CREG

Commissie voor de Regulering
van de Elektriciteit en het Gas

Note

(Z)2359
31 March 2022

Note on the functioning and the results of the Core Day-Ahead Flow-Based Market Coupling Project's external parallel runs

Done in accordance with article 23, §2, second paragraph, 2° and 19° of the law of 29 April 1999 on the organisation of the electricity market

Non-confidential

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INHOUDSOPGAVE

EXECUTIVE SUMMARY

Through the Core day-ahead flow-based market coupling project ("Core DA FB MC Project"), the transmission system operators and nominated electricity market operators of 12 different bidding zones will implement common, coordinated capacity calculation and allocation methods. This flow-based market coupling will be implemented in the framework of the Single Day-Ahead Coupling ("SDAC") according to the rules and the provisions of the CACM Regulation. This project constitutes, in many respects, the most important milestone resulting from this network code and is expected to bring significant benefits, in terms of social welfare, to the coupled markets.

In line with the legal obligations, the Core DA FB MC Project Parties (Core TSOs and NEMOs) have organized an external parallel run, during which the capacity calculation and allocation procedures were tested. The results of these parallel runs may be used for the Project Parties to assess the robustness of the procedures and the impact of their design choices on the (capacity calculation and allocation) results. For regulatory authorities and market participants, these results provide an insight in the expected changes following the go-live of the project.

The CREG has analysed the results of the Core external parallel runs in detail and compared them against the actual results observed in the CWE FB MC and the CEE cNTC-based coupling (which are currently in place). Including this counterfactual allows to assess the impact of the shift from the CWE and CEE to the Core context. This note presents the conclusions of the analyses on the capacity calculation and the market coupling data.

Concerning capacity calculation, severe issues with the quality of the reported data have been observed. Despite an apparent robust process for calculating cross-zonal capacities and processing these into the external parallel runs, a significant share of the observed network elements and the considered market time units could not be interpreted, due to the application of fallback procedures or other errors in the capacity calculation process.

The valid observations (after filtering of the erroneous data) show large differences in the applied parameters between the different Core TSOs. Focusing on Elia's network elements in the pre-solved final flow-based domain, average RAM values of 64,0% of F_{max} have been observed. These RAM values result from other parameters such as FRM (11,7%), $F_{0,\,Core}$ (18,2%), AMR (3,9%) and IVA (10,0%).

The reported flow-based parameters show remarkable differences according to the considered TSO. In particular, the CREG notes that certain TSOs apply very high validation reductions and low adjustments for minRAM, which, in combination with high reference flows, lead to very low available margins on the selected critical network elements.

Concerning market coupling, the external parallel run results show a decrease of the average price in the Belgian bidding zone of 2,9 €/MWh in the considered period. At the same time, the average hourly net position increased with 108 MW, moving the bidding zone from being a net importer to being a net exporter in the selected timestamps. The price convergence between all Core bidding zones increased significantly, from 4,0% of all hours in reality to 21,5% under the external parallel runs. Focussing only on the CWE bidding zones, however, price convergence actually decreased, from 47,1% to 38,1% of the observed hours.

The CREG calls upon the Core TSOs to improve the stability of the external parallel runs prior to the Core DA FB MC go-live, in order to ensure that the observed problems are remedied once the final solution is implemented. Furthermore, Core TSOs are urged to improve the transparency, the accuracy and the accessibility of the reported data, so as to allow all regulatory authorities to perform their monitoring duties, and other stakeholders to understand the market functioning, based on precise, reliable and timely data.

INTRODUCTION

The COMMISSION FOR ELECTRICITY AND GAS REGULATION (hereafter "the CREG") investigates, via this note, the results of the external parallel runs conducted in the Core day-ahead flow-based market coupling project (hereafter: "the Core DA FB MC Project"). Based on publicly available data from the JAO Publication Tool, Entso-E Transparency Platform and the CWE TSOs, the results of the external parallel runs are compared against the capacity calculation and market coupling data observed in reality.

In this study, the impact of the Core DA FB MC is assessed. It is intended to provide insight in how the theoretical capacity calculation and market coupling models from the CACM Regulation and the ACER Decision on the Core capacity calculation methodology translate into practice. These results are important for regulatory authorities, ACER and market participants to be able to anticipate the go-live and assess the impact that this will have on the daily market coupling operations under the Core DA FB MC.

This note contains four chapters. In a first chapter, the legal basis which contains the competence of the CREG with regards to this assessment is explored. The second chapter describes the context of the Core DA FB MC Project's external parallel run, linking to the legal obligations and the efforts undertaken by the Project Parties to make the results of these parallel runs available. In a third chapter, the results are presented and assessed against today's reality, hence providing an insight in the expected positive or negative effects of the Core DA FB MC. Conclusions and attention points are included in fourth chapter.

This note has been approved by the CREG's Board of Directors during its meeting of 31 March 2022.

1. LEGAL BASIS

1.1. CACM REGULATION

1.1.1. Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

1. Article 20 of the CACM Regulation lay down the provisions for the development and adoption of a CCM within each CCR.

> *Article 20*
>
> ***Introduction of flow-based capacity calculation methodology***
>
> *1. For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.*
>
> *2. No later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region. The proposal shall be subject to consultation in accordance with Article 12. The proposal for the capacity calculation methodology within regions pursuant to this paragraph in capacity calculation regions based on the 'North-West Europe' ('NWE') and 'Central Eastern Europe' ('CEE') as defined in points (b), and (d) of point 3.2 of Annex I to Regulation (EC) No 714/2009 as well as in regions referred to in paragraph 3 and 4, shall be complemented with a common framework for coordination and compatibility of flow-based methodologies across regions to be developed in accordance with paragraph 5.*
>
> *(…)*
>
> *8. To enable market participants to adapt to any change in the capacity calculation approach, the TSOs concerned shall test the new approach alongside the existing approach and involve market participants for at least six months before implementing a proposal for changing their capacity calculation approach.*
>
> *9. The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones.*

2. In article 21 of the CACM Regulation, the elements which shall be included in each CCM, including input, calculation approach and output are described.

3. The approval and adoption process of the Core DA CCM, as well as other terms and conditions or methodologies, are laid down in Article 9 of the CACM Regulation. According to paragraph 7, the task of developing and approving the CCMs is allocated to the TSOs and NRAs of the concerned CCR (in this case, the Core CCR).

> *Article 9*
>
> ***Adoption of terms and conditions or methodologies***
>
> *(…)*
>
> *7. The proposals for the following terms and conditions or methodologies shall be subject to approval by all regulatory authorities of the concerned region:*

(a) the common capacity calculation methodology in accordance with Article 20(2);

(…)

1.1.2. Core DA CCM

4. In accordance with the provisions in Article 9 of the CACM Regulation, the initial proposal for the Core Day-Ahead Capacity Calculation Methodology (hereafter: "Core DA CCM") was submitted, in September 2017, to all Core NRAs for approval. Upon the request of these NRAs, ACER initiated an approval process for this proposal, which led to a decision in February 2019: the Decision No 02/2019[1] (hereafter: the ACER Decision).

5. In November 2020, all Core TSOs submitted for approval a proposal for amendment to the Core DA CCM. All Core NRAs, including the CREG,[2] approved this – after introducing some amendments – in June 2020.

1.1.2.1. Decision No 02/2019 of the Agency for the Cooperation of Energy Regulators of 21 February 2019 on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

6. Article 28 of the Core DA CCM establishes that, prior to the go-live which is to take place on 28 February 2022, Core TSOs will organize two parallel runs. In the internal parallel run, Core TSOs shall test the operational processes. In the external parallel runs, which shall at minimum extend to 6 months, the Core NEMOs shall be involved to test the integration into the SDAC and market participant shall be involved to estimate the methodology's impact on the functioning of the day-ahead market.

> ***Article 28**. Timescale for implementation*
>
> *1. The TSOs of the Core CCR shall publish this methodology without undue delay after the decision has been taken by the Agency in accordance with Article 9(12) of the CACM Regulation.*
>
> *2. No later than four months after the decision has been taken by the Agency in accordance with Article 9(12) of the CACM Regulation, all Core TSOs shall jointly set up the coordinated capacity calculator for the Core CCR and establish rules governing its operation.*
>
> *3. The TSOs of the Core CCR shall implement this methodology no later than 28 February 2022. The implementation process, which shall start with the entry into force of this methodology and finish by28 February 2022, shall consist of the following steps:*
>
> > *(a) internal parallel run, during which the TSOs shall test the operational processes for the day-ahead capacity calculation inputs, the day-ahead capacity calculation process and the day-ahead capacity validation and develop the appropriate IT tools and infrastructure;*

[1] Decision No 02/2019 of the Agency for the Cooperation of Energy Regulators of 21 February 2019 on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

[2] Decision (B) 2241 on the request of the NV ELIA TRANSMISSION BELGIUM and all TSOs of the Core CCR for amendments to the common capacity calculation methodology

(b) external parallel run, during which the TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, the Core TSOs will involve the Core NEMOs to test the implementation of this methodology within the SDAC, and market participants to test the effects of applying this methodology on the market. In accordance with Article 20(8) of CACM Regulation, this phase shall not be shorter than 6 months.

4. During the internal and external parallel runs, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. For this purpose, they shall develop, in coordination with the Core regulatory authorities, the Agency and stakeholders, the monitoring and performance criteria and report on the outcome of this monitoring on a quarterly basis in a quarterly report. After the implementation of this methodology, the outcome of this monitoring shall be reported in the annual report.

5. The Core TSOs shall implement the day-ahead capacity calculation methodology on a Core bidding zone border only if this bidding zone border participates in the SDAC.

1.2. LAW OF 29 APRIL 1999 ON THE ORGANISATION OF THE ELECTRICITY MARKET

7. Article 23, §2, second paragraph assigns different tasks to the CREG, as national regulatory authority in Belgium. In particular, the responsibility to monitor the functioning of electricity markets is laid out in 2° and 19° of this paragraph.

Art. 23. § 1. (…)

§2. The Commission is charged with an advisory task to the government with regards to the organization and functioning of the electricity market, on the one hand, and with a general task of supervision and control of the applicable laws and regulations, on the other hand.

To this end, the Commission shall:

(…)

2° at its own initiative, or upon request of the minister or a regional government, conduct investigations and perform studies with regards to the electricity market. In this context, the Commission will see to the preservation of the confidentiality of commercially sensitive data and/or personal data and will abstain from making these public;

(…)

19° make sure that in particular the technical and tariff situation of the electricity network as well as the evolution of this sector are in the public interest and adhere to the general energy policy. The Commission ensures the permanent monitoring of the electricity market, both with regards to market functioning as well as with regards to prices. The King can, upon the proposition of the Commission and after a decree adopted after concertation in the Council of Ministers, define the rules for a permanent monitoring of the electricity markets further.

2. CONTEXT

2.1. CORE DA FB MC EXTERNAL PARALLEL RUN

8. The external parallel run is organized by the TSOs and NEMOs that participate to the Core DA FB MC Project, (hereafter the "Project Parties"). It is performed in accordance with the legal obligation laid out in article 28(2)(b) of the Core DA CCM. The aim of this parallel run, which should last for at least six months and be conducted prior to the Core DA FB MC Project's go-live, is to involve stakeholders in the testing of the methodology. To this end, the TSOs and NEMOs will test the methodology within the framework of the SDAC, to assess the effects of the capacity calculation and allocation methodology on the prices, net positions and welfare in the participating bidding zones.

