Paper accepted for presentation at 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania

Hourly-Discretized Mid-Term Power System Operation in a Competitive Energy Market

Costas G. Baslis, *Student Member, IEEE*, and Anastasios G. Bakirtzis, *Senior Member, IEEE*

Keywords—**Power system operation, perfect competition, asymmetric oligopoly, dominant firm, competitive fringe, mixed integer programming.**

Abstract—**This paper presents an optimization-based method to model the mid-term operation of a hydrothermal power system in a competitive market. Two market structures are examined: perfect competition and oligopoly comprising a dominant firm with a competitive fringe. In the latter, the dominant firm bidding strategy is determined by solving a profit maximization problem; forward contracts are also modeled. Producers submit offers to a day-ahead market, which is cleared by the system operator on a bid-cost minimization basis. A yearly planning horizon with hourly time intervals is adopted. A real size hydrothermal system, similar to the Greek Power System, is used for our tests. Hourly thermal unit commitment and start-up / shut-down decisions, market clearing prices, hydroplant generation / pumping and reservoir volumes, monthly price duration curves, ISO payment and thermal producer profits are among the results obtained.**

I. NOMENCLATURE

$\eta_{P,k}$	cycle efficiency of pumped storage plant k
π_{CO_2}	CO_2 allowance price (€/ton CO_2)
$\pi_{i,s,t}^{offer}$	offer price of step s of the energy offer curve of thermal unit i (€/MWh)
$\pi_t\left(q_t^{DF}\right)$	residual demand curve, representing market clearing price as a stepwise monotonically decreasing function of dominant firm quota q_t^{DF}
$b_{i,s,t}$	quantity of step s of the i-th thermal unit's energy offer curve dispatched (MWh)
$c_{i,s,t}$	marginal cost of step s of the marginal cost function of thermal unit i (€/MWh)
D_t	load demand (MW)
er_i	emission rate of thermal unit i (ton/MWh)
$f_{t,n}$	fraction of dominant firm quota for residual demand curve step n (in MWh)
$\underline{f}_{t,n}$	minimum dominant firm quota for residual demand curve step n (in MWh)
$g_{i,s,t}$	quantity of step s of the i-th thermal unit's marginal cost function dispatched (MWh)
$i\,(I)$	index (set) of thermal units
$i_{DF}\ (I_{\mathcal{DF}})$	index (set) of thermal units belonging to the dominant firm ($I_{\mathcal{DF}} \subseteq I$)
$i_F\,(I_{\mathcal{F}})$	index (set) of fast-start thermal units ($I_{\mathcal{F}} \subseteq I$)
$j\,(\mathcal{J})$	index (set) of hydroplants
$k\,(\mathcal{K})$	index (set) of pumped storage plants ($\mathcal{K} \subseteq \mathcal{J}$)
$l_u^j\ (\mathcal{L}_u^j)$	index (set) of hydroplants / reservoirs immediately upstream of hydroplant / reservoir j
MDT_i	minimum down time of thermal unit i (hours)
MUT_i	minimum up time of thermal unit i (hours)
$n\,(\mathcal{N}^t)$	index (set) of residual demand curve step
$P_{H,j,t}$	power output of hydroplant j (MW)
$\overline{P_{H,j,t}}$	maximum power output of hydroplant j (MW)
$P_{i,t}$	power output of thermal unit i (MW)
$\underline{P_{i,t}}$	minimum power output of thermal unit i (MW)
$\overline{P_{i,t}}$	maximum power output of thermal unit i (MW)
$P_{P,k,t}$	pumping load of pumped storage plant k (MW)
$\overline{P_{P,k,t}}$	maximum pumping load of pumped storage plant k (MW)
q_t^{DF}	dominant firm quota (summation of its units' power output, MWh)
$R_{j,t}$	mean net inflow in reservoir j (hm^3)
Res_t^{req}	tertiary reserve requirement (MW)
$s\,(\mathcal{S}^i)$	index (set) of steps of the i-th thermal unit's marginal cost function / offer curve
sc_j	specific consumption of hydroplant j (hm^3/MWh)
$Sp_{j,t}$	spillage over reservoir j (hm^3)
$t\,(\mathcal{T})$	index (set) of time periods (hours)
$u_{i,t}$	binary variable representing the commitment decision for the thermal unit i
$V_{j,t}$	volume of water stored in reservoir j, at the end of hour h (hm^3)
$\overline{V_j}$	upper bound of water storage in reservoir j (hm^3)
$V_j^{initial}$	volume of water stored in reservoir j, at the beginning of the scheduling period (hm^3)
V_j^{final}	target final volume for reservoir j (hm^3)
$w_{t,n}$	binary variable indicating the selection of residual demand curve step n
$\mathbf{x}_{i,t}$	vector of the continuous and the binary decision variables of thermal unit i

