2013 IREP Symposium-Bulk Power System Dynamics and Control –IX (IREP), August 25-30, 2013, Rethymnon, Greece

Impact assessment of large scale RES penetration for the Hellenic power system; a market simulation model analysis

Christos Nakos
Centre of Renewable Energy Sources and Saving

Abstract

This paper presents an hourly simulation model for the analysis in an annual context of the impact of large scale RES penetration on the Hellenic Power System. The impact is assessed in terms of the System Marginal Price of the Day Ahead Market (DAM), taking into account the intermittency of the Renewable Energy Sources (RES) production and its optimal integration into the power system along with operational technical and economic considerations.

The model is based on a slightly simplified version of the DAM clearing algorithm of the Hellenic wholesale electricity market [1]. Its purpose is to examine how the system behaves under large scale RES penetration and different configurations of the thermal capacity. It runs for milestone years such as 2020 or 2030, and it helps in evaluating, from an operational perspective, configurations stemming from optimal capacity expansion models that do not fully cover operational issues. Results provide an assessment of the potential cooperation between thermal, hydro and RES plants, highlighting that none of the above should be treated independently.

Nomenclature

e(E) index (set) of generating units

- *lige(e)* index (set) of lignite fired generating units
- *nge(e)* index (set) of natural gas fired generating units of the combined cycle
- *gte(e)* index (set) of natural gas fired generating units of the open cycle type
- *hyd(e)* index (set) of hydroelectric generating units
- *wnd(e)* index (set) of wind generating units
- *res(e)* index (set) generating units from Renewable Energy Sources except wind
- *pmps(e)* index (set) of pump storage generating units

p(P) index (set) of hour for the period of study

- *hr(p)* index(set) of hour for the scheduling period
- *fhr(p)* index(set) of the first hour of each scheduling period
- *lhr(p)* index(set) of the last hour of each scheduling period

b(B^e) index (set) of steps of the energy offer function of unit e

ld(LD) index (set) of type of load demand

d(D) index(set) of steps of the energy demand function of load ld

$Blockprice_{e,b,p}$ price of block b of the energy offer function of unit e during p in €/MWh

$Blockprice1_{ld,d,p}$ price of block d of the energy demand function of load ld during p in €/MWh

$Blockmax_{e,b,p}$ maximum value of block b of the energy offer function of unit e in MW

$Loadmax_{ld,d,p}$ maximum value of each block d of the energy demand function of load ld in MW

$MinMW_e$ minimum power output of unit e in MW

978-1-4799-0199-9/13/$31.00 ©2013 IEEE

$MaxMW_e$	maximum power output of unit e in MW
$MinUp_e$	minimum up time of unit e in MW
$MinDn_e$	minimum down time of unit e in MW
$Desyntime_e$	time to desynchronize for unit e in hours
$Syntime_e$	time to synchronize for unit e in hours
$Soaktime_e$	soak time for unit e in hours
$Synload_e$	load level after synchronization during soaktime in MW
$HotSUCost_e$	start up cost (€)
$EntitySDCost_e$	shut down cost (€)
$PRAGC_e$	ramp rate in MW/min

Variables

$BlockClearedMW_{e,b,p}$	power injection of block b of unit e during hour p in MW
$LoadBlockMW_{ld,d,p}$	power absorption of block d of load ld during hour p in MW
$EntityMW_{e,p}$	power injection of unit e during hour p in MW
$EntityDeficitMW_{e,p}$	quantity of power that violates the maximum down capability change of production for unit e in MW
$EntitysurplusMW_{e,p}$	quantity of power that violates the maximum up capability change of production for unit e in MW
$RampsurplusMW_{e,p}$	violation rate of the up capability rate of change of production in MW per hour
$RampDeficitMW_{e,p}$	violation rate of the down capability rate of change of production in MW per hour
$unserved_p$	load quantity that stays unserved during hour p in MW
$rejected_p$	RES generation that fails to get injected in the system during hour p in MW
$totcost$	total system costs in €
$gencost$	generation costs in €
$stupcost$	start up costs in €
$stdncost$	shut down costs in €
$LoadRevenue$	compensation for serving load in €
$penaltycost$	virtual cost that summarizes the penalty cost of various violations

Binary Variables (0/1)

$Xsd_{e,p}$	represents a decision to shut down for unit e in hour p
$Xsu_{e,p}$	represents a decision to start for unit e in hour p
$Xup_{e,p}$	shows if unit e is operation during hour p
$Xdisp_{e,p}$	shows if unit e is dispatched during hour p
$Xsyn_{e,p}$	shows if unit e is in synchronization phase during hour p
$Xsoak_{e,p}$	shows if unit e is in soak phase during hour p
$Xdesyn_{e,p}$	shows if unit e is in soak phase during hour p

Introduction

A fundamental pillar for tackling climate change is the development of renewable energy sources for electricity generation. At the EU level this strategic direction is reflected in the 20-20-20 Climate and Energy Package that sets a target of 20% of RES in EU's final energy consumption by 2020. In view of this target EU Member States have to present their National Renewable Energy Action Plans (NREAPs), where it should be described the development path of the renewable energy technologies in order to meet the targets. More specific NREAPs, which have to be updated every two years, project also the share of RES in 2020 in terms of electricity production. For the Hellenic power system this target is set to the level of 40%, including also electricity production coming from large hydroelectric plants. [2]