9. Core Project Parties started the external parallel run at the end of November 2020. While initially capacity calculations and market coupling results were only published for a select number of business days, the frequency of calculations and publication of the results increased progressively over the following weeks and months. This increased stability of the external parallel runs led to a switch to the immediate publication for capacity calculation results for 7 out of 7 business days in April 2021. Market coupling results are also published for all business days, but with a delay of 21 days, as these simulations involve confidential (anonymized) order books from NEMOs to be processed as well.

2.2. JAO PUBLICATION TOOL

10. Core Project Parties ensure the publication of capacity calculation (immediate) and market coupling results (delayed) on the dedicated webpage of JAO.[3,4] This Publication Tool allows all interested parties to easily access the capacity calculation data. The market coupling data (prices and net positions per bidding zone) are available separately under the "Download" section. These data are, as per the requirements in the Core DA CCM, publicly available to all stakeholders.

11. A "Publication Handbook" is available for download from the website. This document describes the navigation of the Publication Tool and how to interpret the different data sets that are published, ranging from the capacity calculation inputs (virgin domains, remedial actions, D2CF, etc.) to the outputs and validation (final computation, maximum net positions or exchanges, shadow prices, etc.). An additional tool is provided, the "Core Market View", which allows market participants to assess the interaction between the cross-zonal capacities and exchanges between bidding zones.

2.3. KPI REPORTS

12. In addition to the raw data made available through the Publication Tool, reports with Key Performance Indicators (hereafter: "KPI Reports") are drafted on a regular basis, in accordance with article 28(4) of the Core DA CCM. These KPI reports are drafted based on agreed metrics between Project Parties, ACER and Core regulatory authorities. For transparency purposes, they are also made available to other interested stakeholders. A "Reading Guide" is included in order to contribute to the understanding of the KPIs.

[3] The Joint Allocation Office offers trading platforms for implicit and explicit cross-border auctions to European TSOs.

[4] Data, documentation, announcements and a Q&A forum on the Core DA FB MC external parallel runs are available on: https://www.jao.eu/core-fb-da-parallel-run-0

3. CORE DA FB MC PARALLEL RUN

3.1. TECHNICAL AND ORGANIZATIONAL ASPECTS

13. Capacity calculation and market coupling data are available starting from 14 November 2020. From that moment onwards, data for a select number of business days are available yet the stability of the external parallel runs only allowed for a daily publication from April 2021 onwards. As the reliability of the data in the first weeks of the external parallel runs seems to be less than the more recent data, the CREG decided to show the market coupling results in this note starting **from 1 January 2021 to 28 February 2022**.[5]

3.1.1. Application of fallback procedures in the capacity calculation

14. Due to technical or organizational issues in the daily capacity calculation processes, reliable results might be unavailable for several hours. In these cases, the corresponding hours are marked as having the fallback procedures applied, by introducing spanning (in case of only a few missing hours) between the hours before and after, or by introducing default flow-based parameters. This practice will also be applied as a fallback in the actual Core DA FB MC, yet the results during those hours are obviously less representative (as the aim is to have a fully stable capacity calculation by the time of the go-live). The number of hours with spanning / default flow-based parameters significantly decreased as experience in the external parallel run grew. Figure 1 shows that the application of default flow-based parameters decreased since reaching a peak in the August and September of 2021.

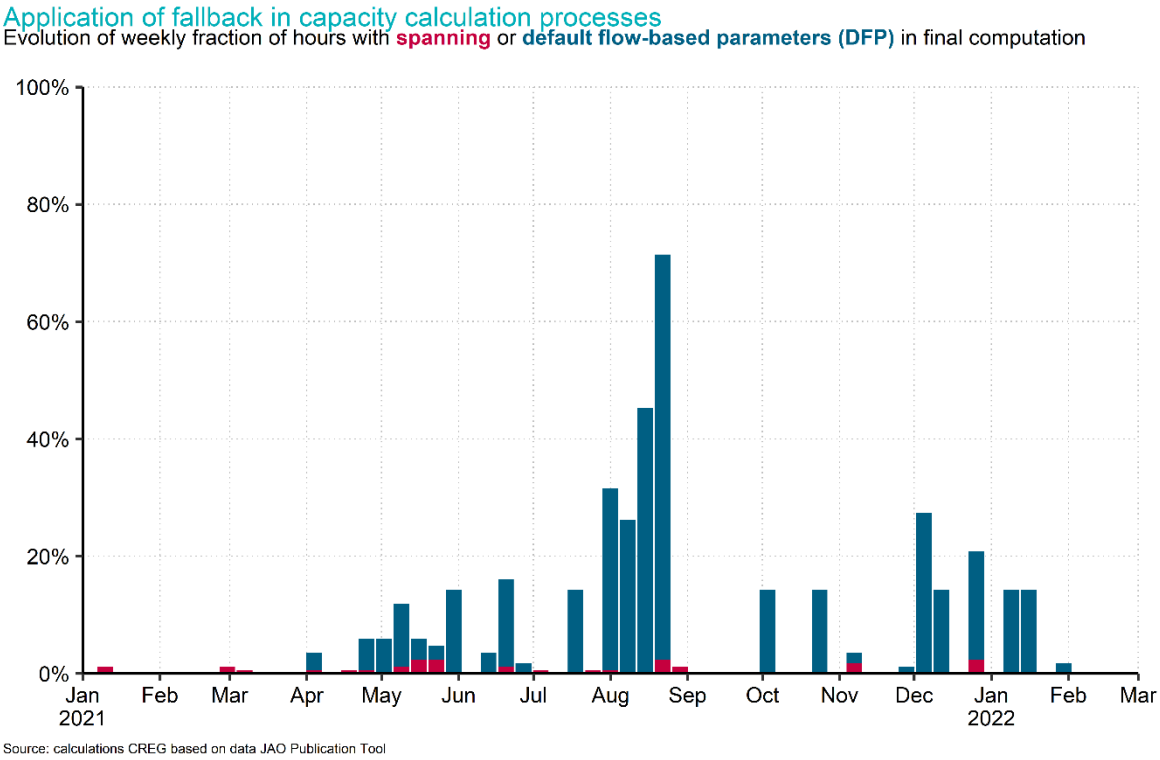

Figure 1 Application of fallback in capacity calculation processes

[5] Except for the flow-based domains, where presenting the data for this long period is not considered realistic: here the analyses are focused on the period between 1 October 2021 and 28 February 2022 (see section 3.2.1.1).

15. The stability of the capacity calculation (and, subsequently, market coupling) processes are crucial to the successful go-live of the Core DA FB MC process. The (temporary) increase of the application of default flow-based parameters in the final computation of the flow-based domains is therefore a concern for which the CREG urges Core TSOs to investigate without delay the root causes. This applies even more strongly to the hours where, formally, no spanning / DFP applies but the CREG observes "DFP-like" results, as there the problems persist but they are not labelled transparently.

3.1.2. Introduction of CNECs with 0% RAM

16. In addition to the significant number of hours where spanning or DFP are applied (see also paragraph 14), there is a very significant share (+80%) of the observed CNECs in the final domains which show RAM values equaling 0% of F_{max}. Table 1 shows the occurrence of CNECs with 0% RAM per TSO for the considered period. All in all, these occurrences were concentrated on 592 hours or 17,4% of the MTUs.

(1 Oct 2021 – 28 Feb 2022)	CNECs with 0% RAM	All CNECs	Fraction where RAM = 0%
AT - APG	38.408	78.273	49,1%
BE - Elia	2.600	33.065	7,9%
CZ - CEPS	182	11.852	1,5%
DE - 50Hertz	7.795	15.307	50,9%
DE - Amprion	503.973	525.462	95,9%
DE - TenneTGmbH	77.359	91.574	84,5%
DE - TransnetBW	306.763	314.536	97,5%
FR - RTE	182	7.327	2,5%
HR - HOPS	186	26.432	0,7%
HU - MAVIR	182	27.691	0,7%
NL - TenneTBV	78.128	88.979	87,8%
PL - PSE	88.390	108.485	81,5%
RO - Transelectrica	213	12.064	1,8%
SI - ELES	183	12.933	1,4%
SK - SEPS	182	28.236	0,6%

Table 1 Occurrence of CNECs with 0% RAM per TSO

17. It is not clear what may explain these values. In section 3.2.1, the results will be shown excluding the CNECs where the RAM equals 0% of F_{max}. This filtering does not imply that these results are not important. To the contrary: Core TSOs are urged to analyze the root causes for the occurrence of these parameters and implement procedures to avoid this prior to the go-live of the Core DA FB MC.

In what follows, the analysis on the capacity calculation results will be restricted to the CNECs with a non-zero RAM value. CNECs with 0% RAM are filtered out given that the underlying flow-based parameters seem erroneous and the CREG estimates that it does not make sense to analyze these non-representative figures as they tend to significantly distort the observations.

18. As we will see later on, the CREG only analyzed the pre-solved flow-based domains between 1 October 2021 and 28 February 2022, so it is only possible to assess the impact of the spanning/DFP and DPF-like CNECs and MTUs for that period. This breakdown is provided in Table 2. It is clear that this breakdown mostly has an impact on the number of CNECs to consider in the pre-solved domains: about 20% of the MTUs with 0% RAM entries leads to about 80% of the CNECs being invalid. Considering these in the subsequent analyses (at least when considering the flow-based parameters as in section 3.2.1.1) would significantly and negatively impact the results shown, hence these analyses focus on the last row in the Table 2 below.[6]

(1 Oct 2021 – 28 Feb 2022)	Number of CNECs	Number of MTUs
All hours	1.401.811	3.395
Hours where no spanning / DFP applies	1.395.332 (99,5% of total)	3.318 (97,7% of total)
Hours where no spanning / DFP applies and no 0% RAM CNEC entries exist	281.300 (20,1% of total)	2.803 (82,6% of total)

Table 2 Breakdown of the representativeness of the CNECs and MTUs in the considered period

3.2. RESULTS

19. The focus of the CREG's analyses lies on the capacity calculation and market coupling data resulting from the external parallel runs for all Core bidding zones, as the benefits of the Core DA FB MC Project should be assessed on a regional level. However, where possible, the impact on the functioning of the Belgian market (notably when prices and import / export positions are concerned) will be explored in more detail.

20. Where possible, the results from the external parallel runs are compared against a counterfactual, namely the results of the actual market coupling processes in the SDAC framework (CWE FBMC and CEE cNTC). These data are also publicly available: the main data sources used in these analyses are the Entso-E Transparency Platform[7] and the data from CWE TSOs (for the CWE FBMC)[8].

21. In a first section, capacity calculation results (mostly TSO data) are presented and compared, for Belgium, against the data from the CWE FMBC. Subsequently, market coupling data will be explored more in detail and compared against the SDAC output.

3.2.1. Capacity calculation

3.2.1.1. Flow-based parameters (final pre-solved flow-based domain)

22. The Core TSOs publish the Critical Network Elements ("CNEs") and their Contingencies ("Cs") (combined, "CNECs") that form the final flow-based domain. This domain shows the possible combinations of exchanges between bidding zones and are constrained by the margins on these CNECs.

