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Impact of the penetration of renewables on flexibility needs

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ABSTRACT

The paper aims to quantify the impact of the penetration of renewables on the flexibility needs and their price signal. It uses a generic Mixed Integer Linear Programming (MILP) model that integrates long-term power system planning with a Unit Commitment (UC) model, which performs the simulation of the Day-Ahead Electricity Market (DAEM). The integrated model evaluates the need of flexibility services, under different conditions of renewable penetration. A case study of the Greek interconnected electric system is examined. Results show that the main flexibility needs concern photovoltaics causing the sunset effect, while the needs from stochastic wind are alleviated from the fact that wind output is de-linked from the demand evolution and that wind installations' positions are diversified. The identification of flexibility needs from the Transmission System Operators (TSOs) require detailed data to depict the spatial and technical characteristics of each power system, which can reveal that ramping rates, and not just the magnitude of ramping capacity, can be an important flexibility requirement, due to large single-hour ramp contribution in some months. Such an analysis can also reveal the options for increasing flexibility, which are power system specific.

1. Introduction

The penetration of Renewable Energy Sources (RES) imposes additional challenged to electricity markets and power systems. It strongly depends on the capability of the Transmission System Operators (TSOs) to evolve towards tackling critical reliability issues, such as voltage dip and power balance management, dedicated predictability for electricity generation from RES as well as advanced flexibility services (Lannoye et al., 2012). Advanced electricity markets are considering the introduction of flexibility services towards enhancing the stability of the system (Cochran et al., 2014). Those flexibility services are supplementary to the ancillary services, such as frequency control, reactive power and voltage control, load regulation, replacement reserve, spinning and non-spinning reserve. The intermittent and variable generation from RES creates new challenges to balancing authorities, particularly to ramping capability. The capability of a power plant to start and stop on command as well as the request for high rates at which a power plant increases or decreases its output, namely its ramping up or down capability, is very crucial for a system with high penetration of RES. The identification of the flexibility services needed, depending on the penetration level of renewables as well as the topology of the electric systems, is of high priority. The identification of flexibility needs is very crucial for the TSOs, aiming at the enhancement of reliable and efficient electric systems, especially considering the fact that a considerable number of electricity markets are de-linked from central dispatch design towards self-dispatch design, either portfolio of unit based.

The incorporation of flexible products has already been implemented in advanced electricity markets, such as the approval of the California ISO Board of a flexible ramping product as well of its compensation methodology (CAISO, 2015). This product created a new short-term energy market that serves to shift energy supply or demand within minutes. However, this type of ramp capability differs from traditional ancillary services markets such as spinning reserves, which are aimed at minimizing the effects of a generator tripping or regulation, which is aimed at maintaining frequency. Instead, this ramp market attempts to send generators sufficient price signals for upward and downward flexible ramping capability, towards accounting for uncertainty due to demand and renewable forecasting errors. The incorporation of similar flexible products is being considered in European electricity markets, aiming to tackle such reliability issues but as well to provide a fair compensation for power plants.

Abbreviations: IPTO, Independent Power Transmission Operator; HEMO, Hellenic Electricity Market Operator; GAMS, General Algebraic Modelling System; MILP, Mixed Integer Linear Programming; RES, Renewable Energy Sources; DAEM, Day-Ahead Electricity Market; SMP, System Marginal Price; UCP, Unit Commitment Problem; ANN, Artificial Neural Network

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Nomenclature

Sets

$s \in S$	set of subsystems
$t \in T$	set of hours
$b \in B$	set of blocks of the energy offer function (bids) of each hydrothermal unit
$e \in E^z$	set of pumped storage units $e \in E$ interconnected with zone $z \in Z$
$g \in G^{hth}$	set of hydrothermal units
$g \in G^z$	set of units $g \in G$ that are (or can be) installed in zone $z \in Z$
$z \in Z$	set of zones
$n \in N^z$	set of interconnected power systems $n \in N$ with zone $z \in Z$
$n \in N$	set of interconnected power systems

Parameters

$CB_{g,b,t}$	Marginal cost of block $b \in B$ of the energy offer function of each unit $g \in G^{hth}$ in hour $t \in T$ (€/MW)
$CEP_{n,b,t}$	Marginal export bid of block $b \in B$ to interconnection $n \in N$ in hour $t \in T$ (€/MW)
$CIP_{n,b,t}$	Marginal cost of block $b \in B$ of the imported energy offer function from interconnection $n \in N$, in hour $t \in T$ (€/MW)
$CPM_{e,b,t}$	Marginal bid of block $b \in B$ of pumped storage unit $h \in H$ in hour $t \in T$ (€/MW)
$L_{z,t}$	Injection losses coefficient in zone $z \in Z$ and hour $t \in T$ (p.u.)
P_g^{min}	Technical minimum of each unit $g \in G^{hth}$ (MW)
P_g^{max}	Maximum power output of each unit $g \in G^{hth}$ (MW)
$RC1_{g,t}$	Price of the primary energy offer of each unit $g \in G^{hth}$, in hour $t \in T$ (€/MW)
$RC2_{g,t}$	Price of the secondary range energy offer of each unit $g \in G^{hth}$, in hour $t \in T$ (€/MW)
SDC_g	Shut-down cost of each unit $g \in G^{hth}$ (€)
$CAP_{s,t}$	Maximum allowed price for priced energy offers in subsystem $s \in S$ and hour $t \in T$
$SMP_{s,t}$	System Marginal Price in subsystem $s \in S$ and hour $t \in T$ (Euro/MWh)
$SMP_{n,t}$	System Marginal Price in interconnected system $n \in N$ and hour $t \in T$ (Euro/MWh)

Continuous Variables

$exb_{n,b,t}$	Cleared quantity of power capacity block $b \in B$ exported to interconnected system $n \in N$ in hour $t \in T$ (MW)
$imb_{n,b,t}$	Cleared quantity of power capacity block $b \in B$ imported from interconnected system $n \in N$ in hour $t \in T$ (MW)
$pb_{g,b,t}$	Quantity of power capacity block $b \in B$ of unit $g \in G^{hth}$, dispatched in hour $t \in T$ (MW)
$pmb_{e,b,t}^{pum}$	Cleared quantity of block $b \in B$ of pumping unit $h \in H$ in hour $t \in T$ (MW)
$r1_{g,t}^{up}$	Contribution of unit $g \in G^{hth}$ in primary-up reserve in hour $t \in T$ (MW)
$r2_{g,t}^{down}$	Contribution of unit $g \in G^{hth}$ in secondary-down reserve in hour $t \in T$ (MW)
$r2_{g,t}^{up}$	Contribution of unit $g \in G^{hth}$ in secondary-up reserve in hour $t \in T$ (MW)