C. G. Baslis and A. G. Bakirtzis are with the Department of Electrical and Computer Engineering, Aristotle University of Thessaloniki, GR-54124, Thessaloniki, GREECE (e-mail: bakiana@eng.auth.gr, cbaslis@ee.auth.gr).

978-1-4244-2235-7/09/$25.00 ©2009 IEEE

$y_{i,t}$ binary variable representing the start up decision for the thermal unit *i*

$z_{i,t}$ binary variable representing the shut down decision for the thermal unit *i*

II. Introduction

Mid-term hydrothermal scheduling aims at optimizing the power system operation by managing its limited physical resources over a planning time horizon of a few months to two years [1].

In a regulated power system, the operation decisions are coordinated centrally with the objective of minimizing total thermal production cost [2]. In deregulated energy markets though, where various power producers participate with the goal of maximizing their profits, operation scheduling is decentralized [3]. Nevertheless, the independent system operator (ISO), apart from clearing and operating the day-ahead market, is still responsible for ensuring medium and long-term system reliability, by monitoring, for example, reservoir water management [4].

Several models have been developed to simulate the behaviour of players in the energy market. Among them, a perfect competition model could prove to be realistic for the early restructuring stages of a former energy monopoly, where the dominant ex-monopolist still operates under maximum social benefit criteria, thus trying to maintain his production cost and market prices as low as possible [5]. On the other hand, such a recently reformed market could either operate as an asymmetric oligopoly, where a dominant firm faces a competitive fringe of independent power producers [6], [7]. This is the case, for example, of an ex-monopolist, possibly having been obliged to sell a portion of its power capacity, who acts as a price-maker in order to maximize its profit, whereas independent power producers, willing to maximize their market share, bid their marginal cost.

In the present paper, we examine both perfect competition and asymmetric oligopoly models, adopting a two-stage approach. First, the supply offers of all power producers are calculated. Thus, in the oligopoly model, a dominant firm profit maximization problem is solved first, in order to determine its bidding strategy. Second, producer supply offers are submitted to the system operator, who schedules power system operation by solving a bid-cost minimization problem. The case of a price-maker who is also the main retail supplier is studied through the modeling of energy contracts. The planning horizon is yearly and is discretized into hourly time steps. In this way, both medium-term aspects (e.g. water resources allocation) and short-term related operation constraints (e.g. thermal unit minimum up/down times) are jointly modeled. This results in detailed and realistic system operation representation and straightforward coordination of medium and short-term decisions.

III. Model Formulation and Assumptions

The power system modeled consists of thermal units, hydroplants and pumped storage plants. The yearly scheduling problem is divided into successive hourly time intervals and formulated as a mixed integer optimization problem. Integer variables are binary and represent hourly thermal unit commitment, start-up and shut-down decisions. Predictions over the system's stochastic parameters, i.e. hourly load demand, reservoir inflows and unit availabilities are used.

A. Energy Market Modeling

The energy market is modeled assuming that producers participate in the day-ahead energy market and submit energy supply offers to the independent system operator (ISO) for each hour of the following day. Hourly unit offers are non-decreasing stepwise functions of up to four price (€/MWh) – quantity (MWh) pairs.

The behaviour of thermal producers in the energy market is modeled under two different assumptions. First, a perfectly competitive market model is formulated; thermal unit bids reflect the unit's incremental cost. On the other hand, imperfect competition is modeled assuming an asymmetric oligopoly of a dominant firm versus a competitive fringe. The dominant firm is considered as a purely thermal producer. In order to maximize its profit, it acts as a price-maker facing a residual demand curve, which models the dominant firm's interaction with its competitors [3]. The remaining independent thermal producers act competitively in order to maximize their market share, thus bidding the marginal cost of their units. A piecewise linear curve is used to model the operating cost of a thermal unit as a function of its output, thus resulting in a stepwise incremental cost curve. Dominant firm's bidding strategy is calculated for each hour of the yearly planning horizon, based on corresponding hourly residual demand curves and thermal unit operating constraints.