23. In this section, the flow-based parameters that form the final domains are analysed, in order to evaluate TSO-specific trends. Given the size of the datasets that build up these domains, the considered period is limited **from 1 October 2021 until 28 February 2022**. Only the CNECs that make

[6] Where the considered period is longer (i.e. in sections 0 and 0), only the MTUs without spanning / DFP are considered: the "DFP-like" results remain in the datasets as it was not possible to extract these from the pre-solved domains for those dates.
[7] https://transparency.entsoe.eu/
[8] https://www.jao.eu/implict-allocation

up the so-called “pre-solved domain” are shown, i.e. only the final set of binding constraints for capacity calculation without redundant CNECs are included. As mentioned in paragraph

24. Table 3 and Table 4 show, per TSO and per type of CNE, the number of unique CNEs and CNECs in the filtered pre-solved final flow-based domains. For Elia, 27 different CNEs were found, of which 14 were internal, 7 were cross-border and 4 were PSTs (while 2 did not have a type specification). Adding the considered continencies, these numbers obviously increase, as the same network element is monitored under a number of different contingencies.

	Internal line	PST	Cross-border line	Transformer	<>	TOTAL
AT - APG	37	2	10	10	16	75
BE - Elia	14	4	7		2	27
CZ - CEPS	2		14	1		17
DE - 50Hertz	19	2	2			23
DE - Amprion	57	1	7		7	72
DE - TenneTGmbH	27		7		4	38
DE - TransnetBW	13	1	7		2	23
FR - RTE	2		5		1	8
HR - HOPS	5		8		1	14
HU - MAVIR	8		14			22
NL - TenneTBV	21		9		2	32
PL - PSE	6	2	8	2		18
RO - Transelectrica	12	2	4	5		23
SI - ELES	5		5		1	11
SK - SEPS	8		10			18

Table 3 Number of unique CNEs per TSO and per type

	Internal line	PST	Cross-border line	Transformer	Unknown	TOTAL
AT - APG	66	10	21	26	45	168
BE - Elia	87	60	62		2	211
CZ - CEPS	3		30	1		34
DE - 50Hertz	29	4	6			39
DE - Amprion	175	17	20		39	251
DE - TenneTGmbH	53		37		7	97
DE - TransnetBW	54	4	24		2	84
FR - RTE	3		11		1	15
HR - HOPS	8		14		1	23
HU - MAVIR	29		37			66
NL - TenneTBV	54		54		2	110
PL - PSE	15	6	49	15		85
RO - Transelectrica	34	7	11	13		65
SI - ELES	8		13		4	25
SK - SEPS	16		19			35

Table 4 Number of unique CNECs per TSO and per CNE-type

25. The margins on these CNECs determine the size of the flow-based domains and the combination and level of the exchanges that can take place in the market coupling. Figure 2 shows the average margin (measured as "RAM" or "Remaining Available Margin") of internal and cross-border network elements, per TSO. Clear differences can be observed among the TSOs. On internal CNECs, the margins provided by some TSOs (in particular, TransnetBW, Transelectrica, TenneTGmbH, TenneTBV, RTE, Amprion and 50Hertz) are (significantly and structurally) below 50% of the thermal limit F_{max}. On cross-border lines, the average RAM values are higher, even though for TransnetBW and TenneTBV still below 50%. This is very alarming from a capacity calculation perspective and should be explored in further detail by the respective TSOs. Average RAM values on Elia's internal network elements reached 64,1%, and 64% on cross-border lines. These values should be increased as well, especially in light of the Clean Energy Package's 70% requirement.[9]

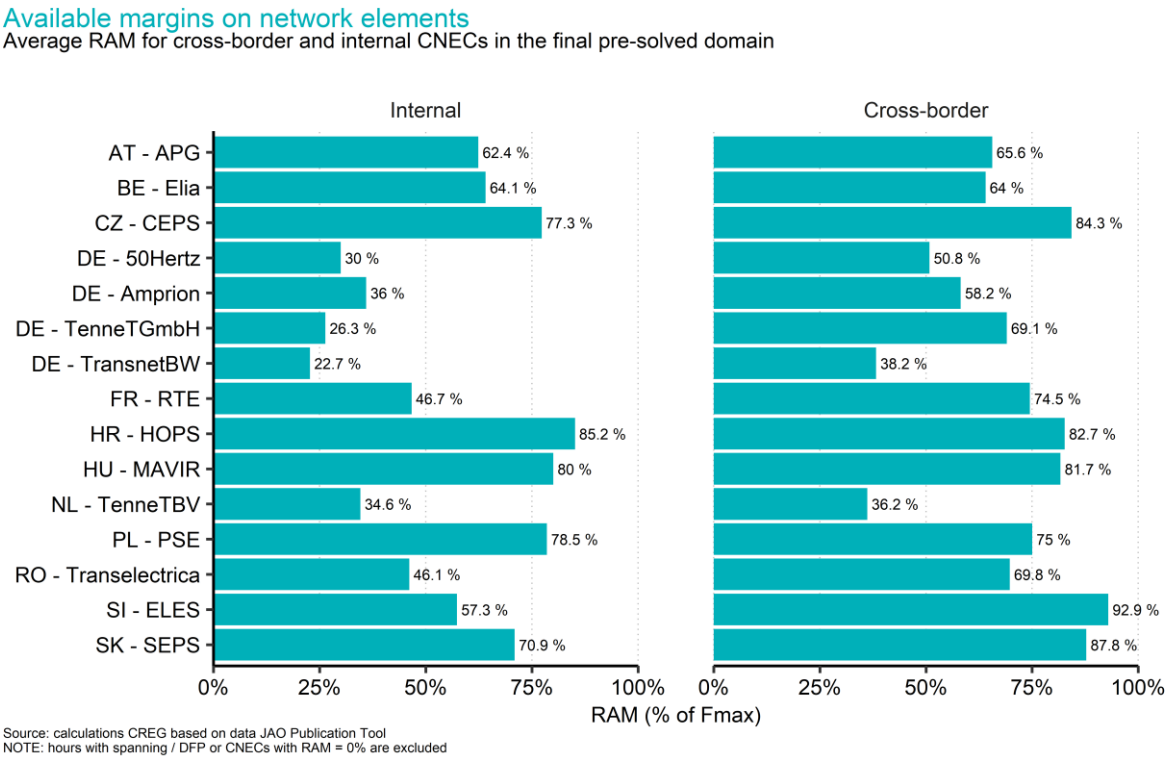

Figure 2 Available margins on network elements

26. For each CNEC, the available margin is calculated as follows:

$$RAM = F_{max} - FMR - F_{0,Core} + AMR - CVA - IVA$$

where:

- F_{max} is the thermal line capacity defined on a static, seasonal or hourly (dynamic) basis (Core DA CCM Article 6);
- FRM is the Flow Reliability Margin (Core DA CCM Article 8);
- $F_{O,\ Core}$ are the reference flows in the base case, i.e. prior to any cross-zonal exchanges in the concerned capacity calculation region (Core DA CCM Article 11);

[9] Even though the RAM values do not correspond to the MACZT values in the 70% compliance monitoring: in the latter, also the MNCCs (i.e. the margins for non-coordinated capacity calculation) are considered and derogations or action plans may apply.

- AMR is a virtual margin used to increase the RAM up to the required minRAM value (Core DA CCM Article 17);
- CVA is a Coordinated Validation Adjustment to decrease the capacity on a CNEC based on a coordinated validation by the Coordinated Capacity Calculators (Core DA CCM Article 20(3));
- IVA is an Individual Validation Adjustment to decrease the capacity on a CNEC based on a local validation by an individual TSO, not shared with the CCCs (Core DA CCM Article 20(5))

All these parameters are published. In the next paragraphs, each of these parameters defining the available margins are explored one by one, per TSO. Presenting these parameters separately is done in order to increase the understanding. In order to present a comprehensive approach per TSO of the breakdown of the F_{max} into the RAM values, see Figure 14 in the annex.

27. Table 5 shows on how many network elements a specific TSO applies a certain F_{max} calculation policy. Many TSOs apply different calculation methods, depending on the circumstances and probably on the type of network element (not shown).

	Dynamic	Fixed	Seasonal	Unknown
AT - APG			71	
BE - Elia			25	2
CZ - CEPS	7	10		
DE - 50Hertz		23		
DE - Amprion	36	26	10	
DE - TenneTGmbH	10	26	1	
DE - TransnetBW	4	11	8	
FR - RTE			7	
HR - HOPS			14	
HU - MAVIR		18	4	
NL - TenneTBV			30	2
PL - PSE	18			
RO - Transelectrica			23	
SI - ELES	11			
SK - SEPS		17	1	

Table 5 F_{max} policy per TSO (number of CNEs which apply a certain F_{max} policy)

28. Even though Elia could apply dynamic line rating on its network elements, the parallel run results suggest that this is not done. [10] However, further interaction with Elia shows that this parameter in the final domains does not correctly represent the reality, since Elia does apply a dynamic F_{max}-value. To check the validity of these results, the F_{max} values for each CNE over the considered 5-month period are shown in the figure below. It is clear that the observed F_{max} values show a dynamic pattern for Elia. The other direction also applies: for some TSOs that report to apply a dynamic calculation, the timeseries of the F_{max} values have a more static look, suggesting that either a seasonal or fixed limit applies (examples include Amprion and PSE).

29. Of course, this figure does not say anything about the absolute value of the $F_{max,}$ as it only looks at the variation of the F_{max} against its own maximum in the observed period. It is therefore possible that, on CNEs where always 100% is observed throughout the period, these values are fixed and very

[10] Elia currently applies Dynamic Line Rating in several timeframes of the CWE market coupling: https://www.elia.be/en/infrastructure-and-projects/our-infrastructure/dynamic-line-rating. The CREG expects that these will also be applied in the Core DA FB MC after go-live.

low. In any case, Core TSOs are urged to correctly represent the manner in which they calculate the F_{max} on their critical network elements in the datasets.

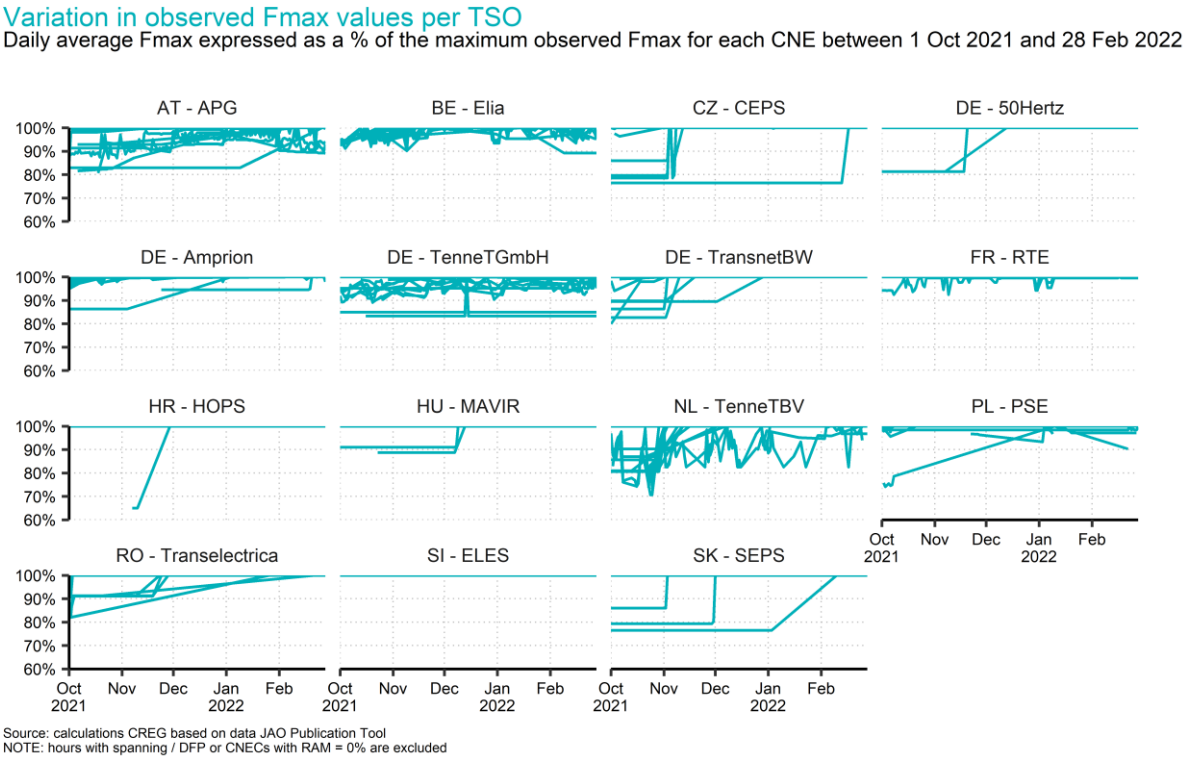

Figure 3 Variation in observed Fmax values per TSO

30. The average reliability margins which are taken into account by TSOs on internal and cross-border lines are shown in Figure 4. The CREG notes that Elia applies an 11,7% average FRM value on both internal and cross-zonal network elements. These values are lower than the observed FRMs in the CWE FBMC (where average RAM values, in particular on internal network elements, often exceeded 20% of F_{max}).[11] On average, these are still some percentage points higher than other TSOs' observed FRMs, in particular on internal network elements.