Power markets do not evolve independently compared with the rest of the energy system. Competition between different energy carriers such as electricity or natural gas is a significant aspect which shapes technological developments in each separate market. For this reason, studies which focus on the power market should take into account the general energy market framework. Energy systemic models [3] cover the interactions between power markets and energy market as a whole. However this specific attribute comes with an expected deficit. These models usually follow the mathematical formulation of linear programming, which is very efficient on manipulating large sets of data at the cost of ignoring major operational aspects of the particular energy markets. This trade-off seems unavoidable and the majority of the methodologies aiming to assess the evolution of the power markets in the mid or long term combine models of different formulation, i.e. energy systemic models with models that focus on operational issues, e.g [4]. An illustration of this incompetence for the energy systemic models is their aggregate methodology used to represent the dispatching of the generation units. In [5] a methodology has been developed to bridge short term power market scheduling framework within a mid-term scheduling period.

In this paper a simulation model is presented, aiming at covering the aforementioned gap by using hourly analysis to evaluate on annual basis possible power system configurations, resulting from various runs of the energy systemic models. In particular, the model presented here emphasizes on the integration of the provisioned amounts of renewable electricity to meet the targets for the Hellenic power system. The intention is to further investigate whether the capacity mix provided by the energy systemic models remains also sustainable when benchmarked under an operational perspective. The operation perspective involves technical constraints which affect the final operation of the generating units. Such technical constraints are related to decisions regarding the start-up/shut-down procedure, minimum up/down time constraints and ramp rates of each unit.

Using an hourly simulation model to evaluate RES integration into the power system on an annual basis implies that the model should be tested for all the 8760 hours of the study year. That kind of approach had to confront with two major issues : 1. Computational issues that do not allow the simultaneous treatment for all the hours of the year, and 2. The methodological flaw of the perfect foresight. Perfect foresight means that the evolution of the parameters of the model is known for the entire scheduling period and therefore this knowledge is assumed when model decisions are being made. This could lead to more adaptive representations of the system and certainly deviate from the information in place when decisions are being made in reality.

In this sense the model presented confronts with the structural restrictions described above. Model equations inherit the rationale included in the current version of the Manual of market operation issued by the Hellenic IPTO[1]. However simplifications have been adopted as it will be made clearer in the following section.

Mathematical formulation of the model

The model is formulated in GAMS as a Mixed Integer Programming (MIP) problem towards maximizing the social surplus in the DAM context. It mainly follows the formulation of the UC model as described in [1]. This section will provide a detailed description of the equations included in the model. Moreover the data used as input in the model will be also presented. In parallel, modifications and adaptations made to the model equations will be further explained.

Objective function

The objective function summarizes all the costs and revenues included in the problem formulation. Equation (1) is the opposite of the social surplus which will be minimized.

$$totcost = gencost + stupcost + stdncost + -LoadRevenue + penaltycost \tag{1}$$

The equations (2)-(5) define the elements of the objective function. Equations (2)-(3) relate the decision of starting up or shutting down a unit with the respective costs which are assigned as data inputs. Equation (5) accounts the load revenues when certain load quantities are satisfied by the generation units. In principle the level of the load satisfied is an output of the optimization, implying that in the MIP framework the aggregate demand function is a decreasing step-wise function while the aggregate supply function is an increasing step-wise function. The mathematical program maximizes social surplus taking also into account costs related with the binary variables (start up/shut down costs).

In the case presented, load representation diverges from the theoretical framework, in the sense of adopting an inelastic way to represent demand function. Two types of load have been considered, one for demand and one for pumping. Both types contain only two blocks. The first block of each load type is compensated at the high level of 300 €/MWh. This price has been set arbitrarily to ensure that the consumer willingness to pay reflected to the first load block exceeds the most expensive generation unit of the capacity mix. The second block of each type of load is priced lower than the lowest existing energy offer. Therefore, these blocks will not be satisfied during the optimization.

The quantity of the first load block equals to the quantity of the load demand which is given exogenously as an input parameter. By this, the possibility to partially shed load of the first block is, thus, minimized. Furthermore, a penalty cost for the unsatisfied load demand has been assumed. This cost described in (4), as the sum of products of unserved load multiplied with the unserved penalty price, pushes the solution to the "fixed" demand given exogenously. That kind of approach directs the burden of integrating large amounts of renewable electricity to the supply side. Nevertheless, it is the reaction of the supply which makes up the basic reason to build such kind of models. Load shedding can occur but at very high costs which involve the violation of given constraints, as will be explained in detail below. Additional penalty costs represented in the model deal with the violation of technical constraints regarding the power output and the ramp rates of the generation units.

