2013 National Report to the European Commission

(Covering the period 01.01.2012 – 31.12.2012)

Regulatory Authority for Energy (RAE)

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1. Foreword

In 2012, the energy market fully reflected the severe ongoing recession of the Greek economy. Major liquidity problems and credit risk issues, which had started to emerge in 2010 and 2011, sharply escalated during 2012. The continuing recession reversed the growth trend in electricity demand and rendered a surplus of capacity, which severely challenged the financial viability of the new power plants and the recovery (return) of the large investments involved. In addition, the liquidity crisis unveiled the internal inconsistencies and large inefficiencies of implemented policies, especially those regarding retail (regulated) tariffs, as well as fixed (feed-in) tariffs for renewables. It was these policies that led to huge deficits in the energy sector.

Consumer debts (unpaid electricity bills) escalated to 1.3 billion € total at the end of 2012, partly due to the recession, but also due to the incorporation, since autumn of 2011, of a property tax into the electricity bill, which substantially increased its total amount due. This customer debt accumulation did not allow the main electricity supplier, the incumbent PPC SA, to fully pay the TSO (ADMIE SA) and the Market Operator (LAGIE SA) for the electricity purchased from the daily market. In turn, LAGIE and ADMIE were unable to pay the generators (especially the IPPs, who own gas-fired plants) for the electricity they produced and sold to the grid. Equally concerning was the eventual impact of this debt chain on the gas sector, as IPPs gradually accumulated large debts to the incumbent gas supplier, DEPA SA, amounting to €300 million at the end of 2012. On various occasions, these electricity producers received disconnection notices from DEPA.

Simultaneously, the large (and widening) gap between the – depressed - wholesale price levels (SMP) and the high feed-in-tariffs reimbursed to renewables, created a sustained and ever growing debt in the Renewables Account managed by the Market Operator, LAGIE SA. The deficit of this RES account reached €400 million at the end of 2012, further reducing the liquidity of the Market Operator and, hence, its ability to pay conventional generators, importers and renewable producers in 2012.

This explosive situation raised unprecedented challenges not only for the consumers and the market participants, but also for the Regulator. The need for structural reforms, so as to resolve structural asymmetries and to remove market distortions, both at a horizontal and at a vertical level, became more urgent. This market direction must also take into account the necessary adjustments to the internal market operation, envisaged for 2015, in order to comply with the European Target Model.

In this very difficult economic and market environment, RAE undertook several initiatives and measures to foster liquidity in the market and to help create a financially viable environment, through effective management of the credit and market risk. In November 2012, RAE published its final proposals on the restructuring of the domestic electricity market. These proposals, which followed an extensive 3-stage public consultation process, cover both the wholesale and the retail markets, including RES generation. In summary, the RAE proposals encompass, among others: a) the application of NOME-type auctions, in order to allow third-party access to the country's lignite and hydro recourses, b) the abolishment of the so-called Cost Recovery transitional mechanism, c) the complete redesigning of the transitional Capacity Assurance Mechanism (CAM), d) the shift in the operation of the market to a daily basis (clearing within 24 hours), for the reduction of volume traded and the minimisation of credit risk, e) the creation of a “Credit and Clearing House” facility, which would undertake the market clearing and the associated credit risk, instead of the Market and System Operators (as is done today), and f) the gradual transformation/transition of the domestic energy market, through a series of well-defined steps, towards the European Target Model.

The further elaboration and implementation of the above measures and actions will be the focus of RAE’s efforts in 2013.

The Greek Regulatory Authority for Energy (RAE)

2. Main developments in the gas and electricity markets

2.1. Electricity

On the 1st of February 2012, ADMIE SA, a 100% subsidiary of the incumbent, PPC SA, commenced operation as the Transmission System Operator. Its establishment was the result of the secession of the Transmission Directorate of PPC and the Transmission Branch of the former Hellenic Transmission System Operator (TSO), DESMIE SA, and their integration into a unified company. ADMIE SA owns and operates the transmission system, and was certified as an ITO in December of 2012. On the other hand, the newly established company LAGIE SA undertook the role of the Market Operator, which was previously performed by DESMIE SA as well. The ownership of the distribution network remained with PPC, although its operation was assigned to another 100% subsidiary of PPC, DEDDIE SA, which commenced operation in May 2012.

In 2012, the wholesale electricity market exhibited features that could be perceived as signs of increasing maturity. The substantial new capacity that had entered the system in 2010 and 2011 intensified competition for mid and peak demand; it is notable that the total installed capacity of gas-fired plants has reached that of lignite plants. PPC's share in the generation sector was reduced substantially, to 79.5% in the interconnected system, if only conventional technologies are taken into account, and to 63.5%, if RES capacity is also included. Moreover, the country's continuing economic recession reversed the demand growth trend that existed prior to the crisis, rendering a surplus of capacity, which severely challenged the financial viability of the new power plants. Wholesale prices remained relatively low, but still not reflective of the full energy production cost. Their levels were suppressed due to significant amounts of mandatory electricity entering, by priority, the System, including: a) mandatory hydro, b) plants' minimum operational levels, and c) renewables.

Prices for LV customers remained regulated in 2012, in accordance with the existing national legislation. Regulation of LV prices is scheduled to be removed on 01.07.2013. On the other hand, PPC's MV prices became deregulated as of 01.01.2012. In February 2012, PPC applied uniform MV pricing, at new levels considerably higher than the 2011 (regulated) ones, for all MV customers except the agricultural ones, and regardless of their consumption profile, without entering into any kind of negotiation with them. This resulted in several formal complaints filed by MV customers to RAE, in addition to numerous similar complaints by HV customers, as well. It is worth mentioning that, until the end of 2012, no supply contract agreement had been concluded between PPC and HV or large MV customers.

The retail electricity market in 2012 was also marked by the abrupt exit of four (4) independent electricity supply companies, due to their significant debts that had been accumulated with the Transmission System and Market Operators. These companies included the two major alternative suppliers, namely "Energa Power Trading" and "Hellas

Power", which represented 3.8% and 3.6%, respectively, of total volume of the retail market in 2011. After the market exit of these electricity supply companies, PPC acted as the Supplier of Last Resort, according to the relevant provisions of Law 4001/2011. At the end of the 2012, there were only 6 active suppliers (PPC plus 5 independent suppliers) in the retail market, with no new market entrants. By the end of 2012, the incumbent had regained 99.9% of the market share (by eligible volume), compared to 92% at the end of 2011.

The third key element that characterised the retail electricity market in 2012 was the big surge of arrears of consumers of all categories to their suppliers (that is, almost exclusively to PPC). The high taxation on electricity and the significant increase in taxes unrelated to electricity, but collected through the electricity bills (property and municipal taxes, various levies, radio & TV fees, etc), led to a 1.3 billion € of arrears to PPC SA at the end of the year. This created a very large debt to the suppliers, transferred throughout the electricity chain and on to the gas market.

In December of 2012, RAE issued its formal Opinion to the Minister of Environment, Energy and Climate Change regarding a new Electricity Supply Code, following extensive public consultation. The new Supply Code covers key issues such as suppliers' and customers' obligations and rights, principles of tariff setting, procedures for switching suppliers, minimum content of the supply contract, data publishing obligations, dispute resolution, etc. Additionally, the new Code includes provisions regulating the services of the Supplier of Last Resort and the Universal Service Supplier, as well as specific provisions for vulnerable customers.

2.2. Natural Gas

In the natural gas sector, the year 2012 was characterised by a slowing down of gas market activities, due primarily to the decreasing economic activity in the country. Natural gas demand in 2012 decreased by ten percent (10%) compared the demand in 2011, reaching a level of 4.4 bcm, mainly due to a decrease in the demand from gas-fired power plants and a relatively mild winter period.

In the regulatory front, and in addition to its key contribution in the transposition of the Third Energy Package into national legislation, RAE successfully completed in 2012 the next step in the transformation of the TPA regime to an entry-exit system, by approving a new Tariff Regulation, whereby the postage-stamp system became obsolete. The new Tariff Regulation includes the detailed methodology by which entry-exit TPA tariffs are set, regardless of the actual gas transportation route. The new entry-exit tariffs will enter into force in February of 2013.

The Greek TSO submitted a proposal to the Regulator, at the end of 2012, for an amendment to the Gas Network Code, to disentangle entry and exit capacity bookings. The proposal is under review by the Regulator, to be completed in 2013.

In addition, RAE continued the elaboration and completion of the required regulatory framework set in the Security of Supply (SoS) Regulation. A bilateral meeting took place in Athens between the Greek and Bulgarian Competent Authorities, Regulators and TSOs, in order to coordinate the next steps regarding the implementation of the SoS Regulation, including the realisation of physical reverse flow in the north interconnection point Kula-Sidirokastro. In the course of the year, both the National Preventive Action Plan and the Emergency Action Plan were prepared by RAE (the Competent Authority for the implementation of the SoS Regulation in Greece) and were sent for comments to the competent authorities of the neighbouring countries, as mandated by the SoS Regulation.

3. Regulation and Performance of the Electricity Market

3.1. Network Regulation

3.1.1. Unbundling

3.1.1.1. Certification of ADMIE SA as an ITO

ADMIE SA is the Independent Transmission Operator (ITO). Its establishment was the result of the secession from PPC (Vertical Integrated Utility - VIU) of its Transmission Directorate and, similarly, the secession from the HTSO (former Hellenic Transmission System Operator), of its Transmission Branch, followed by their integration into a new unified company. The secession/unification process and the transfer of the above assets and personnel was performed as specifically prescribed in Chapter B of Law 4001/2011 (Articles 98, 99 and 102-104), which transposed the requirements of Directive 2009/72/EC into Greek Law, and further detailed in RAE's Decision 1412/2011 (General Guidelines for the Certification of the ITO Model). According to RAE's Decision, the independence of the Transmission Operator refers to its legal and operational unbundling from the VIU and distinguished three forms of independence for certification purposes: (a) the independence of management, (b) the independence of financial resources, and (c) the independence of operational activities. More specifically:

- Independence of management refers to the separation of management control and, in particular, the requirement that ADMIE SA possesses independence in decision making from the VIU. This independence is foreseen in the company's Corporate Charter where according to Law 4001/2011, in June 2012 a Supervisory Board was nominated, to which the Board of Directors refers, and a Compliance Officer was appointed.
- Independence of financial resources refers to the requirement that the company possesses and owns the necessary technical and financial resources, so that it can successfully accomplish its mission, as described in the Corporate Charter and the relevant legal documentation. An initial due diligence was performed in August 2011 but due to market developments, it was performed again in April 2012, and resulted in asset reconciliation and debt sharing between ADMIE and LAGIE (the market operator which succeeded the former HTSO). The exercise showed that after the secession from PPC of its Transmission Directorate and the subsequent unbundling of assets, ADMIE owned the necessary resources. From the analysis of the financial data submitted and their correlation with the rolling 10-year Development Plan (2013-2022), ADMIE was certified to possess the required financial resources to proceed with its investment plan.

- Independence of operation refers to the human, technical and other resources deemed necessary for the efficient operation of the TSO. It also implies various restrictions regarding the use and/or provision of services by/to the VIU. More specifically:

    a. The proposed organisational structure met the requirements and needs of ADMIE, as verified by an audit performed by independent consultant (PwC), while the transfer of executives and personnel from PPC ensured that the human resources were available to ADMIE to successfully implement its objective. The specification of processes and operational procedures of the ADMIE Units/Departments were based on state of the art methods of business administration, taking into consideration the particularities of both the industry and of the secession.

    b. For the purpose of verification of the full separation of ADMIE's IT systems from those of PPC, a full IT audit was carried by an independent Consultant (Deloitte Greece) in all physical premises. The audit concluded that there is full IT unbundling between ADMIE and PPC.

In July 2012, and following the examination of ADMIE's Notification for Certification and the relevant documents submitted, RAE issued its conditional Decision 672/2012, which verified ADMIE's compliance with the requirements and restrictions of the relevant Law and RAE guidelines. Following the procedure described in the Directive 2009/72/EC, and after taking into consideration the Opinion of the European Commission, RAE with its final Decision 962A/2012 in December, certified ADMIE as the Independent Transmission Operator.

3.1.1.2. Secession of the Distribution Branch of PPC S.A. – DEDDIE S.A.

The secession of the activity of the Distribution Branch of PPC, including the Non–Interconnected Islands Operator, took place in 2012, in accordance with Law 4001/2011 and Directive 2009/72/EC. Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.), the new Independent Network Operator, is a 100% subsidiary of PPC S.A. and is responsible for the development, operation and maintenance of the Hellenic Electricity Distribution Network (HEDN). PPC S.A. remains the owner of the Distribution Network assets (herein the "Distribution Network activity of PPC S.A.") and, therefore, receives from its subsidiary a Distribution Network usage fee[1].

The secession process and the transfer, from the parent company to HEDNO S.A., of the assets and liabilities which fall under the above mentioned activities were completed in April 2012 and the Operator had submitted to RAE the relevant documentation, in order to obtain the operation license, according to Law 4001/2011.

[1] The relevant amount was approved by RAE (Decision 1017/2012).

3.1.2. Technical functioning

3.1.2.1. Security and reliability standards, quality of service and supply

Network Performance and Quality of Service

In December of 2010, RAE published an integrated set of Regulatory Instructions for the reporting of the Transmission System performance[2]. Following these instructions, the TSO published reports on the performance of the Transmission System for the years 2010 and 2011[3]. The reports provide availability indices for overhead lines, underground cables and autotransformers, as well as indices for the impact of the system unavailability to customers (system minutes).

Performance and quality-of-service standards and obligations, as well as the respective monitoring processes, have not yet been set for the Distribution System Operator (DSO). Therefore, currently, the DSO does not report any Quality of Service (QoS) indicators. Relevant requirements are to be developed under the umbrella of the Distribution Network Code. The proposal of RAE for the Distribution Network Code envisages a penalty/reward scheme for QoS regulation. In this context, the role of the Regulator includes the following:

- Setting, per regulatory review period, of the regulated service quality parameters, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, in conjunction with the allowed revenue of the distribution activity.
- Approval of rules, procedures and methodologies for monitoring, assessing and reporting service quality levels.
- Validation of data completeness and accuracy.

Until the Code is finally enforced, substantial preparatory work has already been completed. Since 2008, the Regulator is continuously reviewing the PPC rules and procedures, and has been monitoring certain QoS parameters. So far, this has allowed the Regulator to report on the overall service quality level, based on available, non-verified, historical data up to 2010, and to formulate and publish its opinion on these data, as well as on current PPC practices regarding service quality monitoring and reporting, and on necessary improvements thereof.

3.1.2.2. Monitoring time taken to connect and repair

Monitoring DSO performance in connecting new users falls within the aforementioned initiative undertaken by the Regulator over the previous four (4) years.

Concerning connection of new generation facilities, monitoring issues do arise for the DSO as, in several circumstances, significant delays arise in responding to requests for

[2] http://www.rae.gr/site/system/docs/misc/11012011.csp
[3] March 2012 - http://www.admie.gr/fileadmin/groups/EDAS_DSES/DSES/PERFORMANCE_REPORT2011-IPTO.pdf

connection offers to RES generators. On the other hand, connection offers by the TSO do not exhibit significant delays, as the number of requests is by far smaller than the requests faced by the DSO.

3.1.3. Network tariffs for connection and access

Network access tariffs in Greece are of the 'Postage Stamp' type, with the 'G' component being equal to 0% and the 'L' component to 100%. Since 2011[4], RAE approves the tariffs for access to national networks (Transmission System and Distribution Network), one month before their entry into force, based on the proposals submitted to the Regulator by the Greek Electricity Transmission System and the Greek Electricity Distribution System Operators (ADMIE and DEDDIE, respectively).

During 2013, a tendering process will take place regarding costing, pricing and access issues for transmission and distribution networks in Greece.

3.1.3.1. Transmission network tariffs for access

During 2012, and after conducting public consultation[5], RAE decided[6] an amendment to the methodology of calculating the Required Revenue for Transmission System, mainly concerning:

- the calculation of capital employed (Regulated Asset Value)
- the settlement for any deviations between forecasted and actual operating expenses and investments

Based on RAE's Decision 840/2012, tariffs are calculated on the basis of the annual Required Revenue for Greek Electricity Transmission System (ESMIE), which is defined in the System Operating Code[7] as the sum of:

- the estimated annual Transmission Cost[8] ,
- the estimated annual cost of any work for the expansion of the System.
- the over-recovered funds /surplus (-) or under-recovered funds/shortfall (+)[9] from customers.
- the settlement for differences between forecasted and actual operating expenses (OPEX) and investments of previous years.
- Interconnection auction revenues[10].

[4] Law 2773/2011, article 140.
[5] Public consultation took place from 17 May to 15 June 2012
[6] RAE Decision 840/2012
[7] RAE Decision 57/2012 (Government Gazette B' 103/31-01-2012) and subsequent amendments.
[8] According to article 275 of System Operating Code
[9] Deviations between the forecasted and the actual revenue from system users during previous years

Given the above, RAE, with its Decision 1016/2012, approved the Required Revenue for Transmission System for 2012 and 2013, respectively, as follows:

	2012 (mil €)	2013 (mil €)
Operating Expenses	78.8	77.9
Annual Depreciation	57.5	53.7
Return (RAV*r)	113.1	114.4
Total Cost	**249.4**	**246.0**
Other settlements (Under-recovered funds[11], Interconnection revenues, Other Revenues)	**(25.0)**	**(16.3)**
Total Required Revenue	**224.0**	**229.7**

Table 1. Annual Transmission Cost and Required Revenue for 2012 and 2013

Regarding the elements of return, RAE approved:

- A Regulatory Asset Value (Capital employed) equal to €1,413 m (including €61.1m for new investments) and €1,429 m (including €62.1m for new investments), for 2012 and 2013, respectively.
- An Allowed Rate of Return (nominal, pre-tax) equal to 8% for both years.

The Regulatory Asset Value (RAV) and the annual depreciations were determined, for the 4-year period 2010-2013, by excluding the effect of the asset revaluation carried out by PPC in 2009 (the revaluation surplus for the Transmission Branch was €340.4m).[12]

The methodology for Transmission Use of System (TUoS) tariffs for HV connected customers is set out in the Grid Operation Code, while the one for customers connected to the Distribution Network (MV and LV) is set out in a related Manual approved by RAE[13] in 2010.

Tariffs for HV-connected customers follow a €/MW structure, charged on the customer's average hourly demand during three (3) key hours: system summer peak, system winter peak and the maximum of the two. Demand is adjusted for losses depending on the connection voltage. Transmission system cost is further allocated between MV and LV connected customers on the basis of the contribution of each customer category to the

[10] According to Regulation 714/2009, article 16. For 2012, the relevant amount was €21.4 m and for 2013, €26.9 m.

[11] The cost under-recovered through the charges applied in 2010 (€16.1m) was taken into account in the Required Revenue of 2013.

[12] The revaluation was carried out by an independent firm of appraisers for accounting purposes (according to IAS 16).

[13] RAE Decision 2215/2010.

transmission system summer and winter peak demand. For the purpose of calculating TUoS charges for customers connected to the distribution network, the methodology set out in the relevant manual, further specifies the following:

- For the purposes of TUoS charging, the following four (4) customer categories apply: Medium Voltage (MV), Domestic, Domestic with Social Tariff (KOT)[14], Other Low Voltage (LV) and Public Lighting Use LV, excluding Agricultural MV and Agricultural LV that have zero TUoS charges.
- Only capacity charge (no energy charge for TUoS) is applied to MV customers, which is charged based on their monthly maximum metered demand (MW) during peak hours (11am-2pm).
- Only energy charge (no capacity charge for TUoS) is applied to Domestic customers with Social Tariff (KOT).
- For Domestic customers (except for Domestic customers with Social Tariff), only 10%[15] of the allocated cost is recovered through capacity charges, which are charged on the basis of the connection capacity (kVA), given the lack of appropriate meters and data on individual demand.
- For other LV customers, only 20% of the allocated cost is recovered through capacity charges, which are charged on the basis of the connection capacity (kVA) given lack of appropriate meters and data on individual demand.

According to the above mentioned methodology, RAE approved the following tariffs for 2013[16]:

Customer Category	Capacity Charge (€/MW or €/kVA)	Energy Charge (c€/kWh)
HV	25,703 €/MW chargeable demand (3 coincident peaks)	-
MV (non agricultural)	1,801 €/MW of Monthly Maximum Demand at peak-period, per month	-
Domestic	0.17 €/kVA of Subscribed Demand per year	0.541*
Domestic with Social Tariff (KOT)	-	0.602
LV (non agricultural)	0.60 €/kVA of Subscribed Demand per year	0.527*
Public Lighting Use LV	0.60 €/kVA of Subscribed Demand per year	0.176

*Applies to daytime consumption only, for customers with zonal metering

Table 2. Transmission Use of System (TUoS) charges for 2013

[14] In July 2010, a third public service was introduced, a Social Tariff for Domestic Customers, referred to as "KOT". This reduced tariff applies to vulnerable social groups of consumers and particularly to individuals with low income, families with 3 children, long-term unemployed, disabled people, as well as people on life support. The starting date for the implementation of the new tariff was set for the 1st of January 2011.

[15] Based on RAE's Decision 2215/2010, this cost percentage was reduced from to 20% to 10%.

[16] According to RAE's Decision 1456/2011, the transmission tariffs for 2012 remained the same as for 2011.

3.1.3.2. Distribution network tariffs for access

There is currently no formal methodology set for the calculation of the allowed distribution revenue, given that the Distribution Network Code (which will include the methodology for estimating the annual distribution costs) has not been adopted yet. As a transitional measure, the methodology applied is the one currently used for the transmission system[17].

In accordance with Decision 840/2012, RAE approved the total Required Revenue for the Distribution Network (for the Operator and the parent company, PPC S.A., as owner of the Network assets), for 2012 and 2013 respectively (RAE Decision 1017/2012), as follows:

	2012 (mil €)		**2013 (mil €)**	
	PPC S.A.	DEDDIE S.A.	PPC S.A.	DEDDIE S.A.
Operating Expenses	-	409.8	-	420.5
Annual Depreciation	139.3	7.0	124.4	7.4
Return (RAV*r)	219.6	7.2	228.8	7.7
Other settlements (rentals)	(5.5)		-(12.0)	
	353.4	**424.0**	**341.2**	**435.6**
Total Cost	**777.4**		**776.8**	
Other settlements (over/under-recovered funds, actual vs forecast OPEX and investments, other revenues)	**(6.0)**	**-**	**(23.3)**	**-**
	347.4	**424.0**	**318.0**	**435.5**
Total Required Revenue	**771.4**		**753.5**	

Table 3. Annual Distribution Cost and Required Revenue for 2012 and 2013

Regarding the elements of return, RAE approved:

- A Regulatory Asset Value (Capital employed) equal to €2,835m. (including €297m. for new investments) and €2,860m. (including €336m. for new investments), for 2012 and 2013, respectively.
- An Allowed Rate of Return (nominal, pre-tax) equal to 8% for both years.

The Regulatory Asset Value (RAV) and the annual depreciations were determined, for the 4-year period 2010-2013, by excluding the effect of the asset revaluation carried out by PPC in 2009 (the revaluation surplus for the Distribution Branch was €421.9m).

About €64m of the above RAV were set to be recovered by MV connected consumers and the remaining by LV connected consumers. Distribution network cost is allocated between

[17] Ministerial Decree of 31 Dec. 2007, following RAE's Opinion 294/2007.

MV and LV connected customers on the basis of the contribution of each customer category to the distribution network summer and winter peak demand.

For the purpose of calculating Distribution Use of System (DUoS) charges, customers are categorised based upon their connection voltage and metering capabilities. More specifically, consumers are distinguished into five (5) categories: MV customers, LV customers with subscribed demand >25 kVA (with and without reactive power metering), LV residential customers, and other non-residential LV customers.

For MV customers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. For domestic customers, 10% of the cost is recovered through a capacity charge and 90% through an energy charge. Those percentages for the Other LV customers are 20% and 80%, respectively.

