# Evaluating the New Greek Electricity Market Rules

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# Evaluating the New Greek Electricity Market Rules

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***Abstract*-- The Greek Regulatory Authority for Energy (RAE), in view of the initiation of the new wholesale electricity market on January 1st 2009 as a Day-Ahead mandatory pool, undertook the design and implementation of a simulator for the market. The simulator consists of several interacting modules representing all key market operations and dynamics including day-ahead scheduling, natural gas system constraints, unplanned variability of loads and available capacity driven either by uncertain stochastic outcomes or deliberate participant schedule deviations, real time dispatch, and financial settlement of day ahead and real-time schedule differences. The modules are integrated into one software package. The intended use of the simulator is to elaborate on and allow RAE to investigate the impact of participant decision strategies on market outcomes. The ultimate purpose is to evaluate the effectiveness of Market Rules, whether existing or contemplated, in providing incentives for competitive behaviour and in discouraging gaming and market manipulation.**

**In this paper the simulator is used to analyze market design aspects and rules concerning the co-optimization of energy and reserves in the Day-Ahead energy market and the efficiency of the imbalance settlement procedure compared to real-time pricing.**

***Index Terms*-- Electricity Market Design, Market Simulation, Regulation, Unit Commitment.**

## I. Introduction

THE development of a liberalized electricity market in Greece began with the enactment of Law 2773/1999 [1], harmonizing the national legislation with Directive 96/92/EC. The Law established new entities within the electricity sector in Greece, including the Regulatory Authority for Energy (RAE) and the Hellenic Transmission System Operator (HTSO), as well as gave general directions for the creation of a competitive electricity market. The initial market design of year 2001 (based on bilateral transactions and actually being a market for deviations) was not considered successful, at least in terms of opening the market to new players, given the existence of the incumbent utility (Public Power Corporation - PPC), with a market share over 99% both in generation and supply. Thus, a subsequent law (L 3175/2003) and a new Grid and Market Operation Code (2005) provided for a new market design of the day-ahead wholesale market, in the form of a mandatory pool [2],[3].

In order to evaluate the new electricity market design as well as to develop and analyze potential ways in which the market may evolve, RAE contracted an external consultant (LCG Consulting) to develop a software model (a ´Simulator´) of the Greek wholesale electricity market.

This paper describes both the Simulator as well as results of initial work performed using the Simulator to study specific rules of the Greek wholesale electricity market. Section II describes the basic concepts of the Greek wholesale electricity market, Section III presents an overview of the Simulator, Section IV presents the study case on co-optimization of energy and reserves in the Day-Ahead energy market, while Section V presents the study case on comparison of the imbalance settlement procedure to real-time pricing. Section VI summarises the results and presents some next steps regarding the applications of the Simulator.

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## II. The Greek Wholesale Electricity Market

### A. Market Structure

Generation on the Greek interconnected electricity system is based mainly on lignite steam units, but also on significant hydro capacity which contributes about 10% of total demand. In 31.12.2008 the total maximum net generation capacity on the interconnected system was 11,871 MW, distributed as shown in Table I.

TABLE I.
INSTALLED GENERATION CAPACITY

| Plant type | Net capacity (MW) |
|---|---|
| Lignite units | 4,808.1 |
| CCGT (n.gas) | 1,962.1 |
| Natural gas - other | 486.8 |
| Oil units | 718 |
| Lake Hydro units | 3,016.5 |
| RES and small cogeneration | 769.7 |
| Other cogeneration | 109.7 |

As far as the market structure is concerned, the national integrated electricity company, PPC, owns about 95% of the installed capacity of 'dispatchable' units (lignite, natural gas, oil and large-hydro). Two competitors hold the remaining about 5% with two natural gas fired units (390MW CCGT and 150 MW open cycle GT). Considering the RES units (wind, photovoltaic, small hydro, biomass, etc) and small co-generation not owned by PPC, then PPC´s market share in terms of installed capacity amounts to around 90%.

### *B. The Greek wholesale electricity market*

The Greek wholesale electricity market consists of:

1) The Day Ahead (DA) market, where the scheduling and clearing of the total energy produced and consumed in Greece, as well as imports and exports, takes place ('mandatory' pool).
2) The Real Time Dispatch operation.
3) The Imbalances Settlement, which includes the settlement of deviations from the DA program and the settlement of the services required for the balancing of the system.
4) The Capacity Assurance Mechanism, through which part of the fixed costs of the production capacity are covered[1].

