Impact assessment of a minimum threshold on cross-zonal capacity in a flow-based market

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***Abstract*—The current organization of the internal electricity market in Europe relies on a zonal market system: the European power system is divided in bidding zones, electricity trades within a bidding zone can occur in an unconstrained manner, while electricity trades between bidding zones are limited by cross-zonal capacities. Two approaches can be used to calculate and allocate cross-zonal capacity: the coordinated Net Transmission Capacity (NTC) approach or the flow-based approach. In Central Western Europe, the flow-based approach is implemented for the day-ahead market since 2015. To avoid undue discrimination between internal and cross-border power exchanges, a minimum threshold of 70% on the cross-zonal capacity available for trade will be enforced in a near future. Such a threshold could significantly impact the socio-economic welfare and its distribution between the various actors. However, no assessment of the impacts of such a threshold has been performed so far, in particular because no convincing approach exists to perform such an assessment (e.g. N-1 security constraints and redispatch neglected). This paper develops such an approach and demonstrates its applicability on a case study, in order to assess the impact of a minimum threshold on cross-zonal capacity in a flow-based market.**

***Index Terms*—Flow-based market coupling, Zonal market, Capacity allocation, Congestion management, Redispatch, Optimal power flow**

Nomenclature

Indices

- n: nodes
- l: branch (line or transformer)
- g: generator
- c: index to the contingency state of the system; $c = 0$: base state without contingency; $c = c_{l'}$: state with outage of branch l'
- z: zone
- k: critical network element with a contingency (CNEC)

Variables

- θ_{nc}: voltage angle at node n in system state c
- P_g: active power supplied from generator g
- P_{lc}: power flow through transmission element l in system state c
- I_n: net power injection of node n
- NEP_z: net position of zone z

Parameters

- P_g^{min}/P_g^{max}: minimum/maximum active power generation of generator g
- F_l^{max}: thermal rating of transmission element l
- P_{nd}: active power load at node n
- C_g: cost of production of generator g
- B_l: electrical susceptance of transmission element l
- A_{nk}: incidence matrix
- $\mathbb{1}_{ng}$: binary indicator parameter, equal to 1 if generator g connected to node n, 0 otherwise
- $\mathbb{1}_{zn}$: binary indicator parameter, equal to 1 if node n belongs to zone z, 0 otherwise
- $\mathbb{1}_{zg}$: binary indicator parameter, equal to 1 if generator g belongs to zone z, 0 otherwise
- $\mathbb{1}_{lc}$: binary indicator parameter, equal to 0 if contingency of branch l in system state c, and 1 otherwise
- $PTDF^N_{nlc}$: nodal PTDF associated to node n and branch l in system state c
- $PTDF^Z_{zlc}$: zonal PTDF associated to node z and branch l in system state c
- $PTDF^Z_{zk}$: zonal PTDF associated to node z and CNEC k

I. Introduction

The current organization of the internal electricity market in Europe is mainly ruled by the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, often called the CACM guideline. It relies on a zonal market system: the European power system is divided in bidding zones, electricity trades within a bidding zone can occur in an unconstrained manner, while electricity trades between bidding zones are limited by cross-zonal capacities. In order to deal with possible grid congestion within a zone, remedial actions such as redispatching might have to be taken after the market clearing. Two approaches can be used to calculate and allocate cross-zonal capacity: the coordinated Net Transmission Capacity (NTC) approach or the Flow-Based (FB) approach. The FB approach is the preferred approach, in particular when cross-zonal capacity between bidding zones is highly interdependent (e.g. meshed configuration of bidding zones). The FB approach aims at modeling explicitly flows on critical transmission elements in N and in N-1 conditions to avoid a pre-allocation of the transmission capacity between borders, contrarily to the coordinated NTC approach. By avoiding this pre-allocation, the trading domain, i.e. the set of allowed cross-zonal power exchanges, is larger. This is illustrated by figure 1 for a three-zone system. Because the FB trading domain is normally larger, the FB approach is expected to be more efficient.

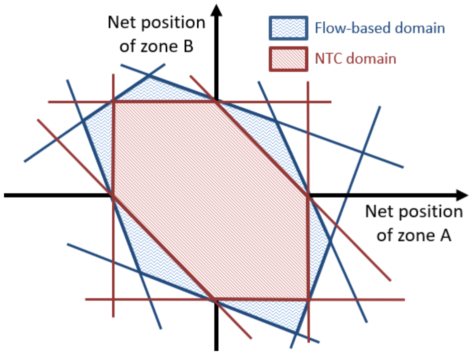

Fig. 1. Comparison of FB and NTC domains.

