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Incorporating unit commitment aspects to the European electricity markets algorithm: An optimization model for the joint clearing of energy and reserve markets

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HIGHLIGHTS

- An MILP model for the extension of EUPHEMIA hourly offers module is presented.
- Power reserves market is jointly cleared with energy market.
- Minimum income condition is extended to include also welfare from reserve market.
- Intra-hourly ramping constraints guarantee system's flexibility capability.
- Strategy, market structure, and power trading affect techno-economic decisions.

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ABSTRACT

The European electricity markets' integration aims at the market coupling among interconnected power systems and the enhancement of market competitive forces. This process is facilitated by the adoption of a common clearing algorithm among European power exchanges, entitled EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm), which however lacks to capture critical technical aspects of power systems, as done by the unit commitment problem including start-up and shut-down decisions, time constraints (minimum on- and off-times), as well as the consideration of ancillary services. This paper presents an optimization-based framework for the optimal joint energy and reserves market clearing algorithm, further utilizing the hourly offers module of the EUPHEMIA algorithm. In particular, through the formulation of a mixed integer linear programming (MILP) model and employing an iterative approach, it determines the optimal energy and reserves mix, the resulting market clearing prices, and it calculates the welfares of the market participants. The model incorporates intra-hourly power reserve constraints, as well as introduces new market products such as the option of forming linked groups of power units, aiming at supplying additional flexibility in the decision-making of the market participants. The model applicability has been assessed in the Greek power system and its interconnections with neighboring power systems in Southeast Europe. The proposed optimization framework can provide useful insights on the determination of the optimal generation and interconnection portfolios that address the new market-based operational challenges of contemporary power systems subject to technical and economic constraints.

1. Introduction

Global transition towards low-carbon power systems constitutes a declared target at an international level, with the objective of mitigating average global temperature increase to "well below 2 °C" in the current century, in comparison with pre-industrial levels. Since 1990,

Abbreviations: EUPHEMIA, Pan-European Hybrid Electricity Market Integration Algorithm; LIG, lignite-fired units; LP, Linear Programming; MCP, Mixed Complementarity Problem; MILP, Mixed Integer Linear Programming; MIP, Mixed Integer Programming; MIQCP, Mix Integer Quadratic Constraint Problem; NGCC, natural gas-fired combined cycle units; NGGT, natural gas-fired open cycle units; PCR, Price Coupling of Regions; PUN, Prezzo Unico Nazionale; SEM, Single Electricity Market

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Nomenclature

Sets

f^{ht} set of operational blocks f of each hydrothermal unit ht, representing a specific price-quantity pair
f^{dm} set of blocks f of each load bid dm, representing a specific price-quantity pair
f^{in} set of operational blocks f of each interconnection in, representing a specific price-quantity pair
h set of hydroelectric units
ht set of hydrothermal units
a set of supply entities, including thermal, hydroelectric, and renewable units
dm set of load entities
dt set of representative days
in set of interconnections of the studied power system
res set of renewable units
t set of time periods
th set of thermal units

Parameters

$B^{prd}_{ht,t,f^{ht},dt}$ quantity of each block f^{ht} of the energy supply function of each unit ht in each time period t and representative day dt (MW)
$B^{dem}_{dm,t,f^{dm},dt}$ quantity of each block f^{dm} of the load bid function of each load entity dm in each time period t and representative day dt (MW)
$B^{exp}_{in,t,f^{in},dt}$ quantity of each block f^{in} of the exported energy function of each interconnection in in each time period t and representative day dt (MW)
$B^{imp}_{in,t,f^{in},dt}$ quantity of each block f^{in} of the energy supply function of each interconnection in (imports) in each time period t and representative day dt (MW)
$C^{prd}_{ht,t,f^{ht},dt}$ energy supply cost function of each unit ht in each operational block f^{ht}, time period t and representative day dt (€/MW)
$C^{2-}_{ht,t,dt}$ secondary-down reserve provision cost function of each unit ht in each time period t and representative day dt (€/MW)
$C^{2+}_{ht,t,dt}$ secondary-up reserve provision cost function of each unit ht in each time period t and representative day dt (€/MW)
$C^{3ns}_{ht,t,dt}$ non-spinning (offline) tertiary-up reserve provision cost function of each unit ht in each time period t and representative day dt (€/MW)
$C^{3s-}_{ht,t,dt}$ spinning tertiary-down reserve provision cost function of each unit ht in each time period t and representative day dt (€/MW)
$C^{3s+}_{ht,t,dt}$ spinning tertiary-up reserve provision cost function of each unit ht in each time period t and representative day dt (€/MW)
$C^{dem}_{dm,t,f^{dm},dt}$ load bid cost function of each load entity dm in each segment f^{dm}, time period t and representative day dt (€/MW)
$C^{exp}_{in,t,f^{in},dt}$ exported energy cost function of each interconnection in (exports) in each operational block f^{in}, time period t and representative day dt (€/MW)
$C^{imp}_{in,t,f^{in},dt}$ energy supply cost function of each interconnection in (imports) in each operational block f^{in}, time period t and representative day dt (€/MW)
$C^{var}_{th,t,dt}$ minimum average variable cost of each thermal unit th in each time period t and representative day dt (€/MW)
C^{sd}_{th} shut-down cost of each thermal unit th (€)
DT_{th} minimum down-time of each unit th (h)
$INT^{exp}_{in,t,dt}$ capacity of each interconnection in (exports) in each time period t and representative day dt (MW)
$INT^{imp}_{in,t,dt}$ capacity of each interconnection in (imports) in each time period t and representative day dt (MW)
$LG^{dn}_{ht,t,dt}$ maximum decrease gradient of each ht in each time period t and representative day dt imposed by a Load Gradient Order (MW/min)
$LG^{up}_{ht,t,dt}$ maximum increase gradient of each unit ht in each time period t and representative day dt imposed by a Load Gradient Order (MW/min)
$LNK_{th,th',dt}$ linkage status among thermal units th (parent-unit) and th' (child-unit) in each representative day dt (1, if there is linkage, and 0, otherwise)
$L_{a,t,dt}/L_{in,t,dt}$ power injection losses coefficient of each supply entity a or interconnection in (imports) in each time period t and representative day dt (per unit)
$M_{a,t,dt}$ non-priced mandatory energy production of each unit a in each time period t and representative day dt (MW)
N^{sec} percentage of secondary reserve requirements on the energy demand requirements (%)
N^{ter} percentage of tertiary reserve requirements on the energy demand requirements (%)
$P^{max}_{ht,t,dt}$ available technical maximum of each unit ht in each time period t and representative day dt (MW)
$P^{min}_{ht,t,dt}$ technical minimum of each unit ht in each time period t and representative day dt (MW)
$R3^{ns}_{ht}$ tertiary offline reserve capability of each unit ht (MW)
$RR^{dn,15}_{ht}$ ramp-down capability of each unit ht during a 15-min time interval (MW/min)
$RR^{dn,30}_{ht}$ ramp-down capability of each unit ht during a 30-min time interval (MW/min)
$RR^{dn,60}_{ht}$ ramp-down capability of each unit ht during a 60-min time interval (MW/min)
$RR^{up,15}_{ht}$ ramp-up capability of each unit ht during a 15-min time interval (MW/min)
$RR^{up,30}_{ht}$ ramp-up capability of each unit ht during a 30-min time interval (MW/min)
$RR^{up,60}_{ht}$ ramp-up capability of each unit ht during a 60-min time interval (MW/min)
$Tolerancelevel_{th,dt}$ desired tolerance level of each thermal unit th in each representative day dt, for the minimum income condition order activation/deactivation check (p.u.)
UT_{ht} minimum up-time of each unit ht (h)
$Z^{2-}_{th,t,dt}$ desired cost coefficient added in the secondary-down reserve provision cost function of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)
$Z^{2+}_{th,t,dt}$ desired cost coefficient added in the secondary-up reserve provision cost function of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)
$Z^{3nsp}_{th,t,dt}$ desired cost coefficient added in the non-spinning (offline) tertiary-up reserve provision cost function of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)
$Z^{3sp-}_{th,t,dt}$ desired cost coefficient added in the spinning tertiary-down reserve provision cost function of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)
$Z^{3sp+}_{th,t,dt}$ desired cost coefficient added in the spinning tertiary-up reserve provision cost function of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)
$Z^{e}_{th,t,dt}$ desired cost coefficient added in the minimum average

variable cost of each thermal unit th in each time period t and representative day dt, when submitting a minimum income condition order (€/MW)

Positive variables

$AR_{th,dt}$ acquired revenues of each thermal unit th in each representative day dt, when submitting a minimum income condition order (€)
$NR_{th,dt}$ net acquired revenues of each thermal unit th in each representative day dt, when submitting a minimum income condition order (€)
$QR_{th,dt}$ required revenues of each thermal unit th in each representative day dt, when submitting a minimum income condition order (€)
$RD^{2-}_{t,dt}$ secondary-down reserve requirements of the studied power system in each time period t and representative day dt (MW)
$RD^{2+}_{t,dt}$ secondary-up reserve requirements of the studied power system in each time period t and representative day dt (MW)
$RD^{3-}_{t,dt}$ tertiary-down reserve requirements of the studied power system in each time period t and representative day dt (MW)
$RD^{3+}_{t,dt}$ tertiary-up reserve requirements of the studied power system in each time period t and representative day dt (MW)
$e^{prd}_{ht,t,f^{ht},dt}$ cleared energy supply of each unit ht in each operational block f^{ht}, time period t and representative day dt (MW)
$e^{dem}_{dm,t,f^{dm},dt}$ cleared energy load of each load entity dm in each segment f^{dm}, time period t and representative day dt (MW)
$e^{exp}_{in,t,f^{in},dt}$ cleared energy exports of each interconnection in in each operational block f^{in}, time period t and representative day dt (MW)
$e^{imp}_{in,t,f^{in},dt}$ cleared energy imports of each interconnection in in each operational block f^{in}, time period t and representative day dt (MW)
$p_{ht,t,dt}$ total cleared energy supply of each unit ht in each time period t and representative day dt (MW)
$r^{2-}_{ht,t,dt}$ cleared secondary-down reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{2+}_{ht,t,dt}$ cleared secondary-up reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{3-}_{ht,t,dt}$ cleared tertiary-down reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{3+}_{ht,t,dt}$ cleared tertiary-up reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{3ns}_{ht,t,dt}$ cleared non-spinning (offline) tertiary-up reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{3sp-}_{ht,t,dt}$ cleared spinning tertiary-down reserve provision of each unit ht in each time period t and representative day dt (MW)
$r^{3sp+}_{ht,t,dt}$ cleared spinning tertiary-up reserve provision of each unit ht in each time period t and representative day dt (MW)

Binary variables

$x_{ht,t,dt}$ 1, if each unit ht is operational in each time period t and representative daydt0, otherwise
$x^{3ns}_{ht,t,dt}$ 1, if each unit ht provides offline tertiary reserve in each time period t and representative daydt 0, otherwise
$x^{su}_{ht,t,dt}$ 1, if each unit ht starts up in each time period t and representative daydt 0, otherwise
$x^{sd}_{ht,t,dt}$ 1, if each unit ht shuts down in each time period t and representative daydt 0, otherwise

13,667 publications have been recorded coping with power system's decarbonization issues [1]. One of the ten key priorities of the European Commission for the period 2015–2019 is the Energy union and climate[2], aiming at the development of a fully functioning and interconnected internal energy market, towards maintaining security of energy supply, increasing competitiveness and ensuring affordable prices for final consumers. The interdependence between electricity and gas systems creates significant challenges in terms of security of supply and potential impacts of gas supply disruptions [2], especially when combined with nuclear energy supply disruptions [3], on power systems. In that context, the process of transferring the real electricity generation costs on the final consumers by bridging the gap between the day-ahead wholesale markets and individual customers is of paramount importance in the contemporary power markets [4]. A vital pillar of this process is the adoption of a common algorithm for determining volumes and prices in all relevant zones, based on the marginal pricing principle. The liberalization of power markets has created new dynamics in the electricity prices formation, with significant impacts on the operational scheduling of power systems due to the volatile nature of renewable energy sources and the highly fluctuating prices [5]. The Price Coupling of Regions (PCR) project of the European Power Exchanges has developed an algorithm called EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm)[3], which allocates cross-border transmission capacity and calculates day-ahead electricity prices across Europe. Already, 23 European countries have adopted the EUPHEMIA algorithm, through national power exchanges.

An important aspect of this algorithm is that it is a simple economic algorithm, compared to more techno-economic traditional approaches, such as the unit commitment problem. On the other hand, most well-established power markets in the USA, such as the liquid PJM market, are based on co-optimization of energy and ancillary services, implementing mathematical approaches that consider the technical characteristics of the units and the power system. The technical challenges arising from the penetration of renewables, storage and other technical factors are captured through the development of new-generation unit commitment approaches [6]. A considerable advantage of those approaches, compared to more economic ones, is the provision of more robust scheduling, enhancing power system's stability, and aiming at evaluating energy and reserve prices in low-carbon power systems [7]. The unit commitment problem is not only important for the short-term dispatching of the power units, but also for the medium-term, examining interconnection issues [8], and/or impacts of a series of uncertainties on the energy mixes [9], long-term planning of power systems with Monte Carlo techniques [10] or scenario-based analysis [11], as well as for risk management in electricity trading [12].

However, the vision for the development of an integrated and harmonized European electricity market, based on a European energy-only target model, is justified by the fact that it is expected to enhance liquidity, efficiency and social welfare. Newbery et al. [13] examined the benefits of integrating European electricity markets, providing evidence that the benefits could be €1 bn/year from the day-ahead market coupling, while intra-day and balancing benefits could add a further €1.3 bn/year. The total benefits, when considering unscheduled flows, are estimated to be €3.4 bn/year. In addition, Newbery [14] concluded

[2] https://ec.europa.eu/commission/priorities_en.
[3] https://www.n-side.com/pcr-euphemia-algorithm-european-power-exchanges-price-coupling-electricity-market/.

that energy-only markets, adopting the electricity Target Model, can work if they are well-designed to avoid missing money (price caps are bounded, being unable to reflect resources' scarcity, and/or ancillary as well as flexibility services are inadequately remunerated) and missing market (hedging options against potential risks) problems. This paper concludes that capacity auctions tend to over-procure capacity, enhancing the missing money problem, while addressing missing market problems makes under-procurement more economical than over-procurement, and facilitates trade among different capacity markets.

The redesign of market structure and the adoption of the EUPHEMIA algorithm by different European countries, have already led to several research papers on national power markets, either on their design so as to comply with the provisions of the European Target Model, or on the effects of the implementation of the new market design. A recent paper [15] provides a proposal for the high-level design of the Greek wholesale market, as well as the specifications for creating a day-ahead, intra-day, forward and balancing market for Greece. Cosmo and Lynch [16] examined the evolution of the Irish Single Electricity Market in order to comply with the European Target Model, identifying the crucial role of a competitive forward market, as it will enhance competition on both spot and retail markets. Tanrisever et al. [17] provided an overview of the Dutch market, describing the organization of financial trading and clearing mechanism of electricity for the day-ahead and intra-day markets, as well as for the futures exchange, the imbalance market and the reserve capacity management in the Netherlands. Newbery [18] examined the impact of EU energy policy from electricity market reforms in Britain and Ireland, identifying the contrast between the energy-only European target model with the policies adopted in Britain, concerning the capacity mechanisms and the feed-in-tariffs schemes to support renewables. The paper concludes that it is necessary to consider auctions that provide competition for market entry, suitable flexibility and ancillary services markets, as well as efficient pricing of the regulated assets, namely transmission and distribution networks. Menezes and Houllier [19] examined market integration before and after the closures of eight nuclear power plants in Germany. Two Multivariate Generalized Autoregressive Conditional Heteroscedasticity (MGARCH) models with dynamic correlations are used to assess short-run electricity spot market behaviour, while the long-run behaviour of electricity spot prices, is examined through the implementation of a fractional co-integration analysis. The results show a positive time-varying correlation between prices in highly interconnected markets and a negative correlation between wind power penetration in Germany and electricity spot prices in the German and neighboring markets. Nepal and Jamasb [20] studied the market integration in the Irish Single Electricity Market (SEM), using a time-varying Kalman filter technique. The results indicate no market integration between SEM and other European markets, except for Elspot and Great Britain. The paper indicated the importance of liquidity in wholesale markets in the market integration process.

