The Impact of Cross-Border Transmission Constraints on Resource Adequacy Assessment

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***Abstract*—Most European adequacy assessments consider transmission constraints through fixed caps on power exchanges per border. This method fails to portray the flexibility introduced by modern market design, leading to incorrect final results. This paper investigates different cross-border capacity representations and proposes a way to model transmission constraints using the flow-based approach while accounting for the market's adequacy relevant rules. Using the latest update of the IEEE Reliability Test System, a case study shows that the representation of the cross-border transmission constraints plays a primary role in resource adequacy, and representing them through detailed models is needed.**

***Index Terms*—resource adequacy, flow-based market coupling, power markets, power system reliability**

I. Introduction

Although there has been significant progress in performing European resource adequacy assessments, the impact of the flow-based approach to capacity calculation on the resulting indicators has never been thoroughly investigated. Since methodologies evolved from classical *generation adequacy* assessments [1], their focus is more on generation modeling without considering detailed transmission constraints. Some of these studies are used to justify costly capacity mechanisms, encouraging the further deployment of units into a market that often has negative prices and very few price spikes[1][3].

The Clean Energy Package created a need for robust flow-based (FB) methods that are currently lacking. Studies performed by ENTSO-E[2], and most national studies, consider a market coupling based on Net Transfer Capacity (NTC) values. Although some recent regional and national studies use geometric clustering of flow-based domains [4], this approach can't guarantee traceable transmission constraints (Section: II-A). There have also been recent developments in market design that need to be investigated. In preparation for the CWE[3] FB coupling go-live, an impact assessment concluded that small bidding zones (BZ) could have a higher scarcity risk because of flow factor competition [5]. Consequently, the stakeholders updated the coupling algorithm with special rules concerning curtailment (Section: II-C). The recast electricity regulation introduced a mandated minimum margin available for cross-zonal trade on any branch. As an effect of this, cross-zonal capacities are expected to significantly increase, resulting in stronger dependence on neighboring zones for the security of supply while facilitating renewable generation integration. (Section: II-D).

No publicly available assessment takes into account the impact of the listed updates. Furthermore, as the curtailment rules treat scarcity effectively outside of the welfare maximization framework, local curtailment is conditional on active transmission constraints— underlining the possibility to diminish scarcity risk by more robust interconnections instead of generation investment.

This paper's main idea is to show that transmission constraints play a fundamental role, and accurately representing them is required. We propose a methodology to assess European resource adequacy that considers transmission infrastructure, then study the model's behavior on a test system. The resulting adequacy indicators are evaluated comparatively with NTC-based models. The main contributions are:

- We show that NTC-based approaches overestimate the frequency and magnitude of curtailment events (Section: V).
- We compose the flow-based domain considering a static grid, with n-1 branch contingencies, taking into account the legally guaranteed minimum margins for trade (Section: III-B). The NTC values are calculated using the resulting FB domain (Section: III-C).
- We propose a quadratic program that imitates the curtailment sharing and minimization rules of the market coupling (Section: III-A).
- We show that the rules of the day-ahead market with the flow-based approach to the capacity calculation facilitate the spread of scarcity over bidding zone borders but decrease the overall risk by pooling resources, emphasizing the need for regional studies (Section: V).

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[1]Can be symptoms of overcapacity. Still, flexibility plays a role [2].
[2]European Network of Transmission System Operators for Electricity
[3]Central Western European

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II. Background

A. Adequacy assessment in Europe

Assessing the adequacy of large interconnected power systems is not an easy task. There is not only the apparent computational challenge stemming from the study's extent, but one also needs to consider the different operational and legislative practices of the studied area.

Currently the prime study on the subject is the yearly publication called Mid-Term Adequacy Forecast (MAF). The latest MAF [6] uses a common data-set covering all of Europe, historical climate data spanning decades, and a combination of five software tools (ANTARES[4], BID3[5], GRARE[6], PLEXOS[7], POWRSYM[8]) to calculate the adequacy indicators of all bidding zones of the European electricity market.

Adequacy assessments were also in the scope for a recent research project, prepared for the European Commission [7]. The software package developed to simulate EU energy markets is used by the commission and some member states' governments to aid policymaking.

Both studies currently use NTC values to model the transmission infrastructure; however, they point to the flow-based approach as a clear direction for improvement.