After defining thermal producers' hourly supply offers, according to the market structure assumed, a second-stage bid-cost minimization problem is solved, representing ISO's operation. The latter clears the day-ahead market in a sealed-bid first-price auction approach, producing the corresponding hourly market clearing prices (MCPs). For the sake of simplicity, demand-side and hydro producer bidding are neglected. In this way, hydro resources management is performed by the ISO. Market clearing is solved for each hour of the yearly horizon within a unified mixed-integer programming problem.

The impact of a greenhouse gas emission reduction policy, has been modeled according to the European Emissions Trading Scheme (ETS). Each power producer is granted a certain amount of annual emission allowances for free; any deficit/surplus allowances are purchased/sold on the open market. Producers are assumed to fully internalize the allowance price into their marginal costs [8]; therefore, the latter is increased as follows:

$$c'_{i,s,t} = c_{i,s,t} + \pi_{CO_2} \cdot er_i \tag{1}$$

B. Problem Formulation

1) First stage – Supply offer calculation

Under the perfect competition assumption, producers submit offers that equal their marginal costs. In the asymmetric oligopoly model though, the dominant firm determines its supply offer on a profit maximization approach, taking into account the residual demand curve. The latter is calculated on an hourly basis, given the load demand and the supply offers of the competitive fringe firms, which bid their marginal costs. Figure 1a shows the aggregated supply bid curve, formulated by sorting the competitors' supply bids in ascending order, together with load demand, which is considered inelastic. The dominant firm's residual demand curve is then obtained as shown in Fig. 1b; it represents market clearing price as a stepwise monotonically decreasing function of the dominant firm quota. Therefore, the dominant firm determines its optimal quota by maximizing its profit:

$$Max\ \Pi_T = \sum_t \left\{ \pi_t(q_t^{DF}) \cdot q_t^{DF} - \sum_{i_{DF}} \sum_{s \in \mathcal{S}^{i_{DF}}} c'_{i_{DF},s,t} \cdot b_{i_{DF},s,t} \right\} \quad (2)$$

Subject to:

$$q_t^{DF} = \sum_{i_{DF}} P_{i,t} \quad (3)$$

$$\mathbf{x}_{i_{DF},t} \in \mathcal{T}_{i_{\mathcal{DF}}} \quad (4)$$

Problem (2) - (4) is nonlinear, as profit is determined by the product of two variables (dominant firm quota and the resulting market clearing price). In order to overcome difficulties posed by nonlinearity, the problem is linearized by using proper binary variables, indicating corresponding steps of the residual demand curve [3], as shown in Fig. 1c. Thus, the profit maximization problem is reformulated as a mixed-integer linear program:

$$Max\ \Pi_T = \sum_t \left\{ \sum_{n \in \mathcal{N}^t} \pi_{t,n} \cdot (f_{t,n} + \underline{f}_{t,n} \cdot w_{t,n}) - \sum_{i_{DF}} \sum_{s \in \mathcal{S}^{i_{DF}}} c'_{i_{DF},s,t} \cdot g_{i_{DF},s,t} \right\} \quad (5)$$

Subject to:

$$q_t^{DF} = \sum_{i_{DF}} P_{i,t} \quad (6)$$

$$q_t^{DF} = \sum_{n \in \mathcal{N}^t} f_{t,n} + \underline{f}_{t,n} \cdot w_{t,n} \quad (7)$$

$$f_{t,n} \le (\underline{f}_{t,n+1} - \underline{f}_{t,n}) \cdot w_{t,n} \quad (8)$$

$$\sum_{n \in \mathcal{N}^t} w_{t,n} = 1 \quad (9)$$

$$\mathbf{x}_{i_{DF},t} \in \mathcal{T}_{i_{\mathcal{DF}}} \quad (10)$$

Constraints (7) - (9) describe the linearization of the profit maximization problem [3], while (6) and (10) are the same as (3) and (4), respectively. As hydro bidding is neglected, dominant firm's operating constraints include thermal unit technical limitations (10); for reasons of a more compact presentation, these constraints are analyzed below in eq. (15) - (19).

