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Investigating the Impact of the Greek Electricity Market Reforms on its Day-Ahead Market Prices

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***Abstract*— This empirical study assesses the impact of specific regulatory policy measures, adopted in the Greek wholesale electricity market during the period 2004-2011, on the Day-Ahead Market Price. We consider an ARMA-GARCH model extended to include dummies and other exogenous variables that affect market prices, such as RES and Hydro electricity production, as well as load volumes and Brent crude oil prices. In order to analyse the impact of the regulatory reforms on price and volatility dynamics, we include regime dummy variables, reflecting the timeline of these reforms. Based on the results, we discuss the impact of the examined reforms and their significance**.

***Index Terms*--Electricity Market, Greek Wholesale Market, Regulatory Reform, Day-Ahead Price, GARCH**

I. Introduction

During the last thirty years we have witnessed significant efforts towards the deregulation of the electricity sector, mainly through the introduction of wholesale electricity markets and the unbundling of the traditional vertically integrated monopolies. The pioneer in electricity sector reform was Chile, commencing its efforts in 1987. Since then, many countries all around the world, from New Zealand to US and from Argentina to the EU member-states, deregulated their markets, following different paths, some proving to be more successful than other.

The differences in the pace and extent of market reforms are mainly related to the starting point of each reform and the problems associated than with the internal environment of the market. This is more evident in Europe, where although a goal for a single market has been set since 1996, when Directive 96/92/EC was adopted, different levels of unbundling and introduction of competition have been implemented across the member-states. In some cases market reforms are slow because of fear for unintended consequences, while in other cases the requirement to move away from the status quo and the need to take difficult decisions with benefits that will be observed only in the long-run seem unappealing to the politicians in charge.

In this context it is crucial to evaluate, in a simple and stylized manner, the results of each deregulation process, relevant reform steps and policy decisions taken. Although this is usually done by examining only the wholesale or retail prices, the peculiarities of the electricity markets and the complexity of the respective wholesale markets call for a multi-dimensional approach, which includes exogenous variables affecting price formation. By removing the effect of these variables on the wholesale price, one can then better assess the impact of each specific policy decision.

This empirical study assesses the impact of specific regulatory policy measures, adopted in the Greek wholesale electricity market during the period 2004-2011, on the Day-Ahead System Market Price (SMP). For this purpose we consider an ARMA-GARCH model, extended to include seasonal dummies and other exogenous variables that play a crucial role in the price formation, such as must-take renewable energy sources (RES) production, must-run hydro plant production, Brent crude oil prices and load volumes. This way we disentangle the SMP from components that systematically affect it and proceed to analyze the impact of regulatory reforms on price and volatility dynamics by including regime dummy variables, which are created based on the timeline of these reforms, as presented in Fig.1.

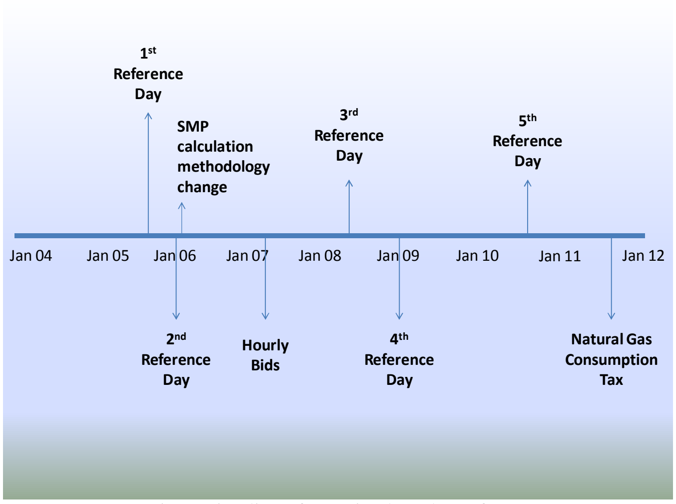

Fig.1. Timeline of examined market reforms

This paper contributes to three different strands of literature. The first one examines the impact of market reforms on electricity prices. In general, empirical research has focused on retail prices, through the analysis of cross-country panel data [1]-[4], [3] including a detailed survey of the relevant literature. On the other hand there is a lack of relevant econometric analyses on wholesale prices. The existing studies mainly focus on the UK market and especially on the question whether the replacement of the UK Pool market mechanism by NETA was beneficial [5]-[7]. By constructing a general regression model, the authors find that the drop observed in the UK wholesale prices can be explained by the changes in market structure [5], the changes in market rules [7], or both [6]. The only other study we are aware of is [10], assessing the impact of market reforms on the Italian electricity spot price. The authors, following a similar methodology to the one in this paper, show that changes in the electricity industry architecture have affected both the wholesale price level and its volatility.

