking the same internal congestions into account (at nodal level)[9]. This difference of valuation creates arbitrage possibilities for producers which may be costly for the consumers. This combination mitigates (or destroys) the incentives to bid truthfully in the day-ahead market and may lead to a dispatch where the most efficient unit may not run. Several Inc-Dec strategies exist: One of these Inc-Dec strategies corresponds, for a producer located in the export-constrained area of a bidding zone with a (foreseeable) structural congestion, to bid below its costs in the day-ahead market coupling in order to be selected as a "running" unit and then surrender the artificially low variable costs for compensating the energy not produced when re-dispatching occurs in a second stage and thereby, keeping an high infra-marginal rent. Regulators will monitor this behaviour. However, Inc-Dec gaming is especially difficult to monitor especially with portfolio bidding (as compared to countries where unit-based bidding is in place).

Because electricity systems are normally affected by a high degree of market power at local level, Inc-Dec gaming is further exacerbated by the exercise of market power at local level. These problems must be conceptually separated but are mutually reinforcing.

Market-based redispatch

In market-based redispatching, the default solution of the Electricity Regulation, redispatching is organised via a voluntary, free-to-access market. All market participants (generators, local flexibility providers, consumers, prosumers), with appropriate technical capabilities, can provide bids to TSOs for being ramped up or down in order to relieve a physical congestion or otherwise ensure system security. The TSO will then select the cheapest set of bids taking into account system constraints in order to solve the issue.

From the paper by Hirth et al., 2019[10]),one can take that, in a zonal design, market-based redispatch is not recommended because "the coexistence of zonal and local markets results in an incentive structure that systematically rewards problem-exacerbating rather than system-stabilising behaviour" and "this fundamental problem cannot be solved easily". From a

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[8] According to paragraph (6) of Article 2 of Regulation (EU) 2019/943, "'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".

[9] See also the "CEER Paper on DSO Procedures of Procurement of Flexibility", C19-DS-55-05, 16 July 2020, p. 40.

[10] Lion Hirth, Ingmar Schlecht (Neon), Christoph Maurer, Bernd Tersteegen (Consentec) (2019); Final Report: Cost- or market-based? Future redispatch procurement in Germany, Conclusions from the project "Beschaffung von Redispatch".

theoretical point of view, a necessary precondition for market-based mechanisms for redispatching is that the congestion (or the system security issue) that needs to be solved, is non-predictable by market participants. This would reduce the likelihood of Inc-Dec gaming behaviour. If the congestion is non-structural (because of an adequate bidding zone delineation) and therefore non-predictable, it would at least reduce this risk associated with a market-based mechanism for redispatching.

The following table summarises some of the advantages and disadvantages of market-based mechanisms for redispatching.

Market-based mechanisms for redispatching	
Advantages	**Disadvantages**
True costs of a generator or load are private information, which can only be revealed via a competitive market-based procurement.	High risk of Inc-Dec gaming between local redispatch markets and wholesale markets[11] in case of structural congestions[12] or needs ancillary services to ensure system security with lack of competition.
Allows for the inclusion of storage and loads into redispatching, which is considered necessary by some in light of decreasing conventional power plant generation.	*Ceteris paribus*, leads to aggravation of structural congestions or needs ancillary services to ensure system security and, therefore, to higher redispatch volumes[13].
May provide investment incentives for units redispatched up.	Perverse investment incentives for power plant operators (power plants in excess regions benefit from increased contribution margins in a market-based redispatching regime).
Open, independent, unbundled markets are considered preferable over regulatory redispatch obligation.	Market power issues in local markets when there are only a few power plants capable of solving the congestion or providing ancillary services to ensure system security.

Table 1 – Advantages and disadvantages of market-based mechanisms for redispatching

Cost-based redispatch

In the cost-based redispatch regime, power producers are usually obliged to participate in redispatching measures. The power plant is not restricted from participating in the market coupling. The guiding principle with cost-based redispatch is (and it should also be for market-based redispatch) that no power producer is better off or worse off after the redispatching takes place as compared with before. In other words, the redispatching has to ensure the financial neutrality of all parties involved.

