MARKET DESIGN EFFECTS ON PRIVATE PRODUCERS IN GREECE

P. N. Biskas*, G. H. Naziris, C. K. Simoglou, C. E. Zoumas, A. G. Bakirtzis

Power Systems Laboratory, Department of Electrical and Computer Engineering
Aristotle University of Thessaloniki
54124, Thessaloniki, GREECE
*Corresponding author: pbiskas@auth.gr

Abstract – This paper investigates the financial and operational behavior of privately-owned combined cycle gas-fired units (CCGTs) in the Greek deregulated electricity market. A mid-term scheduling model formulated and solved as a mixed integer program is presented. This model is based on the day-ahead market clearing algorithm of the Greek wholesale electricity market. The economic viability of the units is examined through the computation of their total profits under different producer strategies and market regulatory frameworks. Simulations of the Greek electricity market during the years 2011-2012 determine the height of the capacity payment for full recovery of the operating and investment costs of the private CCGT investors.

Keywords: day-ahead market, mid-term scheduling, peak-shaving, mixed integer programming, Monte-Carlo simulation

1 NOMENCLATURE

b ($\mathcal{B}^i$)	index (set) of steps of the energy offer function of unit i
c ($\mathcal{C}^z$)	index (set) of corridors of system operating zone z
exp ($\mathcal{E}xp^z$)	index (set) of energy exports from zone z
i ($\mathcal{I}^z$)	index (set) of generating units of zone z
imp ($\mathcal{I}mp^z$)	index (set) of energy imports in zone z
m ($\mathcal{M}$)	index (set) of reserves types $\mathcal{M} = 1, 2+, 2-, 3S, 3NS$, where m=1: primary, m=2+: secondary-up, m=2-: secondary-down, m=3: tertiary (spinning - 3S and non-spinning - 3NS)
r ($\mathcal{R}^z$)	index (set) of Renewable Energy Sources (RES) in zone z
t ($\mathcal{T}$)	index (set) of hours of the scheduling horizon
z ($\mathcal{Z}$)	index (set) of system operating zones
π_{bit}^{NRG}	price of block b of the energy offer function of unit i, during hour t, in €/MWh
π_{it}^{1}	price of the primary reserve offer of unit i during hour t, in €/MW
π_{it}^{2R}	price of the secondary range offer of unit i during hour t, in €/MW
CL_{ct}	corridor limit of corridor c during hour t, in MW
cf_{ct}	corridor flow in corridor c during hour t, in MWh
D_{zt}	load of system operating zone z during hour t, in MWh
DT_i	minimum down time of unit i, in h
E_t^{exp}	energy withdrawal of export exp during hour t, in MWh
GLF_{it}	generation loss factor of unit i during hour t
I_t^{imp}	energy injection of import imp during hour t, in MWh
P_{it}^{fix}	mandatory injection of unit i during hour t, in MWh
$P_i^{\max}$	maximum power output of unit i, in MW
$P_i^{\max,AGC}$	maximum power output of unit i while operating under AGC, in MW
$P_i^{\min}$	minimum power output of unit i, in MW
$P_i^{\min,AGC}$	minimum power output of unit i while operating under AGC, in MW
p_{it}	energy injection of unit i during hour t, in MWh
p_{it}^{net}	net energy injection (at the market point) of unit i during hour t, in MWh
Q_{bit}	quantity of block b of the energy offer function of unit i, during hour t, in MWh
q_{bit}	portion of step b of the i-th unit's energy offer function loaded in hour t, in MWh
R_i^m	maximum contribution of unit i in reserve type m, in MW
R_i^{2R}	maximum secondary range capability of unit i, in MW
r_{it}^m	contribution of unit i in reserve type m during hour t, in MW
RR_t^m	system requirement in reserve type m during hour t, in MW
RES_{rt}	energy injection of Renewable Energy Source (RES) r during hour t, in MWh
RD_i	ramp-down rate of unit i, in MW/min
RU_i	ramp-up rate of unit i, in MW/min
SDC_i	shut-down cost of unit i, in €
SUC_i	start-up cost of unit i, in €