The adequacy assessment of Belgium [8] and the Penta Lateral Energy Forum's regional study [9] are the first ones to consider flow-based constraints. Their methodology relies partially on historical data and geometric clustering of the flow-based domains [4]. While this method looks promising, it can not guarantee traceable transmission constraints, making it difficult to propose alternates to generation expansion.

Accounting for the growing reliance on renewable energy sources poses its challenges [10]. Adequacy assessments that use conservative cross-border limits can underestimate these resources' potential to serve demand in times of scarcity.

The recast Electricity Regulation [11], mandates among the rules on the methodology for future resource adequacy assessments that they need to be based on a FB market model if applicable. It also specifies that the assessment scope for national studies should be at least regional.

B. Markets considered

The flow-based approach is the target capacity calculation method for the day-ahead and intraday markets over most of Europe [12]. We propose a study using a market model broadly similar to the single day-ahead market. Cross zonal capacity is allocated implicitly to energy exchanges. The objective function considers the adequacy-related rules of the market while aiming to increase overall welfare. A single-stage optimization calculates the dispatch of all units and the required curtailment in all zones. Adequacy indicators are calculated based on the obtained curtailment values. We do not consider the impact of forward capacity allocation or the intraday markets. Reserve provisions are not considered.

C. Curtailment rules

In a market coupled through NTC values, any price difference saturates the transfer capacity. This is not the case for the FB approach, where the exchanges among the zones are co-optimized; importing more requires higher and higher price differences. Due to price caps, the required price difference to achieve maximum simultaneous imports can be challenging to reach. Because of flow factor competition, this mainly affects smaller bidding zones competing with larger ones for capacity [5][13]. Since this phenomenon can increase the scarcity risk, special rules were introduced for curtailment in the day-ahead market [14][15].

Curtailment in a bidding zone occurs when the price cap is reached, but the submitted quantity at these extreme prices is not entirely accepted. Buy orders, offered at the maximum permitted price, are called *price taking demand orders (PTDOs)*. *Curtailment of PTDOs* is studied in this paper, as this is an often-used proxy[9] for loss-of-load events. We find it essential to model the rules governing it for adequacy studies:

a) Curtailment Minimization: The welfare maximization objective is only secondary to minimizing the rejection of PTDOs. This rule guarantees that curtailment is avoided or minimized independently of the welfare loss of other participants.

b) Curtailment Sharing: Suppose curtailment can not be avoided entirely, and more than one BZ is affected. In that case, the goal is to equalize the ratio of accepted price taking orders among curtailed zones, ensuring a fair split. This rule eliminates the volume indeterminacy on the exchanges between two bidding zones facing simultaneous curtailment coupled through NTCs.

c) Local matching: A zone can choose not to export if it needs the generation to serve PTDOs in the same BZ. In the presented case study, we consider that all zones are cooperating.

D. Minimum margin available for cross-zonal trade

Since loop flows and other non-market flows contribute to internal congestions, capacity is reserved for them during the capacity calculation, as they enjoy "priority access" compared to market-induced flows. To counter the effects of this, Transmission System Operators (TSOs) were mandated to offer at least 70% margin for cross-zonal trade on any line, considering contingencies, by 2024.[11]

If only a single capacity allocation step using the flow-based approach is modeled, this translates to a 70% minimum Remaining Available Margin (RAM) requirement. Minimum RAM requirements mandate a lower bound value for RAM as a percentage of the maximum theoretical flow (F^{max}) on any Critical Network Element - Contingency (CNEC). They detach the capacity calculation from the physics of the grid.

[4]RTE International, https://antares-simulator.org/

[5]ÅF PÖYRY, https://www.poyry.com/BID3

[6]CESI, https://www.cesi.it/news_ideas/ideas/Pages/System-Adequacy-and-Market-Modelling.aspx

[7]Energy Exemplar, https://energyexemplar.com/solutions/plexos/

[8]Operation Simulation Associates, http://www.powrsym.com/index.htm

[9]There are several out-of-market measures the system operator can take ex-post to avoid actual loss of load.