In Central Western Europe[1] (CWE), this FB approach is implemented for the day-ahead market since 2015 to calculate and allocate transmission capacity. However, the operational feedback shows that this approach did not fully deliver its promises, in particular because power exchanges within a bidding zone have *de facto* a priority over cross-border power exchanges. To reduce this discrimination between internal and cross-border power exchanges, the regulation of the European Parliament and of the Council on the internal market for electricity of 2019 imposes a minimum threshold of 70% of cross-zonal capacity for trade. Such a threshold could impact the socio-economic welfare and its distribution between the various actors. However, no assessment of the impacts such a threshold has been performed so far.

A major barrier hampering the impact assessment of a minimum threshold on cross-zonal capacity in a FB market is the lack of filly convincing approach to perform such an assessment. Indeed, although various models have been proposed to simulate a FB market, none of them consider in a fully consistent way N-1 security constraints, as it will be shown in more details in this paper. Furthermore, as it will be shown also in this paper, most of these works do not simulate the possible redispatch needed in case the market clearing leads to violation of operational and security constraints within a zone. Indeed, because a zonal market does not constraint electricity trades within a bidding zone, the outcome of the market clearing can lead to overloads in N and/or in N-1 security conditions within a zone and redispatch is then needed to alleviate these overloads. Because the feedback from the CWE FB market shows that the trading domain is mainly defined by N-1 security constraints, and that redispatch costs can be significant[2], previously proposed models are not deemed fully relevant to asses the impact of a minimum threshold on cross-zonal capacity in a FB market.

This paper aims thus: (i) to develop an convincing FB market simulation model considering in a consistent way N-1 constraints and redispatch based on previously proposed models, and (ii) to demonstrate the applicability of that approach on a case study, in order to assess the impact of a minimum threshold on cross-zonal capacity in a FB market.

For that purpose, this paper is organized as follows. Section II summarizes the concept of FB market coupling and introduces the main parameters. Section III reviews the literature dealing with the simulation of FB markets. Then, section IV presents and motivates the models that will be used in this paper. Section V develops the proposed framework to the 3-area Reliability Test System (RTS), to understand the impacts of a minimum threshold on cross-zonal capacity in a FB market. Finally, section VI concludes.

II. Flow-based market coupling

As explained in the introduction, the FB approach aims at representing directly and explicitly in the market clearing the main grid limitations constraining the energy exchanges between the different bidding zones. However, for computational reasons, a simplified representation of the network based on the linearized version of the power flow equations (i.e. DC power flow approximation) is used. Due to this simplification, only thermal limitations of transmission elements can be explicitly considered in the FB approach. Furthermore, for a large grid such as the European one, it would be computationally intractable to represent explicitly in the market clearing all thermal constraints of all transmission elements under N and all N-1 contingencies. Consequently, only the thermal limitations of specific Critical Network Element (CNE) under specific contingencies are considered. The CNE with an associated contingency is called CNEC.

It has thus some similarities with a nodal market. Indeed, a nodal market makes use of the DC power flow approximation in the market clearing process, and does not include explicitly in the market clearing all the grid constraints but only the ones that are expected to be critical. For these reasons, the mathematical model of a nodal market is often based on the Power Transfer Distribution Factor (PTDF) formulation and not on the so-called $B\theta$ formulation. Indeed, it leads to fewer variables and it reduces thus the size and the complexity of the optimization problem. In a nodal market, enforcing the thermal limitation of a transmission element l in a contingency state c can be simply expressed in the mathematical model by the constraint

$$-F_l^{max} \leq \sum_n PTDF_{nlc}^N I_n \leq F_l^{max}, \qquad (1)$$

where F_l^{max} is the thermal capacity of transmission element l, $PTDF_{nlc}^N$ is the nodal PTDF associated to node n and branch l in system state c and I_n is the net injection at node n, given by

$$I_n = \sum_g \mathbb{1}_{ng} P_g - P_{nd}, \qquad (2)$$

where P_g is the power output of generator g and P_{nd} is the load at node n.

[1] Austria, Belgium, France, Germany, Luxemburg and the Netherlands

[2] In Germany, according to the ENTSO-E transparency platform, the total redispatch cost reached 930 M€ in 2019 (i.e. 11.2 €/inhabitant).