[11] See, for example, also Study (F) 2183 on the compliance of ELIA TRANSMISSION BELGIUM SA with the requirements related to the transmission capacity made available for cross-zonal trade in 2020.

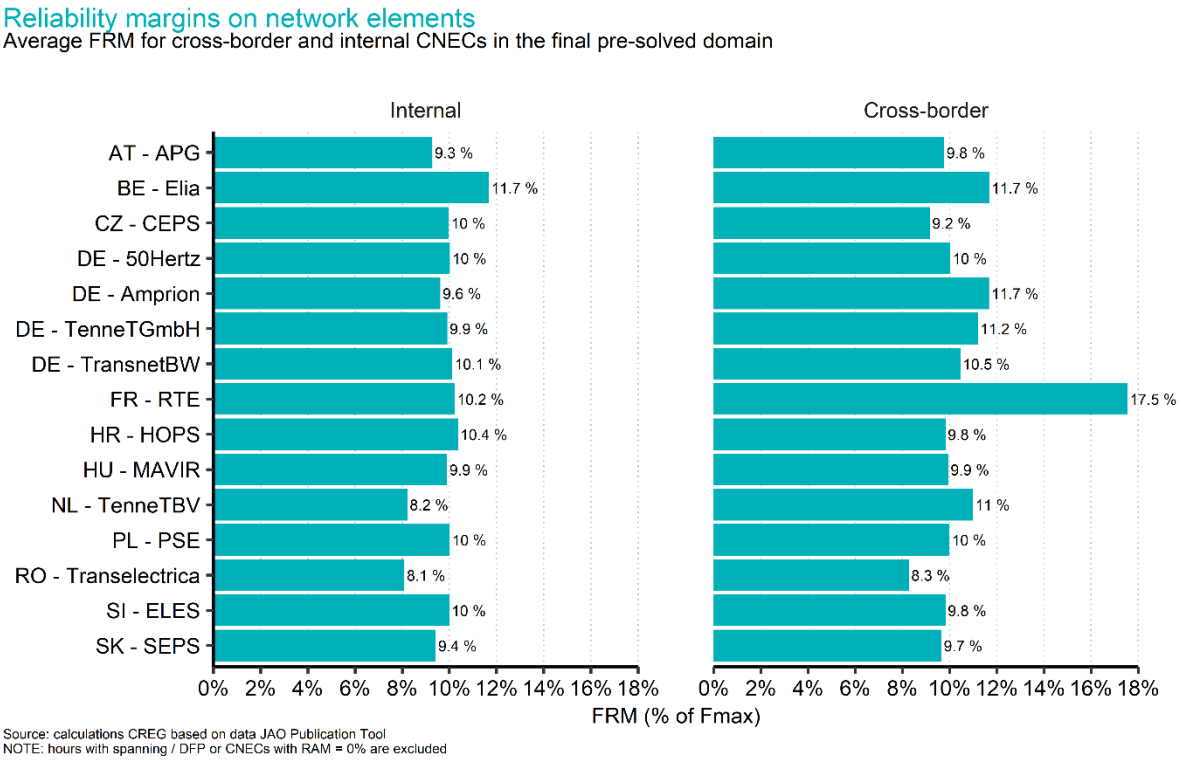

Figure 4 Reliability margins on network elements

31. Figure 5 shows the reference flows on network elements, again per TSO, differentiating between internal and cross-border lines. The upper panel distinguishes between $F_{0,\,all}$ and F_{uaf}, or the flows in the base case resulting from exchanges within Core bidding zones and exchanges with non-Core bidding zones, respectively. The magnitude of these flows shows how much capacity is already used in the base case. It is clear that, for some TSOs (mostly German ones, but also the Dutch and Romanian TSO) these high reference flows severely impact the base case and the available capacities. Sometimes certain reference flows (in particular unscheduled ones, from non-Core bidding zones) can have a relieving effect, i.e. they free up margins on the considered network elements.

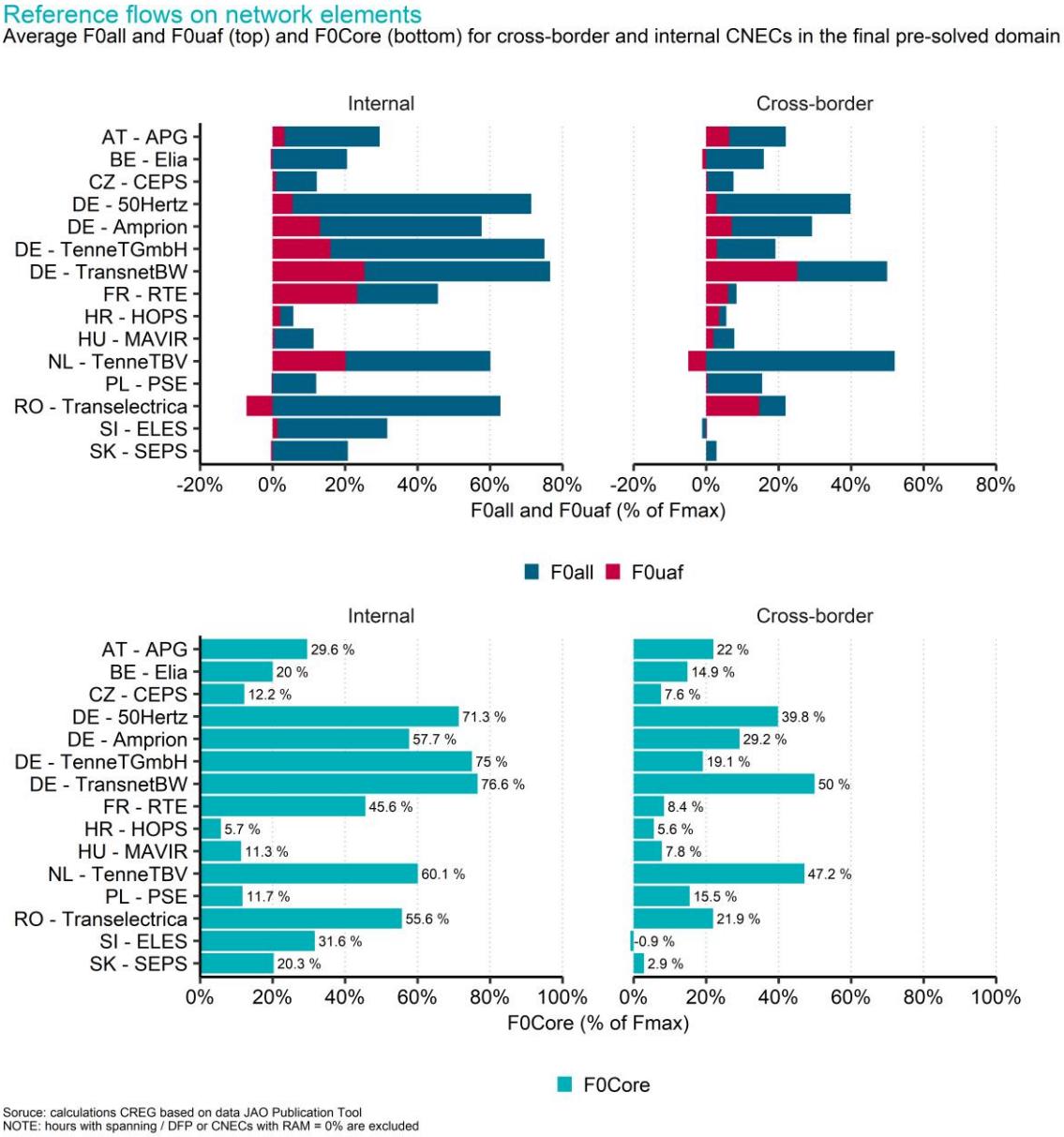

Figure 5 Reference flows on network elements

32. When focusing on cross-border network elements, the high reference flows are mainly caused by loop flows ($F_{0,all}$). We can also calculate these by subtracting F_{uaf} from $F_{0,\ Core}$, in order to ignore the flows that are caused by exchanges with countries that fall outside of the scope of Core coordinated capacity calculation. Table 6 shows the 10 network elements which, when considered in the pre-solved final domain, suffer from the highest average loop flows. In order to provide a complete overview of the impact, the column "Observation" shows the number of times in the considered period when the corresponding network element was considered in the pre-solved domain. On these network elements, in particular interconnectors with Germany, very high loop flows (on average) are observed. For information, the average RAM and AMR values on these CNECs are also included.

	Border	Direction	Average loop flows	Count	Average AMR	Average RAM
Diele - Meeden 380 White	DE - NL	DIRECT	92,7%	18	42,7%	34,8%
Krajnik - Vierraden 507	PL - DE	OPPOSITE	91,0%	152	18,6%	18,8%
Diele - Meeden 380 Black	DE - NL	DIRECT	85,8%	940	22,1%	28,4%
Krajnik - Vierraden 508	PL - DE	OPPOSITE	85,5%	397	16,5%	18,9%
St. Peter 2 - Altheim 233_230	AT - DE	DIRECT	60,5%	134	6,4%	21,8%
Rosiori - Mukacevo	RO - UA	OPPOSITE	60,2%	21	2,6%	31,0%
Dobrzen - Albrechtice	PL - CZ	DIRECT	52,5%	200	0,8%	37,4%
Nadab - Bekescsaba	RO - RO	OPPOSITE	51,7%	13	1,1%	33,1%
Meiningen - Ruetli 408	AT - CH	OPPOSITE	42,0%	32	0,0%	69,8%
Etzenricht - Prestice 442	DE - CZ	OPPOSITE	38,4%	893	0,1%	46,4%

Table 6 Top-10 network elements with highest average loop flows

33. Without focusing on these ten network elements, the below figure shows the density curves of the observed loop flows on all CNECs in the considered dataset. The median value is 9,5% of F_{max} (across all CNECs), implying that 50% of the CNECs in the pre-solved domain have higher values. About 3,9 % of all CNECs in the pre-solved domains suffer from loop flows exceeding 50% of the F_{max} (this is the right tail of the distribution).