[11] Hirth, Lion; Schlecht, Ingmar (2020); Market-Based Redispatch in Zonal Electricity Markets: The Preconditions for and Consequence of Inc-Dec Gaming, ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg.
Unfortunately, Inc-Dec gaming does not disappear with a competitive redispatch market. The relevant power plants will in either way engage in Inc-Dec behaviour in order to aggravate the grid situation and therefore increase TSOs' demand for redispatching measures which in turn will drive up redispatch needs and prices in a redispatch market.

[12] See footnote 6.

[13] A study for the German government calculated, that redispatching volumes would increase by 700 % if a market-based redispatching would be introduced in Germany.
Lion Hirth, Ingmar Schlecht (Neon), Christoph Maurer, Bernd Tersteegen (Consentec) (2019); Final Report: Cost- or market-based? Future redispatch procurement in Germany, Conclusions from the project "Beschaffung von Redispatch".

Power plants that are required by the TSO to ramp down, have to pay their saved fuel and CO_2 costs (plus any other saved cost) to the TSOs but keep their profits/losses from selling their energy, whereas power plants that are required to ramp up will get compensated for their additional fuel and CO_2 costs (plus any other additional operating cost). In the end, the cost of redispatch for the TSO is roughly limited to the fuel-cost differences of the two affected plants.

With respect to the financial compensation, Article 13(7) of Regulation (EU) 2019/943 further specifies that "*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.*"

Regarding the balancing responsible party (BRP), the electricity produced in the ramped-up plant is transferred to the ramped-down plant (physical compensation within the BRP portfolio, i.e. balancing group adjustment). In doing so, both, financial and market neutrality are considered satisfied; this is also in the spirit of the Regulation's requirements.

Some argue, however, that cost-based redispatch measures cannot respond to the future challenges of flexibility and active prosumers.

The following table summarises some of the advantages and disadvantages of cost-based mechanisms for redispatching.

Cost-based mechanisms for redispatching	
Advantages	**Disadvantages**
Avoids Inc-Dec gaming.	Does not allow for the participation of loads and active prosumers. Consequently, if their participation is considered necessary, it may not be adapted to the future challenges of short-to-real-time system design.
Is close to a cost-efficient means for TSOs to organise redispatch.	Information asymmetries between involved parties: The data to verify whether the costs submitted by market participants correspond to their true costs is very difficult to obtain[14].

Table 2 – Advantages and disadvantages of cost-based mechanisms for redispatching

[14] NRAs should in theory be able to calculate the marginal cost (including all opportunity costs) of a power plant to check whether its conduct is legitimate with respect to REMIT provisions. NRAs are requested to verify whether the costs submitted by market participants correspond to their true costs. This would imply, for example, an effort on the NRAs' side to collect data on heat and emission rates by power plant.

4 The Reality: Presentation of national case studies on currently applied redispatching regimes in Europe

This chapter sets out to present actual implementation of redispatching mechanisms in Europe. However, as noted before, one has the option, if one fulfils the criteria set out in Article 13 of Regulation 2019/943, to opt for a cost-based solution.

4.1 Germany

Germany explicitly opted for a redispatching that is organised on a cost-based basis. Power plants are legally obliged to participate in redispatching measures. A justification for this decision can be found in the German "Action Plan" as defined by Art. 15 of Regulation 2019/943[15].

"*In the event that Germany were to switch to market-based redispatch, the experts would expect considerable distortions in the electricity market and a massive increase in network congestion. The advantage that new potential such as storage facilities and flexible consumers could be more easily integrated into redispatch would be more than offset by the expected disadvantages. The coexistence of zonal electricity trading and a necessarily regional or local marketplace for the elimination of network congestion would lead to economically rational market players optimising their interests between the two markets. To the extent that network congestion would be foreseeable, market players would try to generate higher revenues from the local marketplace by saving their flexibility for the latter and not making it available for zonal electricity trading or already pricing it in there. This would be economically rational and could not be objected to under competition law. […]*

Based on the expert appraisal cost-based redispatch is being retained. The appraisal shows that two of the exceptions provided for in Art. 13, Para. 3 of the EU Electricity Market Regulation are present: considerable strategic and therefore congestion-worsening behaviour is to be expected and there is insufficient competition."

The cost-based measures have no impact on the overall balance between generation and load since it is ensured that the reductions in feed-in are balanced physically and economically by increases elsewhere.