All transactions are made via the Day-Ahead market (pool), which does not include bilateral transactions with physical delivery and respective contracts between producers, suppliers and customers. However, bilateral financial contracts may be freely concluded outside the Pool.

*1) The Day-Ahead (DA) Market:* The DA market constitutes the first stage of the wholesale market process and comprises of the following individual markets, which are co-optimized:

- Energy Market
- Energy Reserves Market
- Market mechanism for the allocation of the production near the consumption centers

On a daily basis, participants in the Energy Market submit offers (bids) for energy generation (demand) in the form of a 10-step stepwise increasing (decreasing) function of prices (Euro/MWh) and quantities (MWh) for each of the 24 hour periods of the next day. Generators also submit offers for the Reserves Market, as a single pair of price (Euro/MW) and quantity (MW) for each reserve category (Primary & Secondary reserve).

After the gate closure (at 12.30 pm), the HTSO, in its role of Market Operator, solves the DA problem based on the bids and offers of the participants. More specifically, the problem is formulated as a Security Constrained Unit Commitment, maximizing the social welfare for all 24 hours of the next day simultaneously. The algorithm matches the hourly energy to be absorbed (according to the Load Declarations) with the energy to be injected in the System (based on the Injection Offers, separate for each unit), while meeting a set of constraints. The main constraints considered are transmission system constraints (mainly in the form of North to South maximum transfer of power), technical constraints of the generating units and the reserve requirements. The solution of the DA problem (formulated as a Mixed Integer Program) determines for each Dispatch Period (i.e. each hour) of the Dispatch Day the state (ON/OFF) of generation units, generation of each unit and also the clearing prices of the Energy (System Marginal Price - SMP) and Reserve Markets.

The incorporation in the DA problem of the reserve requirements and of the transmission system constraints minimizes the deviations of the DA Schedule from the real time operation of the generation units and therefore reduces the volume of Imbalances Settlement transactions.

The resulting hourly SMP of the DA energy market is the uniform price at which the Load Representatives buy the energy they expect their customers will absorb from the System and at the same time is the price paid to the Producers. In most cases the SMP takes a single price for all the Producers, independently of their geographical position. However, if the Transmission System Constraints are activated, this will result in two different Marginal Prices for generation, for the North and South System respectively[2]. The differentiation of the SMP for the Producers reflects the zonal value of electricity and provides the necessary economic signals to the Producers for the construction of their units in sites where their value to the System is higher, so as to remove the existing constraints.

All the procedures of DA, including financial settlement of the resulting energy transactions, are concluded within the day that precedes the Dispatch Day (i.e. the day of the physical delivery of energy).

*2) The Real Time Dispatch operation (RTD):* In real-time, i.e. every 5 minutes, the HTSO dispatches generating units already committed by the DA market in order to meet the load and minimise generation costs while ensuring overall system reliability [4]. To this objective, the problem is formulated as a Linear Program, with objective to minimize generation costs subject to constraints for meeting the load (here as load is assumed the load projection for the next 5-min interval), generation units technical constraints, network constraints and reserve requirements. The same as in the DA offers (and bids) are used for the RTD.

*3) Imbalances Settlement:* Differences between (i) the production and consumption quantities, as well as the reserves scheduled in the DA Market and (ii) the corresponding quantities measured according to the actual operation of the System, are settled during the Imbalances Settlement operation. The participants are credited or debited depending whether they had positive or negative deviations from their DA Schedule. Moreover, all instructed deviations of the Producers are paid at least at their variable cost. The imbalances are settled at the ex-post zonal SMP (EPSMP) calculated by solving again the same DA problem as in the day-ahead, but this time using the actual data for the load, RES generation and generation unit availability (ExPIP).

## III. Overview of the Simulator

The Simulator consists of several modules, which can be classified as simulating modules, or auxiliary modules. Simulating modules utilize main computational engines, many of which are used in more than one module. The main Simulator modules are (a more detailed description of the Simulator may be found in [3]):

[1] This mechanism is not part of the Simulator and thus will not be discussed.

[2] The current implementation calls for two zones, however more zones can be supported by the Simulator.