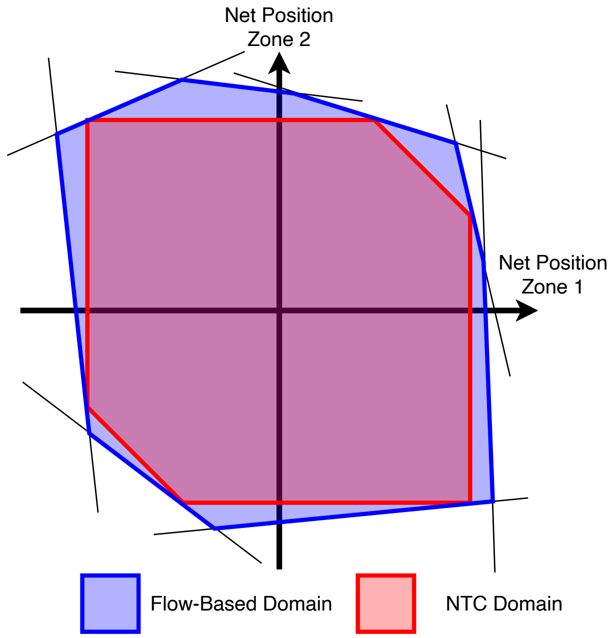

Fig. 1. Illustration of the Flow-Based and NTC domains.

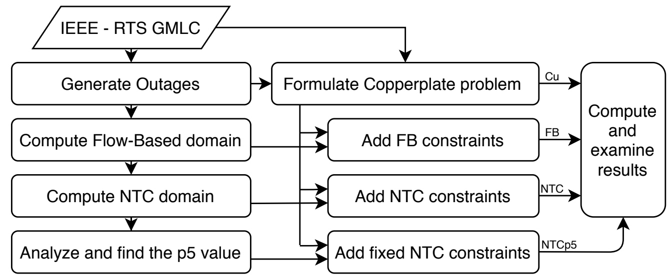

Fig. 2. Overview of the simulation framework

As a rule, they were first implemented in the CWE region (at 20% of F^{max}) to increase the tradable domain. The 70% value is drastically higher than this, and ENTSO-E advocated against it [16]. If the allocated capacities are not available in the physical grid, operators need to rely on remedial actions[10] for shipping.

For NTC based capacity calculation, ACER[11] recommends [17] monitoring using the positive zone-to-zone Power Transfer Distribution Factors (PTDFs) [12].

E. Capacity calculation

The cross-zonal capacity (CZC) calculation is the daily process of estimating the domain available for cross-zonal trade. There are two fundamentally different approaches (Figure 1).

1) Net transfer capacities: The classical approach to CZC calculation is to establish a cap on the maximum energy that can be exchanged on an oriented border for a given market time unit. This value offers a transparent and straightforward way for market participants to anticipate grid congestion. However, it requires the system operators to make decisions ex-ante on where to make the capacity available. Ideally, this process of calculation is coordinated among the TSOs of the capacity calculation region [3].

2) Flow Based approach: Cross zonal flows are interlinked through the grid's physics; these interactions can not be well translated into independent transfer capacities per border. When using net transfer capacity (NTC) based approaches, one has to consider the worst possible combination of flows, resulting in a reduced capacity being given to the market.

The solution proposed as early as 2001 is not to have independent transfer capacities rather a model of how different exchanges interact [18]. The idea was further refined and resulted in an implementation using implicit auctions, where energy and capacity are sold during the same process. It was first operational in the Central Western European (CWE) region for day-ahead auctions. Shortly after, the Capacity Allocation and Congestion Management (CACM) guideline set the flow-based approach as a target model for most continental Europe.

Europe's zonal market design relies on a single price per zone and a merit order to dispatch generators. This design enables the algorithm to represent a zone's contribution to the whole system by a single variable: by grouping a set of nodes into a zone, we can replace all the individual injections using their share of the zone's net position. This method reduces the number of columns in the PTDF matrix and the optimization problem's dimensionality. Generation Shift Keys (GSKs) are defined by the TSO, representing the degree a single node contributes to the zone's net position. The resulting zone-to-hub PTDF matrix is directly used for the constraints of the coupling.[19] [20].

III. Simulation Framework

A framework was developed to analyze the impact of transmission constraint representation on the system's adequacy (Figure 2). The framework simulates multiple cases with the same inputs but using different models for transmission constraints. In all other aspects, the simulations are identical. This framework guarantees that any difference in the resulting adequacy indicators is solely the result of the different capacity calculation methods.