A distinction in the monitoring of redispatching is made between electricity-related and voltage-related redispatching. Electricity-related redispatching is used to avoid or relieve overloading of affected power lines and transformer stations. Voltage-related redispatching, by contrast, is used to maintain the voltage in the affected network area, for instance by adjusting reactive power. The cost-based administration of the different redispatching measures do not differ.

Power plants continuously send generation schedules and updates of schedules to TSOs, which also indicate the available redispatch volumes. TSOs will then calculate the optimal combination of remedial actions to deal with grid congestions in an iterative approach until real-time, ensuring latest possible activation of power plants to enable most efficient redispatch. For this purpose, the Common Grid Model (CGM) of the DACF (Day-Ahead Congestion Forecast) is used. Redispatching decisions are made according to an OPF (Optimal Power Flow)-algorithm including penalty costs. Redispatching-up actions are managed the same as redispatching-down actions. Redispatching does not impede the participation in the day-ahead

[15] Link to the English courtesy translation of the Action Plan can be found here, pp. 22f: https://www.bmwi.de/Redaktion/EN/Downloads/a/action-plan-bidding-zone.pdf?__blob=publicationFile&v=6

market coupling. Redispatching measures are only executed after market clearing. If a power plant is contracted for the provision of balancing energy this capacity will not be accessible for redispatching by the TSO. The demand side does not participate in any redispatching.

The rules for redispatching in Germany are stipulated in national statutory law (the German Energy Act) and further detailed in administrative acts by the regulator towards German TSOs. The cost remuneration is dealt with bilaterally between TSOs and power plant operators. Power plant operators send invoices of the incurred costs and justify the costs. In other words, there is no ex-ante price submission for all plants, but an ex-post validation of invoices by the TSO. Based on publicly available information (fuel prices, CO_2-certificates…), past exchanges and comparisons with other power plants, costs can be evaluated by TSOs. Other damages are of minor relevance and subject to ex-post validation in the same way. Because this kind of remuneration happens on a regular basis, comparison and validation is a manageable task for TSOs. The moment in time when a redispatching measure is chosen and applied by the TSO does not change the general principle of this cost remuneration.

The NRA is not directly involved in this process. However, the costs for redispatching need to be approved by the national regulator. Specific remuneration could be checked in depth by the regulator (a random examination session started in spring 2021). If costs are not properly evaluated, they may not be eligible for recognition in the cost approval. Therefore, TSOs coordinate with the national regulator, if specific cost positions are disputed.

Details of the cost remuneration of redispatching measures are compiled in an “industry guideline”[16].

In 2019, Germany had to redispatch down around 2.2% of the total electricity generated[17]. The transparency regarding the redispatching measures is high. Indicators include costs, quantities and specific congested network elements. The figures are updated on a regular basis and can be found and accessed on the webpage of the German regulator[18] as well as in the yearly published monitoring report[19].

The magnitude of applied redispatching is (still) rather small and does not justify severe measures[20].

[16] In German, *Branchenleitfaden “Vergütung von Redispatch-Maßnahmen*“, 18 April 2018, https://www.bdew.de/media/documents/Branchenleitfaden_Verguetung-von-Redispatch-Massnahmen.pdf

[17] 13.5 TWh of downward redispatch (incl. 6.5 TWh of RES curtailment) and 612.4 TWh of total electricity generation.

[18] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html

[19] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/DatenaustauschundMonitoring/Monitoring/Monitoring_Berichte_node.html

[20] The figure compares to other effects in the energy system as follows:

- The prescribed accuracy level of network operation is defined to be 2%.
- Losses in pump storages relevant to the German market amount to about 1% of total demand.
- Self-supply of German prosumers result in a certain unpredictability of their demand pattern that result in differences of about 1% of total demand.
- Network losses are hard to predict and to manage. From a systematic point of view losses are expected to sum up to 5% of electricity consumed. Error rates in this field are about ±1%.

4.2 Spain

In the Spanish system, the TSO applies redispatch on a market-based basis in two different time horizons: D-1 and real-time.

Day-ahead system constraints solution process

This process is performed after the day-ahead market clearing time. From 12:00 D-1 until 15 minutes after the publication of the daily base operating schedule (PDBF[21], which is the result of the economic market clearing performed by the Nominated Electricity Market Operators (NEMO) plus bilateral contracts nominated by market participants), power plants send the system constraints solution bids to the TSO, which carries out the security analysis and publishes an updated schedule, i.e. the feasible daily schedule, which includes the redispatch program changes.