$$stupcost = \sum_e \sum_p Xhotsu_{e,p} * HotSUcost_e \tag{2}$$

$$stdncost = \sum_e \sum_p xsd_{e,p} * EntitySDcost_e \tag{3}$$

$$PenaltyCost = \sum_e \sum_p EntityDeficitMW_{e,p} * DeficitCapacityPrice + {} + \sum_e \sum_p RampDeficitMW_{e,p} * DeficitRampPrice + \sum_e \sum_p RampSurplus_{e,p} * SurplusRampprice + \sum_p unserved_p * UnservedPrice + \sum_p rejected_p * Rejectedprice \tag{4}$$

$$LoadRevenue = \sum_{ld} \sum_p \sum_d LoadBlockMW_{ld,d,p} * Blockprice_{ld,d,p} \tag{5}$$

Market clearing condition

Equation (6) is the market clearing condition, where demand should equal supply for each hour. In equation (7) the generation of the unit breaks down to its blocks, which, as mentioned above, forms an increasing step-wise function. The price of the last block of the most expensive unit that serves load demand during the optimization provides the System's Marginal Price.

$$\sum_e EntityMW_{e,p} = \sum_{ld} \sum_d LoadBlockMW_{ld,d,p} \tag{6}$$

$$EntityMW_{e,p} = \sum_b BlockClearedMW_{e,b,p} \tag{7}$$

Management of the binary variables

The equations described so far are modifications of the equations included in the Manual of Market Operation of the Hellenic IPTO[1]. In [1] there are no equations to describe how the binary variables should be managed in order to replicate the operational principles that generation units have to follow. However in [6] the operational principles are described in detail. Equations (8) – (13) deal with the management of the binary variables of the generation units.

$$\mathrm{Xup}_{\mathrm{e,p}} = \mathrm{Xsyn}_{\mathrm{e,p}} + \mathrm{Xsoak}_{\mathrm{e,p}} + \mathrm{Xdisp}_{\mathrm{e,p}} + \mathrm{Xdesyn}_{\mathrm{e,p}} \tag{8}$$

$$\sum_t^{p \le t < p+Syntime_e} Xsyn_{e,t} = \sum_t^{p \le t < p+Syntime_e} (t-p) * xsu_{e,t-syntime_e} + \sum_t^{p \le t < p+Syntime_e} \big(Syntime_e - (p-t)\big) * xsu_{e,t} \tag{9}$$

$$\sum_t^{p+Syntime_e \le t < p+Syntime_e+Soaktime_e} Xsoak_{e,t} = \sum_t^{p\,+\,Syntime_e \le t < p+Syntime_e+Soaktime_e} (Soaktime_e - (t - p - Syntime_e)) * xsu_{e,t-Syntime_e}) + \sum_t^{p \le t < p+Syntime_e} \big(-(p-t)\big) * xsu_{e,t-Syntime_e}) \tag{10}$$

$$\sum_t^{p-Desyntime_e \le t < p} Xdesyn_{e,t+1} = \sum_t^{p-Desyntime_e \le t < p} (Desyntime_e - (p-t)) * xsd_{e,t} + \sum_t^{p-Desyntime_e < t < p} \big((p-t)\big) * xsd_{e,t+Desyntime_e}) \tag{11}$$

$$Xhotsu_{e,p} = Xsu_{e,p} \tag{12}$$

$$Xup_{e,p} = \sum_t^{t \le p} xsu_{e,t} - \sum_t^{t<p} xsd_{e,t} + xup_{e,h_0} \tag{13}$$

Equation (8) defines each hour if the unit is operating or not. Operation phase is distinguished in four sequential phases which are the synchronization, soaking, dispatch and de-synchronization as depicted in Fig.1. Variables *xsu* and *xsd* are defined for each unit and for each hour of the scheduling period and their activation means the ignition of a start-up or a shut-down decision respectively. Equations (9)-(11) regulate the binary variables which define each operations phase with the aforementioned variables. Equation (12) indicates that in the proposed model only one synchronization phase has been considered. In this sense the model does not distinguish between hot, warm or cold start-ups. Finally equation (13) relates the decisions for start-up and shut down with the initial operating status for the whole scheduling period.

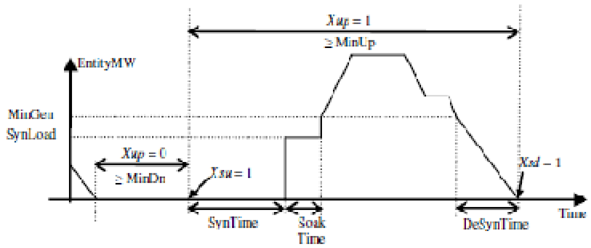

Fig. 1. Operating States of thermal units

Technical constraints

The technical constraints of the generation units are represented in the equations (14)–(19). In particular, equations (14) and (15) define each unit's generation level according to its operational phase. Equations (16) and (17) define and force the units to comply with their minimum up and down times, while (18) and (19) force the units to operate according to their ramp rates regarding to the operational phase during each hour. Compatible with the mathematical formulation adopted, violation variables can be activated but at prohibitive cost levels.