The resulting Use of System (UoS) unit charges for Distribution in 2013[18], per customer category, are presented in the following table. The unit capacity charge is applied on the customer's subscribed demand for LV customers and on the Monthly Maximum Demand registered at daily peak-hours for the MV customers. The unit energy charge is applied to the metered energy, adjusted for the average power factor (assumed to be equal to 1 for customers without reactive power metering).

Customer Category	Capacity Charge (€/MW of Monthly Maximum Demand at peak-period, per month)	Energy Charge (c€/kWh)
MV	1,192	0.29
	Capacity Charge (€/kVA of Subscribed Demand per year)	**Energy Charge (c€/kWh)**
LV (subscribed demand >25 kVA) with reactive power metering	3.61	1.59
LV (subscribed demand >25 kVA) without reactive power metering	2.95	1.8
Domestic	0.63	2.03
Domestic with Social Tariff (KOT)	-	2.26
Other LV (subscribed demand ≤ 25 kVA)	1.50	1.80

Table 4. Distribution Use of System (DUoS) charges for 2013

3.1.3.3. Transmission network connection tariffs

Only "shallow" connection costs, i.e. from the production plant site to the appropriate connection point of the Transmission System, are charged to producers. The charges are applied by the TSO, for specific tasks carried out by the Operator that are related to the

[18] According to RAE's Decision 1456/2011, the distribution tariffs for 2012 remained the same as in 2011.

connection works performed by the generators themselves (e.g., review of connection works studies, acceptance tests for built connection networks, etc.). Such charges have not been formally approved by the Regulator yet. According to the provisions of Law 4001/2011, a detailed pricelist is to be submitted by the TSO to RAE for final approval.

3.1.3.4. Distribution network connection tariffs

A methodology for setting connection tariffs has not yet been approved by the Regulator. The methodology is envisaged to be part of the Distribution Network Code, which is still in preparation.

3.1.4. Cross-border issues

3.1.4.1. Access to cross-border infrastructure

The relevant electricity market for Greece is, to a significant extent, the national market, as a regional market has not emerged yet. The total interconnection capacity was increased in 2012, with the average NTC corresponding to exports increasing from 1380 MW in 2011 to 1530 MW in 2012 (+10.87%), and the respective NTC for imports increasing to 1550 MW in 2012, compared to 1367.5 MW in 2011 (+13.35%). However, the Winter-NTC for imports was actually decreased in the same period by 3.57% (from 1400 MW in 2011 to 1350 MW in 2012), although the difference was compensated by the Summer-NTC increase (31.09%), which reached 1750 MW in 2012, compared to only 1335 MW in 2011. Figure 1 displays the allocation of NTC in 2012 and its evolution relatively to 2011.

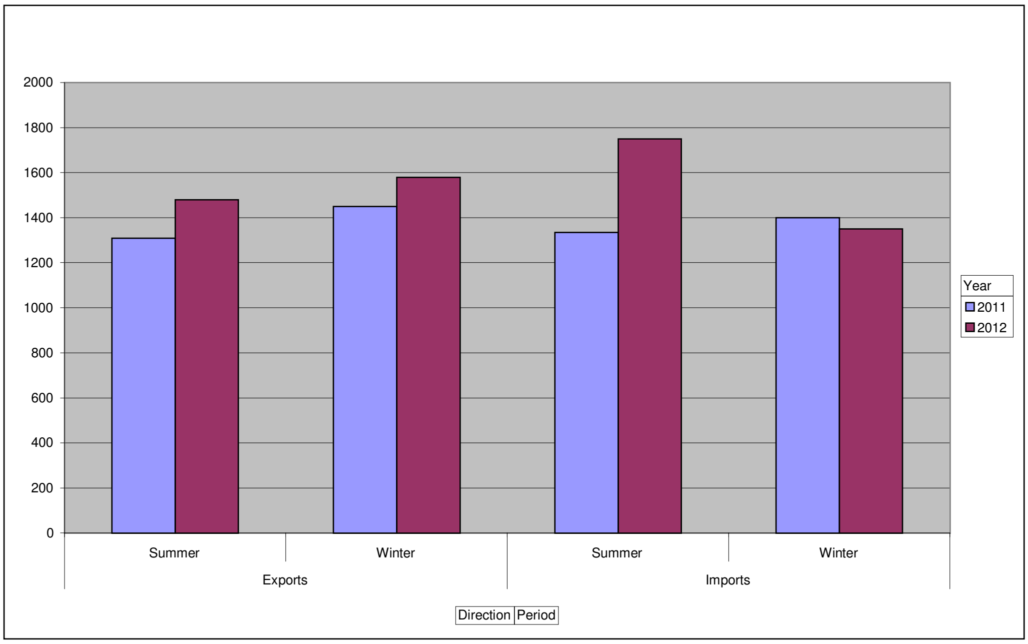

Figure 1. Comparison of Summer-NTC and Winter-NTC for Imports and Exports

Overall, the net interconnection balance declined further, from 3.2 TWh in 2011 to 1.8 TWh in 2012, adding to the decrease already experienced in 2011 (from 5.7 TWh in 2010). This decline is better understood if split into import and export patterns. Overall, imports declined from 7.2 TWh in 2011 to 6 TWh in 2012 (-17%), adding to the decline of -15% from 2010 to 2011, while exports increased marginally from 3.9 TWh in 2011 to 4.2 TWh in 2012 (+5.6%).

The marginal increase in exports is disproportionately distributed to the various country borders. The significant decrease in exports to Albania, from 2.1 TWh in 2011 to 1.5 TWh in 2012 (-30.33%), was "compensated" by the large increase of exports to Italy, from 1.7 TWh in 2011 to 2.5 TWh in 2012 (+48%), while the other borders experienced also significant increases, percentage-wise. Bulgaria recorded exports of 2.2 GWh in 2012, compared to zero in 2011, while exports to Turkey were increased by 2096% (from 0.18 GWh in 2011 to 3.9 TWh in 2012) and by 35.5% to FYROM (from 0.11 TWh to 0.15 TWh).

The impressive increase of imports that was observed through the Turkish border during 2011 (from 0.7 to 2.6 TWh), due to the development of commercial trading with Turkey, faded out in 2012 and, in fact, it reversed itself, turning into a significant decrease reaching 1.7 TWh in 2012 (-34.2%). Imports from Italy remained low, but further increased from 274 GWh in 2011 to 327 GWh in 2012 (they were only 67 GWh in 2010). Imports from Bulgaria declined further by 18.4%, from 2.8 GWh in 2011 to 2.3 GWh in 2012 (compared to the 3.5 GWh of 2010), while imports from the other borders were increased. Imports from FYROM recorded an increase of 7.8%, from 1.5 TWh in 2011 to 1.6 TWh in 2012, covering 2/3 of all imports' increase in 2012. Imports from Albania, although recording a big percentage increase of 365.4% in 2012, remained at low absolute levels: from 3.7 GWh in 2011 to 17.4 GWh in 2012.

Figures 2 and 3 display the distribution of interconnection trading in 2012 and its evolution relatively to 2011.

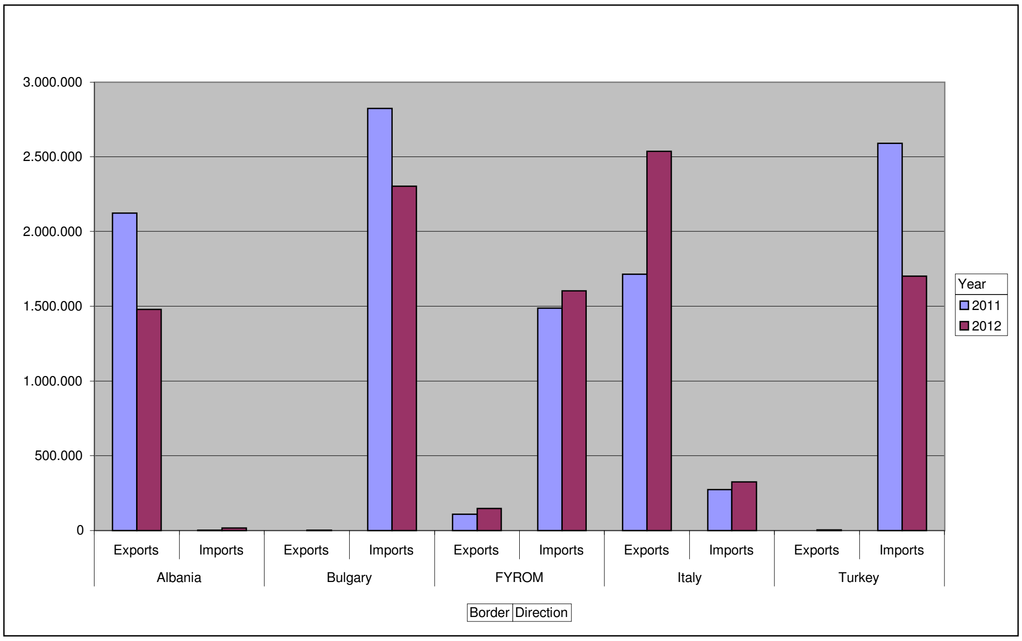

Figure 2. Distribution of import and export trading in 2012, compared to 2011

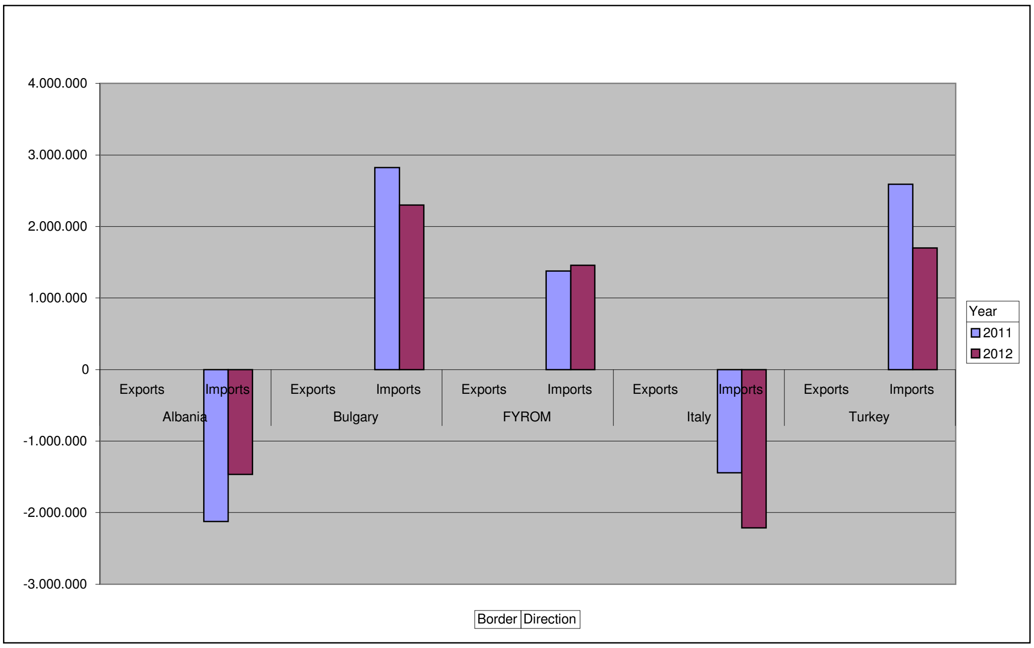

Figure 3. Net trading volumes across bordering countries (positive values for imports).

Overall, the trading volume in all borders was decreased by 1 TWh (9%), with Italy having the higher percentage increase (+44%, corresponding to 875 GWh) and Turkey having the highest percentage decrease (-34%, corresponding to 883 GWh).

Significant changes also occurred in the auction rules and the implementation of auctions in 2012, both in the interconnection with Italy and the interconnection with the Balkan countries. In order to facilitate market integration and harmonisation of cross-border congestion management, the capacity allocation for the Italian borders, within the Central – South Europe (CSE) Region, was performed (already since April 1st 2011) by the Capacity Allocation Service Company (CASC S.A.), which also performs the capacity allocation functions for the CWE Region borders. Since the 1st of January 2012, the Common Rules for Capacity Allocation by Explicit Auctions, which was available for Public Consultation between the 13th of September 2011 and the 4th of October 2011, have applied[19]. This development enhanced compliance with the EC Regulations 1228/2003 and 714/2009, since there are no special appendices for each border separately, but all the rules are unified into a single document. Moreover, the rules are issued without expiration date and the update of the document takes place only when it is required.

Although no further changes were adopted in 2012, regarding the Common Auction Rules of CASC, a Public Consultation was held by ADMIE, from November 7th to November 14th, 2012, for the Capacity Allocation Auction Rules in the borders with Albania, FYROM, Bulgaria and Turkey. RAE then approved the aforementioned Auction Rules, with its Decision 962/2012.

[19] RAE's Decision 1426/2011.

Regarding the interconnections with Albania and FYROM, the main characteristics remained unchanged, with independent rules for the calculation of NTC in force, since the provisions of the relative EU regulations and the 50%-50% management scheme for the capacity allocation were not fully accepted by the neighbouring TSOs. However, a change, associated to participants in temporary suspension, was introduced. During that period, the rights acquired by the participant through the yearly auction cannot be re-allocated in monthly auctions, but only in daily ones.

At the border with Bulgaria, Common Capacity Allocation Rules are being applied since 2011 to the joint auctions for the allocation of the total capacity, with the Bulgarian TSO performing the monthly auctions, while the Greek TSO performs the yearly and daily ones, along with the secondary market management. The rules have slightly changed after the aforementioned public consultation, with the adoption of the definition of the term “Force Majeure”, in accordance to the ACER CACM Framework Guideline.

Regarding Turkey, the interconnection with Greece entered its commercial operation in June 2011, but full implementation of the 714/2009 EU Regulation has not been possible yet. Independent rules have been adopted for the capacity allocation, with the scheme of 50%-50% management applied by the two national TSOs. There are no yearly products, as the current trial operation phase of the interconnection does not ensure the actual availability of the rights. ADMIE manages the agreed NTC in monthly auctions and, then, allocates in daily auctions only the monthly rights that were not declared (the Turkish TSO does not hold daily auctions).

The main principles of interconnection congestion management rules in 2012 remained the same as in 2011, namely:

- Yearly, Monthly and Daily (D-1): Explicit Auctions of Physical Transmission Rights (PTRs)
- UIOSI (“Use It Or Sell It”) rule applied to long-term PTRs (reallocation by HTSO at Monthly and Day-Ahead Auctions) and UIOLI (“Use It Or Lose It”) at the time of firm nomination
- Long-term PTRs are freely transferable between participants, subject to TSO approval of transferee eligibility.
- Allocated long-term PTRs are subject to cancellation by the TSO until the deadline for declaration of intention to use (D-1, prior to day-ahead auction) and up to a total of 35 days per year, in which case PTR holder is compensated at 100% of the long term auction price.
- Daily PTRs are firm.

Under this scheme, ADMIE managed, during 2012, capacity allocation on the interconnections and directions as follows:

Counterpart Country	Imports to Greece % of NTC	Exports from Greece % of NTC
Bulgaria	100% yearly, 100% monthly	100% yearly, 100% monthly
FYROM	50%	50%
Albania	50%	50%
Turkey	50%	50%

Table 5. HTSO responsibility for capacity allocation on interconnections

Income from congestion management has been used for purposes complying with the provisions of Reg.1228 and CM Guidelines, namely to reduce transmission network tariffs (see also Section 3.1.3.1 above).

3.2. Promoting Competition

3.2.1. Wholesale market

3.2.1.1. Description of the wholesale market

The Greek wholesale electricity market has been organised as a pure mandatory pool since its inception in 2005, so as to allow competition to emerge in a context with a severe constraint: no structural reforms were implemented on PPC, the incumbent vertically integrated monopoly utility, such as plant divestments or consumers release, as elsewhere in Europe. In particular, the incumbent remained dominant in both the generation and retail sectors, retaining exclusive access to cheap lignite and hydro resources, while retail prices, despite the gradual removal of cross-subsidies, were not linked to wholesale costs, but rather regulated at PPC's average cost, in order to transfer the benefit of the generator surplus to consumers. This combination of market features posed severe obstacles to new entry in the early years of market liberalisation, giving a strong signal for upcoming capacity shortages in the following years. The capacity certificates introduced in 2006 created incentives for new investment, which turned out to be adequate. More specifically, following the introduction of the capacity mechanism, 2024 MW of new, IPP gas capacity were added to the system by the end of 2012. However, projections for strong and prolonged growth of demand (around 2.5% at the annual level) were disrupted in 2009, when demand sank by 7% in a single year, due to the erupting economic crisis, and has not recovered since then. Hence, a substantial capacity surplus has emerged, with limited export possibilities and limited cost-reduction flexibility. In addition to diminished demand levels, the increasing penetration of renewables steadily curtails gas generation to an extent that may even expose them to the take-or-pay penalties set in their gas supply contracts.

In this challenging environment, the market experienced a significant change in 2012, in order to adapt to the implementation, from February 2012 onwards, of the ITO model, as opposed to the ISO model previously in place. In this context, the former ISO was restructured into two discrete entities:

- The Market Operator (LAGIE), which solves the day-ahead market, conducts its clearing, and engages into contracts with renewable energy producers, also managing the so-called Special Renewables Account.
- The System Operator (ADMIE), which, as a 100% subsidiary of PPC, owns the network, conducts the real time dispatch, the clearing of the imbalance market and the settlement of all other charges or payments.

It was mainly the allocation of tasks between the above two companies that changed, while the rest of the features of the market design remained the same. Various design details were progressively made more clear in 2012, so as to address technical, operational and legal issues that emerged. In essence, the current market design involves two distinct settlement processes:

- The settlement of the day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the SMP prices and the plant schedules derived from the day-ahead dispatch (load declarations submitted).
- The settlement of imbalances, in which deviations from day-ahead schedules are charged or compensated, based on the Imbalance Price, depending on whether they reflect the TSO dispatch orders or plant-specific reasons.

There is also a provision for imbalance penalties, if certain limits are violated, regarding the magnitude and the frequency of the deviations.

It should be noted that SMP prices, computed by LAGIE, and imbalance prices, computed by ADMIE, are derived by solving the same cost-minimisation algorithm with respect to the same technical and network constraints, based on the offers and bids submitted by generators and suppliers. In the former case, the values inserted for the various stochastic inputs (demand, plant availabilities and renewables output) are declared (day-ahead expected) values, while in the latter case, they are actual, metered, values.

In the day-ahead market, uniform pricing still applies, reflecting the offer of the most expensive unit dispatched, so that predicted demand is satisfied along with plant technical constraints and reserve requirements. Zonal pricing, intended to reveal congestion problems and signal the location for new capacity, has not been activated yet, although two zonal prices (for northern and southern Greece), applicable to generators, are explicitly derived, currently only as an indication. Participants may enter into bilateral financial contracts (CfDs), but physical delivery transactions are constrained within the pool and related contracts do not exist. A cap of 150 €/MWh has been imposed on all generators' offers.

The following rules or supplementary mechanisms remained in force in 2012:

- A lower limit is imposed on generators' offers, equal to the minimum variable cost of each unit in each trading period. This has been introduced because, in the current structure, the incumbent has a strong incentive to suppress wholesale prices.
- An exception to the previous rule is the 30% rule, which allows generators to offer 30% of their plant's capacity at a price below its minimum variable cost, as long as the total weighted average of their bids is still at or above their minimum variable cost.
- A cost-recovery mechanism ensures that generators dispatched by the TSO, beyond the day-ahead schedule, are remunerated based on their declared minimum variable costs plus a 10% margin. This mechanism creates a safety net, which often makes participants rather indifferent to the price levels.
- A Capacity Adequacy Mechanism (CAM) is applied for the partial recovery of capital costs of generating plants, with suppliers being obliged to buy capacity certificates from generators. In 2012, the value of these certificates remained regulated, at 45,000 €/MW/year (a level set back in November 2010), due to the significant market share of

PPC in the retail market and the consequent lack of liquidity and contracting between suppliers and generators.

The challenging issues that emerged in the electricity market during 2012 emphasised that apart from plant portfolio diversification, a crucial element for a more competitive market evolution, with self-sustained financial outcomes and less dependency on supplementary mechanisms, would be the emergence of vertical companies. Vertical structures would enable firms to mitigate risks through balancing their production and retail activities, with consumers being a physical hedge, hence, allowing transfer of costs and creation of value across the value chain. Apart from the liquidity crisis, which manifested clearly the effects of asymmetries, the need for such a market adjustment was emphasised further by the fact that the two main alternative suppliers exited the market in early 2012, creating a deficit of €172 million, and hence, the incumbent, PPC, recaptured a market share of 99.1% in the retail sector. In this context, RAE initiated an assessment of market design modifications, with the aim to stimulate structural market changes. These changes included virtual plant power auctions or more regulated measures, similar to the NOME approach applied in France. The common objective in such measures, irrespectively of their technical parameters, would be to allow generation portfolio diversification and reduction of average cost of supply for IPP generators, in order to facilitate their entry into the retail market and, hence, to enhance consumers' options and potential benefits. At the same time, RAE assessed market restructuring options, so that the local market becomes compatible with the Target Model framework (in particular, the market coupling with Italy, envisaged for the end of 2014). It should be noted that throughout the deregulation process, since its initiation in 2000, the market design has evolved, not independently of the underlying market structure, but in response to its asymmetries or inefficiencies, intending to alleviate the distortions arising from structural features.

In 2012, the wholesale electricity market exhibited features that could be perceived as signs of increasing maturity. More crucially, substantial new capacity had entered the system, intensifying competition for mid and peak demand. It is notable that the total installed capacity of gas plants became equal to that of lignite plants. In addition, PPC's share in the generation sector was reduced substantially to 79.5%, if calculated on conventional technologies (thermal and hydro) in the interconnected system, and to 63.5%, if renewable capacity is also taken into account. In addition to contributing to security of supply, the new gas capacity is expected to play a significant role through its flexibility in supporting the large-scale penetration of renewables, alleviating the strong fluctuations of intermittent output (mainly wind) and, also, entailing the ramping rates required to address the sudden elimination of solar energy in the evenings (sunset effect). These elements would be crucial for the revision of the various supplementary market mechanisms that RAE started reviewing in 2012.

Still, severe liquidity problems and credit risk issues, which started to emerge in early 2011, escalated in 2012. This crisis escalation partially reflected the deepening economic recession, which reversed the demand growth trend prior to the crisis and rendered a surplus of capacity, something that challenged severely the financial viability of the new plants and the prospects of recovery of the large investments made. Moreover, the liquidity crisis unveiled the internal inconsistencies of policies that the Greek State had implemented regarding retail and renewables tariffs. Although appealing in the context of social policy and renewables growth respectively, these policies, interpreted as revenue streams, led to large deficits. Costs were not correctly reflected or adequately transferred across the value chain. Most crucially, wholesale prices remained relatively low, but in no way reflective of the full energy production cost. Their levels are suppressed due to significant amounts of compulsory quantities, including mandatory hydro, plants' minimum operational levels, and renewables, which currently constitute a fast escalating component, with the rate of penetration of photovoltaic panels, in particular, rising exponentially. Nevertheless, the deviation between the depressed wholesale price levels (SMP) and the high feed-in-tariffs applied for renewable electricity reimbursement has created a sustained and continually increasing (not temporal, but structural) debt in the Renewables Account. This account is currently managed by the Market Operator (LAGIE), which was formed in February 2012, as a distinct entity to the TSO, in the context of the ITO model which was adopted, as opposed to the ISO model previously in place. The deficit of the RES account reached €400 million at the end of 2012, reducing the liquidity of the Market Operator and, hence, its ability to pay conventional generators, importers and renewable producers throughout 2012. Simultaneously, consumers' debts (unpaid electricity bills) escalated to 1.3 billion (estimated value) at the end of 2012, due to the severe economic recession and the incorporation, from autumn 2011 onwards, of a very substantial property tax into the electricity bill, which bulged its total amount. Another concerning element of the liquidity crisis in 2012 was its eventual impact on the gas sector, as IPPs accumulated substantial debts towards DEPA, amounting to €300 million. Given the delays in their payments by the Market and System Operators, the management of these debts was extremely difficult, and on various occasions gas producers received notices for disconnection of their gas supply.