The second related strand of literature deals with electricity price models that include fundamental factors. These factors usually concern demand and fuel prices [8]-[12], as well as market design changes [13]-[14]. As indicated in [15], models with an extensive set of factors have more efficient estimates.

Finally, the present paper is the second, to our knowledge, to study the Greek electricity spot price, following [16], where, by applying a variety of econometric models, the authors find that the GARCH model has the best estimation and forecasting ability. In addition, by splitting the examined period into two sub-periods, before and after a specific market reform (RAE's Decision dated 13.01.2006 discussed below), and by comparing their estimation outputs for the two periods, the authors find that the explanatory power of their model is greater in the first period than the second, concluding that the regulatory framework change has a significant impact on the explanatory and forecasting power of the models.

In the rest of the paper, Section II describes the Greek Wholesale Electricity Market, the various reforms that were implemented, and the structure of the market, while Section III discusses the data used for this study and their summary statistics. Section IV presents the econometric model applied and the results of the respective analysis. Based on the results, we discuss the impact of the examined market reforms and their significance in the concluding Section.

II. The Greek Wholesale Electricity Market

A. *Market Reforms – Past and Present*

The liberalization of the Greek Electricity Market began with the adoption of Law 2773/1999. Prior to that, it was a pure monopolistic market, with PPC, the vertically integrated public company, being the single supplier and retailer, as well as the sole owner and operator of the grids.

At the beginning of the market liberalization, base-load electricity was mainly produced by lignite plants, with natural gas and oil plants acting as mid-merit order units and hydro plants acting as peakers. Hydro units were also providing, almost exclusively, the ancillary services. On the retail market, electricity tariffs were characterized by artificially low prices and cross-subsidies between various customer categories.

The market opening efforts can be divided into three phases: (a) 2000 – 2005, (b) 2005 – 2010 and (c) 2010 – present. Below we present a synopsis of these reforms, while for more details we refer the interested reader to [17]-[20].

(a) First Phase. The initial plan was to open the wholesale and retail markets simultaneously. A bilateral market was foreseen, where the suppliers were required to own generating capacity in EU, equivalent to their customers' consumption. The dispatching of the units was performed centrally by the Hellenic Transmission System Operator (HTSO) according to the economic merit order of the units, based on their short-run marginal cost declarations. The new generation units were expected to cover their fuel costs from the daily market, while their capital cost would be recovered by signing bilateral contracts with suppliers or self-supplied customers. The new retailers would have access to the same fuel mix as PPC through the central dispatch procedure, independently whether their units were dispatched or not. Under these arrangements, the wholesale market was very closely linked with the retail market. In practice though, this was the main weakness of this design, as the artificially low retail prices, along with the dominant position the incumbent electricity utility (PPC), sole owner of lignite and hydro plants, and the fact that the independent power producers (IPPs) could only enter the market by building "expensive" natural gas plants (compared to the cost of lignite and hydro plants), prevented any firm, either supplier or retailer, to enter the market, as it was impossible for them to recover their costs from the tariffs and compete with PPC.

(b) Second Phase. Substantial amendments aiming at the enhancement of market opening and competition in the electricity sector were foreseen in Laws 3175/2003 and 3426/2005. The main restrictions of cost-based dispatch and generation capacity ownership for suppliers were dropped and a pure mandatory pool model was adopted. The focus this time was mainly placed at the wholesale market and the attraction of new investments in generation capacity. To this end, a capacity obligations mechanism was foreseen, through which part of the fixed costs of the electricity generation would be recovered. At the same time measures were taken for the gradual improvement of the retail market and the development of competition, such as the unbundling of PPC accounts and the removal of various retail market distortions.

As the new market model envisaged a series of changes to the initial model, a Transitional Period was foreseen, originally planned to last 2 years and 3 months, but in practice was expanded to 5 years (from October 2005 to September 2010). During this Transitional Period, a series of market reforms foreseen were introduced at five "Reference Days". These reforms gradually transformed the cost-based centralized dispatch first to an ex-post (offer-based) mandatory pool and subsequently to a centralized mandatory day-ahead market with an ex-post imbalance settlement.

