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European Electricity Market Integration under Various Network Representations

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Abstract

The integration of the European electricity market constitutes a critical and contemporary issue, expected to take place within year 2015. In view of the forthcoming RES penetration, physical markets with unit-based offers -either power pools or Power Exchanges (PXs)- check the feasibility of the electricity market solution against their intra-zonal transmission capacity constraints. An iterative process is examined, with two variations, differentiating only in the way that the internal network of each physical market is represented. In each iteration of the proposed algorithm, intra-zonal power flows are calculated, possible violations of internal transmission limits are identified and additional constraints are incorporated in the centralized market splitting problem, in order to avoid the overloading of internal transmission lines. The attained results are compared to those of a centralized market-splitting problem, considering the full European network configuration. The above methods are compared in terms of (a) solution efficiency, (b) correct pricing and (c) computational efficiency.

Keywords: Internal Electricity Market, Power Pool, Power Exchange, Market Splitting, Mixed Integer Linear Programming, Power Transfer Distribution Factors

Nomenclature

A. Sets and Indices

$a \in \mathcal{A}$ set of bidding areas/zones in Europe, belonging to both power pools ($ap \in \mathcal{AP}$) and PXs ($ax \in \mathcal{AX}$), where $\mathcal{A} = \mathcal{AP} \cup \mathcal{AX}$

$pm \in \mathcal{PM}$ set of physical markets in Europe, where $PM \subseteq \mathcal{A}$

$p \in \mathcal{P}_{ax}$ set of market participants in European PXs

$g \in \mathcal{G}_{ap}$ set of generating units in bidding area ap

$d \in \mathcal{D}_{ap}$ set of demand entities (load representatives) in bidding area ap

$m \in \mathcal{M}$ set of reserves $\mathcal{M} = \left\{1^+, 1^-, 2^+, 2^-, 3^s, 3^{ns}\right\}$, where m denotes the different reserve types ($1^{+/-}$ is the primary up/down reserve, $2^{+/-}$ is the secondary up/down reserve and $3^{s/ns}$ is the tertiary spinning/non-spinning reserve)

$t \in \mathcal{T}$ set of dispatch or trading periods of the trading day (typically one hour)

$f \in \mathcal{F}$ set of steps of the priced energy offer or priced load declaration, where $\mathcal{F} = \mathcal{F}^g \cup \mathcal{F}^d \cup \mathcal{F}^p$, $\mathcal{F}^g$: set of steps of priced energy offers of production, $\mathcal{F}^d$: set of steps of the priced load bids of demand entities, $\mathcal{F}^p$: set of steps of participants' p selling offer or purchasing bid.

$n \in \mathcal{N}$ set of interconnections and inter-zonal corridors

$l \in \mathcal{L}$ set of all examined lines containing all physical markets' internal lines and all interconnections (or inter-zonal corridors); $\mathcal{L}_{pm} \subseteq \mathcal{L}$ denotes the set of physical market's pm internal lines, while superscript ext in set $\mathcal{L}_{pm}$ denotes an extended network representation of each physical markets' internal lines, meaning that $l \in \mathcal{L}_{pm}^{ext} = \mathcal{L}_{pm} \cup N$ for each physical market pm, where $\mathcal{N} \subseteq \mathcal{L}$

$b \in \mathcal{B}$ set of buses of all physical markets' bidding areas and "imaginary" nodes of non-physical markets; $\mathcal{B}_{pm} \subseteq \mathcal{B}$ denotes the set of physical market's pm internal buses, while superscript ext in set $\mathcal{B}_{pm}$ denotes an extended network representation containing all internal buses $b \in \mathcal{B}_{pm}$ and an "imaginary" node for each area $a \in \mathcal{A}$ excluding the examined physical market pm, meaning that $b \in \mathcal{B}_{pm}^{ext} = \mathcal{B}_{pm} \cup \mathcal{A} - \{\mathcal{PM}\}$ for each physical market pm

B. Parameters

C_{gft}, Q_{gft} price-quantity pair of step f of the generating unit g priced energy offer in dispatch period t, in €/MWh and MWh

C_{dft}, Q_{dft}	price-quantity pair of step f of demand entity d priced load bid in dispatch period t, in €/MWh and MWh
RC_{gt}^{m}	reserve offer of generation unit g for the procurement of reserve type m, in dispatch period t, in €/MW
SUC_g	start-up cost of generating unit g, in €/start-up
SDC_g	shut-down cost of generating unit g, in €/shut-down
$P_{pft}^{sell}, Q_{pft}^{sell}$	price-quantity pair of step f of hourly energy selling offer of participant p in trading period t, in €/MWh and MWh
$P_{pft}^{pur}, Q_{pft}^{pur}$	price-quantity pair of step f of hourly energy purchasing bid of participant p in trading period t, in €/MWh and MWh
RES_{at}	total injection of Renewable Energy Sources (RES), including the mandatory injection from large hydro units, in bidding area $a \in \mathcal{AP}$ in dispatch period t, in MWh
$ATC_{nt}^{a,a'}$	Available Transmission Capacity (ATC) on the interconnection n from bidding area a to bidding area a' in trading period t, in MW
$PTDF_{n}^{a,a'}$	Power Transfer Distribution Factor on interconnection (or inter-zonal corridor) n for an energy transfer from area a to area a'
$PTDF_{l}^{b,ref}$	Power Transfer Distribution Factor on internal line l for an energy transfer from internal bus b to the reference bus
$F_{l}^{\max}$	normal rating of line l, in MW
E_{n}^{b}	Node-to-Interconnection matrix which is equal to 1/-1 if interconnection n is ending/beginning to/from internal bus b and 0 otherwise

C. Variables

q_{gft}	cleared quantity of step f of the generating unit g priced energy offer in dispatch period t, in MWh
q_{dft}	cleared quantity of step f of demand entity d priced load bid in dispatch period t, in MWh
r_{gt}^{m}	contribution of unit g in reserve type m during dispatch period t, in MW
y_{gt}	binary variable which is equal to 1 if generating unit g starts-up at dispatch period t
z_{gt}	binary variable which is equal to 1 if generating unit g shuts-down at dispatch period t
q_{pft}^{sell}	energy sold from step f of hourly energy selling offer of participant p in bidding area ax in trading period t, in MWh
q_{pft}^{pur}	energy purchased from step f of hourly energy purchasing offer of participant p in bidding area ax in trading period t, in MWh
P_{at}^{inj}	net energy injection to bidding area a during trading period t, in MWh
P_{bt}	net energy injection on bus b during trading period t, in MWh
$flow_{nt}$	power flow on interconnection or inter-zonal corridor n, connecting area a to area a', in trading period t, in MW
$flow_{lt}$	power flow on line l in trading period l, in MW

D. Functions

$\boldsymbol{c}_{gt}^{gen}$	energy offer cost function of generation unit g in dispatch period t, in €
$\boldsymbol{c}_{gt}^{com}$	commitment cost (based on the submitted techno-economic data) function comprising the start-up and shut-down cost of generating unit g in dispatch period t, in €
$\boldsymbol{c}_{gt}^{rsv}$	reserve offer cost function, based on offer function and provision of reserves of unit g in dispatch period t, in €
$\boldsymbol{u}_{dt}^{dem}$	utility function (as bid) of demand entity d in dispatch period t, in €
$\boldsymbol{c}_{pt}^{sell}$	energy offer cost function of participant p in trading period t, in €
$\boldsymbol{u}_{pt}^{pur}$	energy load utility function of participant p in trading period t, in €

Introduction

In the last decade, the European Commission has prioritized in its energy agenda the creation of an internal European Electricity Market. Regulators and other involved institutions have laid the necessary foundations for the merging of European electricity markets through the drafting and implementation of European Directives [1], [2] and Regulations [3], [4]. However, the route towards the creation of an internal electricity market has not been easy, since most European electricity markets are organized and operated under different structures. Several important milestones have been achieved in the last years, such as the Trilateral Market Coupling [5], the

Interim Tight Volume Coupling (ITVC) [6] and the Price Coupling of Regions (PCR) initiative [7]. The forthcoming merging of the European electricity markets will eventually lead to a common internal market with a size even greater than the joint market of Midwest ISO and PJM [8].