This explosive situation raised unprecedented challenges, not only for the consumers and the market participants, but also for the Regulator. The need for structural reforms so as to resolve structural asymmetries and remove market distortions, both at a horizontal and a vertical level, became more urgent. This market restructuring direction must also be consistent with the required adjustments to the internal market paradigm (Target Model) envisaged for 2015.

Provision of Balancing Services

Balancing is not performed through a separate balancing market, but as an extension of the day-ahead market, through the Imbalance Settlement Mechanism, according to the following rules:

- All imbalances – referring to deviations between the day-ahead schedule and the real production or withdrawal of electricity – are settled through the Imbalance Settlement Mechanism.
- The imbalance settlement is conducted for each hourly trading period.
- During real-time operation, balancing energy is provided by the responsible body, based on the economic merit order of the offers that are submitted by the committed units on the day-ahead market.

- As soon as the relevant meter measurements are available, the imbalances are settled. Without explicit reference to technical details, the main concept is that each imbalanced party pays or receives an amount, depending on whether it injected or withdrew energy from the System, taking into account whether the change of its output compared to its day-ahead schedule is consistent with the TSO's instruction or is caused due to other, plant-specific reasons. The final amount is mainly determined by three (3) parameters: a) the ex-post clearing price, b) the imbalance quantity (TSO instructed or not), and c) the real (metered) quantity.

- The ex-post clearing price results from the re-run of the day-ahead scheduling algorithm under the realised values of the stochastic variables and corresponds to the "Market Clearing Price" (i.e. uniform price).

- Moreover, a cost recovery mechanism is included, so as to ensure that generators will receive at least their marginal cost whenever they operate. The objective of the imbalance mechanism setting is to minimise the total cost of operation of the System, while reimbursing plant flexibility.

The Balancing Settlement is performed by the TSO. Under certain circumstances (emergency cases), it is possible to use balancing energy from abroad, by using the residual capacity of interconnectors.

In view of the EU Target Model implementation, RAE is exploring the necessary market design changes, including the introduction of intraday and balancing markets.

Market Settlement

In 2012, the second year of the implementation of the revised market design, the day-ahead market represented 74% of generators' cash-flows. More specifically, the generators' annual revenues from the day-ahead market amounted to €2.7 billion, while ex-post settlements amounted to €1.04 billion. Hence, the turnover of the wholesale market reached €3.8 billion. The supplementary mechanisms of cost-recovery and capacity payments reached 462 and 457 million €, respectively, compared to 282 and 418 million € in 2011. While the parameters of the capacity mechanism remained stable, the total amount increased as new plants were added to the system. A crucial difference relative to 2011 was the escalation of the amount relating to the cost-recovery mechanism. This outcome was the result of more gas plants being dispatched at their minimum generation level. For PPC, the day-ahead market reflected 81% of its income as a producer, while for IPPs the corresponding percentage was 56%. Hence, ex-post settlement amounts became crucial for the viability of the new plants.

In particular:

- The balancing cost remained a minor fraction of the energy cost in the day-ahead market. More specifically, the generators' annual revenues from the day-ahead market amounted to €2.7 billion, while in total, their imbalance charges exceeded imbalance payments by a small percent, yielding a (negative) net amount of €34 million, with PPC contributing €13 million and independent producers receiving €48 million. For PPC, the imbalance charges for its lignite plants (which tend to exhibit production shortage in real time, relatively to their day-ahead dispatch) were counter-balanced, to a large extent, by the imbalance payments received by its hydro plants.

- The provision of ancillary services, in particular secondary reserves, amounted to €3.9 million, yielding less than 1% of total generators' revenues in 2012. Given the capacity surplus and the co-optimisation of energy and ancillary markets, generators diminished their offers for reserve provision, so as to secure their dispatch, even at their minimum operation level, and to receive, subsequently, a cost-recovery payment.
- The two supplementary mechanisms (cost-recovery and capacity certificates) yielded 25% of the total generators' revenues in 2012. For the IPP producers, the cash-flows from the supplementary mechanisms represented 39% of their annual revenues, with their day-ahead market component being constrained to 56%. For PPC production, the day-ahead market represented 81% of its revenues. The differentiation regarding the allocation of cash-flows across PPC and IPPs is evident, reflecting various structural asymmetries. Perhaps the most crucial factor is that, supplementary mechanisms translate into charges for suppliers and that PPC was the dominant supplier in 2012, recapturing also the customers of the two alternative retailers that defaulted. Being a vertically-integrated company, PPC reduced substantially its gas production in 2012 and, hence, constrained to 5%, its compensation from the cost-recovery mechanism, which was going to be charged to its supply business. Nevertheless, the cost-recovery component reached 32% for IPPs, as most of the time they got dispatched with levels of offers less than the SMP price, by using, as allowed, the 30% dispatch rule.
- The cost-recovery mechanism translated into a €319 million cost for PPC as a supplier in 2012, as opposed to €130 million in 2011 and 28.5 million in 2010, reflecting the increase of IPP production as a share of the total energy supplied to their customer base.

The distribution of generators' revenues from the day-ahead market and ex-post settlements is displayed in Figure 4. The excise tax imposed on natural gas is not displayed due to its different nature from the other streams.

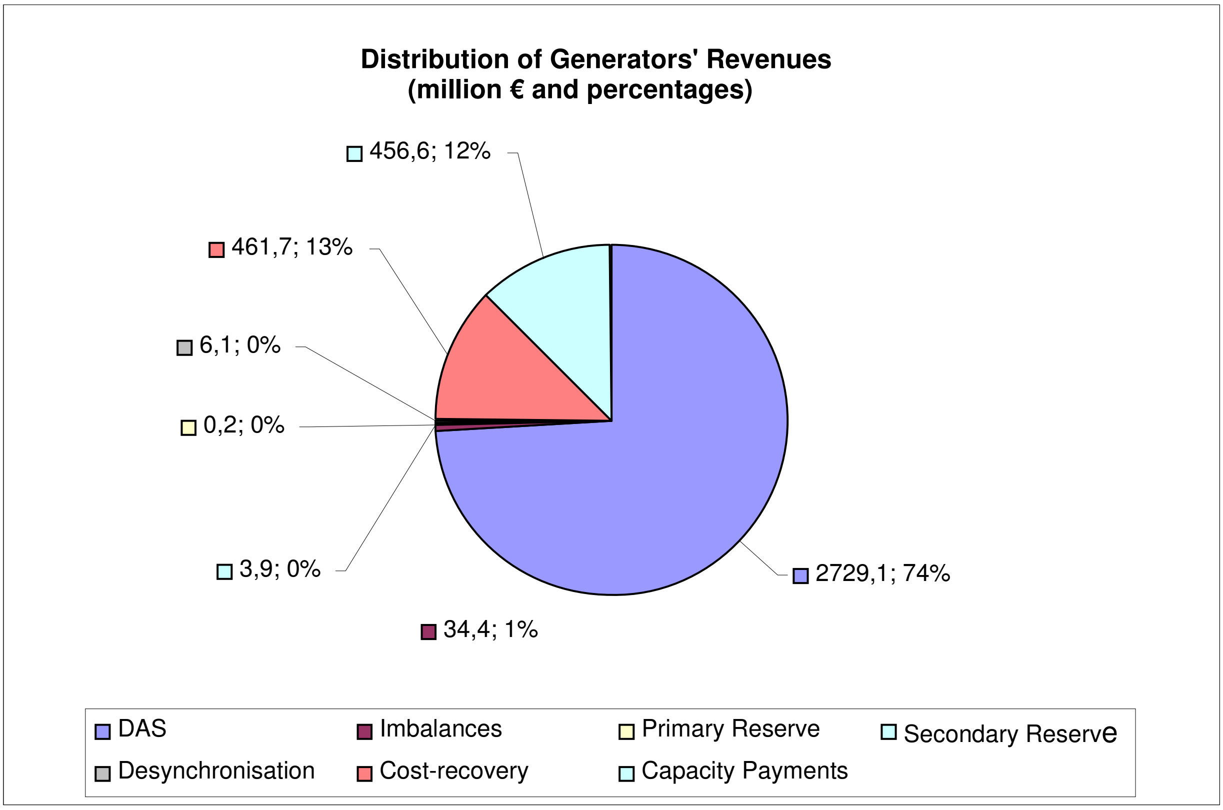

Figure 4. Generators' revenues from the day-ahead market and ex-post settlements in 2012

Market Volume

The day-ahead market yields the reference price for the industry, as it constitutes the major component on which generators' cash-flows are based. Due to the mandatory physical trading in this market, the traded volume of electricity is equal to the total production scheduled (the DAS outcome) plus the net interconnection balance. This value was equal to 50,507,475 MWh in 2012, reflecting a decline of 1.12% relative to 2011.

Given the compulsory nature of the market, it should be noted that the above figure reflects quite accurately the annual electricity demand, but does not coincide with it. Apart from the settlement of imbalances, emerging after the day-ahead market, a significant extra component is the production of renewables, mainly PVs, which are connected to the distribution network (as opposed to the transmission grid) and are not included in the TSO's metering, which is focused on the interconnected transmission system. This extra production was 2.59 GWh in 2012. Hence, the "true" demand in 2012 was not 50.56 GWh, as the TSO reported, but 53.15 GWh, partly covered by PVs connected to the distribution network.

Figure 5 displays the demand fluctuations at the aggregated monthly level, both based on grid metering and, also, by taking into account the PVs connected to the network.

A futures market has not been developed yet, while OTC trading has not been activated either.

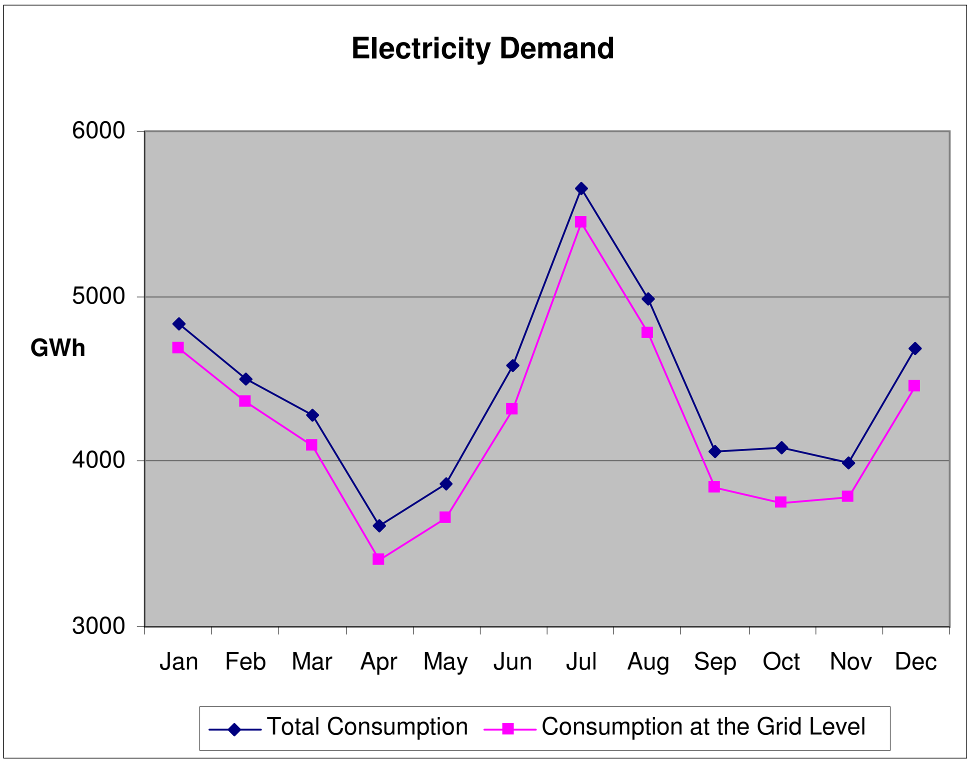

Figure 5. Electricity demand evolution over 2012

The installed capacity at the end of the year, as well as the annual production shares across fuels and imports, are presented in Section 3.4.1.

Market shares

Regarding the market structure, PPC retained in 2012 its dominant position. In the generation side, however, its market share declined substantially, reaching a level of 79.5% in terms of conventional technologies (thermal and hydro) in the interconnected system, and 63.5%, if renewable capacity is also taken into account. In the retail sector, the developments were in the opposite direction, as the incumbent restored a 99.1% market share after the exit of the two main alternative suppliers. In the generation sector, a less concentrated structure has been emerging gradually since 2010, when two new IPP units entered into commercial operation. This change was reinforced in 2011, with the addition of another two IPP plants, and subsequently, in 2012, with the addition of a fifth plant, all being similar in terms of capacity and technology (gas CCGT). In terms of thermal capacity, this direction of market evolution is not expected to persist in the future, as all private plants have now been completed, and the new plants expected to come on stream (Aliveri V and Megalopoli V) are owned by PPC. This outcome could change, however, if: a) plant divestments, included as a prerequisite in the Greek MoU on Specific Economic Policy Conditionality, or b) alternative measures on PPC's capacity allocation are implemented by the government in the coming years. Apart from conventional generation, changes in market structure were enhanced by an almost explosive penetration of renewables, in which PPC's share remains minor.

More specifically, following the entry of two new CCGT plants in 2010 (Elpedison Thisvi and Heron CC) and another one in 2011 (Protergia), a fourth similar plant, in terms of capacity and technology, i.e. Korinthos Power (434 MW), commenced its commercial operation in April 2012, having initiated its trial operation in December 2011. Hence, the market impact of new plants became more pronounced in 2012. Korinthos Power is a subsidiary company of the Mytilinaios Group, owned jointly with Motor Oil S.A., with shares of 65% and 35%, respectively. Given the above developments, the Mytilinaios Group became the largest IPP player in terms of installed capacity, followed by Elpedison with a total capacity of 812 MW. A new CCGT plant owned by PPC (Aliveri V, 417MW) was expected to start commissioning in the Spring of 2013.

Given the above developments, eight (8) IPP gas plants are currently active in the wholesale market. Their ownership structure is presented below:

- Enthess (389 MW) and Thisvi (410 MW), both CCGT plants, are owned by Elpedison.
- Heron II (422 MW, CCGT) and Heron I[20] (147.5 MW, OCGT) are owned by Heron Thermoelectric (GEK Terna - Gdf Suez).
- Protergia (433 MW, CCGT), Korinthos Power (434 MW, CCGT) and Alouminion (334 MW, large-scale CHP) are owned by the Mytilinaios Group.
- A cogeneration unit of 2 MW net capacity, with very limited activity in 2012, is owned by the Motor Oil refinery.

Moreover, as stated by the TSO in its most recent Ten-Year Network Development Plan (2014-2023), six (6) other thermal units, of total capacity 2476 MW, had also applied for connection by December 2011. This capacity included the incumbent’s new CCGT units and, more specifically, Aliveri V (417MW), projected to be completed in Autumn 2012, and Megalopoli V (811MW), the progress of which is linked to the expansion of the gas network in the Peloponese central region. The above capacity of 2476 MW does not include, however, the unit Ptolemaida V (660 MW), for which private investor involvement, along with PPC, has been discussed. In addition, five (5) hydro units, of total capacity 335 MW, had applied for connection by the end of 2011, while another 287 MW, already licensed, had not yet applied for connection (including Mesochora). The obsolete lignite units Megalopoli I and II, of 250 MW total capacity, were decommissioned.

Despite the substantial amount of capacity that had applied for connection in the past, the TSO estimated that due to the economic recession, various investment plans would be cancelled, which seems a reasonable assessment. The units expected to be added to the System over the next decade, which were used for system analysis, are Aliveri V, Megalopoli V, Ptolemaida V and Ilarion (a 153 hydro unit on the Aliakmonas river).

Electricity demand at the interconnected system remained quite stable in 2012, at 53.15 TWh, exhibiting a minor decline of 0.9% relatively to 2011. At the national level, demand reached

[20] The Heron OCGT unit, previously contracted with the TSO for the provision of ancillary services, retained, for a fourth consecutive year, a long-term capacity availability contract with the incumbent, PPC. As noted by Heron, this contract, similar to a tolling arrangement, increased the unit’s limited number of hours in operation, hence reducing gas transportation charges. During the June 2012 strike, this plant operated quite intensively and the same occurred in the gas crisis of February 2012.

63.4 TWh in 2012, relatively to 61.9 TWh in 2011, exhibiting an increase of 2.4%. It is notable that demand declined over the last quarter of 2012 by 2.4% relatively to Q4 2011, possibly due to milder temperatures or deepening recession effects, despite the fact that air-conditioning units continued to be used quite intensively for heating purposes (perceived by consumers as a less expensive option than oil). If exports and hydro pumping are not taken into account, the actual demand level was equal to 58.5 TWh in 2012, remaining close to that of the previous year.

Given the addition of substantial production capacity over three (3) consecutive years (2010-2012), the incumbent's market share declined significantly in 2012. In the interconnected system, PPC's share, in terms of volume, dropped to 77% of domestic production (excluding RES), while independent gas producers achieved a share of 23% (Elpedison 8.3%, Mytilinaios Group 11.5% and Heron Thermoelectric 2.9%). Renewables connected to the Grid, mainly wind, accounted for 6.3% of domestic production in 2012 vs 5.2% in 2011, reaching a total of 3113 GWh in 2012 vs. 2535 GWh in 2011. Taking into account this renewable output, PPC's overall market share dropped to 72.4%. In particular, PPC's gas production declined by 28% in 2012, i.e. to 1459 GWh, creating more space for IPP's production. This development yielded a €25 million reduction in PPC's gas cost.

At the national level (including non-interconnected islands), PPC's production covered 66.7% of total demand in 2012, the corresponding shares being 70.1% in 2011, 77.3 % in 2010 and 85.6% in 2009. Subsequently, this market share was suppressed further, reaching 64.2% in Q4 2012. In absolute terms, PPC's production plus imports decreased by 1083 GWh in 2012, adding to a reduction of 4451 GWh in 2011 and 5123 GWh in 2010. The import activity of PPC increased to 1992 GWh (+146 GWh relatively to 2011).

The HHI index for the wholesale market in 2012, a measure of market concentration, attained the value of 6183 in terms of volume, and 6507 in terms of installed capacity. In this calculation, it should be clarified that the plants Korinthos Power, Protergia and Alouminion are all assumed to belong to the Mytilinaios Group, as its ownership share in all is larger than 50%. It is notable that the HHI index exhibited, up to 2009, substantially higher values, close to the upper bound of 10000. This value indicates that the market is evolving in a more competitive direction, the basic structural constraint being the lack of fuel diversification for IPPs, as well as the lack of physical hedge for them (consumers).

3.2.1.2. Price Monitoring

Wholesale prices retained low levels in 2012, displaying a time-weighted average value of 56.60 €/ MWh, hence exhibiting a small decline of 4.7% relatively to their average value in 2011 (59.41 €/ MWh). Still prices remained quite higher than their depressed levels of 2010 and 2009, two years of intense wet conditions and very large hydro production. Focusing on monthly variations, depicted in Figure 8, the average SMP exhibited substantial variability up to September 2012, while remaining more stable in the last quarter of the year. At a monthly level, the average price fluctuated between 42.45 €/MWh in November, due to the large increase in hydro production, and 81.64 €/MWh in February (+45% compared to February 2011), due to the crisis that emerged in gas supply.

Overall, the above price evolution in 2012 reflected a convolution of factors, including:

- the high penetration of renewables, which enjoy by law a must-run status in the day-ahead market, reducing the net demand to be covered by thermal and large scale hydro plants, thus exerting a downward pressure on prices, with the relevant RES production quantities increasing by 18% (+512 GWh) compared to 2011.
- the capacity surplus of conventional plant, as 1700 MW of new CCGT capacity were added to the System over the last three (3) years, while demand declined by 4% over the same period, reflecting the deep economic recession.
- the large increase of hydro quantities in Q4 2012, that reversed earlier indications, up to that point, for a dry 2012 year, and led to an overall increase in hydro production by 60% (+ 1334 GWh) compared to 2011.
- the modification of the controversial excise tax, which had been imposed on natural gas from September 1st 2011 onwards, as an explicit component of the gas plants' fuel cost, raising concerns about its asymmetric impact on gas production vs. lignite and imports. As introduced initially, this tax implied an increase of 5.4€/MWh (thermal) on the unit price of gas, which resulted in an almost double increase in the variable electricity production cost of the gas plants (depending on plant efficiency). Following RAE's proposal, from January 18 2012 onwards, this tax ceased to be incorporated into the plants' offers, as an additive component.
- the impact of the 30% rule and the cost recovery mechanism, as gas plants attained stable dispatch profiles irrespectively of demand fluctuations, while lignite plants presented more variable dispatch profiles than usual.

While water scarcity exerts an upward pressure on wholesale prices, due to the need for substitution by more expensive energy, this effect was less pronounced in 2012 than in previous years due to the substantial capacity surplus in the market. At a more subtle level, the intra-yearly evolution of prices reflects: a) the seasonal variation of hydro releases (typically increasing in the summer, with a peak-shaving objective), b) the dynamics of gas prices, c) annual seasonality in renewable energy (mainly wind and solar), d) variations in the carbon price, affecting particularly the lignite plants, e) maintenance schedules and outages. Regarding the annual demand pattern, which is a crucial driver of intra-yearly price variations, it should be noted that in 2012 air-conditioning units were used extensively for heating purposes, as a substitute to heating oil, since the latter was perceived by consumers as a more expensive option. This consumers' reaction had an impact on electricity demand levels and, hence, on prices during the 2012 winter months.

Despite the declining trend in price levels, volatility of hourly prices increased quite substantially in 2012. Prices exhibited a standard deviation of 27.22 €/MWh, compared to 23.18 €/MWh in 2011 and 19.55 €/MWh in 2010. Regarding extreme levels, the SMP reached its maximum value of 150 €/MWh (price cap) in 39 hourly trading periods, all in February 2012, due to the gas supply crisis experienced in that month. The minimum level of 0 was attained in

97 hourly trading periods (compared to 35 periods in 2011), while prices exceeded 80 €/MWh in 30% of the trading hours. Zero levels occur during demand troughs (historically, over the Easter break in April), in which cases compulsory quantities (minimum plant generation, renewables and imports) may exceed consumption. Due to this surplus, imports, offered at a zero value, may get curtailed, setting the price to its minimum level. It is notable that this extreme case occurred only a single time in 2009, but escalated in subsequent years, reflecting the increasing penetration of wind generation, but also the stable dispatch of gas plants at their minimum levels, coupled with the decline in demand.

Figures 6 to 9 display the dynamics of the day-ahead price, SMP, across the year, as well as its intra-day profile. Given the market design changes introduced in September 2010, this price is the relevant market index, as it determines the largest part of the participants' cash-flows.