Bidding downward energy is compulsory for all power plants scheduled in PDBF, bidding upward energy is compulsory for power and pumped storage plants, except small plants of renewable technologies; international exchanges are not modified in this process. Demand and batteries' participation is being implemented. Bids are unit-based and can be simple or, in case of thermal plants, complex, which allow the inclusion of start-up and ramp-up costs. Submitted bids can be later modified by providers up to real time.

The TSO applies redispatch both to prevent network congestions/overloads and voltage control issues. In addition, redispatching in real time may be used to provide capacity reserves in case the TSO considers that there are not enough balancing energy resources in the system[22].

The system constraints solution consists of two stages:
Stage I: The purpose of the first stage is to solve the technical constraints that are identified in the daily base operating schedule (day-ahead plus bilateral contracts) by means of limitations and redispatching of power, in order to guarantee that electrical power can be supplied with appropriate conditions of security, quality and reliability. The solution is based on a security analysis, taking into account forecasts of demand, wind and solar power production, as well as declared outages. The outcome of this process is the increase or reduction of a power plants' generation[23].

For each system constraint, the TSO selects the cheapest solution of all the equivalent technical solutions available.
Settlement: In case of a schedule increase (more generation or more pumping consumption), the redispatch will be settled at the system constraints bid price. In case of a schedule decrease, the redispatch is considered an override of the schedule and it is settled at the hourly day-ahead spot (marginal) price, that is, the provider pays back or receives the day-ahead marginal price[24].

[21] PDBF = *Programa diario base de funcionamiento* = Day ahead market coupling + bilateral nominations.
[22] The process is under revision, a reactive power market is being developed, with the objective that voltage issues can be solved without redispatch.
[23] Demand participation expected in 2022.
[24] It is worth clarifying some points concerning downward redispatching conditions. Firstly, requests for new production connections located in grid nodes under congestion risk must accept a connection agreement under which there is no guarantee of firm delivery of energy. On the other hand, even if bidding is mandatory, power plants may avoid being selected in the downward redispatching process by implementing the remote disconnection. This is a system service that consists in automatic disconnection of power plants in case congestion occurs in real time (remotely controlled by the TSO), so there is no need to provide a preventive solution by means of D-1 or real-time redispatching. So far, most thermal power plants have implemented it.

Stage II: Once the technical system constraints have been solved, the TSO restores the system balance by counteracting the net value of activations in stage I.
Settlement: Bids activated (either upward or downward) are settled at the system constraints bid price (pay as bid).

Real-time system constraints resolution process
As a result of its process of continuous security analysis, the TSO can activate system constraints bids in real time when there is no time to put a load limitation and correct it in the intraday markets, following the minimum cost criterion.
Settlement: these redispatches are also settled at the system constraints bid's price for both upward and downward modifications (pay as bid).

	Stage 1		Stage 2		Real time	
	Upward	**Downward**	**Upward**	**Downward**	**Upward**	**Downward**
Bidding	D-1 After day-ahead market gate closure time (GCT)					
Purpose	Solve technical constraints identified in the PDBF		Restore the balance generation-demand		Solve technical constraints identified in real time	
Bid selection	D-1		D-1		Real-time	
Criterion	Minimum cost	Max. contribution	Minimum cost		Minimum cost	
Settlement	Pay as bid / Market price (*)		Pay as bid		Pay as bid	

Table 3 – Characteristics of Stage I, Stage II and Real time system constraints solution process
(*) Pay as bid settlement for schedule increases – upward energy for generation units, downward energy for PS consumption units– and market price settlement for schedule decreases.