Binary Variables

$x_{g,t}^{sd}$	1, if unit $g \in G^{hth}$ is shut-down in hour $t \in T$

Considering that several power plants are facing financial viability problems, as long as they don't get the appropriate price signals for their ramping capability, they are considering of preferring the cold-reserve status or even the decommissioning of the units. Besides the depreciation of new power plants, this would accelerate the need for the introduction of energy security compensation schemes, which could increase significantly the total energy cost. Therefore, the introduction of flexibility products provides several supplementary gains for the energy system and the overall energy cost.

Therefore, it is crucial to develop robust methodologies aiming to identify the flexibility needs, as well as their pricing. A recent research paper examines market solutions for managing ramp flexibility (Navid and Rosenwald, 2012). Milligan et al. (2016) explore both traditional and evolving electricity market designs in the United States that aim to ensure resource adequacy and sufficient revenues to recover costs when those resources are needed for long-term reliability (Milligan et al., 2016). It also investigates how reliability needs evolve as the renewables penetrate in the market. A continuation of this work Ela et al. (2016) examines the market design with high penetration of renewables, aiming to offset the inefficient utilization of existing flexibility or unwillingness of resources to provide flexibility, which lead to higher energy system costs (Ela et al., 2016). It explores some of these existing market designs, as well as new market mechanisms, such as pay-for-performance regulating reserve and primary frequency response markets, explicit products for flexible ramping provision and the allowance for non-traditional resources, such as demand response, energy storage, and even variable generation itself. Such market schemes aim to explicitly incentivize the provision of more flexibility to the system, particularly as a result of increasing variable generation penetration levels.

A recent paper reviews different approaches, technologies, and strategies to manage variable electricity generation from RES, considering both supply and demand side measures (Lund et al., 2015). Moreover, it focuses on presenting energy system flexibility measures, ranging from traditional ones such as grid extension or pumped hydro storage to more advanced strategies such as demand-side approaches. Kondziella and Bruckner (2016) provide a review of research results and methodologies on the flexibility requirements deriving from the penetration of renewables. It classifies the results into technical, economic, and market potential categories to enhance their comparability. Moreover, the paper conducts a methodological evaluation of the literature findings, discussing a conceptual framework to quantify the market potential of flexible technologies.

Frew et al. (2016) present a cost optimization planning model of the power system of USA, aiming at evaluating the trade-offs and relative benefits of four flexibility mechanisms as well as comparing pathways to a fully renewable power system. The paper concludes that geographic aggregation is the optimum mechanism among the four flexibility mechanisms considered. Mikkola and Lund (2012) present a fast and easy-to-use optimization model to find cost-optimal ways to manage the energy system with large-scale variable renewable energy, aiming to identify the optimal use of energy system flexibility. Moreover, the model handles both electric and thermal loads, allowing the identification of penetration capability of power-to-heat conversion systems.

Denholm and Hand (2011) examine the changes to the electric power system required to absorb high penetration of variable wind and solar electricity generation in a transmission constrained grid. It concludes that a highly flexible system allows for penetration of electricity generation from RES up to 80% of the system's electricity demand. However, this requires a combination of load shifting and storage equal to about one day of average demand. Després et al. (2016) present a new electricity module of the POLES model, examining the role of electricity storage for the integration of high shares of variable renewable energy sources in the long-term evolution of the power system. The integrated model examines several flexibility options, within-day storage, demand response and grid interconnections, concluding that storage can benefit from high carbon values and from surplus solar energy.

Alizadeh et al. (2016) defines, classifies and discusses the latest flexibility treatments in power systems based on a comprehensive literature study. It specifically considers the abilities, barriers, and inherent attributes of power systems' potential to deal with high integration of variable energy resources in future flexible power systems. Batalla-Bejerano and Trujillo-Baute (2016) aim to estimate the sensitivity of balancing market requirements and costs due to the variable renewable generation. Examining the Spanish electricity system, the paper concludes that integration costs depend on variability, predictability and system flexibility of each power system. Weijde and Hobbs (2012) present a stochastic two-stage optimization model that captures the multistage nature of transmission planning under uncertainty and use it to evaluate interregional grid reinforcements in Great Britain. The model identifies the uncertainty cost and the value of flexibility, concluding that ignoring risk in planning transmission for renewables has quantifiable economic consequences, and that considering uncertainty can yield decisions that have lower expected costs than traditional deterministic planning methods.

Welsch et al. (2014) compare the performance of an extended version of an open source energy system model (OSeMOSYS), which incorporates operation constraints, to an integrated model that links a long-term energy system model (TIMES) with a unit commitment and dispatch model (PLEXOS) for the case the Irish power system. The paper concludes that omitting the variability of renewables may underestimate the overall energy system costs and therefore the costs for meeting climate change or energy security targets. Papaefthymiou and Dragoon (2016) outline the necessary steps towards creating power systems with the flexibility needed to maintain stability and reliability while relying primarily on variable energy resources. It provides a comprehensive overview of policies, technical changes, and institutional systems towards the transition to a power system with 100% renewables. Kubik et al. (2015) explores the role that conventional generation has to play in managing the variability of RES, especially related to wind ramping, aiming at identifying the significance of specific plant characteristics for reliable system operation. The paper proposes market specific strategies for using the existing fleet of generation to reduce the impact of renewable resource variability.