(c) Third Phase. In October 2010 the Transitional Period ended and the market moved to the intended market design. In brief, the current Greek Electricity Market design consists of the following markets/mechanisms:

1. Day-Ahead Market
2. Ancillary Services Market
3. Imbalance Settlement Mechanism
4. Cost Recovery Mechanism
5. Capacity Adequacy Mechanism

6. Explicit Auctions for Interconnection Capacity Rights

Note that the duration of two mechanisms from the Transitional Phase, the Cost Recovery Mechanism and the Transitional Capacity Adequacy Mechanism, which greatly attributed to the construction of a number of new CCGTs, was extended for two more years, as it was decided that the market wasn't mature enough for their removal.

B. *Structure of the Market*

Although until recently the Greek electricity system was dominated by lignite units, amounting to almost half of total net generation capacity, the significant investments by independent power producers (IPPs) in natural gas units and renewable energy sources (RES) the last few years evened out the generation fuel mix. Table I summarizes the net generation capacity data for Greece in the last decade, while more detailed information can be found in [20] and [21].

TABLE I. INSTALLED CAPACITY IN GREECE

Plant type	**Net capacity (MW)** *(at the end of each respective year)*		
	2011	**2007**	**2004**
Lignite units	4496	4808	4808
CCGT (n.gas)	3526	1962	1572
OCGT (n.gas)	487	487	487
Oil units	698	718	718
Lake Hydro units	3017	3017	3017
RES and small cogeneration	2141	880	345
Total	**14.365**	**11.872**	**10.947**

The market was fully dominated by PPC until 2004. As RAE didn't approve new generation licenses for PPC, in order to offer the opportunity to new generation companies to enter the market, concerns were raised by HTSO on the basis of security of supply. Thus, a tender was conducted for the provision of ancillary services by new generating units, which lead to the entrance of the first IPP (HERON) in 2004 with an open cycle natural gas fired 148 MW (OCGT) unit. In the end of 2005, right before the launching of the new pool, ENTHES – at the time a state controlled company – became the second IPP operating a combined cycle natural gas fired 390 MW (CCGT) unit.

During the period 2005 to 2009, PPC owned about 95% of the installed capacity of 'dispatchable' units (lignite, natural gas, oil and large-hydro). Apart from the two IPPs, there was also some limited competition from importers, both at the wholesale level and at the retail level. The competition at the retail level lasted only for about a year (2005), after which the increase in fuel prices (combined with the existing low tariffs) lead most retailers to withdraw from the market.

After 2009, the improving market conditions, combined with incentives offered to generators through the Transitional Capacity Adequacy and Cost Recovery Mechanisms, as well as the gradual removal of some retail market distortions, led to significant entry of new players. As a result, the wholesale and retail market shares of PPC fell from 90% and 100% in 2009 to approximately 70% and 90% in 2011.

C. *Examined Reforms*

In this paragraph we will highlight a number of dates where important market reforms were implemented and briefly discuss their content and the effect they were expected to have[1] on the SMP. The actual effect of the presented reforms will be discussed in more detail later on, after the relative econometric analysis is performed. A summary of this paragraph is presented in Table II.

As it was mentioned above, during the First Phase of the Greek Electricity Market opening the dispatch was performed based on the marginal-cost of the units. An indicative ex-post price (SMP) was calculated for each hour, equal to the cost of the most expensive unit operating unconstrained during the respective hour. The combination of the specific market structure with the marginal cost based SMP and the low fuel cost during that period, lead to relatively stable and low SMPs for the largest part of the First Phase. These low SMPs weren't considered to reflect the actual value of the produced electricity at each hour, leading to the previously discussed market reforms.

The Second Phase of the market was split into five "Reference Days", with the Fifth Reference Day coinciding with the beginning of the Third Phase of the market.

1st Reference Day (1.10.2005): It marked the beginning of a market-based operation of the system. The System Operator started dispatching units according to an offer based unit commitment. The SMP was calculated the same way as before, only this time it was based on offers instead of costs. As a price floor, equal to the minimum variable cost of each unit, was (and still is) placed to the offers in order to prevent PPC from bidding below cost[2], equal to the minimum variable cost of each unit, in combination with the beginning of commercial operation of ENTHES, the SMP was expected to increase.

2nd Reference Day (1.1.2006)[3]: The only change in the market rules was the introduction of the Transitional Capacity Adequacy Mechanism, in the form of a capacity payment, through which the generation units would be able to recover part of their fixed costs. Thus – if the market was more mature – one would have expected the prices to drop.