	Stage I		Stage II		Real-time	
	Upward	**Downward**	**Upward**	**Downward**	**Upward**	**Downward**
Wind		-76,743	1,931	-2,407,721		-48,886
Hydro	46,802	-2,657	2,355	-1,043,064	7,885	-9,562
Solar		-851	134	-764		-862
CHP	1,939	-2,088	50	-844,670		-4,225
Nuclear				-10,281		
Pumped hydro	1,034	-400	1,368	-1,173,368	17,558	-99,974
CCGT	4,284,056	-167,761	3,257	-933,217	61,096	-29,549
Coal	2,467,605	-6,569	30	-134,808	10,265	-274
Total	***6,801,437***	***-257,068***	***9,124***	***-6,547,893***	***96,804***	***-193,332***

Table 4 – Characteristics of Stage I, Stage II and Real time system constraints solution process: Energy (MWh) in 2019(*) per technology in system constraints resolution

(*) Data are provided for the year 2019 because the values for 2020 may not represent normal conditions due to the impact of the COVID pandemic.

	Stage I		Stage II		Real-time	
	Upward	**Downward**	**Upward**	**Downward**	**Upward**	**Downward**
Wind		-3,403,676	106,883	-109,688,860		-77,351
Hydro	4,417,502	-136,356	132,455	-51,229,736	611,297	-23,007
Solar		-42,242	7,306	-34,879		
CHP	102,087	-89,715	2,733	-37,158,396		-5,092
Nuclear				-287,369		
Pumped hydro	36,077	-21,606	74,810	-50,816,643	1,018,923	-3,518,714
CCGT	327,421,954	-8,587,098	184,038	-44,732,040	7,987,919	-551,720
Coal	220,690,694	-330,953	1,582	-7,070,018	1,693,938	-6,270
Total	***552,668,314***	***-12,611,645***	***509,808***	***-301,017,943***	***11,312,076***	***-4,182,153***

Table 5 – Characteristics of Stage I, Stage II and Real time system constraints solution process: Settlement (€) in 2019 per technology in system constraints resolution
Positive value means payment from the TSO to the provider, negative value means payment from the provider to the TSO. The cost of redispatching is the net value.

4.3 Switzerland

In Switzerland, predominantly hydroelectric power plants take part in the redispatch process. The design currently only allows for short-term activations (usually 30 minutes in advance) and with a maximum activation period of two hours. Power plants send to Swissgrid (the Swiss TSO) at the latest at 4:30 pm D-1 their production schedules for the next day in quarter-hour resolution, including for each time unit the maximum power available and the minimum forced production, taking into account the technical and hydraulic conditions. In the intraday timeframe, the power plants constantly update their data in case of changes in production. Based on these data and the balancing power needs, Swissgrid calculates the available capacities for downward and upward redispatch for each time unit. The decision regarding which unit(s) is (are) activated is based on the sensitivity of each power plant on the observed congestion(s) with the aim to minimise the needed redispatch amount.

The remuneration for the redispatched power plants is based on the bids submitted in the tender for tertiary control energy. The price is set to the volume-weighted median of the bid prices for tertiary control energy (positive or negative), considering only the bids up to the quantity of tertiary control power awarded for the relevant frame, starting from the lowest price (upward redispatch) or highest price (downward redispatch). However, if tertiary control energy has to be activated for the same time frame and the price resulting from the tender is higher (for positive control energy) or lower (for negative control energy), then the resulting price is also used for the redispatch remuneration.

In a way, the Swiss system could also be interpreted as a cost-based mechanism for redispatch. The difference is that since for hydro the relevant costs to consider are not variable costs of running the unit (which are close to 0 €/MWh for hydro) but rather costs linked to lost opportunities in close-to-real-time markets, the prices on these close-to-real-time markets have to be considered in the remuneration. How to consider them and which markets should be considered is a difficult question. Also, it needs to be ensured that no incentives are set that would accentuate bottlenecks (and therefore, Inc-Dec gaming).

Interplay between national and international redispatch

As a general rule, Swissgrid uses zonal redispatch for international redispatch. The necessary energy is procured on the continuous market for tertiary energy. The bids from the tertiary energy tender are activated for this purpose and the power plants are remunerated accordingly. Bids are always made for a time unit of one hour (though activation can happen during this hour) and bids become binding 30 minutes before the start of the given time unit. Until then, bids can be submitted, changed or withdrawn.

In exceptional cases, redispatch on a nodal level (following the rules explained in the section above) may be activated. This can be the case if the following conditions are met:

- If redispatch on a nodal level is explicitly asked for by the foreign TSO requesting an international redispatch activation.
- If international redispatch is used as a replacement for national redispatch, meaning if Swiss power plants can only activate redispatch in one direction and the other direction must be activated in another country.
- If there is not enough tertiary control power bids to cover the need arising from international redispatch.
- If the grid situation is tense, usually when both international and national redispatch are needed at the same time.