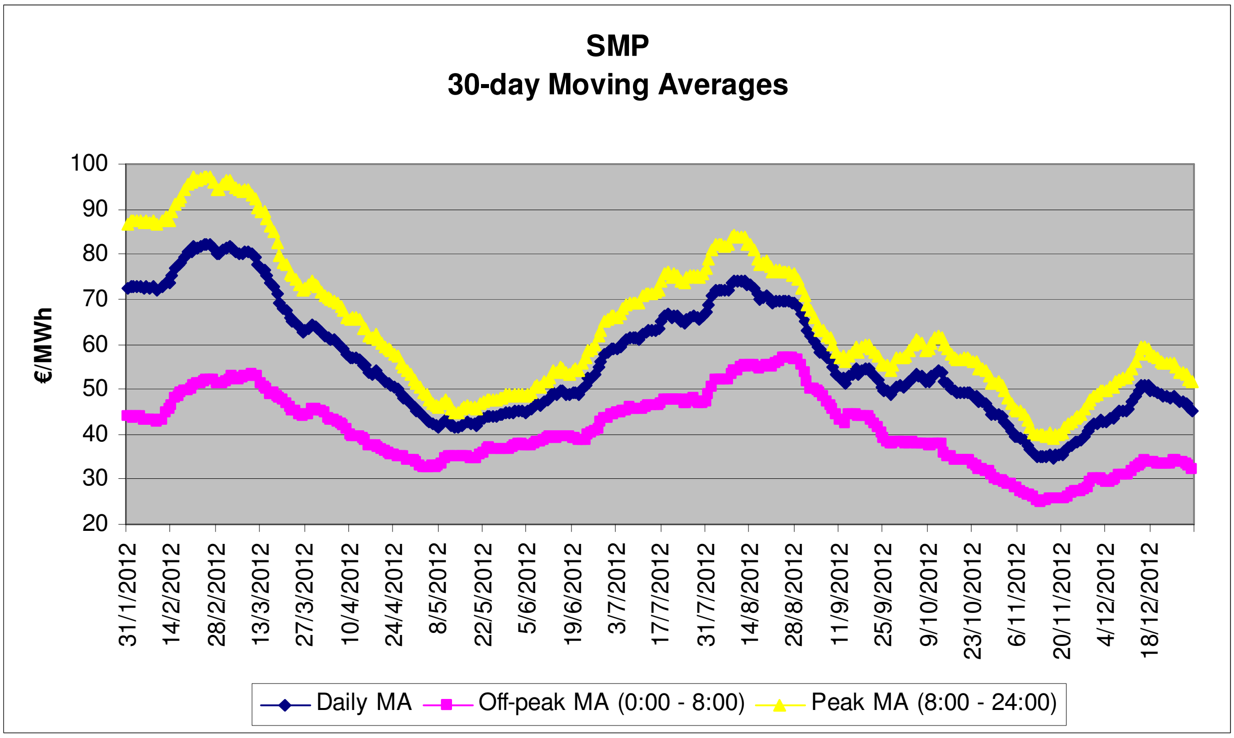

Figure 6. SMP dynamics (actual and smoothed levels) in 2012

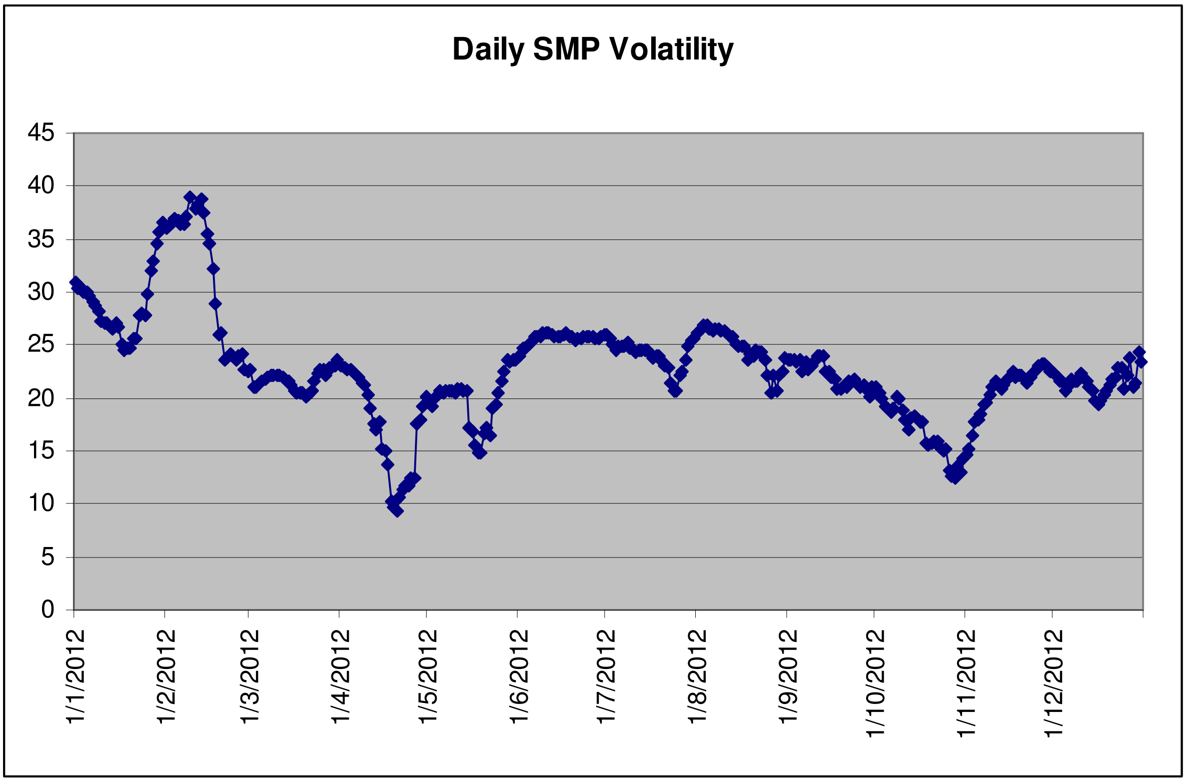

Figure 7. SMP volatility (st. deviation) in 2012

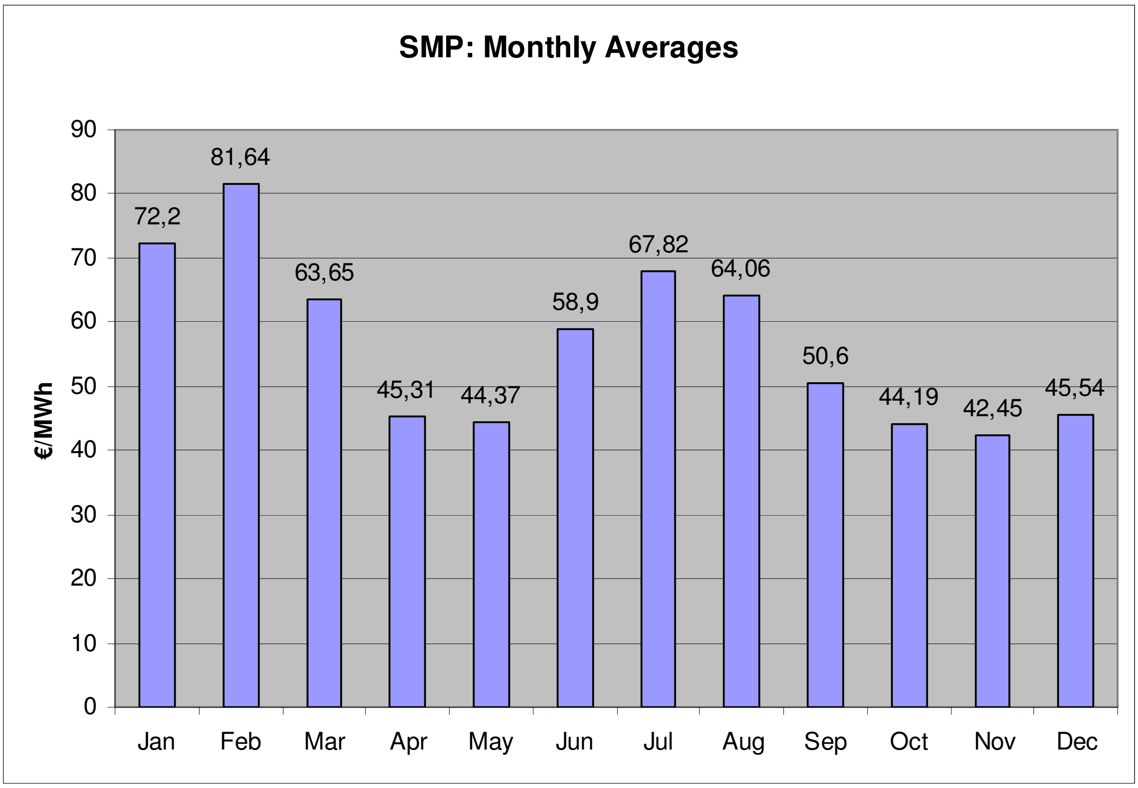

Figure 8. SMP intra-yearly pattern in 2012

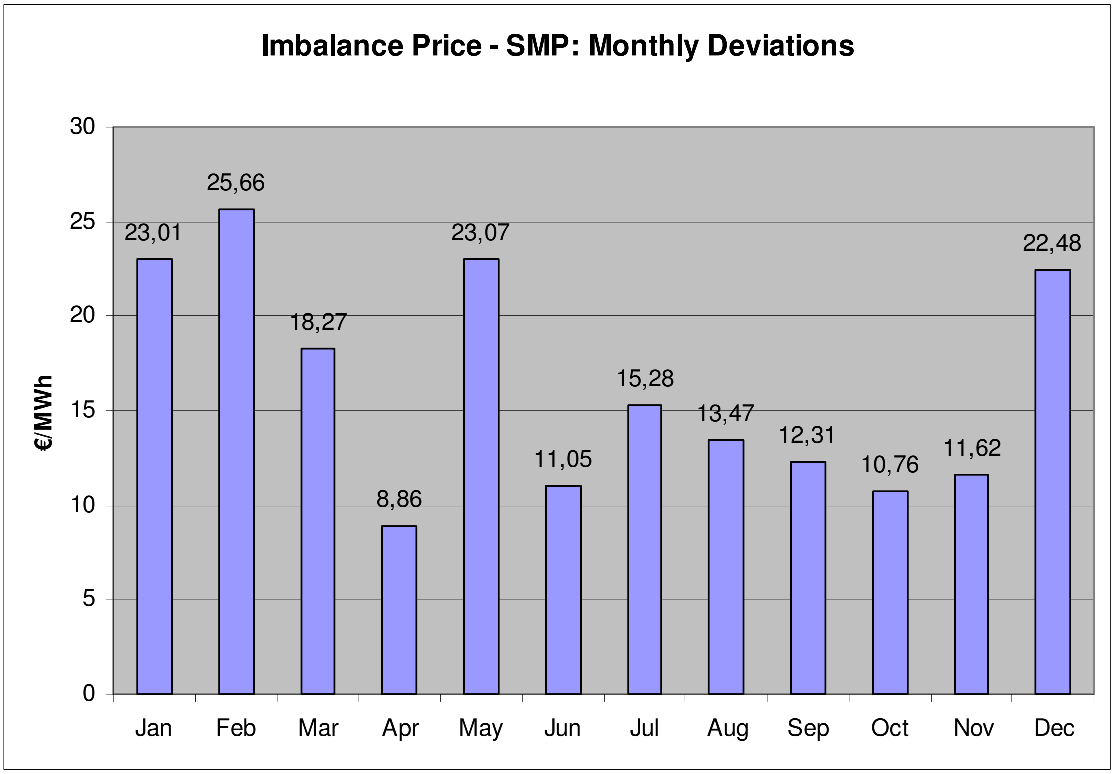

Figure 9. Imbalance Price - SMP: intra-yearly pattern of deviation in 2012

The declining market concentration at the generation side of the market would imply that the price impact of PPC would be reduced, particularly at peak demand intervals. The dominant objective of the incumbent over the previous years seemed to be to suppress wholesale prices, in order to reduce the cost of energy purchases (effectively from renewables, independent generators and imports) and, possibly, to curtail IPPs' revenues. Nevertheless, the addition of new plants and the stable dispatch patterns they achieved (large intervals of continuous operation with less shut-downs than demand variations would imply), which was a result of market rules interactions and generators' bidding, led to the increase of the wholesale market uplift accounts, which are covered by the suppliers. In this new context, it seems possible that PPC was not able to mitigate the substantial change in plant dispatch patterns and its cost implications (i.e. the escalation of its cost-recovery payments to IPPs). In addition, the stable dispatch pattern of IPPs reduced their risk and, possibly, their incentives also to get into the retail sector, along with the big obstacles that structural asymmetries posed. Simultaneously, PPC restored its retail market share to 99.1% in 2012, which meant that as a supplier it would be required to cover a larger amount of uplift charges, on top of wholesale prices. Given its vertical structure, a reasonable reaction of PPC would be to reduce the wholesale market cost and the uplift charges, to the extent that this would be feasible. Indeed, PPC chose to shrink its gas production, and hence, its expenses for the tax levy contribution, mainly being exposed to the compensation of IPPs through the supplementary mechanisms.

As in previous years, price offers by the thermal plants of the incumbent appeared to be very close to the minimum variable cost, with large discontinuities across plant technologies. In the past, this behaviour translated into high risk exposures for suppliers and exporters, whenever marginal technologies were altered between the (indicative) day-ahead dispatch schedule and the ex-post one, which determined cash-flows. Still, due to the imbalance settlement mechanism that now exists, this effect has been constrained to those players exposed to imbalances charges and it applies only to their deviations, not to their entire quantities. In addition, changes in the Italian market design implied that importers to Greece would be able to adjust their positions after the closure of the day-ahead market in Greece. This intra-day flexibility allowed them to better manage their risk in the Italian market and set the SMP in the Greek market more frequently, by interpolating between the levels of different technologies, usually approaching their upper level (instead of submitting a zero bid, as in the past). Hence, interconnection trading occasionally reduced price discontinuities, but to a small extent. LNG imports by IPPs did occur, yielding, temporally, significant cost reductions, but did not attain the frequency or extent that one would expect, partially due to severe take-or-pay penalties set in their gas supply contracts with DEPA.

Overall, following the addition of two new CCGT plants in 2011 and another one in 2012, competition has intensified between PPC's gas plants and IPPs for mid and peak demand. This effect has been amplified due to the continuous decline of electricity demand over the last four (4) years. The market dynamics changed as a result, but only to the extent that the details of the market design allowed. A critical factor for market outcomes was the market rule that allows generators to offer 30% of their plant's capacity at a price below its minimum marginal cost. This rule allows the dispatch of various plants for reserve provision, which is crucial for the plants' viability in an era of capacity surplus, but suppresses SMP prices to levels not reflective of the full production cost. In this context, RAE has proposed the removal of this rule, which has turned out to be rather distorting. Furthermore, the cost-recovery mechanism - a supplementary scheme - creates a safety net, which often makes generators rather indifferent to the price levels and induces an emphasis on quantities produced, rather than on prices shaped.

Competition in the reserves market has been particularly intense, as well. In the provision of secondary reserve, which is crucial for renewables penetration, all new IPP units were active in secondary reserve provision, while PPC was represented only by the units Komotini and Lavrio 4.

An appropriate link between wholesale and retail prices and, more importantly, the development of competition in plant technologies other than gas (either through PPC plant divestments or energy release e.g. through auctions) are critical factors for the market to evolve in a more competitive direction.

3.2.1.3. Monitoring of transparency

Following the transparency requirements posed by the Codes, the TSO and the Market Operator publish on a daily basis detailed market data related to the day-ahead market and the imbalance settlement mechanism, respectively. The published data are not confined to hourly levels of prices and key fundamentals. Both ADMIE and LAGIE upload Excel files with clear quantitative market inputs (except generators' offers and suppliers' bids which constitute confidential data), as well as all outputs relevant to the cost-minimisation algorithms that each operator solves. In this context, ADMIE publishes on a daily basis forecasts for various market inputs, including demand and renewable production (across technology categories), plant availability declarations, mandatory water declarations submitted by PPC on a weekly basis (forecasts or metered data), reserve requirements, long-term interconnection capacity rights and NTC values. Apart from market inputs, the TSO also publishes the real-time plant schedule (DS), solved with the TSO's demand forecast (instead of load declarations) and with network constraints more explicitly incorporated. This schedule is obtained initially on a day-ahead basis and subsequently, gets updated within the day. In addition, ADMIE publishes the outcomes of the ex-post market clearing obtained with metered data (instead of predicted values) for the various inputs. LAGIE publishes the values of inputs inserted to the DAS algorithm and all the resulting market outcomes, including prices and plant schedules for the day-ahead market, along with primary and secondary reserve (which are co-optimised), as well as tertiary reserve quantities. Monthly reports, which had been developed before the adaptation of the ITO model, continued to be published by ADMIE, focusing on production allocation, fuel market shares and demand segmentation, but not on prices.

With the objective to increase transparency by further clarifying market parameters and market conduct, a daily market report, which has been developed by RAE and has been uploaded on its website since July 2011, continued to be released. The report displays and summarises the dynamics of market fundamentals and market outcomes, such as schedules, market shares, emissions, as well as deviations between day-ahead and real-time quantities. In this context, distortions, such as systematic over- or under-declarations in generation or supply, are illustrated in easy-to-follow graphs. During 2012, RAE requested from LAGIE and ADMIE to develop their own monthly reports, displaying outcomes of the day-ahead market and ex-post settlements respectively, so as to comply with the requirements of the new codes. LAGIE issued its first report for the month November 2012, which was subject to revisions and additions, before its standardised format was finally approved by RAE. This report is uploaded on LAGIE's website, on a monthly basis, from November 2012 onwards.

3.2.1.4. Regulatory progress in wholesale market issues in 2012

The regulatory focus in 2012 was mainly on managing/certifying/finalising the structural changes of the TSO, on the better handling of the escalating cash liquidity crisis in the energy sector, and on the fine-tuning of the Regulator's market restructuring proposals, which were finalised by RAE in November 2012, after a series of public consultations, with the aim to alleviate structural asymmetries and remove market distortions, promote a sustainable market in terms of liquidity, and create a framework progressively more compatible with the Target Model requirements.

Indicatively, during 2012, RAE worked on the following issues:

- The implementation of the ITO model (as opposed to ISO), from February 2012 onwards, and hence, the re-structuring of the former ISO into two discrete entities:
    - The Market Operator (LAGIE), which solves the day-ahead market, conducts its clearing, and engages into contracts with renewable energy producers.

    - The System Operator (ADMIE), which owns the network, as a 100% subsidiary of PPC S.A., conducts the real time dispatch, the clearing of the imbalance market and the settlement of all other charges or payments.

- The certification of the new TSO, ADMIE, according to the principles and criteria defined by RAE in its Decision 962A/2012, in compliance with EC requirements.

- The separation of the unified Grid and Market Operation Code, which was in force up to January 31st 2012, into the Transmission Network Code and the Market Operation Code.

- The assessment of the potential for virtual power plant auctions or measures similar to NOME applied in France, so as to allow portfolio diversification and average cost reduction for independent producers and suppliers, facilitating their entry into the retail market, enhancing competition on a level playing field, and increasing consumers' options and potential benefit.

- Determining the cost and efficiency of market restructuring options, so as to become compatible with the Target Model framework (in particular, the market coupling with Italy).

- The modification of the controversial excise tax imposed on natural gas from September 1st, 2011, which created substantial asymmetries among fuels. Initially, added to the fuel cost of plants and, hence, reflected on wholesale prices, this tax inflated market costs that were passed on to suppliers and, eventually, to consumers. Following RAE's proposal, this tax was removed from the plants' offers (with effect from January 18th, 2012 onwards). The corresponding amount would get recovered more directly, through a specific market uplift account (UA-3).

- The incorporation, from July 18th, 2012 onwards, of the renewable electricity production from plants connected to the distribution network, into the market resolution, so that this production is also taken into account explicitly, along with the RES output connected to the high-voltage transmission grid. The TSO was required to develop a forecasting model, so that this generation is explicitly taken into account into the market resolution, as an additive term to the predicted RES production from plants connected to the transmission grid (rather than taking it into account implicitly, in the load declarations submitted by PPC through its subtraction from their customers' estimated demand).

- The determination of the opportunity cost of water, explicitly linking this cost to reservoir levels and to the cost of the substitution fuel mix, as its main parameters. The methodology submitted to RAE by LAGIE in November 2012 was subject to refinements, assessment of reservoir security issues, and preliminary testing. More specifically, RAE worked on refinements so as to mitigate the volatility of preliminary outcomes, arising from the inevitable technical complexities, as well as the values of key parameters (the response rates to changes in reservoir levels and the windows of historical data sets involved).

- The correction of an error made by the TSO in the application of the formula computing secondary reserve payments and charges and the imposition of a penalty.
- The incorporation of high-efficiency, large-scale cogeneration dispatch issues and reimbursement mechanisms in the Codes.
- The calculation of losses in transit flows and TSO's potential reimbursement for loop flows.
- A stricter framework for the TSO's credit cover approach and a close follow-up of its practice towards suppliers' liquidity problems, in particular, regarding the guarantees required for their participation in the market (following indications in the past of a lenient approach and not strict application of the Code).
- An investigation of the abnormal conditions that led to curtailments of electricity exports in February 2012, during the crisis that at the time had erupted in natural gas. A report was sent to ACER, in response to the questions raised by the Agency.

Regulatory measures regarding the above issues were either adopted during 2012 or carried over to 2013 via public consultations. The implementation of market reforms, along with further elaboration of their features, will continue in 2013.

RAE's proposals on the restructuring of the domestic electricity market

On 26.11.2012, RAE published its final detailed proposals on the restructuring of the domestic electricity market. These proposals cover both the wholesale and retail markets, including RES generation, but are presented in this section as they mostly affect the wholesale market. The final RAE proposals were the product of further elaboration, detailing and optimisation of its initial proposals, that were unanimously approved by the Board of RAE in the summer of 2012, followed by an extensive 3-phase public consultation process and an open day at RAE's premises, on 15.11.2012.

In summary, RAE's proposals include:

- Auctioning procedures for securing third-party access to the country's lignite and hydro recourses, aiming at the transfer of part of the producer surplus to the final consumer through other than PPC market participants (suppliers, etc.). More specifically, RAE proposed the adoption of a model similar to the French market model (NOME), according to which lignite and hydro energy production is sold by PPC to alternative participants through auctioning procedures. The participants purchasing these energy products will be restricted to selling them in the Greek retail market. The result of this will be the enhancement of competition on the production and supply side of the Greek electricity market chain, by making supplier portfolios more equitable in terms of fuel mix and costs, and eventually by transferring the benefit of the reduced average cost for alternative suppliers to the final consumers, in the form of lower tariffs and prices (in comparison to prices paid under marginal pricing mechanisms), since it will also reflect the economic surplus of a lignite and hydro energy producer.

- One (1) year of final transition period for the complete abolition of the variable cost-recovery mechanism and the 30% rule. This 1-year period would start with the immediate elimination of the margin of the variable cost-recovery mechanism, from 10% to 0%, followed by the abolition of the 30% rule within the next six (6) months and, finally, by the abolition of the cost-recovery mechanism altogether, six (6) months later. The basic precondition of this step-by-step elimination process is the full and effective implementation of the rest of the proposed RAE measures and, foremost, those related to the auctioning of PPC energy output, as described above.
- Redesigning of the transitional Capacity Assurance Mechanism (CAM), particularly taking into account the steady reduction of the load factors of thermal units, as a result of high RES penetration. This mechanism is considered absolutely necessary and must be given a stable long-term structure and status through the application of market rules, as it is perceived playing a key role in ensuring the viable and efficient coexistence of conventional thermal and RES production units, in the long term.
- Designing a detailed Code for the management of large hydro stations and water resources and, foremost, developing of a specific methodology for the calculation of the minimum bid price that can be offered by a large hydro station on the wholesale market.
- Shifting the operation of the market to a daily basis (clearing within 24 hours), which will result in the reduction of volumes traded and cleared, thus decreasing the resulting credit risk and financial guarantees required by the participants, and also improving risk management, which is crucial in view of rising unpaid invoices. The proposed solution has a 6 to 12 months horizon for final implementation and, combined with the parallel promotion of bilateral contracts (such as contracts that will be auctioned through the NOME market model), can immediately and proportionately reduce (with respect to the volume of the auctioned MW & MWh) the managerial risk of the Market Operator (LAGIE), creating a more stable and secure economic transactions environment.
- Creation of a “Credit and Clearing House” (CCH) facility, which would undertake the market clearing and credit risk, instead of the market and system operators. The implementation of this proposal is considered difficult, for the time being, due to the country’s still weak economic environment and the difficulties faced by the domestic banking sector that would be called upon to undertake this CCH role.
- Alternatively, the creation of a specialised Energy House was proposed by RAE, which would manage all market cash flows, with an emphasis on the management of the unpaid electricity bills of the suppliers and especially those of the PPC.
- Specific recommendations on structural changes to the national RES support schemes and compensation mechanisms currently in effect, in order to alleviate the large accumulating deficit in the RES Special Account.
- Proposals concerning the retail market and prices (removal of distortions from end-user tariffs, studies concerning cost reduction and efficiency incentives, removal of all non electricity-related charges from the electricity bills (e.g. property tax, municipality taxes, radio & TV fees, etc), reduction of direct and indirect taxes on electricity, etc.