RAE Decision (13.1.2006): The complaints by market participants for the artificially low SMPs due to its calculation methodology, along with the practice of the System Operator to operate most units at all times for security reasons, even if

[1] As evident from the arguments supporting the relevant decisions and RAE's comments in the Annual Reports to the EC [20].

[2] The price floor does not apply to the first 30% of the quantity bid. This facilitated the dispatching of units at least at their technical minimum.

[3] This date is presented only for reasons of completeness, as it is not analyzed in our paper due to its small chronological distance with the next and more critical reform.

TABLE II. EXAMINED MARKET REFORMS

Variable	Date of Reform	Reform	Expected effect on wholesale price
MR1	*01.10.2005*	Mandatory pool with ex-post settlement	price increase
MR2	*01.01.2006*	Transitional Capacity Adequacy Mechanism	none
MR3	*13.01.2006*	Changing of SMP calculation methodology	price increase
MR4	*01.04.2007*	Hourly Bids	none (on daily average price)
MR5	*01.05.2008*	Cost Recovery Mechanism	None
MR6	*01.01.2009*	Changing of SMP calculation methodology	price decrease
MR7	*30.09.2010*	Mandatory day ahead market with Imbalance Settlement	price decrease
MR8	*01.09.2011*	Natural Gas Consumption Tax	price increase

that meant having a large number of units operating at their technical minimums, led eventually to the change of the SMP methodology. The new methodology didn't consider any longer the technical minimum constraints of the units, thus it resembled to a pure economic dispatch. Obviously this change was expected to significantly increase the prices.*Code Amendment (1.4.2007):* Up to this date the offers submitted by the generators were daily. This lead to a relatively stable hourly price pattern, as a unit couldn't reflect the daily load pattern on its offers. From 1st of April 2007 the status of the offers changed from daily to hourly, i.e. each generator could submit a different bid for each hour of each trading day, bidding higher during peak hours and lower during off-peak hours. No overall change on the (daily average) SMP was expected.

3rd Reference Day (1.5.2008): The most important reform on the 3rd Reference Day, not foreseen in the original transitional plan but added later on, was the establishment of the "Cost Recovery Mechanism", which was considered necessary until the Imbalances Settlement Mechanism was set (scheduled for the 5th Reference Day). According to this mechanism, if the SMP was lower than a unit's marginal cost (plus 5%), the unit would receive the difference as compensation. No change on the SMP was expected.

4th Reference Day (1.1.2009): The main reform, originally scheduled for the 3rd Reference Day, but postponed because the relevant software was not ready, was a change of the ex-post SMP calculation methodology according to the unit commitment algorithm that would be used on the Third Phase of the market. This algorithm considers all technical constraints of the units and the reserve requirements of the HTSO and is very similar to the one actually used during the dispatch procedure[4]. The inclusion of the technical minimum constraints was expected to lead to lower SMPs.

5th Reference Day (30.9.2010): On the Third Phase of the market the mandatory day-ahead market model was initiated[5], co-optimizing energy and ancillary services under the aforementioned unit commitment algorithm. The clearing of the market was thereon based on the non-priced demand declarations submitted by the retailers, instead of the HTSO's forecast used till then. Moreover the Imbalance Settlement Mechanism was introduced (no separate offers). As the same SMP methodology was retained, with the only change being the submission of demand declarations (where demand is usually under declared), a slight fall to the SMP was expected.

Ministry of Finance Decision (1.9.2011)[6]: The Ministry of Finance introduced an excise duty on natural gas, applied also on the use for electricity production, equal to 1.50 €/GJ. As the marginal units for the majority of trading periods were natural gas fired units, the relevant cost was expected to be increase the SMP.

III. DATA AND SUMMARY STATISTICS

A. *Data*

We used hourly data on SMP, load, RES production (RES) and must-run hydro production (HYDRO), all acquired from the Regulator's database. SMP values are denominated in Euros (€) per megawatt hours (MWh), whereas the other variables are expressed in megawatts (MW) per hour. Additionally, we collected data for the Brent crude oil prices (B), denominated in €/bbl, from Reuters' database. As the data for Brent crude oil prices were available only for the working days (Monday to Friday), we adjusted HTSO's data in the same way, i.e. by excluding weekends[7]. The sample period covers eight years, from January 1st 2004 to November 30th 2011.