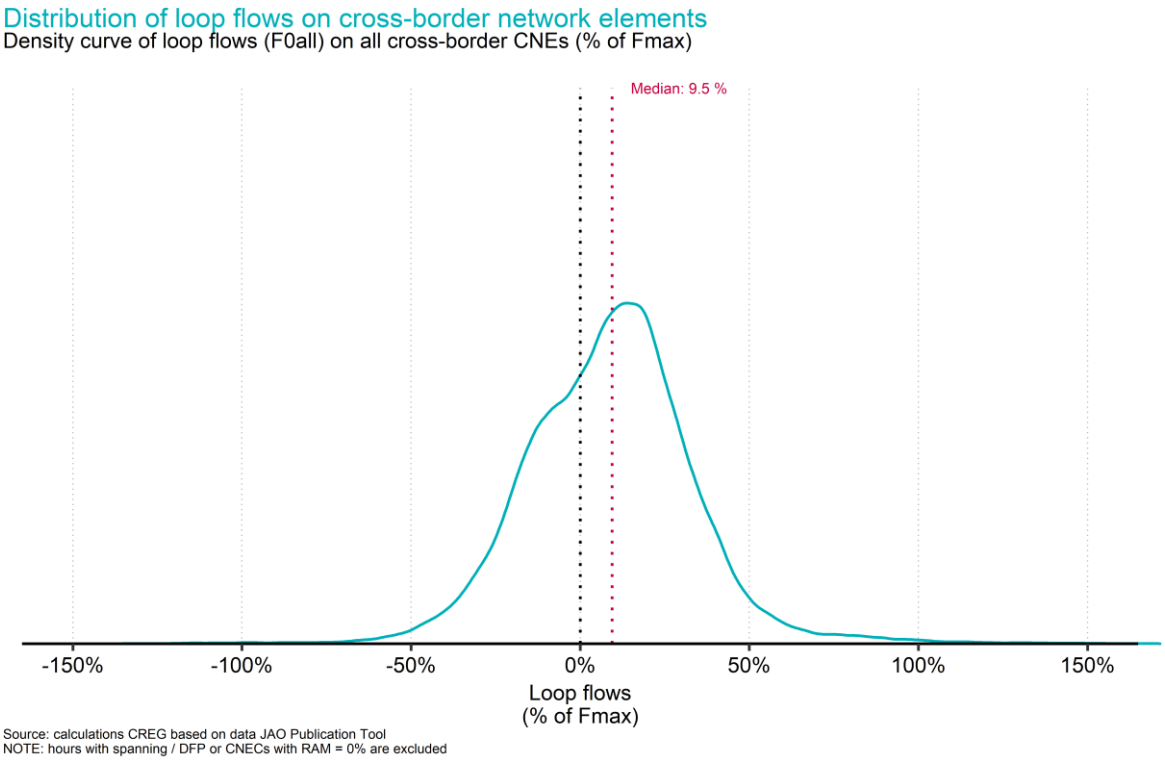

Figure 6 Distribution of loop flows on cross-border network elements

[12] When the direction is listed as "opposite", the order of the border should be reversed in order to obtain the direction of the loop flows.

34. In order to avoid undue discrimination, TSOs implement a minimum RAM requirement, which can be met by adjusting the AMR ("Adjustment for minRAM") parameter. This is meant to ensure that TSOs are able to comply with the 70% requirement (except where temporary derogations or action plans apply, *in casu* everywhere,[13] which leads to a reduction of this target). The average AMR values for internal and cross-border lines are shown, per TSO, in Figure 7.

35. The highest average AMR values are observed on the internal network elements of German, French, Slovenian and Romanian TSOs. On cross-border elements, the average AMR values for TenneT in Netherlands are remarkable. The average AMR values for Elia are 4,5% on internal lines and 3% on cross-border lines.

36. It is worth noting that higher AMR values in itself are not necessarily reflected in higher absolute RAM values. Firstly, the ambition level on available capacities (through the application of derogations or action plans) differs among TSOs. Secondly, TSOs may free up the necessary capacity on CNECs by reducing reference flows within the base case, instead of using virtual capacities. In this sense, the extent by which virtual capacities are used to reach the minRAM targets is symptomatic and signaling an underlying problem of high reference flows not resolved in the base case. The use of AMR to achieve the minRAM target not only matters for system security but also for the market[14].

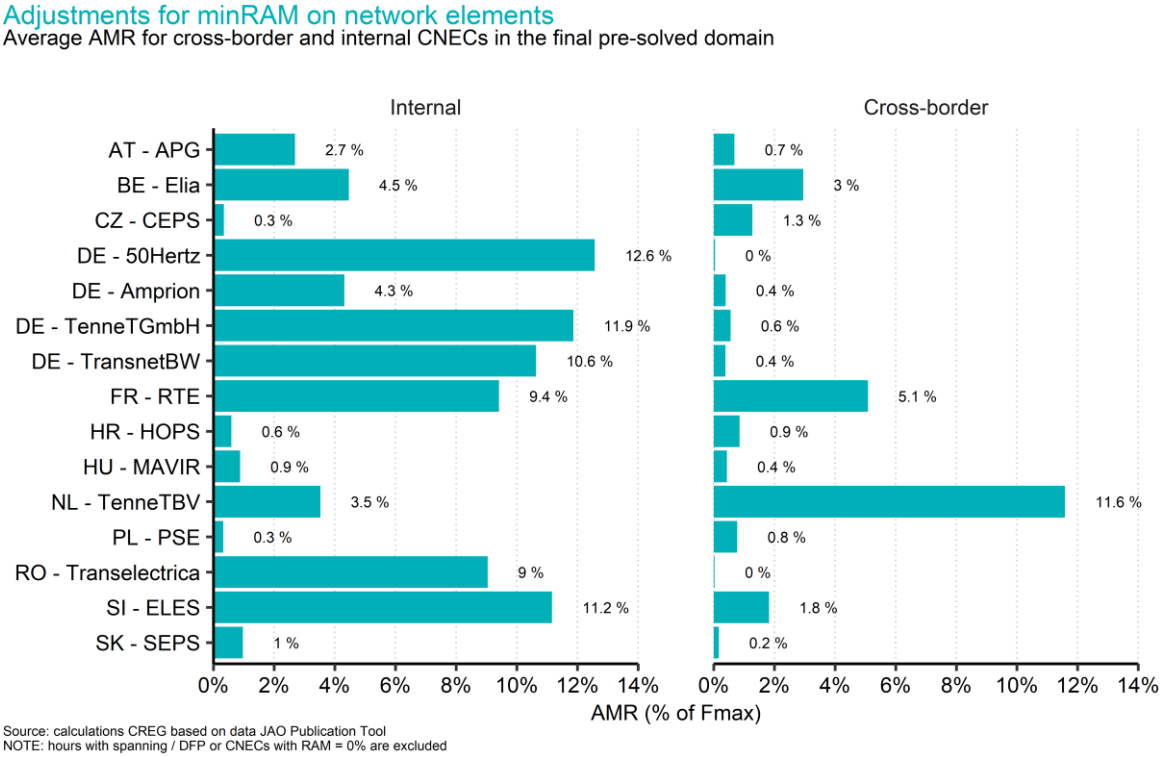

Figure 7 Adjustments for minRAM on network elements

37. Depending on how the Core ID CCM methodology will be implemented, the use of virtual margins will in the short term probably also directly affect the ID ATC-values since Core TSOs may remove virtual margins when determining the day-ahead left-over flow-based domain. To assess the potential impact of the removal of virtual capacities for the intraday capacity calculation, the CNEs with the highest average AMR-values are shown in **Table 7**. It is clear that, despite showing only the CNEs with the highest average AMR-values, the resulting RAMs are very different.

[13] An overview of which countries / TSOs apply action plans and / or derogations may be found at: https://acer.europa.eu/electricity/market-monitoring-report/cross-zonal-capacity-70-target

[14] See CREG study 1987, https://www.creg.be/nl/publicaties/studie-f1987

	Border	Direction	Average AMR	AMR 25% percentile	AMR 75% percentile	Count	Average RAM
Strass - Thaur 274B	AT - AT	DIRECT	53,9%	32,1%	77,0%	27	17,6%
Diele - Meeden 380 White	DE - NL	DIRECT	42,7%	0,0%	83,4%	18	34,8%
Doel - Zandvliet 380.25	BE - BE	OPPOSITE	36,0%	31,4%	42,9%	65	74,2%
Y-Meppen (-Doerpen West - Niederlangen) EMSLD OW	DE - DE	OPPOSITE	28,8%	10,3%	47,3%	33	20,3%
Doerpen West - Hanekenfaehr EWBL	DE - DE	DIRECT	28,2%	11,9%	45,6%	40	21,7%
Y-Mercator (-Doel - Lillo) 380.51	BE - BE	OPPOSITE	27,8%	6,6%	40,8%	290	50,5%
Y-Doerpen West (-Meppen - Niederlangen) EMSLD OW	DE - DE	DIRECT	27,0%	10,3%	43,0%	165	21,3%
Pasewalk - Vierraden 306	DE - DE	DIRECT	24,7%	6,0%	36,5%	1821	23,7%
Y-Ohlensehlen (-St.Huelfe - Wehrendorf) DUEMM S1	DE - DE	DIRECT	24,3%	9,1%	44,0%	15	22,2%
Y-Gramme (-Courcelles - Tergnee) 380.31	BE - BE	DIRECT	22,9%	11,1%	34,8%	98	18,1%

Table 7 Top-10 network elements with highest average AMR

38. Today, no coordinated validation is applied by the Coordinated Capacity Calculator. Hence, the reported "CVA" values are zero in the final pre-solved flow-based domains. The local validation tools result in Individual Validation Reductions on each CNEC, when applied. Figure 8 shows, again per TSO, the average IVAs applied on its network elements. It is worth noting that a pilot project "DaVincy" is currently being developed by German, Dutch and Austrian TSOs. Given that this validation is not coordinated on a RCC-level, the validation reductions following from this sub-regional assessment are also reported as "individual".

39. With respect to the application of IVA, we also see relatively high values for Elia (both on internal as well as on cross-border elements). After further alignment with Elia, it appears that high IVAs were needed on the business days 9 January and 9 February 2022, where following issues with the local validation tool a fallback minRAM value (20%) needed to be applied manually. Since then, mitigation measures and an industrialized tool for local validation have been implemented and these high validation reductions are no longer witnessed. Excluding these two business days from the analyses lowers the average IVA on Elia's internal lines from 8,7% to 5,0% and from 12,3% to 8,4% on cross-border lines. Based on recent information from German TSOs during the Core CG meeting of 29 March 2022, the occurrence of CNEC entries with zero RAM during the Core parallel runs (see paragraph 16 to 17) can also be attributed to issues with the local validation tool, i.e. in this case the DaVincy local validation tool. According to their information, those issues should have been resolved in the updated version of beginning of March 2022.

40. Even if these errors now seem to have been rectified, these cases clearly illustrate the inherent weakness of local validation tools which are not subject to the scrutiny, peer-review and cross-validation by other TSOs, CCCs, NRAs and – in the end – market parties. The use of Coordinated Validation Tools, developed at CCR-level with a high level of transparency and peer-review, should instead be fostered. Furthermore, from a legal perspective, validation tools should in the first place be regarded as a sanity check and to provide an input to the local congestion management processes. The validation step shall not be used to reduce cross-zonal capacities in a systematic manner (see also article 20, paragraphs 13 to 15 of the Core DA CCM methodology).