After calculating its optimal hourly quotas, the dominant firm defines the supply offers for each of its thermal units as follows. For every step s of the unit's marginal cost curve the corresponding offer quantity is set equal to the magnitude (in MWh) of the step. For steps that are dispatched ($g_{i,s,t}$>0) offer price is defined as a lower bound to the hourly MCP obtained from the solution of problem (5) - (10). The larger the marginal cost of the step is, the closer its offer price is defined to the MCP. If a step is not dispatched ($g_{i,s,t}$=0), its offer price is set equal to price cap.

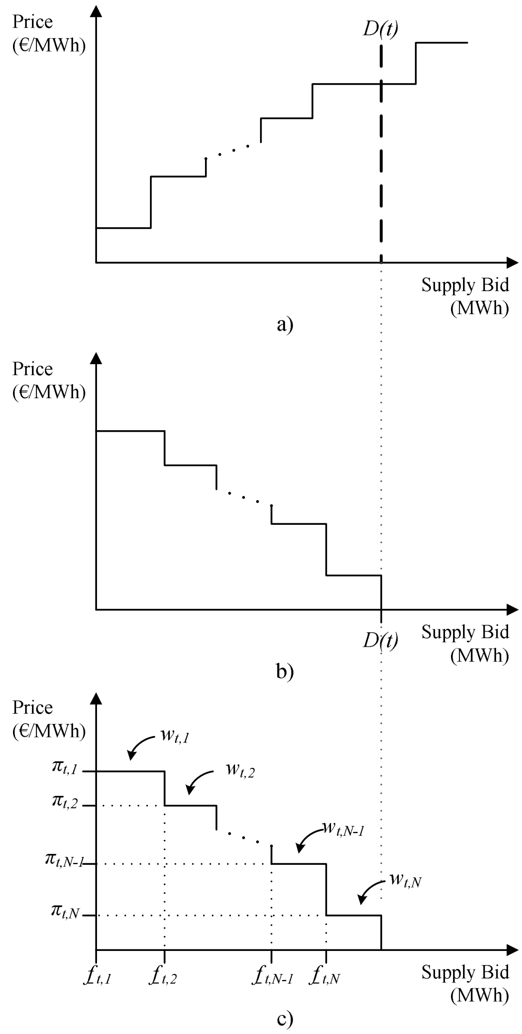

Figure 1. a) Aggregated bid curve and load demand, b) Dominant firm's residual demand curve, c) Linearization of the residual demand curve [3]

2) *Second stage – Bid-cost minimization by the ISO*

The previously calculated supply offers are submitted to the system operator. In turn, the operator's objective is to minimize total annual bid cost, by solving the following mixed integer optimization problem:

$$Min\ C_T = \sum_t \sum_i \sum_{s \in \mathcal{S}^i} \pi_{i,s,t}^{offer} \cdot q_{i,s,t} \quad (11)$$

Subject to:

$$\sum_i P_{i,t} + \sum_j P_{H,j,t} - \sum_k P_{P,k,t} = D_t \quad (12)$$

$$\sum_{i \notin I_{\mathcal{F}}} \left(\overline{P_{i,t}} \cdot u_{i,t} - P_{i,t} \right) + \sum_{i_F} \left(\overline{P_{i_F,t}} - P_{i_F,t} \right) + \sum_j \left(\overline{P_{H,j,t}} - P_{H,j,t} \right) + \sum_k P_{P,k,t} \ge Res_t^{req} \quad (13)$$

$$P_{i,t} = \sum_{s \in S^i} q_{i,s,t} \tag{14}$$

$$\underline{P_{i,t}} \cdot u_{i,t} \le P_{i,t} \le \overline{P_{i,t}} \cdot u_{i,t} \tag{15}$$