There is also an increasing literature on the identification of the market coupling effects, as well as on the market splitting determinants among interconnected power systems. Santos et al. [21] presented a multi-agent simulation of competitive electricity markets, aiming at demonstrating the advantages that the integration of various market models and simulation platforms have for the study of the electricity markets' evolution. Grimm et al. [22] investigated the long-run effects of market splitting, identifying the reasons for the decreased welfare of introducing prices zones. Moreover, Figueiredo et al. [23] evaluated the market splitting determinants of the Iberian spot electricity prices, using logit and non-parametric models to express the market splitting probability response. By using the main technologies in the generation mix, namely wind, hydro, thermal and nuclear power, the available transfer capacity and demand as explanatory variables, the paper concludes that an increase of market splitting probability exists in case of higher availability of low-marginal cost electricity, such as renewables. Meeus et al. [24] examined block order restrictions in combinatorial electric energy auctions. Those orders are used in European power exchanges, because generators face non-convex costs, in particular start-up costs and minimum run levels. The paper discusses the rationale of those block order restrictions, through the examination of representative scenarios, concluding that the restrictions could be relaxed, concerning the block size restrictions as well as the number of blocks a participant can submit per day.

Vlachos et al. [25] provided a comparison of two mathematical programming models, solving a convex portfolio-based European day-ahead electricity market. A Mixed Complementarity Problem (MCP) and a Linear Programming model (LP), implemented in the pan-European zonal power system, are evaluated in terms of computational efficiency. The MCP model is computationally demanding, however it can formulate more adjustable product types by formulating respective non-linear mixed pricing rules. The LP model is computationally efficient, but it is not flexible enough to handle adjustable block order types. Biskas et al. [26] examined the volume-coupling between a power exchange and a mandatory power pool, providing evidence that the implementation of a single centralized market splitting has significant advantages, being computationally more efficient, reaching global optimum solution and providing proper price signals to the market participants. The paper also argues that in contradiction to several papers stating that the rules' harmonization is a precondition to successful market integration in the EU, each market could retain its regional/national rules and mechanisms, without threatening the overall market coupling efficiency.

There is also a growing list of works examining different order types of the EUPHEMIA algorithm, or proposing alternative ones so as to capture more technical aspects of the power systems operation. Lam et al. [27] examined European day-ahead electricity market coupling, by developing a complete European day-ahead market model, formulating it as a Mix Integer Quadratic Constraint Problem (MIQCP). It also applies an iterative procedure, aiming to mitigate the non-convexity of electricity prices across Europe, arising from the EUPHEMIA order types and conditions, including "fill or kill" condition of blocks, complex and Prezzo Unico Nazionale (PUN) orders. Sleisz and Raisz [28] presented an integrated mathematical model for uniform purchase prices on European multi-zonal power exchanges. Due to the presence of continuous non-convexities, the paper proposes a new formulation so as to avoid non-convex Mixed Integer Programming (MIP) formulation. The model applies explicit income-expense balance to execute the prices clearing. Kiesel and Kusterman [29] developed structural models for coupled electricity markets, deriving analytical formula for the distribution of spot prices, of futures prices and of other options. The model is calibrated to the French–German market region, providing insights on the effect of market coupling on electricity prices.

Madani and Vyve [30] presented a new market model for examining the non-convex uniform price electricity auctions, where bidders, either producers or consumers, can specify a minimum profit or maximum payment condition. Such types of conditions, similar to block orders with a minimum acceptance ratio used in France, Germany or Belgium, and especially to the complex orders with a minimum income condition used in Spain and Portugal, aim at start-up costs recovery of a power plant or of a large consumer. When compared to the minimum income condition orders currently used at the OMIE power exchange, they have some advantages, as the methodology is faster in its implementation, while the proposed order types are more aligned with the operating constraints of the power units. In addition, Sleisz and Raisz [31] presented a model for load gradient conditions on all-European power exchanges, implementing complex supply order types with ramping limitations. The proposed methodology provides useful insights, such as shadow prices, which represent hidden costs of ramping limits. Focusing on ramping constraints, Morales-España et al. [32] examined the evolution and incorporation of power and ramping capacity reserves, due to the penetration of wind generation, in the unit commitment model. In another paper, Madani and Vyve [33] examined different algorithms for European day-ahead electricity market auctions. More specifically, they provided a new MIP formulation of the European day-ahead electricity market problem, avoiding complementarity constraints and auxiliary variables, as well as a Benders decomposition procedure with locally strengthened cuts. Both approaches are proved to be very powerful, through the implementation of computational tests on real data provided by main European power exchanges. Finally, Savelli et al. [34] proposed an optimization approach for electricity markets clearing in the European context, incorporating uniform purchase price and curtailable block orders.

1.1. EUPHEMIA algorithm's complex orders and paper's contributions

The available complex orders for each thermal unit in the EUPHEMIA algorithm include the conditions of minimum income, load gradient and scheduled stop, providing the option to each entity to activate them or not. More specifically:

1.1.1. Load gradient order

Complex orders (with their set of hourly sub-orders) on which a Load Gradient constraint applies are called Load Gradient Orders. In general terms, the Load Gradient constraint means that the amount of energy that is matched by the hourly sub-orders belonging to a Load Gradient order in one period is limited by the amount of energy that was matched by the hourly sub-orders in the previous period. There is a maximum increment/decrement allowed. Period 1 is constrained by the energy matched in the last hour of the previous day.

1.1.2. Scheduled stop order

In case the owner of a power plant which was running the previous day offers a Minimum Income Condition order to the market, he may not want to have the production unit stopped abruptly in case the Minimum Income Condition is deactivated. For the avoidance of this situation, the sender of a Minimum Income Condition order has the possibility to define a "scheduled stop". Using a schedule stop will alter the deactivation of the Minimum Income Condition: the deactivation will not imply the automatic rejection of all the hourly sub-orders. On the contrary, the first (i.e. the cheapest) hourly sub-order in the periods that contain scheduled stop (up to period 3) will not be rejected but will be treated as any hourly order. The hourly sub-orders in the periods declared as Scheduled Stop interval must have decreasing energy as period increases.

1.1.3. Minimum income condition order

The Minimum Income Condition constraint is defined by:

- A fixed term in Euros, typically accounting for the shut-down cost of the unit in our study, and
- A variable term in Euros per accepted MWh, typically representing the minimum variable cost plus a desired cost coefficient (can be also zero).

Its detailed mathematical formulation is provided in Section 2.

The EUPHEMIA algorithm, although enhancing the integration of European electricity markets, faces critical challenges concerning the provision of robust dispatching solutions. The literature review shows an increasing number of papers providing options for consideration of more technical characteristics of the power system, aiming to more realistically represent power units' behaviour. However, none of the papers incorporate a vital component of the unit commitment problem as used in several liquid power exchanges, namely the consideration of reserves, challenging the EUPHEMIA's energy-only nature. Besides the reserves provision, this work also considers other technical characteristics of the thermal units, such as the minimum up and down times, as well as the technical minimum in the market clearing process. The paper aims to enhance EUPHEMIA's algorithm technical aspects, so as to resemble more the robust unit commitment problem.

This paper presents an optimization-based framework for the optimal joint energy and reserves market clearing algorithm, further utilizing the hourly offers module of the EUPHEMIA, the official clearing algorithm at a Pan-European level. In particular, through the formulation of a mixed integer linear programming (MILP) model and employing an iterative approach, it determines the optimal energy and reserves mix, the resulting market clearing prices, and it calculates the welfares of the market participants. As a consequence of the reserves' market incorporation, the design of the minimum income condition order has been modified to integrate the new sources of potential welfare. It examines also the impacts of a series of key operating characteristics of thermal units such as the minimum up and down times, as well as the consideration or not of each thermal unit's technical minimum in the market clearing process. It provides also the option to market participants to link their power units in specific groups (linked hourly orders), enabling them to more efficiently utilize their portfolios.

The key decisions to be determined by the proposed optimization framework include: (i) the composition of the optimal power and reserves mix, (ii) the electricity trading, (iii) the resulting system's marginal price as well as the market clearing prices per reserve type, and (iv) the welfares achieved by each market participant.

Therefore, the paper contributes to the relevant literature on the quantification of the impacts of several new market products (modified minimum income condition, linked hourly orders, and consideration of key technical characteristics of thermal units), introduced on the current EUPHEMIA market clearing algorithm, on a series of power systems' operational and economic aspects. The main contributions and the prominent features of our work include: (i) incorporation of the interaction of power capacity reserves with an energy-only market, (ii) incorporation of the linked hourly orders, facilitating the creation of a correlated portfolio consisting of a series of units, (iii) consideration of power reserve constraints satisfaction at an intra-hourly level, (iv) quantification of the impacts of key operational aspects of thermal units on the currently utilized economic-based market clearing algorithm, and (v) provision of price signals on potential investors for the optimal determination of investments in the power sector.

By providing key insights on the optimal determination of energy and reserve markets, guaranteeing simultaneously the technical feasibility of the solution through the introduction of unit commitment aspects into the pure economic algorithm, the model can be utilized by policy makers, energy regulators, and potential investors to investigate the operational and economic impacts of the new market products on specific aspects incorporated in the objective function and model constraints. The paper demonstrates that the algorithm used by the European power exchanges for the day-ahead market clearing can enhance its robustness towards providing more technically feasible solutions, by incorporating unit commitment aspects.

The remainder of the paper is organized as follows: Section 2 provides the definition of the problem statement, while the formulation of the mathematical model is given in Section 3. Section 4 introduces the description of the case study employed, while Section 5 provides a critical discussion of the results obtained from the model implementation. Finally, Section 6 draws upon some concluding remarks.

2. Problem statement

This work deals with the problem of the optimal clearing of a power exchange based on simple offers, providing also the options of complex orders (minimum income condition order, scheduled stop order, and load gradient order). Apart from the clearing of an energy-only market, the proposed model incorporates also the ancillary services market (reserves market), modifying accordingly the formation of the complex orders provided. The problem under consideration is formulated according to the following:

- The time horizon under consideration is split into sets of hourly time periods t, and representative day-types dt with a 24-h duration.
- A set of supply entities a is available including thermal units th, hydroelectric units h (both referred to as hydrothermal ones ht), and renewable ones res. Apart from this, on the demand side, a group of load entities dm is also considered, while a set of interconnections in is also available, including both imports (supply side) and exports (demand side).
- On the supply side, each unit ht is characterized by a specific energy supply function being defined by a specific price-quantity pair in each operational block f^{ht} (offers have to be submitted on a strictly non-decreasing order). More specifically, parameter $B^{prd}_{ht,t,f^{ht},dt}$ accounts for the quantity of each block f^{ht} of the energy supply function of each unit ht in each time period t and representative day dt, while the corresponding energy supply cost function of each unit ht in each operational block f^{ht}, time period t and representative day dt is provided by parameter $C^{prd}_{ht,t,f^{ht},dt}$. Apart from the priced offers, each unit a can provide a certain amount of non-priced energy in each time period t and day-type dt according to the specific market organization and regulatory framework, provided by parameter $M_{a,t,dt}$ (with regard to the renewable units res, this is the only offer type, since they are given priority when entering the system and their forecasted production is considered as mandatory). Thermal units have also the option of being linked among each other, based on a specific structure selected in each case (linked hourly orders). In case two units are linked between them (parent-unit and child-unit), each child-unit th' cannot operate unless its parent-unit th operates. The specific linkage structure of all units among them during each representative day-type, if any, is provided by parameter $LNK_{th,th',dt}$.
- In addition, the respective price-quantity pairs for each operational block f^{in} of electricity imports from each interconnection in, are provided by parameters $C^{imp}_{in,t,f^{in},dt}$ and $B^{imp}_{in,t,f^{in},dt}$, respectively. The total capacity of each interconnection in (imports) in each time period t and representative day dt is given by parameter $INT^{imp}_{in,t,dt}$. For each supply entity a and interconnection in (imports), there is a certain power injection losses coefficient in each time period t and representative day dt, given by parameters $L_{a,t,dt}$ and $L_{in,t,dt}$, based on the estimated load per time period and the topology of each installed entity.
- On the demand side, the requested power consumption is priced whose corresponding price-quantity pairs for each segment f^{dm} are given by parameters $C^{dem}_{dm,t,f^{dm},dt}$ and $B^{dem}_{dm,t,f^{dm},dt}$, respectively. Similarly, the electricity exports to each interconnection in are characterized by a specific bid function per segment f^{in}, including both a price, given by parameter $C^{exp}_{in,t,f^{in},dt}$, and a quantity component, provided by parameter $B^{exp}_{in,t,f^{in},dt}$. The total capacity of each interconnection in (exports) in each time period t and representative day dt is given by parameter $INT^{exp}_{in,t,dt}$.
- Each unit ht is identified based on specific technical characteristics:
  - Available technical maximum (minimum) of each unit ht in each time period t and representative day dt, $P^{max}_{ht,t,dt}$ ($P^{min}_{ht,t,dt}$),
  - Minimum up (down)-time of each unit ht, UT_{ht} (DT_{ht}), subject to the decision if each unit ht starts up (shuts down) in each time period t and representative day dt, $x^{su}_{ht,t,dt}$ ($x^{sd}_{ht,t,dt}$),
  - Ramp-up (down) capability of each unit ht during a 60-min time interval, $RR^{up,60}_{ht}$ ($RR^{dn,60}_{ht}$),
  - Ramp-up (down) capability of each unit ht during a 30-min time interval, $RR^{up,30}_{ht}$ ($RR^{dn,30}_{ht}$),
  - Ramp-up (down) capability of each unit ht during a 15-min time interval, $RR^{up,15}_{ht}$ ($RR^{dn,15}_{ht}$),
  - Tertiary offline reserve capability of each unit ht, $R3^{ns}_{ht}$, and
  - Maximum increase (decrease) gradient of each unit ht in each time period t and representative day dt imposed by a Load Gradient Order (if activated by the entity), $LG^{up}_{ht,t,dt}$ ($LG^{dn}_{ht,t,dt}$).
- The reserves to be met by the supply entities ht include secondary-up and –down reserves (must be fully available within 15 min), as well as tertiary-up and -down reserves (must be fully available within 30 min). Tertiary reserve include both spinning (up and down), as well as non-spinning (offline) up reserve. It is assumed that they are proportional to the energy demand requirements (as a consequence, they are converted into positive variables since the total energy demand is priced and is to be determined by the optimization process), correlated with them with specific coefficients, N^{sec} for secondary reserve, and N^{ter} for tertiary reserve. With regard to the pricing of each reserve type provision, each unit ht is characterized by the following cost components:
  - Secondary-up (down) reserve provision cost function of each unit ht in each time period t and representative day dt, $C^{2+}_{ht,t,dt}$ ($C^{2-}_{ht,t,dt}$),
  - Spinning tertiary-up (down) reserve provision cost function of each unit ht in each time period t and representative day dt, $C^{3s+}_{ht,t,dt}$ ($C^{3s-}_{ht,t,dt}$), and
  - Non-spinning (offline) tertiary-up reserve provision cost function of each unit ht in each time period t and representative day dt, $C^{3ns}_{ht,t,dt}$.
- The decision variables to be determined by the optimization process include:
  - Cleared energy supply of each unit ht in each operational block f^{ht}, time period t and representative day dt, $e^{prd}_{ht,t,f^{ht},dt}$, subject to the decision if each unit ht is operational in each time period t and representative day dt, $x_{ht,t,dt}$,
  - Cleared energy imports (exports) of each interconnection in in each operational block f^{in}, time period t and representative day dt, $e^{imp}_{in,t,f^{in},dt}$ ($e^{exp}_{in,t,f^{in},dt}$),
  - Cleared energy load of each load entity dm in each segment f^{dm}, time period t and representative day dt, $e^{dem}_{dm,t,f^{dm},dt}$,
  - Cleared secondary-up (down) reserve provision of each unit ht in each time period t and representative day dt, $r^{2+}_{ht,t,dt}$ ($r^{2-}_{ht,t,dt}$),
  - Cleared tertiary-up (down) reserve provision of each unit ht in each time period t and representative day dt, $r^{3+}_{ht,t,dt}$ ($r^{3-}_{ht,t,dt}$),
  - Cleared spinning tertiary-up (down) reserve provision of each unit ht in each time period t and representative day dt, $r^{3sp+}_{ht,t,dt}$ ($r^{3sp-}_{ht,t,dt}$),
  - Cleared non-spinning (offline) tertiary-up reserve provision of each unit ht in each time period t and representative day dt, $r^{3ns}_{ht,t,dt}$, subject to the decision if each unit ht provides offline tertiary reserve in each time period t and representative day dt, $x^{3ns}_{ht,t,dt}$,
  - Secondary-up (down) reserve requirements of the studied power system in each time period t and representative day dt, $RD^{2+}_{t,dt}$ ($RD^{2-}_{t,dt}$), and
  - Tertiary-up (down) reserve requirements of the studied power system in each time period t and representative day dt, $RD^{3+}_{t,dt}$ ($RD^{3-}_{t,dt}$).