- Gradual transition of the domestic energy market organisation/structure towards the European Target Model in the 2014-2015 period.

RAE's detailed proposals, including a proposal for the formation of three (3) high level RAE-ADMIE-LAGIE Working Groups, in order to analyse in further detail and design the required actions and timetables for the implementation of the said proposals, were submitted to the Ministry of Environment, Energy and Climate Change for final approval (which was granted in February of 2013).

In parallel, RAE conducted a separate public consultation process, focusing on the step-by-step adoption and, finally, full compliance with the EU Target Model. Following RAE's publication, in December of 2011, of a Strategy Paper entitled "*RAE's Roadmap and Action Plan in the context of completion of the integrated European electricity market*", and in an effort to assess alternative options, approaches and scenarios for the restructuring of the domestic wholesale electricity market, in light of the country's obligations stemming from its participation in the integrated European energy market (EU Target Model), RAE, in close collaboration and co-funding with the Independent Power Transmission System Operator (ADMIE), commissioned a relevant study to an international Consultant. The study examined three (3) alternative approaches/scenarios for the restructuring of the Greek electricity market, all in final compliance with the provisions of the Target Model (taking into account European regulations and guidelines available at the time of the study):

- An adaptation scenario based on the existing Greek market model ("Adaptation Option"),
- An adaptation scenario based on the North-Western European Power Exchange model ("NWE Option"),
- A hybrid model, combining a voluntary (instead of mandatory) pool, with forward, physical bilateral contracts ("Hybrid Option").

The findings of the study were announced on RAE's web page, as the basis for a public consultation initiated in November 2012, and within the broader scope of the restructuring of the existing domestic electricity market. The consultation's results and participants' comments will be taken into account in shaping up RAE's final proposals.

3.2.1.5. Market liquidity in 2012

During 2012, the conditions in the electricity market became increasingly more difficult, as participants were faced with an unprecedented lack of liquidity, resulting from the deterioration of the Greek economy for the fourth year in a row. At the same time, the recapitalisation of the Greek banks reduced the available credit, which resulted in an increased level of risk and interest rates and, subsequently, decreased the overall cash flows of the market.

More specifically, at the end of 2012, PPC had a € 1.3 billion of mature receivables from its customers and, due to its key position in the market, this huge lack of liquidity severely affected all market participants. The utilisation of PPC by the Greek Government as a collection mechanism (instead of the tax authorities) for a new property tax, substantially increased the electricity bill of all customers and, coupled with a Supreme Court decision not to cut off electricity to customers that had not paid this property tax, resulted in a free fall for the collection of PPC's receivables. This situation negatively affected the cash flow of PPC and, due to its dominant position in the market, a spill-over occurred in all participants' cash flows. The Market Operator (LAGIE) presented a deficit of approx. € 400 million – mainly debts to IPP's, importers and RES producers. In turn, the debt of IPPs towards DEPA (the national gas supplier) was approx. € 300 million, causing large difficulties to DEPA in its payments to its own suppliers (Gazprom, Botas, ENI), especially during the summer months of 2012. Moreover, the exit from the market of the two biggest alternative electricity suppliers, "Hellas Power" and "Energa Power Trading", created an additional deficit of €172 million - a debt which, during 2012, was transferred to ADMIE and LAGIE[21].

<u>Structural Reasons</u>

These refer to the process of liberalising the electricity market, the distortions in the wholesale and retail markets and the very generous incentives for the RES producers. More specifically:

- The Greek Government did not move forward aggressively the liberalisation of the market but, instead, opted for solutions that can be characterised as "middle of the road", ensuring the continuation of the dominant position of PPC, both in wholesale and retail:
    - The retail price, still, does not reflect the System Marginal Price (SMP), i.e. the price of the wholesale market. PPC continues to have the opportunity and the motive to keep the SMP at low levels through its regulated tariffs, but with the imposition, since September of 2011, of the 20% special tax on natural gas (including gas for electricity production), the company has suffered a significant financial burden.
    - On the retail side, the low price of SMP helped open up the retail market, but attracted participants that were mostly interested in short-term profits. When the SMP (from September 2011 onwards) started to increase considerably, these participants were not able to adjust accordingly, and it was a matter of time before they exited the market. Moreover, the abrupt exit of the two major alternative retail players ("Hellas Power" & "Energa") "closed" again the retail market, since it practically returned PPC to its previous monopoly condition (98% of the retail market), and also left a debt of €172 million to the market[22].
- PPC's tariffs are burdened with various levies and taxes, which increase the electricity bill by approximately 40%.

[21] Even today (2014), it has not been possible to disclosure and retrieve these amounts (debts) from the frozen bank accounts of the said two suppliers, because, according to a judicial ruling, they are considered to be the product of illegal and money laundering activities.

- The continuous and rapid penetration of RES in the electricity system and their generous fixed-price compensation, set by law for twenty (20) contractual years, has opened up a deficit that increases monthly by about €25-30m for the Market Operator (LAGIE), which cannot be financed further.
- Another structural reason was the extremely difficult position of the Greek banking system due to their mandatory participation in the PSI (Public Sector Initiative), which resulted in the dramatic reduction of available credit for the market participants and affected considerably their cash flows.

In this extremely difficult environment, RAE undertook several initiatives and measures to foster liquidity in the market and to help create a financially viable environment, through effective management of the credit and market risk.

- In order to better monitor the debts of market participants to ADMIE (the TSO) and LAGIE (the Market Operator), RAE has requested from 2011 onwards, to be informed by the two Operators, on a monthly basis, on the status and evolution of these debts, as well as on the specific actions the two Operators were undertaking to recover them. Moreover, RAE has requested that the debts of the two Operators to the participants be also presented. In this way, RAE was able to have a more complete view and understanding of the cash flows among Operators, Producers, Suppliers and Traders. During 2012, RAE systematically monitored the flow of economic transactions and when reasons for further investigation were identified, RAE proceeded even to the point of calling the companies in question for official hearing procedures.
- In May 2012, RAE asked both the TSO and the Market Operator to establish detailed, step-by-step processes, by which the two Operators would collect their receivables, in case a participant does not comply with his financial obligations. Special attention was given to the case where a participant cannot pay back his debt, after a prespecified period of time has expired, and, in this case, a detailed timetable, with specific steps and actions was drawn up by each of the two Operators. These were evaluated in detail by RAE and both Operators were asked to adjust their processes and action plans accordingly.
- Taking into account the extreme market difficulties of issuing Credit Letters by the banking sector, RAE decided to retain in 2012 the same amounts as in 2011, for the Credit Letters that the participants had to submit, as guarantees, to the Operators. Nevertheless, in January 2012 and in April 2012, RAE was obliged to issue strong recommendations and warnings to numerous participants, to submit their Credit Letters and to honour their financial obligations towards the Operators.
- Despite the strong RAE warnings, a number of market participants did not fully comply, and taking also into consideration the urgency that the tight liquidity situation presented even from the beginning of 2012, RAE called, for official hearing procedures, a number of market participants, as well as the two Operators themselves. More specifically:

- In February 2012, the companies Energa and Hellas Power were called by RAE to an official hearing, in order to provide information and disclose their actions regarding their financial transactions related to the network charges
- The following companies were called by RAE, between May and July 2012, to official hearings, in order to provide information concerning their overall financial obligations and transactions:
  - Vivid Power EAD
  - Revmaena EPE
  - Greek Energy SA
  - Electriki Thrakis SA
  - OET Hellas
  - Elpedison Power SA
  - In July 2012, PPC SA, ADMIE SA, LAGIE SA and the company Elpedison Energy SA, were called by RAE to an official hearing, in response to a formal Complaint submitted by Elpedison to the Regulator, about the netting practices between PPC SA and LAGIE SA.
  - In November 2012, the two Operators (ADMIE SA and LAGIE SA) were called by RAE to an official hearing, in order to provide necessary information about their financial transactions and detail their specific actions to ensure the timely response and full honouring by the market participants of their financial obligations to them.
  - Also in November 2012, PPC was called by RAE to an official hearing, in order to provide information concerning its financial obligations towards ADMIE and LAGIE.

Moreover, the integrated body of proposals publicly announced by RAE in November 2012, regarding the restructuring of the domestic electricity market (see Section 3.2.1.4), included:

1. Shift to a Daily Market (clearing within 24 hrs)

The optimal solution for improving liquidity is the transition to a daily market, in which the clearing takes place within 24 hrs. This solution has the following advantages:

1. It drastically and immediately reduces the credit risk of the participants
2. Based on the above point, it accommodates and simplifies significantly the cash flow management of the participants and, in case a problem is presented, it can be easily identified and corrected.
3. It reduces the amount (level) of Credit Letters required by the participants
4. There is sufficient liquidity in the market, which can easily address any potential deficits

5. Even if a certain participant cannot comply with his financial obligations and creates a potential debt, the market is in a position to “absorb” this obligation, as the amount refers to a daily market, is smaller and more manageable.

This daily-clearing solution proposed by RAE has a time frame for its overall implementation of 6-12 months and if co-ordinated with the promotion of bilateral contracts (as envisaged by RAE in a variation of the NOME model), it reduces substantially the market risk of the Operator (LAGIE) and creates a viable and secure environment for financial transactions.

2. Credit House and Clearing House

After extensive research by RAE and various meetings with banks and other financial institutions, it became apparent that the creation of a Credit House and Clearing House was, at that time (late 2012 – early 2013), not feasible, due to the adverse economic environment and the severe pressure that the Greek banking sector was facing. The lack of interest on behalf of the Greek banks to participate in such a scheme (Credit House/Clearing House) can be attributed to the following reasons:

- The difficulty of determining the exact size of the credit risk to be covered, a figure which, in any case, would be quite high
- The need to cover initially the already existing debt of the Market Operator (LAGIE), which at the end of 2012 was approx. € 400 million, an extremely high figure even in the case of syndicated co-operation of banks
- The critical condition of the domestic banks, especially after their mandatory participation in the “haircut” of Greek Bonds (PSI).

In case the above combined approach, proposed by RAE and put forward for 2013 (transition to a daily market and introduction of bilateral contracts through NOME) proves unsuccessful, then, in 2014, an even more “radical” option will be examined by the Regulator. More specifically, an “Energy House” could be established, that would take over the responsibilities of a Credit House and Clearing House. The “Energy House” will manage all the financial transactions among the various players in the energy market, with special emphasis given to the collection of receivables at the retail level. Its responsibilities will include:

- Financial transactions as they are cleared by the Operators. These transactions refer to both the retail and the wholesale markets and cover all regulated and non-regulated charges
- Credit cover, monitoring of credit performance and determination of credit letters and credit lines
- Provision for financing, liquidity pool
- Loan facility to both Operators, if costs occur which cannot be handled by them
- Reporting

3.2.2. Retail market

3.2.2.1. Description of the retail market

Competition and market shares

The retail electricity market was marked in 2012 by the exit of four (4) independent electricity supply companies, due to their significant debts accumulated with the Transmission System & Market Operator (then, DESMIE SA). These companies included the two major independent suppliers, “Energa Power Trading SA” and “Hellas Power SA”, which represented 3.8% and 3.6%, respectively, of the total market volume in 2011. PPC (the incumbent utility) then acted as Supplier of Last Resort, according to the provisions of Law 4001/2011, for all former customers of the above 4 suppliers.

As a result of the market exit of the said independent suppliers, PPC’s market share increased to 99.8% of total volume, with only 0.75% of the total volume of medium (MV) and low voltage (LV) customers serviced by other suppliers. At the end of 2012, there were only 6 (swix) active suppliers (5 independent ones plus PPC) in the retail market, with no new market entrants. The tables that follow show the breakdown of customer numbers and MWhs sold by each active supplier (interconnected system only).

Among the remaining independent suppliers, only “Elpedison Energy SA” and “Heron SA” belong to vertically-integrated companies, representing 2.5% of the total number of eligible meter points in the MV category.

Overall, in the domestic electricity market, the total number of customers in 2012 was 7,365,582 and their total consumption was 52,125,266 MWh, showing only small differences compared to the corresponding 2011 data. Regarding household customers, their total number was 5,681,124 in 2012, while the total number of household customers with a supplier other than the incumbent was only 6,053 (see Table 6).

By eligible meter points							
Customer type	**Total**	**PPC SA**	**ELPEDISON ENERGY SA**	**WATT & VOLT SA**	**HERON SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**VOLTERRA SA**
Household customers	5.062.141	5.059.776	3.688	1.761	278	321	5
Small Industrial and Commercial customers	1.150.421	1.144.057	10.998	2.039	2.789	1.502	34
Other LV customers (eg. agricultural, public, traction)	307.540	307.540					
Total LV customers	**6.520.102**	**6.511.373**	**14.686**	**3.800**	**3.067**	**1.823**	**39**
Industrial and Commercial customers of MV	7.658	7.528	92	13	98	9	10
Other MV customers (eg. agricultural, public, traction)	1.639	1.639					
Total MV customers	**9.297**	**9.167**	**92**	**13**	**98**	**9**	**10**
Total LV & MV customers	**6.529.399**	**6.520.540**	**14.778**	**3.813**	**3.165**	**1.832**	**49**
By eligible volume (MWh)							
Customer type	**Total**	**PPC SA**	**ELPEDISON ENERGY SA**	**WATT & VOLT SA**	**HERON SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**VOLTERRA SA**
Household customers	16.714.282	16.709.824	6.028	1.631	1.914	893	21
Small Industrial and Commercial customers	10.123.052	10.015.005	107.279	12.097	74.954	16.860	4.137
Other LV customers (eg. agricultural, public, traction)	3.734.028	3.734.028					
Total LV customers	**30.571.362**	**30.458.857**	**113.307**	**13.727**	**76.868**	**17.752**	**4.158**
Industrial and Commercial customers of MV	8.470.684	8.375.027	86.137	2.404	82.920	3.666	6.667
Other MV customers (eg. agricultural, public, traction)	1.513.379	1.513.379					
Total MV customers	**9.984.063**	**9.888.406**	**86.137**	**2.404**	**82.920**	**3.666**	**6.667**
Total LV & MV customers	**40.555.425**	**40.347.263**	**199.444**	**16.132**	**159.787**	**21.418**	**10.825**

Table 6.Market share of the active suppliers, by eligible meter points and by volume, per consumer category in 2012

Electricity consumption for the interconnected system (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small Industrial and Commercial customers**	**Other** (eg. agricultural, public, traction)	**Total (GWh)**
LV	**2009**		16.368	11.432	3.608	**31.408**
	2010		16.477	12.257	2.805	**31.539**
	2011		16.116	10.535	3.526	**30.177**
	2012		16.714	10.123	3.734	**30.571**
MV	***2009***			9.273	1.425	**10.698**
	2010			9.674	1.447	**11.121**
	2011			9.125	1.397	**10.522**
	2012			8.471	1.513	**9.984**
HV	***2009***	*6.007*			1.358	**7.365**
	2010	*6.355*			989	**7.344**
	2011	*6.613*				**6.613**
	2012	*6.507*				**6.507**
Total	***2009***	*6.007*	16.368	20.705	6.391	**49.471**
	2010	*6.355*	16.477	21.931	5.241	**50.004**
	2011	*6.613*	16.116	19.660	4.923	**47.312**
	2012	*6.507*	16.714	18.594	5.247	**47.062**

Electricity consumption for the non-interconnected islands (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small Industrial and Commercial customers**	**Other** (eg. agricultural, public, traction)	**Total (GWh)**
LV	**2009**		1.763	1.814	476	**4.053**
	2010		1.750	1.804	509	**4.063**
	2011		1.771	1.720	461	**3.952**
	2012		1.815	1.682	484	**3.982**
MV	***2009***			805	222	**1.027**
	2010			873	220	**1.093**
	2011			855	210	**1.066**
	2012			874	208	**1.081**
Total	***2009***		1.763	2.619	698	**5.080**
	2010		1.750	2.677	729	**5.156**
	2011		1.771	2.576	671	**5.018**
	2012		1.815	2.556	692	**5.063**

(Source: DSO network; data refer to metered consumption at customer site)

Table 7. Evolution of the electricity consumption in the interconnected (mainland) system and the non-interconnected islands, 2009-2012

Supplier switching

Given that the retail electricity market in 2012 was marked by the exit of four (4) independent electricity supply companies, the total number of switches observed during 2012 is not indicative (especially during the first two quarters of the year), as it reflects the switches to and from the Supplier of Last Resort (SoLR) and the Universal Service Supplier (USS), namely PPC S.A. in both cases.

More specifically, from the total number of customers of the SoLR (92,691), 34% (31,475) returned to the incumbent company (PPC), 55% (51,223) defaulted to the USS and the rest (11%) returned to other independent suppliers. Additionally, from the total number of customers supplied by the USS (51,223), 59% returned to PPC (30,194) and 8,840 (17%) to other independent suppliers.

The following tables quantify the observed trends:

Switching rate (%)	Q1	Q2	Q3	Q4
Domestic	1.65	1.60	0.57	0.09
General use LV	2.67	2.52	0.91	0.18
Industrial use LV	7.84	7.19	2.67	0.61
General use MV	8.37	7.03	1.35	0.54
Industrial use MV	10.20	8.52	1.63	0.65

Table 8. Switching rate per customer category and quarter, in 2012

	Total customers		Customers having changed supplier		% of customers having changed supplier	
Customer type	By number of eligible meter points	By eligible volume	By number of eligible meter points	By eligible volume	By number of eligible meter points	By eligible volume
Household customers	5.062.141	16.714.282	199.736	241.838	3.95%	1.45%
Small Industrial and Commercial customers	1.150.421	10.123.052	213.899	918.108	18.59%	9.07%
Other LV customers (eg. agricultural, public, traction)	307.540	3.734.028	5	7	0.00%	0.00%
Total LV customers	6.520.102	30.571.362	413.640	1.159.953	6.34%	3,79%
Industrial and Commercial customers of MV	7.658	8.470.684	1.592	300.567	20.79%	3.55%
Other MV customers (eg. agricultural, public, traction)	1.639	1.513.379				
Total MV customers	9.297	9.984.063	1.592	300.567	17.12%	3.01%
Total LV & MV customers	6.529.399	40.555.425	415.232	1.460.520	6.36%	3.60%
HV customers	38	6.506.900				
Total HV, LV & MV customers	6.529.437	47.062.325	415.232	1.460.520	6.36%	3.10%

Table 9. Switching rate per consumer category in 2012, by eligible meter points and by eligible volume

Under the VaasaETT description scale of the levels of switching, the Greek electricity market, at the end of 2012, is considered a dormant market.

Supplier of Last Resort (SoLR) and Universal Service Supplier (USS)

After the exit of four (4) independent electricity supply companies in the retail market due to their significant debts accumulated with the Transmission System & Market Operator (then DESMIE S.A.), PPC (the incumbent company) assumed, as decreed by law 4001/2011, the role of the Supplier of Last Resort (SoLR).

In this rapid chain of events, RAE took the following initiatives and actions, in accordance with the relevant provisions of law 4001/2011:

- Published on its website a series of official announcements (20.01.2012, 24.01.2012, 12.04.2012, 23.04.2012, 30.05.2012, 15.06.2012 and 30.08.2012), to inform consumers regarding the defaulting suppliers, the services of the Supplier of Last Resort and the services of the Universal Service Supplier, their rights, obligations and procedures to follow.
- Issued Decision No. 53/27.01.2012, which amended the "Market Operation Code" and the "Manual for the Metering Management and Periodic Settlements of Distribution Network Suppliers", that were in effect at that time, in order to include and elucidate specific provisions concerning the Supplier of Last Resort. Corresponding amendments were included in the "Supply Code" as well (RAE Opinions 1/2012 and 4/2012).
- Continuously monitored the smooth and effective transfer of customers to the Supplier of Last Resort.
- Investigated a considerable number of consumer complaints about billing charges by the SoLR. PPC (as the SoLR) billed these customers according to estimations of meter readings at the time of switching to the SoLR, based on historical consumption data. However, this approach led to incorrect calculation of charges in several cases, and RAE issued its Decision 752/2012, with which it specified a correction index based on actual meter readings and pro-rata allocation of energy based on the number of days supplied by each supplier, in the period between the two (consecutive) meter readings. RAE instructed PPC to correct the calculation of consumption and charges, in order to send corrective bills where necessary.
- Issued its Decision 545/2012, according to which, and until the completion of the competitive procedure for the official designation of a Universal Service Supplier (article 58 of law 4001/2011), PPC was allowed to charge an extra fee, uniform for all customers under the USS regime, up to 5% on the value of electricity before taxes, as compensation for providing this service.
- Conducted a Public Consultation Procedure (05.11.2012), regarding the "Methodology of calculating the compensation for the provision of SoLR services, in accordance with

paragraph 4 of article 56 of law 4001/2011". Essentially, the proposed methodology is based on the comparison between the cost of providing the Last Resort service to customers and the revenues from the tariffs applied (as published by PPC for each customer category). The Public Consultation resulted in the issuing of RAE's Decision 95/2013.

- Issued its Decisions 543/21.06.2012 and 544/21.06.2012, setting out the procedure, the terms and conditions, as well as the selection criteria for choosing the Supplier of Last Resort and the Universal Service Supplier, respectively. More specifically, RAE within its authorities under article 57, paragraph 2.b and article 58 par. 4 of Law 4001/2011, issued a Call for Expression of Interest and regulated the conditions and the procedures for providing those electricity supply services (SoLR & USS).

In general, and according to law 4001/2011, art. 57, the SoLR must supply all customers who are not any more represented by a supplier, as a result of their ex-supplier's "default", and not as a result of their own fault.

"Default" is defined as:

- Planned exit of supplier: a supplier exits the market by its own free will.
- Unplanned exit of supplier: a supplier exits the market due to insolvency.
- Serious breach of license: a supplier's license is revoked, following repeated serious breaches of its license conditions.

The SoLR supply period cannot exceed three (3) months, during which the customers have enough time to negotiate with a supplier of their own choice.

According to art. 58 of the same Law, the Universal Service Supplier must supply customers who do not choose a supplier of their own:

- either because they have neglected it or are unable to negotiate with such a supplier, or
- they are unable to find any supplier, because, for example, of their poor payment record

This is a special regulation specifically for the protection of small customers, i.e. all domestic customers and small businesses with a connection up to 25kVA.

New Supply Code

In the Spring of 2012, RAE conducted a public consultation procedure on an updated draft of a new Electricity Supply Code, taking into account the results of previous consultations, as well as the relevant requirements of Directive 2009/72/EC and Greek Law 4001/2011. Following further drafting, to incorporate comments received during public consultation, as well as specific observations and hands-on experience from the eventful operation of the market during the first quarter of 2012, RAE issued its final Opinion on the Code (No. 14/20.12.2012) to the Minister of Environment, Energy and Climate Change. The Ministerial Decision enacting the new Electricity Supply Code was issued in April 2013 (Government Gazette B' 832/9.4.2013).

In summary, the new Supply Code covers the following areas:

- suppliers' and customers' obligations and rights
- principles of tariff setting
- procedure for submitting an offer to supply
- procedure for switching suppliers
- minimum content of the supply contract
- minimum content of electricity bills
- bill payment procedures and management of bad debt
- data publishing obligations
- dispute resolution

Additionally, the new Code includes provisions regulating the services of the Supplier of Last Resort and the Universal Service Supplier, respectively in accordance with articles 57 & 58 of law 4001/2011, and incorporating the experience gained from the activation of these services during 2012, due to the default status of four (4) independent suppliers that exited the retail electricity market.

Furthermore, the new Code incorporates three (3) specific annexes, which set out guidelines and good practices, to be followed by all suppliers, regarding: a) pricing and billing of services, b) communication with the customer, and c) management of customer requests and complaints.