$$u_{i,t} \ge \sum_{\tau=t-MUT_i+1}^{t} y_{i,\tau} \tag{16}$$

$$1-u_{i,t} \ge \sum_{\tau=t-MDT_i+1}^{t} z_{i,\tau} \tag{17}$$

$$y_{i,t} - z_{i,t} = u_{i,t} - u_{i,t-1} \tag{18}$$

$$y_{i,t} + z_{i,t} \le 1 \tag{19}$$

$$\begin{aligned} V_{j,t} = {} & V_{j,t-1} + R_{j,t} - sc_j \cdot P_{H,j,t} - Sp_{j,t} + \eta_{P,j} \cdot sc_j \cdot P_{P,j,t} \\ & + \sum_{l_u^j \in \mathcal{L}_u^j} sc_{l_u^j} \cdot P_{H,l_u^j,t} + Sp_{l_u^j,t} - \eta_{P,l_u^j} \cdot sc_{l_u^j} \cdot P_{P,l_u^j,t} \end{aligned} \tag{20}$$

$$0 \le P_{H,j,t} \le \overline{P_{H,j,t}} \tag{21}$$

$$0 \le P_{P,k,t} \le \overline{P_{P,k,t}} \tag{22}$$

$$0 \le V_{j,t} \le \overline{V_j} \tag{23}$$

$$V_{j,0} = V_j^{initial} \tag{24}$$

$$V_{j,T} = V_j^{final} \tag{25}$$

System-wide constraints involving both thermal unit and hydroplant decision variables, include hourly power balance (12) and tertiary reserve requirement (13), which is defined as a percentage of hourly load. Contribution to tertiary reserve from hydro and fast-start thermal units is considered as always available, irrespective of their commitment status.

Thermal unit constraints include unit dispatched power output (14), minimum and maximum operating limits (15), minimum up /down times (16), (17) and start-up / shut-down procedures (18), (19).

Hydro constraints comprise hourly reservoir water balance (20), where hydraulic coupling among reservoirs is explicitly expressed, hydroplant and pumped storage plant operating limits (21), (22), reservoir stored volume limits (23) and reservoir initial and target volume (24), (25). The latter is actually set equal to the initial volume, which is relevant for small or medium size hydroelectric systems with annual regulation, like the Greek one. Hydro unit output is considered proportional to the turbine discharge rate. Optimal pumping operation is obtained as a straightforward model result; no ex ante assumptions, such as MCP levels below which pumped storage plants are operated, are adopted.

IV. Test Results

The proposed method was applied to a real-size hydrothermal system similar to the Greek Power System. The latter is currently under reform toward the establishment of a well-functioning competitive energy market; the presence, though, of independent power producers, apart from the dominant Public Power Corporation (PPC), is not expected to be significant before 2011. Therefore, data used in our tests simulate the expected status of the Greek Power System for 2011, comprising 33 thermal units and 13 hydroplants, including 2 pumped storage plants, in 6 river basins and 4 major blocks of multiple reservoirs in cascade. These data reflect the projections made in the 2008-2012 Transmission System Development Study, published by the Hellenic Transmission System Operator (HTSO) [9]. Table I presents general information on power system data.

Table I
General System Data

Thermal System Data	
Number of thermal units	33
Total capacity (MW)	9000
Lignite-fired (MW)	4340
Gas-fired Combined-Cycle (MW)	3475
Hydro System Data	
Number of hydroplants (pumped storage plants)	13 (2)
Capacity (Pumping) (MW)	2974 (720)
Yearly inflows (GWh)	4300
System Load Characteristics	
Total annual demand (GWh)	62192
Peak load (MW)	11660
Base load (MW)	3530

Thermal unit marginal cost and emission rate data, per fuel type, are presented in Table II. Emission rates are an estimate based on carbon intensity data from [10].

Table II
Thermal Unit Data

Fuel type	Number of thermal units	Marginal cost range (€/MWh)	Emission Rate (tCO_2/MWh)
Lignite	16	20 – 30	1.1 – 1.3
CCGT	9	60 – 72	0.35 – 0.4
OCGT	3	87 – 110	0.7 – 0.75
Oil	4	72 – 140	0.7 – 0.8

In addition to the expected scenario of PPC remaining a strong dominant player (scenario A in Table III), we also examined the hypothetical case where PPC is obliged to sell a certain part of its capacity to its competitors; two such scenarios were formulated (scenarios B and C). In addition, a perfect competition scenario was also tested (scenario PC), where market concentration refers to the expected scenario A. Finally, two CO_2 price scenarios were formulated, namely scenarios I and II (25 €/ton CO_2 and 40 €/ton CO_2, correspo-ndingly, see Table IV), resulting in 8 simulation scenarios in total. Price cap was assumed equal to 200 €/MWh.