The simulations consist of a generation dispatch model running inside a Monte-Carlo framework. First, stochastic outage scenarios are generated for all generators and branches. These outages are coupled with a year-long time series of unit-level renewable generation and nodal demand profiles. For each timestep, the flow-based domain is computed based on which the NTC values are derived. The market outcome is simulated first without transmission constraints (Copperplate assumption). In the later stage, the simulation is repeated for each case based on the same model but with the corresponding

[10] This can be costly, as most non-costly remedial actions are already used during the capacity calculation.
[11] European Union Agency for the Cooperation of Energy Regulators
[12] The reverse of the calculation done in section III-C

transmission constraints added to it. Finally, the adequacy indicators are calculated and examined.

A. Market Coupling Problem

The market coupling is formulated as a quadratic program. For each timestep of the simulation, the objective is to minimize a two-part cost. The first part represents the generation cost (summarized in Table II). Demand is considered inelastic and offered at the maximum price. The second term accounts for the curtailment minimization and sharing behavior of the market coupling; this is achieved by adding a penalty to the objective function in the form of:

$$\sum_{z \in \mathcal{Z}} M \cdot D_z \cdot \mathrm{Cur}_z^2 \tag{1}$$

D_z is the total, and Cur_z is the ratio of curtailed demand in zone z. M is a large number used as a penalty factor. Since the curtailment ratio's square is used, the algorithm will aim to equalize this among the zones. The area balance for each zone can be written as (P_g is the active power output of generator g, NP_z is the Net Position of the zone):

$$\sum_{g \in z} P_g - D_z \cdot (1 - \mathrm{Cur}_z) - \mathrm{NP}_z = 0 \qquad \forall z \in \mathcal{Z} \tag{2}$$

B. Flow-based capacity calculation

1) Generation Shift Key methodology: As some units are assumed to have zero marginal cost, they don't respond to changes in the net position. Let us consider the subset of generation units t that have non-zero marginal cost.

A simple GSK methodology is to assume that each unit t participates proportionally to their installed capacity P_t^{max}. For each node n in zone z we can compute:

$$\mathrm{GSK}_{n,z} = \frac{\sum_{t \in n} P_{t,n}^{max}}{\sum_{t \in z} P_{t,z}^{max}} \qquad \forall n \in z \ \& \ \forall z \in \mathcal{Z} \tag{3}$$

The impact of various GSK methodologies on market outcomes is studied in [21].

2) Power Transfer Distribution Factors: For each updated set of available units or branches, the node to slack PTDFs and the Line Outage Distribution Factors (LODFs) are calculated.

To determine the zone to hub PTDF values used in the constraints of the algorithm we need to consider two distinct cases:

a) For CNECs that have no contingencies: the values can be computed by translating the node-to-hub PTDFs to the zone-to-hub equivalent using the GSKs from section (III-B1).

b) For CNECs that have a contingency: the values can be computed using the $LODF$ values of the contingent element and the zone-to-hub PTDFs of the CNE calculated in the previous section III-B2a.

If the flow on a given CNEC is not influenced by at least 5% of the exchanged power for any bilateral exchange the CNEC is dropped at this stage and not considered for any of the following steps.

3) Remaining Available Margin: To calculate the Remaining Available Margin (RAM) on a branch (l), we propose to rely on the lower bound values provided by the recast electricity regulation. Since no base case simulation is needed the computational speed greatly increases.

$$\mathrm{RAM}_l = 70\% \cdot F_l^{max} \tag{4}$$

4) Flow based simulation: The formulation from section III-A is enriched with new affine constraints representing the transmission grid's limitations. For each CNEC, constraints are created, for both directions of monitoring.

C. NTC based capacity calculation

To define the NTC domain, we need to assess the worst-case impact of the resulting flows on the CNECs. To achieve this, we can use the positive zone-to-zone PTDFs for each oriented BZ border and CNEC, similar to the fallback procedure used in [22].

IV. Case Study

The simulation is based on the latest update of the IEEE Reliability Test System [23]. This data-set contains cost assumptions and time-series data for load and generation for a model that resembles a modern power system. The original three areas are considered separate bidding zones. The DC line is taken out to constrain the domain and simplify the formulations. All inter-zonal lines are duplicated, but their capacity was halved, and their inductance doubled. No generation reserve requirements are considered, but the load was increased by 10%. Rooftop solar units are modeled as negative load. All other renewables are subject to curtailment but generate at no cost. No energy storage is examined, including hydro reservoirs. Hydropower plants, independently of their type, can produce up to their hourly infeed values.