A FB zonal market makes use of a similar formalism to include constraints enforcing the thermal limitation of a transmission element l in a contingency state c, i.e. of a CNEC k, in the market clearing. From the concept of nodal PTDF, the concept of zonal PTDF can be derived. A nodal PTDF associated to a node and a transmission element quantifies the impact of a unit power transferred from that node to the slack node on the power flow in that transmission element. A zonal PTDF associated to a zone and a transmission element quantifies the impact of a unit power transferred from that zone to the the slack node on the power flow in that transmission element. The computation of zonal PTDFs can be based on nodal PTDFs, but it requires an assumption about the nodes within the zone providing that unit power. This is the role of Generation Shift Keys (GSKs). GSKs provide the contribution of each node of a given zone to a change in zonal balance. For example, for a node n in a zone z, the value GSK_{nz} indicates the participation of the node n to the supply of an additional MW. A GSK_{nz} equals to 0.5 means that node n supplies 0.5 MW if the zonal balance of zone z is increased by 1 MW. The zonal PTDF of a transmission element l in a contingency state c, i.e. of a CNEC k, can then be computed by

$$PTDF^Z_{zk} = PTDF^Z_{zlc} = \sum_n \mathbb{1}_{zn} GSK_{nz} PTDF^N_{nlc}. \quad (3)$$

A major difference between nodal and zonal markets lies on the fact that zonal PTDFs consider only the impact of cross-zonal power exchanges on the loading of transmission elements, while power flow exchanges between nodes within a bidding zone usually contribute to a part of the loading of transmission elements (e.g. loop flows and internal/domestic flows). Consequently, not all the thermal capacity of a transmission element F^{max}_l is available for cross-zonal power exchanges. Furthermore, a reliability margin covering uncertainties must be kept. The capacity of a transmission element l in a contingency state c, i.e. of a CNEC k, available for cross-zonal power exchanges is called the Remaining Available Margin (RAM) and is given by

$$RAM_k = RAM_{lc} = F^{max}_l - F^{ref'}_k - FRM_k - FAV_k \quad (4)$$

where $F^{ref'}_k$ is the estimated physical flow when there is no commercial exchange between bidding zones[3] i.e. the physical flow on transmission element l in contingency state c resulting from domestic trade within a bidding zone (loop flows and internal/domestic flows), FRM_k is the Flow Reliability Margin (FRM) on the CNEC k used to cover, in a probabilistic way, deviations between expected power flows at the time of the FB domain computation and realized power flows in real-time, and FAV_k represents the Final Adjustment Value (FAV) on the CNEC k. The FAV is used by Transmission System Operators (TSOs) to consider complex overloads or voltage issues or possible remedial actions not modeled explicitly in the DC power flow approximation. On that basis, in a zonal market, enforcing the thermal limitation of a CNEC k can be simply expressed in the mathematical model by the constraint

$$\sum_z PTDF^Z_{zk} NEP_z \leq RAM_k \quad (5)$$

where NEP_z is the net position of zone z.

However, to compute the RAM, the various terms of Eq. (4) must be estimated. A key term is the reference flow for a CNEC $F^{ref'}_k$ at zero net position. This term is usually derived from a base case reflecting a forecast of the power flows in the grid at the moment of interest. This base case includes thus expected commercial exchanges between bidding areas. The reference flow at zero net position is then obtained by subtracting the estimation of the flows due to exchanges between bidding areas to the computed total flow on the CNEC. These flows are given by the product between the zonal PTDFs and the net positions used in the base case. It leads to the following equation [1]:

$$F^{ref'}_k = F^{ref}_k - \sum_z PTDF^Z_{zk} NEP^{ref}_z \quad (6)$$

where NEP^{ref}_z are the net positions of the zones in the base case.

Another important parameter is the FRM. It covers uncertainties related (i) to the unintentional flow deviations due to load-frequency control, (ii) to approximations of the flow-based approach, and (iii) to forecast errors of supply and demand (e.g. wind, solar, load, conventional generation) and of topology. The absence of spatial information of the accurate supply and demand inside a zone tends to increase the need for FRM as well. The FRM determination is usually done by deriving a probabilistic distribution of the difference between the expected power flows and the actual power flows [1]. The probability distribution is then fit by a normal distribution and the FRM is chosen as a multiple of the corresponding standard deviation based on the desired probability that the actual flows do not exceed the expected power flows.