$$EntityMW_{e,p} + EntityDeficitMW_{e,p} > Xsyn_{e,p} * 0 + Xsoak_{e,p} * Synload_e + \sum_t^{p \le t \le p+Desyntime_e-1} xsd_{e,t} * (t-p) * \frac{MinMW_e}{Desyntime_e} + Xdisp_{e,p} * MinMW_e \quad (14)$$

$$EntityMW_{e,p} - EntitySurplusMW_{e,p} + < Xsyn_{e,p} * 0 + Xsoak_{e,p} * Synload_e + \sum_t^{p \le t \le p+Desyntime_e-1} xsd_{e,t} * (t-p) * \frac{MinMW_e}{Desyntime_e} + Xdisp_{e,p} * MinMW_e \quad (15)$$

$$\sum_t^{p-1 \le t \le p-Minup_e+1} xsu_{e.t} < xup_{e,p} \quad (16)$$

$$\sum_t^{p+1 \le t \le p+Mindn_e} xsu_{e.t} < 1 - xup_{e,p} \quad (17)$$

$$EntityMW_{e,p} - EntityMW_{e,p-1} < Xdisp_{e,p} * PRAGC_e * 60 + (Xsyn_{e,p} + Xsoak_{e,p}) * MinMW_e + Xdesyn_{e,p} * MaxMW_e + RampSurplusMW_{e,p} \quad (18)$$

$$EntityMW_{e,p-1} - EntityMW_{e,p} < Xdisp_{e,p} * PRAGC_e * 60 + (Xsyn_{e,p} + Xsoak_{e,p}) * MinMW_e + Xdesyn_{e,p} * MaxMW_e + RampDeficitMW_{e,p} \quad (19)$$

Additional constraints

The set of equations is complemented by another category of constraints. They modify the optimization problem affecting the decisions made according to the specific methodological framework of the model. Equation (20) calculates the difference between the exogenous given load demand and the production of the generation units. If such difference occurs during the optimization process, then it will be covered but at prohibitive costs. In reality it would be optimal to shed that amount of load than to satisfy it.

Equation (21) represents the energy constraint of the hydroelectric generation units. The available hydroelectric energy of each scheduling period is given exogenously, while the allocation of this energy in every hour of the scheduling period is an output of the model. If there is a program of mandatory levels of hydroelectric production due to irrigation demands or other reasons it should be assigned exogenously and the model will comply with it, as implied by Equation (23).

Equations (22) and (24) regulate the generation of renewable electricity. The overall renewable generation potential is given exogenously for each hour. Nonetheless, the optimal amount of renewable electricity to be absorbed depends on the optimization. The rejection of renewable energy is penalized similarly to the energy not served (20). Penalty costs for the rejection of renewable electricity vary depending on the aim of the study. If, for example, the aim of the study is to prioritize the absorption of renewable energy electricity then the penalty for the realization of renewable energy rejection should be prohibitively high. If, on the other, hand the aim is to investigate the economic equivalent result of the rejection of renewable electricity then the penalty for the realization of renewable energy rejection should be as high as the FIT level.

Finally, equation (25) provides an upper limit of shut downs for NGCC generation units. In the proposed methodology it has not been allowed to shut down more times than the quotient of the number of hours of the scheduling period divided to the duration of 72 hours. This is an arbitrary constraint adopted to avoid start-ups and shut-downs of very high frequency, based on common engineering experience. Moreover, this constraint prevents the overutilization of the most efficient NGCC plants.

$$unserved_p = mustload_p - \sum_e EntityMW_{e,p} \quad (20)$$

$$\sum_p EntityMW_{hydro,p} \le \sum_p mand_p + AvailHydroEnergy \quad (21)$$

$$EntityMW_{RES,p} \le ResLoad_p \quad (22)$$

$$EntityMW_{Hydro,p} \ge mand_p \quad (23)$$

$$rejected_p = Resld_p - \sum_e EntityMW_{Res_e,p} \quad (24)$$

$$\sum_p xsd_{ngcc_e,p} \le SDupperlimit \quad (25)$$

Input data

Data input refer to:

a) Energy price offers of each generation unit. These offers remain fixed for each unit for all the scheduling periods (8760 hours). They are represented by increasing step- wise functions of ten blocks, the first of which equals to the level of the unit's technical minimum generation. Energy offers reflect the total variable cost of the units, i.e. the fuel cost, the emission cost and the variable operation and maintenance cost. Emission costs are calculated based on the value of 20€/tnCO2. In Table 1 the energy offers of the first block for indicative generation units are shown.