UT_i	minimum up time of unit *i,* in h
u_{it}	binary variable which is equal to 1 if unit *i* is committed (on-line) during hour *t*
u_{it}^{AGC}	binary variable which is equal to 1 if unit *i* operates under AGC and provides secondary reserve during hour *t*
u_{it}^{3NS}	binary variable which is equal to 1 if unit *i* provides tertiary non-spinning reserve during hour *t*
y_{it}	binary variable which is equal to 1 if unit *i* is started-up during hour *t*
z_{it}	binary variable which is equal to 1 if unit *i* is shut-down during hour *t*

2 INTRODUCTION

In the past twenty years, the electric power industry all over the world has experienced major regulatory and operational changes towards the introduction of competition in both the generation and supply level [1]. In this context, wholesale electricity markets have emerged in several countries to facilitate the competitive operation of the electricity sector.

The Greek deregulated wholesale electricity market started its operation in 2000, when the Regulatory Authority for Energy (RAE) and the Hellenic Transmission System Operator (HTSO) were founded. The market design consists of a mandatory pool operated by the HTSO and a day-ahead market that solves a short-term unit commitment problem performing co-optimization of energy, primary and secondary reserve.

However, the first steps towards the actual liberalization took place in 2006, when the first privately-owned power plant became commercially available. The need to gradually replace the old, polluting lignite units has motivated private investors to construct and operate more gas-fired power units. Four privately-owned combined cycle gas-fired units (CCGTs) have been constructed and operated in Greece during the last four years and another two are expected to become commercially available within 2011. These units are expected to partially replace the lignite units up to 2018 acting as “base-load” units.

Despite the fact that gas-fired CCGTs are more efficient than lignite units, they still have higher variable cost under current gas and CO_2 prices. Thus, during the period 2011-2018 the dispatching of these units is problematic, owing to the following reasons:

a) Economic recession in Greece has led to a decrease in system load of up to 3% per annum.
b) Increased Net Transfer Capacities (NTCs) in the Greek northern interconnections have led to increased imports of up to 100%.
c) The extremely wet years 2009 and 2010 have led to excessive hydro inflows, leading to increased mandatory hydro operations of up to 60%.

The above factors resulted to a significant decline of day-ahead market clearing prices. The privately-owned units would have suffered severe losses, were it not for the “Cost Recovery” mechanism, which covers the variable cost of the units plus an additional profit (regulatory defined uplift).

In this paper, the viability of gas-fired units in the Greek electricity market during years 2011 and 2012 is studied, and different setups of the regulatory framework are proposed so that the private investors fully recover their operating and investment costs. For this purpose, a Mid-Term Scheduling (MTS) model, based on the day-ahead market clearing algorithm (Day-Ahead Scheduling - DAS) of the Greek wholesale electricity market, has been developed. For the formulation and solution of the large-scale MTS model, an integrated software, called Long-Term Scheduling (LTS) program, has been developed. In fact, the LTS program simulates the wholesale joint energy and ancillary services market for each day of a whole year and provides results concerning market clearing prices as well as quantities of all commodities (energy, primary reserve, secondary range, tertiary reserve) on an hourly basis. The optimization horizon of the LTS program may vary from one month to 25 years and in this paper is set equal to two years (2011-2012).

3 MID-TERM SCHEDULING PROBLEM FORMULATION

The MTS is a unit commitment (UC) problem that can be formulated and solved either as a Linear Programming (LP) problem or a Mixed-Integer Programming (MIP) problem.

The LP model is useful when fast program executions are needed, but it lacks accuracy in the results when the market design involves solution of a unit commitment problem.

The MIP model is able to incorporate unit commitment, respect the units’ technical minimum and facilitate the provision of secondary and non-spinning tertiary reserve as well as the inclusion of the units' intertemporal constraints. The MIP model provides maximum accuracy in the unit commitment problem, but its execution is very time-consuming.

Before the formulation and solution of the MTS problem, the well-known “Peak-Shaving” (PS) problem [2] is formulated and solved by the LTS program as an MIP model, in order to compute the hourly mandatory hydro injections that are subsequently used as input in the MTS. The PS problem is briefly presented in Section 3.2.

3.1 Input Data

The input data that are taken into account in the PS and MTS problem formulations are the following:

a) the system and zonal load,
b) the import and export schedules on the interconnections,
c) the injection of Renewable Energy Sources (RES),
d) the pumping schedule of the hydro pumped-storage units,

e) the corridor (inter-zonal) constraints,
f) the schedule for the construction of new units and for the withdrawal of old units,
g) the techno-economic data of the units (including the emission cost of thermal units)
h) the forced outage rates ($EFOR_d$) and the maintenance periods of the units.