A major challenge that Market Operators in Europe shall face is the integration of various markets organized and operated under different market designs. The two currently prevailing market-clearing models are the power pool and the Power Exchange. In the first one, the Market Operator solves a complicated unit commitment problem with a simultaneous co-optimization of energy and ancillary services. The day-ahead optimization problem takes into consideration the full set of system constraints, while simultaneously satisfying all unit technical characteristics (technical minimum/maximum constraints, minimum up/down times, start-up and shut-down constraints, etc) [9]-[10]. On the other hand, in the Power Exchange model the Market Operator applies primarily a pure economical clearing procedure, disregarding the various system and unit constraints while satisfying only the power balance constraint. These two different market clearing models currently co-exist in the European region, putting obstacles in the efficient integration of the European electricity markets and challenging the Market Operators in finding feasible market coupling solutions, without altering the basic features of their market schemes. Up until recently, the issue of coupling markets with different regulatory frameworks has not been addressed in the existing literature. This issue has been thoroughly discussed in [11] and [12], where the authors proposed a market-splitting approach for the solution of the pan-European market clearing problem, without altering the basic regulatory framework of each electricity market. The same approach is followed in this paper.

Congestion management, namely the security of supply, has been one of the most important factors leading to the efficient European electricity market integration. Many researchers have studied various market coupling solutions [13]-[21]. The common feature of all of the aforementioned cases is that the intra-zonal lines are considered to be uncongested, since the internal network is assumed to be “strong” enough to bear the attained power flows. Moreover, apart from the above mentioned market coupling solutions, various researchers have also compared different congestion management schemes, for the evaluation and highlighting of advantages and disadvantages of each proposed approach [22]-[24].

The implementation of European Commission’s 20/20/20 [25] goals creates additional problems to System Operators, since the existing market clearing procedures do not deal efficiently with the intra-zonal congestions created on a large part due to the constantly increasing volume of variable energy sources, leading to additional high counter-trading costs. These costs will inevitably be allocated to the end consumers. In order to alleviate these costs and to avoid infeasible market solutions, better congestion management techniques may be required to cope with the bottlenecks created by the forthcoming RES penetration.

Considering the above, three congestion management approaches are examined in this paper for the solution of the day-ahead European electricity market, consisting of both power pools and power exchanges. In this context, physical markets monitor their intra-zonal congestions, while non-physical markets solve a purely economical model, without taking into consideration the line limits within their internal network. The first approach involves the modeling of the whole European network according to the nodal congestion management scheme, currently applied in many regions of the USA. The two remaining approaches employ an iterative process, iterating between the overall pan-European market splitting and intra-zonal power flows of the constituent countries/zones. Their difference is that in the second approach a myopic network representation inside each country/zone is considered, while in the third approach physical markets extend their view to the network beyond their own system, considering each European bidding area as one node. In the latter two approaches, the identified congestions in the intra-zonal network are incorporated as additional constraints in the main pan-European market splitting model. The power flows in each case are computed using the respective Power Transfer Distribution Factors (PTDFs), computed on nodal/zonal level, depending on the network configuration of each country.

The above methods are compared in terms of (a) solution efficiency, (b) correct pricing and (c) computational efficiency.

Mathematical Formulation

As mentioned in the Introduction, the proposed single pan-European market-splitting problem respects fully the basic features of each markets’ regulatory framework. As a result, the day-ahead market-clearing problem is modeled as a mathematical optimization problem, without considering any network representation, as follows:

$$Min \sum_{t \in \mathcal{T}} \left[\sum_{g \in \mathcal{G}_{ap}} \boldsymbol{c}_{gt}^{gen} - \sum_{d \in \mathcal{D}_{ap}} \boldsymbol{u}_{dt}^{dem} \right] + \sum_{t \in \mathcal{T}} \sum_{p \in \mathcal{P}_{ax}} \left[\boldsymbol{c}_{pt}^{sell} - \boldsymbol{u}_{pt}^{pur} \right] \qquad (1)$$

Subject to the following constraints:

$$\boldsymbol{c}_{gt}^{gen} = \sum_{f \in \mathcal{F}^g} C_{gft} \cdot q_{gft} + \boldsymbol{c}_{gt}^{com}\left(y_{gt}, z_{gt}\right) + \boldsymbol{c}_{gt}^{res}\left(r_{gt}^{m}\right) \quad \forall g \in \mathcal{G}_{ap}, t \in \mathcal{T} \quad (2)$$

$$\boldsymbol{c}_{gt}^{com} = SUC_g \cdot y_{gt} + SDC_g \cdot z_{gt} \quad \forall g \in \mathcal{G}_{ap}, t \in \mathcal{T} \quad (3)$$

$$\boldsymbol{c}_{gt}^{res} = \sum_{m \in M} RC_{gt}^{m} \cdot r_{gt}^{m} \quad \forall g \in \mathcal{G}_{ap}, t \in \mathcal{T} \quad (4)$$

$$\boldsymbol{u}_{dt}^{dem} = \sum_{f \in \mathcal{F}^d} C_{dft} \cdot q_{dft} \quad \forall d \in \mathcal{D}_{ap}, t \in \mathcal{T} \quad (5)$$

$$\boldsymbol{c}_{pt}^{sell} = \sum_{f \in \mathcal{F}^p} \left(P_{pft}^{sell} \cdot q_{pft}^{sell}\right) \quad \forall p \in \mathcal{P}_{ax}, t \in \mathcal{T} \quad (6)$$

$$\boldsymbol{u}_{pt}^{pur} = \sum_{f \in \mathcal{F}^p} \left(P_{pft}^{pur} \cdot q_{pft}^{pur}\right) \quad \forall p \in \mathcal{P}_{ax}, t \in \mathcal{T} \quad (7)$$

$$\mathbf{x}_{gt} = \left[q_{gft}, u_{gt}, y_{gt}, z_{gt} \ldots\right] \in \Omega_{gt} \quad \forall g \in \mathcal{G}_{ap}, t \in \mathcal{T} \quad (8)$$

$$0 \le q_{dft} \le Q_{dft} \quad \forall d \in \mathcal{D}_{ap}, f \in \mathcal{F}^d, t \in \mathcal{T} \quad (9)$$