Similar to other studies [22]-[23], we generated a new time series by calculating the arithmetic average of the 24

[4] During this phase the market strongly resembled the current (2011) market design of SEM in Ireland.

[5] Thus SMP changed from ex-post to ex-ante.

[6] This reform is included as an example of a reform "outside" the specific context of electricity wholesale markets, which may affect them though significantly.

[7] Alternatively we could include a dummy variable for weekends and use Brent's Friday prices for Saturday and Sunday.

hourly values for each day and then taking the logarithms of the respective values. Furthermore, as the numerical values of average daily load are significantly larger than the SMP ones, possibly affecting numerically our results, we normalized the daily load by dividing all values with the maximum load value observed during the sample period[8]. Finally, since Greek wholesale natural gas prices are based on a formula linking them to the average prices of specific fuel products (Diesel, Heavy Fuel Oil) during the previous three months, we calculated the three-month moving average of Brent prices (MB) and used this series in our analysis, instead.

B. *Summary Statistics*

Table III presents some key descriptive statistics of our dataset with 2043 observations for each time series.

TABLE III. DESCRIPTIVE STATISTICS OF DATA

Statistics	SMP	Load[9]	RES	Hydro	Brent
Mean	54.00	6287.84	136.58	443.62	49.87
Max	117.91	9330.42	686.95	2134.75	130.11
Min	18.48	3927.08	0.83	28.04	18.97
Std. dev.	19.16	725.19	101.74	341.38	26.88
Skew	0.47	0.75	1.32	1.56	1.07
Kurtosis	2.72	3.91	5.26	5.68	3.57
J-B test	83.18	260.18	1031.62	1436.56	420.91
ADF test	-3.47*	-6.90*	-6.67*	-6.22*	-3.51*
Obs	2043	2043	2043	2043	2043

*indicates statistical significance for Prob< 5% .

By examining Table I, a number of interesting findings may be noted. First, consistent with findings from other electricity wholesale markets ([12], [15]) we find that none of our variables are normally distributed, based on Jarque-Bera test. All series are slightly right-skewed (except for some of the logs) with high excess kurtosis (fat tails). Volatility is extremely high, ranging from 11% for the load to 90% for the RES production[10]. The mean SMP is equal to 54 €/MWh, presenting a maximum of 117 €/MWh, observed on 23.06.2011, as a result of the decreasing hydro electricity production, and a minimum 18.48 €/MWh, observed on 09.04.2011, when average daily demand reached one of its lowest levels at 4.384MWh. Although, many studies have found [24]-[25] that electricity prices exhibit seasonal behavior during the year, mainly due to the seasonal behavior of the load, this feature was not observed over the whole sample period.

[8] This is a usual practice, see for example [12]

[9] The load statistics are presented for the average load values, not the normalized ones (ADEM).

[10] A big part of the observed RES volatility is due to their gradual increasing penetration over the examined years.

Finally, the Augmented Dickey-Fuller test (ADF-test) in all cases rejects the null hypothesis that a unit root exists (at the 5% significance level or lower).

IV. ECONOMETRIC ANALYSIS

A. *Model*

As the focus of our investigation is not only the modeling of electricity prices and their volatility, but also the interpretation of the impact of recent wholesale market reforms - as well as other exogenous variables - on them, we implement an ARMAX-GARCH model with exogenous and binary variables as in [10]. More particularly, taking into account the conditions in Greek wholesale electricity market , we claim that electricity prices can be related to either their own past values (ARMA term), as well as to other various exogenous factors, such as RES and must-run Hydro electricity production, the three-month moving average Brent prices and the normalized demand. Therefore, to accurately capture the relationship among prices and other exogenous variables, including the binary variables representing the Greek electricity reforms, an autoregressive moving average model-ARMAX(l,m) written as follows, is used:

$$\Phi(\Delta)\ln S_t = c + \Theta(\mathrm{B})e_t + d\ln X_t + k\sum_{i=1}^{n} MR_i + u_t$$
$$u_t = e_t * \sigma^2 - N(0,\sigma^2) \qquad (1)$$

where l and m are the number of order of autoregressive and moving average term, respectively, S is the natural logarithm of the spot price level, e_t are the random innovations, X_t is the vector of the exogenous variables in logs, Δ is the back shift operator and MR are binary variables that represent market reforms in the Greek electricity market. These binary variables take the value of *0* for the period preceding the market reform, and the value of *1* for the successive period.