Finally, the new Code has specific provisions for vulnerable customers. Indicatively, the following measures are included in the provisions of Chapter 6 of the Code, regarding "Domestic Vulnerable Customers":

- The date upon which the bill is due for vulnerable customers cannot be shorter than forty (40) days from the day the bill is dispatched to the customer.
- The supplier is obliged to offer the Domestic Vulnerable Customers an interest-free, instalment payment option for settling their current and/or past electricity bills. Each monthly payment cannot exceed 50% of the Domestic Vulnerable Customer's typical monthly expenditure for electricity supply. The aforementioned option does not exempt the customer from his obligation to make due payments to the supplier.
- Disconnection or contract termination due to outstanding debt is, according to paragraph 6, article 39 of the Code, forbidden for customers registered as Domestic Vulnerable Customers during the winter months (November to March) and the summer months of July and August.

- Especially for the Domestic Vulnerable Customers described in cases 1(b) and 1(d) of article 52 of law 4001/2011, namely customers depending on life support systems and those with serious health problems, the supplier can terminate their supply contract only in the case where the Customer is in arrears due to non-payment of six (6) consecutive electricity bills and provided that the Supplier has already notified the Customer about: a) the options available to him/her for settling his/her outstanding debt, and b) the supplier's intention to terminate the supply contact, if within the next twenty (20) days the customer does not pay or settle his arrears. If the supplier finally terminates the supply contract, the aforementioned Domestic Vulnerable Customer, who is dependent on life support systems or has serious health problems, is automatically transferred to the Universal Service Supplier, without prior disconnection, by any means, of his electricity supply.

Formal complaints by suppliers against the Distribution System Operator (DSO), regarding its services supporting the retail market operation

During 2012, suppliers "Energa Power Trading", "Hellas Power", "Elpedison" and "Heron Thermoelectric" submitted to RAE formal complaints under article 34 of Law 4001/2011, against the Distribution System Operator, charging abusive behaviour regarding the non-application by the TSO of the provisions of the "Manual for the Metering Management and Periodic Settlements of Distribution Network Suppliers" and the "Market Operation Code".

In investigating the complaints, RAE found out that there were, indeed, problems with the implementation of the customer switching process. Those problems arose both due to inefficiencies of the switching monitoring software application by the DSO, but also due to structural weaknesses of the relevant Manual.

The examination of these complaints resulted in RAE Decisions 800/2012, 812/2012 and 996A/2012, by which the DSO was obliged to: a) amend the relevant Manual, b) take the necessary steps to improve and upgrade the relevant software switching monitoring application, and c) proceed, in compliance with the previous similar RAE Decision 870/2011, to upgrade and supplement existing internal procedures, in order to ensure the coordination and efficient operation of all the regional / local units of the DSO.

The examination of the complaints resulted in a thorough and effective amendment of the relevant Manual. This amendment substantially improved the existing framework and simplified the customer switching process.

Monitoring of supplier activity in the retail electricity market

RAE, as part of its responsibilities for the overall monitoring of the retail energy market (article 22 of law 4001/2011), and specifically in order to monitor the activity and the compliance with obligations of all active supply license holders (article 13 of law 4001/2011 & relevant provisions of the Electricity Supply Code), sent a letter to all suppliers in June 2012, requiring the submission of detailed data related to their supply business activity for the 2-year period 2011-2012.

In specific, the required data included:

- Annual financial statements.
- Historic data on the volume and value of electricity sales by customer group.
- Applicable charges for the supply of electricity for each category of customers, and conditions attached to each tariff.
- Relevant promotional material accompanying the supplier's offer to the consumer and any other standard document which accompanies the Supply Agreement.
- Typical bills and description of payment methods, frequency of bill issuance and alternative payment methods available to customers.
- Updated information regarding the suppliers' organisational and administrative structure, representation, share capital, etc.

RAE's goal was to check compliance with the supply license conditions and the Supply Code, particularly with regard to marketing practices, tariffs offered and related contractual terms, so as to investigate the possible presence of abusive terms or conditions, that conflict with the existing legal framework and to effectively protect consumers from deceptive and abusive behaviours. As a result and where necessary, RAE sent targeted letters to suppliers, with specific amendments suggested to the terms and conditions offered by them to their customers.

New Electricity Supply and Trading Licensing Regulation

In early 2012, and in order to adjust regulations to the provisions of article 135 of the new law 4001/2011, RAE conducted a public consultation regarding the "Electricity Supply and Trading Licensing Regulation". RAE's main objectives were: a) to simplify the procedure for license application submission and assessment, b) to ensure fair and equal treatment among interest parties and transparency in transactions, and c) to specify the requirements for issuing a trading license, which was included, for the first time, as a new type of license, in law 4001/2011 (this activity was previously covered by the supply license).

More specifically, the new Licensing Regulation:

- clarifies the licensing regime for the activity of wholesale electricity trading,
- clarifies the licensing regime applicants already holding a license in another Member State,
- simplifies the procedure and criteria for license modifications, and clarifies the changes for which a simple notification is sufficient, rather than a license amendment,
- clarifies the regime for the license extension/renewal,
- establishes a detailed procedure for license revocation.

Based on the results of the public consultation, and in accordance with article 135 of Law 4001/2011, RAE submitted its official Opinion to the Ministry of Environment, Energy and Climate Change in September 2012. The final Ministerial Decision enacting the new Licensing Regulation was issued in November 2012 (Government Gazette B' 2940/05.11.2012).

Licensing activity of RAE

Regarding RAE's activity in relation to Supply and Trading licenses, it is noted that in December of 2012, 24 Supply licenses and 39 Trading licenses were active. Specifically, during 2012:

- 16 new trading licenses were issued
- 2 supply license applications were rejected for non-compliance with the relevant provisions of law 4001/2011,
- 1 application for a supply license amendment was rejected for non-compliance with the relevant provisions of law 4001/2011,
- 8 supply licenses and 1 trading license were revoked upon RAE's decision for non-compliance with the relevant provisions of law 4001/2011,
- RAE imposed a fine to a supply license holder, for breach of the terms of the license, as well as a recommendation to TSO and DSO
- 1 supply license expired.

The table in Appendix I presents the active supply and trading licenses, respectively, at the end of 2012.

3.2.2.2. Price monitoring

This section concentrates on the prices offered by PPC in 2012, given that, for this particular year, PPC's market share in retail was over 99%. The PPC (average) prices by consumer category are presented in the table below, broken down by tariff element.

	€/MWh	Energy	TUoS	DUoS	PSO	Other	Total	Δ(2011-2012) Energy only	Δ(2011-2012) Total
MV Commercial	2010	82.14	3.92	6.09	8.35	0.77	**101.26**	14%	18%
	2011	67.76	4.92	6.35	11.41	0.44	**90.75**		
	2012	76.91	5.02	6.44	17.90	0.44	**106.72**		
MV Industrial	2010	63.13	5.55	7.15	6.58	0.77	**83.18**	15%	13%
	2011	68.69	6.19	7.19	5.87	0.44	**88.39**		
	2012	79.07	6.12	7.16	6.91	0.44	**99.70**		
MV Agricultural	2010	36.90	0.00	0.00	3.24	0.77	**40.91**	20%	29%
	2011	50.76	0.00	0.00	0.95	0.44	**52.15**		
	2012	61.09	0.00	0.00	5.62	0.44	**67.15**		
LV Commercial	2010	94.28	16.01	16.51	11.51	0.83	**139.14**	-1%	4%
	2011	88.82	6.75	22.57	14.37	0.42	**132.93**		
	2012	88.25	7.16	24.22	18.24	0.46	**138.33**		
LV Industrial	2010	79.03	10.39	23.66	10.34	0.83	**124.25**	3%	7%
	2011	84.63	6.50	24.23	13.22	0.43	**129.00**		
	2012	87.12	6.95	25.87	18.24	0.46	**138.65**		
LV Agricultural	2010	43.43	0.00	0.00	3.70	0.83	**47.96**	0%	10%
	2011	58.05	0.00	0.00	1.15	0.44	**59.64**		
	2012	58.26	0.00	0.00	7.07	0.46	**65.79**		
LV Public Lighting	2010	65.76	2.66	22.36	7.65	0.83	**99.27**	-3%	12%
	2011	70.73	2.46	19.39	2.32	0.41	**95.32**		
	2012	68.44	3.03	21.33	13.71	0.46	**106.97**		
LV Domestic	2010	67.78	5.89	22.43	8.06	0.83	**104.99**	2%	11%
	2011	75.68	4.96	17.83	7.90	0.38	**106.76**		
	2012	77.16	5.75	20.69	14.31	0.45	**118.36**		

Table 10 2010-2012 average PPC retail electricity prices and tariff elements per consumer category (excluding taxes and levies), €/MWh

During 2012, prices for LV customers remained regulated, in accordance with the existing legal framework. Regulation is scheduled to be removed on 01.07.2013.

Final PPC retail tariffs (LV customers only) for 2012 were set through a Ministerial Decision on January 3, 2012 (Official Gazette B 7), following PPC's submission of its 2012 budget estimate (revenues/expenses) and RAE's official Opinions 36/2011 and 39/2011 on it. The approved tariffs, although higher than in 2011, reflected a significant decrease in PPC's 2012 allowed expenses, relative to the corresponding amount requested by the company itself.

Household tariffs (competitive elements only) for 2012 increased by 4-14% compared to 2011, depending on the consumption level. Price differentiation into four (4) price categories according to consumption levels, continued in 2012, with household consumers of less than 800 kWh consumption per 4-month period enjoying significantly lower prices (56.25 €/MWh), while household consumers of more than 2.000kWh consumption per 4-month period, being charged with 91.55 €/MWh. These price differentiations are expected to be abolished, following the full liberalisation of electricity prices, expected to take place in July 2013.

Other consumer categories saw increases of around 4-8% in 2012, whereas agricultural tariffs remained at the 2011 level.

Alternative suppliers offered limited discounts and only in certain tariff categories (compared to PPC tariffs). Given PPC's "lion" market share and the very low degree of maturity of competition in the retail market, further information on average prices and discounts was not available, although all alternative suppliers published their tariffs on their websites. The degree of transparency is not yet satisfactory, and RAE will continue its efforts to improving availability and clarity of information, to the benefit of final consumers, while the retail market evolves and matures further.

3.2.2.3. Monitoring the level of transparency

Regulated price system

Although there is no set methodology for determining regulated prices, we describe below the relevant practice that has been followed in the last 3-4 years:

Three-to-four months before the end of the calendar year, the incumbent, vertically integrated utility (PPC) submits a budget proposal to RAE, which includes cost estimates for the competitive activities (generation and supply) in the year to follow, and may also include proposals for the final tariffs to be applied per consumer category.

Costs include:

- Fuel costs
- Opex (personnel costs, third party contracting costs, materials, etc)
- Energy purchases from other (RES, pool, imports)
- Other costs of participation in the wholesale market (capacity payments, ancillary services, net of own generation revenue)
- Depreciation and return on generation assets
- Supply margin

Based on the PPC budget proposal and data, RAE forms an opinion on the reliability and plausibility of its estimates (costs/revenues), taking into account historic data, market conditions, impact on consumers, potential efficiency improvements, etc. The final decision regarding the allowed PPC revenue from regulated tariffs and prices remains with the Ministry of Environment, Energy and Climate Change. The retail tariffs are, therefore, set based on PPC's average cost, rather than the market marginal cost.

As mentioned previously, price regulation is scheduled to be removed on 01.07.2013.

Monitoring and ex-post regulation of non-regulated prices

Only PPC LV tariffs were still regulated in 2012 (until 30^{th} the of June, 2013), through a Ministerial Decision following a (non-binding) opinion by RAE. Regulation of HV (since July 2008) and MV (since January 2012) tariffs has been removed. Under Law 4001/2011 (Art. 140, par. 6), RAE monitors deregulated retail prices and may intervene ex-post, if an abusive behaviour is identified (prices are too high, therefore abusive towards consumers, or too low, therefore abusive towards competitors).

In its Decision 692/2011 (and, subsequently, in the new Electricity Supply Code), RAE set the general principles for tariff setting in the competitive market. According to these principles, tariffs should be simple, transparent, cost reflective and avoid cross subsidies; they must take into account consumer category characteristics, offer real choices to the consumers and, where possible, provide incentives for the efficient use of electricity. Special guidelines were provided for larger consumers, where it is possible to tailor-make price offers and not to have a general published tariff, in order to take into account the specific characteristics of that particular customer.

Recommendations at national level on supply prices and competition

Law 4001/2011 specifies that the Minister of Energy regulates retail tariffs for low voltage PPC customers until the end of June 2013. Given that PPC is the only participant with access to the cheaper generation sources (hydro and lignite), regulation of retail tariffs based on PPC's average cost has been the methodology chosen by the Ministry, so as to pass on the benefit from the generator's surplus to the final consumers. As mentioned in the Wholesale Electricity Market section of this report, RAE has proposed, and is currently working on the final design and implementation, of transitional measures to release energy generated by PPC's cheaper sources through NOME auctions to third parties, which will then supply it to final customers. The aim is to create competition in the retail market on an equal basis and to continue passing on the generator's surplus benefit to final consumers, even after the full deregulation of PPC retail tariffs.

As part of this work, RAE intends to appoint, through open international tendering, a consultant in order to perform a study on the Cost Benchmarking of PPC and its network subsidiaries, including strategic recommendations on their cost improvement potential and roadmap (RAE Decision no. 926/12.11.2012). More specifically, RAE's target is to explore the possibilities to reduce PPC's cost of producing and supplying electrical energy, in order to minimise the inevitable price increases on low, medium and high voltage consumers, and, also, to enhance the competitiveness of the Greek economy.

Experience with PPC liberalised tariffs

Following the liberalisation of MV customer tariffs in January of 2012, PPC introduced a single standard MV tariff, significantly higher in comparison to the regulated medium-voltage tariff that existed till 2011, for all medium-voltage customers, except agricultural ones. This price hike sprung numerous consumer complaints against PPC, as well as the submission of five (5) formal complaints to RAE by respective large industrial MV customers (similar complaints were also filed in 2013). At the course of investigating these complaints, according to which PPC imposed a single standard tariff, without entering into negotiations with its customers and without taking into account their specific energy consumption characteristics, RAE issued a number of relevant decisions (702/2012, 895/2012 and 1024/2012) instructing PPC: a) to continue its efforts for open and effective negotiations with its customers, negotiations which should at least bear the characteristics outlined in relevant national legislation (Civil Code, etc.), with the aim to offer customised tariffs according to the energy characteristics of each customer, and b) to issue (until 01.01.2013) a sufficient number of medium voltage standard tariffs (at least three), in order to reflect different energy profiles (load characteristics) and to apply these new tariffs to each of its medium voltage customers, according to their individual characteristics.

In the meantime, additional complaints had already been submitted to and investigated by RAE, by three (3) high voltage PPC customers, whose tariffs have been liberalised since July 2008. The first relevant decision issued by RAE was no. 345/2012 (following a decision for interim protective measures against the disconnection of a PPC customer), which determined that:

- PPC did not comply with its obligation to enter into open and effective negotiations with the customer, having at least the following elements: (aa) written or verbal exchange of opinions for the formation of a contract, through which the gradual convergence of the different initial positions of the two parties (supplier-customer) is being pursued, leading either to the establishment of common ground or final disagreement. This stage of negotiations lasts until the formation of a contract or the breach and abortion of the efforts of the two parties, (bb) provision of clarifications and explanations with respect to the nature of the contract, especially those that may influence the decision of the prospective customer, the so-called “obligation for clarification and protection”. Moreover, PPC did not submit any kind of explicit, formal and written proposals for acceptance, with explicit, formal and full details, with customised unbundled tariffs per customer category, taking into account the specific characteristics of the said category and the real (not the logistic) cost of the company.
- PPC did not comply with the basic tariff-setting principles, according to the relevant provisions of: a) the Electricity Supply Code, b) RAE’s Decision 692/2011, and c) the Civil Code, regarding all aspects of supply-contract negotiations, such as Proposal, Negotiation, Acceptance, Drafting and Amendment.

RAE also instructed PPC: a) to proceed with genuine negotiations with the given customer, so that an agreement on the competitive tariff element can be reached, taking into account the specific load characteristics of the customer, the investments that he has already realised, in order to adjust his consumption to the structure (and to minimise the cost) of the previous - regulated - PPC tariff, b) to proceed with the signing of a new contract that will reflect all terms agreed upon during negotiations.

In two other HV customer complaint cases, the implementation of interim tariffs was decided, as a temporary measure (RAE Decisions 346/2012 and 822/2012).

PPC, indeed, prepared and submitted to RAE a tariff proposal for high voltage customers. After analysing the proposal, RAE concluded that PPC had not taken into account the individual load characteristics of its customers (or group of customers with similar characteristics), in accordance with the provisions of RAE's Decision no. 692/2011 on the basic tariff setting principles. Specific comments and recommendations were, therefore, made by RAE to PPC, in order to amend the tariff proposal accordingly for high-voltage customers (but also for medium-voltage customers, to the extent that they exhibit similar energy consumption characteristics with those of high-voltage customers), and to enter into proper negotiations with them. Until the end of 2012, no agreements had been reached between PPC and its HV customers.

3.3. Consumer protection

3.3.1. Public Service Obligations

The Public Service Obligations (PSOs) which have been set by Ministerial Decrees (in accordance with Law 3426/2005, Article 28), include the supply of electricity to:

1. consumers connected to the distribution network on the non-interconnected islands and remote micro-grids, at tariffs equal to those of the mainland interconnected system,
2. consumers / families with more than three (3) children at special reduced tariffs, and
3. financially vulnerable consumers at the reduced Social Residential Tariff (referred to as “KOT”, pursuant to the Greek acronym).

In February 2012, the no. 469/2012 Decision of the Council of State (CoS) annulled related ministerial decisions which determined a) the annual required revenues in order to compensate the provision of PSOs in 2008 and 2009, and b) the unit charges for the recovery of these annual required revenues in 2009 and 2010, on the basis that there is practically no access of independent suppliers to the customers on the non-interconnected islands, although recognising that the services provided under the PSO scheme and the corresponding PSO costs are, indeed, legal. The adopted decision by the CoS created a major problem regarding the lawful payments of electricity suppliers, as well as those of final consumers. In order to overcome this issue, the Ministry of Environment, Energy and Climate Change proposed an amendment, which was eventually included as Article 36 in the new law 4067/2012 (Government Gazette A’ 79/9-4-2012). This article, among other things, foresees mainly that the default cost for providing PSOs for the period 2008 to 2011 shall be allocated to each end user (instead of the suppliers of electricity), according to the unit charges per user category, which are equal to those set in the cancelled ministerial decisions. Further, as provided in paragraph 4, the amount obtained under these charges will be offset by (equal) amounts already paid for this period by the end users to electricity suppliers. The law also set the charges to be paid by final consumers in 2012, in order to cover the Public Service Obligation costs.

3.3.2. Social Residential Tariff

The social tariff was applied for the first time on 01.01.2011. The definition of vulnerable consumers for the purpose of the application of KOT in 2012 included the following four categories (electricity consumption limits apply for consumption during the day for those with zonal metering devices):

1. <u>Families with Low Income:</u> Households with total annual income (salary or pension) below 12,000 Euros and having an electricity consumption per 4-month period between 200 kWh and 1400 kWh.

2. Families with 3 children: Households with three children, total annual income (salary or pension) below 22,500 Euros and electricity consumption per 4-month period between 200 kWh and 1600 kWh.
3. Long-term unemployed: Unemployed as of the 30th of November of each year, for a continuous unemployment period of at least 12 months, with total annual household income (salary or pension) below 12,000 Euros - income from employment for the period preceding the unemployment period is not taken into consideration – and electricity consumption per 4-month period between 200 kWh and 1400 kWh.
4. Disabled people: Households including disabled persons with more than 67% handicap, total household annual income (salary or pension) below 22,500 Euros and electricity consumption per 4-month period between 200 kWh and 1600 kWh.

The following table presents the prices per KOT category (as set by Ministerial Decision) which applied in 2012 for the first 800kWh of consumption in the 4-month period. For the remaining consumption and up to the category's consumption limit, the supplier regular domestic prices for the equivalent category apply. KOT I applies to categories 1&2 and KOT II to 3&4.

Social Tariff – prices for first 800kWh of consumption per 4-month period					
		Consumers with total consumption up to 800kWh		***Consumers with total consumption above 800kWh***	
	Type of connection	***Energy Charge (€/kWh)***	***Fixed Charge (€/4Months)***	***Energy Charge for the first 800kWh (€/kWh)***	***Fixed Charge (€/4Months)***
KOT I	***Single-phase***	0.06452	2.77	0.07885	11.13
	Three-phase	0.06904	7.88	0.07885	22.20
KOT II	***Single-phase***	0.05735	2.77	0.07009	11.13
	Three-phase	0.06137	7.88	0.07009	22.20

Table 11. Social Residential Tariff (KOT) prices for the first 800kWh of consumption per 4-month period

The following table presents the number of customers, bills issued and metered demand to which the KOT tariff prices applied in 2012.

<table>
<tr><th colspan="2" rowspan="1"></th><th colspan="2" rowspan="2">Number of customers</th><th colspan="2">Consumers with total consumption up to 800kWh</th><th colspan="2">Consumers with total consumption above 800kWh</th></tr>
<tr><th></th><th>Type of connection</th><th>Energy (kWh)</th><th>No. of bills issued</th><th>Energy (first 800kWh per bill)</th><th>No. of bills issued</th></tr>
<tr><td rowspan="2">KOT I</td><td>Single- phase</td><td>169.690</td><td rowspan="2">192.643</td><td>110.101.578</td><td>205.183</td><td>159.259.493</td><td>191.553</td></tr>
<tr><td>Three-phase</td><td>22.953</td><td>14.388.812</td><td>26.913</td><td>19.623.071</td><td>23.723</td></tr>
<tr><td rowspan="2">KOT II</td><td>Single- phase</td><td>49.177</td><td rowspan="2">57.925</td><td>21.452.908</td><td>38.802</td><td>62.825.484</td><td>75.925</td></tr>
<tr><td>Three-phase</td><td>8.748</td><td>4.095.791</td><td>7.231</td><td>12.586.635</td><td>15.204</td></tr>
</table>

Source: DEDDIE (DSO)

Table 12. Number of customers, bills issued and metered demand receiving the KOT tariffs, in 2012

3.3.3. Statistics on customer disconnections and new connections

RAE monitors customer disconnection and reconnection data provided by the DSO (DEDDIE).

Total number of electricity disconnections increased by almost 2% in 2012, compared to 2011. However, the number of electricity disconnections due to bad debt have declined by almost 4% in 2012, compared to 2011. Thus, the above mentioned increase in the number of disconnections is attributed to the economic crisis, leading mainly to the permanent closure of commercial and industrial premises.

Disconnections due to delays in bill payments accounted for 49% of the total number of disconnections, reflecting the impact of the economic crisis on the ability to pay. This difficulty is further enhanced by the significant increase in taxes collected through the electricity bills, either directly or indirectly (such as property tax, municipal taxes, radio & TV fees, etc). These taxes and levies, which are completely unrelated to the actual supply of electricity, form, in many cases, the largest proportion of the total amount to be paid through the electricity bill.

RAE continues to view disconnections as “the very last resort” measure and will work closely with suppliers to improve payment plans, by reviewing the terms of their standard supply contracts.

The following table depicts the relevant statistical data.

Customer type	New connections	Disconnections due to arrears	Disconnections (reasons other than arrears)	Re-connections due to settlement of arrears	Re-connections (reasons other than settlement of arrears
Total LV & MV customers in the Interconnected System	39.675	296.801	310.385	169.319	153.803
Total LV & MV customers in the Non-interconnected System	5.729	28.210	32.517	21.222	17.239
Total LV & MV customers	**45.404**	**325.011**	**342.902**	**190.541**	**171.042**

Table 13. Statistical data on number of disconnections and re-connections of LV and MV customers

3.3.4. Handling of consumer complaints

The total number of consumer reports (complaints and inquiries) submitted to RAE during 2011 was 42% higher than in 2010, since 2011 was the first year of substantial activity of alternative, other than PPC, electricity suppliers. In 2012, a further increase of 218% was observed, compared to 2011, with the total number of consumer complaints and inquiries reaching 512.