Table III
Market Concentration Scenarios

Scenario	Dominant Firm Market Share (%)	Competitive Fringe Market Share (%)
A	85.2	14.8
B	60.9	39.1
C	39.7	61.3

The model was implemented in GAMS/CPLEX 11, on an Intel Core2 Duo 2.4 GHz PC with 4 GB of RAM running MS Windows 64-bit. Table V shows the basic model characteristics for both model stages described above (dominant firm's supply offer calculation and ISO's bid-cost

TABLE IV
CARBON PRICE SCENARIOS

Scenario	Carbon Price (€/ton CO_2)
I	25
II	40

TABLE V
GAMS MODEL PARAMETERS AND RESULTS

Dominant Firm Supply Offer Calculation	
Equations	603,075
Variables	1,194,749
Integer variables	428,042
Total run time (sec)	3,193
ISO Bid-Cost Minimization	
Equations	1,726,794
Variables	1,995,540
Integer variables	797,616
Total run time (sec)	7,600

minimization), for scenario B-II. Note the large number of integer variables (almost 800,000) of the ISO's problem.

Annual ISO payments, as well as annual profits both for the dominant firm and the competitive fringe are shown in Fig. 2. System operator's payment is significantly lower under perfect competition than under any of the oligopoly scenarios; it increases with dominant player's market share.

Price duration curves for the 4 market test cases under CO_2 price scenario II are presented in Fig. 3. Under perfect competition, price duration curve is quite flat, as thermal unit bids directly reflect marginal costs and internalize CO_2 price. As expected, the stronger the dominant position of the price-maker becomes the more intense price manipulation is. Under scenario A (the expected one for Greece), the dominant player would be able to cause market clearing prices to constantly equal price cap.

In the real case of PPC though, such an aggressive market behavior is highly unexpected due to the fact that the firm remains the only retail supplier in the Greek System, purchasing energy at the market clearing price. In addition, retail prices are strongly regulated and not linked to MCPs. Thus, it is strongly motivated to act competitively and lower MCPs, in order to maximize overall profits. To further analyze the case of a dominant firm being, at the same time, the dominant retail supplier, the firm was assumed to have forward contract obligations. Therefore, its bidding strategy is calculated by the following modified profit maximization problem:

$$Max\ \Pi_T = \sum_t \left\{ \begin{array}{l} \pi_t^{FC} \cdot FC_t + \sum\limits_{n \in \mathcal{N}^t} \pi_{t,n} \cdot (f_{t,n} + (\underline{f}_{t,n} - FC_t) \cdot w_{t,n}) \\ -\sum\limits_{i_{DF}} \sum\limits_{s \in S^{i_{DF}}} c'_{i_{DF},s,t} \cdot b_{i_{DF},s,t} \end{array} \right\} \quad (26)$$

Subject to: Eq. (6) - (10)

where:

π_t^{FC} : contract price (€/MWh)

FC_t : contract volume (MWh).