Furthermore, taking into account that this model assumes homoskedasticity, which in the case of electricity prices [24] does not hold, we complement our model with the Generalized Autoregressive Conditional Hetorskedastic model in order to successfully address the problem of heteroskedasticity. In this way, the conditional variance is considered time dependent and is represented by a constant term, news about volatility from the previous period, measured as the lag of the squared residual from the mean equation, u^2_{t-i} (the ARCH term), last period's forecast variance, σ^2_{t-j} (the GARCH term), as well as by seasonal dummies used in order to capture the day of the week effect, by dummies representing market reforms and by the set of the exogenous variables, included in the conditional mean equation, as follows:

$$\sigma_t^2 = \omega + \sum_{i=1}^{q} a_i u_{t-i}^2 + \sum_{j=1}^{p} \beta_j \sigma_{t-j}^2 + \gamma X_t + \sum_{i=2}^{5} \delta_i D_i + \varepsilon \sum_{i=1}^{n} MR_i \quad (2)$$

The residuals of the conditional mean equation u_t are assumed to be white noise *N (0,1)*. Note that in order to have a positive definite variance-covariance matrix, the coefficients of ω, α and β must be positive. Moreover, the sum of a and b coefficients must be less than one, otherwise shocks are persistent and the variance-covariance matrix is not stationary.

The described methodology differs from [5]-[7] and [16] in respect of the way the reforms were introduced in the model and the exogenous variables included in the analysis.

B. *Empirical Results*

In this section we present the results of the empirical estimation of equations (1) and (2). Before interpreting the results, we present the identification stage, in which we are attempting to obtain the order of ARMA first, through Box-Jenkings Model stages, and then the order of GARCH and ARCH effects. The Autocorrelation Function Coefficients (AFC) and the Partial AFC (PACF) estimates of the residual of our model indicate that an autoregressive term of order 2, and a moving average term of order 1 should be used. Further, the AFC and PACF estimation of the squared residual of the ARMA specification, suggest that a GARCH(1,1) should be chosen. This choice leads to elimination of both aurocorrelation and heteroskedasticity in our model's residuals, as evident in the derived values for the Ljung-Box statistics. Finally, because the residuals are not normally distributed, as the points in the QQ-plots do not lie alongside with the straight line[11], we used instead the t-student distribution[12].

TABLE IV. MEAN AND VARIANCE EQUATION REGRESSION RESULTS

Mean Equation				
Variable	**Coef.**	**Std. Error**	**t-Stat.**	**Prob.**
C	3.389	0.373	9.081	0.000
LOG(HYDRO)	-0.043	0.006	-6.961	0.000
LOG(NDEM)	1.296	0.036	35.765	0.000
LOG(ARES)	-0.010	0.002	-4.803	0.000
LOG(MB)	0.309	0.116	2.668	0.008
MR1	0.184	0.082	2.252	0.024
MR3	0.286	0.081	3.537	0.000
MR4	-0.039	0.044	-0.880	0.379
MR5	0.134	0.083	1.602	0.109
MR6	-0.580	0.036	-15.938	0.000
MR7	-0.045	0.063	-0.718	0.473
MR8	0.244	0.114	2.144	0.032
AR(1)	1.178	0.044	26.715	0.000
AR(2)	-0.201	0.041	-4.843	0.000
MA(1)	-0.655	0.034	-19.154	0.000
R-squared	0.911			

The regression results are reported in Tables IV and V. The goodness of fit is very satisfactory, since most of the independent variables are statistically significant, have the expected sign and interpret more than 90% of the dependent variable variation.

Equation of Mean

First of all, in the conditional mean equation, we observe that the electricity produced by hydro and RES, has both a negative and statistically significant effect on SMP. Moreover, this influence is higher for hydro production compared to RES production, based on the estimated coefficients. A plausible explanation for this is that the volumes of electricity produced by hydro are far greater than those of RES electricity production, the installed capacity of which increased significantly only just in the last two years of our sample (see Table I). In addition, hydro is used more heavily during peak-hours, contributing more to compress peak prices.

In contrast, the level of demand, as expected, has a positive impact on SMP, indicating that a 1% increase of the daily demand subject to the maximum record achieved over the period analysis, will lead to even higher increase of the SMP (1.3%). The three month moving average of Brent crude oil prices also has a positive effect on SMP. The coefficient of this variable implies that its 1% increase is accompanied with a 0.3% increase of SMP. The extent of this impact on SMP is rational is reasonable, if we take into account that almost 25% of the total electricity production is generated by natural gas and oil units.