$$0 \le q_{pft}^{sell} \le Q_{pft}^{sell} \quad \forall p \in \mathcal{P}_{ax}, f \in \mathcal{F}^p, t \in \mathcal{T} \quad (10)$$

$$0 \le q_{pft}^{pur} \le Q_{pft}^{pur} \quad \forall p \in \mathcal{P}_{ax}, f \in \mathcal{F}^p, t \in \mathcal{T} \quad (11)$$

$$P_{at}^{inj} = \sum_{g \in \mathcal{G}_{ap}} \sum_{f \in \mathcal{F}^g} q_{gft} + RES_{at} - \sum_{d \in \mathcal{D}_{ap}} \sum_{f \in \mathcal{F}^d} q_{dft} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (12)$$

$$P_{at}^{inj} = \sum_{p \in \mathcal{P}_{ax}} \sum_{f \in \mathcal{F}^p} q_{pft}^{sell} - \sum_{p \in \mathcal{P}_{ax}} \sum_{f \in \mathcal{F}^p} q_{pft}^{pur} \quad \forall a \in \mathcal{AX}, t \in \mathcal{T} \quad (13)$$

$$\sum_{p \in \mathcal{P}_{ap}} P_{at}^{inj} + \sum_{p \in \mathcal{P}_{ax}} P_{at}^{inj} = 0 \quad \forall t \in \mathcal{T} \quad (14)$$

$$\sum_{g \in \mathcal{G}_{ap}} r_{gt}^{1^+} \ge RR_{a,t}^{1^+} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (15)$$

$$\sum_{g \in \mathcal{G}_{ap}} r_{gt}^{1^-} \ge RR_{a,t}^{1^-} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (16)$$

$$\sum_{g \in \mathcal{G}_{ap}} r_{gt}^{2^+} \ge RR_{a,t}^{2^+} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (17)$$

$$\sum_{g \in \mathcal{G}_{ap}} r_{gt}^{2^-} \ge RR_{a,t}^{2^-} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (18)$$

$$\sum_{g \in \mathcal{G}_{ap}} r_{gt}^{3^s} + \sum_{g \in \mathcal{G}_{ap}} r_{gt}^{3^{ns}} \ge RR_{a,t}^{3} \quad \forall a \in \mathcal{AP}, t \in \mathcal{T} \quad (19)$$

In general, the single Europe-wide market splitting problem comprises of the power pool and power exchange sub-problems. In a power pool, each generating unit g submits a complex offer, comprising an energy price/quantity offer, a reserve offer and a declaration with its techno-economic data, including its start-up and shut-down time-periods and relevant costs [26]. Additionally, demand entities d deposit simple price/quantity bids. On the other hand, in a power exchange participants p submit simple price/quantity offers/bids, either in a unit-based format or under portfolio bidding. The latter implies that each participant (producer, demand entity, trader) submits one hourly portfolio offer/bid curve, internalizing all technical and cost elements of his production facilities, his demand forward contracts and trading contracts.

Equation (1) is the objective function of the optimization problem, where the Central Market Operator (MO) tries to minimize the total generation cost minus the utility function of the demand entities in power pools, plus the total selling cost minus the total purchasing cost from participants p in power exchanges.

Constraints (2) and (5) denote the generating cost and the utility function in a power pool, respectively. The former depends on the commitment and reserve costs, modeled by constraints (3) and (4) respectively, where the commitment cost is equal to the sum of the start-up and shut-down costs, while equation (4) expresses the cost for the procurement of reserve type *m*. It should be noted that the proposed algorithm performs a co-optimization of energy and reserves only in the areas organized as power pools. Equations (6) and (7) model participant's *p* selling and purchasing costs submitting offers and bids in a PX.

Equation (8) describes generating unit's *g* operating constraints, which are bounded by the feasibility set Ω_{gt}. whereas equations (9)-(11) express the demand entities' *d* bids and the participants *p* /offers/bids quantity limits. The unit's *g* operating constraints in power pools are analytically presented and explained in [9]-[10].

Constraints (12) and (13) express the net injection in a power pool and in a power exchange, respectively, where the net injection in a power pool depends not only on the cleared quantities of priced energy offers and bids, but also on the level of RES penetration. On the other hand, in a power exchange the net injection depends only on the cleared selling and purchasing orders. Constraint (14) expresses the power balance equation in the whole European power system.

Finally, equations (15)-(19) describe the reserve requirements in a power pool. For each reserve type *m* the sum of all procured quantities must be equal or greater than the respective reserve requirement, with the exception of the tertiary reserve requirement where the sum of all procured spinning and non-spinning tertiary reserve should be equal or greater to the common tertiary reserve requirement.

Network Representation

As it has been already stated in the introduction, in case European TSOs ignore their internal congestions in day-ahead level, the imminent high RES penetration will create inefficiencies in the clearing of the forthcoming,