(i) The Day-Ahead Electricity Market Clearing (DAEMC). This module implements a MIP algorithm that determines the optimal schedule of generation, demand and reserves of the DA market.
(ii) A module that runs a Load Flow (LF) of the Greek transmission system. The LF module is used to identify the weak points in the transmission system, likely to impose constraints on the ability to transfer power between different zones. It converts this information to input needed for constraint specification in the DAEMC problem. The module provides estimates of inter-zonal power transfer limits in order to specify transmission constraints needed as input to the DAEMC software module.
(iii) A module that solves the five minute Economic Dispatch (ED) problem using look-ahead information from the DAEMC problem solution. The ED module is used to simulate the real-time operation of the Greek electricity system. It operates on a five-minute basis and it is very consistent with the economic dispatch optimization algorithm used by the HTSO. In order to dispatch generation units while respecting transmission constraints, a Power Flow algorithm is incorporated in the ED module. A crucial difference between the ED and the DAEMC, is that the ED module does not perform any unit commitment i.e. it is not required to make any decisions regarding start-up or shut-down. Rather, it follows the existing commitment schedule, unless a significant event has taken place leading to a re-commitment.
(iv) Another functionality of the ED module is to capture variations in the input data that mimic the variations that can be attributed to uncertainty in the real world. These variations are generated by an auxiliary module, the Volatility Module. The purpose of the volatility module is to add a real-time dimension to a scenario by automatically generating deviations between the Day Ahead and the Real Time input data.
(v) A module that compares the DAEMC hourly schedule to the corresponding outcome of the ED and performs the Financial Settlement of Differences (FSoD) according to the market rules. The FSoD module is used to perform the necessary calculations regarding the energy deviations settled during the Imbalances Settlement. It is the settlement module of the Simulator and its principle task is to perform the credit and charge calculations exactly as they appear in the Grid and Market Operation Code.
(vi) the Ex Post Imbalance Pricing (ExPIP) process, which is a 24-hr unit commitment application executed after each Dispatch Day to determine the Ex Post System Marginal Price (EPSMP) for imbalance energy, which is used for settlement of imbalances. ExPIP is very similar to DAEMC, but it takes into account the actual hourly demand, actual unit availability and actual generation by intermittent renewable energy sources.

Further, some special functionality has been added and integrated in the Simulator, in the sense of providing even more realism to the operations simulated.
These features are:

- *Demand priority queue logic*: This logic is used to ensure that demand bid queue will be preserved, even in the event of a market split. Demand bids will be cleared in competitive order, regardless of the zone in which they were bid. This logic was necessary since load bids are cleared to the uniform average price, while production bids are cleared to their respective zonal prices.
- *Uninstructed deviations logic*: Uninstructed deviations logic aims to capture the effects when generators do not follow instructions and dispatch orders issued by TSO in real time. While the HTSO follows a specific procedure for flagging these units and then performs the economic dispatch without considering them thereafter, this procedure is based on the experience and logic of the dispatcher and not on some pre-specified procedure on some operations manual. Thus the aim of the uninstructed deviations logic is to lead to a simulated operation very close to the 'real-life' one, in the case of uninstructed deviations.
- *Recommitment logic*: A special logic controlled within the ED execution, which is used to simulate decisions taken in real time regarding alternation of unit commitment and production schedule, when system conditions and sources availability vary greatly from those predicted in the day-ahead.

## IV. ENERGY-RESERVE CO-OPTIMIZATION STUDY

### *A. Introduction*

The purpose of this study is to analyze the effect of the Energy and Reserve co-optimization in the DA and examine the pricing rule for reserves. Currently, while energy is paid according to marginal pricing, primary and secondary reserves are paid according to the highest respective offer accepted in the DA and tertiary reserve is not paid at all[3]. Alternatively, the marginal pricing rule could also hold for the reserves.

When there is abundant available generating capacity, the energy and reserve commodities are decoupled and the marginal prices are equal to the highest respective accepted offer prices[4]. Under these conditions, generating units may provide several of these commodities and still have some spare capacity. The existence of spare generating capacity nullifies the opportunity cost of providing reserves since it does not come at the expense of energy production. Therefore, under spare capacity, the two pricing rules are equivalent.