Welling (2016) examines the effects of uncertainty and flexibility on investment in renewables under governmental support, analysing the influence of support schemes and flexibility in the case of Germany. The paper develops a model of the investment decision regarding a renewable electricity project, where the investor has the possibility to optimally choose the size of the project's capacity. The investors' decision is analysed applying the net present value decision rule. Belderbos and Delarue (2015) introduce a new power system planning model, considering technical operational constraints, aiming at determining the optimal mix of generation units. The paper demonstrates that operational constraints of power plants, especially related to the volatile nature of renewables, have an important impact on the capacity and energy mix. Concerning models of the Greek power system, Bakirtzis et al. (2014) developed a multiple time resolution unit commitment model for short-term operations scheduling under high renewable penetration, demonstrating its application to the Greek power system. Andrianesis et al. (2011) developed a Medium-Term Unit Commitment (MTUC), by extending the unit commitment problem to a longer horizon of several days, and keeping only the solution for the next day as binding (rolling horizon). Koltsaklis et al. (2014; 2015; 2016) developed a mid-term market based power system planning model, incorporating a unit commitment model. The model identifies the power mix and the day-ahead prices of the Greek interconnected system. Moreover, Panapakidis and Dagoumas (2016), implemented artificial neural networks for day-ahead price forecasting of the Italian market, examining also the influence of renewables.

The above literature review and analysis showed that an increasing number of researchers are focusing on examining different market schemes for flexibility services, related to the penetration of renewables. Several papers focus on the market design and new market mechanisms for incorporating flexibility needs. Most of the papers conduct qualitative research, aiming at identifying the capabilities and barriers related to high integration of variable energy resources in the power systems. Few papers provide robust quantitative approaches for the identification of reliability needs as the renewables penetrate in the market, as well as the impact of flexibility services in the market. The majority of the research, especially the quantitative, concerns mature energy markets in the USA, with few exceptions for European markets and no specific research for the Greek power system. Therefore, the literature is not extended concerning the modelling approaches for the identification of the flexibility needs and their remuneration. This signal is critical for enhancement of the on-time deployment of the required flexible units. This paper aims at identifying the requirements and the remuneration of this "ramp market", related to different levels of penetration of renewables in the electricity markets, with special focus on the Greek power system.

This paper uses a generic Mixed Integer Linear Programming (MILP) model that integrates long-term power systems planning with a Unit Commitment (UC) model, which performs the simulation of the Day-Ahead Electricity Market (DAEM), based on recent work (Koltsaklis et al., 2014, 2015, 2016). A case study of the Greek interconnected electric system is examined, where currently a critical policy issue for the Regulatory Authority of Energy (RAE) and the TSO is the identification of flexibility needs. The integrated model is used to evaluate the needs of flexibility services, under different conditions of penetration of RES: optimum energy mix based on the levelized cost of electricity generation from RES under constraints of the power system and the operation of DAEM, exogenous penetration of RES based on energy policy targets. The key contributions and the salient features of our work include: i) integration of flexibility services in long-term power systems planning, (i) identification of the flexibility needs depending on the penetration level of renewables, per technology type (iii) provision of useful insights into the levels of flexibility needs and the remuneration of flexible units (iv) raising the importance of diversification of installation location of RES plants and (v) raising the importance of spatial analysis of the power system towards identifying options for increasing flexibility.

The remainder of the paper is organized as follows: Section 2 provides the formulation of the model. Section 3 presents the details of a case study, while Section 4 provides an analytical discussion of the results obtained for some indicative scenarios. Finally, Section 5 draws the main conclusions arising from the implementation of this work.

2. Formulation of the model

The paper uses a MILP model for the optimal long-term energy planning of a (national or regional) power system, incorporating the unit commitment problem (Koltsaklis et al., 2016). The objective function is based on the short-term market operation, namely the minimization of the total annual operational cost of the studied power system at one daily period. Therefore, the model's objective function includes: (i) marginal production cost of the power units incorporating fuel cost, variable operating and maintenance (O & M) cost, and CO_2 emission allowances cost, (ii) power imports cost, (iii) power exports revenues, (iv) pumping load revenues, (v) units' shut-down cost, and (vi) reserves provision cost, as represented by Equation (1).

$$\begin{aligned}
\boldsymbol{Min}\ Cost^{daily} = & \overbrace{\sum_{u\in(U^{hth}\cap U^{z})}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(CB_{u,z,b,t}\cdot PEO_{u,z,b,t}\cdot L_{z,t})}^{Marginal\ production\ cost}\\
& + \overbrace{\sum_{n\in N^{z}}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(ICB_{n,z,b,t}\cdot IEO_{n,z,b,t}\cdot L_{z,t})}^{Power\ imports\ cost}\\
& - \overbrace{\sum_{n\in N^{z}}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(ECB_{n,z,b,t}\cdot EEO_{n,z,b,t})}^{Power\ exports\ revenues}\\
& - \overbrace{\sum_{e\in E^{z}}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(PMCB_{e,z,b,t}^{pum}\cdot PMEO_{e,z,b,t})}^{Pumping\ load\ revenues}\\
& + \overbrace{\sum_{u\in U^{hth}}\sum_{t\in T}(x_{u,t}^{sd}\cdot SDC_{u})}^{Shut-down\ cost}\\
& +\\
& \overbrace{\sum_{u\in U^{hth}}\sum_{z\in Z}\sum_{t\in T}[(PR_{u,z,t}^{up}\cdot PRO_{u,z,t}) + (SR_{u,z,t}^{up} + SR_{u,z,t}^{down})\cdot SRO_{u,z,t}]}^{Reserves\ provision\ cost}
\end{aligned} \tag{1}$$

The minimization of the objective function leads to the estimation of the System's Marginal Price (SMP), representing the intersection of aggregate sale and purchase curves, as shown in Fig. 1. The overall problem is formulated as an MILP problem, involving the cost minimization objective function (1) subject to constraints defined in a recent paper (Koltsaklis et al., 2015).

The model determines the optimal planning of the power generation system, the selection of the power generation technologies, the type of fuels, the imports/exports and the plant locations so as to meet expected electricity demand, while satisfying environmental constraints in terms of CO2 emissions or floors in RES share in the energy mix. The model identifies the ramping products depending on the spatial penetration of RES. The model is useful for real case study problems of the TSOs, resulting from increased penetration of RES in their energy systems, such as Elia in Belgium, TERNA in Italy and Independent Power Transmission Operator in Greece (IPTO, 2016).