The technical maximum, the $EFOR_d$ and the maintenance periods of the units define the final maximum hourly unit availabilities that will be considered in the MTS problem, further explained in the following.

3.2 Peak-Shaving (PS) Problem

The aim of the PS problem is the computation of the mandatory hydro injections that are used as input in the MTS problem.

The PS problem is solved:

a) per year, if the optimization horizon is greater than one year, or
b) for the entire scheduling horizon, if the optimization horizon is less than or equal to one year.

In the first case, the Peak Shaving is performed with consecutive yearly runs, which are hereinafter called “internal Peak-Shaving runs”.

In the solution of the PS problem, the thermal unit commitment status (on/off) is not modelled (no commitment binary variables are used). Consequently, the inter-temporal constraints that involve the minimum-up/down time are disregarded.

On the other hand, the hydro units are modelled with binary variables for on-line status, start-up and shutdown. This is necessary, in order to impose maximum number of start-ups per day. The priced energy offers and reserve offers of the hydro units are not considered in the PS problem. The total hydro injection throughout the year is given as input and it is included in an equality constraint. This problem actually simulates the twelve-month usage of hydro resources that is performed by the hydro producers annually.

3.3 Mid-Term Scheduling Problem

In this paper the MTS problem is formulated and solved as an MIP problem. The mandatory hydro injections exported from the PS solution (which correspond to the minimum hourly energy injection of the hydro units) are inserted in the MTS problem as non-priced energy offers. All units’ commitment constraints are active in this problem, which is solved successively on a daily basis for the entire year; the solution of the UC problem (DAS) for day N-1 provides the initial state of the UC problem for day N.

The basic assumptions and the mathematical formulation of the MTS problem are given in the following subsections.

3.3.1 Modeling of start-up and shut-down phases

In the MTS problem, the unit operating phase modeling follows, in general, the one presented in [3]. The only difference is that the synchronization and soak phases (which both comprise the unit start-up phase) as well as the desynchronization phase of the generating units are ignored in the current LTS formulation. The duration of both phases is considered to be one hour. This is an acceptable model simplification for long-term simulation.

3.3.2 Energy and reserve offers of units

The priced energy offer consists of a monotonically increasing, step-wise function of up to ten (10) price-quantity steps. This function can be initialized to the minimum average variable cost of each thermal unit, taking into account the emissions cost. There are one-step priced reserve offers for primary reserve and secondary range, in cohesion with the provisions of the Greek Grid and Exchange Code (GGEC) [4]. The quantity involved in these offers is the maximum capability of each unit to provide each type of reserve.

There are no priced reserve offers for tertiary reserve. Tertiary reserve requirements are defined per dispatch period and are inserted as constraints in the LTS problem.

3.3.3 Monte Carlo Simulation

Monte Carlo simulation is widely used for the modeling of stochastic parameters. The only stochastic parameter that is modelled in the MTS is the thermal unit availability. A two-state Markov model is used, taking into account the Equivalent Forced Outage Rate (EFOR) of the units.

The MTS problem is solved using external and internal runs. First, the external runs are used for Monte Carlo simulation iterations. A list of values for the hourly thermal unit availabilities is created taking also into account the units' maintenance periods. These values are entered in the LTS solver and the MTS problem is solved in successive internal runs. The Monte Carlo runs are solved successively. The internal runs are used in order to split the optimization period in smaller time-periods (one hour), since the solution time of MIP runs increases exponentially with the number of binary variables.

3.3.4 Objective function

The MTS goal is the maximization of the total social welfare (or equivalently the minimization of the total production cost minus the load utility) within a year. The load utility refers to the priced-load declarations of the demand-side. In this paper, the load utility is considered equal to zero, since the system load demand is considered inelastic.