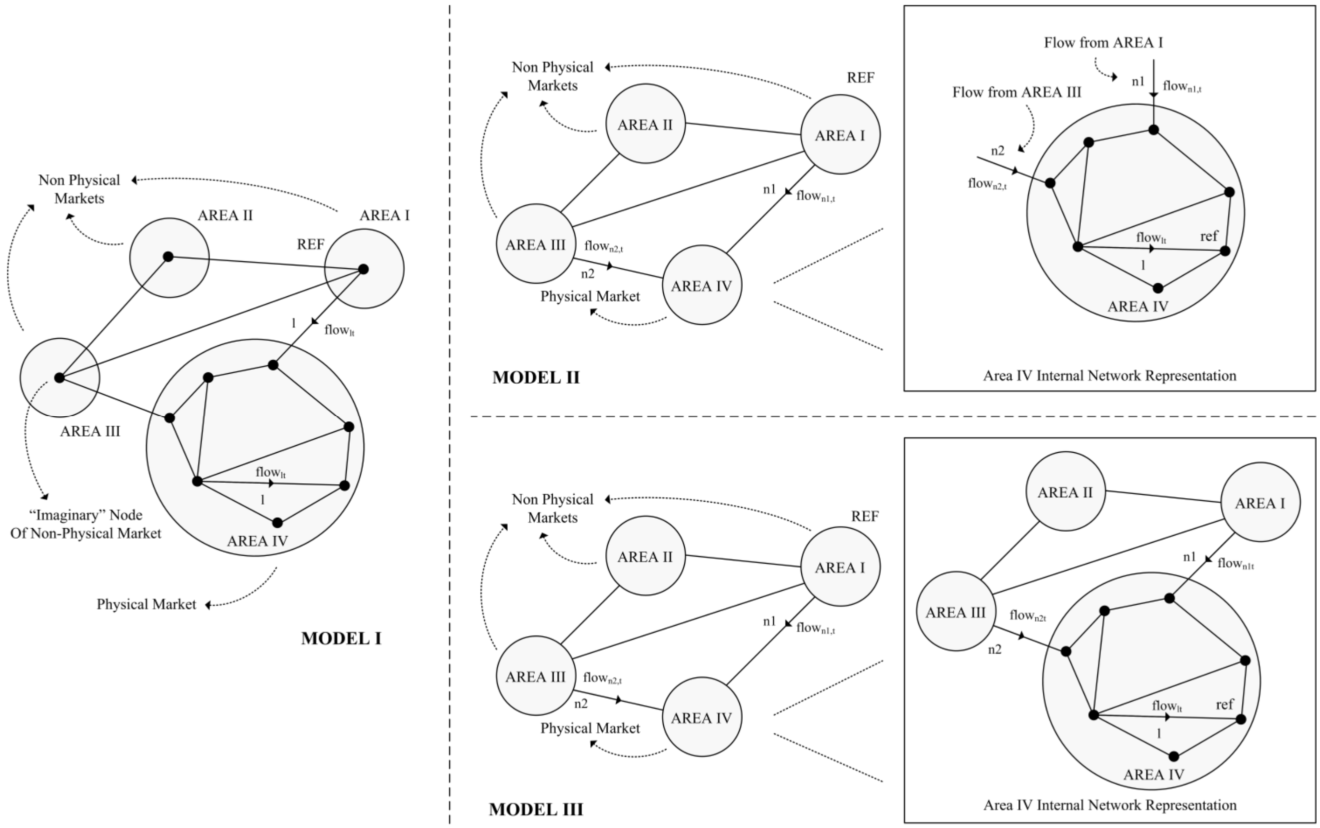

Fig. 1. Graphical representation of the network in the three proposed models

common European Electricity market. As a consequence sub-optimal day–ahead solutions will arise leading to high redispatching and counter-trading costs in real-time operation, which will be socialized to end consumers. In this direction, three congestion management approaches for the day-ahead operation of the European electricity market are presented here, in order to deal with the afore-mentioned problems.

In all three approaches, the network of each bidding area of the non-physical markets is approximated with a single "imaginary" node, in which all simple or portfolio offers/bids are submitted, and which is connected with all interconnections or inter-zonal corridors with the neighboring bidding areas/zones. This approximation (network reduction) is necessary for the purposes of this paper, in order to simulate the existing or prospective non-physical markets in Europe.

In the physical markets, since all offers/bids are available per bus, the internal line power flows can be computed, and as a result the internal (intra-zonal) congestion can be monitored. For notation simplicity, a single bidding area has been assumed in this paper for all physical and non-physical markets. The extension to markets with more than one bidding areas is straightforward.

For the network representation in the three approaches, the full network representation of all European power systems is used, covering the transmission grid of the Continental Europe. The network data has been provided by ENTSO-E under a non-disclosure agreement and comprises of 4,078 buses, 5,781 transmission lines and 1076 transformers. Moreover, the introduction of a central Super Market Operator (SMO) is deemed necessary. The SMO collects all offers/bids and solves the market-splitting problem in all three studied methodologies.

In the first network representation, denoted as **Model I**, the PTDF matrix used, is computed using the whole European power system, bearing all nodes/lines for the bidding areas of physical markets and one "imaginary node" for non-physical markets, as shown in the left part of Fig. 1. This network representation will be hereinafter referred as "reduced European network representation" of the European power system. This implementation requires a level of centralized coordination between the TSOs of all physical markets and the SMO, since the computation of the $PTDF_l^{b,REF}$ matrix, denoting the change of power flow in internal line or interconnection l with respect to a power injection in physical bus or "imaginary" node b and withdrawal from reference area/bus REF, requires at least the knowledge of the admittance matrix of the European power system [27]. Thus, TSOs of physical markets should communicate this information to the central SMO, which presupposes the willingness of all involved parties (TSOs, MOs, regulators) to overcome the administrative, regulatory and political difficulties and adhere to such a central market operation.

In **Model II**, a 'myopic' decentralized approach is followed, thus avoiding information exchange on the local network configuration between the TSOs of the physical markets and the central SMO. Initially, the European market-splitting problem is formulated and solved in a zonal level, with each bidding area (physical or non-physical) modeled by an "imaginary" node, referred hereinafter as "zonal European network representation". The computation of the $PTDF_n^{a,REF}$ matrix, denoting the change of power flow in interconnection n with respect to a power injection in bidding area a and withdrawal from a reference area REF, is necessary for the modeling of the European market-splitting problem. The SMO can easily calculate this PTDF matrix, since only the interconnecting lines n admittances are required for its computation. After the solution of the European wide market-splitting problem, local TSOs of physical markets check the feasibility of the cleared generation and demand quantities against their internal congestion. For this ex-post calculation only the $PTDF_l^{b,ref}$ matrix, representing the power flow change in physical market's internal lines l with respect to an injection in internal bus b and withdrawal in internal reference bus *ref*, along with the internal line flow limits are required. Thus, in this way, a "myopic" decentralized operation of the European power system with regard to physical markets' internal congestions can be achieved, without the need for network data exchange between regional TSOs and the SMO. This approach is demonstrated in the upper right part of Fig. 1.

Model III, is similar to **Model II**, with the exception that each physical market's TSO checks the feasibility of the attained results against an extended network representation of his internal network. This extended network comprises of the examined physical market's internal network along with all the other physical and non-physical bidding areas, all represented by an "imaginary" node. As a result, the examined set of congested lines includes the respective physical market's internal lines augmented by the set of interconnecting lines, as it is illustrated in the lower right part of Fig. 1. A minimum amount of data exchange is required in this approach, since the SMO communicates to each TSO the interconnecting network line data and the required for the power flow calculations $PTDF_l^{b,ref}$ matrix can then be easily computed from each TSO. It should be noted that the aforementioned PTDF matrix denotes the power flow

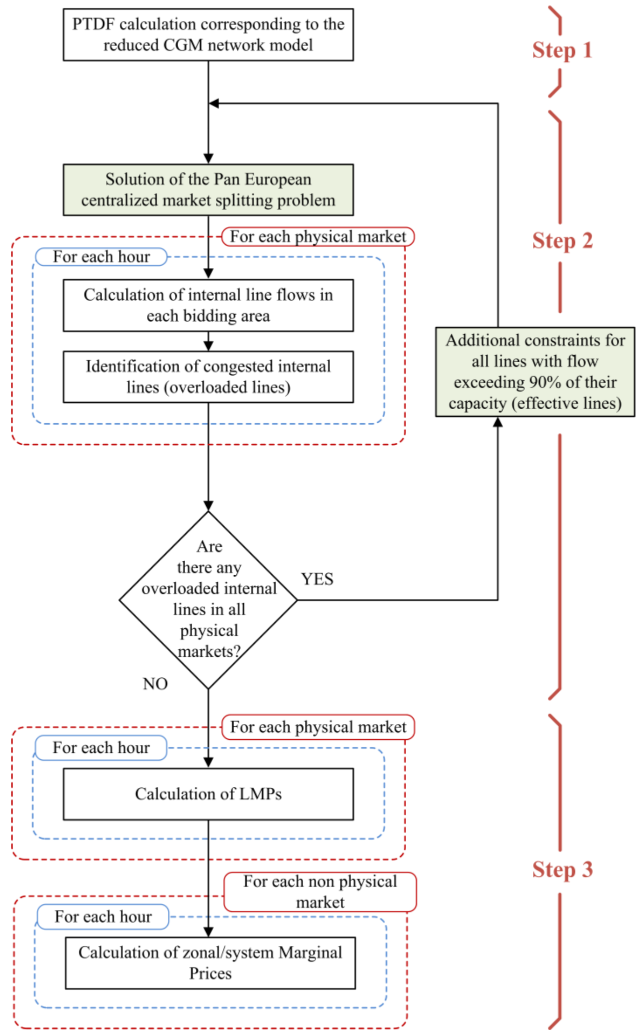

Fig. 2. Solution algorithm of the three proposed models

change in each line $l \in \mathcal{L}_{pm}^{ext}$ of the extended network representation with respect to an injection in bus $b \in \mathcal{B}_{pm}^{ext}$ and withdrawal from reference bus *ref* (the reference bus in this case is an internal bus of the examined physical market). This PTDF matrix is computed for each examined physical market.