Table 1. Economic and technical characteristics of thermal and hydro units

	OLD_LIG	NEW_LIG	NGCC_T1	NGCC_T2	NGCC_T3	GT	HYDRO
Tech_Min (MW)	**200**	**250**	**400**	**200**	**210**	**30**	**10**
Tech_Max (MW)	**335**	**610**	**800**	**437**	**476**	**150**	**2700**
Ramp Rate (MW/min)	**1.05**	**1.05**	**12**	**12**	**12**	**6**	**210**
MinUp (hours)	**48**	**12**	**4**	**4**	**4**	**1**	**1**
MinDn (hours)	**72**	**16**	**2**	**2**	**2**	**1**	**1**
Syn_time (hours)	**5**	**5**	**3**	**3**	**3**	**0**	**0**
Soak_time (hours)	**5**	**5**	**3**	**3**	**3**	**0**	**0**
Desyntime(hours)	**3**	**3**	**2**	**2**	**2**	**0**	**0**
Stup Cost (€)	**85559**	**85559**	**48964**	**48964**	**48964**	**0**	**0**
StDn Cost (€)	**10000**	**10000**	**5000**	**5000**	**5000**	**0**	**0**
Energy offer (€/MWh)	**59.5**	**40.36**	**74.15**	**74.15**	**85.19**	**127**	**~0**

b) Demand Bids which remain also fixed for all the scheduling periods. The details of the representation of load are mentioned above.
c) The penalty costs as depicted in Table 2.

Table 2. Values assigned for constraint violation

Penalty Cost	€
DeficitCapacityPrice	**40000**
SurplusCapacityPrice	**40000**
DeficitRampPrice	**35000**
SurplusRampPrice	**35000**
unservedPrice	**40000**
rejectedPrice	**300**

d) The technical characteristics of each unit which remain fixed for all the scheduling periods
   a. Level of technical minimum generation for each unit
   b. Level of technical maximum generation unit
   c. Minimum down/up times
   d. Times of synchronization/ soaking/ desynchronization phase in hours
   e. Start up/shut down cost for each unit

e) The time series of the potential wind farm generation (8760 hours)
f) The time series of the potential generation from the rest of the Renewable Energy Sources (8760 hours)
g) The available hydroelectric energy for each scheduling period (240 hours)
h) The annual maintenance schedule of the thermal generation units
i) The annual schedule of mandatory hydroelectric production due to irrigation needs or reservoir constraints

Data Manipulation

Due to computational time restrictions, the model simulates DAM on an hourly base for a time horizon of 240 hours, in which perfect foresight has been assumed. The year has therefore been split in sections of 10 days (240 hours) which run successively. The information generated in each run serves as an input for the next one, transferring the necessary information of the operation conditions of the power plants, i.e. the exact shut-down/start-up hour and the operation phase (synchronizing, soaking, dispatching, desynchronizing) of the previous run.

The final run is preceded by a run where the constraint (20) is deactivated when the percentage of the potential of the Renewable Energy generation exceeds the threshold of 50% of the first block of the Load Demand, both of which are given exogenously. This format combined with the prohibitive costs of the rejected energy from RES, formulate the background for the particular operational rationale of the pump storage units in the model. They no longer act like arbitragers exploiting the daily price fluctuations, but they represent a load category that can be activated when the optimal dispatch leads to the rejection of RES production. In other words, pump storage load is activated only to prevent the "expensive" rejection of renewable electricity. After the run is completed for all scheduling periods, the realization of the load in the first run serves as pump storage load input in the final run. The price of the pump storage load type follows exactly the same rationale with regular load demand. The efficiency of the pumping cycle has been set at the level of 72%. Therefore the energy balance of the pump storage operation is guaranteed since the 72% of the pump storage load is available to generate electricity in each scheduling period. The behavior of the pump storage generation imitates hydroelectric generation.

The technical characteristic of the hydroelectric generation units are shown in Table 2. Energy offers of the hydroelectric generating units are nearly zero. However they are restricted to produce under a certain energy amount which is provided exogenously for each scheduling period.

RES priority uptake is guaranteed by the fact that energy offers from RES generating units is nearly zero. This option implies that - the exogenously given - potential of renewable electricity generation is an upper limit for the optimization procedure. In addition possible rejected amounts increase significantly the objective function due to equations (4), (24).

The initial version of the model included also the reserve market equations. Both energy and reserve markets were cleared simultaneously. Empirically tested, the model version equipped with the reserve market parameters and equations increase the computational burden. The decision to exclude the reserve market equations is also related with the fact that the assumption to provide the reserve requirements for each scheduling period without correlating them with the injected power from renewable sources will likely distort the optimization procedure.

Finally, the model does not include any representation of the network nor the zonal division of the Hellenic power system. Consequently, the provided solution should be assessed for its grid sustainability.

Results

A fundamental economic figure of the contemporary power markets is the formulation of the System Marginal Price, which is the bidding value of the most expensive unit committed at each period. In our model SMP results should be considered as a low estimator of the system actual marginal price since the competition among power producers has not been explicitly modeled. Nevertheless, the model provides an elementary framework to study or evaluate bidding strategies without being able to compete with power market models implemented on a game theory background. Additionally, it has been described in previous section that the bidding value of the hydroelectric units is close to zero. Hydroelectric energy offers are the most competitive among all generation technologies, but with an energy constraint for each period. This fact drives the model to allocate hydroelectric energy resources where the shadow prices of the optimization problem are of a very high value, thus optimal allocation is guaranteed. Consequently the presented methodology lacks in accuracy when SMP is calculated but it ensures optimal allocation of hydroelectric resources, assuming that an efficient operation of the power market serves the objective of optimizing hydroelectric resources. Moreover the accuracy sacrificed on the calculation of the SMP could be overcome by processing results: if the hourly simulation model is rerun with the absence of hydroelectric energy then a new higher SMP will accrue. The actual SMP will almost surely lie between the resulted SMP from the first run and the second one.