The objective function of the MTS problem is described as follows:

$$Min\left\{\sum_{t\in\mathcal{T}}\sum_{i\in I}\left[GLF_{it}\cdot\sum_{b\in\mathcal{B}^i}\pi_{bit}^{NRG}\cdot q_{bit}+\pi_{it}^{1}\cdot r_{it}^{1}+\right.\right.$$
$$\left.\left.+\pi_{it}^{2R}\cdot r_{it}^{2+}+r_{it}^{2-}+SUC_i\cdot y_{it}+SDC_i\cdot z_{it}\right]\right. \quad (1)$$

The total system cost in (1) includes the units' generation cost, the units' reserve provision cost and the units' start-up and shut-down cost. In this model, the start-up cost is considered equal to zero and, therefore, omitted from the objective function, in cohesion with the provisions of the Greek Grid and Exchange Code (GGEC) [4].

The problem constraints for each hour of the dispatch day can be classified in the following groups:

3.3.5 System Constraints

$$\sum_{i\in I^{z}} p_{it}^{net} + \sum_{r\in\mathcal{R}^{z}} RES_{rt} + \sum_{imp\in Imp^{z}} I_{t}^{imp} - \sum_{exp\in\mathcal{E}xp^{z}} E_{t}^{exp} - D_{zt} = \sum_{c\in C^{z}From} cf_{ct} - \sum_{c\in C^{z}To} cf_{ct} \qquad \forall z\in\mathcal{Z}, t\in\mathcal{T} \qquad (2)$$

$$\sum_{i\in I} r_{it}^{1} \geq RR_{t}^{1} \qquad \forall t\in\mathcal{T} \qquad (3)$$

$$\sum_{i\in I} r_{it}^{2+} \geq RR_{t}^{2+} \qquad \forall t\in\mathcal{T} \qquad (4)$$

$$\sum_{i\in I} r_{it}^{2-} \geq RR_{t}^{2-} \qquad \forall t\in\mathcal{T} \qquad (5)$$

$$\sum_{i\in I} r_{it}^{3S} + \sum_{i\in I} r_{it}^{3NS} \geq RR_{t}^{3} \qquad \forall t\in\mathcal{T} \qquad (6)$$

$$0 \leq cf_{ct} \leq CL_{ct} \qquad \forall c\in\mathcal{C}, t\in\mathcal{T} \qquad (7)$$

Constraints (2) enforce the power balance equation in each zone z for each dispatch period t. Constraints (3)-(6) enforce the system requirements for all types of reserves.

Constraints (7) ensure that the corridor flow on each corridor c for each hour t should be less than or equal to the respective corridor limit at that hour.

3.3.6 Unit Operating Constraints

$$y_{it} - z_{it} = u_{it} - u_{i\ t-1} \qquad \forall i\in I, t\in\mathcal{T} \qquad (8)$$

$$\sum_{\tau=t-UT_i+1}^{t} y_{i\tau} \leq u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (9)$$

$$\sum_{\tau=t-DT_i+1}^{t} z_{i\tau} \leq 1-u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (10)$$

Constraints (8) model the logic of the start-up and shut-down status change of unit i, while constraints (9)-(10) enforce the minimum up and down time constraints, respectively, i.e. unit i must remain committed (de-committed) at hour t if its start-up (shut-down) started during the previous UT_i-1 (DT_i-1) hours [3].

$$p_{it} = P_{it}^{fix} + \sum_{b\in\mathcal{B}^{i}} q_{bit} \qquad \forall i\in I, t\in\mathcal{T} \qquad (11)$$

$$0 \leq q_{bit} \leq Q_{bit} \qquad \forall i\in I, b\in\mathcal{B}^{i}, t\in\mathcal{T} \qquad (12)$$

$$p_{it}^{net} = p_{it}\cdot GLF_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (13)$$

Equation (11) enforces that, for each generating unit i, the power injection can be divided into two components:

a) The first term represents the non-priced component of the energy offer function of the entity, including the mandatory hydro energy injection and the energy production of units in commissioning tests. This component may follow a constant and pre-specified schedule.

b) The second term represents the priced component of the energy offer function of the unit. This component is equal to the sum of the cleared blocks of energy.

Constraints (12) denote that the portion of step b of the i-th generating unit energy offer function that is cleared in hour t cannot exceed the size of the corresponding step.