On the other hand, when generating capacity is limited, this equivalence does not hold any more. Consider for example a 0-100MW unit with a low Energy Offer (equal to its variable cost) of 20 €/MWh and a Reserve Offer of 2 €/MWh. If the SMP clears at 30 €/MWh in a given Dispatch Period, this unit is infra-marginal for Energy profiting €10 for each MW schedule. Ignoring reserves, the optimal schedule for this unit would be 100MW, i.e., full load. Assume now that this is the only unit that can provide the specified Reserve and that the Reserve requirement is 10MW. The optimal solution would be to back down this unit to 90MW so that it can provide the required Reserve. Assume also that the SMP remains at 30 €/MWh. The net cost to the unit for providing each MW of the Reserve is its Reserve Offer price of €2 plus the foregone

[3] Energy produced during real-time operation by units selected for providing reserves is paid according to the imbalance settlement rules.
[4] Assuming no transmission congestion.

profit of €10 for not producing Energy out of that capacity. Therefore, the marginal cost of providing the next increment of Reserve from this unit is its Reserve Offer price of €2 plus the lost opportunity cost of €10, for a total of 12 €/MW. Consequently, due to opportunity costs, the marginal price for a given reserve may exceed the highest accepted price for that reserve. Even if a certain reserve, such as tertiary reserve, is priced at zero, i.e., all tertiary Reserve Offers are at zero price, the marginal price for tertiary reserve may not necessarily be zero.

### *B. Data Setup*

The market data for Tuesday, July 22, 2008 are used (found in [2]), which can be considered a typical summer day. This day was selected as a peak load case, where the available thermal units' capacity cannot meet energy demand and reserve requirements, hence dispatching hydro units is necessary. In general, year 2008 was a dry year, which implies a rather high value for the hydro units' offers. More specifically, the energy offers of the hydro units are assumed to be priced at €125/MWh, which is higher than the highest thermal unit energy offer, assumed equal to their variable cost[5]. This bidding strategy ensures that hydro units, although fully available to provide reserves, are scheduled for energy only after all available online thermal unit capacity is fully scheduled; this bidding strategy is consistent with dry year conditions where water needs to be preserved. For simplicity, generating units submitted the same reserve offers: Primary Reserve Offers were priced at 2 €/MW, Secondary Reserve Offers were priced at 1 €/MW, and Tertiary Spinning and Non-Spinning Reserve Offers were priced at 0 €/MW.

### *C. Energy-Reserve Co-Optimization*

The results of the simulation show that hydro units are on the margin for energy for the most part of the day, setting the SMP to 127.68 €/MWh, which is the (loss-adjusted) hydro Energy Offer price. Although the Primary Reserve Offer price was only 2 €/MW, the Primary Reserve marginal price ranged between 2 €/MW to 40.43 €/MW. The difference between the marginal price and the bid price is due to the relevant opportunity cost for providing Primary Reserve. Similar results were obtained for Secondary Reserve Up and Down, whose prices ranged between 1 €/MW to 1.87 €/MW and 1 €/MW to 61.72 €/MW, respectively. The marginal prices are presented in Fig.1.

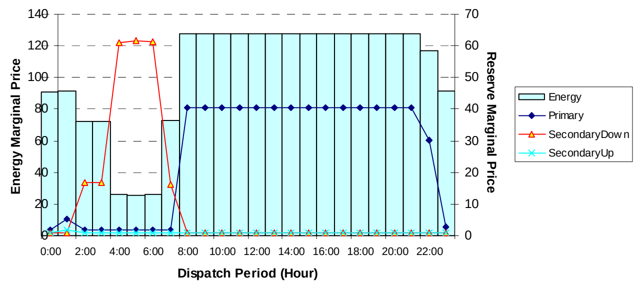


*Fig.1. Energy and Reserve Marginal Prices.*

As discussed above, the opportunity cost for providing either Primary or Secondary Up Reserves, in this example, becomes nonzero when the unit called for the reserve is infra-marginal. Primary Reserve is offered only by the thermal units. Therefore, during the peak hours of the day, when hydro units are marginal and thermal units infra-marginal, the least-cost dispatch is achieved by the provision of Primary Reserve from the committed units with the most expensive energy offers[6]. Then, the Primary Energy Requirement will be satisfied by first exhausting the Primary Reserve capability of the most expensive unit, then proceed to the second most expensive, etc until the Requirement is satisfied. The last unit, in the above sequence, to provide this Reserve will also define the marginal price, equal to its offer price plus its opportunity cost. Similarly for Secondary Reserve Down, during the off-peak hours of the day, when lignite units are marginal (but without the capability to provide Secondary Reserve), thermal CCGT units are dispatched. In this case the units will be dispatched starting from the ones with the lowest energy offers.