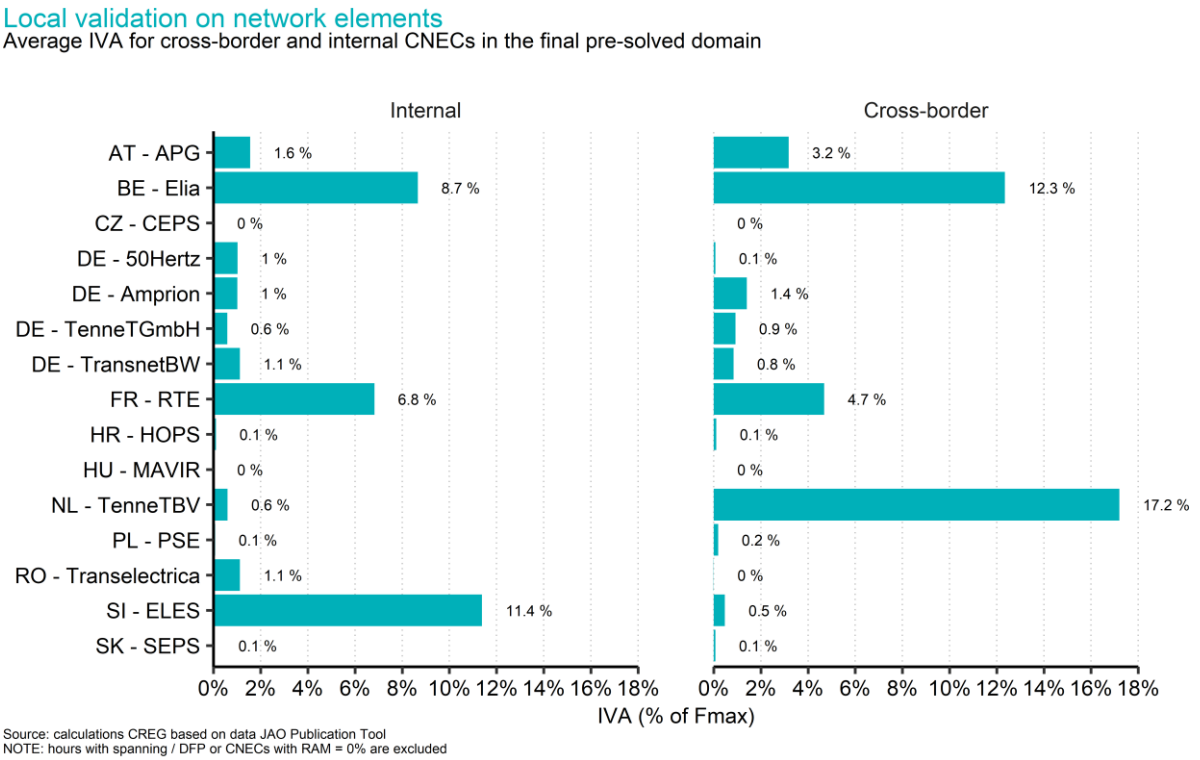

Figure 8 Local validation on network elements

3.2.1.2. Maximum import and export positions

41. One of the other output parameters of the capacity calculation process is the maximum export and import positions: within these bounds, exchanges may take place to import and export electricity to and from the Belgian bidding zone. Figure 9 shows, in blue, the real results (taken from the CWE FBMC) and, in red, the results from the Core external parallel run. The lines show the weekly average values, the coloured ranges show the weekly maximum and minimum values.

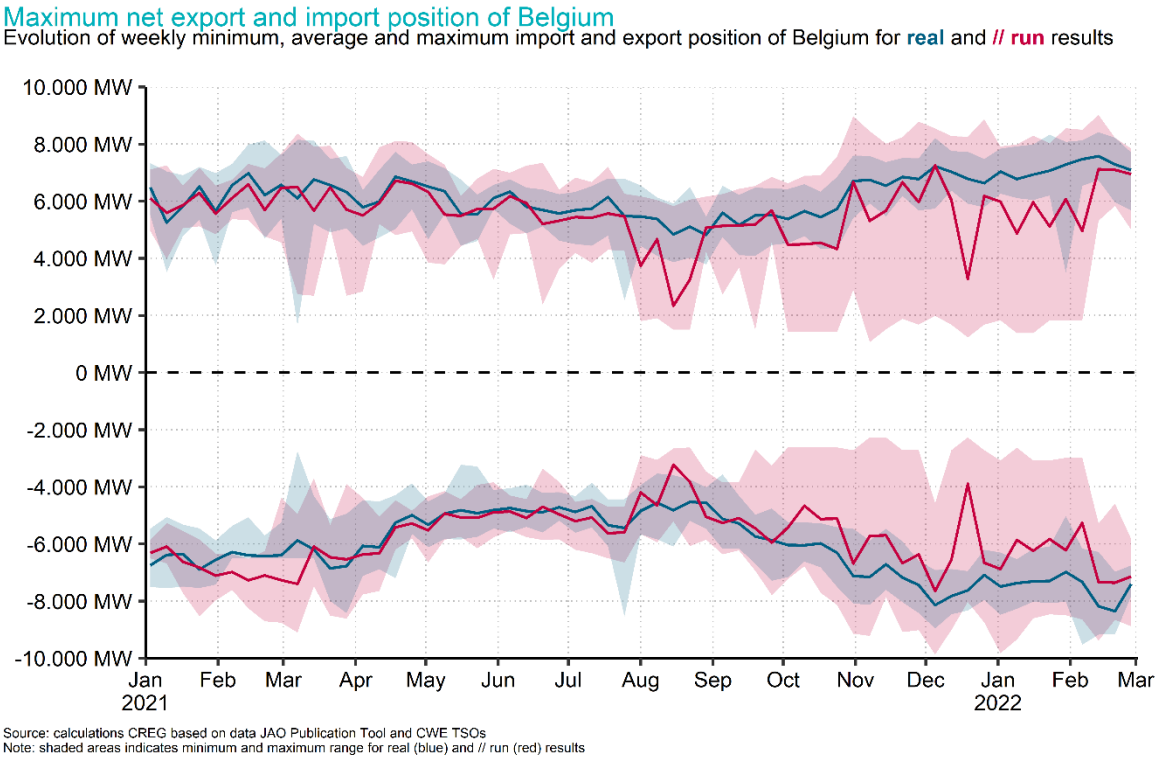

Figure 9 Maximum net export and import position of Belgium

42. From this figure, it can be observed that, the average external parallel run results (red line) are often, in absolute terms, (slightly) below the real maximum positions (blue line). What is more, the volatility in the external parallel runs is higher. This means that the possible values for the maximum import and export position of Belgium reach a wider range, allowing higher import and export or lower import and export, depending on the market circumstances. On average during the considered period, the maximum export and import values resulting from the parallel runs ranged between 1.800 MW to 5.603 MW and between 2.100 and 5.818 MW respectively, while the real observed values in the CWE FBMC showed maximum export and import values ranging from 4.000 MW to 5.965 and from 4.000 to 5.745 MW. The big difference lies, therefore, that the maximum net export and import positions in the Core external parallel runs may reach significantly lower values than the ones observed in the CWE FBMC, indicating a strong deterioration of the reliability of available cross-zonal exchanges. Figure 9 shows notably a big difference in the month of August, when a significant share of the calculated hours resulted from the application of default flow-based parameters (see also Figure 1). This is notably linked to the high proportion of the DFP or of MTUs with zero RAM entries observed during the period between October 2021 and February 2022. These values are not filtered from these results.

3.2.2. Market coupling

43. The main output parameters of the market coupling process are, per bidding zone, the resulting net positions and prices. It is possible to derive, from the individual prices, the price convergence rates between bidding zones. The average prices and net positions between 1 January 2021 and 28 February 2022 are shown in Table 8 and Table 9. The delta between the prices and net positions of the external parallel run and reality are shown for the parallel run, not including the timestamps during which default flow-based parameters or spanning were applied.

44. From the resulting prices, it is clear that the average price level increases in a few countries (Austria, Hungary and Slovakia) while in most countries, they decrease. In Belgium, the price decrease reached 2,1 €/MWh on average during the observed period (1 January 2021 to 28 February 2022). The corresponding average net position increased from -8 MW (import) to +100 MW (export).

PRICE *(€ / MWh)*	(a) **// runs** (all timestamps)	**(b) // runs** (timestamps without DFP / spanning)	(c) **Reality** (timestamps without DFP / spanning)	**Δ** (b) – (c)
AT	108,3	109,1	108,3	0,8
BE	102,0	103,7	106,6	-2,9
CZ	99,5	99,4	101,3	-1,9
DE_LU	93,9	93,8	96,9	-3,1
FR	109,5	110,3	111,2	-1,0
HR	118,4	115,8	116,9	-1,1
HU	120,9	118,4	116,3	2,1
NL	101,1	101,2	105,0	-3,8
PL	86,1	86,4	86,3	0,1
RO	119,2	117,1		
SI	115,4	114,3	116,9	-2,5
SK	113,6	114,0	104,0	10,0

Table 8 Prices resulting from external parallel run and reality

NET POSITION *(MW)*	(a) **// runs** (all timestamps)	**(b) // runs** (timestamps without DFP / spanning)	(c) **Reality** (timestamps without DFP / spanning)	**Δ** (b) – (c)
AT	-1.806	-1.948	-2.162	214
BE	98	100	-8	108
CZ	915	937	1.110	-173
DE-LU	1.487	1.565	1.512	54
FR	1.530	1.298	1.320	-22
HR	309	328	368	-40
HU	-1.490	-1.487	-1.420	-67
NL	-686	-597	-504	-93
PL	-7	-2	71	-73
RO	-38	-41	-89	48
SI	-240	-260	-258	-1
SK	53	43	27	15

Table 9 Net positions resulting from external parallel run and reality

45. The highest and lowest observed prices per bidding zone are listed in Table 10. For Belgium, the very low negative prices in the external parallel run (first column) reaching -150,1 €/MWh are remarkable, yet these have been observed during timestamps where default flow-based parameters were applied. This implies that the activation of DFP's restricted the export of excess electricity in the Belgian system. Still, even without taking into account timestamps with DFP / spanning, very low negative prices (up to -75,3 €/MWh) were observed. On the other side, the maximum prices remained the same irrespective of whether all timestamps were considered, suggesting that these peaks were reached during hours where no DFP/spanning were applied. For Belgium, the highest observed prices under the external parallel run was significantly higher than the one observed in reality (470,6 €/MWh versus 442,9 €/MWh).