Constraints (13) define that the net energy injection at the market point of each unit i for each hour t is equal to the energy injection at the unit metering point multiplied by the respective generation loss factor, GLF_{it}.

$$u_{it}^{AGC} \leq u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (14)$$

$$r_{it}^{2+} + r_{it}^{2-} \leq R_{i}^{2R}\cdot u_{it}^{AGC} \qquad \forall i\in I, t\in\mathcal{T} \qquad (15)$$

$$0 \leq r_{it}^{1} \leq R_{i}^{1}\cdot u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (16)$$

$$0 \leq r_{it}^{3S} \leq R_{i}^{3S}\cdot u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (17)$$

$$0 \leq r_{it}^{3NS} \leq R_{i}^{3NS}\cdot u_{it}^{3NS} \qquad \forall i\in I, t\in\mathcal{T} \qquad (18)$$

$$r_{it}^{3NS} \geq P_{i}^{\min}\cdot u_{it}^{3NS} \qquad \forall i\in I, t\in\mathcal{T} \qquad (19)$$

$$u_{it}^{3NS} \leq 1-u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (20)$$

$$p_{it} - r_{it}^{2-} \geq P_{i}^{\min}\cdot\ u_{it} - u_{it}^{AGC}\ + P_{i}^{\min,AGC}\cdot u_{it}^{AGC} \qquad \forall i\in I, t\in\mathcal{T} \qquad (21)$$

$$p_{it} + r_{it}^{2+} \leq P_{i}^{\max}\cdot\ u_{it} - u_{it}^{AGC}\ + P_{i}^{\max,AGC}\cdot u_{it}^{AGC} \qquad \forall i\in I, t\in\mathcal{T} \qquad (22)$$

$$p_{it} + r_{it}^{1} + r_{it}^{2+} + r_{it}^{3S} \leq P_{i}^{\max}\cdot u_{it} \qquad \forall i\in I, t\in\mathcal{T} \qquad (23)$$

$$p_{it} - p_{i\ t-1} \leq RU_{i}\cdot 60 \qquad \forall i\in I, t\in\mathcal{T} \qquad (24)$$

$$p_{i(t-1)} - p_{it} \leq RD_{i}\cdot 60 \qquad \forall i\in I, t\in\mathcal{T} \qquad (25)$$

Constraints (14) state that unit i may provide AGC if and only if it is committed (on-line). Constraints (15) enforce that the sum of the secondary-up and down reserve provided by unit i, provided that it is under AGC, should be less than or equal to the maximum secondary range capability of the unit. Constraints (16)-(18) set the upper limits of primary, tertiary spinning and tertiary non-spinning reserves, respectively. As shown by constraints (14)-(17), unit i may contribute in synchronized reserves if and only if it is committed.

Constraints (19) enforce the tertiary non-spinning reserve contribution to be greater than the minimum power output of unit i. Constraints (20) state that unit i may provide tertiary non-spinning reserve if and only if it is off-line.

Constraints (21)-(23) define the limits of the power output of unit i, while constraints (24)-(25) introduce the effect of ramp rate limits on the power output.

4 TEST RESULTS

The MTS problem is solved for the Greek Power System, which currently comprises of 32 thermal units and 13 hydroplants, with a total installed thermal and hydro capacity of 8,545 MW and 3,050 MW, respectively.

Two new CCGTs are scheduled to become commercially available during the year 2011, therefore increasing the total number of the private producers' units from four to six and the total installed capacity of the Greek Power System by 840 MW. The Greek Power System overview at the end of July 2011 (excluding Renewable Energy Sources - RES) is shown in Table 1.

Unit Type	Number of Units	Installed Capacity [MW]	MAVC Range [€/MWh]
Base-Load (Lignite-Fired)	17	4,269	28.7 - 37.3
Intermediate-Load (CCGTs)	9	3,759	58.2 - 65.2
Peak-Load (OCGTs & Oil)	8	1,357	87.8 - 96.8
Hydro Units	13	3,050	-
Total	**47**	**12,435**	

Table 1: Greek Power System Overview (July 2011)

According to the Greek Grid and Exchange Code [4], there are two markets operating in the Greek electricity market:

a) the Day-Ahead Scheduling (DAS) Market, in which all generating units are remunerated for the energy that they actually inject to the system, following the Uniform Marginal Pricing (UMP) scheme [1].

b) the Capacity Assurance Market (through the Capacity Availability Tickets - CAT) in which energy producers are remunerated for their availability; this remuneration aims to cover the fixed annual costs (loans, depreciation, etc.) of the operating units.