A. Scenarios

To be able to isolate the effects of transmission constraints on the outcome, the following cases were considered:

- **Cu**: where no transmission constraints are taken into account (Copperplate assumption)
- **FB**: where the calculated Flow-Based constraints are directly fed into the model (Section III-B)
- **NTC**: where time-dependent NTC values are used to constrain the model (Section III-C)
- **NTCp5**: where based on the distribution in the NTC case, the 5th percentile values are fixed for all simulation timesteps.

V. Results and Discussion

The case study results were obtained from a simulation considering 200 Monte-Carlo years, nearly 1.8 million hourly timesteps for each case. We use a Julia[13] based framework and Gurobi[14] to solve each hourly optimization problem. Two key adequacy indicators are calculated for each bidding zone and the whole system:

[13] https://julialang.org/

[14] Gurobi Optimization, https://www.gurobi.com/products/gurobi-optimizer/

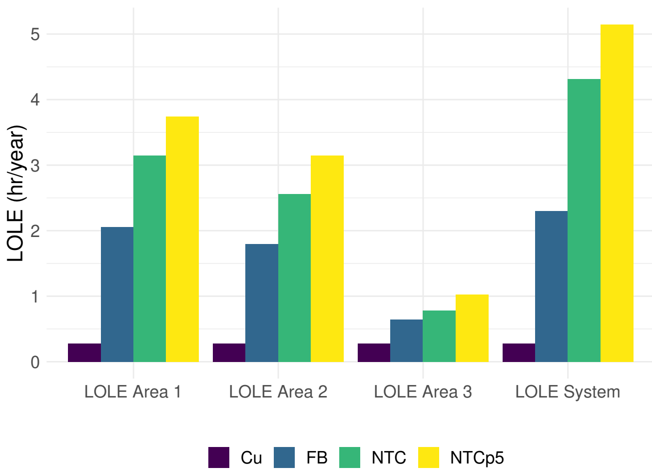

Fig. 3. Loss of Load Expectation in 3 areas and the total system

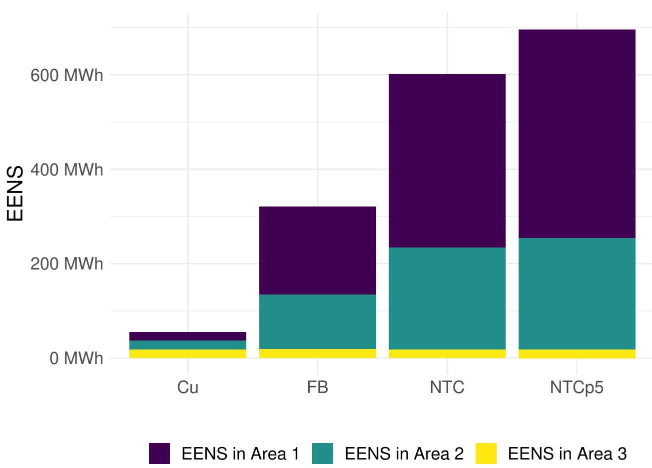

Fig. 4. Expected Energy not Served

a) Loss of Load Expectation - LOLE (hr/year): is the average number of hourly timesteps in a simulated year with curtailment in the zone/system (Figure 3).

b) Expected Energy Not Served EENS (MWh): is the mean Energy Not Served (ENS) over all the simulated years (Figure 4).

Both indicators show that simulations performed considering a flow-based approach to the capacity calculation resulted in improved outcomes on all levels compared to the results from NTC-based cases (Table I). The NTC-based methods overestimate the scarcity risk even if the values are calculated, in a coordinated way, taking into account the same margins for cross-zonal trade as with the FB scenario. The simulated curtailment events in the FB case are rarer and smaller in magnitude, which is well reflected in the expected costs[15] (Table II).

[15]To calculate curtailment costs, we assume a fixed value of the lost load at $10k/MWh.

TABLE I
GENERATION PER TYPE IN MWH/YEAR

Generation Type	Cu	FB	NTC	NTCp5
Area 1				
Fossil based	8 117 905	7 700 622	7 544 166	7 488 055
Nuclear	2 999 786	3 086 012	3 080 937	3 079 342
Renewables	4 177 186	4 236 269	4 231 887	4 230 518
Total	**15 294 878**	**15 022 903**	**14 856 990**	**14 797 916**
EENS	*19*	*186*	*367*	*442*
Area 2				
Fossil based	8 676 953	8 965 565	9 150 585	9 210 128
Renewables	2 628 559	2 724 538	2 724 625	2 724 625
Total	**11 305 512**	**11 690 103**	**11 875 210**	**11 934 753**
EENS	*19*	*116*	*217*	*236*
Area 3				
Fossil based	4 311 959	4 756 493	4 776 808	4 794 845
Renewables	8 361 326	7 803 910	7 764 120	7 745 520
Total	**12 673 285**	**12 560 403**	**12 540 928**	**12 540 365**
EENS	*17*	*18*	*18*	*18*