As described in the Introduction section, the available complex orders for each thermal unit th in the EUPHEMIA algorithm include the conditions of minimum income, load gradient and scheduled stop, providing the option to each entity to activate them or not. More specifically:

2.1. Load gradient order

The Load Gradient constraint represents the ramp up/down constraints used in the current EUPHEMIA market clearing algorithm. Note that this constraint (activation/deactivation) is incorporated in the main optimization process, thus there is no need for a post-optimization check.

2.2. Scheduled stop order

This work implements Scheduled Stop order similarly to the desynchronization process used in the unit commitment problem, i.e., a linear decrease according to the rate technical minimum/desynchronization time, submitted as a non-priced offer without checking if it is at- or in-the-money. For the units that were initially accepted by the optimization process and failed to satisfy the Minimum Income Condition order, or were initially rejected and simultaneously were operating during the previous day (both cases), their submission offer is converted into a new one according to the above described, and the model is solved again with that modification.

2.3. Minimum income condition order

As described in the Introduction section, the Minimum Income Condition order includes a fixed term in Euros, typically accounting for the shut-down cost of the unit in our study, as well as a variable term in Euros per accepted MWh, typically representing the minimum average variable cost plus a desired cost coefficient (can be also zero). In our approach, since we have additionally incorporated the power reserves market, the variable term includes also the variable reserve, per type, provision cost plus a desired cost coefficient (can be also zero). Eqs. (1)–(4) define the determination of the minimum income condition orders, according to the following:

$$NR_{th,dt} = AR_{th,dt} - QR_{th,dt} \qquad \forall\ th,\ dt \tag{1}$$

$$\frac{AR_{th,dt}}{QR_{th,dt}} \geq ToleranceLevel_{th,dt} \qquad \forall\ th,\ dt \tag{2}$$

$$\begin{aligned} AR_{th,dt} = & \sum_{t}\sum_{f^{ht}}\left[e^{prd}_{th,t,f^{ht},dt}\cdot MP^{nrg}_{t,dt}\right] + \sum_{t}[r^{2+}_{th,t,dt}\cdot MP^{2+}_{t,dt}] \\ & + \sum_{t}[r^{2-}_{th,t,dt}\cdot MP^{2-}_{t,dt}] + \sum_{t}[r^{3+}_{th,t,dt}\cdot MP^{3+}_{t,dt}] \\ & + \sum_{t}[r^{3-}_{th,t,dt}\cdot MP^{3-}_{t,dt}] \qquad \forall\ th,\ dt \end{aligned} \tag{3}$$

$$\begin{aligned} QR_{th,dt} = & \overbrace{C^{sd}_{th}\cdot\sum_{t}x^{sd}_{th,t,dt}}^{Fixed\ term} + \overbrace{\sum_{t}\sum_{f^{ht}}[e^{prd}_{th,t,f^{ht},dt}\cdot(C^{\text{var}}_{th,t,dt} + Z^{e}_{th,t,dt})]}^{Variable\ term\ (energy)} \\ & + \overbrace{\sum_{t}[r^{2+}_{th,t,dt}\cdot(C^{2+}_{th,t,dt} + Z^{2+}_{th,t,dt})]}^{Variable\ term\ (secondary-up\ reserve)} \\ & + \overbrace{\sum_{t}[r^{2-}_{th,t,dt}\cdot(C^{2-}_{th,t,dt} + Z^{2-}_{th,t,dt})]}^{Variable\ term\ (secondary-down\ reserve)} \\ & + \overbrace{\sum_{t}\{[r^{3sp+}_{th,t,dt}\cdot(C^{3s+}_{th,t,dt} + Z^{3sp+}_{th,t,dt})] + [r^{3ns}_{th,t,dt}\cdot(C^{3ns}_{th,t,dt} + Z^{3nsp}_{th,t,dt})]\}}^{Variable\ term\ (tertiary-up\ reserve)} \\ & + \overbrace{\sum_{t}[r^{3sp-}_{th,t,dt}\cdot(C^{3s-}_{th,t,dt} + Z^{3sp-}_{th,t,dt})]}^{Variable\ term\ (tertiary-down\ reserve)} \qquad \forall\ th,\ dt \end{aligned} \tag{4}$$

In particular, for each unit *th* and representative day *dt* the model calculates its total welfare, i.e., the net revenues of each unit *th* during each representative day *dt*, defined as the difference between achieved ($AR_{th,dt}$) and required revenues ($QR_{th,dt}$), as represented by Eq. (1).

With Constraint (2), the model incorporates a desired tolerance level in the Minimum Income Condition activation/deactivation check, providing a relaxation to the algorithm and giving space for acceptance to units very close to comply with the imposed condition. In our employed case study, a conventional value for the tolerance level (1 or 100%) has been considered, denoting that the minimum income condition order is satisfied if and only if the achieved net revenues, defined in Eq. (1), are non-negative.

Eq. (3) formulates the calculation of the acquired revenues for each unit *th* in each representative day *dt*. One component of the acquired revenues is equal to the product of the total daily energy produced by unit *th* in each representative day *dt* with the system's market clearing price ($MP^{nrg}_{t,dt}$). This calculation is conducted on an hourly basis and finally the total daily welfare is derived from the sum of these hourly computations. In addition, the acquired revenues include the revenues acquired from each unit's reserves provision per type, amounting to the product of the total daily reserve provision by unit *th* in each representative day *dt* and in each reserve type with the corresponding system's market clearing price for each reserve type ($MP^{2+}_{t,dt}$ for secondary-up, $MP^{2-}_{t,dt}$ for secondary-down, $MP^{3+}_{t,dt}$ for tertiary-up, and $MP^{3-}_{t,dt}$ for tertiary-down reserve). Note that all market clearing prices are directly calculated during the MILP model solution, being equal to the marginal values of the demand balance equation. These calculations are also conducted on an hourly basis and finally the total daily welfares are derived from the sum of these hourly computations. The total net welfare is equal to the sum of all those achieved welfares including energy, as well as secondary-up, secondary-down, tertiary-up, and tertiary-down reserve welfares.

Eq. (4) formulates the calculation of the required revenues for each unit *th* in each representative day *dt*, divided into two terms, a fixed term and a series of variable ones. The fixed component in our approach accounts for the cost derived from the product of each unit's number of shut-downs on a daily basis with the corresponding shut-down cost, namely the power producer wants to fully recover, in economic terms, any potential shut-down decisions imposed by the solution. With regard to the variable terms, they are quite similar with the variable terms of the acquired revenues case. However, instead of the clearing prices for the energy and reserve markets, the market participants typically declare the minimum average variable cost plus a desired coefficient (energy market), while for the reserve markets they want to recover the reserve provision cost of each unit plus a desired cost coefficient. As a consequence, their aim is to totally retrieve their whole variable cost and in case they employ a more aggressive strategy, they are eager to impose a desired profit margin with the introduction of the desired costs coefficients. These calculations are also conducted on an hourly basis and finally the total daily required welfares are derived from the sum of those hourly computations. The total net required welfare is equal to the sum of all these required welfares including energy, as well as secondary-up, secondary-down, tertiary-up, and tertiary-down reserve welfares.

In the final solution, the Minimum Income Condition orders are activated or deactivated, according to the following:

In case a Minimum Income Condition order is activated, each of the hourly sub-orders of the Minimum Income Condition behaves like any other hourly order, which means accepted if they are in-the-money (meaning the achieved revenues are greater than the required by the Minimum Income Condition ones) and rejected if they are out-of-the-money (meaning the achieved revenues are less than the required by the Minimum Income Condition ones), and can be either accepted (fully or partially) or rejected when at-the-money (meaning the achieved revenues are equal to the required by the Minimum Income Condition ones).

In case a Minimum Income Condition order is deactivated, each of the hourly sub-orders of the Minimum Income Condition is fully rejected, even if it is in-the-money. For the units that were initially accepted by the optimization process and failed to satisfy the Minimum Income Condition order, the model implements a sorting based on a numerical order and the unit with the worst achieved welfare is withdrawn from the Order Book and the model is iteratively solved again without its consideration.

2.4. Solution algorithm

Fig. 1 depicts the flowchart of the methodological solution framework. The whole problem is formulated as a mixed integer linear programming model and its solution is executed within an iterative process so as to deal with the orders that do not satisfy the minimum income

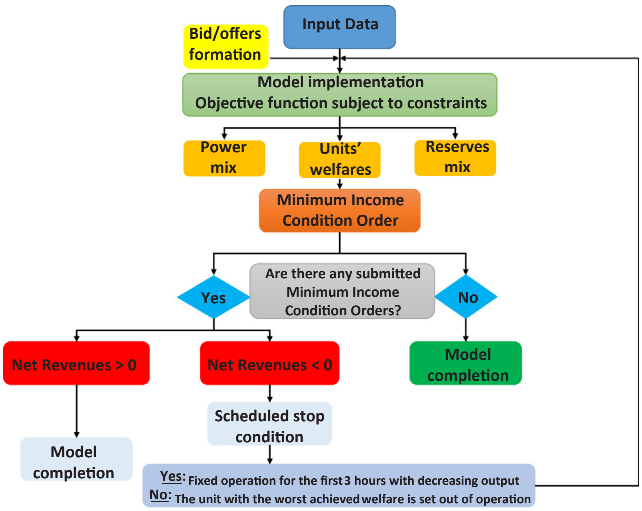

Fig. 1. Flowchart of the methodological solution framework.

condition order. Initially, the MILP problem is solved, and the model determines the hourly market clearing prices of each representative day and for each bidding area, as well as the achieved welfare of each supply entity, in case it has activated the minimum income condition order, with or without considering the scheduled stop order. Note that based on the minimum average variable cost of each thermal unit th, $C^{var}_{th,t,dt}$, the border price of each interconnection in during time period t and representative day dt, $C^{bor}_{in,t,dt}$, and applying the same methodology for the determination of offers/bids described in a previous work (Koltsaklis and Nazos [9]), a realistic market-based formation of quantity-price pairs for both thermal power units and interconnections $(B^{prd}_{ht,t,f^{ht},dt} - C^{prd}_{ht,t,f^{ht},dt}$, $B^{imp}_{in,t,f^{in},dt} - C^{imp}_{in,t,f^{in},dt}$, and $B^{exp}_{in,t,f^{in},dt} - C^{exp}_{in,t,f^{in},dt})$ has been implemented. After that, a post-optimization algorithm is employed to check the satisfaction or not of the imposed complex orders (minimum income condition order with or without scheduled stop condition), and the model is iteratively solved up to the point where all the imposed conditions are fully satisfied.

The optimization goal of the proposed methodological approach refers to the daily cost minimization of the underlying power system for each of the selected representative days, taking into account a series of technical, economic, and regulatory constraints, so as to satisfy the energy demand, as well as the system's requirements for a series of power reserves, and subject to the imposed economic and technical conditions. At this point, it should be stressed that the optimization is cost-based including also the minimum income condition order, providing thus the option to market players to determine their desired profits. In addition, the approach considers also the co-optimization of energy and reserve markets, while the provision of balancing energy (real-time or at an intraday level) and the related costs are not taken into account.

3. Mathematical formulation

This section provides the mathematical formulation of the proposed optimization approach, including the objective function and subject to a series of constraints to be satisfied.

3.1. Objective function

The objective function to be optimized refers to the minimization of the total daily cost for the optimal day-ahead clearing of a power exchange for a group of selected representative days, including: (i) hydrothermal units' supply cost (supply side), (ii) electricity imports cost (supply side), (iii) electricity demand pricing (demand side), (iv) electricity exports revenues (demand side), (v) secondary-up reserve provision cost (supply side), (vi) secondary-down reserve provision cost (supply side), (vii) tertiary-up spinning reserve provision cost (supply side), (viii) tertiary-down spinning reserve provision cost (supply side), and (ix) tertiary-up non-spinning reserve provision cost (supply side), as provided by Eq. (5).

$$
\begin{aligned}
\boldsymbol{Min\ Cost^{day}} = {} & \overbrace{\sum_{ht}\sum_{t}\sum_{f^{ht}}\sum_{dt} e^{prd}_{ht,t,f^{ht},dt}\cdot C^{prd}_{ht,t,f^{ht},dt}}^{Hydrothermal\ units'\ supply\ cost} \\
& -\overbrace{\sum_{dm}\sum_{t}\sum_{f^{dm}}\sum_{dt} e^{dem}_{dm,t,f^{dm},dt}\cdot C^{dem}_{dm,t,f^{dm},dt}}^{Priced\ load\ revenues} + \\
& \sum_{in}\sum_{t}\sum_{f^{in}}\sum_{dt}\Big[\overbrace{(e^{imp}_{in,t,f^{in},dt}\cdot C^{imp}_{in,t,f^{in},dt})}^{Electricity\ imports\ cost} - \overbrace{(e^{exp}_{in,t,f^{in},dt}\cdot C^{exp}_{in,t,f^{in},dt})}^{Electricity\ exports\ revenues}\Big] \\
& \sum_{ht}\sum_{t}\sum_{dt}\left[\overbrace{\begin{aligned}
& \overbrace{(r^{2+}_{ht,t,dt}\cdot C^{2+}_{ht,t,dt})}^{Secondary-up\ reserve\ provision\ cost} \\
& + \overbrace{(r^{2-}_{ht,t,dt}\cdot C^{2-}_{ht,t,dt})}^{Secondary-down\ reserve\ provision\ cost} \\
& + \overbrace{(r^{3sp+}_{ht,t,dt}\cdot C^{3s+}_{ht,t,dt})}^{Tertiary-up\ spinning\ reserve\ provision\ cost} \\
& + \overbrace{(r^{3sp-}_{ht,t,dt}\cdot C^{3s-}_{ht,t,dt})}^{Tertiary-down\ spinning\ reserve\ provision\ cost} \\
& + \overbrace{(r^{3ns}_{ht,t,dt}\cdot C^{3ns}_{ht,t,dt})}^{Tertiary-up\ non-spinning\ reserve\ provision\ cost}
\end{aligned}}^{Total\ reserve\ provision\ cost\ (secondary\ and\ tertiary)}\right]
\end{aligned} \tag{5}
$$

3.2. Model constraints

The optimization goal of the proposed methodological approach concerns the minimization of the daily cost of the market clearing operation of a power exchange for each of the selected representative days, based on simple offers and subject to a series of complex orders. Moreover, the optimization approach considers several technical, economic, and regulatory constraints, in order to fully cover the electricity load, as well as the system's requirements for power reserves, subject to certain imposed conditions, both economic and technical. These constraints are formally defined in the following subsections.

3.2.1. Hydrothermal blocks

$$e^{prd}_{ht,t,f^{ht},dt} \le B^{prd}_{ht,t,f^{ht},dt} \qquad \forall\ ht,\ t,\ f^{ht},\ dt \tag{6}$$

$$p_{ht,t,dt} = \sum_{f^{ht}} e^{prd}_{ht,t,f^{ht},dt} + M_{ht,t,dt} \qquad \forall\ ht,\ t,\ dt \tag{7}$$

Constraints (6) define the upper limits for the cleared energy supply of each unit ht in each operational block f^{ht}, time period t and representative day dt, while Eq. (7) set the total balance of the cleared energy supply of each unit ht in each time period t and representative day dt, being equal to the total priced cleared energy supply $(\sum_{f^{ht}} e^{prd}_{ht,t,f^{ht},dt})$ and the non-priced mandatory one $(M_{ht,t,dt})$, entering the system with priority and without taking part in the market auction.

3.2.2. Load demand blocks

$$e^{dem}_{dm,t,f^{dm},dt} \le B^{dem}_{dm,t,f^{dm},dt} \qquad \forall\ dm,\ t,\ f^{dm},\ dt \tag{8}$$

Constraints (8) define the upper bounds for the cleared energy load of each load entity dm in each segment f^{dm}, time period t and representative day dt.

3.2.3. Power imports blocks

$$e^{imp}_{in,t,f^{in},dt} \le B^{imp}_{in,t,f^{in},dt} \quad \forall\ in,\ t,\ f^{in},\ dt \tag{9}$$

Constraints (9) set the upper bounds for the cleared energy imports of each interconnection in in each operational block f^{in}, time period t and representative day dt.

3.2.4. Power exports blocks

$$e^{exp}_{in,t,f^{in},dt} \le B^{exp}_{in,t,f^{in},dt} \quad \forall\ in,\ t,\ f^{in},\ dt \tag{10}$$

Constraints (10) guarantee that cleared energy exports of each interconnection in in each operational block f^{in}, time period t and representative day dt should not exceed the quantity of each block f^{in} of the exported energy function of each interconnection in in each time period t and representative day dt.