The opportunity costs for Secondary Reserve Up and Tertiary Spinning Reserve were almost always zero. The situation would be different if hydro energy bids were lower than thermal energy bids; in that case, hydro units would be infra-marginal in energy, hence reserve provision would demand high opportunity costs.

To illustrate the effects of Energy-Reserve co-optimization, Fig.2 and Fig.3 display the allocation of the capacity of a CCGT and a hydro unit among energy and reserves.

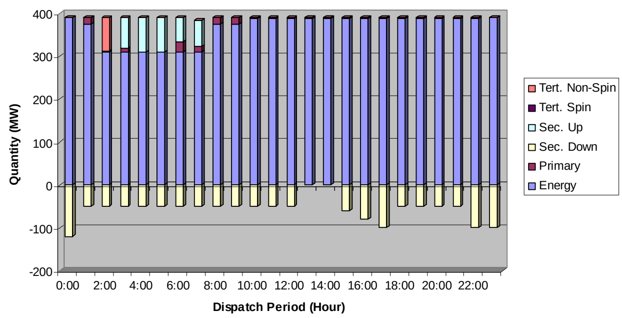


*Fig.2. Energy and Reserve Schedule of a CCGT Unit.*

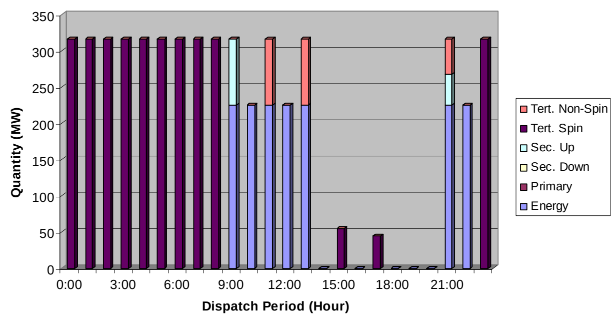


*Fig.3. Energy and Reserve Schedule of a Hydro Unit.*

From the above analysis it is evident that the current reserve pricing scheme underpays Producers for providing Reserves. Opportunity costs cannot be denied to Participants; they will eventually capture them, but at the cost of imposing risks in

[5] The exact level of offer prices is not important for our results.

[6] Since, in our example, all units make the same Reserve offers.

market participation and providing incentives against cost reflective bidding.

The conclusions from this study are as follows:

1. The remuneration price of reserves should not be the highest accepted Reserve Offer, because that may be an insufficient price.
2. A separate settlement should apply to Secondary Reserve Up and Secondary Reserve Down, since these two services have in general different marginal prices.
3. Tertiary Reserve schedules should be remunerated at the relevant marginal price and Tertiary Reserve Offers should be permitted.

## V. Real-Time Pricing Study

### A. Introduction

This study compares the existing imbalance settlement mechanism, based on the hourly Ex-Post System Marginal Price (EPSMP), determined by the Ex Post Imbalance Pricing (ExPIP) process, with a real-time deviation settlement using the 5-min System Imbalance Marginal Price (SIMP) determined by ED.

### B. Data Setup

The analysis was performed for an average demand case, in order to allow for significant price changes in real time due to load deviations. Therefore we used the market data for Sunday, February 17, 2008, which can be considered a typical winter weekend day [2]. We assumed that the actual demand was about 5% higher than the demand forecast used in the DAEMC, due to demand under-scheduling and demand forecast error. The demand deviation was met in real time by ED using tertiary reserve procured by DAEMC and other available capacity from online units or offline hydro units that have a fast-start capability.

The actual demand was created by using the Volatility module of the Simulator. This was done by taking the original hourly demand forecast used in DAEMC and generating from it 5-minute demand values using a quadratic interpolation method. The quadratic interpolation was assumed to have an interpolation error which followed a normal distribution function, with a mean of 1.05 and a standard deviation of 0.001[7]. The resulting 5-min simulated actual demand that was used in ED is presented in Fig. 4.