These two markets, even though operating independently from one another, are related in the sense that the profits of the producers from these two markets should cover their total annual costs (fixed and variable) in order to ensure their viability in the long-run.

In this paper, the economic viability of the private units for years 2011 and 2012 is examined through the computation of their total profits under different producer strategies and market regulatory frameworks. The units' total profits are computed as the sum of their profits from the DAS and the CAT markets, further explained in the following.

Sixteen (16) scenarios have been created regarding different values of the following factors:

a) The priced energy offer of the private units. Two different energy bidding rules for the private units are simulated. In the first one, the units' energy offer consists of a single block at the Minimum Average Variable Cost (MAVC), while in the second one a strategic bidding rule is adopted; the first block corresponding to the 30% of the unit capacity is fixed well below the unit's marginal cost at values 0.01 – 1 €/MWh (this is allowed by the GGEC), while the remaining unit capacity is assigned appropriate offer prices so that the weighted average energy offer price remains above the MAVC. All other thermal units (except for the private ones) follow the first bidding rule.

b) The incorporation of the full (marginal) or partial (average) CO_2 emissions cost in the units' variable cost. The CO_2 emissions cost has been set equal to 15.5 €/T, according to forecasts based on the current values taken from the European Energy Exchange [5]. The partial cost has been set equal to 13% of the full CO_2 emissions cost, corresponding to the current deficit against the total free allowances that have been allocated to Greece, according to the National Emissions Allocation Plan 2008-2012 [6].

c) The unit Cost Recovery Mechanism (CRM) versus a Bid Recovery Mechanism (BRM). In case that the units operate in the DAS market under economic loss, these mechanisms assure that the units will cover their variable costs or energy offer bids, respectively, plus an additional remuneration of 5% on the units' variable costs (or energy offer bids).

d) The value of the Capacity Availability Tickets. The current value is equal to 45,000 €/MW-year. In this study, two different values are simulated, namely 50,000 €/MW-year and 70,000 €/MW-year and their effect on the units' total profits is examined.

Parameters (a), (b) and (c) refer to the DAS-market, while parameter (d) refers to the CAT-market. Table 2 presents the combination of the aforementioned parameters that formulate all scenarios studied. Scenarios 1-8 refer to the case that the priced energy offer (parameter (a)) is equal to the MAVC, while scenarios 9-16 refer to the case that a strategic bidding rule is employed. It should be noted that only scenarios 1, 3, 9 and 11 require the execution of both the PS and the MTS problems, since the solution of all other scenarios can be obtained by post-processing of the solution of the above four scenarios.

In this study, five (5) Monte-Carlo iterations are performed for each scenario with stochastic unit availabilities. Two separate yearly PS runs are performed (for years 2011 and 2012), whereas the MTS internal iterations are daily intervals, in order to accurately simulate the DAS market.

Scenarios	CAT Value [€]	CO_2 Emissions Cost	Recovery Mechanism
1 (9)	50,000	Partial	Cost
2 (10)	50,000	Partial	Bid
3 (11)	50,000	Full	Cost
4 (12)	50,000	Full	Bid
5 (13)	70,000	Partial	Cost
6 (14)	70,000	Partial	Bid
7 (15)	70,000	Full	Cost
8 (16)	70,000	Full	Bid

Table 2: Simulation Scenarios

Unit	Energy Injection [GWh]	Primary Reserve Injection [GW]	Energy Income [M€]	Ancillary Services Income [M€]	Income from Cost Recovery Mechanism (CRM) [M€]	Income from Bid Recovery Mechanism (BRM) [M€]	DAS Income (with CRM) [M€]	DAS Income (with BRM) [M€]	Total Variable Cost [M€]	Total Profits (with CRM) [M€]	Total Profits (with BRM) [M€]
# 1	2,255.5	229.5	141.798	0.270	32.412	12.876	174.480	154.945	167.904	**6.576**	**-12.959**
# 2	2,892.0	147.4	184.083	0.378	30.104	10.111	214.565	194.572	206.158	**8.407**	**-11.586**
# 3	4,960.3	348.5	310.671	0.526	34.594	22.067	345.791	333.264	331.517	**14.273**	**1.747**
# 4	4,827.1	355.0	302.079	0.578	37.568	21.699	340.225	324.356	325.236	**14.989**	**-0.880**
# 5	3,550.1	45.3	223.322	0.155	33.843	17.102	257.320	240.580	246.305	**11.016**	**-5.725**
# 6	3,809.6	223.0	239.237	0.225	32.731	18.406	272.192	257.867	260.253	**11.939**	**-2.386**