Solution Algorithm

The overall solution algorithm of all three models is illustrated in Fig. 2 and comprises the following steps:

1) Step 1: Solution pre-process
   In Model I, the PTDFs corresponding to the reduced European network configuration are computed, along with the PTDFs corresponding to the zonal European network configuration.

2) Step 2: Problem solution
   An iterative process begins, in each iteration of which

the following steps are performed:

a) In Model I, the European market-splitting problem is solved, considering only the interconnections of the reduced European network. The constraints describing the interconnection flows of the reduced European power system are the following:

$$flow_{nt} = \sum_{b \in \mathcal{B}} \left(PTDF_n^{b,REF} \cdot P_{bt} \right) \quad \forall n \in N,\, t \in T \tag{20}$$

$$-ATC_{nt}^{a',a} \le flow_{nt} \le ATC_{nt}^{a,a'} \quad \forall n \in N,\, t \in T \tag{21}$$

In Models II and III, the pan-European market-splitting problem is solved, considering the zonal European network configuration. In this case, the constraints describing the interconnection flows in the zonal European network representation are the following:

$$flow_{nt} = \sum_{a \in \mathcal{A}} \left(PTDF_n^{a,REF} \cdot P_{at} \right) \quad \forall n \in N,\, t \in T \tag{22}$$

$$-ATC_{nt}^{a',a} \le flow_{nt} \le ATC_{nt}^{a,a'} \quad \forall n \in N,\, t \in T \tag{23}$$

b) The power flow on each line internal *l* is computed for each trading period as follows:

$$flow_{lt}^{DC} = \sum_{b \in \mathcal{B}} \left(PTDF_l^{b,ref} \cdot P_{bt} \right) \quad \forall\, l \in \mathcal{L}_{pm},\, t \in T \tag{24}$$

$$flow_{lt}^{DC} = \sum_{b \in \mathcal{B}_{pm}} \left(PTDF_l^{b,ref} \cdot P_{bt} \right) \quad \forall\, l \in \mathcal{L}_{pm},\, t \in T \tag{25}$$

$$flow_{lt}^{DC} = \sum_{b \in \mathcal{B}_{pm}^{ext}} \left(PTDF_l^{b,ref} \cdot P_{bt} \right) \quad \forall\, l \in \mathcal{L}_{pm}^{ext},\, t \in T \tag{26}$$

where the superscript *DC* in equations (24), (25) and (26) denotes that parameter $flow_{lt}^{DC}$ is computed from an ex-post DC power flow calculation, for Models I, II and III respectively.

c) The overloaded internal lines are identified (if any). In case there are no overloaded lines, the algorithm continues with Step 3. Otherwise, an additional constraint is created for each "effective" line (bearing a flow exceeding 90% of its normal rating) and is incorporated to the pan-European market-clearing problem in (a), in the form of the following equations:

$$flow_{lt} = \sum_{b \in \mathcal{B}} \left(PTDF_l^{b,REF} \cdot P_{bt} \right) \le F_l^{\max} \quad \forall l \in \mathcal{L},\, t \in T \tag{27}$$

$$flow_{lt} = \sum_{b \in \mathcal{B}_{pm}} \left(PTDF_l^{b,ref} \cdot P_{bt} \right) \le F_l^{\max} \quad \forall l \in \mathcal{L}_{pm},\, t \in T \tag{28}$$

$$flow_{lt} = \sum_{b \in \mathcal{B}_{pm}^{ext}} \left(PTDF_l^{b,ref} \cdot P_{bt} \right) \le F_l^{\max} \quad \forall l \in \mathcal{L}_{pm}^{ext},\, t \in T \tag{29}$$

where the nodal injection P_{bt} is given by:

$$P_{bt} = P_{bt}^{gen} - P_{bt}^{dem} \quad \forall b \in \mathcal{B}, t \in T \tag{30}$$

$$P_{bt} = P_{bt}^{gen} - P_{bt}^{dem} + E_n^b \cdot flow_{nt} \quad \forall b \in \mathcal{B}_{pm},\, t \in T \tag{31}$$

$$P_{bt} = P_{bt}^{gen} - P_{bt}^{dem} \quad \forall b \in \mathcal{B}_{pm}^{ext},\, t \in T \tag{32}$$

for Models I, II and II respectively. It should be noted that set $\mathcal{L}_{pm}^{ext}$ in equation (29) contains not only the physical markets' internal lines but also all interconnections of the European power system, as stated in the Nomenclature. As a result, in these cases the line limit $F_l^{\max}$ is equal to the respective ATC value.

Variables P_{bt}^{gen} and P_{bt}^{dem} denote the total generation and load in node *b* respectively. The process continues with step (a), considering all the additional constraints mentioned here.

3) Step 3: Solution post-process
An iterative process begins, in each iteration of which the system/zonal and nodal prices are computed for all non-physical and physical markets. The pricing mechanism for each of the three models is analytically presented in the next Section.

Pricing Mechanisms

In this section, the computation of the system/zonal and nodal prices for all non-pysical and physical markets respectively, are presented for the three studied models.

In **Model I**, the computation of the zonal/nodal prices for non-physical and physical markets follows the classic approach [28], in which the zonal prices for non-physical markets are derived from:

$$\lambda_t^a = \lambda_t^{REF} + \sum_{l \in \mathcal{L}} \left[PTDF_l^{a,REF} \cdot \mu_{lt} \right] \quad \forall a \in \mathcal{A},\, t \in T \tag{33}$$

while the nodal prices for the internal buses of all physical markets are computed from:

$$\lambda_t^b = \lambda_t^{REF} + \sum_{l \in \mathcal{L}} \left[PTDF_l^{b,REF} \cdot \mu_{lt} \right] \qquad \forall b \in \mathcal{B}_{pm},\, t \in T \tag{34}$$

where λ_t^{REF} is the Market Clearing Price (MCP) of reference area/bus REF of the reduced European network in trading period *t*. It should be noted here, that set $b \in \mathcal{B}_{pm}$ contains physical market's *pm* internal buses, while set $a \in A$ contains the "imaginary" nodes of non-physical markets. The union of all physical markets' sets $\mathcal{B}_{pm}$ along with set $\mathcal{A}$ denotes the set $\mathcal{B}$, as stated in the nomenclature.