III. Literature review

Although the first ideas of FB allocation dates back to an ETSO discussion paper of March 2001 [2], FB zonal electricity markets are relatively young. Indeed, the main general concepts behind the FB approach to calculate and allocate cross-zonal capacity as it is implemented now in the CWE region have been defined for the first time in 2008 in [3] and refined in 2012 in [4]. Furthermore, the FB market coupling went live for the day-ahead market coupling in the CWE region only in May 2015, which means that the underlying concepts strongly evolved between 2008 and 2015. Consequently, works related to the simulation of FB zonal electricity markets can be classified in two main categories: the ones based only on the general concepts, and the ones based then also on implementation details presented in section II, with a transition between these two categories around 2015.

Regarding the first category, the initial works discuss the general concepts and the ways to implement them. For example, [5] and [6] discuss the feasibility of a FB zonal model

[3] In reality, no commercial exchange beyond long-term nominations, but we will not consider long-term nominations in this paper.

for the UCTE grid, and different ways of grouping the nodes of a network into zones and of computing associated transfer limits using zonal PTDFs, respectively. In [7], the impact of different ways to define GSKs on the zonal PTDFs for the border between Montenegro and Albania is assessed. First methodologies to simulate a FB market are then proposed in [8], [9], [10]. These works differ mainly in the way they compute zonal PTDFs, but they all neglect N-1 security constraints and the potential need of redispatch.

Regarding the second category, to the best of the authors' knowledge, ref. [11], [12] are among the first works proposing a framework to simulate FB market coupling following the full definition of the FB approach for the CWE region. The proposed framework consists in three main steps. The first step consists in solving either a Unit Commitment (UC) or an Economic Dispatch (ED) considering grid constraints on the basis of on a nodal network model and of the DC power flow equations, i.e. DC Optimal Power Flow (OPF), in order to obtain a base case. In a second step, based on the outcome of the first step and on the definition of zones, zonal network parameters (PTDFs and RAMs) are computed. The final step consists then in simulating the zonal market outcome by solving an economic dispatch with flow-based constraints for exchanges between zones. In [11], all lines are considered in the OPF, but only cross-border lines are considered in the zonal market simulation. In In [12], all lines are considered in both the OPF and in the zonal market simulation. However, N-1 security constraints are not considered, and the redispatch process is neither considered nor simulated.

The lack of explicit consideration of N-1 security constraints appears also in approaches proposed by [13] and by [14]. Indeed, although N-1 security analysis appears to be used to identify critical branches, N-1 security constraints are not enforced in the process. Note that, contrarily to [12], the base case is not obtained through an OPF) but is obtained through a NTC-based market simulation. It could thus lead to a base case not compliant with operational criteria (e.g. some transmission elements might be overloaded), which could be a shortcoming. It must also be emphasized that [13] (but not [14]) assesses the need of redispatch on the presented case study, but no detail is provided on the model used to estimate the redispatch volume.

In [15], the authors follow a methodology very similar to [14]: the base case is obtained through a NTC-based market simulation, N-1 security constraints are not considered, and the potential need for redispatch is neglected.

The base case is also obtained through a NTC-based market simulation in [16] and in [17]. In these works, the N-1 security constraints are considered for the construction of the flow-based domain. However, the base case is not necessarily in N-1 security, which could lead to an empty flow-based domain. Furthermore, the need for redispatch is only estimated in a qualitative way in [17] through a N-1 security analysis. In particular, the redispatch cost is not estimated.

A variant for the computation of the base case is proposed in [18]: the authors propose to derive a base case by imposing a null net position to each market zone (i.e. each market zone has to meet its demand with its own zonal generation capacity). Such a methodology does not appear to be consistent with current TSOs' practices. Note that this paper neglects also N-1 security constraints and redispatch.

The potential need for redispatch is considered in [19] and in [20]. Both works are based on game theory to model the optimal behavior of producers. In [19], the authors do not develop a full simulation model, but they analyze a simple isolated 2-bus power system to study the difference between regulatory redispatch with cost compensation and market-based redispatch. The authors in [20] make use of a full simulation model with market-based redispatch, but they assume then that the RAM of a transmission element corresponds simply to its transmission capacity, which appears to be an over-simplistic assumption. Furthermore, N-1 security constraints are not considered. Redispatch is also simulated in [21], but a purely corrective approach is adopted for N-1 security.

As a conclusion, although these various works establish strong foundations for FB market simulation, they must be enriched to have a consistent consideration of N-1 security constraints and of the redispatch process. This is the objective of the next section.