Table 3: Economic analysis of the units' profits and costs from the DAS market for the years 2011-2012 (Scenarios 3 & 4)

4.1. DAS market

In Table 3, a brief economic analysis of all private units' profits and costs from the DAS market is presented. For the sake of simplicity, Scenarios 3&4 are only presented. It is shown that under the Cost Recovery Mechanism (CRM) the total profits of all units are always positive due to the higher remuneration obtained, in contrast to the Bid Recovery Mechanism (BRM) that may even lead to losses (Units 1, 2, 4, 5, 6). This is observed in all sixteen scenarios studied. It should be noted also that without the CRM, no private unit would be able to cover its variable costs from its participation in the DAS market, as shown in Fig. 1.

Figure 2 illustrates the average monthly system marginal price (SMP) for both years and for the four aforementioned scenarios.

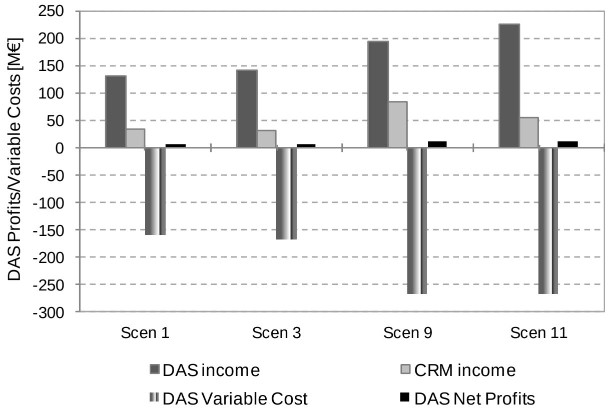

Fig. 1: DAS profits/Variable Costs (Unit 1-Years 2011-2012)

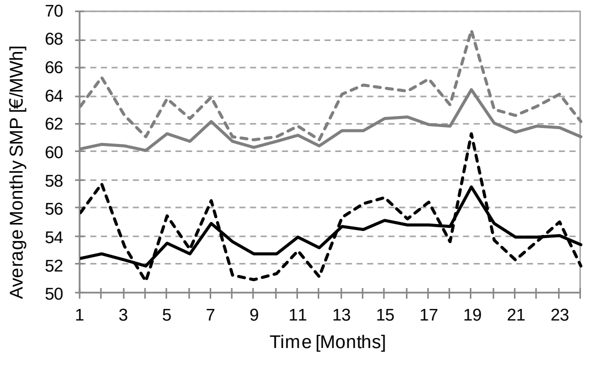

Fig. 2: Average Monthly SMP

It is apparent that regardless of the bidding rule the private units follow, the consideration of the full CO_2 emissions cost (instead of the partial one) in the units' energy offer results in a considerable increase of the SMP up to 10 €/MWh.

4.2 CAT Market

In this Section, the total fixed cost of a CCGT is initially calculated and then, the appropriate CAT value which allows the private producers to fully recover their total operational and investment costs is computed.

Table 4 briefly presents the calculation of the annual fixed cost of a typical CCGT established in Greece. The investment cost as well as the fixed O&M cost are typical values for a CCGT and are taken from [7]. The weighted average capital cost (WACC) is computed taking into account the risk-free rate of the 30-year bonds, the country and market risk premiums, the beta factor and the cost of debt in Greece. The capital recovery factor (CRF) transforms the total investment cost into the annual capital cost, taking into account the WACC of the investment. The annual fixed charge to DESFA for the natural gas network depreciation is imposed proportionally to the unit's installed capacity and currently equals 23,100 €/MW-y.