5 Conclusions

Against the background of the legal requirements of the Electricity Regulation 2019/943 with respect to redispatching arrangements in Europe, this paper set out to reflect on the different mechanisms for redispatching, namely market-based or cost-based mechanisms. It presents some challenges and advantages and disadvantages of the mechanisms.

These conclusions are without prejudice to the main congestion management option presented in the Electricity Regulation based on a market-based solution – market-coupling – applied on bidding zones without structural congestions. However, one has the option, if one fulfils the criteria set out in Article 13 of the Regulation, to opt for a cost-based solution.

Redispatching at the nodal level is required by zonal dispatching as zonal dispatching ignores or oversimplifies one or more system constraints. Therefore, the combination of the dispatch resulting from the zonal design and the redispatch happening at the nodal level can easily lead to Inc-Dec gaming opportunities that rational agents will eventually exploit leading to a sub-optimal outcome. Because electricity systems are normally affected by a high degree of market power at local level, Inc-Dec gaming is further exacerbated by the exercise of market power at local level. These problems must be conceptually separated but are mutually reinforcing.

To sum up, in order to overcome, or at least limit, Inc-Dec gaming, two approaches are in principle possible:

- Cost-based mechanism of redispatching, which would be the best choice in zonal markets; or
- Avoid redispatching in the first place through the introduction of a market-based dispatch, compatible with the reality of the electricity system, which would therefore imply a shift towards the nodal design (security-constrained economic dispatch), narrowing down cost-based regulation to conditions where *"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"* [25].

In addition, the paper presents actual approaches to redispatching in Germany, Spain and Switzerland. While Germany is using a cost-based mechanism for some time now, Spain and Switzerland opted for a market-based approach, with some elements of cost-based, such as a compulsory participation or the regulatory fixing of compensation for PHS.

As can be expected from the chosen European framework, there is not a uniform approach to redispatching in Europe but rather individual set-ups that try to accommodate for country specificities. Also, there is not a standardised way of deciding on the respective mechanism: while in one country it may be the government deciding, in others it is the ministry or even the regulator. In addition, there is no requirement regarding the level of transparency with respect to the decision-making process and the final decision. In this context, it may be of interest and beneficial to strive for more transparency and a better understanding of the different regimes and their respective reasoning across Europe.

[25] Article 13(3) c) of Regulation (EU) 2019/943.

Annex 1 – List of abbreviations

Term	Definition
ACER	EU Agency for the Cooperation of Energy Regulators
BRP	Balance Responsible Party
CACM	Capacity Allocation and Congestion Management
CEER	Council of European Energy Regulators
CEP	Clean Energy for All Europeans Package
CGM	Common Grid Model
CHP	Combined Heat and Power
DA	Day-ahead
DACF	Day-ahead Congestion Forecast
DER	Distributed Energy Resources
DSO	Distribution System Operator
EU	European Union
FP WS	Future Policy Work Stream
GCT	Gate closure time
GL	Guideline
mFRR	Manual Frequency Restoration Reserve
MS	Member States
MW	Megawatt
MWh	Megawatt hour
NEMO	Nominated Electricity Market Operators
NRAs	National Regulatory Authorities
OPF	Open Power Flow
PHS	Pumped Hydro Storage
RES	Renewable Energy Sources
RR	Replacement Reserve
SO	System Operation
TSO	Transmission System Operator

Annex 2 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's members and observers comprise 39 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

CEER supports its NRA members/observers in their responsibilities, sharing experience and developing regulatory capacity and best practices. It does so by facilitating expert working group meetings, hosting workshops and events, supporting the development and publication of regulatory papers, and through an in-house Training Academy. Through CEER, European NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

In terms of policy, CEER actively promotes an investment friendly, harmonised regulatory environment and the consistent application of existing EU legislation. A key objective of CEER is to facilitate the creation of a single, competitive, efficient and sustainable Internal Energy Market in Europe that works in the consumer interest.

Specifically, CEER deals with a range of energy regulatory issues including wholesale and retail markets; consumer issues; distribution networks; smart grids; flexibility; sustainability; and international cooperation.

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