IV. Proposed simulation framework

A. General framework

The developed simulation framework should mimic the way a FB market is managed. There is obviously a need to simulate the market clearing process and the redispatch process. However, as explained in section II, the market clearing relies on specific parameters: the zonal PTDFs and the RAMs for specific CNECs. The computation of the RAMs relies on the derivation of a base case. The proposed framework consists thus in four main steps. In a first step, the base case is obtained. In a second step, based on the outcome of the first step and on the definition of zones, zonal network parameters (PTDFs and RAMs) are computed. The third step consists then in simulating the zonal flow-based market clearing process. The fourth step simulates finally the redispatch. The subsections hereafter details models for these steps using three specific simplifying assumptions: (i) there is no uncertainty (perfect foresight of future conditions), (ii) generating units are fully flexible (no consideration of unit commitment constraints) and (iii) the market is perfect. Note that these assumptions limit the applicability of the methodology to real grids, as they are not necessarily met in practice, and that further improvements of the simulator will thus be needed. Nevertheless, they allow to improve existing methodologies in a step-by-step approach.

B. Computation of the base case

The starting point to compute main parameters involved in the flow-based market coupling is a forecast by TSOs of what will be the load and the generation dispatch, as well as associated power flows, for the period of interest (e.g. the two-day ahead congestion forecast for the day ahead market coupling). This is called the base case and it is prepared such that it is compliant with operational and security constraints (e.g. N-1 security constraints). In line with what is proposed in [12], but considering N-1 security constraints, we propose to obtain this base case through a Preventive Security-Constrained Optimal Power Flow (PSCOPF). The optimization problem can then be formulated as

$$\min \sum_{g} C_g P_g \tag{7}$$

such that

$$\sum_{g} \mathbb{1}_{ng} P_g + \sum_{l} A_{nl} P_{lc} = P_{nd}, \forall n, c \tag{8}$$

$$P_{lc} = \mathbb{1}_{lc} B_l \sum_{n} A_{nl} \theta_{nc}, \forall l, c \tag{9}$$

$$P_g^{min} \leq P_g \leq P_g^{max}, \forall g \tag{10}$$

$$-F_l^{max} \leq P_{lc} \leq F_l^{max}, \forall l, c \tag{11}$$

For all operating states, Eq. (8) balances the powers at each node, and Eq. (9) enforces power flows in the branches, while taking into account possible failures. Equation (10) limits the active power outputs to physical capabilities. Equation (11) enforces the line flows to be less or equal to the thermal rating in all states.

C. Computation of flow-based parameters

Final flow-based parameters are zonal PTDFs and RAMs of selected CNECs. For these two categories of parameters, the definition of GSKs is needed. As explained in section II, GSKs map a change in a net position of a bidding zone to the generating units of that area. There are various possibilities to define GSKs. However, GSKs include in general market-driven (i.e. power plants that are sensitive to market changes) and flexible power plants. Baseload units (e.g. nuclear units in some countries) and renewable energy sources with a negligible marginal cost (e.g. wind and solar) generally do not participate to GSKs (i.e. the GSK of those units is zero). In the CWE region, a typical way to compute GSKs is to consider that each flexible unit participates to the change in a net position of its zone proportionally to its dispatchable power range (i.e. difference between its maximum power output and its minimum power output). Mathematically, it means that

$$GSK_{nz} = \frac{\mathbb{1}_{zn} \sum_g \mathbb{1}_{ng} \left(P_g^{max} - P_g^{min}\right)}{\sum_n \mathbb{1}_{zn} \sum_g \mathbb{1}_{ng} \left(P_g^{max} - P_g^{min}\right)} \tag{12}$$

Based on these GSKs, zonal PTDFs can be computed using Eq. (3) for selected CNECs.

The process to select the CNECs that will be considered in the market clearing is the following. A first list containing all the interconnectors (in N condition and for N-1 conditions involving the outage of another interconnector), as well as CNECs highly loaded in the base case (e.g. more than 90%) is derived. Zonal PTDFs are computed explicitly for that first list. The final list keeps only the CNECs with a significant cross-border impact, i.e. at least one zone-to-zone PTDF higher than 5% to reflect current criteria. Note that the selected CNECs are automatically considered in the two directions (forward and backward).