This sharp increase is attributed to the serious problems created in the electricity market by the abrupt cease of activity (market exit) of four (4) alternative electricity suppliers, and especially the two larger ones, “Hellas Power” and “Energa Power Trading”, as presented in section 3.2.2.1 Because of this fact, serious issues arose, related to: a) switching, overnight, tens of thousands of consumers to the Supplier of Last Resort (PPC S.A.), for the first time in Greece, and b) the clearing of financial transactions of the four (4) alternative suppliers that discontinued their operation.

More specifically, in January of 2012, the customers of the two major alternative suppliers experienced an unprecedented situation for the recently liberalised Greek retail market, during which, the response and information offered to them by those suppliers was totally insufficient or even non-existent, and failed to respond satisfactorily to the large volume of requests from their former customers. Therefore, many consumers turned to RAE, in order either to receive information or to file a complaint against their former suppliers, both in writing and by telephone. RAE made every effort to timely and accurately inform these customers, through successive official announcements on its website, while taking, in a very short time period, all necessary regulatory actions and decisions, supplementing the existing legal and regulatory framework, in order to ensure uninterrupted power supply to all consumers.

The statistics on the complaints/inquiries of electricity supply cases, registered to RAE in 2012, are summarised in Figure 10, by thematic category.

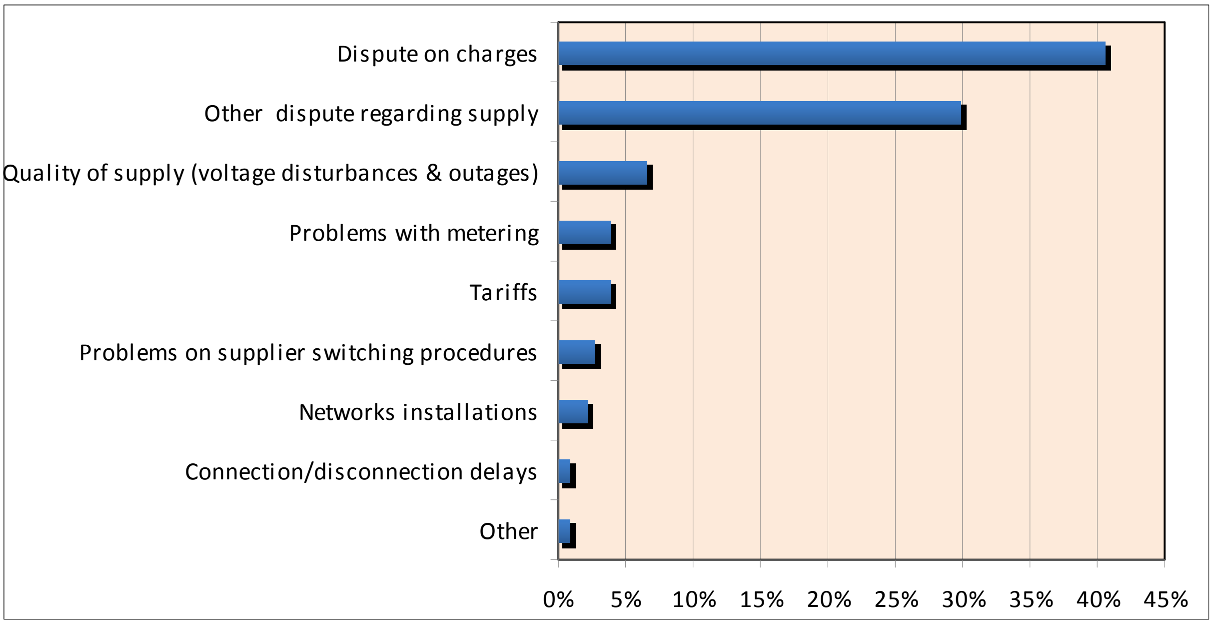

Figure 10. Complaints/inquiries by thematic category of electricity supply cases

Forty percent (40%) of all complaints were related primarily to disputes on charges. These disputes mainly concerned the increase of the competitive element of the electricity tariff, and were almost equally distributed between PPC and the alternative suppliers.

The complaints submitted to RAE in 2012 focused primarily on the following issues:

1. Disputes on consumption rates and charges (40.5%), disagreements / disputes on "other charges" (not related to electricity consumption), and issues related to increases of the competitive element of the tarrifs. The complaints appear to be split equally between PPC SA and the two major alternative suppliers, “Hellas Power” and “Energa Power Trading”. The disagreements on consumption charges were associated with either higher than expected bills, on which the consumers did not receive adequate explanation from their suppliers, or with the wrong allocation of consumption and charges between the alternative supplier and the Supplier of Last Resort, during the mass transition of “Hellas Power” and “Energa Power Trading” customers to the SoLR. The dispute on "other charges" was mainly associated with: i) the increase of regulated charges and especially the PSOs, ii) the legality of charging PSOs associated with the supply of electricity to the consumers on the non-interconnected islands, at tariffs equal to those of the mainland, after the repeal by the Supreme Court of the relevant article of Law 2773/1999, iii) the distinction / separation of payments for the electricity, from those of the property tax (EETIDE), and iv) illegal charge of PSOs to vulnerable (KOT) customers.
2. Other issues during the contractual period (29.9%), mainly about the return of the guarantee payment by the suppliers that exited the market to their former customers, as well as issues encountered during the transition of these customers to the SoLR, most often not related to the electricity charges.

3.4. Security of supply

3.4.1. Monitoring the balance of supply and demand

Table 14 presents the evolution of annual electricity consumption in the interconnected system, since 2007, as reported by the TSO, ADMIE SA. According to ADMIE's data, consumption in 2012 decreased by 2.5%, compared to 2011. However, as explained in detail in section 3.2.1.1 (Market Volumes), if the RES (mainly PV) production from plants that are connected to the distribution network and not measured by the TSO is taken into account, then the total consumption in 2012 was 53.15 GWh, showing only a minor decline with respect to 2011.

	2007	2008	2009	2010	2011	2012
Electricity consumption excluding pump storage (GWh)	55,253.4	55,675.3	52,436.5	52,365.8	51,872.3	50,558.1
Peak load (MW)	10,610 (11,110 including curtailed)	10,393	9,828	9,902	10,055	9,894

Source: HTSO

Table 14. Energy and peak power demand in the interconnected system, for the 6-year period 2007-2012

<u>*Fuel Shares*</u>

A critical factor for the allocation of fuel shares in the Greek market is the level of hydro production, which reflects both stochastic elements (due to uncertain water inflows) and the management approach implemented by PPC. After two successive years (2009 and 2010) of adequate, or even excessive, water inflows, which had resulted in an escalation of hydro production, and subsequently a dry year (2011), 2012 was anticipated to be a rather dry year, according to early indications which, however, later were reversed during the year. This instability in inflow patterns signified that the alternation and duration of water cycles was becoming less predictable, most probably due to climate change effects. Overall, hydro production in 2012 increased by 5.9% relatively to 2011, attaining a value of 3.9 TWh. This increase was achieved over the last quarter of the year (+307 GWh in Q4 2012 relatively to Q4 2011), driven by intense inflows over this period, which counteracted the conservative hydro output in earlier periods.

More specifically, in January 2012, inflows remained lower than the dry (worse-case) scenario by 12%, creating scarcity concerns. The reservoirs, at the beginning of the year, dropped to levels below the worse-case scenario, reaching a value of 1547 GWh, as opposed to the prediction range of 1623-1895 GWh. In particular, water inflows from September to December

2011 had been very limited, as opposed to their annual pattern. Indicatively, November 2011 inflows diminished to 50 GWh, as opposed to a conventional expectation of 196-369 GWh, and a value of 689 GWh in November 2010. In this context, January 2012 seemed to sustain the scarcity trend displayed in preceding months. Still, this tendency was progressively reversed. In February, inflows approached the mid (normal) scenario and in March, they exceeded the wet scenario by 6%. In April, inflows reached extremely high values, exceeding the upper scenario by 48%, eventually attaining 928 GWh vs. an upper prediction of 629 GWh. The subsequent period up to September displayed characteristics close to the mid hydro scenario. In October, inflows escalated again, exceeding the best scenario by 33%, and while November was regular, December exceeded the highest prediction by 15%, attaining 666 GWh vs. an upper prediction of 579 GWh.

PPC seemed to react effectively to the inflows' patterns, adjusting upwards mandatory waters from the mid of April up to July. Overall, mandatory hydro amounted to 3141 GWh, a value lying between the mid and the upper scenarios. Mandatory waters exceeded the upper scenario levels in November and December, signalling the increasing risk of over-flooding. It should be noted that in 2011, mandatory waters dropped below the dry-scenario prediction by 28%, hence increasing the competitive part of the supply curve, creating more space for gas generation.

Overall, local generation remained stable in 2012, exhibiting a minor increase of 0.3% relative to 2011, with demand in the interconnected transmission system remaining almost stable (minor decline of -0.9%). Lignite production remained almost stable (27.6 TWh), with a minor increase of 0.5%, as no decommissioning occurred in 2012. Due to its base-load nature, lignite production followed closely the demand fluctuations, peaking in July and August, as well as in the winter period (in particular, January and December). Oil generation, which had shrank substantially over the previous three (3) years, being substituted by gas, became essential over the gas supply crisis in January-February, offering 78 GWh at this crucial time period. As opposed to an impressive increase of 43.3% and 10.7% over the two previous years (2011 and 2010, respectively), gas production dropped by 4.8% in 2012, amounting to 14.1 TWh, being partly counteracted by the hydro escalation over the last quarter of the year. PPC's gas production declined by 21% in 2012 (51% over the fourth quarter of the year). The increase of gas prices by almost 30%, partially due to the imposition of the excise tax, was reflected on this outcome.

Renewable generation from plants connected to the high-voltage network, which mainly involve wind parks, peaked in August, a pattern which is rather typical of wind dynamics and remained stable afterwards, reflecting also the penetration of new capacity. Renewable production increased substantially (by 22.8%) in 2012, following a similar trend of 24.3% increase in 2011, but its overall market share still remained low.

Imports reached 5.95 TWh and exports 4.2 TWh, with net balance (1.78 TWh) exhibiting a drop by 45% in 2012 relatively to 2011. This outcome reflected a considerable decline of imports, from 7.2 TWh in 2011 to 6 TWh (-17%), and a marginal increase of exports, from 3.9 TWh in 2011 to 4.2 TWh in 2012 (5.6%). The main components in this aggregated picture was the substantial increase of exports to Italy, from 1.7 TWh in 2011 to 2.5 TWh in 2012 (48%), in response to attractive spreads being more frequent, along with the considerable decline of imports from Turkey by 1.7 TWh (-34.2%), as well as from Bulgaria (by 0.5 TWh), reflecting the reduction of the price spreads, particularly when lignite was the marginal plant, and changes in the cost fundamentals of the neighbouring countries.

Figures 11 and 12 focus on the day-ahead market, presenting the allocation of production across the various technologies, as well as net imports, at the monthly level, while Figure 13 displays the annual market shares across fuel and net imports, taking into account total energy (emerging both from the day-ahead schedule and real-time operations). Finally, Table 15 depicts the changes in fuel mix in 2012, compared to 2011. All figures refer to the interconnected system, to which the wholesale market relates. If the production on the non-interconnected islands is taken into account, the oil share would rise significantly.

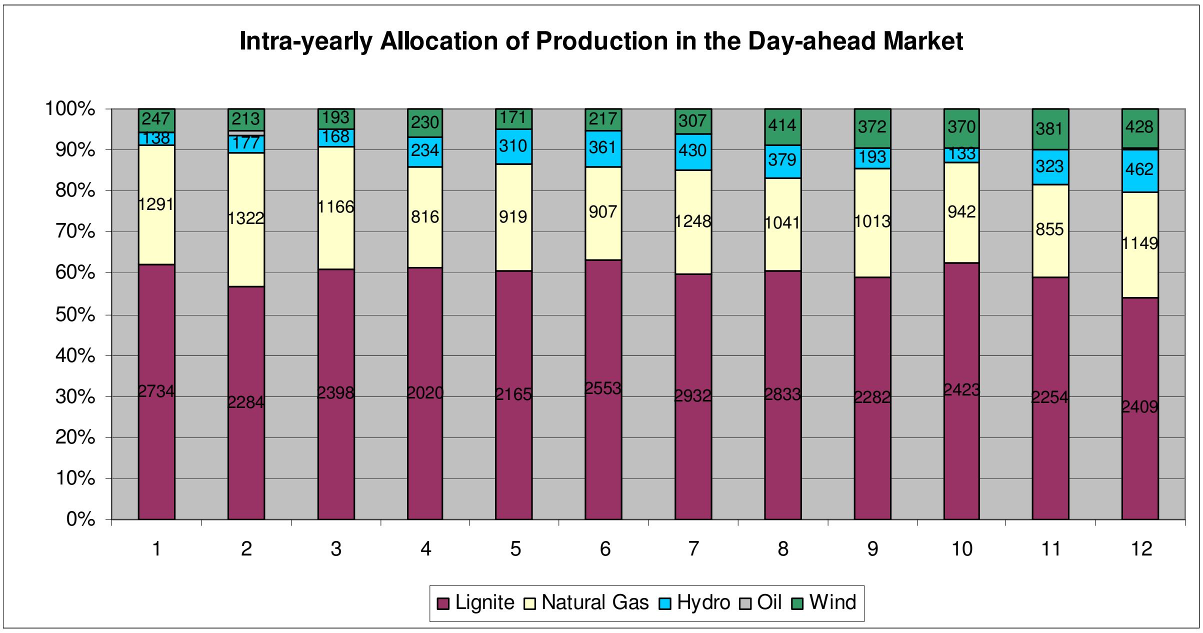

Figure 11. Production allocation across fuels and net Imports at monthly level

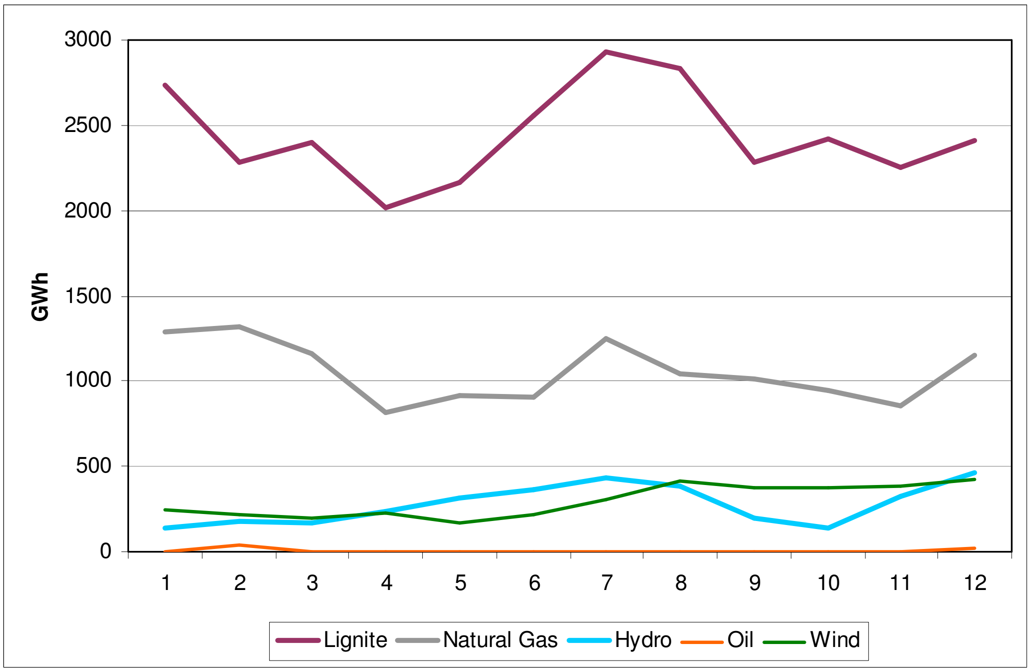

Figure 12. Production allocation across fuels and net imports at monthly level during 2012

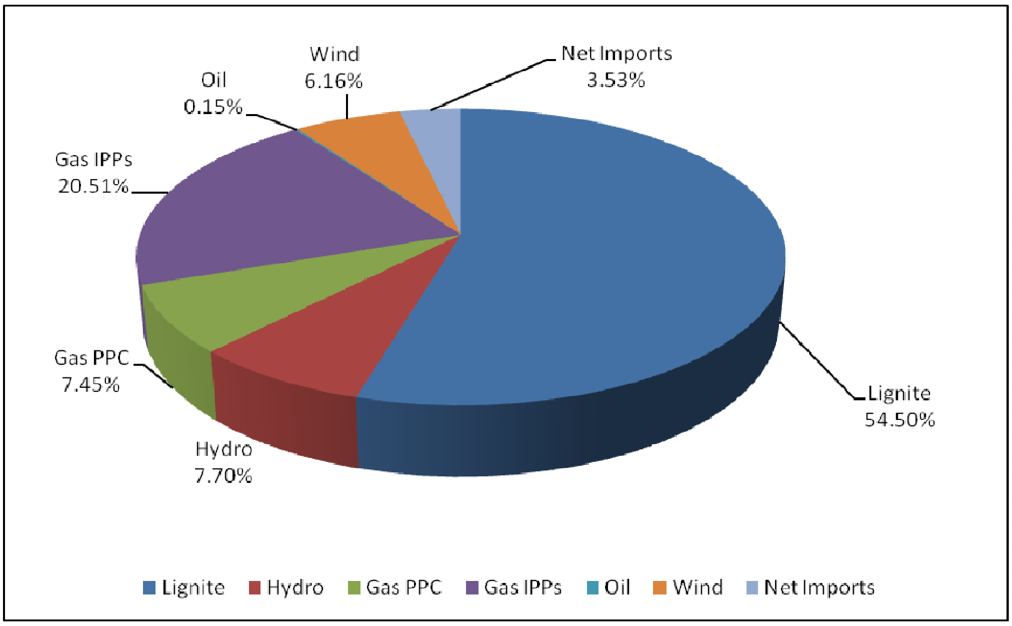

Figure 13. Annual shares of fuels and net imports

	2011 (TWh)	2012 (TWh)	% difference
Lignite	27.57	27.55	-0.06
Fuel Oil	0.009	0.078	808.86
Natural Gas	14.85	14.14	-4.81
Large Hydro	3.68	3.89	5.88
RES	2.53	3.11	22.81
Net Imports	3.23	1.78	-44.80
Total	**51.87**	**50.55**	**-2.53**

Table 15. Change in fuel-mix generation between 2011 and 2012 in the interconnected system

Regarding the market concentration in the imbalances settlement, balancing involves usually flexible units, such as gas plants, a significant portion of which is owned now by private investors (72%). Hydro plants, owned exclusively by PPC, may also be used due to their fast response rates, depending on hydro conditions and storage levels. In 2012, the involvement of hydro in correcting imbalances remained substantial, but allowed more space for contribution by the gas plants. Hydro quantities in real time exceeded their day-ahead dispatch schedules by 0.6 TWh, a substantial amount compared to 3.3 TWh in day-ahead dispatch. These additional quantities implied substantial payments for hydro units, and counter-acted the shortage of its lignite production (1.7 TWh) by 33% in terms of energy, as opposed to a fraction of 48% in 2011.

Installed capacity

Installed capacity in Greece at the end of 2012, by fuel, is depicted in Figure 14 and Table 16 below. Except for a significant increase in RES installation capacity (from 2140MW in 2011 to 3237MW in 2012), no other changes in installed capacity took place during 2012.

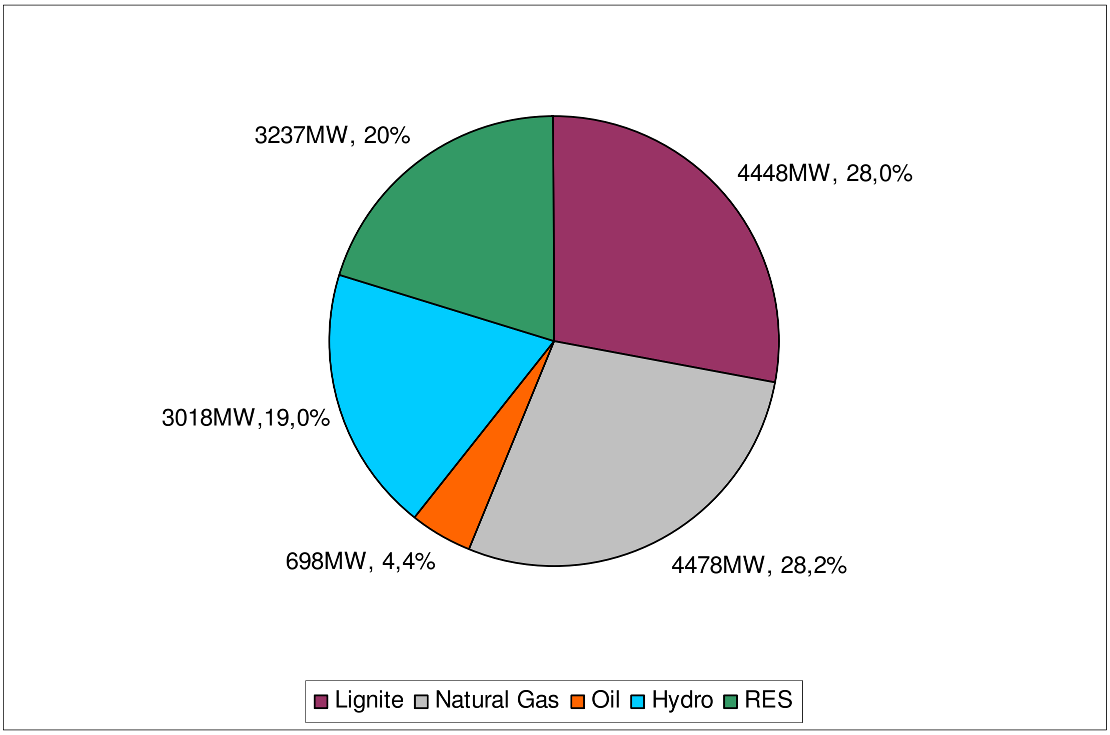

Figure 14. Installed capacity per fuel type in the interconnected system, at the end of 2012

	Ownership	Installed Capacity (MW)	Total Production (GWh)	Capacity Factor
Thermal				
Lignite	**PPC**	**4448**	**27555**	**70.72%**
Oil	**PPC**	**698**	**78**	**1.28%**
OCGT	PPC	339	41.5	**1.40%**
	Heron Thermoelectric	148	3	**0.26%**
	Total	**487**	**44.5**	**1.05%**
CCGT	PPC	1578	3725	26.95%
	Elpedison	799	3790	54.16%
	Heron Thermoelectric	422	1331	36.01%
	Protergia (Mytilineos)	433	2352	62.01%
	Korinthos Power (Mytilineos + Motoroil)	434	1810	47.60%
	Total	**3666**	**13012**	**40.51%**
CHP (Large-scale)	Alouminio (Mytilineos)	**326**	**1082.4**	37.90%
Total Thermal		**9625**	**41768.9**	**49.50%**
Large Hydro	**PPC**	**3018**	**3891.7**	**14.72%**
Renewables				
Small Cogeneration	**IPP**	90.1	1489	25.52%
Wind	**IPP (mainly)**	1465.8	3160.8	21.74%
Small Hydro	**IPP (mainly)**	212.9	669.4	32.28%
Biofuels – Biomass	**IPP (mainly)**	44.8	196.5	36.31%
PVs & PVs on buildings	**IPP (mainly)**	1126.1 297.8	1231 279	11.48%
Total Renewables (Grid + Network)		**3237.5**	**5685.9**	**20.10%**
TOTAL		**15879.2**	**51346.5**	

Sources: ADMIE and LAGIE

Table 16. Installed Capacity and Capacity Factor by Fuel and Ownership

4. The Gas Market

4.1. Network Regulation

4.1.1. Unbundling

A) TSO Unbundling

The TSO of the National Natural Gas System (NNGS) in Greece was established as a "société anonyme" under the name of "DESFA S.A." in February 2007. DESFA S.A. is a 100% subsidiary of DEPA S.A., the incumbent and vertically-integrated gas company in Greece. DESFA S.A. is the owner and operator of the NNGS, which is comprised of the main high-pressure pipeline and its branches, as well as the LNG Terminal at the Revithoussa island, broadly resembling the "ITO" model of the Third Energy Package. DESFA S.A. has exclusive rights for the operation, maintenance, development and exploitation of the NNGS and is currently the only gas transmission system operator in the country.