3.2.5. Capacity limits

- At the end of the hour

$$p_{ht,t,dt} + r^{2+}_{ht,t,dt} + r^{3+}_{ht,t,dt} \le P^{max}_{ht,t,dt}\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{11}$$

$$p_{ht,t,dt} - r^{2-}_{ht,t,dt} - r^{3-}_{ht,t,dt} \ge P^{min}_{ht,t,dt}\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{12}$$

Constraints (11) and (12) state the upper ($P^{max}_{ht,t,dt}$) and lower ($P^{min}_{ht,t,dt}$) operational limits of each unit ht at the end of each time period t, in each representative day dt, subject to the decision if it is operational in each time period t and representative day dt ($x_{ht,t,dt}$).

- At a 15-min level

$$\frac{3}{4}p_{ht,t-1,dt} + \frac{1}{4}p_{ht,t,dt} + r^{2+}_{ht,t,dt} + \frac{1}{2}r^{3+}_{ht,t,dt} \le P^{max}_{ht,t,dt}\cdot \left[\frac{3}{4}x_{ht,t-1,dt} + \frac{1}{4}x_{ht,t,dt}\right] \quad \forall\ ht,\ t>1,\ dt \tag{13}$$

$$\frac{3}{4}p_{ht,t-1,dt} + \frac{1}{4}p_{ht,t,dt} - r^{2-}_{ht,t,dt} - \frac{1}{2}r^{3-}_{ht,t,dt} \ge P^{min}_{ht,t,dt}\cdot \left[\frac{3}{4}x_{ht,t-1,dt} + \frac{1}{4}x_{ht,t,dt}\right] \quad \forall\ ht,\ t>1,\ dt \tag{14}$$

Constraints (13) and (14) set the upper and lower operational limits of each unit ht at a 15-min level of each time period t, in each representative day dt, assuming that the energy changes at an intra-hourly level follow a linear rate. Note that the coefficient of ½ in front of the tertiary reserve provision of both constraints is added to represent the fact that the tertiary reserve must be fully activated within 30 min.

- At a 30-min level

$$\frac{1}{2}p_{ht,t-1,dt} + \frac{1}{2}p_{ht,t,dt} + r^{2+}_{ht,t,dt} + r^{3+}_{ht,t,dt} \le P^{max}_{ht,t,dt}\cdot \left[\frac{1}{2}x_{ht,t-1,dt} + \frac{1}{2}x_{ht,t,dt}\right] \quad \forall\ ht,\ t>1,\ dt \tag{15}$$

$$\frac{1}{2}p_{ht,t-1,dt} + \frac{1}{2}p_{ht,t,dt} - r^{2-}_{ht,t,dt} - r^{3-}_{ht,t,dt} \ge P^{min}_{ht,t,dt}\cdot \left[\frac{1}{2}x_{ht,t-1,dt} + \frac{1}{2}x_{ht,t,dt}\right] \quad \forall\ ht,\ t>1,\ dt \tag{16}$$

Constraints (15) and (16) set the upper and lower operational limits of each unit ht at a 30-min level of each time period t, in each representative day dt, assuming that the energy changes at an intra-hourly level follow a linear rate.

3.2.6. Ramp limits

- At the end of the hour

$$p_{ht,t,dt} - p_{ht,t-1,dt} + r^{2+}_{ht,t,dt} + r^{3+}_{ht,t,dt} \le RR^{up,60}_{ht}\cdot 60 \quad \forall\ ht,\ t>1,\ dt \tag{17}$$

$$p_{ht,t-1,dt} - p_{ht,t,dt} + r^{2-}_{ht,t,dt} + r^{3-}_{ht,t,dt} \le RR^{dn,60}_{ht}\cdot 60 \quad \forall\ ht,\ t>1,\ dt \tag{18}$$

Constraints (17) and (18) define the ramp-up ($RR^{up,60}_{ht}\cdot 60$) and ramp-down ($RR^{dn,60}_{ht}\cdot 60$) rates of each unit ht at the end of each time period t, in each representative day dt.

- At a 15-min level

$$\frac{1}{4}\cdot[p_{ht,t,dt} - p_{ht,t-1,dt}] + r^{2+}_{ht,t,dt} + \frac{1}{2}r^{3+}_{ht,t,dt} \le RR^{up,15}_{ht}\cdot 15 \quad \forall\ ht,\ t>1,\ dt \tag{19}$$

$$\frac{1}{4}\cdot[p_{ht,t-1,dt} - p_{ht,t,dt}] + r^{2-}_{ht,t,dt} + \frac{1}{2}r^{3-}_{ht,t,dt} \le RR^{dn,15}_{ht}\cdot 15 \quad \forall\ ht,\ t>1,\ dt \tag{20}$$

Constraints (19) and (20) set the ramp-up and ramp-down rates of each unit ht at a 15-min level of each time period t, in each representative day dt, assuming that the energy changes at an intra-hourly level follow a linear rate.

- At a 30-min level

$$\frac{1}{2}\cdot[p_{ht,t,dt} - p_{ht,t-1,dt}] + r^{2+}_{ht,t,dt} + r^{3+}_{ht,t,dt} \le RR^{up,30}_{ht}\cdot 30 \quad \forall\ ht,\ t>1,\ dt \tag{21}$$

$$\frac{1}{2}\cdot[p_{ht,t-1,dt} - p_{ht,t,dt}] + r^{2-}_{ht,t,dt} + r^{3-}_{ht,t,dt} \le RR^{dn,30}_{ht}\cdot 30 \quad \forall\ ht,\ t>1,\ dt \tag{22}$$

Constraints (21) and (22) set the ramp-up and ramp-down rates of each unit ht at a 30-min level of each time period t, in each representative day dt, assuming that the energy changes at an intra-hourly level follow a linear rate.

3.2.7. Reserve limits

$$r^{2+}_{ht,t,dt} \le RR^{up,15}_{ht}\cdot 15\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{23}$$

$$r^{2-}_{ht,t,dt} \le RR^{dn,15}_{ht}\cdot 15\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{24}$$

$$r^{3sp+}_{ht,t,dt} \le RR^{up,30}_{ht}\cdot 30\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{25}$$

$$r^{3sp-}_{ht,t,dt} \le RR^{dn,30}_{ht}\cdot 30\cdot x_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{26}$$

$$r^{3ns}_{ht,t,dt} \ge P^{min}_{ht,t,dt}\cdot x^{3ns}_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{27}$$

$$r^{3ns}_{ht,t,dt} \le R3^{ns}_{ht}\cdot x^{3ns}_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{28}$$

$$r^{3+}_{ht,t,dt} = r^{3sp+}_{ht,t,dt} + r^{3ns}_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{29}$$

$$r^{3-}_{ht,t,dt} = r^{3sp-}_{ht,t,dt} \quad \forall\ ht,\ t,\ dt \tag{30}$$

Constraints (23)–(26) define the upper bounds of cleared secondary-up, secondary-down, spinning tertiary-up, and spinning tertiary-down reserve provision of each unit ht in each time period t and representative day dt, correspondingly, subject to the decision if it is operational in each time period t and representative day dt ($x_{ht,t,dt}$). Constraints (27) and (28) state that the cleared non-spinning (offline) tertiary-up reserve provision of each unit ht in each time period t and representative day dt must be between its technical minimum ($P^{min}_{ht,t,dt}$) and its tertiary offline reserve capability ($R3^{ns}_{ht}$), subject to the decision if it provides offline tertiary reserve in each time period t and representative day dt ($x^{3ns}_{ht,t,dt}$). Constraints (29) state that the cleared tertiary-up reserve provision of each unit ht in each time period t and representative day dt equals the sum of cleared spinning and non-spinning tertiary-up reserve provision of each unit ht in each time period t and representative day dt. Finally, Constraints (30) state that the cleared tertiary-down reserve provision of each unit ht in each time period t and representative day dt is identical to the cleared spinning tertiary-down reserve provision of each unit ht in each time period t and representative day dt.

3.2.8. Interconnections' balance

$$\sum_{f^{in}} [e^{imp}_{in,t,f^{in},dt} - e^{exp}_{in,t,f^{in},dt}] \le INT^{imp}_{in,t,dt} \qquad \forall\ in,\ t,\ dt \tag{31}$$

$$\sum_{f^{in}} [e^{exp}_{in,t,f^{in},dt} - e^{imp}_{in,t,f^{in},dt}] \le INT^{exp}_{in,t,dt} \qquad \forall\ in,\ t,\ dt \tag{32}$$

Constraints (31) and (32) set that the net energy imports and exports must not exceed the capacity of each interconnection in, imports and exports correspondingly, in each time period t and representative day dt.

3.2.9. Demand balance

$$\sum_{res} M_{res,t,dt} \cdot L_{res,t,dt} + \sum_{ht} p_{ht,t,dt} \cdot L_{ht,t,dt} + \sum_{in}\sum_{f^{in}} e^{imp}_{in,t,f^{in},dt} \cdot L_{in,t,dt} = \sum_{dm}\sum_{f^{dm}} e^{dem}_{dm,t,f^{dm},dt} + \sum_{in}\sum_{f^{in}} e^{exp}_{in,t,f^{in},dt} \qquad \forall\ t,\ dt \tag{33}$$

Eq. (33) express the demand balance of the studied power system. In particular, the non-priced mandatory energy production of renewables in each time period t and representative day dt, plus the net total cleared energy supply of all hydrothermal units (priced and non-priced) in each time period t and representative day dt, plus the net cleared energy imports from all interconnections in each time period t and representative day dt must equal to the total cleared energy load of all load entities in each time period t and representative day dt, plus the total cleared energy exports to all interconnections in each time period t and representative day dt.

3.2.10. Load gradient order

$$p_{th,t,dt} - p_{th,t-1,dt} \le LG^{up}_{th,t,dt} \cdot 60 \qquad \forall\ th,\ t > 1,\ dt \tag{34}$$

$$p_{th,t-1,dt} - p_{th,t,dt} \le LG^{dn}_{th,t,dt} \cdot 60 \qquad \forall\ th,\ t > 1,\ dt \tag{35}$$

Constraints (34) and (35) express the Load Gradient Order constraints, meaning that the amount of energy that is cleared by the hourly sub-orders belonging to a Load Gradient order in one time period is limited by the amount of energy that was cleared by the hourly sub-orders in the previous time period, with a maximum allowable increase ($LG^{up}_{th,t,dt} \cdot 60$) and decrease ($LG^{dn}_{th,t,dt} \cdot 60$), respectively.

3.2.11. Logical constraints

$$x^{su}_{th,t,dt} - x^{sd}_{th,t,dt} = x_{th,t,dt} - x_{th,t-1,dt} \qquad \forall\ th,\ t > 1,\ dt \tag{36}$$

$$x^{su}_{th,t,dt} + x^{sd}_{th,t,dt} \le 1 \qquad \forall\ th,\ t,\ dt \tag{37}$$

Eq. (36) account for a logical operational constraint of each unit th in each time period t and representative day dt, correlating the operational phase with the start-up and shut-down decisions. In addition, Constraints (37) guarantee that a start-up and a shut-down decision cannot be taken simultaneously in the same time period.

3.2.12. Minimum up- and down-time constraints

$$\sum_{tt=t-UT_{th}+1} x^{su}_{th,tt,dt} \le x_{th,t,dt} \qquad \forall\ th,\ t,\ dt \tag{38}$$

$$\sum_{tt=t-DT_{th}+1} x^{sd}_{th,tt,dt} \le 1 - x_{th,t,dt} \qquad \forall\ th,\ t,\ dt \tag{39}$$

Constraints (38) and (39) formulate the minimum up (if it starts up during a specific time period t, it must remain operational the next $UT_{th}-1$ hours), and down (if it shuts down during a certain time period t, it must remain offline the next $DT_{th}-1$ hours) time constraints of each unit th in each time period t and representative day dt, comprising an additional complex order which can be activated or not by each market participant.

3.2.13. Non-spinning reserve status constraints

$$x^{3ns}_{th,t,dt} \le 1 - x_{th,t,dt} \qquad \forall\ th,\ t,\ dt \tag{40}$$

Constraints (40) state that each unit th can provide offline tertiary reserve in each time period t and representative day dt, if and only if it is not operational during the same time period.

3.2.14. Reserve requirements

$$RD^{2+}_{t,dt} = N^{sec} \cdot \sum_{dm}\sum_{f^{dm}} e^{dem}_{dm,t,f^{dm},dt} \qquad \forall\ t,\ dt \tag{41}$$

$$RD^{2-}_{t,dt} = N^{sec} \cdot \sum_{dm}\sum_{f^{dm}} e^{dem}_{dm,t,f^{dm},dt} \qquad \forall\ t,\ dt \tag{42}$$

$$RD^{3+}_{t,dt} = N^{ter} \cdot \sum_{dm}\sum_{f^{dm}} e^{dem}_{dm,t,f^{dm},dt} \qquad \forall\ t,\ dt \tag{43}$$

$$RD^{3-}_{t,dt} = N^{ter} \cdot \sum_{dm}\sum_{f^{dm}} e^{dem}_{dm,t,f^{dm},dt} \qquad \forall\ t,\ dt \tag{44}$$

$$\sum_{ht} r^{2+}_{ht,t,dt} \ge RD^{2+}_{t,dt} \qquad \forall\ t,\ dt \tag{45}$$

$$\sum_{ht} r^{2-}_{ht,t,dt} \ge RD^{2-}_{t,dt} \qquad \forall\ t,\ dt \tag{46}$$

$$\sum_{ht} [r^{2+}_{ht,t,dt} + r^{3+}_{ht,t,dt}] \ge RD^{2+}_{t,dt} + RD^{3+}_{t,dt} \qquad \forall\ t,\ dt \tag{47}$$

$$\sum_{ht} [r^{2-}_{ht,t,dt} + r^{3-}_{ht,t,dt}] \ge RD^{2-}_{t,dt} + RD^{3-}_{t,dt} \qquad \forall\ t,\ dt \tag{48}$$

Eqs. (41)–(44) define the system's requirements for secondary-up, secondary-down, tertiary-up, and tertiary-down reserve in each time period t and representative day dt, correspondingly. These are expressed as variables, correlated with specific coefficients with the system's priced energy load. Finally, Constraints (45)–(48) express the power system's coverage with secondary-up, secondary-down, tertiary-up, and tertiary-down reserve, respectively.

3.2.15. Linked hourly orders

$$x_{th',t,dt} \le x_{th,t,dt} \qquad \forall\ (th,\ th') \in LNK_{th,th',dt},\ t,\ dt \tag{49}$$

Constraints (49) state that if a pair of units are linked between them (parent-unit and child-unit), the operation of each child unit th' is dependent on the operation of its parent-unit th. The specific linkage of all units among them, if any, is provided by the parameter $LNK_{th,th',dt}$.

The overall problem is formulated as an MILP problem, involving the cost minimization objective function (5), and subject to Constraints (6)–(49), incorporating also the complex orders consideration.

4. Case study description

An illustrative case study of the Greek power system has been selected so as to demonstrate the applicability of the proposed approach, the main characteristics of which are presented below. Eight representative day types have been selected (24-h profile), including a weekday and a weekend day type for each of the four seasons (Winter,

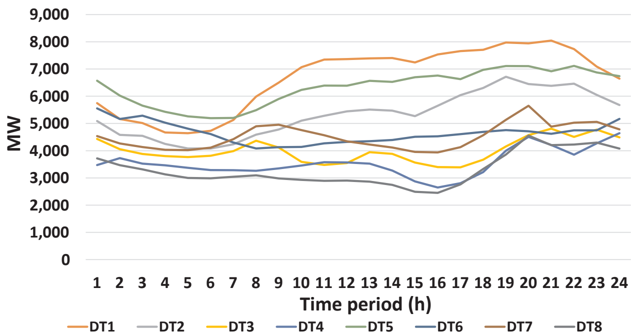

Fig. 2. Net power demand in each of the selected representative days (MW).

Spring, Summer, Autumn), as follows:

- DT1: Winter-Weekday
- DT2: Winter-Weekend
- DT3: Spring-Weekday
- DT4: Spring-Weekend
- DT5: Summer-Weekday
- DT6: Summer-Weekend
- DT7: Autumn-Weekday
- DT8: Autumn-Weekend

Fig. 2 depicts the net power demand in each of the selected representative days, namely total power demand minus mandatory non-priced electricity production from renewables and hydroelectric units.

Fig. 3 portrays indicatively the minimum average variable cost of each thermal unit during the representative days of autumn, while Fig. 4 presents the hourly border prices of each interconnection during the representative day of winter weekday. Based on these values (minimum average variable costs of thermal units, 27 in total, and border prices of interconnections) and according to the methodology developed in a previous work [9], the priced offers of both thermal units and electricity imports/exports per interconnection are constructed. The methodology for the detailed calculation of the power injection losses coefficients can be found in a relevant work [10].