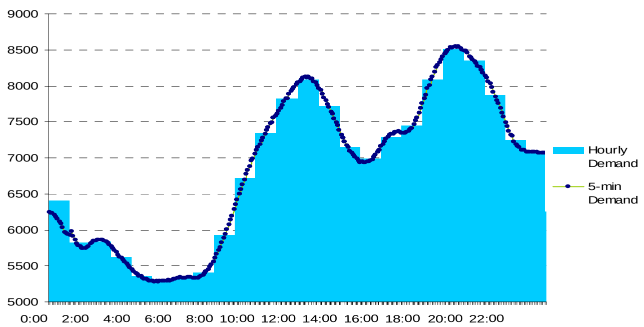


*Fig.4. Simulated 5-minute Demand Curve.*

On the day we are investigating, three lignite units and a natural gas unit, with a total capacity of almost 1000 MW, weren't operating, due to maintenance and outage reasons. As this would stress our case and wouldn't illustrate the differences between EPSMP and SIMP, we have assumed that two of the three lignite units were actually operational. Still most of the thermal units operate at full capacity during most of the peak hours. Finally, we used the same bids as in the previous study.

### C. Comparison of Real-Time Pricing Alternatives

The two settlement methods described above, based on EPSMP and SIMP, are compared. To simplify the analysis and isolate the effects of real-time volatility, it is assumed that no uninstructed deviations take place, so that the metered energy production matches the instructed energy production. Then the imbalances' cost is determined as the product of the imbalance quantity with the corresponding price. The imbalance is defined as the difference between the day-ahead schedule and the 5-min dispatch instructions from ED. A positive outcome is a charge, whereas a negative outcome is a payment. Under the previously mentioned simplification, the two methods of imbalance settlement differ only on the calculation period, being hourly for EPSMP and 5-min for SIMP. The hourly imbalances are equal to the average of the twelve 5-min imbalances during the hour.

The 5-min SIMP from ED and the hourly EPSMP from ExPIP are displayed in Fig.5. It is demonstrated that the hourly EPSMP fails to capture the volatility of the real-time market, which is evident in the 5-min variation of the SIMP. The differences manifest mostly:

a. During the sharp ramp up and down periods of the Dispatch Day. This is mainly due to the fact that the ramping limitations of the units constrain the 5-min ED problem more than the hourly ExPIP problem.
b. During hours 16:30 to 18:00 and 22:00 to 00:00. Here, the reason is that ED takes the commitment of the DAEMC as given, while ExPIP assumes recommitment is possible. In our study, the DAEMC solution decommited a large natural gas unit, replacing it with a smaller one, set to begin operation at 18:00. ED took this timing as given, while ExPIP shifted it.

Note that the above differences are exaggerated in Fig. 5, as the marginal price switches between lignite or natural gas unit bids to hydro unit bids, since hydro units provide the additional capacity required, due to their fast-start capability.

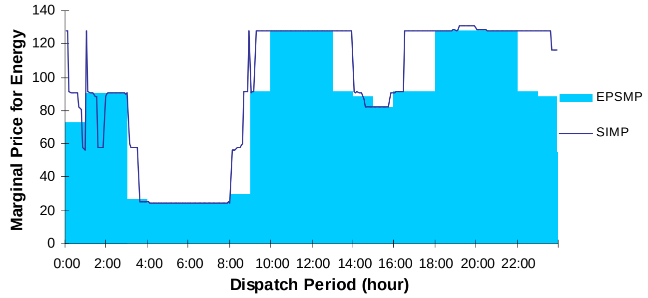


*Fig.5. Marginal Prices for ExPIP and ED.*

[7] Specifically for the first hour the mean error was assumed equal to 1 (i.e. no shifting), in order to avoid infeasibilities related to the initial conditions.

It is interesting to note that by running again the ED, but assuming also a recommitment at 12:00, the differences in SIMP and EPSMP decrease significantly, as seen in Fig.6.

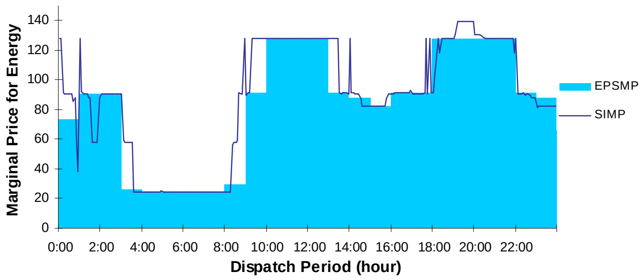


*Fig.6. Marginal Prices for ExPIP and ED, under ED with recommitment.*

The hourly ED and ExPIP net generator imbalance payments are illustrated in Fig. 7, for the ED run without recommitment. Note that the net generator imbalance settlement in each Dispatch Period was negative, i.e., it was a payment, due to the 5% demand increase in real time. The total cost of imbalances amounted to 700,000 € in the case of ExPIP and to 800,000 € in the case of ED, when the value of energy traded in the DA was 23,5 mil. €. More than half (about 55%) of this payment was made to hydro units, as they were dispatched to meet the load deviations from one 5-min interval to the next.