3. Case study

The paper examines the interconnected Greek power system. The Greek wholesale electricity market has been structured in mid' 2000's, adopting the mandatory pool structure. Together with the Irish market they are considered as the most technical in Europe, concerning the information they require by the market participants and the TSO to provide the day ahead schedule. Currently, in the Greek day-ahead electricity market, the value of ancillary services is determined endogenously through the co-optimization of energy and ancillary services, while the generators provide detailed techno-economic offers for every hour. The initial plan of the Greek regulator was to incorporate the flexibility services within the ancillary services, as part of the overall co-optimization, therefore adding an extra component in the objective function of our model. However, due to the commitments of Greece to adopt the "target model" of the internal European market, this initial plan has been aborted. Practically, the Greek market has to simplify its algorithm by adopting a simple economic algorithm for the energy, as well as supplementary markets for ancillary services, including flexibility, which will be part of the balancing market, to be operated by the TSO. Within this roadmap, currently the most critical issue concerning flexibility is the identification of the flexibility needs based on the level of the penetration of RES.

Concerning the Greek interconnected power system, the monthly energy report of Greek electricity market operator for July 2016, reports nineteen lignite-fired units with a total capacity of 4.46 GW, four oil-fired power plants with a total capacity of 698 MW, seventeen natural-gas fired (both natural gas combined cycle and natural gas open cycle units) power plants with a cumulative capacity of 5.2 GW, and sixteen hydroelectric units whose capacity equals 3.2 GW (HEMO, 2016). With regard to the installed capacity of renewables in the interconnected power system, there have already been installed 1.9 GW of wind turbines, 2.4 GW of photovoltaics, 100.1 MW of high-efficiency combined heat and power units, 52.2 MW of biomass units, and 223.1 MW of small hydroelectric units in the five zones of the Greek interconnected power system. The wind farms are distributed along the country, as shown in Table 1. This is crucial, as the electricity generation from wind farms does not follow similar patterns in the different zones of the power system. Therefore, a sharp change in the power output of the wind farms does not concern the whole system, but three from the five zones at most, namely less than 70%.

The main operational and economic characteristics of the installed units of the Greek power system are available in our previous contributions (Koltsaklis et al., 2014; 2015; 2016). These data include: (i) representative ramp rates, maximum contribution in primary, secondary, spinning and non-spinning tertiary reserve per technology type, (ii) representative power outputs in different operational stages (automatic generation control, soak phase, dispatch phase) per technology type, (iii) representative CO_2 emission factor per capacity block and technology type, (iv) representative non-operational time intervals

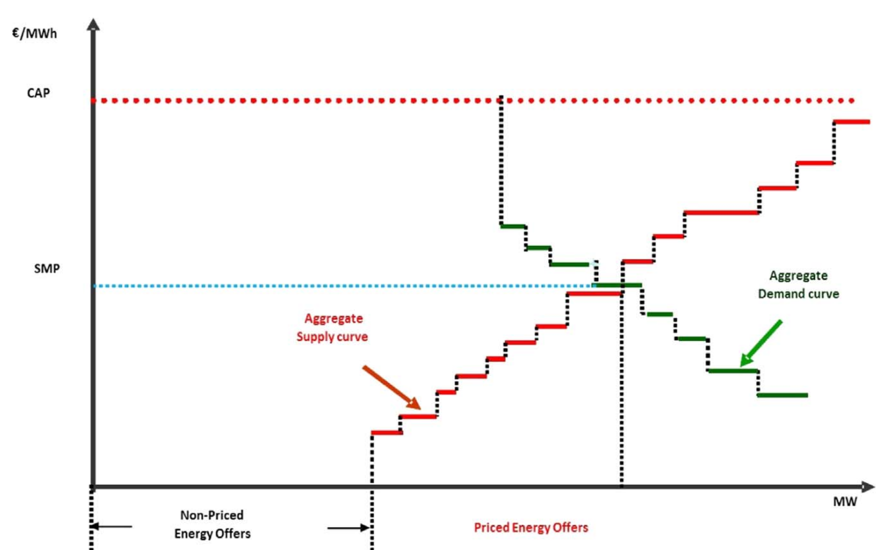

Fig. 1. Determination of System Marginal Price (SMP), where the aggregate Supply and Demand curves intersect.

Table 1
Installed wind capacity in different geographical regions and zones of the Greek interconnected power system (MW).

Geographical region	Zone	Installed capacity
Evia	3	250.4
Central Greece	3	460.8
East Macedonia & Thrace	1	304.4
West Greece	4	130.4
Peloponnese	5	414.3
Ionian Islands	4	83.7
Central Macedonia	2	64.1
West Macedonia	2	52.9
Thessaly	3	17.0
Attica	3	113.9
Islands	3	2.0
Remote Islands	3	69.0

before each representative unit's transition to the next standby condition and shut-down cost, and (v) representative synchronization (per start-up type), soak (per start-up type), desynchronization, minimum up and down time per technology type.

The Greek power system is interconnected with the power systems of five countries: Italy, Albania, FYROM, Bulgaria and Turkey. The model, in order to identify the imports and exports, requires assumptions on the marginal cost of the power systems. To develop those bidding curves for the interconnections, we apply an ANN model, which was developed for the Italian system and is described in our recent work (Panapakidis and Dagoumas, 2016). The load, solar, wind, biomass and small hydro generation profiles for each month, have been developed based on historical data of existing plants (Koltsaklis et al., 2014; 2015; 2016).

4. Results and discussion

This section provides the results and a detailed discussion of various scenarios that have been considered. The model uses the CPLEX solver with the 24.7.2 version of the General Algebraic Modelling System (GAMS, 2016) tool. An integrality gap of 1% has been achieved in all cases. The model examines the power system expansion over the period 2016–2020. By assuming typical representative days, namely twenty four hourly data for all parameters, the model provides twenty four hourly data for each month over the examined period. The day-ahead electricity market results, i.e. SMP, electricity generation per technology type comprise decision variables and they are determined based on a robust, systematic, and analytical optimization approach. They are also characterized by high sensitivity in the effect of critical factors, such as power demand

As mentioned above the model is used to evaluate the need of flexibility services, under different conditions of renewables penetration:

- optimum energy mix based on the levelized cost of electricity generation from RES under constraints of the system and the operation of the DAEM,
- exogenous penetration based on energy policy targets

Those scenarios are compared with a scenario where no new RES are installed.