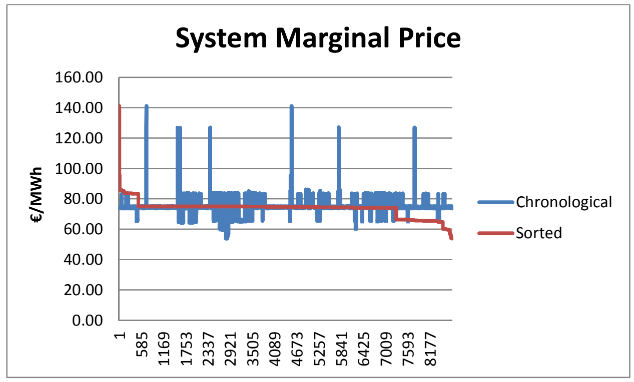

Fig. 2 Chronological Evolution of System Marginal Price

Fig. 2 shows the chronological evolution of the SMP for the Hellenic power system for a possible configuration of the Hellenic power system for year 2020. Table 3 shows the capacity mix that has been studied. The resulted average SMP is 73.6 €/MWh converging to the exogenous bidding values for the NGCC generation units that participate in the system.

Table 3. Case study configuration and technology Capacity Factors

	LIG	NGCC	GT	HYDRO	PUMP	WIND	RES
Capacity (MW)	3742	5050	1200	2700	1595	5196	2455
Annual Capacity Factor (%)	83	22.15	~0	18.75	-	25.6	21

Fig. 2 shows that at least one NGCC unit is committed for the 83.25% of the time of a year (7293 hours), since the SMP is equal or greater to the energy offers prices of NGCC generation units. Such result functions at least as an alarming indicator for the sustainability of the NGCC plants. Taking into account the projected installed capacity of NGCC plants for year 2020 at the level of 4634 MW and the assumptions regarding the economic and technical characteristics of this type of generation units it is significant to investigate which percentage of the capacity is occupied on annual basis and how does this reality affects each plant in particular. The annual capacity factor of the NGCC generation units is at the level of 22.15%. Compared with the capacity factor of the lignite fired generation units which is at the level of 83% a major conclusion is drawn. Under the presented framework of analysis the integration of large amounts of renewable electricity affects disproportionally more the units of NGCC rather than the lignite fired ones.

High RES electricity integration requires the redefinition of notions of the traditional electrical economy like base load. In our case by subtracting RES generation that has been eventually absorbed during the optimization, the residual load can be calculated, which has to be captured by thermal and hydroelectric units. An additional sorting of these values yields the load duration curve after RES integration. Fig. 3 shows the load duration curve, the residual load duration curve – after the subtraction of RES, and the thermal load duration curve, which is calculated by subtracting the hydroelectric generation and pump storage generation from the residual load duration curve.

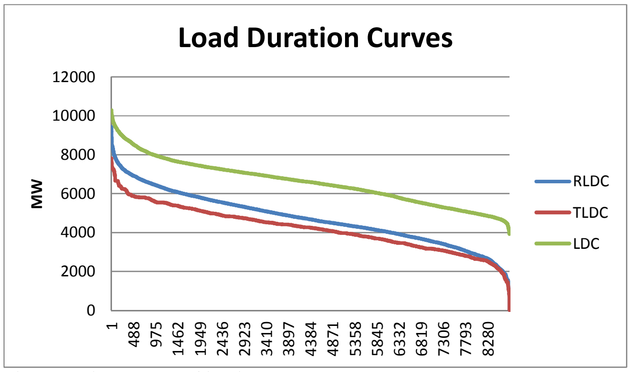

Fig. 3 Various types of load curves

Minimum load values after RES integration are significantly lower compared to the values before integration. For 145 hours the residual load - after RES integration- is lower than 2GW while the thermal load remains below the threshold of the 2GW for 182 hours. The minimum load values are 815MW and 667MW respectively.

RES integration should also be assessed by the number of start-ups and shut-downs of the thermal power plants. In Table 3 the average per category number of start-ups and shut-downs of the thermal generation units are shown. Before interpreting these values one should also take into account the operational constraint (25) which regulates the maximum number of shut downs of NGCC so as not to exceed three shut-downs in a 10-day period. A direct result drawn from the Table 3 is that the required system flexibility for the RES integration is almost exclusively provided by the NGCC and hydroelectric generation. This is also illustrated in Fig. 4 where results have been collected for a period of 1440 hours(4320-5760).