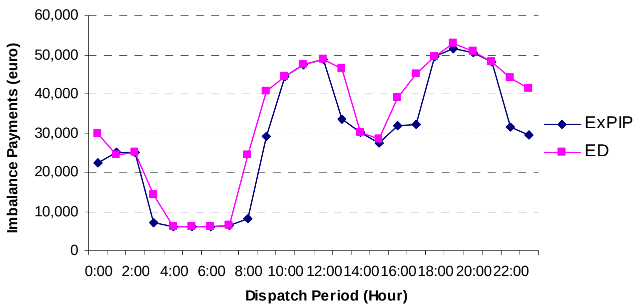


*Fig.7. ED and ExPIP net generator imbalance payments.*

The conclusions from this study are as follows:

1. The hourly EPSMP, determined from ExPIP, does not capture the volatility of the 5-min SIMP, determined from ED.
2. Since the 5-min dispatch instructions, and thus the resultant instructed imbalance energy, are the outcome of ED, the 5-min SIMP is the marginal price that corresponds to these instructions, and not EPSMP.
3. The imbalance settlement using the EPSMP results in lower payments to Producers than using the 5-min SIMP. Hydro units are most affected by this shortfall, as they are dispatched to meet the 5-min load deviations that are not reflected in the flat hourly load of ExPIP, particularly during the sharp ramp up and down periods of a day.

## VI. Conclusions

In order to analyze the electricity market design, RAE developed a ´Simulator´ of the Greek wholesale market. The Simulator is used to analyze current rules concerning: (a) the co-optimization of energy and reserves in the DA energy market, and (b) the efficiency of the imbalance settlement procedure compared to real-time pricing. Results from the first case study show that the current rule concerning the price of reserves (equal to the highest accepted Reserve Offer) should be re-considered since, when the energy and reserve commodities are coupled, Producers are underpaid for providing Reserves. Results from the second case study show that the imbalance settlement using hourly step (as in the EPSMP module) results in lower payments to Producers than using a 5-min step (as in SIMP). Hydro units are most affected by this shortfall, as they are dispatched to meet the 5-min load deviations that are not reflected in the flat hourly load of the hourly commitment schedule (ExPIP module), particularly during the sharp ramp up and down periods of a day.

## Disclaimer



## VII. References

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## VIII. Biographies

**Kostis Sakellaris** (b. 1977) received his undergraduate degree in Mathematics from the University of Athens, Greece (1998) and his MSc degree in Mathematical Finance from the University of British Columbia, Canada (2000). He is working as an electricity market expert in the Markets and Competition Department of the Greek Regulatory Authority for Energy since 2004. He is also a Ph.D. candidate in the Economics Department of the Athens University of Economics and Business. His topics of research include industrial organization, capacity constrained competition, market design, electricity market modeling and simulation.

**Dr. Kostis G. Perrakis** (b. 1957) holds an E.E. degree (1981) and a Doctor of Engineering degree from NTUA and a Master's degree in Electric Power Engineering from the RPI, N.Y., USA (1982). He has worked with the Public Power Corporation, the Center of Renewable Energy Sources and the Hellenic Transmission System Operator. Currently is responsible for Transmission System unit at the Regulatory Authority for Energy. His topics of interest include optimal operation of electric power systems, costing of transmission services, as well as integration of renewable energy into the energy systems.

**Dr. George A. Angelidis** was born in Athens, Greece, in 1962. He received his B.Sc. degree from the Aristotle University of Thessaloniki in 1984, and his M.A.Sc. and Ph.D. degrees from the University of Toronto in 1988 and 1992, respectively, all in Electrical Engineering. He worked for four years for PG&E Company in San Francisco as a Principal Market Analyst on issues related to the California Electricity Industry Restructuring. He is currently an Independent Consultant working for the Project Management Office of the California Independent System Operator where he is involved heavily in the design and implementation of many aspects of the California Electricity market. His research interests and expertise are in electricity market design and advanced computer applications in large-scale electric power systems, with emphasis on steady-state and dynamic analysis and optimization. Dr. Angelidis is a member of IEEE and the Technical Chamber of Greece.