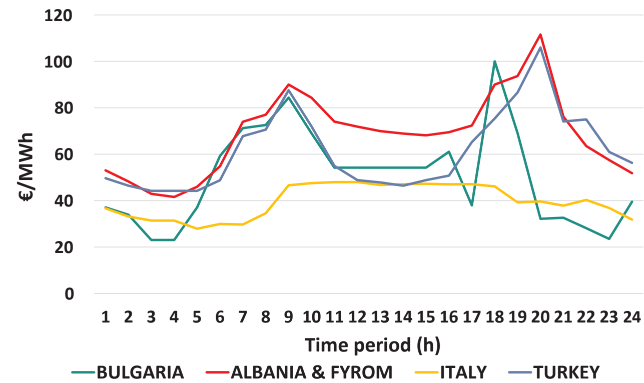

Fig. 4. Hourly border prices of each interconnection during the representative day of winter weekday (€/MWh).

Fig. 5 depicts the power availability per technology type, split into technical minimum and additional capacity up to available technical maximum in each representative day. It can be observed that the ratio of technical minimum to the total available capacity exceeds that of 60% in lignite-fired units, while in the natural gas-fired combined cycle units (NGCC) is around 45% on average. On the other hand, it amounts to only 10% in the natural gas-fired open cycle (NGGT) units, highlighting the significant flexibility provided by this type of units.

Table 1 presents representative technical characteristics per technology type including minimum up and down times, as well as ramp-up and –down rates. From these data, it can be derived that lignite-fired

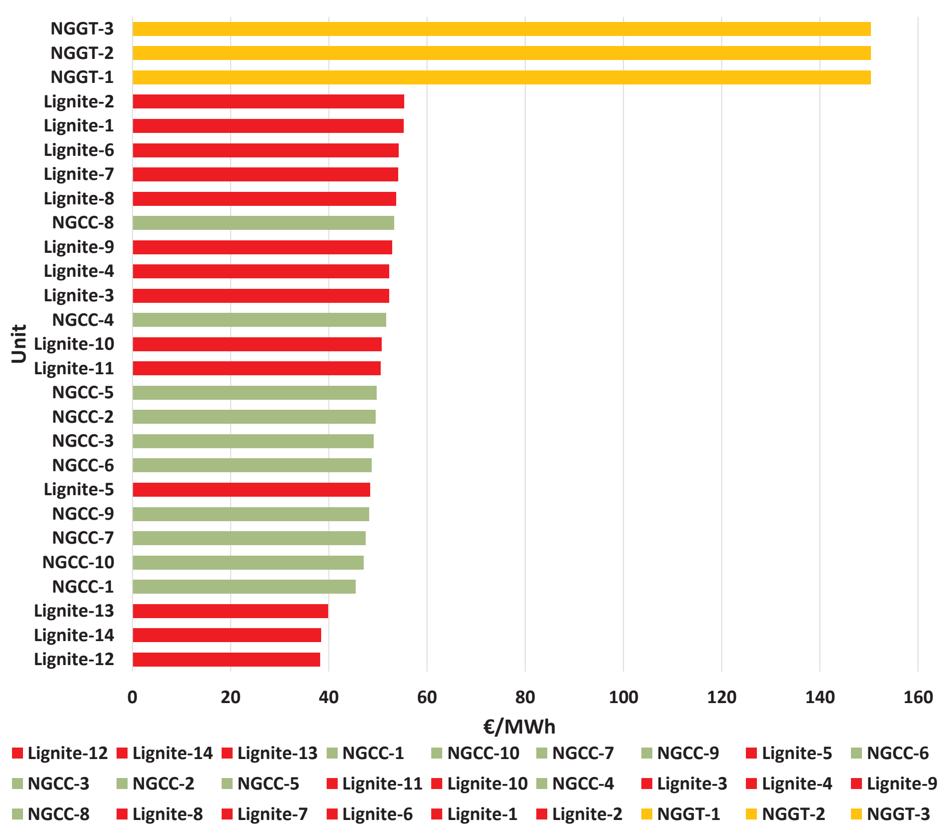

Fig. 3. Minimum average variable cost of each thermal unit during the representative days of autumn (€/MWh).

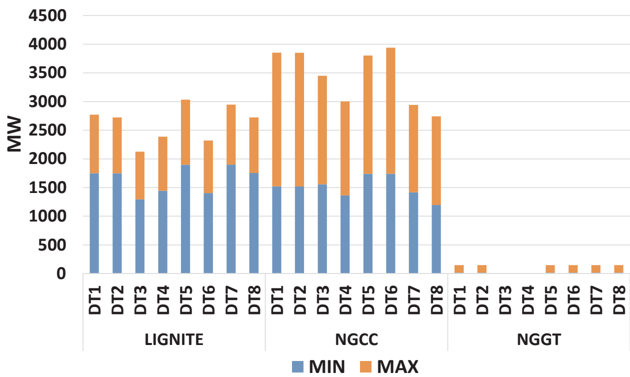

Fig. 5. Power availability per technology type, split into technical minimum and additional capacity up to available technical maximum in each representative day (MW).

units are designed for stable and continuous operation, while NGGT and hydroelectric units are characterized by their increased flexibility with short up- and down-times, and significant ramp rates, in both upward and downward directions. NGCC units are in the middle of the above technology types, combining both the characteristics of stable and continuous operation with noticeable ramping capability. The secondary, up and down, reserve requirements are assumed to be 2.5% of the cleared power demand, while the tertiary, up and down, reserve requirements are assumed to be 5% of the cleared power demand in each time period [32]. The quarterly and half-hourly units' ramp capabilities amount to 150% and 100% of their hourly ramp-rates, while the units' secondary, spinning tertiary, and non-spinning tertiary reserve offers are considered to be 20%, 10%, and 40% of their minimum average variable costs (weighted average for the hydroelectric units).

Table 2 presents the daily minimum, average, and maximum hydroelectric availability for priced offers per representative day type. As can be observed, it is not characterized by significant fluctuations per representative day type, being in the range of 2.4–2.5 GW on average.

Table 3 presents the minimum, weighted average and maximum price offer values of the priced hydroelectric production per representative day type, based on real market historical data. As can be seen, there are significant variations in the water values among the hours of the same day, as well as among the different day types, underscoring a specific scenario of hydro management.

The determination of the optimal clearing of a power exchange based on simple offers requires the implementation of energy system modeling for the whole energy system. Therefore, the proposed approach is useful in providing insights on the power scheduling decisions, incorporating post-optimization conditions with the use of an iterative algorithm, as part of an overall energy system modeling approach. Based on the reference values of the model implementation (*Base Case*), without (*Base_Case_A – BCA*) and with (*Base_Case_B – BCB*) the incorporation of complex orders, several sensitivity analyses have been executed so as to capture the impacts of a series of the following aspects:

- *ECO_Case*, in which each thermal unit's operation above its technical minimum (in case it is online), as well as its minimum up and down times are not imposed by relevant technical constraints, without (*ECO_Case_A – ECA*) and with (*ECO_Case_B – ECB*) the incorporation of complex orders,
- *PEX_Case,* including the characteristics of the *ECO_Case* plus the non-consideration of reserve requirements, as is the case in the current power exchanges clearing, without (*PEX_Case_A – PCA*) and with (*PEX_Case_B – PCB*) the incorporation of complex orders,
- *Linked_Case*, including the characteristics of the *Base_Case_B*, namely it incorporates the activation of complex orders, as well all the thermal units' technical characteristics (minimum up/down times, and technical minimum), plus it involves the linkage option among specific units based on three specific portfolio constructions: (i) technology group (*Linked_Case_A – LCA*), (ii) ownership group (*Linked_Case_B – LCB*), and (iii) power station group (*Linked_Case_C – LCC*).

Table 4 summarizes the main characteristics of the examined case studies. Note that the options of technology group, ownership group, and power station group are only available for the *Linked_Case* scenario, in which the thermal units can be linked among them based on three criteria, namely if they belong to the same technology (Lignite, NGCC, NGGT), if they belong to the same owner (public and private utilities), and if they belong to the same power station, i.e., each power station contains a number of power units. In each case, based on a numerical order sorting from the most expensive to the most economical power unit, an extreme strategy has been examined, in which the most expensive unit of each category is selected as the parental unit, and the next most expensive unit is linked to it, followed by the next most expensive unit etc. The first power unit of each category is only parent-unit, while the last one is only child-unit. All the intermediate units are simultaneously both parent- and child- units.

Table 1
Main technical characteristics per technology type.

Technology type	Minimum up time (h)	Minimum down time (h)	Ramp-up rate (MW/min)	Ramp-down rate (MW/min)
Lignite	16	1	3	4
NGCC	12	3	11	11
NGGT	1	1	9	9
Hydro	0	0	25	25

Table 2
Daily minimum, average, and maximum hydroelectric availability for priced offers per representative day type (MW).

Date	Min	Average	Max
DT1	1306	2594	2747
DT2	1292	2569	2723
DT3	1186	2366	2621
DT4	983	2378	2666
DT5	1162	2395	2835
DT6	1050	2393	2823
DT7	1217	2275	2437
DT8	1312	2627	2821

5. Results

This sections provides the results derived from the model execution for a series of case studies and for different representative day types. The problem has been solved to global optimality making use of the ILOG CPLEX 12.6.0.0 solver incorporated in the General Algebraic Modeling System (GAMS) tool [35]. An integrality gap of 0% has been achieved in all cases.

With the aim of investigating the impacts of a variety of aspects on the power market clearing process, and as a consequence on the system's operational scheduling, several cases have been identified, the summary of which is provided in Table 4. A comparative and detailed analysis is provided below focusing on a series of decision variables including the resulting energy and reserve mix, the system's marginal price and the reserves' market clearing price per type, as well as the achieved welfares in each case and representative day type.

Table 3
Minimum, weighted average and maximum price offer values of the priced hydroelectric production per representative day (€/MWh).

Date	Value	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DT1	Min	54	54	54	54	54	54	54	54	61	40	40	40	40	61	61	61	47	47	47	47	47	47	61	54
DT2		26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
DT3		60	60	60	60	60	60	60	60	47	47	47	47	47	60	60	60	60	60	60	47	47	47	60	60
DT4		47	60	61	61	61	61	61	61	61	47	47	61	61	61	61	61	61	61	61	60	47	47	47	47
DT5		62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
DT6		64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
DT7		66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	12	66	12	66	66
DT8		68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	1	1	1	41	68
DT1	Weighted average	94	94	94	94	94	94	94	94	97	95	91	90	95	96	96	96	97	96	97	97	100	96	96	94
DT2		113	113	113	113	113	113	113	117	118	116	116	115	115	116	116	116	116	117	121	119	122	116	116	116
DT3		97	97	97	97	97	97	97	97	103	108	107	100	96	97	97	96	97	97	97	97	102	97	97	98
DT4		107	103	103	103	103	103	103	103	104	103	103	103	102	102	102	102	103	104	103	103	113	113	112	103
DT5		89	89	90	90	90	89	89	90	90	90	90	89	90	86	91	91	91	88	87	89	93	92	93	89
DT6		92	92	90	90	90	89	89	91	91	91	91	89	90	91	91	91	90	91	88	89	91	88	89	89
DT7		109	109	109	109	109	109	110	110	111	110	110	110	110	110	110	109	109	109	109	114	132	123	111	109
DT8		81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	78	73	75	80	81
DT1	Max	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
DT2		150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
DT3		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
DT4		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
DT5		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
DT6		147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147
DT7		300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
DT8		150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

5.1. Energy mix

Fig. 6 depicts the total daily energy mix per selected case and representative day type. The basic differences regarding the structure of the selected representative days concern the demand level, affected both by seasonal characteristics (winter, spring, summer, autumn) and day type (weekday, weekend), as well as the non-priced contribution from renewables and hydroelectric units, being mainly dependent on the meteorological conditions (seasonal characteristics). The results provided highlight the significant impacts of complex orders, and especially of the minimum income condition order, on the power mix, denoting that the owners of thermal units are willing to operate their power plants only on the condition that their net revenues are non-negative. Another aspect that exerts significant influence on the power scheduling decisions is the strategy adopted by market participants, and especially from producers owning thermal power units, namely lignite-fired units (LIG), natural gas-fired combined cycle (NGCC) units, and natural gas-fired open cycle (NGGT) ones. This issue is obvious in the three *Linked_Cases* (LCA, LCB, and LCC), sharing the same characteristics with the *Base_Case_B* (BCB), but with different adopted strategy in each case, since the producers activate the linkage option among their thermal power units in the three *Linked_Cases*, forming a certain linked portfolio in each case.

The relevant competitiveness of border prices (available interconnections) with the minimum average variable costs of the domestic thermal power units constitutes another parameter of great significance for the determination of the optimal energy mix. Not surprisingly, due to the correlation adopted in the formation of priced offers between interconnections (electricity traders) and installed thermal power units, the flows direction can have significant impacts on the production scheduling of thermal power units, increasing or decreasing their contribution to a noticeable extent.

The impacts of the complex orders' incorporation are noticeable during specific representative day types. A representative example is the winter weekend (DT2) in scenarios BCA and BCB. In the first scenario (BCA) where complex orders are deactivated, the resulting generation mix is characterized by a high share of fossil fuel-based generation units (lignite-fired and natural gas-fired) covering around 89% of the total demand including losses, while the remaining part is met by renewables and hydroelectric units. The net position of the power system's exchanges balance is negative, meaning that the studied power system is a net electricity exporter, exporting around 4% of the total daily domestic generation to the neighboring interconnected power systems. In the second scenario (BCB) where complex orders are activated, the fact that some lignite-fired units fail to satisfy the minimum income condition order, leads to their shut-down and, as a consequence, to an energy deficit in the total generation. This deficit is offset by increased generation from natural gas-fired and hydroelectric units (almost doubled), while the net position of the power system's exchanges balance becomes positive, denoting that the studied power

Table 4
Summary of the examined case studies.

Case	Technical minimum	Minimum up-time	Minimum down-time	Reserves requirements	Complex Orders	Technology group	Ownership group	Power station group
Base_Case_A	✓	✓	✓	✓	✗	✗	✗	✗
Base_Case_B	✓	✓	✓	✓	✓	✗	✗	✗
ECO_Case_A	✗	✗	✗	✓	✗	✗	✗	✗
ECO_Case_B	✗	✗	✗	✓	✓	✗	✗	✗
PEX_Case_A	✗	✗	✗	✗	✗	✗	✗	✗
PEX_Case_B	✗	✗	✗	✗	✓	✗	✗	✗
Linked_Case_A	✓	✓	✓	✓	✓	✓	✗	✗
Linked_Case_B	✓	✓	✓	✓	✓	✗	✓	✗
Linked_Case_C	✓	✓	✓	✓	✓	✗	✗	✓

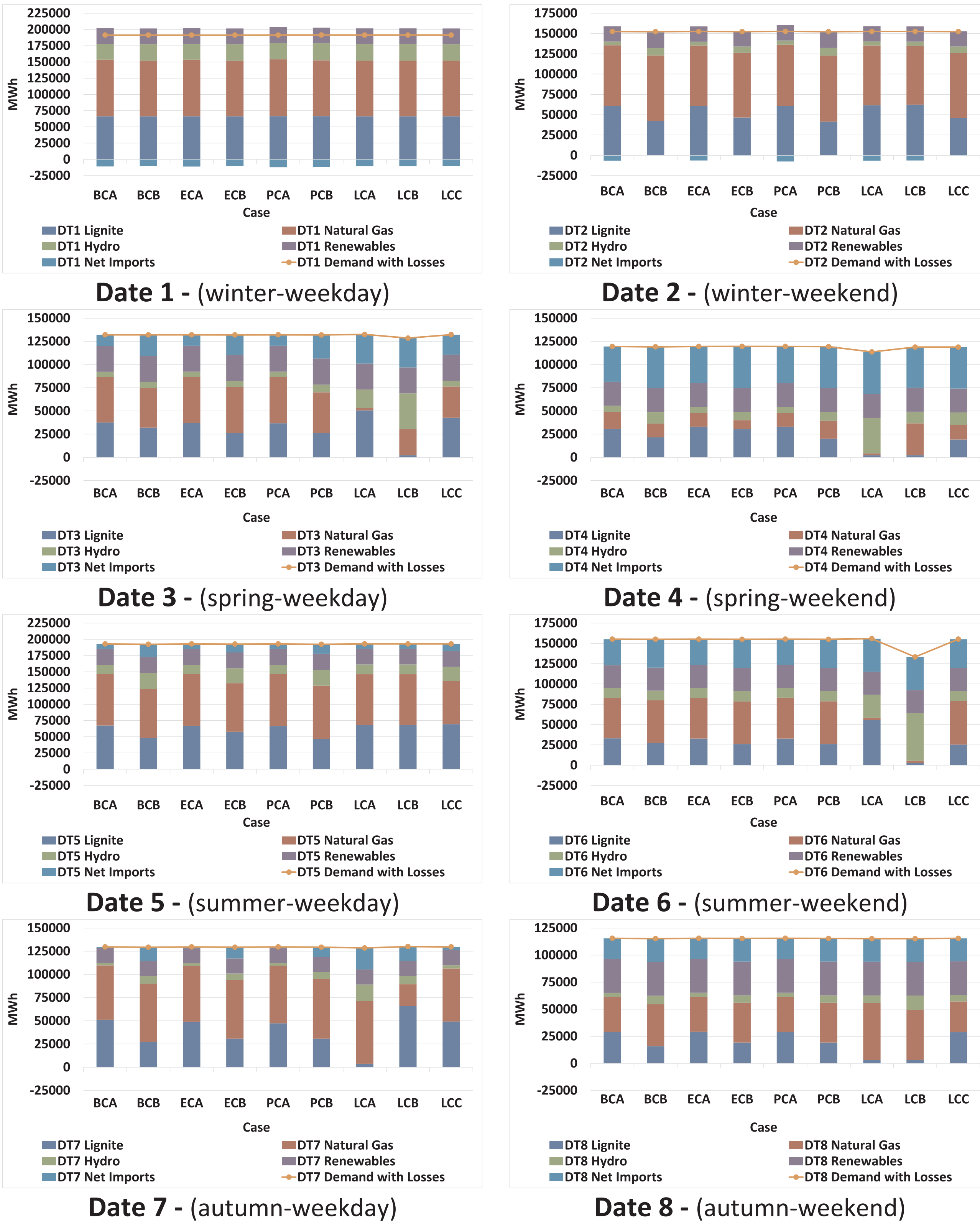

Fig. 6. Total daily energy mix per selected case and representative day type (MWh).

system is converted into a net electricity importer, receiving energy from the neighboring interconnected power systems.