Those two scenarios depict in fact two different perspectives on the role of RES. The first one reflects the increasing concerns over the cost of RES, and therefore states that RES evolve in the market only if they are more competitive than conventional units. The second states that RES still need further incentives to penetrate in the market as they provide overall gains to the macro-economy and therefore RES should penetrate further based on exogenous targets, set by national or regional policy.

We introduce in the model information on the capacity cost, operational and maintenance costs, as well as the hourly availability factors for each RES technology type. Those data construct the curves of the Levelized Cost of Energy (LCOE) per RES technology type, for potential RES investments, as presented in Fig. 2. This figure shows that solar and wind plants have relevantly low LCOE, as their capital cost has been decreased sharply over the last years. Moreover, the availability factor of those technologies are relevantly high in Greece.

The model identifies the additional capacity and the energy mix of each hour of each month over the period 2016–2020. Figs. 3–4 present the evolution of average hourly demand for February and July 2020 (in MW), under those two different scenarios of RES penetration. Months February and July are chosen to be presented, as they represent winter and summer months, with increased energy demand.

For our analysis, we identify that the flexible requirements are the Ramp-Up and Ramp-Down requirements at one-hour and two-hour level. Practically the model identifies the upward and downward

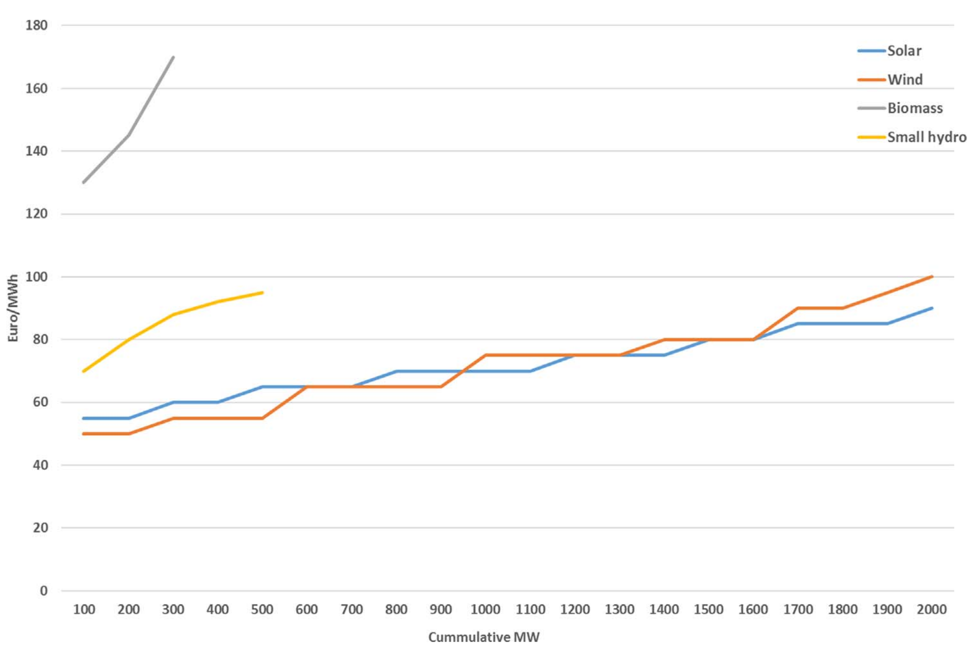

Fig. 2. Evolution of the Levelized Cost of Energy in €/MWh for potential RES investments, per RES technology type.

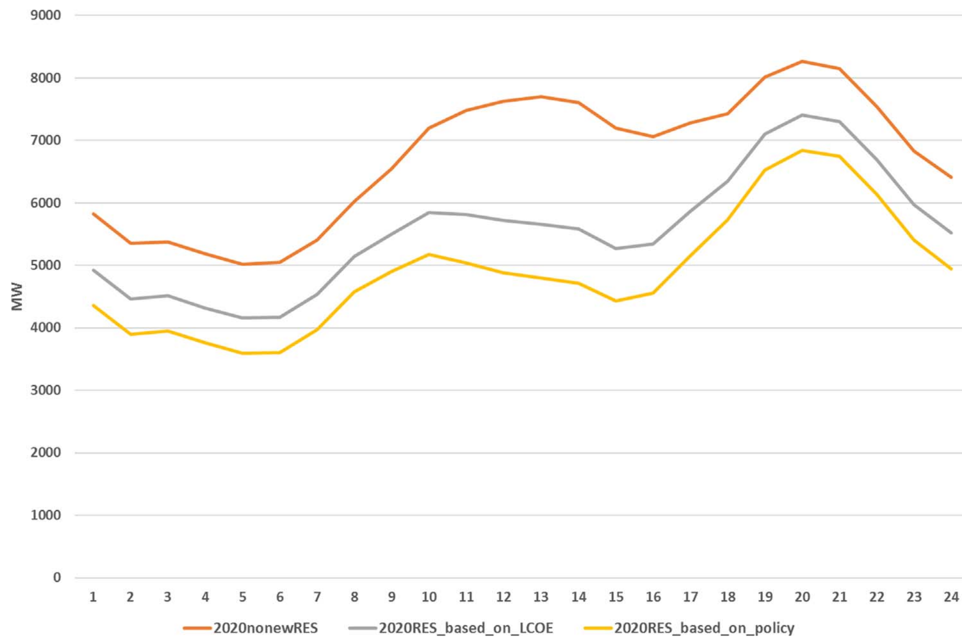

Fig. 3. Evolution of average hourly demand for month July 2020 (in MW), under different scenarios of RES penetration.

ramping capacity that the TSO needs for the power system stability, because of the penetration of RES. Figs. 5–6 show the maximum Ramp-Up and Down flexible requirements at 1-h and 2-h levels in MW per month in 2020, under the different scenarios of RES penetration. Fig. 7 summarized the maximum flexible requirements at 2-h level in MW per month in 2020. The flexibility needs are almost 2 GW, which is comparable to the needs estimated by the Belgian TSO for 2018 (Elia, 2013). An interesting result is the fact that the maximum requirements do not exist in the summer months, but in the months where there is a high increase rate of demand in the evening hours. The pattern of those results is in alliance with the flexible requirements at the ISO California system, which has similar weather conditions with Greece (CAISO, 2015; 2016). Moreover, it is obvious that the needs for ramping up are higher from those of ramping down, for all months.