TABLE II
ANNUALIZED COSTS IN K$

	Type	Cu	FB	NTC	NTCp5
Area 1	Generation	164 359	155 049	151 848	150 687
	EENS	187	1 863	3 671	4 421
	Total	**164 546**	**156 912**	**155 520**	**155 108**
Area 2	Generation	180 065	184 647	188 589	189 850
	EENS	194	1 159	2 170	2 357
	Total	**180 258**	**185 806**	**190 759**	**192 207**
Area 3	Generation	87 716	101 046	101 606	102 148
	EENS	171	183	176	181
	Total	**87 888**	**101 229**	**101 782**	**102 329**
System	Generation	432 140	440 742	442 044	442 685
	EENS	552	3 205	6 016	6 959
	Total	**432 692**	**443 947**	**448 060**	**449 644**

We choose to examine the *NTCp5* case, as this somewhat represents the current practices. A fixed capacity value per border that is conservatively calculated has a large impact on the outcomes. Both the frequency and the magnitude of curtailment events are over-estimated for all areas and the system.

Even the case using time-dependent NTC values fails to capture the complex possible outcomes of curtailment sharing and minimization rules. A hard limit on the available capacity can not accurately portrait the edge cases. The maximum import capacities, guaranteed by the curtailment minimization rules, obtained with the FB approach, are more far-reaching than those permitted by the NTCs and are proven to help the affected area.

Market rules dictate that a more costly dispatch with reduced curtailment is preferred to one that minimizes costs. The simulated outcomes all consider this, and still, we see the smallest overall costs using the flow-based approach. The flow-based market coupling delivers better reliability for all and aids a more efficient operation of the system; these effects should be considered for adequacy assessments.

From the simulation results under a copperplate assumption, we can see that curtailment events are rare and small in magnitude when no transmission constraints are present. Studying the behavior of the pooled generation resources indicates the importance of transmission capabilities for system adequacy. It shows that transmission expansion can often remedy resource scarcity. On simulations performed with no trade allowed between zones (self-reliance), we saw extremely high LOLE indicators, reaching 80 hours per year on the system level (Area1: 51, Area 2: 40, Area 3: 12).

A. Limitations

While this case study shows that the approach to the capacity calculation method used for adequacy assessments has a significant impact on the outcome, there are important limitations to mention. The assumption in section III-B3 lets us calculate the flow-based domain without any power-flow simulations. In reality, some CNECs could have a higher margin available for cross-zonal trade than our assumption. The shape and size of the final flow-based domains are also significantly impacted by the CNEC selection, GSK methodology, and other sophisticated steps of the capacity calculation process that we only study partially. The enormous uncertainty space one has to consider to model a power system's future operation is significantly reduced for this study (Section: III).

VI. Conclusions

Resource adequacy in Europe is a complicated matter and often subject to much controversy. Choosing the right methodology to assess adequacy is an increasingly difficult task, where a balance is needed between computational speed and the expected accuracy of the results. While rules governing the market are clear on how scarcity is handled, they rely on detailed data on the transmission grid and generating units. This data is often not available even for stakeholders performing the studies.

An often-made shortcut to quicker results is to neglect these complex rules and rely on hard set caps on energy exchanges. We clearly show in this paper that this assumption not only distorts the results but, depending on the values chosen, can result in adequacy indicators that are wrong by orders of magnitude. As the current tools do not allow scarcity events to be traced back to the limiting grid components, transmission investment is rarely tested as an alternative to generation expansion when addressing long-term supply security. While perhaps this also has to do with the EU power system's segmented national governance, the approach shown here would allow this.

Flow-Based constraints are shown to allow for more spread of scarcity events beyond bidding zone borders. The expected magnitude of these events is considerably lower than what an NTC-based simulation might suggest. Since the scarcity is not easily contained within a zone, the need for regional approaches in studying and ensuring supply security is once again stressed.

On our path to decreased reliance on fossil-fueled plants, understanding our current system's limits is crucial. When performing adequacy assessment, amply considering the market and operational rules seems like the next major step to take us there.

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