Another illustrative example that incorporates the combined effects of the adopted strategy and complex orders' consideration is the spring weekend (DT4) in scenarios BCA and LCA. In the first scenario (BCA) where complex orders are deactivated and the thermal units are not linked among them, the resulting power mix is characterized by a relative balance where fossil fuel-based units cover 41% of the total demand including losses, net imports account for 31.8%, as well as renewables and hydro units represent around 21.6% and 5.6% of the total load with losses, respectively. In the second scenario (LCA) where complex orders are activated and the thermal units are linked among

Table 5
Number of iterations required for the satisfaction of the minimum income condition order, if applied, in each day type of each selected scenario.

Date	BCA	BCB	ECA	ECB	PCA	PCB	LCA	LCB	LCC
DT1	0	2	0	2	0	1	1	1	1
DT2	0	5	0	4	0	5	1	1	5
DT3	0	7	0	7	0	8	7	6	6
DT4	0	11	0	10	0	10	8	6	9
DT5	0	6	0	4	0	5	1	1	2
DT6	0	6	0	10	0	10	8	9	6
DT7	0	9	0	8	0	8	4	5	3
DT8	0	8	0	9	0	9	4	5	6

them based on a technology group structure (all the units which belong to the same technology group are sorted based on their minimum average variable cost, beginning from the most expensive of all available units, which comprises the parental unit, and successively continuing with the next less economic unit in each time, until all the available thermal units to be linked among them), the resulting generation mix is totally different. The fact that the adopted strategy is highly aggressive, combined with the quite low levels of electricity demand, leads to the shut-down of all available thermal units, which fail to satisfy the minimum income condition order and operate only during the first 3 h of the dispatch day, having activated the scheduled stop order. The resulting energy deficit is mainly covered by electricity imports (39.8% of the total load with losses), and from a skyrocketing increase in the energy contribution from hydroelectric units (33.9% of the total load with losses). The remaining part is met by renewables and fossil fuel-based units (in the first 3 h), accounting for around 22.7% and 3.6% of the total demand with losses, respectively.

The impacts of technical characteristics consideration (minimum up/down times, and technical minimum) are not significant on the operational scheduling (BCB case), when compared to the corresponding ones of the ECB case, where all these technical characteristics are not considered. This is mainly due to the fact that the offers' formation strategy is uniform at a 24-h level and thus, the trends do not alter at an intraday level. Under the assumption that market participants follow different intraday strategies (more aggressive and/or more conservative than the reference one during some time intervals), it can be expected that these aspects are going to exert some influences on the resulting operational scheduling (decrease/increase of operational hours in the generation scheduling, as well as potential start-ups and shut-downs, according to the selected strategy).

Table 5 presents the number of iterations required for the satisfaction of the minimum income condition order, if applied, in each day type of each selected scenario. Note that the zero values reported in some scenarios means that no complex orders are imposed in those scenarios.

Fig. 7 portrays a 24-h energy mix during a winter weekend in the Base Case scenarios with and without the activation of complex orders (BCB and BCA), correspondingly. Lignite-fired and NGCC units are characterized by a stable production profile during all hours, while hydroelectric units are mainly responsible for balancing the fluctuations caused in the power system by electricity trade and the renewables' contribution. The main differences among the two scenarios is that some lignite-fired units are forced to shut down, due to the fact that they fail to satisfy the minimum income condition order in the BCB case. A direct consequence of this is that although the studied power system exports electricity to its interconnected power systems during 13 of the 24 h in the BCB case, it is converted into a net electricity importer at a daily level, importing significant amounts of electricity during hours of low (1–5 h) and high (18–22 h and 24th hour) demand levels. On the other hand, the power system in BCA case is a net electricity exporter to other interconnected power systems.

5.2. Power market clearing prices

Fig. 8 shows the average daily system's marginal price (energy market), and market clearing prices per reserve type for each selected case and representative day type. System's marginal price is defined as "*the price that all electricity suppliers (e.g., producers, importers) are going to be paid for the amount of energy they sell and all power load representatives (e.g., exporters, large consumers) are going to pay for the amount of energy they buy*" [8]. Analogously, the market clearing price of each reserve type is defined as the price that all power producers are going to be paid for the amount of each type of power reserve they provide. As can be observed, the largest deviations are reported in the three *Linked_Cases* (LCA, LCB, and LCC), underscoring again the

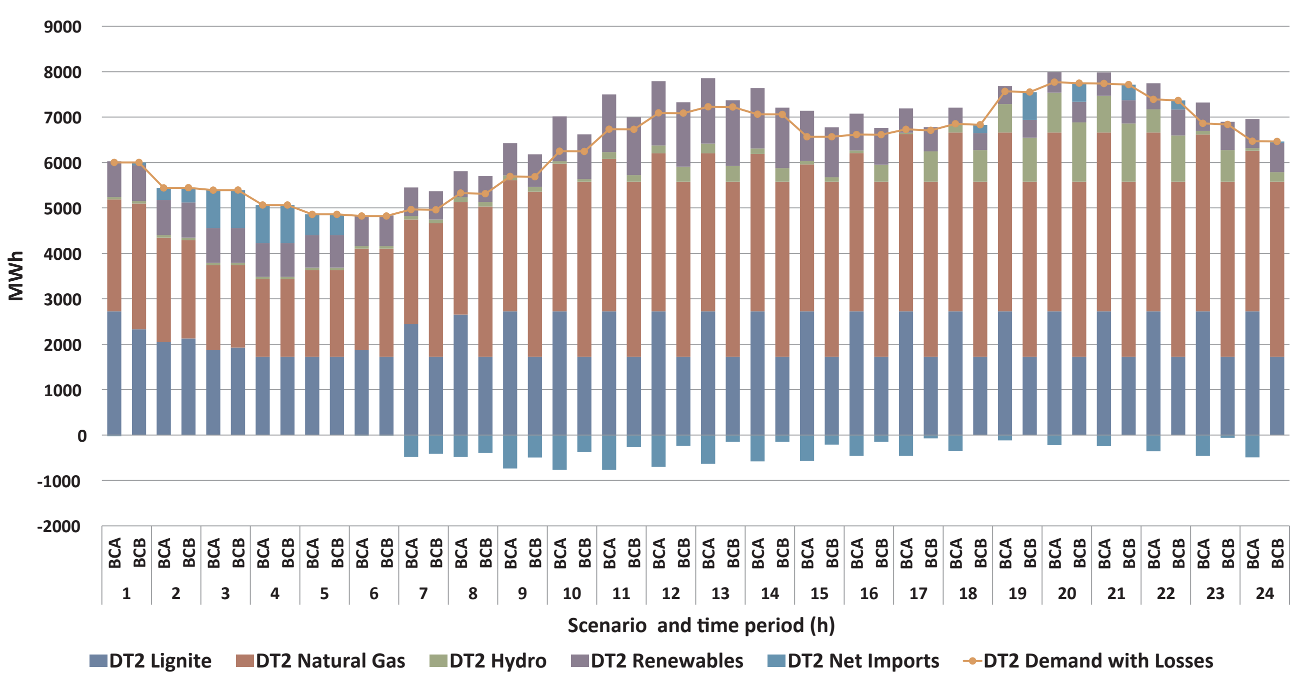

Fig. 7. Daily energy mix during a winter weekend in the BCA and BCB scenarios (MWh).

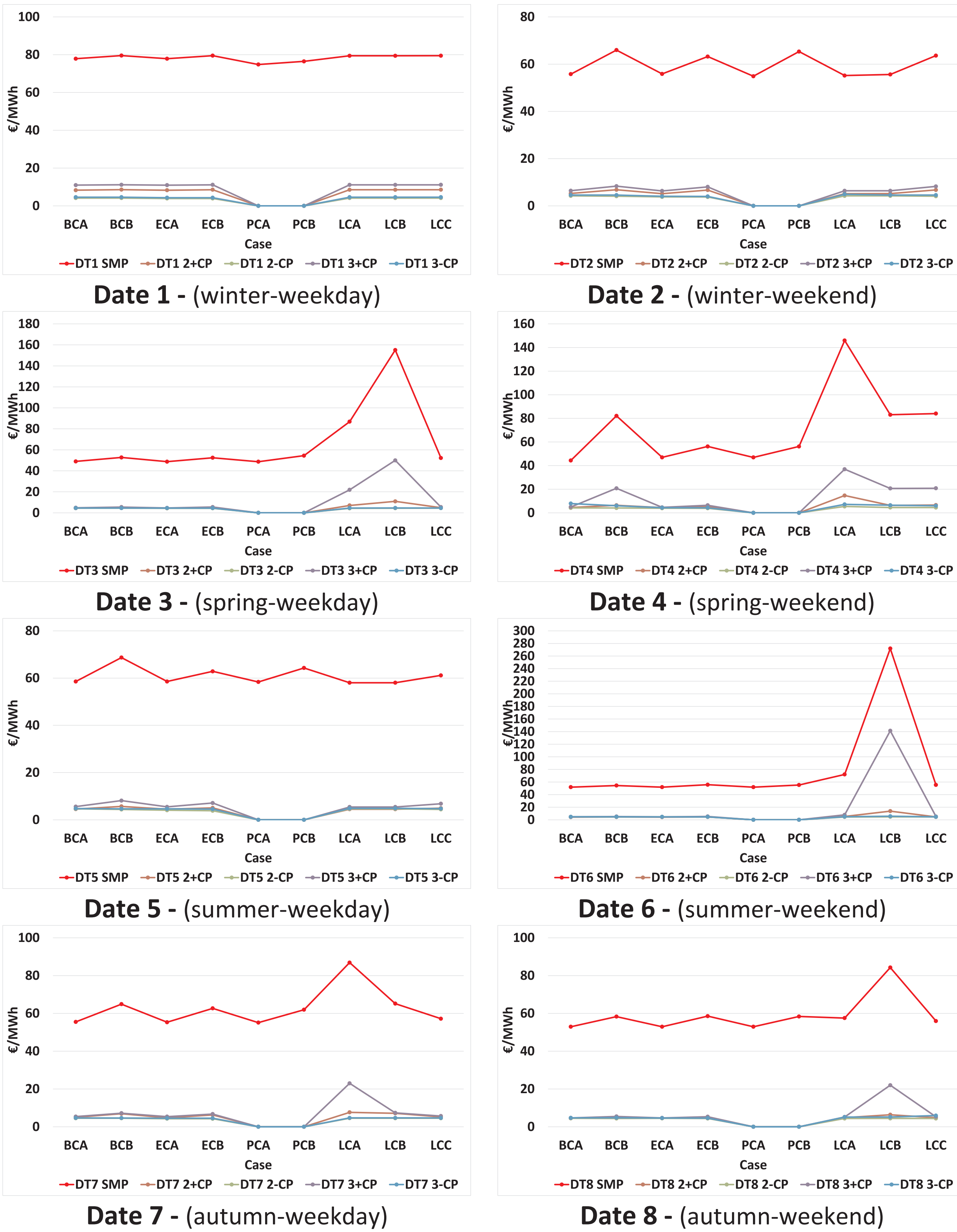

Fig. 8. Average daily system's marginal price (energy market), and market clearing prices per reserve type for each selected case and representative day type (€/MWh).

significance of the employed strategy by market participants. The significant differences reported in the resulting marginal prices of the linked cases can be mainly attributed to the capacity size and economic competitiveness of each formed group in each case, as well as the relationship between each group's total capacity with the net demand level of each case, considering the linkage criterion and the units'

Table 6
Daily system's marginal prices for the three Linked cases during each representative day type (€/MWh).

Scenario	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LCA	Date1	54	50	50	49	49	53	54	57	68	89	89	91	93	90	85	92	96	109	130	131	110	87	70	60
LCA	Date2	49	48	47	38	47	48	49	49	51	54	54	55	55	55	54	55	59	66	75	70	68	66	58	54
LCA	Date3	51	50	60	60	60	60	62	91	114	74	59	60	64	61	60	60	60	60	71	93	298	275	94	91
LCA	Date4	41	61	102	108	104	103	104	113	119	119	150	150	150	107	103	63	102	104	154	295	293	280	288	288
LCA	Date5	53	52	51	50	48	50	51	57	59	62	62	62	63	63	64	64	62	61	62	62	60	62	57	54
LCA	Date6	64	64	67	73	65	64	64	64	64	64	64	64	64	64	66	66	66	66	66	96	96	104	98	97
LCA	Date7	53	53	54	58	56	62	74	79	87	78	75	70	67	67	67	67	68	80	89	299	264	79	75	66
LCA	Date8	41	53	54	54	54	54	54	54	54	54	54	54	54	54	54	53	54	56	68	81	69	68	68	68
LCB	Date1	54	50	50	49	49	53	54	57	68	89	89	91	93	90	85	92	96	109	130	131	110	87	70	60
LCB	Date2	49	48	48	47	48	48	49	49	51	54	54	55	55	55	54	55	59	66	75	70	68	66	58	54
LCB	Date3	54	60	62	93	90	92	114	212	294	282	171	150	117	115	92	90	90	93	150	288	298	276	288	151
LCB	Date4	37	45	49	61	54	54	53	53	61	61	61	61	61	61	50	35	37	53	66	150	298	275	150	112
LCB	Date5	53	52	51	50	48	50	51	57	59	62	62	62	63	63	64	64	62	61	62	62	60	62	57	54
LCB	Date6	92	106	288	289	295	279	297	279	288	295	283	294	281	287	288	288	297	279	296	280	298	273	286	288
LCB	Date7	51	49	48	50	50	56	67	74	77	71	66	66	62	59	57	61	63	75	76	116	80	69	64	56
LCB	Date8	41	54	57	68	68	68	68	68	68	68	68	68	68	60	56	55	59	68	77	298	272	84	81	81
LCC	Date1	54	51	50	49	49	53	54	57	68	89	89	91	93	90	85	92	96	109	130	131	110	87	70	60
LCC	Date2	51	49	48	48	49	49	51	54	54	57	58	63	66	66	58	66	72	81	97	89	85	81	70	65
LCC	Date3	48	47	47	48	48	48	50	58	59	54	52	54	54	51	50	49	49	50	52	55	64	55	60	52
LCC	Date4	40	49	50	61	61	52	50	50	61	61	61	61	61	61	61	37	41	49	66	150	298	275	150	116
LCC	Date5	54	53	52	52	51	52	52	59	62	65	65	65	68	68	75	74	65	63	63	65	64	64	60	54
LCC	Date6	53	52	56	64	55	53	52	51	52	52	53	54	54	53	54	54	55	57	57	59	58	59	57	64
LCC	Date7	53	51	51	52	52	54	58	63	66	61	56	56	55	55	54	55	55	60	66	74	58	57	56	54
LCC	Date8	41	52	53	53	53	53	53	53	53	54	53	54	54	53	41	41	54	55	68	80	69	68	68	68

availabilities in each representative day type. An aggressive strategy has been selected in all cases, namely in order for the most economical unit to be operational, all the other available units, linked with it, have to be operational at least to their technical minimum. As a consequence, according to the structure criterion employed in each case (technology group, ownership group, and power station group criterion), the model can determine the shut-down of all lignite-fired units, of the units belonging to specific market participants and/or any kind of combinations among them, leading to the fluctuations observed in the daily average marginal prices. The cases where identical strategies are followed but they do not share the same market structure (technical minimum, minimum-up and down-times, complex orders, reserves' market incorporation), report also some differences among them, especially during the weekends, highlighting the combined effects of all the above mentioned market aspects. Note also that the zero reserves' market clearing prices values during the *PCA* and *PCB* scenarios are due to the non-incorporation of reserve markets in these scenarios. Due also to the fact that the energy and reserve priced offers are correlated among them, the system's marginal price and the reserves' market clearing prices follow, more or less, the same trend and shape.