An important outcome from Figs. 5–7 is the fact that the 1-h flexibility requirements are about 60% of the 2-h needs for some months. The same conclusion, namely that for some months the flexibility needs are already high from the 1-h level, was drawn when we made simulations for longer periods, i.e. 3-h and more. This practically means that the ramping rates, and not just the magnitude of the flexibility needs, can be an important flexibility requirement. Therefore, the robust identification of flexibility products from the TSOs require detailed data to depict the spatial and technical characteristics of each power system, towards identifying the evolution of flexibility needs through time.

Moreover, Figs. 5–7 show that the main flexibility requirements result from the sunset effect, as the photovoltaics rapidly decrease their electricity generation. Photovoltaics have a relevantly high capability to forecast their output, compared to the more stochastic nature of wind. However the sharp decrease of photovoltaics' power output in the evening hours, which is almost synchronized with increasing demand, leads to increasing need of flexibility services. Over a period of 2-h, about 2 GW of ramping-up flexible services are needed, which is almost 50% of demand for some months. If we consider that at the same period of 2-h, a conventional power unit triggers and/or the operating wind farms deviate significantly from their projected output, then it

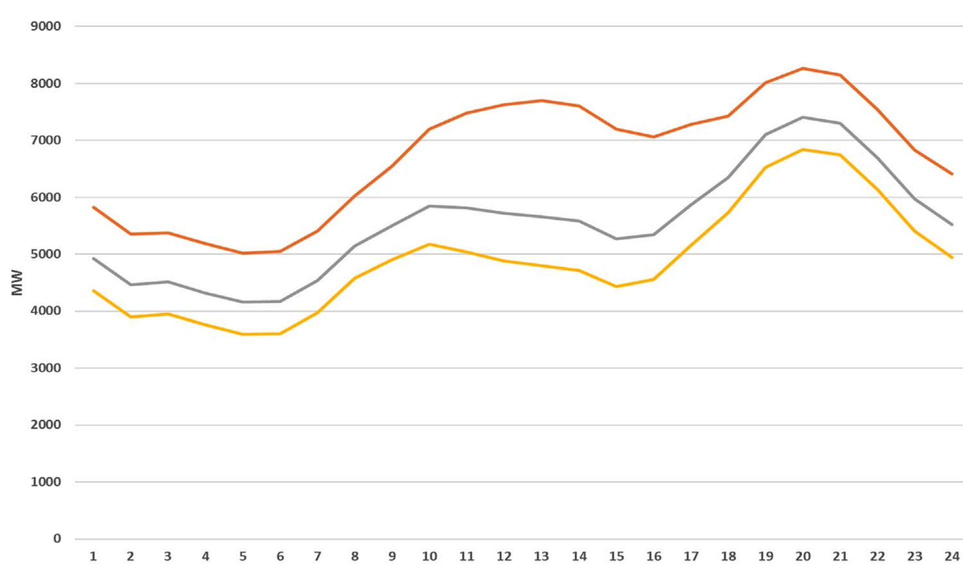

Fig. 4. Evolution of average hourly demand for month February 2020 (in MW), under different scenarios of RES penetration.

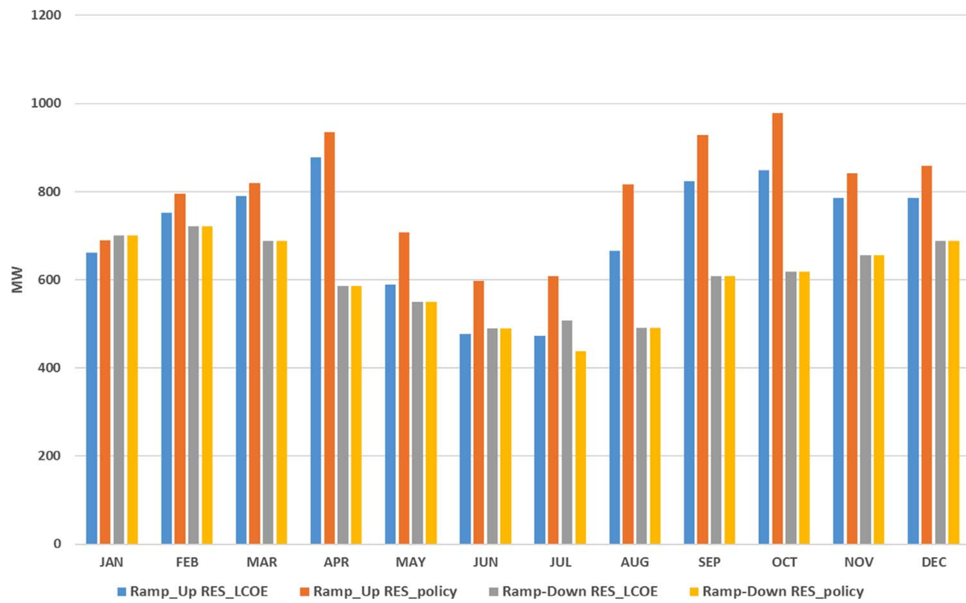

Fig. 5. Maximum Ramp-Up and Down requirements at 1-h level in MW per month in 2020, under different scenarios of RES penetration.