Finally, the RAMs can be computed using equations (4) and (6). No FAV will be considered here (i.e. $FAV_k = 0$ $\forall k$), because voltage issues are out-of-scope of a purely DC power flow model and because no specific remedial action has to be modeled. Furthermore, because uncertainty is neglected (assumption of perfect foresight), there is no need to include a FRM (i.e. $FRM_k = 0 \; \forall k$)[4]. When a minimum threshold of RAM_k^{min} is imposed, equation (4) becomes then simply

$$RAM_k = RAM_{lc} = \max\left(F_l^{max} - F_k^{ref'}, RAM_k^{min}\right) \tag{13}$$

The combination of PTDFs and RAMs leads to the flow-based domain itself, which can be used in the simulation of the market clearing process.

D. Simulation of the flow-based market

That simulation is performed by maximizing the socio-economic welfare such that the load/generation balance is met in the system and such that the power flow on the considered CNECs due to cross-zonal exchanges is below their RAM. When the load is considered inflexible, maximizing the socio-economic welfare is equivalent to minimizing the total variable cost of generation. The optimization problem can then be formulated as

$$\min \sum_{g} C_g P_g \tag{14}$$

such that

$$NEP_z = \sum_{g} \mathbb{1}_{zg} P_g - \sum_{n} \mathbb{1}_{zn} P_{nd}, \forall z \tag{15}$$

$$\sum_{z} NEP_z = 0 \tag{16}$$

$$\sum_{z} PTDF_{zk}^{Z} NEP_z \leq RAM_k \tag{17}$$

E. Simulation of the redispatch

If the market outcome cannot be accommodated physically by the grid because it would lead to the overload of one or several transmission elements (in N and/or in N-1 conditions), TSOs will have to relieve these overloads by redispatching some of the generating units, i.e. by decreasing the power output of some generating units and by increasing the power output of other ones. This redispatch process can be organized in different ways. In particular, the current organization is not the same from one TSO to another. We propose thus to model regulatory redispatch but two different approaches for cost compensation: cost compensation only for upward redispatch and cost-compensation for upward and downward redispatch. Furthermore, we propose also to model two levels of cooperation between TSOs: no cooperation and full cooperation. In all cases, the redispatch will be simulated by solving an optimization problem and it will have to lead to a N-1

[4] Alternatively, a standard FRM of 10% can be considered.

secure operating state. Equations (8)-(11) will thus be used as constraints in that optimization problem.

In a regulatory redispatch with cost compensation model, it is considered that all generators are obliged to participate to redispatch. When a cost-compensation only for upward redispatch is used, it is considered that generators enduring an upward redispatch (i.e. having to increase their generation) are paid their marginal cost in addition to their market revenues, and that generators enduring a downward redispatch (i.e. having to decrease their generation) can keep their market revenues, but do not have to surrender avoided variable cost, and do not receive an extra-compensation. In that case, the objective function can be expressed as

$$\min \sum_g C_g \Delta P_g^+, \tag{18}$$

with

$$P_g = P_g^0 + \Delta P_g^+ - \Delta P_g^-, \forall g, \tag{19}$$

where P_g^0 is the outcome of the market clearing, and with

$$\Delta P_g^+, \Delta P_g^- \geq 0, \forall g. \tag{20}$$

On the contrary, in an approach relying on cost-compensation for upward and downward redispatch, we consider that generators generators enduring a downward redispatch can keep their market revenues but have to surrender avoided variable cost[5]. In that case, the objective function can be expressed as

$$\min \sum_g \left[C_g \Delta P_g^+ - C_g \Delta P_g^- \right], \tag{21}$$

with equations (19)-(20).

In the case we assume full cooperation between TSOs, the redispatch will be performed across zones without the need to keep the zonal net positions equal to the outcome of the market clearing. This inter-zonal redispatch will thus include counter-trading. On the contrary, if we assume no cooperation between TSOs, the redispatch will be intra-zonal and the zonal position of each zone will need to be kept equal to the outcome of the market clearing. Mathematically, this constraint can be expressed as

$$\sum_g \mathbb{1}_{zg} \Delta P_g^+ = \sum_g \mathbb{1}_{zg} \Delta P_g^-, \forall z. \tag{22}$$

V. Case study

This simulation model will then be applied on a modified version of the 3-zone IEEE RTS to understand how the market efficiency, the redispatch costs and the distribution of the socio-economic welfare evolves with a minimum threshold on cross-zonal capacity. Generation mixes in the three zones will be different to motivate cross-zonal flows and different levels of load and of renewable energy sources will be tested.

[5]It corresponds then to the model proposed by [19], and it is in line with the current practice in the CWE region.