(€/MWh)	**// runs** (all timestamps)			**// runs** (timestamps without DFP / spanning)			**Reality**		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
AT	-63.0	108.3	418.5	-38.5	109.1	418.5	-66.2	108.3	428.6
BE	-150.1	102.0	470.6	-75.3	103.7	470.6	-66.2	106.6	442.9
CZ	-27.1	99.5	418.5	-27.1	99.4	418.5	-36.3	101.3	428.6
DE_LU	-69.9	93.9	450.0	-69.9	93.8	450.0	-69.0	96.9	442.9
FR	-63.7	109.5	750.0	-63.7	110.3	750.0	-66.2	111.2	427.0
HR	-19.9	118.4	496.2	-19.9	115.8	496.2	-66.2	116.9	428.6
HU	-18.0	120.9	544.4	-18.0	118.4	544.4	-35.0	116.3	428.6
NL	-71.2	101.1	469.9	-71.2	101.2	469.9	-66.2	105.0	442.9
PL	0.0	86.1	466.0	0.0	86.4	466.0	14.9	86.3	400.0
RO[15]	-10.1	119.2	458.8	-10.1	117.1	458.8			
SI	-24.8	115.4	418.5	-24.8	114.3	418.5	-66.2	116.9	428.6
SK	-18.0	113.6	426.9	-18.0	114.0	426.9	-36.3	104.0	428.6

Table 10 Minimum, average and maximum prices

46. It is not intuitively clear how bidding zones which increase their net export position (like Belgium), hence exporting more, also show lower prices under the Core parallel runs. A possible explanation could be the increased occurrence of so-called non-intuitive flows, i.e. flows going from high-priced to low-priced areas. These non-intuitive flows can result from the market coupling algorithm if generally, they contribute to an increased social welfare, for example by freeing up capacity on other borders with higher price differentials, or to allow for exchanges to other, even higher-priced zones. It might be that non-intuitive flows have a disproportionately high impact on the average results.

47. This assumption is checked in Figure 10: the difference between the prices and net positions observed under the parallel runs are plotted (prices vertically, net positions horizontally). Intuitively, no hours should be observed in the upper left or lower right quadrant (because an increase in net export would imply an increase in price, and vice versa). Generally, this trend Is confirmed. Nevertheless, a relatively limited number of hours (in the lower right quadrant) shows a high shift towards more net export in the Belgian zone under the parallel runs than in reality, combined with a significant decrease in the resulting prices. Without these observations, the positive relation between the price increases and the net position shift under the parallel runs would be much stricter. It is not clear what may explain these hours: in any case it is not the application of spanning / DFP as these are filtered out of the datasets. Possibly the MTUs with high shares of RAM = 0% could have an impact.

[15] Prices observed in reality for Romania could not be included as these are not published on the Entso-E Transparency Platform in € / MWh. Same remark applies to Table 9.

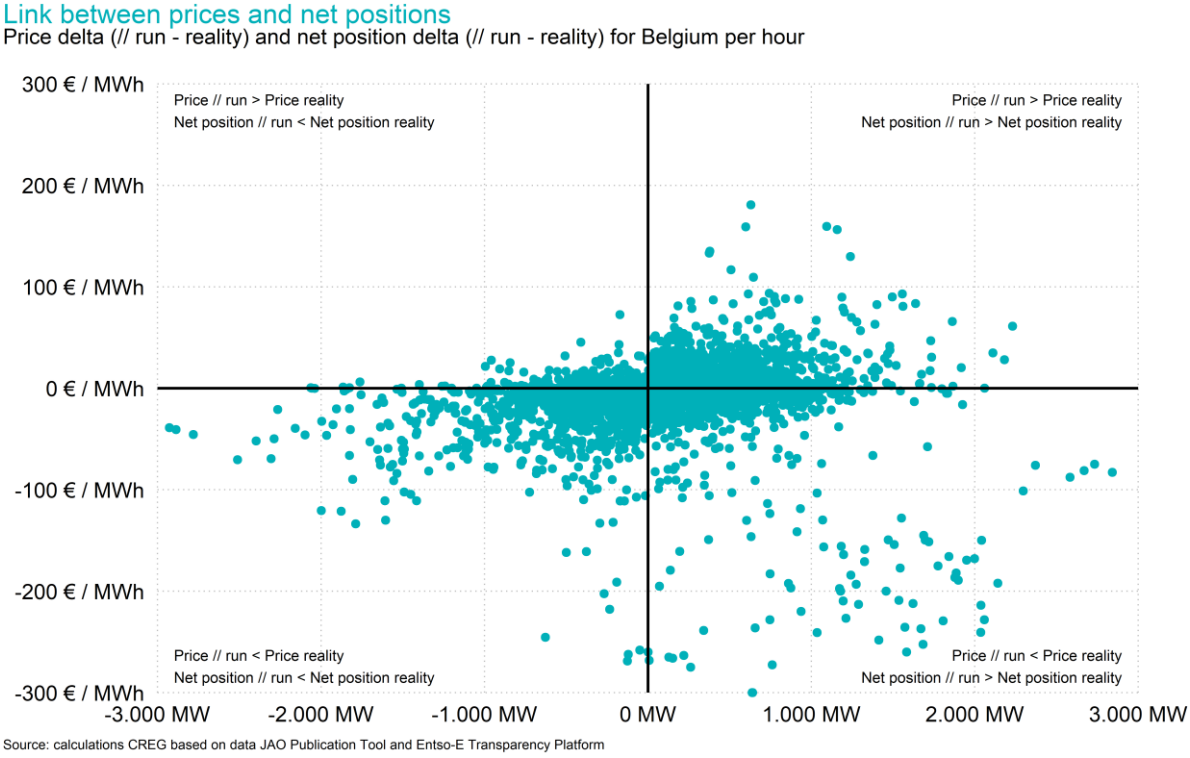

Figure 10 Link between prices and net positions

48. Figure 11 focuses on the Belgian bidding zone's net position. The red lines and areas show, respectively, the average and extreme net positions per week resulting from the external parallel run, while the blue show the values observed in reality. Both timeseries align closely, as is also reflected in Table 9: the impact of the Core DA FB MC on Belgium's net position was +108 MW (going from net import to net export). The weekly highest and lowest observed values are also remarkably aligned and follow the same up- and downwards patterns.

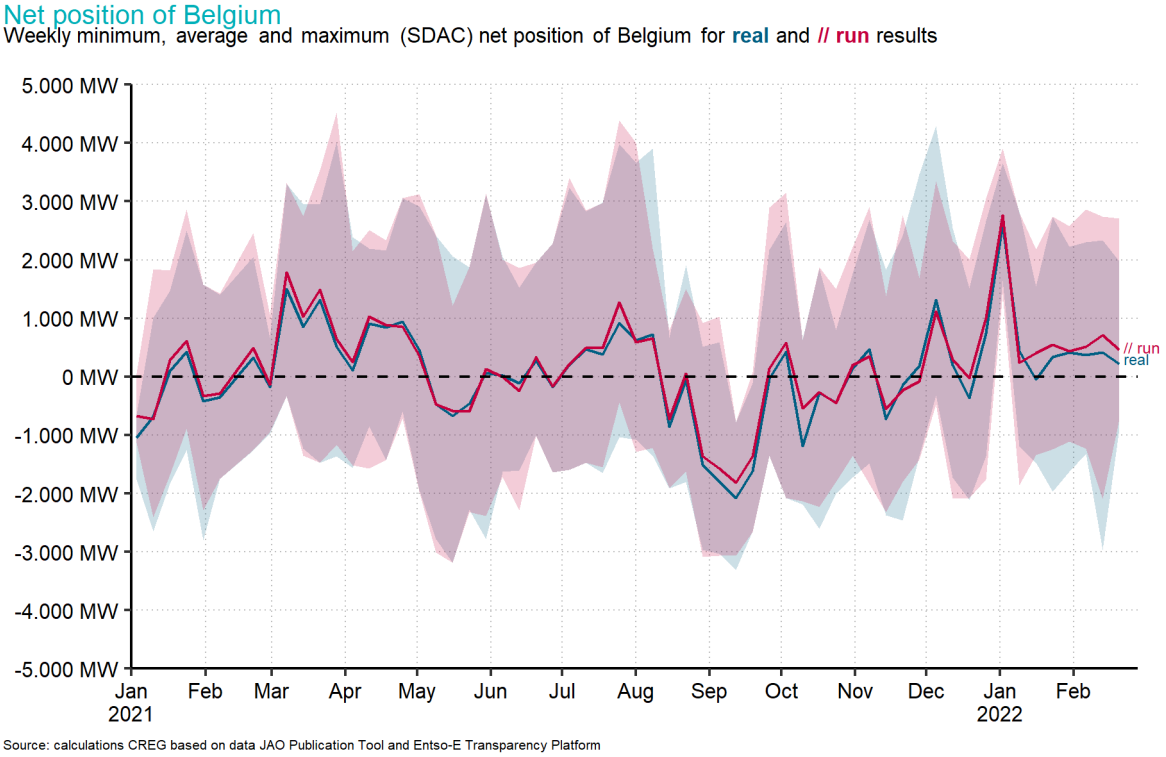

Figure 11 Net position of Belgium

49. From the prices per bidding zones, it is possible to derive the price convergence rate. When the transmission capacity is sufficient to allow for import and export between bidding zones, up until the point where price levels are the same between these zones, price convergence is achieved. The convergence rate (i.e. the number of hours in a given period with price convergence divided by all hours) is shown in Figure 12, for all Core bidding zone borders. It is clear that full price convergence between all Core bidding zones, while relatively low (usually not above 20%), still increases under the Core DA FB MC parallel runs. While the global convergence rate between all Core bidding zone was only 4,0% in reality, this increased to 21,5% of all hours (without DFP/spanning) of the parallel runs. Including timestamps with DFP/spanning, this convergence rate reached 15,6%.

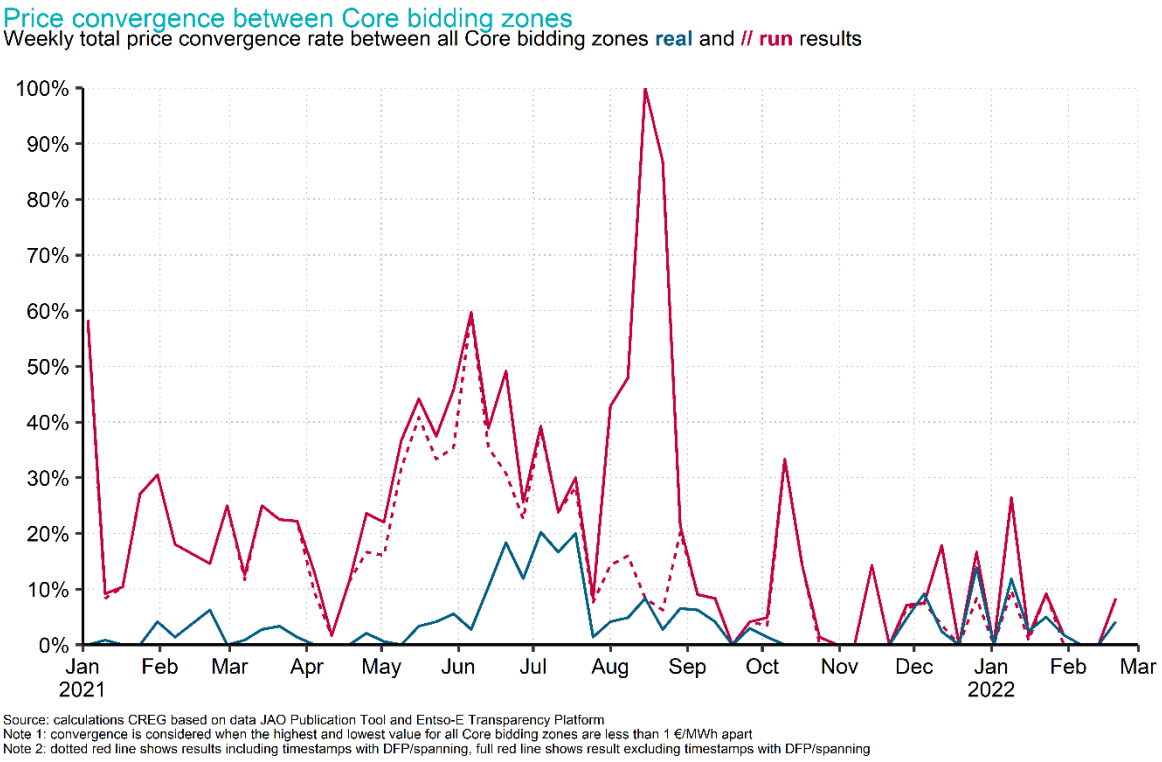

Figure 12 Price convergence between Core bidding zones

50. As the counterfactual (i.e. the reality) is a mix of flow-based and cNTC market couplings, it makes more sense to look at the subset of CWE bidding zones which are already coupled in the CWE FBMC. This is done in Figure 13. Focusing on these bidding zones (Belgium, France, the Netherlands, Germany/Luxembourg and Austria), the price convergence actually decreases in the external parallel run. While the global convergence rate in the observed period was 47,1% in reality, this dropped to 38,1% of the hours in the external parallel run excluding DFP/spanning. Including timestamps with DFP/spanning, the convergence rate drops further to only 34,2% of all hours.