Installed Capacity	390 MW
Investment Cost (Total Overnight Cost)	700,000 €/MW
	273,000,000 €
Unit Lifetime	20 years
Weighted Average Capital Cost (WACC)	11.40 %
Capital Recovery Factor (CRF)	12.89 %
Annual capital cost	35,189,700 €/y
Annual fixed O&M cost	3,554,571 €/y
Annual fixed charge for the natural gas network depreciation	9,009,000 €/y
Total annual fixed cost	47,753,271 €/y
Annual specific fixed cost	**122,444 €/MW-y**

Table 4: Capital and fixed costs of a typical CCGT

Figure 3 shows the total losses of three indicative private units (Units 1, 3, 6) for all scenarios studied, taking into account all units' costs (total variable cost & total fixed cost) as well as all units' income (DAS income, CRM income, CAT income) for both years of our study. It should be mentioned that when a strategic bidding rule is applied in combination with the BRM

(Scenarios 10, 12, 14, 16), private producers suffer from significantly higher losses among all scenarios, regardless of the CAT value of the scenarios considered. On the contrary, the CRM in combination with either the MAVC bidding rule or the strategic bidding rule leads to essentially lower losses.

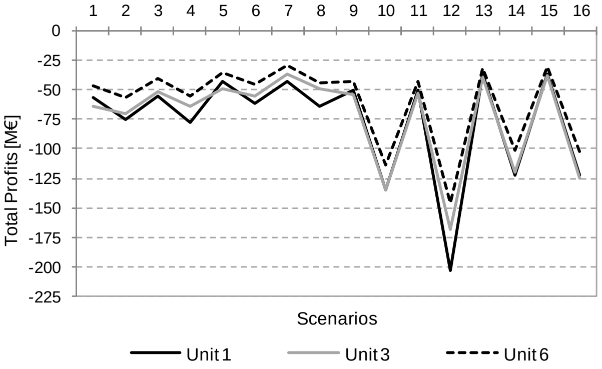

Fig. 3: Total Losses from units' participation in both markets (DAS & CAT) for both years (2011-2012)

As already mentioned and shown in Fig. 1, under the CRM, all private units are able to obtain net profits from the DAS market that partially cover their annual fixed costs. During the year 2012, a total net profit of 37,059,723 € is obtained by all private units through their participation in the DAS market (Scenario 3). Given that the total installed capacity of all private units in year 2012 is 2,417 MW and considering that $\mathrm{EFOR_d}$=5.75% for all units, Table 5 illustrates the calculation of the extra income (besides the total yearly net profits from the DAS market) needed to fully recover the annual fixed costs, which, in fact, represents the appropriate CAT value.

Total installed capacity of CCGTs	2,417 MW
Total available capacity of CCGTs (EFOR=5.75%)	2,278 MW
Total yearly net profits (DAS market-2012)	37,059,723 €/y
Specific yearly net profits (DAS market-2012)	16,268 €/MW-y
Annual specific fixed cost	122,444 €/MW-y
CAT value	**106,176 €/MW-y**

Table 5: Appropriate CAT value for the full recovery of the total costs of a typical CCGT

As results from Table 5, the appropriate CAT value for the full recovery of the total costs of a typical CCGT is equal to **106,176 €/MW-y**, which is considerably higher than the values assumed in the scenarios of this study and even higher than the current value of the Greek Capacity Assurance Market (45,000 €/MW-y).

All runs of both the PS and MTS models were performed under the LTS program platform on a 3.0 GHz Intel Quad Core processor with 8 GB of RAM, running 64-bit Windows and using the CPLEX 11.0 solver under GAMS 23.0 [8]. Each daily interval of the MTS model involves 38,593 constraints and 39,452 real variables of which 19,244 are binary variables. The total execution time for the generation of both models (PS and MTS for five Monte-Carlo iterations) and the solution process was about six hours per scenario.

5 CONCLUSIONS

In this paper, a study for the economic viability of the privately-owned combined cycle gas-fired units (CCGTs) participating in the Greek deregulated electricity market has been presented. A mid-term scheduling model formulated and solved as a mixed-integer program has been developed in order to simulate the Greek electricity market for the years 2011-2012. Various scenarios regarding different producer strategies and market regulatory frameworks were examined. The simulation results showed that the implementation of the cost recovery mechanism for the recovery of the units' variable costs from their participation in the DAS market is preferable to the bid recovery one. Additionally, the capacity availability tickets value should be significantly increased (up to 2.5 times) comparatively to the current enacted value in the CAT market, in order to allow the private units to fully recover their operational and fixed costs.

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