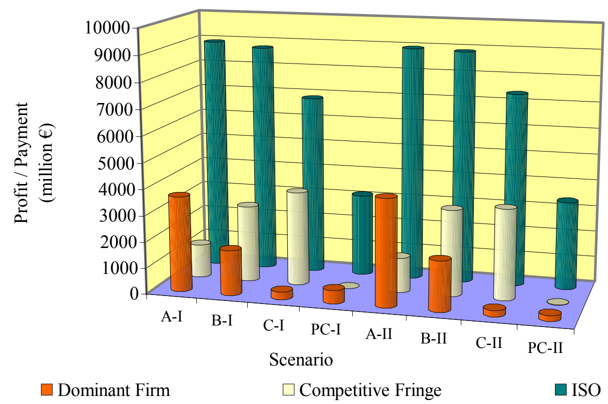

Figure 2. Annual ISO payment and firm profits

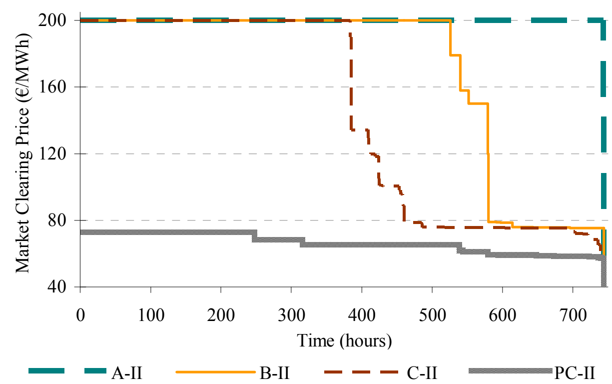

Figure 3. Monthly price duration curves (October)

Two contract scenarios were examined, as presented in Table VI; contract volume was introduced as a percentage of hourly system load. Both these test cases were applied to scenario A-II, where dominant firm's market share is larger than 85% (again, this is the expected scenario for the Greek energy market). Contract price was set equal to 100 €/MWh.

Figure 4, illustrating the price duration curves obtained together with the no-contract test case A-II, confirms the aforementioned observation. Contracts provide strong motivation for the price-maker to offer significantly lower priced bids, thus lowering MCPs; the higher the contracted volume is, the lower the resulting prices are.

System hourly operation for a week of the year is presented in Fig. 5 (for scenario B-II), where peak load shaving can be observed. Pumping is plotted as negative hydro production. Finally, total reservoir volume trajectories are plotted in Fig. 6. Water is gradually stored into reservoirs in order to be more intensively used during the summer peak. Maximum reservoir volume before summer increases with the decrease of market power; this is due to the increasing duration of low MCPs (Fig. 3), during which storing water is more economical than using it for electricity generation.

V. CONCLUSIONS

In this paper, the yearly operation of a hydrothermal power system under a competitive energy market structure was modeled. Two market structures were examined, namely perfect competition and asymmetric oligopoly with a dominant firm facing a competitive fringe. In the former case, producers bid their marginal cost, whereas in the latter, the dominant firm acts as a price-maker; its bidding strategy is calculated by a mixed-integer profit maximization problem, based on hourly residual demand curves. Market is cleared by the ISO on a bid-cost minimization basis, where short-term operating constraints, such as thermal unit minimum up/down times, are modeled in detail. In this way, both medium and short-term system operation can be jointly modeled and analyzed. The method was tested on the Greek Power System, using data projections for 2011 and assuming various market share and carbon price scenarios. Results indicate that price manipulation can be significantly mitigated when price-maker is constrained by forward contracts. Modelling price-maker's strategic behavior in a medium-term framework and obtaining hourly-based operating decisions and results that allow a detailed assessment of the energy market and power system operation are the main advantages of the presented model.

VI. References

[1] O. B. Fosso, A. Gjelsvik, A. Haugstad, B. Mo and I. Wangensteen, "Generation scheduling in a deregulated system. The Norwegian case," *IEEE Trans. Power Syst.*, vol. 14, pp. 75-81, Feb. 1999.

[2] M. V. Pereira and L.M.V.G. Pinto, "Multi-stage stochastic optimization applied to energy planning," *Math. Prog.*, vol. 52, pp. 359-375, 1991.

[3] S. de la Torre, J. M. Arroyo, A. J. Conejo and C. Contreras, "Price maker self-scheduling in a pool-based electricity market a mixed-integer LP approach," *IEEE Trans. Power Syst.*, vol. 17, pp. 1037-1042, Nov. 2002.

[4] Regulatory Authority for Energy, "The Greek Grid and Exchange Code", [Online]. Available: http://www.rae.gr/en/codes/main.htm.

[5] S. Roy, "Introduction of independent players in a centrally planned market: Decision support by long-term production costing," *IEEE Trans. Syst. Man Cybern. Part C Appl. Rev.,* vol. 34, pp. 245-256, Aug. 2004.

[6] M. Bonacina, F. Gulli, "Electricity pricing under "carbon emissions trading": A dominant firm with competitive fringe model," *Energy Policy*, vol. 35, pp. 4200-4220, 2007.