Table 6 presents the daily (at an hourly level) system's marginal prices for the three Linked cases during each representative day type. Note that the maximum allowable level for priced offers is set at 300 €/MWh, as is currently the case in the Greek power market. Increasing this allowable level can lead to even higher market clearing prices, reflecting the resources' scarcity during specific crucial time periods, and sending the appropriate market price signals for relevant power investments, on the supply (generation and/or transmission investments), and/or on the demand side (demand-response, storage, energy efficiency). Note also that an extreme case is observed during the summer weekend (DT6) of the second linked case (LCB), where the model determines as the optimal solution (with that structure and satisfying simultaneously the thermal units' minimum up times) the load curtailment (load is bid at 300 €/MWh), instead of keeping online the linked groups, containing all the available thermal units. This is the main reason that skyrocketing marginal prices are observed in that case, approaching 300 €/MWh.

5.3. Power reserve mix

Figs. 9–12 depict the total daily secondary-up, secondary-down, tertiary-up, and tertiary-down reserve mix correspondingly, per selected case and representative day type. As can be observed from Fig. 9, hydroelectric and natural gas-fired units are mainly responsible for the provision of secondary-up reserve, given their high ramp-up rates.

With regard to the secondary-down reserve provision mix, lignite-fired units comprise the dominant technology in that reserve type satisfaction, given that they constitute an economical option in the energy demand satisfaction, operating close to their maximum levels, and thus they have the potential to provide that reserve type with downward direction (see Fig. 10). Natural gas-fired and hydroelectric units play a complementary role in that reserve type satisfaction.

When it comes to the tertiary-up reserve requirements, the trend is similar to the one of secondary-up reserve, where hydroelectric and natural gas-fired units account for almost total share of the demand satisfaction, as can be seen in Fig. 11. Not surprisingly, the high operating levels of lignite-fired units prevent them again from contributing to a reserve type with upward direction.

Regarding the tertiary-down reserve balance, lignite-fired and natural gas-fired units are the main contributors, depending on each scenario and representative day type (see Fig. 12). A general conclusion that can be derived from all reserve types' balance is that natural gas-fired units contribute to all reserve types to a noticeable extent, in both directions, highlighting the key role of that technology in dealing with both the intermittency of renewables and with security of supply issues. A noticeable characteristic observed in the majority of the selected day types and in both reserve types (secondary and tertiary) and directions (upward and downward) concerns the impacts of complex orders' incorporation in the resulting reserve mix. When comparing the cases without and with the complex orders' activation, namely BCA with BCB and ECA with ECB, the hydroelectric units' share is greatly enhanced in the cases considering complex orders compared to the corresponding one in the cases without their consideration, underscoring the flexibility capability from that energy resource. Its flexibility potential is also highlighted in the extreme conditions of the linked cases, where it contributes in the majority of the selected day types to a significant extent. In general, the introduction of competitive forces in the power

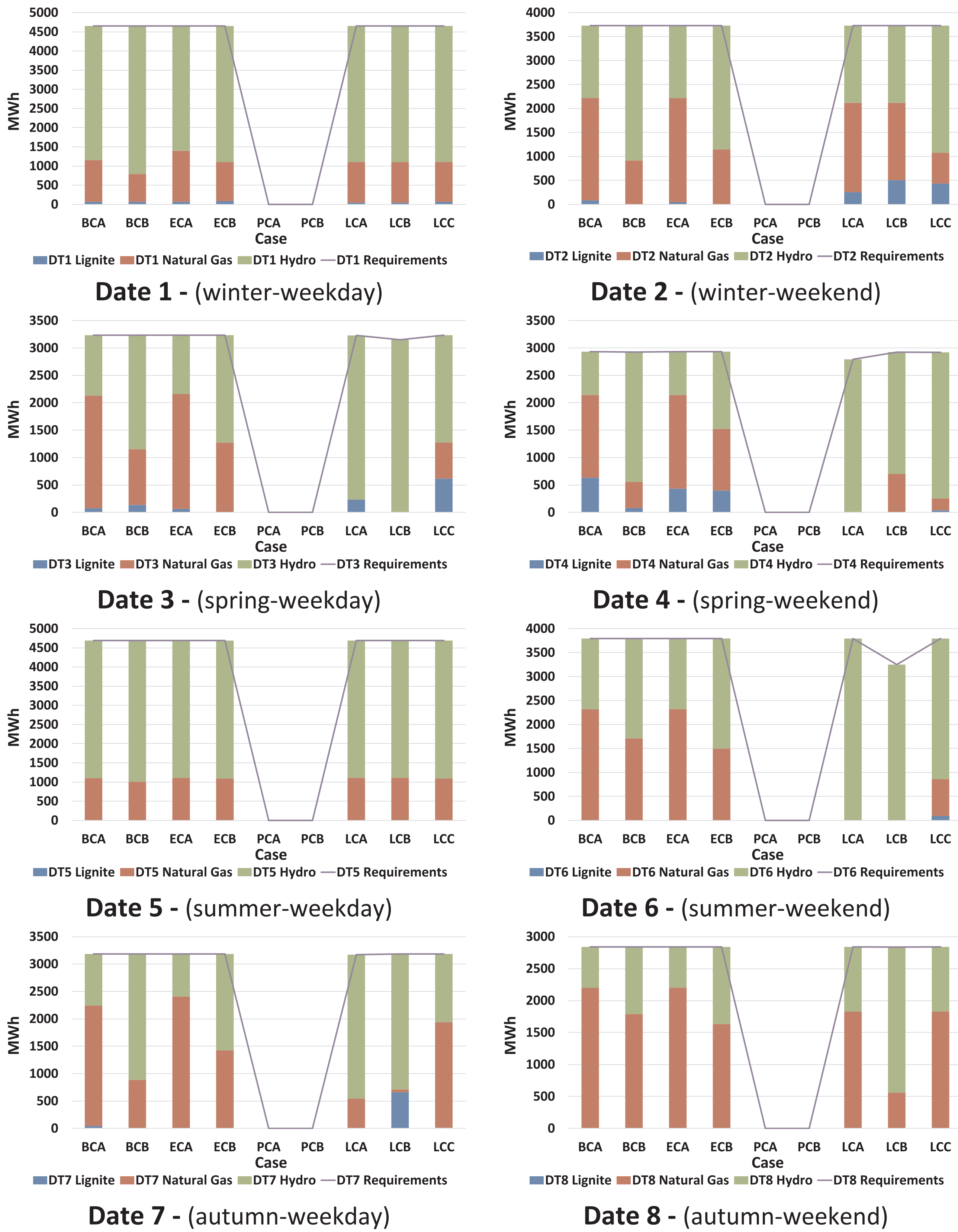

Fig. 9. Total daily secondary-up reserve mix per selected case and representative day type (MWh).

systems' operational scheduling, creates significant challenges for the economic viability of thermal units, while enhances the importance, in both technical and economic terms, of low-cost and flexible energy resources, such as hydroelectricity.

Fig. 13 depicts a daily secondary-up reserve mix during a winter weekend in the ECA and ECB scenarios. As can be observed in that figure, the requirements for that reserve type increase during the periods 8–13 h, while the peak value is reported at hour 20. It is noticeable

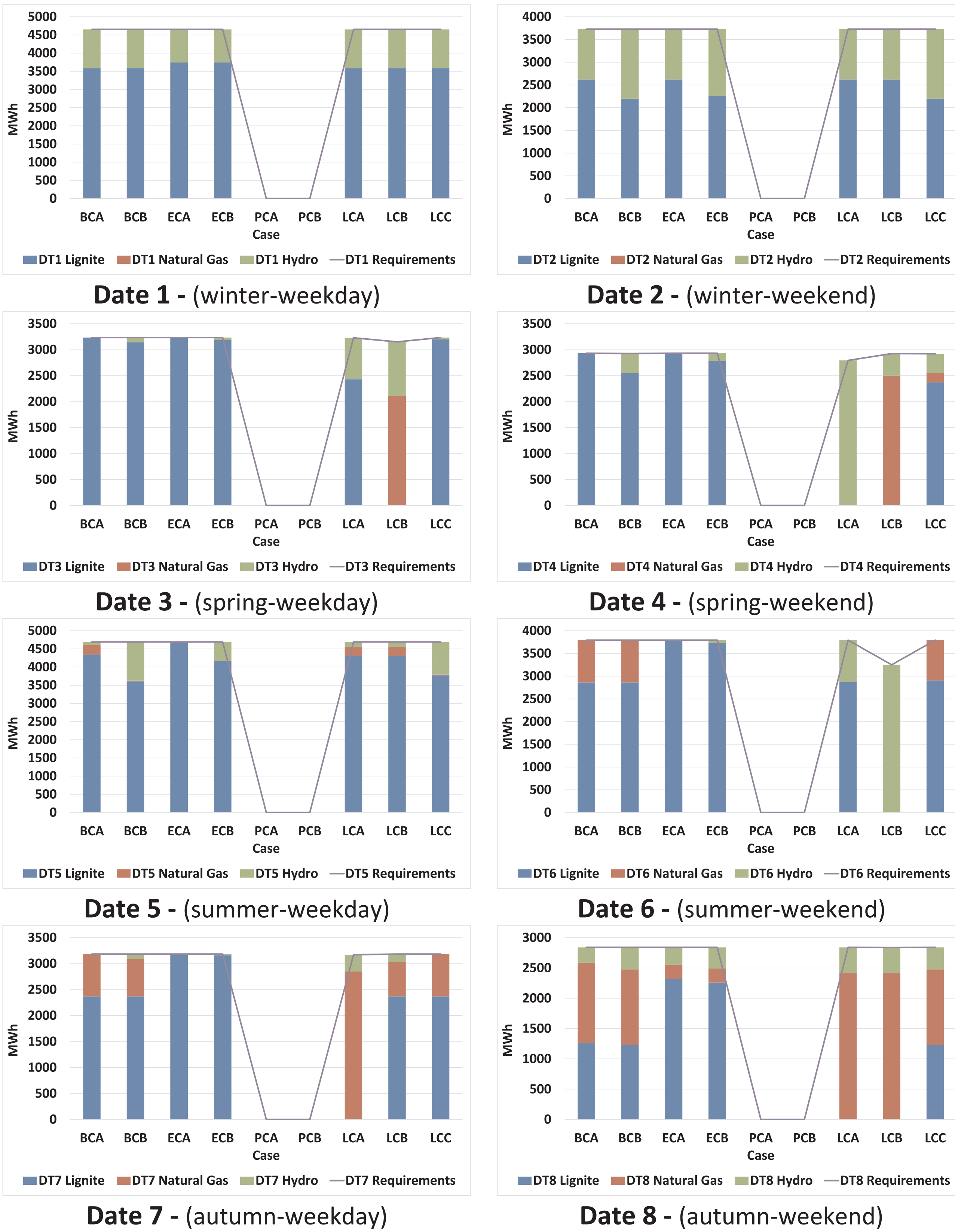

Fig. 10. Total daily secondary-down reserve mix per selected case and representative day type (MWh).

that natural gas-fired units comprise the key technology for the provision of secondary-up reserve during the first 7 h of the day (1–7 h) in both cases, while hydroelectric units start to contribute during the next hours, comprising the dominant reserve supplier from hour 12 in the ECB case, while in the ECA case it has also great contribution during the period 17–23 h. During the period 18–23 h, hydroelectric units constitute the sole secondary-up reserve suppliers in both cases.

Fig. 14 depicts a daily secondary-down reserve mix during a

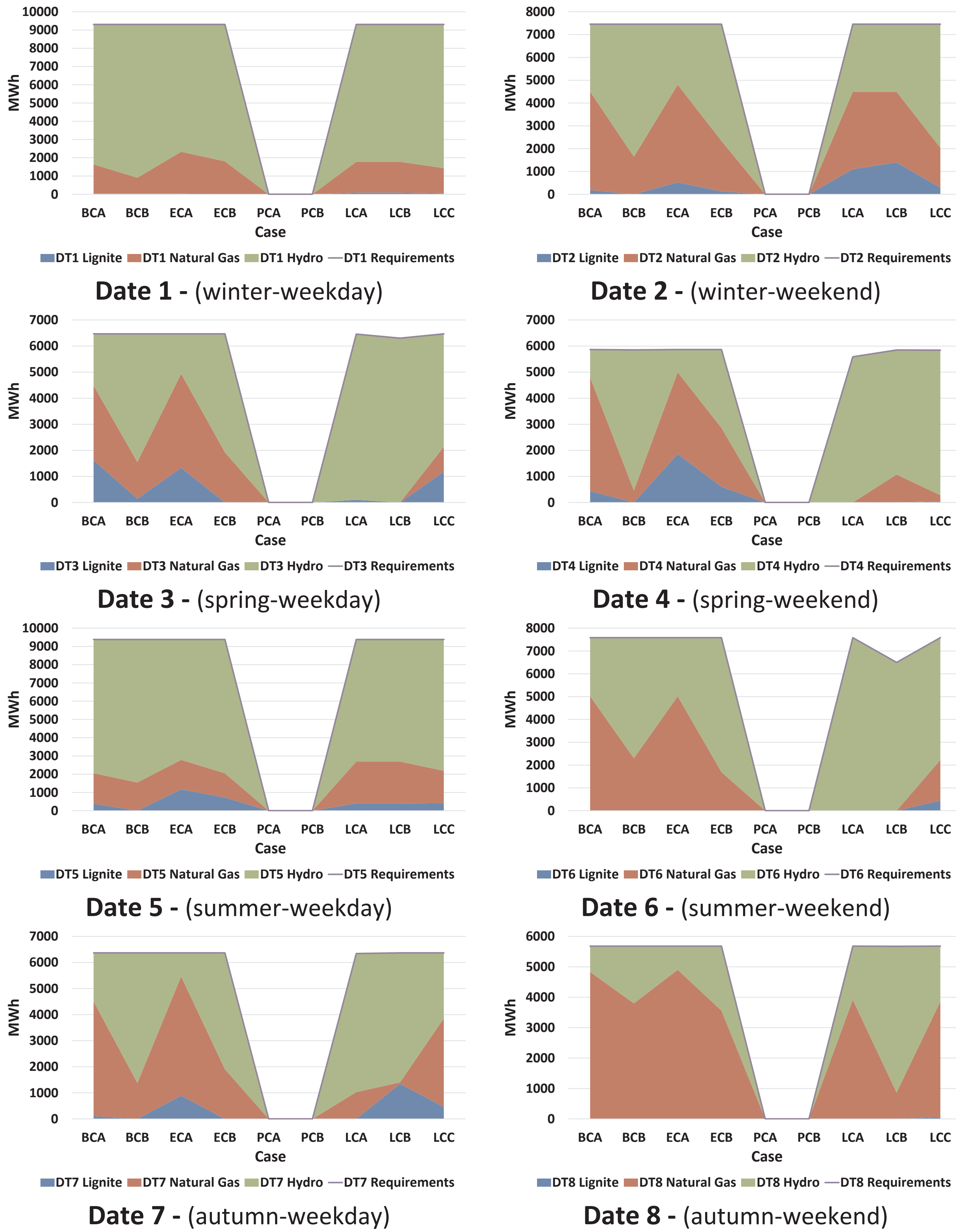

Fig. 11. Total daily tertiary-up reserve mix per selected case and representative day type (MWh).

summer weekday in the BCA and BCB scenarios. As can be also observed, the requirements for that reserve type increase during the period 8–14 h, while the peak value is reported at hour 14. Lignite-fired units comprise the dominant technology in the secondary-down requirements' satisfaction in both cases. It is worth mentioning again that although the hydroelectric units' share in the total is quite small, they