A. Test system

The test system used to demonstrate the applicability of the simulation framework and to assess the impact of a minimum threshold on cross-zonal capacity in a FB market is a modified version of the 3-area RTS [22]. For the transmission system, compared to the standard version, single-circuit lines between buses 107-108, 207-208, 307-308 were transformed into double-circuit lines to avoid radially connected buses with a single-circuit line, and lines were added between buses 122-123 and 207-303 to strengthen the grid. Figure 2 shows this modified RTS.

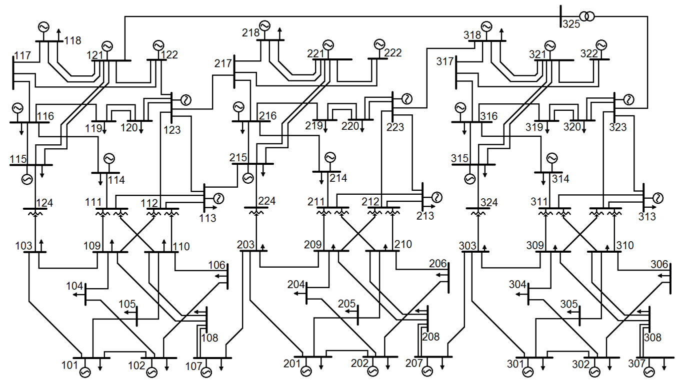

Fig. 2. Modified RTS-96 3-area system.

Compared to the standard version, the peak load of each zone and the load distribution among buses in a zone were not changed. The peak load in each area is thus 2850 MW. However, hourly load profiles have been changed, to introduce variability between the three zones. These three different profiles are taken from three neighboring European countries. The peak load for the overall system is then 8417 MW[6]. The off-peak load for the overall system is 3643 MW. The average load factor is 67.8%.

The generation mix was completely reshuffled compared to the standard version of the 3-area RTS. Table I shows the generation mix per zone. The total conventional capacity (nuclear, coal, gas and oil) is 9120 MW, sufficient to cover the peak load. In addition, 3900 MW of wind energy is installed, mainly in zone 2, with an average capacity factor of 27%. Hourly wind profiles are different for each zone and reflect three neighboring European countries. Table II gives the marginal costs of these generation means. At the exception of wind, marginal costs of various units of a same technology are taken slightly in order to avoid multiple equivalent solutions for the optimization problems. This is why a range is given for each technology, at the exception of wind.

B. Numerical results

This subsection presents the results obtained by applying the simulation framework developed in section IV to the test system presented at the previous subsection, for one year on an hourly basis. Four possibilities exist for the redispatch:

[6]The peak loads are asynchronous.

TABLE I
GENERATION MIX.

	Capacity in zone 1 (MW)	Capacity in zone 2 (MW)	Capacity in zone 3 (MW)	Total for the system (MW)
Coal	0	1700	2200	3900
Gas	1200	750	750	2700
Nuclear	1500	0	0	1500
Oil	420	300	300	1020
Wind	200	3200	500	3900

TABLE II
MARGINAL COSTS OF GENERATING UNITS.

Type	Marginal costs (€/MWh)
Wind	0
Nuclear	[14.1, 14.2]
Coal	[35.2, 36.8]
Gas	[46.6, 47.6]
Oil	[156.0, 157.4]

regulatory redispatch with cost compensation only for upward redispatch and without cooperation between TSOs (case I), regulatory redispatch with cost compensation only for upward redispatch and with full cooperation between TSOs (case II), regulatory redispatch with cost compensation for upward and for downward redispatch without cooperation between TSOs (case III) and regulatory redispatch with cost compensation for upward and for downward redispatch with full cooperation between TSOs (case IV). These four cases are studied with and without a minimum RAM of 70%. Table III gives the total annual cost of generation with and without a minimum RAM of 70%. The variation of the total annual cost of generation corresponds to the variation of the socio-economic welfare (the load is supposed to be inelastic). It can be observed that the minimum RAM does not impact the total cost of generation only when the redispatch compensates for both upward and for downward redispatch and when there is a full cooperation between TSOs. Otherwise, a minimum threshold on cross-zonal capacity tends to increase the total cost of generation, up to 1.9% (cases I and III). It must also be emphasized that the lack of cooperation between TSOs for the redispatch tends to increase the total cost of generation. Note that, if grid congestions are not considered (i.e. copper plate model), the total annual cost of generation is 1210.76 M€/year.

TABLE III
TOTAL ANNUAL COST OF GENERATION.