In **Model II**, the system/zonal prices of the non-physical markets are computed from:

$$\lambda_t^a = \lambda_t^{ref} + \sum_n \left[PTDF_n^{a,ref} \cdot \mu_{nt} \right] + \sum_{pm} \sum_l \left\{ \sum_k \left[PTDF_l^{k,ref} \cdot \sum_n \left(E_k^n \cdot PTDF_n^{pm,ref} \right) \right] \cdot \mu_{lt} \right\} \qquad \forall a \in \mathcal{A},\, t \in T \tag{35}$$

while the nodal prices for all physical markets are derived from:

$$\lambda_t^k = \lambda_t^{pm} + \sum_l \left[PTDF_l^{k,ref} \cdot \mu_{lt} \right] \quad \forall b \in \mathcal{B},\, t \in T \tag{36}$$

where λ_t^a is the MCP on bidding area *a* in trading period *t*, $PTDF_n^{pm,ref}$ is the row of the $PTDF_n^{a,ref}$ matrix, referring to the examined physical market *pm*, λ_t^{pm} is the MCP of the physical market whose LMPs are calculated, which is computed by (35).

Finally, in **Model III**, the system/zonal prices of the non-physical markets are derived from the following equation:

$$\lambda_t^a = \lambda_t^{ref} + \sum_{n \in \mathcal{N}} \left[PTDF_n^{a,ref} \cdot \mu_{nt} \right] + \sum_{pm \in \mathcal{PM}} \sum_{l \in \mathcal{L}_{pm}^{ext}} \left[PTDF_l^{pm,ref} \cdot \mu_{lt} \right] \qquad \forall a \in \mathcal{A},\, t \in T \tag{37}$$

while the nodal prices for the physical markets are computed as follows:

$$\lambda_t^b = \lambda_t^{ref} + \sum_{n \in \mathcal{N}} \left[PTDF_n^{pm,ref} \cdot \mu_{nt} \right] + \sum_{pm \in \mathcal{PM}^*} \left\{ \sum_{l \in \mathcal{L}_{pm}^{ext}} \left[PTDF_l^{pm,ref} \cdot \mu_{lt} \right] \right\} + \sum_{l \in \mathcal{L}_{pm}^{ext}} \left[PTDF_l^{b,ref} \cdot \mu_{lt} \right] \quad \forall b \in \mathcal{B}_{pm},\, t \in T \tag{38}$$

where the subset $\mathcal{PM}^* \subseteq \mathcal{PM}$ denotes all physical markets except the one whose nodal prices are calculated from equation (38). Parameter $PTDF_l^{a,ref}$ is the row of the $PTDF_l^{b,ref}$ matrix of each physical market, where $b \in \mathcal{B}_{pm}^{ext}$. Parameters $PTDF_n^{pm,ref}$ and $PTDF_l^{pm,ref}$ in equation (38) are the rows of the $PTDF_n^{a,ref}$ and $PTDF_l^{b,ref}$ matrices corresponding to the examined physical market.

In all the above equations μ_{nt} and μ_{lt} are the Lagrange multipliers associated with the interconnection and internal flow constraints, respectively.

Equations (33)-(38) are derived from the differentiation of the Lagrangian function of the respective optimization problems. The additional terms in equations (35)-(38), with regard to the classic equation for the ex-post calculation of the market clearing prices [28], are due to equations (25) and (26) and express the effect of all internal transmission lines' congestion to the overall system/zonal and nodal marginal prices of all physical markets. By (33)-(38), it is obvious that in the presence of internal congestions, system marginal prices may be differentiated between countries even in the case with no binding interconnection constraints.

Test Results

I. Test Case System

The proposed algorithm is tested using the full European network with 166 interconnection lines. For simplicity reasons, it is assumed here that each market comprises of a single bidding area (the possible internal zones and corridors within each country are ignored.

For demonstration purposes, it is assumed arbitrarily that the physical markets in Europe are Greece, Italy, Spain, Portugal, Switzerland and Austria. The size of the internal network of these countries is depicted on Table I. The total number of load buses on these countries is 858. In each area an inelastic load in proportion to the summer peak load is considered.

All bidding areas in the European Power System are assumed to be organized as Power Exchanges, with the exception of Greece, which follows the unit commitment (Power Pool) model. The data for the Greek generating units have been derived from [9]-[10], while the bids and offers of all participants in PXs have been randomly created.

In this test case, it is assumed that each unit *g* or participant *p* may submit up to ten randomly created price/quantity offers. For the modeling of the loads, three template profiles corresponding to a typical day of June in Germany, Switzerland and Greece are created and adjusted in each bidding area according to the total load consumption (as provided in the ENTSO-E test case), depending on the area's geographical position. For the physical markets, demand entities submit their bids in specific load buses, whereas in non-physical market the total bids are aggregated in order to construct the inelastic load curve. Finally, the RES injection is considered deterministic and has been implicitly incorporated in the total load.

TABLE I
PHYSICAL MARKETS' NETWORK SIZE

Countries	Buses	Transmission Lines and Transformers
Austria	75	95
Switzerland	149	195
Spain	468	719
Greece	265	412
Italy	316	429
Portugal	148	237
TOTAL	**1,421**	**2,087**

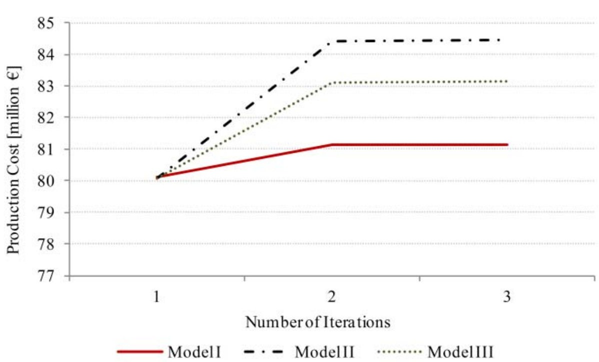

Fig. 3. Production cost in each of the proposed methods

TABLE II
PRODUCTION COST DIFFERENCE IN THE THREE MODELS

Model I [million €]	Model II [million €]	Difference (%)	Model III [million €]	Difference (%)
81.15	84.45	3.9%	83.13	2.3%

TABLE III
TOTAL NUMBER OF SINGLE EQUATIONS AND VARIABLES

		Single Equations	Single Variables
Model I	1	1,029,848	848,022
	2	1,031,033	848,417
	3	1,031,219	848,479
Model II	1	1,029,848	848,022
	2	1,033,103	849,107
	3	1,033,427	849,215
Model III	1	1,029,848	848,022
	2	1,033,334	849,184
	3	1,033,427	849,215

II. Test Results

The total production cost for the whole European Power System is presented for the three proposed methods in Fig.3. As shown, the total production cost in all methods is increased as the iterative algorithm proceeds. Following the solution of the power flow calculations in each respective case, additional constraints are added to the optimization problem, resulting to a "tighter" solution of the optimization problem, in each iteration of the algorithm. Since the load has been assumed to be inelastic in all bidding areas, the total expected generation cost increases in each iteration due to the redispatching of all units in order to satisfy the additionally incorporated power flow constraints. As shown, Model I leads to a solution with lower production cost, thus proving to be more efficient than the two decentralized approaches. The efficiency of the first is further illustrated in Table II, where the total production cost of the two decentralized models is presented as a percentage of the achieved production cost from Model I. Even though the production cost does not differ more than 4% in both decentralized methods, the final solution is completely different from the one achieved from Model I, as shown below.