[7] R. S. Khemani and D. M. Shapiro, "Glossary of industrial organization economics and competition law," 1993, commissioned by the Directorate for Financial, Fiscal and Enterprise Affairs, OECD. [Online]. Available: http://www.oecd.org/dataoecd/8/61/2376087.pdf.

[8] J. Reneses, E. Centeno, "Impact of the Kyoto Protocol on the Iberian Electricity Market: A scenario analysis," *Energy Policy*, vol. 36, pp. 2376-2384, 2008.

[9] Hellenic Transmission System Operator, "Transmission System Development Study". [Online]. Available: http://www.desmie.gr/-up/files/MAΣMC2008_2012.pdf (in Greek)

[10] International Energy Agency, "CO2 emissions from fuel combustion 1971-2000", Paris, 2002.

VII. Biographies

Costas G. Baslis received the Dipl. Electr. Eng. Degree from the Department of Electrical Engineering, Aristotle University of Thessaloniki, Greece, in 2003. He is currently a Ph.D. candidate with the same university. His research interests are in power system operation and planning.

Anastasios G. Bakirtzis (S'77-M'79-SM'95) received the Dipl. Eng. Degree from the Department of Electrical Engineering, National Technical University, Athens, Greece, in 1979 and the M.S.E.E. and Ph.D. degrees from Georgia Institute of Technology, Atlanta, in 1981 and 1984, respectively. Since 1986 he has been with the Electrical Engineering Department, Aristotle University of Thessaloniki, Greece, where he is currently a Professor. His research interests are in power system operation, planning and economics.

TABLE VI
FORWARD CONTRACT SCENARIOS

Scenario	Contract Volume (% of hourly Load Demand)
1	80
2	95

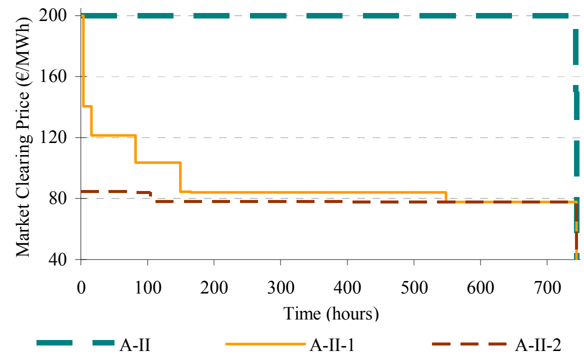

Figure 4. Monthly price duration curves with contracts (October)

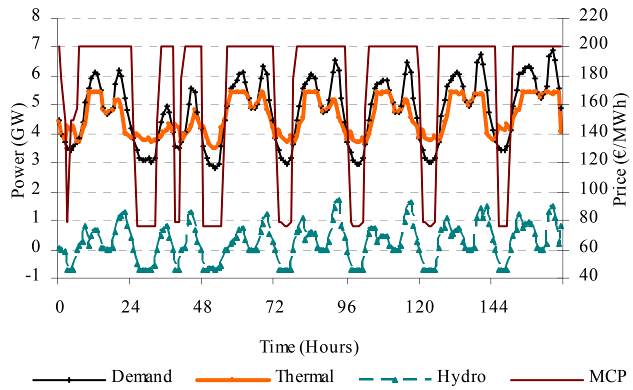

Figure 5. Weekly power system operation

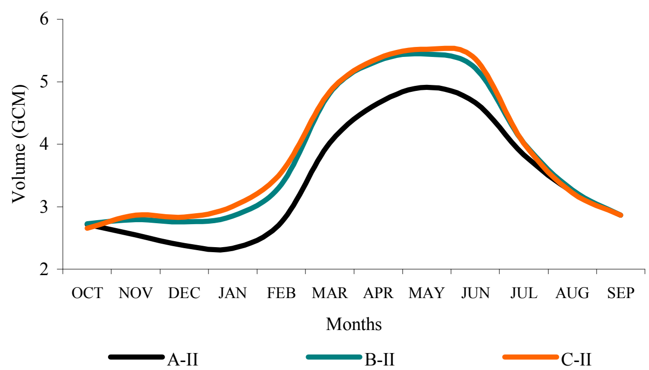

Figure 6. Total stored water volume