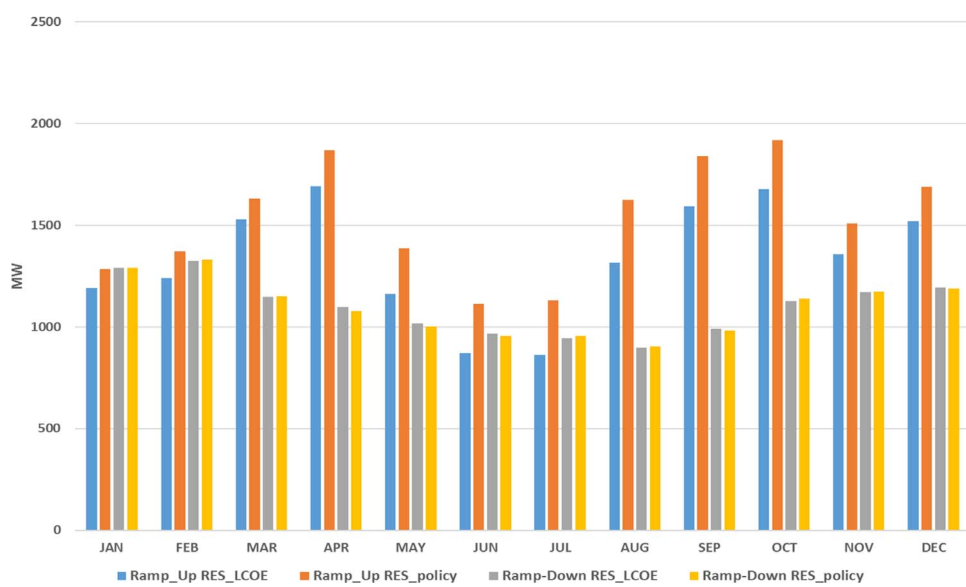

Fig. 6. Maximum Ramp-Up and Down requirements at 2-h level in MW per month in 2020, under different scenarios of RES penetration.

becomes clear that the needs of available flexible units, already synchronized and not operating in their maximum output to increase their production, are relevantly high. Considering that lignite units have a ramping capacity of about 4 MW/minutes while natural gas and big hydro units of 12 and 40 MW/minute respectively, this means that about 8 typical natural gas units, of 400 MW net capacity and 180 MW technical minimum, should be available to provide those services, in case large hydro plants have restrictions due to low reservoir levels. On the other hand, the wind plants, although more stochastic, create relatively lower needs for flexibility services. This is also attributed to the fact that the wind output is not linked to the demand evolution, as it happens with photovoltaics in the sunset effect. Moreover, it is attributed to the fact that wind installations are distributed in the whole country, where -based on historical data- the possibility of a sharp wind change, with the same pattern, in all installations is extremely low.

Considering that the analysis undertaken, which considered the technology, spatial and temporal characteristics of the Greek power system, has identified that the photovoltaics contribute to the higher share of flexibility needs, enables also the identification of options for increasing flexibility. In case of the Greek system, the consideration of storage, geographical dispersion of variable generation and the consideration of regional transmission system planning could provide solutions for tackling the increasing flexibility needs. Therefore, a detailed analysis is crucial for the Transmission System Operators, as it will enable the identification of options for increasing flexibility. Such options, which are specific for each power system, can be: regional transmission system planning to endogenize flexibility of neighbouring markets, larger balancing areas, market design for incorporating flexible demand, capacity, storage and interconnections, geographical diversification of flexible generation, option of curtailment of RES generation, dynamic adjustment of ancillary services.

Fig. 8 shows the compensation of flexible units for flexible requirements at 2-h level in million € per month in 2020, under different scenarios of RES penetration, when flexible services prices are linked to the evolution of SMP. This paper does not estimate endogenously the prices of the flexibility services, as it aims to identify the needs and mix that would be able to satisfy them. However, the flexibility products'

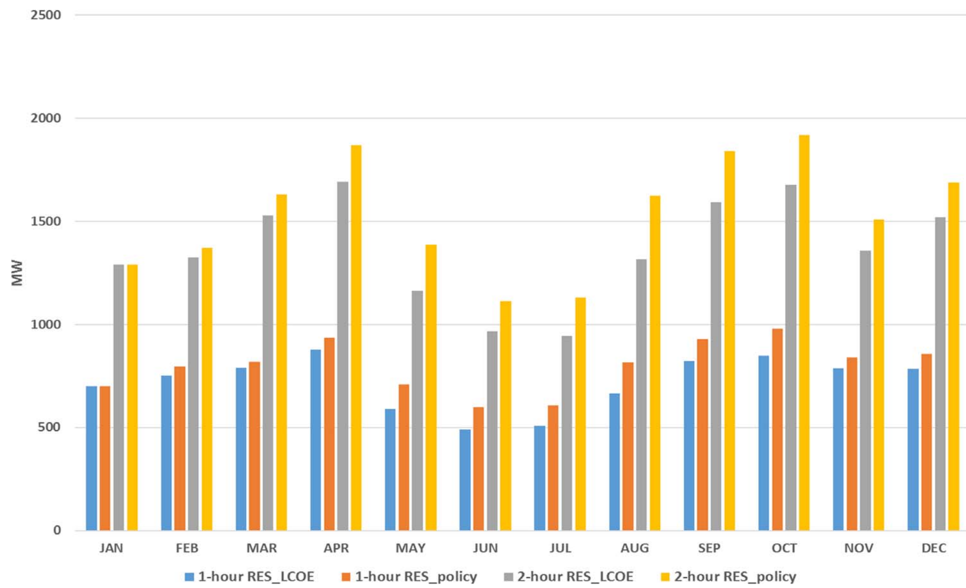

Fig. 7. Maximum flexible requirements at 1-h and 2-h level in MW per month in 2020, under different scenarios of RES penetration.

markets are expected to be liquid, as they concern several market participants: demand–side, cross-border participation, generation units and storage facilities, under technical requirements/constraints identified by the TSOs. Such requirements could be that those reserves are provided under a minimum upward and downward ramping rate and that capacity must be 5-min dispatchable. With a strong price signal from the market, the participants will be willing to invest in smart technologies to enable their capacity to be controllable by the TSO. Therefore, a liquid and competitive flexibility market could be easily established.

Concerning the remuneration of flexibility services, it is assumed that they represent 10% of the SMP, which is about 4.24 €/MWh on average for our case study. The compensation of flexible services is at the level of 20 m€, which is relevantly low as the compensation of the capacity mechanism for year 2016 is almost 200 m€. Moreover, the difference between the two difference RES scenarios is eliminated as the increased RES penetration in the RES policy scenario leads on one hand to higher flexibility needs, but on the other hand to lower SMP prices and therefore to lower flexibility prices. However, if the flexibility services' prices evolve independently of the evolution of the SMP, as in the regulating capacity auctions operated by Elia in Belgium, their pricing can be at the level of the SMP. In such case, the compensation of flexible needs will be even at the level of 200 m€, therefore comparable to the existing capacity scheme.