Regarding the dummy variables representing the examined market reforms, we found that at least four out of the seven had a significant impact on the daily SMP, consequently also on the market structure. Particularly, the 1st Reference Day (MR1), as well as RAE's Decision on the 13th of January 2006 (MR3) and the implementation of the excise tax (MR8) influenced the SMP positively, based on the estimated coefficients. RAE's decision presents the highest impact among them (0.29), followed by the excise tax introduction (0.24) and the 1st Reference Day (0.18). These coefficients imply a 10 €/MWh SMP increase for the first reform and an 8 €/MWh SMP increase for the excise tax introduction.

The accumulated impact of the first two reforms is reasonable, based on two facts. Firstly, because the SMP during the period preceding of their implementation was almost always set by the lignite units (with a marginal cost of 25-30€/MWh), while afterwards the lignite units set the SMP only during the off-peak hours, with the natural gas and oil units setting the SMP for the largest part of the peak hours (with a marginal cost of 55-60€/MWh). Secondly, the number of hours natural gas and oil units set the SMP is roughly 2/3 of total hours[13]. The latter reason also

[11] The plot was indicating that there are primarily large negative shocks that are driving the departure from normality condition.

[12] Due to space limitations, results of the AFC and PACF, as well as QQ-plots are available upon request.

[13] Therefore, by multiplying the difference in marginal costs with the percentage of hours set by natural gas and oil units after the reforms, we get (as part of a "back-of-the-envelope calculation") an effect of 20€/MWh, similar to our estimations.

illustrates why the excise tax introduction on natural gas units had a slightly lower effect on SMP than expected (around 11-15€/MWh).

However, the most significant impact on the SMP is presented by the reforms implemented on the 4th Reference Day (MR6). At a first glance this is surprising, as the change in the SMP methodology was mainly expected to affect the hours when the technical minimum constraints are active, that is the off-peak hours. If examined though in relation with the Cost Recovery Mechanism and the price floor constraint (see ft.2), we can see that the new algorithm offered strong incentives for a specific strategy from the generators: ensure commitment of their units by bidding price zero for 30% of their capacity, and make extra profits whenever the SMP exceeded their costs. Therefore, instead of a slightly milder effect compared with the 13.1.2006 reform[14], the SMP declined more significantly, estimated around 13€/Mwh.

The above argument is presented in Fig. 2, where the supply curve before the reforms (S.C.1), moved to the left after 13.1.2006 (S.C.2), to reflect that the technical minimums of the committed units by the HTSO weren't considered any more. While the curve was expected to move slightly to the right after the 4th Reference Day (S.C.3), for a quantity equal to the units committed by the algorithm (fewer units than HTSO commitment), it moved much more due to the unforeseen change in the bidding offer strategy change (S.C.4), caused by the Cost Recovery Mechanism, practically committing all available thermal units and giving a slight higher slope to the supply curve[15].

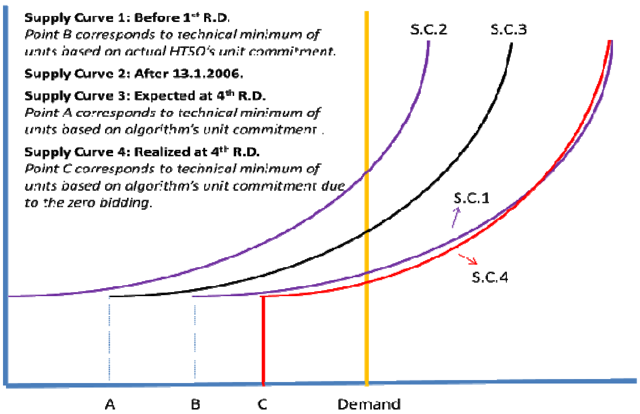

Fig.2. Supply curves during the Second Market Phase

With reference to the 5th Reference Day (MR6) and the transition to the Third Phase of the market opening, the results show that despite the great debate among market participants, raising major concerns regarding the effect it would have to the wholesale market, and the continuously delay of its implementation, the respective reform had an insignificant impact on the market. On the other hand, this may be also a result of sustaining the two transitional mechanisms (Cost Recovery, Transitional Capacity Adequacy).

Finally, the hourly bidding procedure (MR7) did not have any effect on the average SMP, as the producers continued to follow the same bidding strategies with the preceding period.