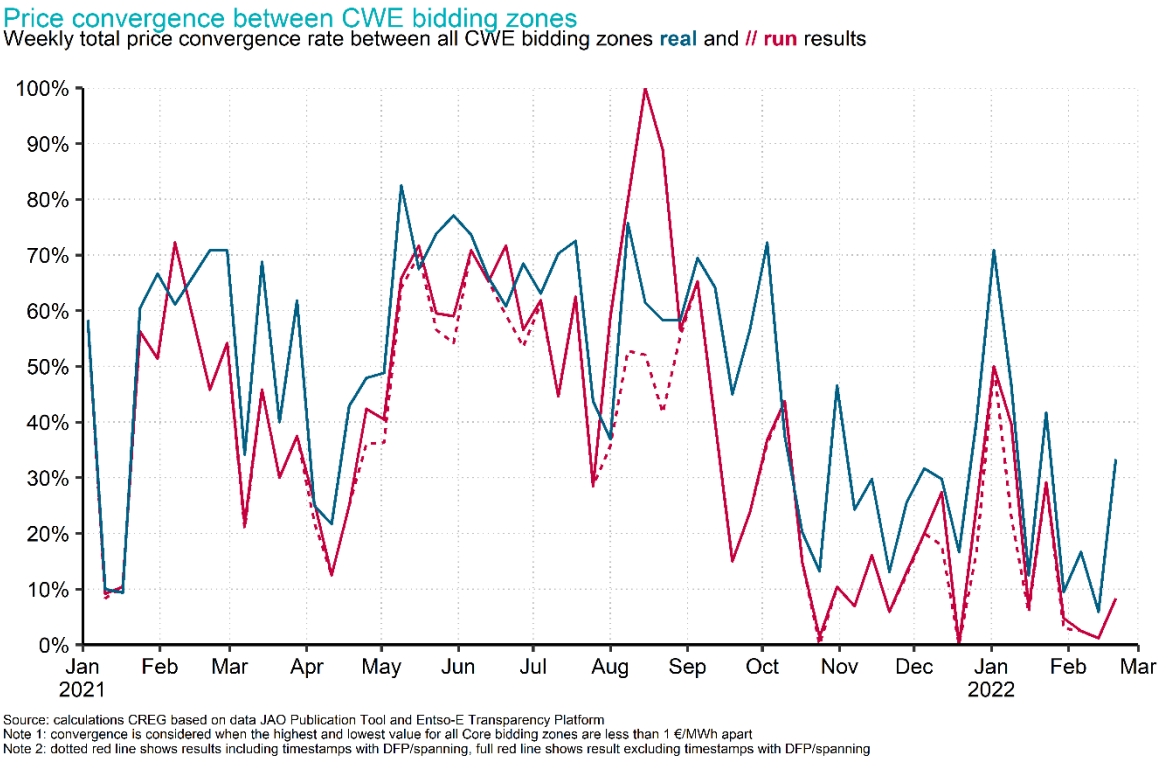

Figure 13 Price convergence between CWE bidding zones

4. CONCLUSION

The CREG analyzed and presented, in this note, the results of the Core DA FB MC Project's external parallel run. The aim of these analyses is to assess the performance of the capacity calculation and allocation processes which will be implemented in the coming weeks by the Core TSOs and Core NEMOs.

Some of the main observations of the CREG are listed below:

- The quality of the data, linked to IT- and organizational issues. The very high impact of so-called "local validation tools" leads to an extensive use of the Individual Validation Adjustments. This is particularly problematic given (a) the large impact on the market outcome, combined with (b) the lack of transparency on the application of these tools and (c) the absence of scrutiny on the underlying methodologies. The CREG calls for an increased effort in the development and implementation of coordinated validation processes and tools.
- Related to the capacity calculation, only 20% of the observed CNECs in the considered 5-month period (from 1 October 2021 to 28 February 2022) show meaningful, interpretable results. This is caused by about 17% of the MTUs where issues in the local validation appeared (see previous point).
- Very large differences may be observed in the application of the Core capacity calculation methodology, as may be observed from the average flow-based parameters per Core TSO. These differences manifest themselves particularly strongly in terms of the reference flows $F_{0,Core}$ and the RAM values. The use of the AMR is to be monitored ever more closely, given that it is symptomatic for the base cases not sufficiently addressing reference flows. This has a potentially very important impact on the extracted intraday ATC values in the very short term.
- Related to market coupling, no unambiguous picture of the impact of the new procedures on the prices and net positions can be presented. Given the disclaimer related to the large share of MTUs with fallback parameters or zero RAM CNEC entries, only the long-term domains are allocated during these hours.
- However, considering all hours, irrespective of the application of fallback procedures, the following observations are made. Convergence between all Core bidding zones increases significantly, yet decreases (to a lesser extent) in the CWE region. The maximum import and export capacities become more volatile, yet on average they remain within the same ranges. The important decrease of the lower bounds of these maximum import and export positions is of particular relevance – while this may be linked to fallback / zero RAM entries, the impact should not be ignored.
- Somewhat counterintuitively, several bidding zones (including Belgium) observe a decrease in the average price level in combination with an increase in the net export position. The reason for this non-intuitive result was not yet further investigated in the framework of this study.

The CREG calls upon all the Project Parties (Core TSOs and NEMOs) to:

- closely assess these results and perform similar analyses in order to identify other issues, their underlying root causes, and room for improvement;
- investigate to which extent fixes for the root causes for the observed issues in this note can be implemented on short notice, ideally prior to the go-live of the Core DA FB MC Project;
- increase their efforts to improve the stability of the external parallel runs, but more importantly, implement the necessary mitigation measures to avoid that the observed issues are repeated after the go-live; and
- improve the transparency and invest all necessary resources in order to publish, without delays, the most complete, reliable and accessible datasets through the existing communication channels.

For the Commission for Electricity and Gas Regulation:

Andreas TIREZ
Director

Koen LOCQUET
Acting President of the Board of Directors

LIST OF FIGURES

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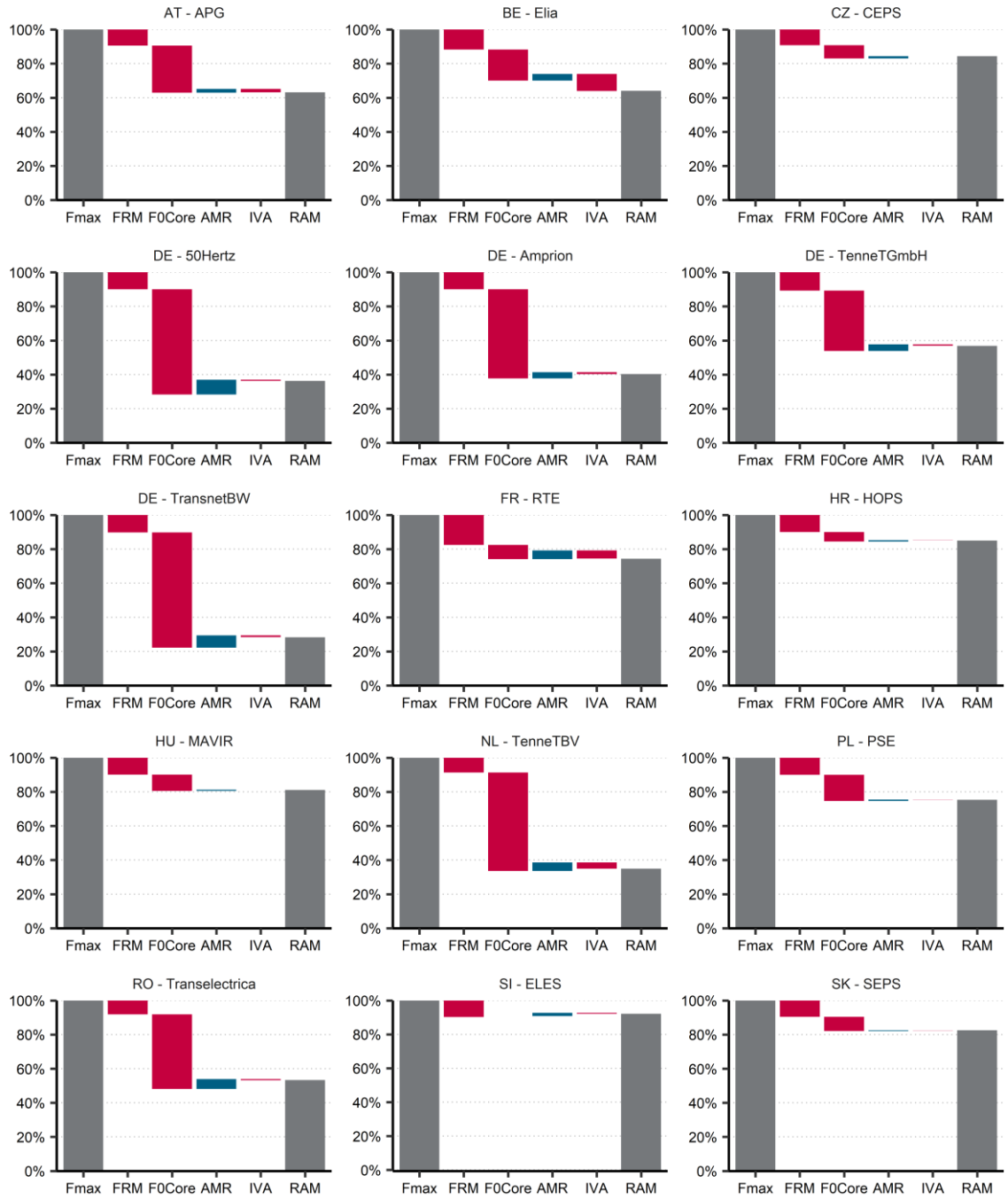
ANNEXES

Breakdown of Fmax and RAM values

Average Fmax, FRM, F0Core, AMR, IVA and RAM per TSO for all CNECs in the pre-solved final domain



Source: calculations CREG based on data JAO Publication Tool

Note 1: blue values (AMR) increase the RAM, red values (FRM, F0Core, IVA) decrease the RAM
Note 2: dataset only includes MTUs without spanning / DFP and CNECs with RAM not equal to 0

Figure 14 Breakdown of Fmax and RAM values