To summarize, this paper provides insights on the flexibility needs and their compensation in a power system, with increasing share of RES, providing illustrative results for the Greek power system. It is useful for decision makers, namely regulators and TSOs, as the incorporation of flexibility services is considered by several TSOs and is in alignment with the "Guidelines on State aid for environmental protection and energy 2014–2020", which in section 3.9.1 for aid for generation adequacy state: "*They may for example aim at addressing short-term concerns brought about by the lack of flexible generation capacity to meet sudden swings in variable wind and solar production, or they may define a target for generation adequacy, which*

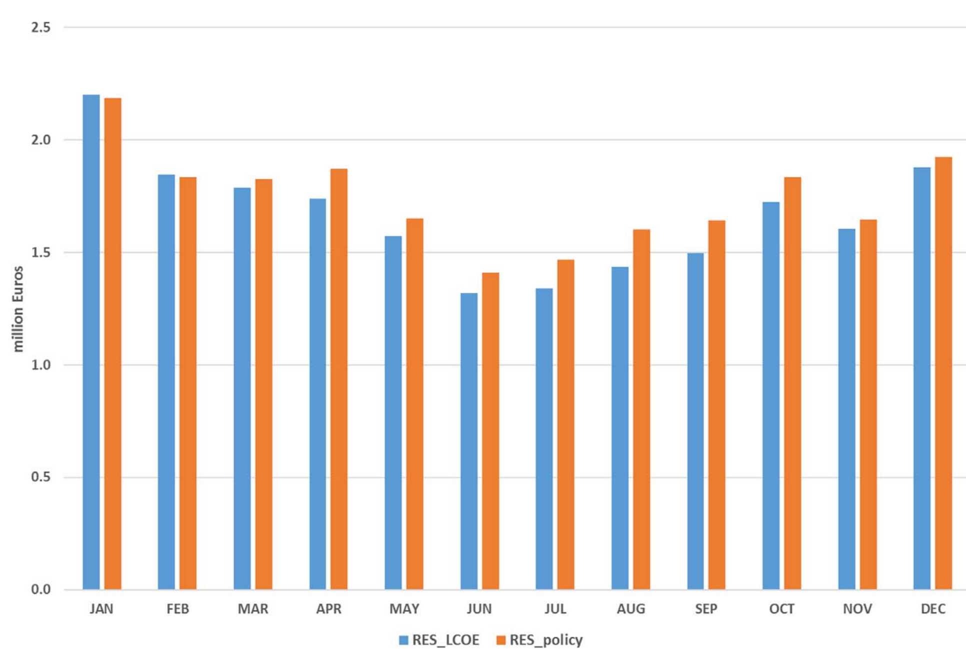

Fig. 8. Compensation of flexible units for flexible requirements at 2-h level in million € per month in 2020, under different scenarios of RES penetration, when flexible services prices are linked to SMP.

Member States may wish to ensure regardless of short-term considerations." The flexibility service should be compensated though a market-based and not regulated mechanisms, as section 3.9.5 states that "*A competitive bidding process on the basis of clear, transparent and non-discriminatory criteria, effectively targeting the defined objective, will be considered as leading to reasonable rates of return under normal circumstances*."

An important outcome of the modelling results, is that flexibility needs not only depend on the technology type, but also on the temporal and spatial characteristics of the system and especially on the diversification of installation location of the RES plants. This is a further argument in favour of the distributed generation. Another important outcome is the fact that the ramping rates, and not just the magnitude of the flexibility needs, can be an important flexibility requirement. Both outcomes come to the same conclusions, namely that the robust identification of flexibility products from the TSOs require high-quality, spatial-temporal-resolution dataset towards identifying the evolution of flexibility needs through time. Such an analysis is also crucial for the Transmission System Operators, as it will enable the identification of options for increasing flexibility, which are power system specific and include both the necessary physical flexibility and the institutional access to that flexibility.

5. Conclusion and policy implications

The penetration of RES imposes additional challenged to electricity markets and power systems. Advanced electricity markets are considering the introduction of flexibility services towards enhancing the stability of the system. The intermittent and variable generation from renewables creates new challenges to balancing authorities, particularly with regard to ramping capability. The identification of the flexibility services needed, depending on the penetration level of renewables, their technology type, as well as the topology of the electric systems, is very crucial for the TSOs.

This paper uses a generic Mixed Integer Linear Programming (MILP) model that integrates the long-term power systems planning with a Unit Commitment (UC) model, which performs the simulation of the Day-Ahead Electricity Market. The integrated model is used to evaluate to needs of flexibility services, under different conditions of penetration of renewables penetration: optimum energy mix based on the levelized cost of electricity generation from RES under constraints of the system and the operation of day-ahead electricity market, exogenous penetration based on energy policy targets. The model is applied to the case of Greek interconnected system to provide illustrative results, considering the spatial characteristic of the model.

The key contributions and the salient features of our work include: i) integration of flexibility services in the long-term power systems planning, (i) identification of the flexibility needs depending on the penetration level of renewables, per technology type, (iii) provision of useful insights into the levels of flexibility needs and the remuneration of flexible units (iv) raising the importance of diversification of installation location of RES plants and (v) raising the importance of spatial analysis of the power system towards identifying options for increasing flexibility. This paper can be valuable to the decision makers, as the regulators, the TSOs and the market participants, as it provides insights on the levels of flexibility needs and their remuneration.

The results show that the main flexibility needs concern the sunset effect, especially for the months/days with increased rate of growth during evening hours. The flexibility needs are relevantly lower for wind farms, although their stochastic nature and the increased deviations from projected power output. This is also attributed to the fact that the wind output is de-linked to the demand evolution, as it happens in the sunset effect, and to the fact that wind installations' positions are diversified, reducing the risk for sharp changes of aggregate wind output. The paper concludes that the flexibility needs depend not only on the technology type, but also on the spatial characteristics of the system and especially on the diversification of installation location of the RES plants.

The implementation of detailed technology, spatial and temporal analysis is crucial for the Transmission System Operators, as it can reveal, as in the case of the Greek power system, that ramping rates, and not just the magnitude of the ramping capacity, can be an important flexibility requirement. Moreover, it can enable the identification of options for increasing flexibility, which are power system specific and include both the necessary physical flexibility and the institutional access to that flexibility.

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