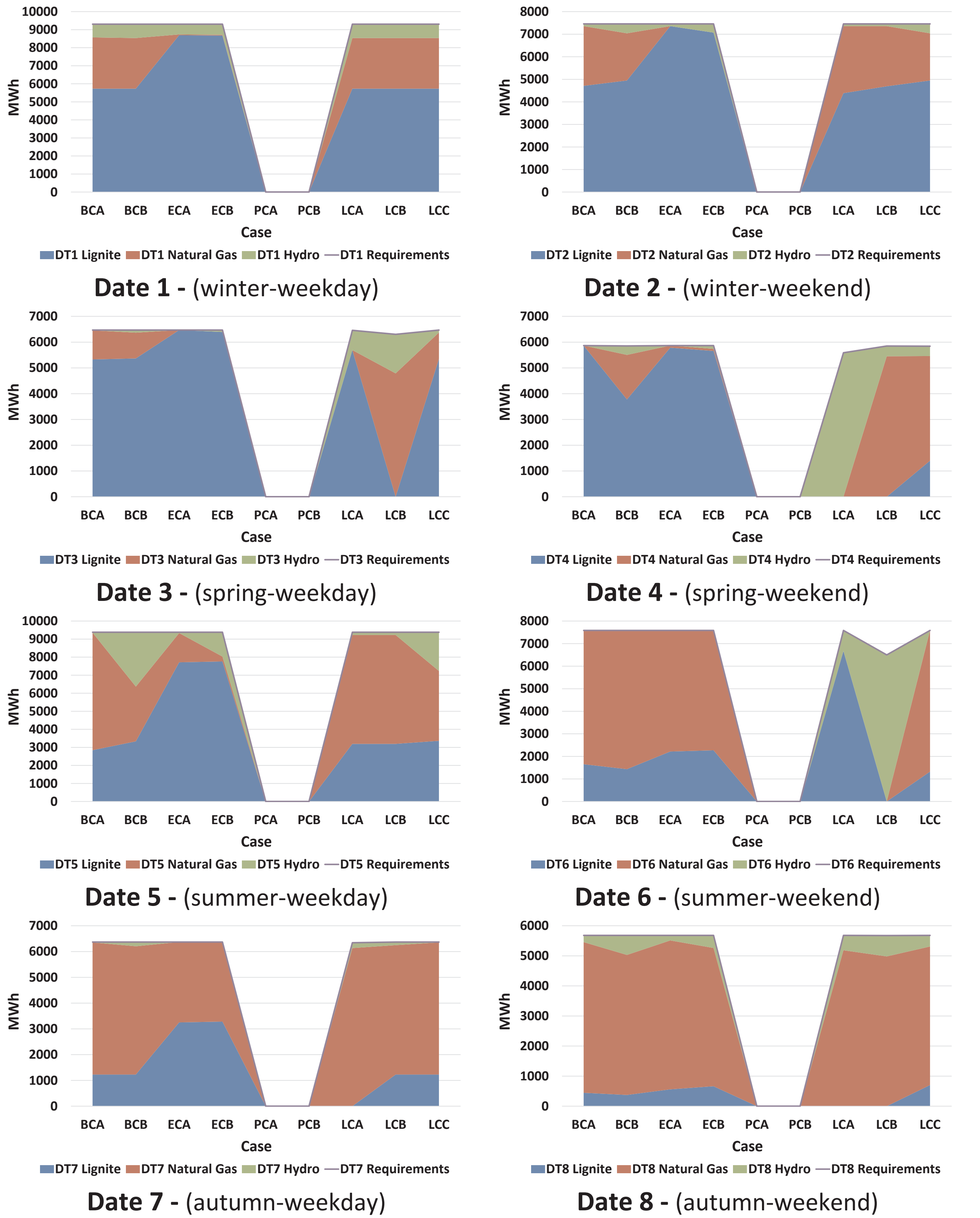

Fig. 12. Total daily tertiary-down reserve mix per selected case and representative day type (MWh).

account for a significant provision of secondary-down reserve during specific peak hours (14, 17, and 20–22 h) in the BCB scenario (with complex orders' incorporation), underscoring the multi-dimensional role of that technology in the provision flexibility when the system operates close to its available technical limits. In the BCA scenario, the role of hydroelectricity as a reserve supplier is more limited than in the

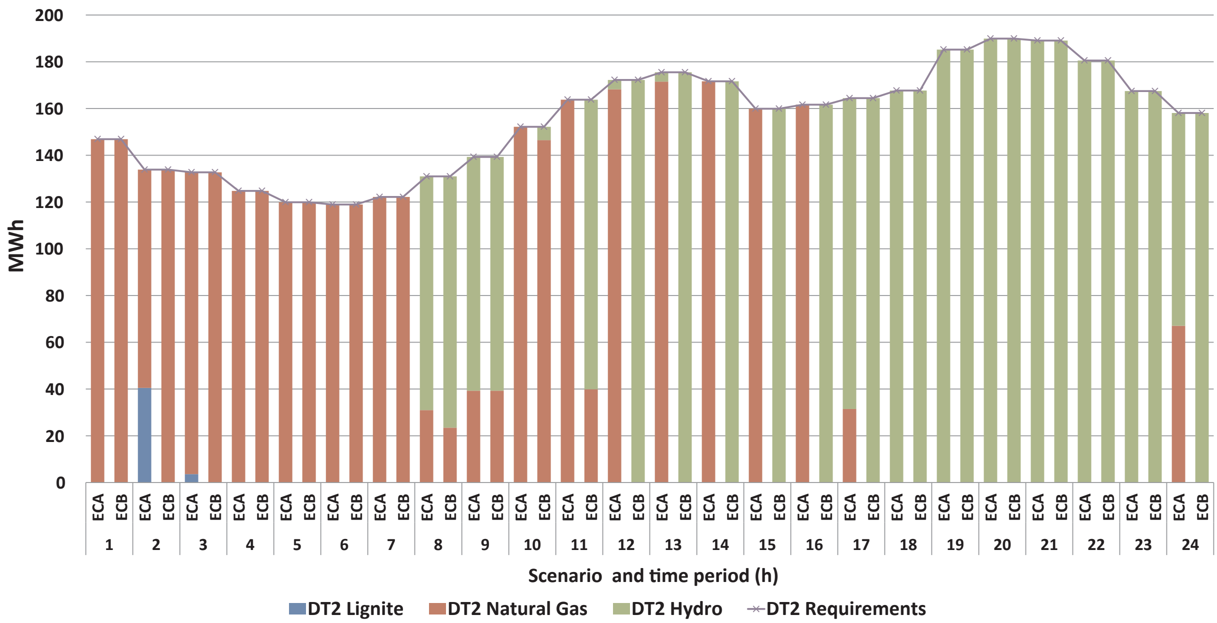

Fig. 13. Daily secondary-up reserve mix during a winter weekend in the ECA and ECB scenarios (MWh).

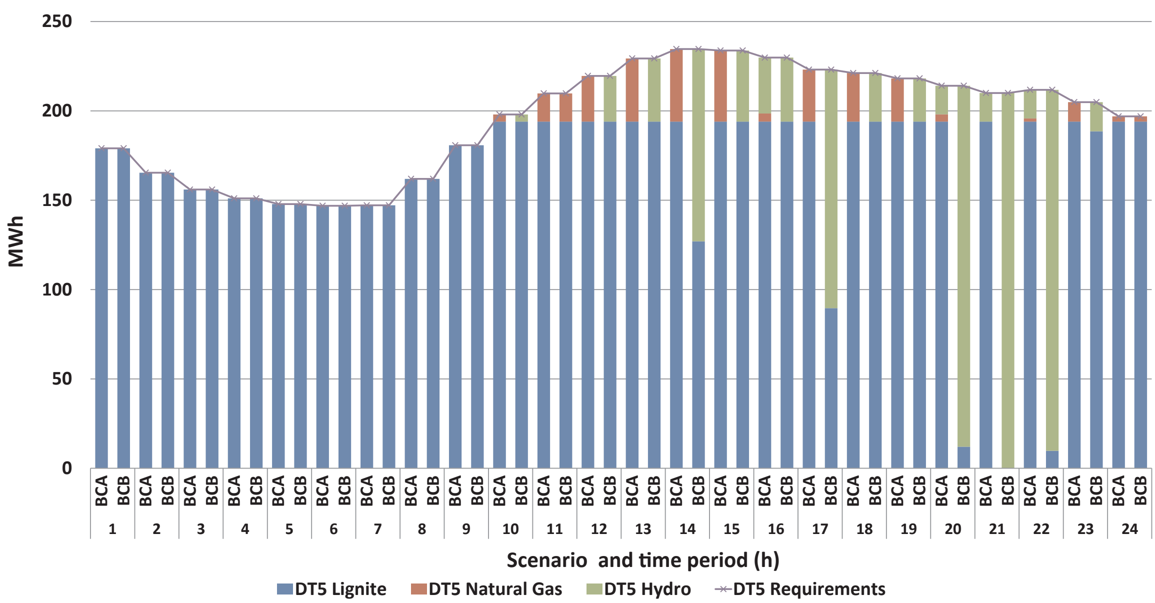

Fig. 14. Daily secondary-down reserve mix during a summer weekday in the BCA and BCB scenarios (MWh).

Table 7
Total daily welfare achievement of all thermal units in each representative day of all the examined scenarios (k€).

Scenario	Date1	Date2	Date3	Date4	Date5	Date6	Date7	Date8
BCB	5129.5	2401.1	556.7	1432.2	2645.3	599.4	1500.9	600.9
ECB	5159.9	2170.9	550.1	596.5	1969.4	721.3	1438.8	715.2
PCB	4641.3	2359.6	640.7	513.3	2055.7	674.3	1367.8	650.4
LCA	5184.3	1291.2	2137.1	0.0	1475.3	1328.9	2691.0	539.6
LCB	6652.3	2110.0	2786.1	874.4	2758.5	209.1	2150.0	1755.8
LCC	5156.9	2185.4	524.4	1358.1	1816.8	659.1	818.0	465.7

BCB scenario, while natural gas-fired units play also a complementary role in the secondary-down requirements' satisfaction.

5.4. Unit welfare composition

Table 7 presents indicatively the total daily welfare achievement of all thermal units in each representative day type of all the examined scenarios, namely the net revenues (achieved revenues minus required revenues from both energy and reserve markets) collected in the final successful iteration of the market clearing algorithm, satisfying the imposed minimum income condition orders. Note that the zero values account for the cases where no thermal units operate in the production

Table 8
Total daily ratio of achieved to required revenues per thermal unit in each representative day of the ECB scenario (%).

Scenario	Unit	Date1	Date2	Date3	Date4	Date5	Date6	Date7	Date8
ECB	Lignite-1	0%	0%	0%	0%	0%	0%	0%	0%
ECB	Lignite-2	173%	138%	0%	0%	0%	0%	0%	0%
ECB	Lignite-3	173%	138%	116%	128%	127%	113%	122%	0%
ECB	Lignite-4	0%	0%	0%	0%	0%	0%	0%	0%
ECB	Lignite-5	186%	150%	124%	135%	136%	121%	130%	121%
ECB	Lignite-6	166%	0%	0%	0%	126%	0%	0%	0%
ECB	Lignite-7	167%	136%	0%	0%	126%	0%	0%	0%
ECB	Lignite-8	167%	0%	0%	0%	124%	0%	0%	0%
ECB	Lignite-9	166%	0%	0%	0%	126%	0%	0%	0%
ECB	Lignite-10	173%	138%	116%	130%	131%	116%	0%	0%
ECB	Lignite-11	0%	0%	0%	0%	0%	0%	124%	116%
ECB	Lignite-12	201%	160%	0%	0%	175%	157%	0%	0%
ECB	Lignite-13	199%	162%	136%	145%	169%	0%	153%	144%
ECB	Lignite-14	208%	167%	0%	150%	171%	0%	160%	0%
ECB	NGCC-1	173%	138%	111%	0%	127%	113%	137%	126%
ECB	NGCC-2	163%	130%	111%	122%	122%	114%	129%	124%
ECB	NGCC-3	172%	138%	116%	0%	132%	0%	131%	126%
ECB	NGCC-4	167%	125%	110%	121%	121%	118%	112%	0%
ECB	NGCC-5	172%	132%	111%	0%	126%	117%	0%	0%
ECB	NGGT-1	0%	0%	0%	0%	0%	0%	0%	0%
ECB	NGGT-2	0%	0%	0%	0%	0%	0%	0%	0%
ECB	NGGT-3	0%	0%	0%	0%	0%	0%	0%	0%
ECB	NGCC-6	176%	125%	0%	0%	106%	0%	0%	0%
ECB	NGCC-7	162%	131%	0%	0%	132%	120%	134%	128%
ECB	NGCC-8	153%	121%	0%	0%	0%	0%	118%	0%
ECB	NGCC-9	0%	0%	0%	0%	113%	0%	130%	0%
ECB	NGCC-10	163%	134%	115%	0%	134%	119%	135%	129%

scheduling during the examined period. According to that Table, the total average values are between 698.6 thousands € (DT6) and 5320.7 thousands € (DT1). If we compare the cases considering complex orders with those that do not take them into account, we can observe that the latter ones report higher net revenues, due to more intensified utilization of thermal units in these cases, highlighting again the challenges that conventional thermal units face in the contemporary power markets. Table 8 presents indicatively the total daily ratio of achieved to required revenues per thermal unit in each representative day of the ECB scenario, calculating in this way the profit margin per operational unit collected in the final successful iteration of the market clearing algorithm, satisfying the imposed minimum income condition order. Note that the zero values account for the units that do not operate in the production scheduling during the examined period. As can be seen in that Table, the highest profit margins vary from 36% to 108%, while the lowest are between 6% and 53%, according to each selected representative day type.

6. Conclusions

The transition from nationwide power markets towards the unification of European day-ahead power markets creates new challenges arising from the design and implementation of the regional power exchanges. The degree of power units' technical and economic representation, as well as the amount of the available market products are of paramount importance for the long-term welfare of all market participants. This integration process is facilitated by the adoption of a common clearing algorithm among European power exchanges, entitled EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm), which however lacks to capture critical technical aspects of the power systems, as done by the unit commitment problem.

The present work provides a new power markets clearing algorithm by extending the current structure of the hourly offers module of EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) model, the official clearing algorithm at a Pan-European level. More specifically, it addresses the problem of the optimal clearing of combined energy and reserve markets based on simple offers, providing also the options of complex orders, the structure of which has been extended in order to incorporate the impacts of the reserve markets clearing.

The paper contributes to the relevant literature on the enhancement of the EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) algorithm with the power reserve markets incorporation, satisfying the relevant constraints at 15-min, 30-min, and hourly level. The minimum income condition is also extended so as to integrate the reserve markets' clearing aspects into the revenues balance, in addition to those derived from the energy-only market. This extension provides new space for strategy formation options, having the objective of facilitating the optimal management of electricity portfolios, adding new dimensions in the current market structure. Another important aspect of the proposed framework is that it introduces the concept of developing linked groups of thermal power generating units, creating dynamic and flexible portfolios, facilitating their management, especially in the case of large power corporations, and providing additional degrees of freedom. Furthermore, the proposed methodological approach provides the basis for an analytical and systematic assessment of a series of key operating aspects of power units including the minimum up and down times, as well as the consideration or not of each thermal power unit's technical minimum in the market clearing process.

The applicability of the proposed mathematical model has been tested on the Greek power system and its interconnections with neighboring power systems in Southeast Europe. With the objective of investigating the influences of a series of technical and economic aspects on the power exchanges clearing, several cases have been identified. The results, derived from the implementation of the selected scenarios, highlight that the activation of the minimum income condition order can significantly affect the resulting power mix, and subsequently the economic elements of the market clearing. The strategy adopted by the market participants constitutes a factor of equal importance, especially when combined with the utilization of the linked groups, creating modified portfolio structures. The market clearing of the neighboring power exchanges, through the determination of border prices, comprises a third key element in the optimal power scheduling, enhancing the market competitiveness and influencing the welfare and economic viability of the domestically installed thermal units. The increasing penetration of renewable energy sources can also act in favor of specific technology types, underlining as key features the flexibility provision through short operational times, high ramp rates, capability of frequent start-ups and shut-downs, as well as the economic competitiveness.

The proposed approach can provide useful insights on the determination of the optimal generation and interconnection portfolios that satisfy the real, market-based operational requirements of contemporary power systems, subject to technical and economic constraints. It also highlights the role of efficient market designs, providing supplementary arguments in favor of further investigating the feasibility of new flexible market products' introduction.

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