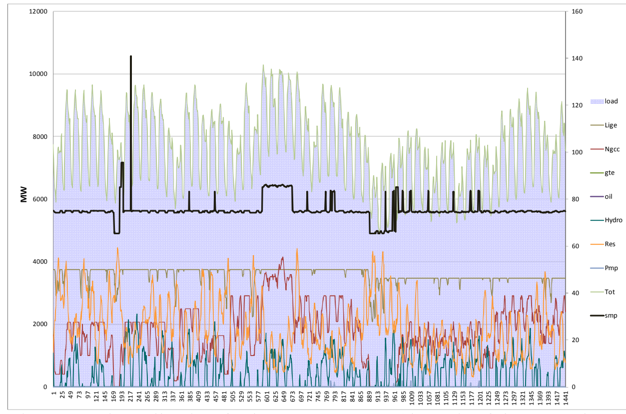

Fig. 4 Results collection for hours 4320-5760(the unit of the secondary axis is €/MWh)

Both old and new lignite fired generation units do not exceed 2 shut downs in the whole study period. The above threshold has been overpassed only by the most expensive lignite fired generation unit, a result which highlights that lignite fired units with more inefficient energy offers will have to face also the undesired and expensive possibility of shutting down frequently. However in the case study presented, the number of start-ups and shut-downs of the lignite fired plants seem quite reasonable, not even optimistic. On the other hand NGCC generation units, split in 3 tiers, offer their flexibility along with hydroelectric generation units. Tier 1 consists of 1 NGCC generation unit with 800MW capacity and 400MW technical minimum. It offers energy as competitively as NGCC units belonging in Tier 2 but it suffers of 3 times more shut downs than them. Fig. 5 demonstrates the uneven contribution to the flexibility of the system between lignite fired and NGCC generation units. The variability of the technical minimum for NGCC generation units is apparently sharper when compared with the lignite ones. The picture is completed with the striking result of 2139MW of old NGCC generation units which face severe competition resulting to a complete failure to participate in the market under these circumstances. The model should be further refined to strongly argue on the quantitative aspects of the results. On the other hand the qualitative trends implied by the model should not be ignored. In this sense the capacity mix in the Hellenic power market, assumed for the year 2020, suffers from thermal overcapacity which cannot be documented in terms of system reliability. The final capacity factor of the NGCC units that succeed to participate in the market rises to 38.41% from 22.15%.

Table 4. Start ups and shut downs of thermal units

	OLD_LIG	NEW_LIG	NGCC_T1	NGCC_T2	NGCC_T3
Start ups	**1**	**2**	**42**	**15**	**-**
Shut downs	**2**	**2**	**42**	**15**	**-**
Capacity	**2840**	**902**	**800**	**2112**	**2139**
Number of units	**10**	**2**	**1**	**5**	**5**

However, it has to be noted that even under these conditions the amounts of rejected energy from RES are negligible in the framework of the present optimization. For this reason a sensitivity analysis has been conducted where the projected generation of wind farms has been increased about 70%. That increase should be equivalent to a 70% increase of the installed capacity of the wind farms, if it is assumed that the total capacity factor of wind generation remains stable. This assumption will shed some light on the reaction of the thermal generation. For reasons of computational ease the analysis has not been applied to the 8760 hours of the year but on the time space of 1560 hours(7200 to 8760).

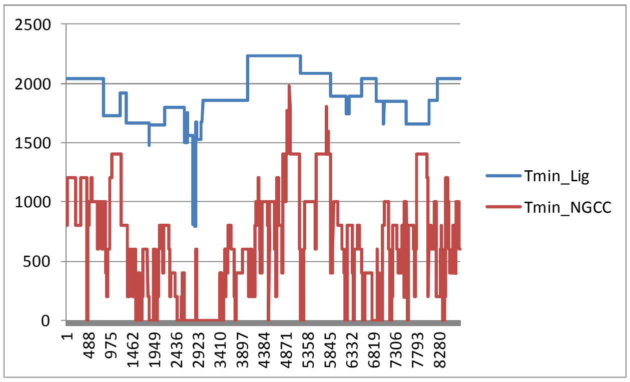

Fig. 5 Chronological Evolution of technical minima for lignite fired and NGCC generation units

The outcome of the sensitivity analysis confirms the ability of the system, in terms of the operational aspects involved in the model, to practically absorb the total amount of the increased wind farm generation. In the base case the percentage of rejected energy was about 0.04% (1 GWh) while in the latter case it has been increased only at the 0.56%(25GWh). The shut downs/start ups of the thermal plants are shown in the Tables 4, 5.

Table 5. Start ups and shut downs of thermal units in the base case [7200 – 8760 hours]

	OLD_LIG	NEW_LIG	NGCC_T1	NGCC_T2	NGCC_T3
Start ups	**0**	**0**	**10**	**5**	**-**
Shut downs	**0**	**0**	**9**	**5**	**-**
Capacity	**2840**	**902**	**800**	**2112**	**2139**
Number of units	**10**	**2**	**1**	**5**	**5**

Table 6. Start ups and shut downs of thermal units in the base case [7200 – 8760 hours]

	OLD_LIG	NEW_LIG	NGCC_T1	NGCC_T2	NGCC_T3
Start ups	**3**	**2**	**15**	**7**	**-**
Shut downs	**2**	**2**	**14**	**7**	**-**
Capacity	**2840**	**902**	**800**	**2112**	**2139**
Number of units	**10**	**2**	**1**	**5**	**5**

In the case of increased wind generation there is an additional amount of energy injected to the system at the level of 1.59TWh. This increase of wind generation results to the decrease of thermal generation. More specific, the lignite-fired generation is reduced at about 856GWh while the NGCC units reduce their generation by 730GWh. Lignite fired generation units are now forced to shut down at least twice while in the base case they didn't shut down at all. The NGCC plants show an increase in shut downs at almost 50%, for all the operating tiers described earlier.