The total number of single equations and variables of the optimization problem is presented in Table III. It should be noted that the total number of discrete (binary) variables is equal to 9,569 in all three methods and in all iterations, since the incorporation of additional line flow equations in the optimization problem does not affect the number of discrete (binary) variables, which are utilized only for describing the commitment status of units in power pools. As shown in Table III, the total number of single equations and variables is increased in each iteration, owing to the addition of the power flow inequality constraints.

The increase in the number of equations has a direct effect in the execution time of the optimization problem. As shown in the third column of Table IV, an increase in the execution time is observed between the first iteration in all three models and the following iterations. This is

TABLE IV
EXECUTION TIMES FOR ALL STEPS OF THE SOLUTION ALGORITHM IN SECONDS

		Data Input	Optimization Time	Expost Calculations	Total Time
Model I	1	37.56	58.72	0.42	235.78
	2		67.28	0.44	
	3		68.56	0.42	
Model II	1	33.15	60.20	0.70	222.09
	2		63.32	0.73	
	3		63.28	0.71	
Model III	1	34.24	61.78	0.68	308.11
	2		95.47	0.69	
	3		114.55	0.69	

TABLE V
TOTAL NUMBER OF EFFECTIVE AND OVERLOADED LINES

		Effective Lines	Overloaded Lines
Model I	1	395	244
	2	457	31
	3	459	**0**
Model II	1	1,085	864
	2	1,193	50
	3	1,196	**0**
Model III	1	1,162	533
	2	1,245	31
	3	1,246	**0**

TABLE VI
FLOWS ON SELECTED LINES IN THE THREE EXAMINED MODELS

					Model III [MW]						
Line	**Time [h]**	**Line Limit [MW]**	**Model I [MW]**	**Model II [MW]**	**Market-splitting solution [MW]**	**AT Extended Network**	**CH Extended Network**	**ES Extended Network**	**GR Extended Network**	**IT Extended Network**	**PT Extended Network**
AT	13	150.526	112.196	130.719		-141.671	-	-	-	-	-
CH	7	124.708	30.694	30.763		-	-142.856	-	-	-	-
ES	15	407.725	407.725	188.169		-	-	21.597	-	-	-
GR	18	456.880	142.390	67.165		-	-	-	-35.395	-	-
IT	20	249.970	218.352	216.45		-	-	-	-	-142.17	-
PT	8	472.503	-130.233	-162.963		-	-	-	-	-	74.657
CZ-SK	3	198.909	162.875	89.606	82.799	93.543	82.833	86.792	82.799	82.799	85.983
BE-FR	9	302.936	-302.936	-302.936	-238.290	-224.226	-238.297	-302.936	-238.290	-238.290	-120.061
BA-HR	17	125.054	125.054	-51.522	-1.758	12.974	-3.065	11.699	-1.758	-1.758	7.601
MK-RS	12	921.451	-357.155	-635.783	-488.367	-488.854	-392.772	-488.774	-488.367	-488.367	-488.732
HU-RS	10	921.451	335.794	11.145	-46.381	-27.374	-47.346	-10.405	-46.381	-46.381	-28.702
PL-SK	21	710.834	236.424	-58.139	-133.872	-123.901	-133.747	-116.381	-133.872	-133.872	-124.395

due to the addition of the power flow equations for all effective lines, which result in a more constrained problem, thus increasing the optimization execution time. The data import and manipulation, PTDF calculations and the internal line flows computation require in total no more than 45 seconds in all three models, as shown in Table IV, while the total execution time in all three cases is less than 6 minutes.

On Table V the total number of effective and overloaded lines is presented, for all hours of the trading day. As shown in Table V, the total number of effective lines, for all hours of the trading day, is increased in each iteration. This is due to the fact that the effective lines of the previous iteration are incorporated also in the current iteration, even if they become ineffective. This is done in order to avoid undesirable oscillations of the iterative algorithm, when effective lines switch on and off in successive iterations of the algorithm, due to the effect of resolving congestions in other parts of the network. This logic is not followed for the overloaded lines in each iteration, since their total number does not depend on the previous iterations and normally decreases as the algorithm proceeds. As shown on Table V, when the total number of overloaded lines is equal to zero in each of the three models the iterative process terminates.

As already stated, the total production cost of the two decentralized methods is close to the one achieved in Model I, with the value of the third Model being closer to the optimal solution. This is due to the fact the local System Operator perceives a network representation closest to the full network used in Model I and thus achieving a social welfare with value closer to the one Model I. Despite this small inefficiency, the flows are totally different in all three Models. This means that the attained solutions of the two decentralized processes contain inconsistent results as compared to the optimal solution achieved through Model I, indicating the basic problem of all decentralized approaches: when the local System Operators check their internal congestion without considering the whole synchronous system topology and characteristics, they attain erroneous flows that may lead to critical congestions in real-time and additional cost from the redispatching procedure.

Table VI presents the resulting flows in six randomly selected internal lines and in six interconnections, for each one of the examined models. The first column contains the identity of each line, the first six lines are internal lines within the examined physical markets (Greece (GR), Italy (IT), Austria (AT), Switzerland (CH), Spain (ES) and Portugal (PT)), whereas the next lines correspond to the interconnections between various bidding areas (Czech Republic (CZ), Slovakia (SK), Belgium (BE), France (FR), Bosnia and Herzegovina (BA), Croatia (HR), FYROM (MK), Serbia (RS), Hungary (HU) and Poland (PL)). The second column gives the trading period of the day, while the rest of the columns provide the information about the line limits and the line flows attained from the solution of the three examined models. As shown, there is a difference in the flows of the decentralized methods compared with the centralized approach, resulting even in flows with opposite direction. Another interesting notice is how the extended network decentralized approach (Model III) conceives the flows in the interconnections. The six last columns of the table contain the flows that are computed in the "extended" network of each physical market. The flows are different from the ones of the Model I solution, indicating the infeasibility of the iterative approaches. These differences in the values of the attained line flows in the 6 physical markets along with the interconnections (IN) are further presented in Fig. 3 and Fig. 4, where they are presented for the 13th hour of the trading horizon in the form of box plots.

As a result, both cases of decentralized network modeling result in not a sub-optimal but in an infeasible solution to the integrated European electricity market, in terms of flows in both internal and interconnection lines.

The reduced view of the whole synchronous system topology and characteristics has a direct impact in the attained zonal/system and nodal market clearing prices. In Fig. 5 the zonal prices for France are presented. As shown, in this area the prices cleared in all three methods are almost the same. This is not the case in other bidding areas such as Serbia (Fig. 6) where, even though the prices follow the same trend, their absolute deviation is huge in some hours of the trading day (for example in the case of Serbia, the attained results between Models I and II and I and III in hour 13 is almost 20 €/MWh and 13 €/MWh respectively). As in the case of power flows, the deviations in the cleared prices from Models I and II and I and III are presented for the 11th hour of the trading horizon in the form of box plots in Fig. 7 and Fig. 8.