C. *Equation of Variance*

Regarding the estimation of the conditional variance equation, we observe that the price volatility of the Greek wholesale market exhibits a GARCH process, confirming the results of the descriptive analysis. The coefficients of ω, α and β are statistically significant and positive, which indicates that the variance-covariance matrix is positive definite. In parallel, the sum of the coefficients α and β is below unity, implying that the variance is stationary, which means that a shock does not have a permanent effect on variance. This adjustment is estimated to 9 days[16].

Regarding the exogenous variables impact on price volatility, we found that although most of them have a significant effect on it, the quantified impact is almost negligible. As expected, the RES and hydro electricity production have a positive impact on price volatility, as they affect also the level of SMP, whereas the increase of the level of demand stabilizes price volatility, because the SMP is set by production units with similar technology. In the same lines we showed that the hourly bidding procedure increased slightly the volatility of the prices.[17]

TABLE V. VARIANCE EQUATION REGRESSION RESULTS

Variance Equation				
Variable	**Coef.**	**Std. Error**	**t-Stat.**	**Prob.**
C	0.015	0.005	2.895	0.004
RESID(-1)^2	0.187	0.025	7.369	0.000
GARCH(-1)	0.710	0.030	23.747	0.000
LOG(ADEM)	-0.002	0.001	-2.967	0.003
LOG(AHYDRO)	0.000	0.000	4.428	0.000
LOG(ARES)	0.000	0.000	1.886	0.059
D2	0.005	0.001	3.802	0.000
D3	-0.005	0.001	-4.994	0.000
D4	-0.001	0.001	-2.379	0.017
D5	-0.001	0.001	-2.286	0.022
MR7	0.000	0.000	2.076	0.038
R-squared	0.911			

[14] Because the new algorithm doesn't commit as many units as HTSO actually does during its dispatch process. See also the related discussion in Section II subsection C.

[15] Note also that after the 4th R.D. a number of new generation units were commissioned.

[16] The average period of adjustment towards the equilibrium is calculated by the following formula: T=ln(0.5)/ln(a+b)

[17] All the other market reforms had no impact on the price volatility according their coefficients. These results are not presented here due to space limitations.

Finally, we found that price volatility exhibits a seasonal behavior during the week, presenting a higher level on Tuesday, compared to the mean ω, which represents Monday, and then follows a declining trend until Friday.

V. CONCLUSIONS

In this paper we have addressed the impact of recent electricity reforms on the Greek wholesale prices and its volatility, a field not adequately explored in the existing literature regarding the Greek electricity market. Our analysis was based on an ARMA-GARCH approach, which proves to accurately represent the volatility of electricity prices and also leads to white noise residuals, thus enhances the reliability of the tests.

Our major finding is that although the ultimate goal of the implemented market reforms was to enhance the competitiveness and effectiveness of the market, some of the reforms distorted not only the wholesale market, but also the retail market.

Most importantly we show that the combined 3rd and 4th Reference Day reforms influenced negatively the SMP more than expected, as a result of the distorted incentives given to the market players. This in turn had two effects: (a) an increase of the out of the market payments, including the RES special levy level, which had to significantly increase due to the higher amounts needed to compensate RES producers, based on the feed in tariffs, due to the drop of the SMP, and (b) on the partial disconnection of the SMP values from the fundamental factors governing its evolution[18].

Moreover, we conclude that the introduction of excise duty natural gas for electricity generation increased significantly the SMP, influencing the mix of electricity production and inducing a competitive disadvantage to natural gas fired generators, as well as decreasing the degree of competition among suppliers, as electricity cost exceeded in various consumer categories the respective regulated retail tariffs.

The results indicate that important policy decisions should be taken under a general framework, always in consideration of both past and planned reforms, and be supported by an impact assessment accounting for a broad array of factors and the expected effects of the reform not just to its target, but also to all related aspects. Especially in oligopolistic markets, like the electricity market, these factors should include the strategic behavior of market players. At the same time the policy makers should continuously monitor the results of these reforms and be prepared to modify or even cancel reforms that may not lead to the expected results.

As a next step, this study can be further extended to include the full range of exogenous variables affecting the wholesale prices, like hydro reservoir values, imports/exports, unit availability, as well as variables describing the strategic behavior of market participants.

[18] For example the recent increase of the Brent oil prices affected the SMP significantly less than before the 4th Reference Day reforms.

DISCLAIMER

The material contained in this paper is for information, education, research and academic purposes only. Any opinions, proposals and positions expressed in this paper are exclusively of the authors and do not necessarily represent the views of RAE, partially or unilaterally.

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