As described above results of the model are on a preliminary phase. Both data input and mathematical formulation of the model will be continuously revisited until the framework under which the hourly simulation model interacts with energy systemic models will be fully established. Apparently computational limitations are another field where significant improvements are also expected.

All cases were performed on a 3.0 GHz Intel Quad Core with 4 MB RAM, running 32-bit Windows.
The model is implemented in GAMS 21.3 using the CPLEX solver 9.0.[7]

The required computational time when model runs for a 10-day scheduling period varies significantly and depends on the input data parameters which highly influence the solver's efficiency. However an average estimation of the 10-day period is about 10 minutes. In extreme cases, for instance when greater amounts of RES integrate in the system, the computational burden may approach 30 minutes. Empirically tested, factors like low availability of hydroelectric energy, high RES amount to integrate, the shortening of minimum down and up times and the synchronization/ soak/ desynchronization times increases significantly the computational burden. Eventually, if the input data stress the solution to its technical limits then the only option left is the violation of the constraints. In the presented cases such violations have been appeared but for very few hours. Most of the times these violations concern the ramp rates of NGCC generation units and their ability to follow load.

Conclusions

The proposed model provides a framework for the analysis in an hour level of detail for different capacity mixtures of the Hellenic Power System on an annual basis. It has been developed mainly to provide detailed description of the impact of high RES penetration, especially in the thermal and hydroelectric generation units and to shed light in operational issues which energy systemic models fail to capture.

An early assessment for a scenario approximating the Hellenic Power System approaching to 2020, provides indications, mainly of qualitative nature, that should be taken into account not only for the future capacity development of the system but also for the future operational challenges. The model offers a tool to estimate System Marginal Price for an annual period, valuable information when investment decisions have to be made. In this sense the preliminary results presented in this paper confirm a high uncertainty regarding the viability of the total NGCC generation units installed in the Hellenic power system in the long term, at least under the proposed framework of analysis. It seems also that the NGCC units are affected disproportionally compared to the lignite fired generation units, when large quantities of Renewable electricity have to be integrated.

On the other hand the model quantifies that the contribution of the NGCC units to the flexibility of the system along with the hydroelectric plants, is significant and cannot be substituted, especially in the long term. Furthermore, rejected renewable energy remains in very low levels, even in the increase RES case. That means that the capacity mixture under investigation succeeds, at least under a technical and operating perspective, to integrate large amounts of renewable electricity.

It is important to further assess this model in many realistic case studies, and to compare with similar attempts in the literature. It would be of significant value to succeed in determining with accuracy and reliability the so called cycling costs, which are directly related with the renewable integration process. That information could also be returned to energy systemic models, in order to better endogenously assess renewable electricity integration.

References

[1] Hellenic IPTO, “Manual of Market Operation”, version 2.0, 2010 [Online] Available: http://www.desmie.gr/fileadmin/groups/EDLES_DHEP/Egcheiridio_Agoras_version_2.0_2010.09.06.pdf

[2] Sakellaridis, N.; Mantzaris, J.; Nakos, C.; Giannakidis, G.; Tigas, K., "Hellenic power generation system: Towards meeting the national targets up to 2020," Environment and Electrical Engineering (EEEIC), 2011 10th International Conference on , vol., no., pp.1,4, 8-11 May 2011 doi: 10.1109/EEEIC.2011.5874755

[3] Van Beeck, N., 1999. Classification of Energy Models. Tilburg University, Tilburg, The Netherlands.

[4] Barth, R.; Brand, H.; Meibom, P.; Weber, C., "A Stochastic Unit-commitment Model for the Evaluation of the Impacts of Integration of Large Amounts of Intermittent Wind Power," Probabilistic Methods Applied to Power Systems, 2006. PMAPS 2006. International Conference on , vol., no., pp.1,8, 11-15 June 2006 doi: 10.1109/PMAPS.2006.360195

[5] Simoglou, C.K.; Biskas, P.N.; Zoumas, C.E.; Bakirtzis, A.G.; , "Evaluation of the impact of RES integration on the Greek electricity market by mid-term simulation," *PowerTech, 2011 IEEE Trondheim* , vol., no., pp.1-8, 19-23 June 2011 doi: 10.1109/PTC.2011.6019220

[6] Simoglou, C.K.; Biskas, P.N.; Bakirtzis, A.G., "Optimal Self-Scheduling of a Thermal Producer in Short-Term Electricity Markets by MILP," Power Systems, IEEE Transactions on , vol.25, no.4, pp.1965,1977, Nov. 2010 doi: 10.1109/TPWRS.2010.2050011

[7] A. Brooke, D. Kendrick, and A. Meeraus, “Gams User Guide” Redwood City, CA: The scientific press, 1990. [Online] Available: http://www.gams.com/docs/documement.htm