Case	Annual cost without a min RAM (M€/year)	Annual cost with a min RAM of 70% (M€/year)
Case I	1264.28	1287.85
Case II	1262.68	1270.18
Case III	1248.57	1272.33
Case IV	1243.44	1243.44

If the total cost of generation is an interesting metric, it is also important to understand how various stakeholders are impacted by a minimum threshold on cross-zonal capacity. Table IV shows the total annual consumers' payments, only at the market level[7]. When a minimum RAM of 70% is enforced, they tend to decrease because the zonal costs tend to decrease (virtual increase of the interconnection capacity).

TABLE IV
TOTAL ANNUAL CONSUMERS' PAYMENTS AT THE MARKET LEVEL.

Case	Consumers' payments without a min RAM (M€/year)	Consumers' payments with a min RAM of 70% (M€/year)
Cases I-IV	1716.18	1709.23

Table V shows the total annual producers' surplus (i.e. difference between the gross revenues and the variable generation costs). When a regulatory redispatch with cost compensation only for upward redispatch is used, no significant change of the producers' surplus is observe with a minimum RAM of 70%. Indeed, on one hand, revenues decrease due to to the decrease of zonal costs, but, on the other hand, redispatch needs increase and, because generators enduring a downward redispatch do not have to surrender avoided variable cost, it leads to an increase of the revenues. The net effect leads to a slight decrease of the producers' surplus for case I and a slight increase of the producers' surplus for case II. When costs are compensated for both upward and downward redispatch, the producers' surplus tends to decrease with a minimum RAM of 70%: zonal costs decrease and redispatch costs do not impact their surplus.

TABLE V
TOTAL ANNUAL PRODUCERS' SURPLUS.

Case	Producers' surplus without a min RAM (M€/year)	Producers' surplus with a min RAM of 70% (M€/year)
Case I	875.88	875.03
Case II	873.84	874.88
Case III	787.19	784.98
Case IV	787.19	784.98

Table VI shows the total annual congestion management costs, computed as the difference between the redispatch cost and the congestion rent. For all cases, they increase when a minimum RAM of 70% is enforced. However, the increase is limited to approximately 5 M€ when costs are compensated for both upward and downward redispatch with full cooperation between TSOs is used. Otherwise, they can increase up to 30 M€ when a regulatory redispatch with cost compensation only for upward redispatch and without cooperation between TSOs is used.

If we consider that the congestion management costs are billed *in fine* to the electricity consumer, Table VII gives the total cost of electricity for the consumer. It decreases in only one case, but slightly: when a regulatory redispatch with cost

[7]They do not depend on the redispatch scheme, because the market clearing occurs before the redispatch.

TABLE VI
TOTAL ANNUAL CONGESTION MANAGEMENT COSTS.

Case	Congestion costs without a min RAM (M€/year)	Congestion costs with a min RAM of 70% (M€/year)
Case I	423.98	453.65
Case II	420.35	435.84
Case III	319.58	348.08
Case IV	314.45	319.2

compensation for both upward and downward redispatch and with full cooperation between TSOs is used. Otherwise, it can increase up to 1.1% (cases I and III).

TABLE VII
TOTAL ANNUAL COST OF ELECTRICITY FOR THE CONSUMER.

Case	Total cost for the consumer without a min RAM (M€/year)	Total cost for the consumer with a min RAM of 70% (M€/year)
Case I	2140.16	2162.88
Case II	2136.53	2145.07
Case III	2035.76	2057.31
Case IV	2030.63	2028.43

VI. CONCLUSIONS

This paper proposed a framework to simulate a flow-based market, including the preparation of a base case to derive the flow-based parameters and the simulation of the redispatch. This framework considers explicitly N-1 constraints, which is its originality. This paper demonstrated also the applicability of that approach on a modernized version of the 3-zone IEEE RTS, in order to assess the impact of a minimum threshold on cross-zonal capacity in a FB market. This application showed that, depending on the way redispatch is organized, a minimum threshold could increase the total generation cost and could thus decrease the socio-economic welfare. However, when the redispatch scheme includes cost compensation for both upward and downward redispatch and when there is full cooperation between the TSOs of the various bidding zones, the total generation cost is not impacted and the total cost of electricity for the consumer can even decrease.

However, the model will have to be enriched to alleviate its current limitations coming from the three simplifying assumptions performed in section IV-A: uncertainty on the load and on the generation (including renewable energy sources), unit commitment constraints, and market's imperfections should be integrated in the model.

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