Consequently, the attained nodal/zonal prices in the two decentralized approaches are incorrect, leading to erroneous day-ahead settlements and providing incorrect price signals to market participants, thus hindering the efficient market integration.

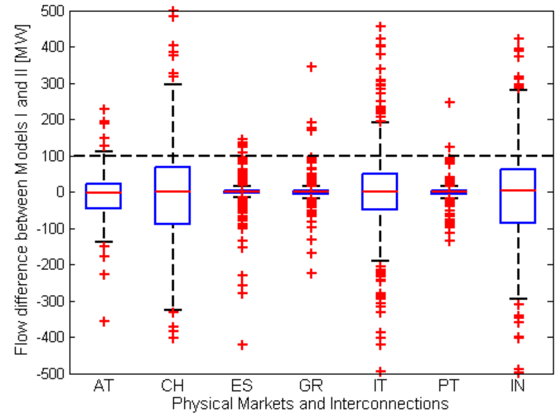

Fig. 3. Flow differences between Models I and II in hour 13

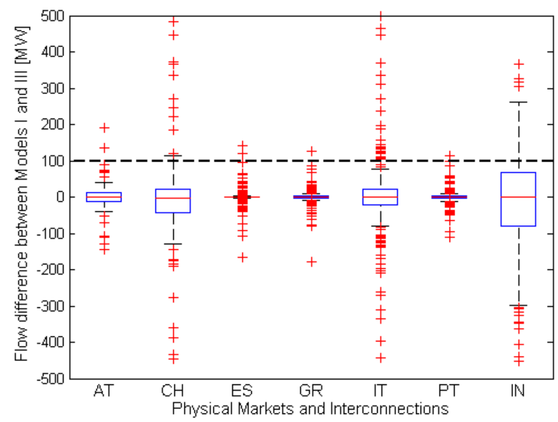

Fig. 4. Flow differences between Models I and III in hour 13

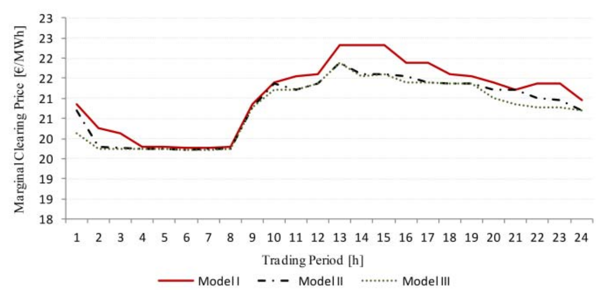

Fig. 5. French zonal prices for all examined Models

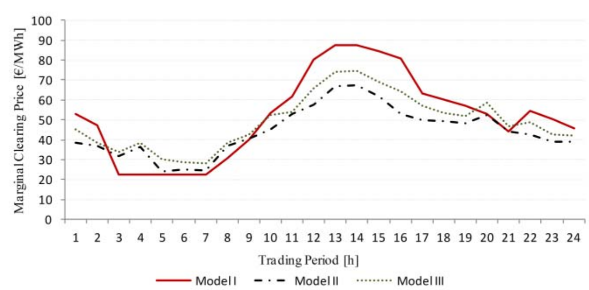

Fig. 6. Serbian zonal prices for all examined Models

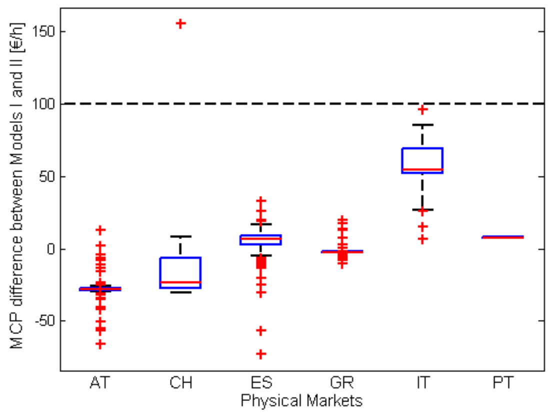

Fig. 7. Nodal MCP differences between Models I and II in hour 11

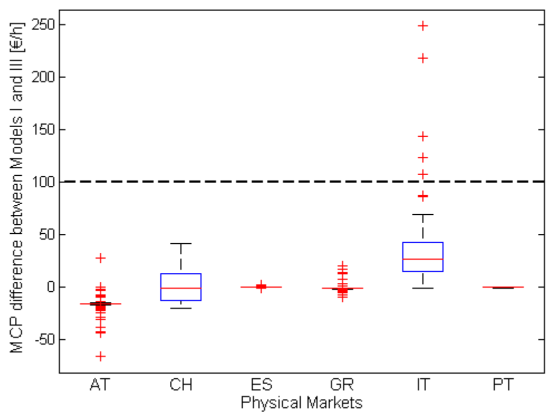

Fig. 8. Nodal MCP differences between Models I and III in hour 11

III. Computational Issues

All cases have been implemented and solved in GAMS [29] and MATLAB [30], running in a desktop PC, with Intel Quad Core i7 CPU processor at 3.4 GHz, 16 GB RAM. The pan-European centralized market-splitting problem, along with the enforcement of additional constraints for all effective lines (green boxes in Fig. 2), was modeled and implemented in the GAMS modeling environment, while the CPLEX solver [31] was utilized for the solution of the mixed integer linear programming problem. Convergence tolerance was set to zero, thus achieving proven optimal results in all cases. MATLAB was required for the data manipulation, the calculation of the PTDF matrices and all ex-post DC load flow computations. The data exchange between GAMS and MATLAB has been achieved through the GDXMRW utilities [32].

Conclusion

In view of the forthcoming high RES penetration, three congestion management approaches for the integration of the European electricity markets with intra-zonal congestions taken explicitly into account in the day-ahead trading period, have been examined in this paper. The first approach follows the reduced network representation of the whole European power system, where each physical market is modeled through all its internal nodes and lines, whereas non-physical markets are modeled by an "imaginary" node. This approach provides the optimal results in terms of social welfare, flow calculations and pricing, but requires the exchange of network data between involved TSOs.

In the other two examined decentralized approaches a market-splitting is performed, where each TSO checks the feasibility of its internal line flows against either a "myopic" representation or an extended version of its internal network. In these two approaches, the TSOs of physical markets are able to monitor their intra-zonal congestions without communicating any data concerning their internal network to other involved parties. Both approaches provide erroneous results, namely the generation and demand are inconsistent with the attained line flows, due to a myopic view of the whole European network.

The authors do not claim that the examined decentralized approaches are the best one, but aim at highlighting the inefficiencies arising in the day-ahead market clearing procedure when the whole synchronous system topology and characteristics are not considered. The erroneous attained power flow results may lead to critical congestions in real time operation, while the unavoidable costs of redispatching and counter-trading will be passed to consumers. Moreover, erroneous day-ahead nodal and zonal prices provide incorrect price signals to market participants, further hindering the efficient operation and integration of the European electricity market.

The authors aim to extend this research in order to uncover up to which point the decentralized operation of the European electricity market is possible and provide ground for fruitful discussions between involved parties and policy makers about the efficiency of the European electricity market design.

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