In September 2011, RAE published on its website detailed guidelines regarding the certification procedure and the relevant data requirements for all the unbundling models provided for in the Directive and for both the electricity and gas TSOs.

Law 4001/2011 that entered into force in August 2011, transposing the Third Energy Package into the national legislation, provided for ownership unbundling of DESFA S.A. from DEPA S.A. However, the above law was subsequently amended, in December 2011, by a Governmental Legislative Act, to allow for either model, Ownership Unbundling or ITO, to be followed in the case of DEPA S.A. and DESFA S.A. This amendment was carried out in view of the government's intent to privatise the incumbent and to allow potential investors to express their interest in acquiring one or both of the above companies. A second amendment of the Law, by two consecutive Government Legislative Acts, took place in November of 2012, to introduce more specific provisions on the implementation of either the Ownership Unbundling or ITO model in the case of DEPA S.A. and DESFA S.A. privatisation tender.

Therefore, the certification procedure started only at the end of December 2012, when DESFA S.A. submitted an application to RAE to be certified as an Independent Transmission Operator (ITO model).

B) DSO Unbundling

During 2012, there was no change in the unbundling regime of the three distribution companies currently active in Greece (hereinafter "EPAs"), which has been presented in detail in the previous National Reports (2008-2011).

4.1.2. Technical functioning

According to the provisions regarding gas balancing services, as included in the Greek legislation, DESFA S.A. prepares and submits every year to RAE for approval an annual balancing plan. The balancing plan includes the estimates of the TSO regarding balancing gas needs, as well as an evaluation of possible balancing gas supply sources for the following year. The plan also includes DESFA's proposal regarding the characteristics of the balancing contracts for the next year. To this effect, DESFA S.A. can either procure balancing gas directly from the long-term LNG contract of the incumbent (in line with an interim – transitional - provision of the Greek Gas Law), or procure balancing gas through a market based approach, in the form of an international tender procedure (in line with the basic provisions of the Gas Law).

In 2012, RAE approved the annual balancing plan for 2013 submitted by DESFA SA, which included the estimates of the TSO regarding balancing gas needs and an evaluation of possible balancing gas supply sources for 2013. According to this plan, DESFA S.A. proposed to acquire balancing gas (in the form of LNG), for the balancing needs of 2013, through an international tender procedure, in compliance with the main provisions of the Gas Law.

All costs arising from the provision of balancing services are recovered by the TSO through relevant charges paid by the users, so that the TSO is cash neutral. RAE is responsible for approving the balancing costs and the methodology for allocating these costs to the Transmission System users.

In the 2012 balancing plan, the TSO had estimated that the balancing gas needs for that year would amount to 4.8% of the total gas consumption, while the year-end data indicated that this figure amounted to 4.0%.

In 2012, RAE also approved the balancing cost allocation scheme and the relevant shippers' charges, which include all costs arising from the provision of balancing services. The corresponding charges include:

- A fixed charge, which covers the fixed costs of the TSO in providing balancing services.
- An energy charge, which corresponds to the cost of balancing gas procured by the TSO, according to the relevant balancing gas supply contracts, which form the basis of the cash-out price (Daily Balancing Gas Price).

All balancing charges and the methodology for their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English[22].

[22] http://www.desfa.gr/default.asp?pid=318&la=2

4.1.3. Network and LNG Tariffs for Connection and Access

A. Transmission system and LNG terminal access tariffs

During 2012, there was no change in the Third-Party Access (TPA) tarification system, which was set by the Ministerial Decision 4955/2006 and described in detail in the previous National Reports. Tariffs were set as follows:

- Tariffs for contracts of a standard duration of one (1) year were simply adjusted for inflation compared to the previous year (2011). The actual tariff coefficients for 2012 are presented in the Table below:

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh)
Transmission	621,967	0,306000
LNG	26,096	0,019690

Table 17.Coefficients of TPA tariffs for one-year duration contracts, for the year 2012

- In case of a short-term contract for the use of the Transmission System or the LNG Terminal, the capacity coefficients of the 1-year contract as presented above, are reduced proportionally to the part of the year, calculated in days, in which the contract is in force and are multiplied by a factor (B) which corresponds to the total duration of the contract, according to the following table:

Contract Duration	B
1-90 days	2.3
91-180 days	1.85
181-364 days	1.6

Table 18. Coefficients of TPA short-term tariffs

DESFA S.A. publishes on its website the Ministerial Decision 4955/2006 establishing the tariffs, the current and historical TPA tariffs, as well as a relevant calculator, in both Greek and English[23].

B. Distribution system access tariffs

During 2012, there were no changes in the scheme of gas distribution, which is carried out by the three EPAs, as described in the previous National Reports (2008-2011). EPAs are operating under a regime of exclusive rights for both the activities of distribution (DSO) and supply of gas in their areas.

[23] http://www.desfa.gr/default.asp?pid=193&la=2, http://www.desfa.gr/default.asp?pid=205&la=2

According to article 82 of the Gas Law, access to EPA's networks is granted to other suppliers serving eligible customers, with annual consumption of more than 100 GWh GCV of natural gas.

Tariffs for TPA in EPAs' distribution systems are currently those set in their concession license. New TPA tariffs will be set by the EPAs and approved by RAE (article 88 of the Gas Law), in compliance with the provisions of the Gas Directive, after the completion of their accounting unbundling, which is currently underway.

C. Development of an entry-exit TPA Tariff System

In November 2011, after extensive discussions with the TSO, that lasted for several months, RAE launched a public consultation on a TSOs proposal for a new Tariff Regulation, introducing a decoupled entry-exit tariff model in the Greek gas market.

The consultation procedure (which was conducted in two rounds) and the approval by RAE of the new Tariff Regulation was concluded in the summer of 2012. In June of 2012, RAE issued its Decision No. 594/2012 entitled "Issuing of National Natural Gas System Basic Activities Tariff Regulation" (Official Gazette B 2093 /05.07.12), which approved the new Tariff Regulation in accordance with the provisions of article 88 of Law 4001/2011 and in line with the provisions of the Third Energy Package (European Directive 2009/73/EC and European Regulation 715/2009). The Tariff Regulation replaced the Ministerial Decision 4955/2006.

The core elements of the new Regulation are summarised as follows:

- Pricing of reserved capacity is based on entry and exit points of the Transmission System (entry-exit system), regardless of the actual transportation route of the natural gas. Specifically, the National Natural Gas System is divided into three (3) entry points and three (3) exit zones.
- The methodology of Price Control for the TSO is established. The normalisation of invoices (Price Control Period) is set at a twenty (20) year period. Every four (4) years, a regular revision of tariffs will be held. The first Price Control Period is set for the twenty year period 2012-2031 and the first regular review will take place in 2015.
- The Regulation provides for the possibility of unscheduled Price Control Review, in case significant changes have occurred prior to the regular tariff review.
- A pricing methodology for reserved capacity on an interruptible basis is established, a key requirement for enabling virtual reverse flow.

In August of 2012, RAE approved the actual entry-exit tariffs (RAE Decision No. 722/2012 entitled «Approval of the National Natural Gas System Tariffs» (Official Gazette 2385/27.8.2012), to be applied from the 1st of February 2013, in accordance with the provisions of the Law 4001/2011 on the Rules of Pricing.

This development constitutes a major step foward in reforming the TPA system, towards a decoupled entry-exit regime, in full compliance with the Gas Regulation.

Accompanied by the necessary revisions in the Gas Network Code, to allow for separate entry-exit capacity booking, a fully fledged entry-exit system will soon be in place. To this end, the TSO submitted to RAE, at the end of 2012, its proposal for the second amendment of the provisions of the Network Code, that constituted the TSO's specific proposal for a fully decoupled entry-exit regime. The approval of RAE is expected in 2013.

4.1.4. Cross-border issues

During 2012, there was no change regarding interconnection infrastructure of the Greek Transmission System with neighbouring gas systems, namely those of Bulgaria and Turkey. Furthermore, no physical or contractual congestion was experienced in both interconnectors during 2012. It has to be noted that there is still no integration between the Greek and the Bulgarian natural gas markets, mainly due to the fact that the pipeline transporting gas to Greece through Bulgaria is a dedicated transit pipeline, exempted from the TPA rights that apply to the rest of the Bulgarian national network. This is also the case for the transit pipelines upstream of Bulgaria. Furthermore, there is no integration between the Greek and the Turkish markets, since there is no clear TPA regime in the latter.

Access to the Greek side of the interconnectors is subject to the capacity allocation and congestion management rules specified in the published Network Code.

During the course of the year, a bilateral meeting took place in Athens between the Greek and Bulgarian Competent Authorities, Regulators and TSOs, in order to coordinate the next steps regarding the implementation of the Security of Supply Regulation, including the realisation of physical reverse flow in the interconnection point Kula-Sidirokastro. The Greek and Bulgarian TSOs are currently working together in order to submit a joint proposal to the Competent Authorities on the realisation of physical reverse flow. This collaboration, on the implementation of the provisions of the Regulation, will become more intensive and may extend to Romania in the near future.

The second Network Development Plan (TYNDP 2013-2022) developed by DESFA S.A., after being put to public consultation by the TSO, during the summer of 2012, was officially submitted to RAE in October of 2012. The Plan will also be put to public consultation by the Regulator, as provided for in the Government Legislative Acts of November 2012, amending certain provisions of the Greek Energy Law 4001/2011. The Plan is currently under review by RAE and is expected to be approved during the next year, according to the revised provisions of the Network Code, and in line with the provisions of the Third Energy Package, as has been incorporated into national law.

4.2. Promoting Competition

4.2.1. Wholesale Markets

4.2.1.1. Price monitoring

RAE, within the framework of its competences regarding monitoring of the energy market, publicised for the first time in 2011, data on the calculated Weighted-Average Import Price (WAIP) of natural gas in the NNGS, on a monthly basis.

The publication of data on WAIP, in combination with the publication of data on daily prices of balancing gas (HTAE) on the TSO's (DESFA) internet site, allows current and potential market participants to gain a better understanding of the price conditions prevailing in the Greek market, and, therefore, to exploit business opportunities and enhance competition, to the final benefit of consumers. Furthermore, the publication of wholesale prices constitutes a necessary prerequisite for the organisation, at a subsequent stage, of a wholesale gas market.

Figure 13 presents the monthly WAIP against the daily price of balancing gas (HTAE) for the same month, as announced on the internet site of DESFA, from June 2009 through December 2012. Data are published on RAE's website[24] and updated on a regular basis.

Starting in April 2011, the deviation of HTAE from the Weighted-Average Import Price is mainly attributed to the change in the price of balancing gas through procurement, which constitutes the basis for the calculation of HTAE. Based on the contracts signed by the TSO for procuring balancing gas, for the period of 1.4.2011 to 31.12.2012, the price of procuring balancing gas only includes a proportionate charge, which incorporates the fixed amount paid out by the Operator according to the previous regime and which was not taken into account in the calculation of HTAE, but was further distributed to the System's users as a distinct charge.

[24] http://www.rae.gr/site/en_US/categories/gas/market/wholesale.csp

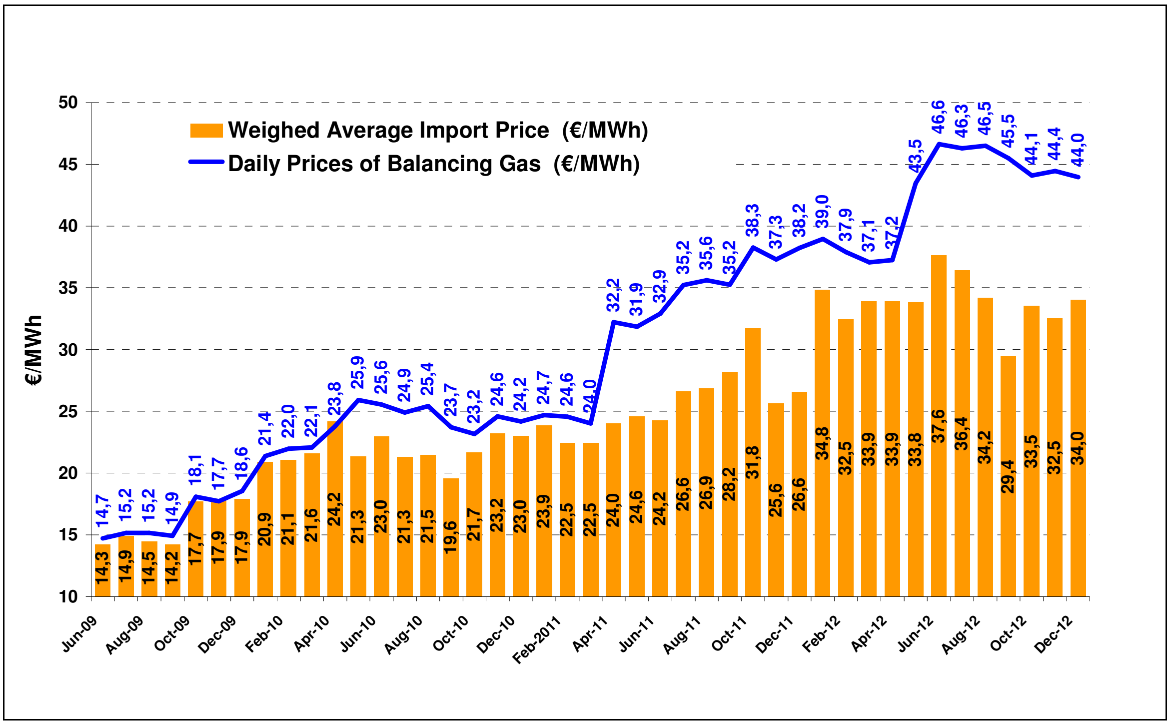

Figure 15. Monthly Weighted-Average Import Price (WAIP) against the price of balancing gas

4.2.1.2. Monitoring the level of transparency

Level of Transparency

RAE, within the framework of its competences regarding monitoring the transparency of information in the energy market, approved, for the first time in 2010, the relevant points of the transmission system, for which the Transmission System Operator shall make data available to potential network users, as described in Regulation 1775/2005. In 2011, RAE launched a public consultation regarding the approval of the list of relevant points, as submitted by DESFA S.A., according to the provisions of Regulation 715/2009, which entered into force in March 2011 and repealed Regulation 1775/2005. In the beginning of 2012, the list of points was approved by RAE's Decision 97/2012.

During 2012, RAE proceeded with one more approval of the list of relevant points as submitted by the TSO, given that one (1) more exit point was put into operation (RAE's Decision 743/6.9.2012, Official Gazette B' 2604/25.09.2012).

Furthermore, following a series of monitoring exercises that RAE carried out in the 2011-2012 period, regarding the transparency compliance of the TSO, the Operator established a separate section on its homepage, dealing with conformity to the transparency requirements set by the Third Energy Package.

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2012. As explained in previous National Reports, there is no indigenous gas production in Greece. Furthermore, there are no storage facilities and the LNG storage tanks are used exclusively for temporary LNG storage. Therefore, as has been noted in the past and fully confirmed in 2012, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market.

Following notable imports of natural gas by third parties, other than DEPA S.A., in 2010 and 2011, the same pattern was observed in 2012. In total, six (6) companies (3 gas suppliers, 2 big industrial consumers/eligible customers and 1 power producer) imported natural gas in the country, in the 3-year period 2010-2012. Out of the 48.1 TWh of natural gas imported in Greece in 2012, ninety percent (90%) were imported by DEPA S.A., and ten percent (10%) by two other parties.

In the year 2012, DEPA S.A. announced its plans to start a series of online auctions of natural gas, as a commitment to a formal decision issued by the National Competition Authority on a legal case brought against DEPA. The first online auction was held in December of 2012, whereby DEPA put to sale a total amount of 0.365 million MWh of natural gas.

The gas market is still organised on the basis of bilateral contracts between suppliers and eligible customers and no organised wholesale market exists yet. Transactions that have been recorded so far involve wholesale trading of LNG quantities in-tank, resale of gas between eligible customers and DEPA's electronic natural gas supply auctions.

The number of companies that have been granted a Gas Supply Authorisation is presented in the Table below:

	Company
1	DEPA S.A.
2	PROMETHEUS GAS S.A.
3	EGL HELLAS S.A.
4	M AND M GAS CO
5	HELLAS POWER S.A.
6	EDISON HELLAS S.A.
7	ENIMEX S.A.
8	TERNA S.A.
9	HERON THERMOELECTRIC S.A.

Table 19. Gas Supply Authorisations Registry

Furthermore, according to the Gas Law, any person wishing to become a shipper has to be registered in the National Natural Gas System Registry, in order to conclude a (transmission or LNG) contract with the TSO. In 2012, twenty one (21) companies were officially registered as potential users of the NNGS, only two (2) of which were active in 2012. The NNGS Registry is continuously being processed and updated by RAE.

	User's Name	Status/Classification
1	ALUMINIUM S.A	Eligible Customer
2	MOTOR OIL(HELLAS) KORINTH REFINERIES S.A.	Eligible Customer
3	PUBLIC POWER CORPORATION S.A. (DEI)	Eligible Customer
4	EDISON S.p.A.	Third Party
5	PUBLIC GAS CORPORATION S.A. (DEPA)	Natural Gas Supplier
6	ELPEDISON POWER S.A.	Eligible Customer
7	ELFE S.A.	Eligible Customer
8	PROMETHEUS GAS S.A.	Third Party
9	HERON THERMOELECTRIC S.A.	Eligible Customer
10	HERON THERMOELECTRIC STATION OF VIOTIA S.A.	Eligible Customer
11	PROTERGIA S.A.	Eligible Customer
12	M AND M GAS CO	Natural Gas Supplier
13	KORINTHOS POWER S.A.	Eligible Customer
14	E.ON RUHRGAS AG	Third Party
15	STATOIL ASA	Third Party
16	EDISON HELLAS S.A.	Natural Gas Supplier
17	TRANS ADRIATIC PIPELINE A.G.	Third Party
18	GASTRADE S.A.	Third Party
19	LARCO S.A.	Third Party
20	ELPE S.A.	Third Party
21	TERNA S.A.	Natural Gas Supplier

Table 20. Companies officially registered as NNGS users during 2012

4.2.2. Retail Markets

Besides DEPA S.A., which supplies gas at the wholesale and the retail level, and the self-importing/self-consuming eligible customers mentioned above, there are three (3) distribution companies (known as EPAs), which supply gas to non-eligible customers, each being a monopoly in a specific geographical area: EPA Attica, EPA Thessaloniki and EPA Thessalia. DEPA S.A. owns 51% of each EPA, thus, by the domination principle, DEPA holds on the retail level the same share as in the wholesale market.

In October 2011, the EPA Attica changed its methodology for setting tariffs. Its previous methodology connected natural gas prices to the price of oil. From 1 October 2011, the EPA Attica pricing methodology is cost oriented and similar to those of EPA Thessaloniki and EPA Thessalia. Natural gas prices for residential, professional and commercial consumers result from the summing up of: a) the cost of gas supply, b) the distribution margins and c) taxes.

Overall, average gas prices in 2012 were higher than 2011 prices.

Some indicative annual average prices for EPA Attica and EPA Thessaloniki, are presented in the table below:

Average end-user price (€/MWh)*	EPA Attica domestic	EPA Attica small commercial	EPA Thessaloniki domestic	EPA Thessaloniki domestic-commercial
2007	40.15	39.51	39.43	40.78
2008	55.50	60.08	48.93	50.39
2009	36.37	44.41	45.88	47.34
2010	45.59	54.55	47.63	49.10
2011	57.54	67.74	51.95	53.49
2012	62.96	67.96	61.40	57.16

** Net of VAT*

Table 21. Indicative, annually-averaged, natural gas prices in distribution, 2007-2012

The minimum contract duration for households is usually one (1) year, after which, there are no obligations (financial or other), or penalties, for the customer who wishes to terminate his gas supply contract.

4.3. Consumer Protection

4.3.1. Compliance with Annex 1

Consumer protection provisions, as described in Annex 1, par. 1 of Directive 2009/73/EC, have been partially incorporated in the Distribution Licenses of the three EPAs. EPAs provide all necessary information regarding offered services and end-user prices, per customer category, on their websites. Moreover, they provide telephone lines through which customers may obtain information regarding prices, connection fees, connection details, etc. They are also obliged to handle customer complaints and to respond to them within a set deadline, as well as to offer a wide choice of payment methods to their customers.

4.3.2. Definition of Vulnerable Customers

The provisions of Law 4001/2011 for vulnerable consumers have not been fully adopted by the EPAs, in terms of compliance with the categories of vulnerable groups and economic protection schemes.

The Distribution License of the EPAs, operating under a regime of exclusive right for both the activities of distribution and supply of gas in their geographical areas, include some non-economic provisions for the so-called “Domestic Customers with Special Needs”.

Since there is still no Ministerial Decision for the provision of specific conditions and economic protection schemes for customers “with Special Needs”, they are currently defined by each EPA, based on transparent criteria according to their Distribution License. The following categories of consumers are included:

- People with permanent disability caused by physical, psychological or mental impairment (movement disabilities, the blind and generally the sight-impaired, the deaf, those who have difficulty in understanding, communication and adaptation, patients with atherosclerosis, epilepsy, kidney failure, rheumatic diseases, heart diseases, etc.).
- People suffering from temporary injury or disability caused by physical, psychological or mental impairment
- People with limited ability for professional employment due to chronic physical or mental illness or injury.
- People over 65 years of age, provided that they live alone, or with another person over the age of 65.

Beneficial measures for domestic gas customers “with Special Needs” include:

- Prohibition of disconnection due to an overdue debt, during the November to February winter period.
- Relocation of the consumption meter, in order for the customer with special needs to have easy access to meter readings.
- Telephone service for blind customers, to be informed on meter readings
- Free visit to customers with special needs, in order to inform them on safety measures in case of an emergency
- The customer with special needs has the right to assign another person for communication purposes (receiving bills, messages, etc).

4.3.1. Handling of consumer complaints

Only a very small number of complaints was filed to RAE regarding the distribution and supply of natural gas to the EPA areas. The only issue of regulatory interest, which RAE plans to investigate in more depth, is the expansion of the grid of the EPAs following the request of a prospective customer, whose installation lies at a short distance from the edge of the existing grid. The current view and practice of EPA Attica is that, if the company’s business plan does not include an expansion to the direction of this customer, however small the distance, the prospective customer should be charged 100% of the cost for building the extension. It is not clear from EPA Attica whether the customer will be partially reimbursed for this cost, if and when a second customer connects to the same line, at a later time.

4.4. Security of Supply

This section provides information in accordance with Directives 73/2009/EC. All data referring to gas quantities are provided in both units of Mtoe (based on gas with a HHV of 9600Kcal/Nm3) and bcm (at 15℃).

During 2012, the Emergency Plan and the Preventive Action Plan, as required according to the provisions of Regulation 994/2010 on Security of Supply, were prepared. The draft plans were submitted to a public consultation process before their adoption in early 2013.

4.4.1. Monitoring Balance of Supply and Demand

4.4.1.1. Current demand

The demand for Natural Gas in 2012 amounted to 4.39 bcm, out of which approximately 66% concerned the power generation sector, as shown in Table 22.

Year 2012	bcm @ 15℃	Mtoe (HHV)
Power Generation	**2.60**	**2.36**
Industry & HP customers	**1.13**	**1.03**
GDCs (Primarily Commercial & Domestic)	**0.66**	**0.61**
Total	**4.39**	**4.00**

Table 22. Natural gas demand by sector in 2012

Gas demand dipped in 2012, primarily due to the very mild winter and a reduction of gas demand from the power sector.

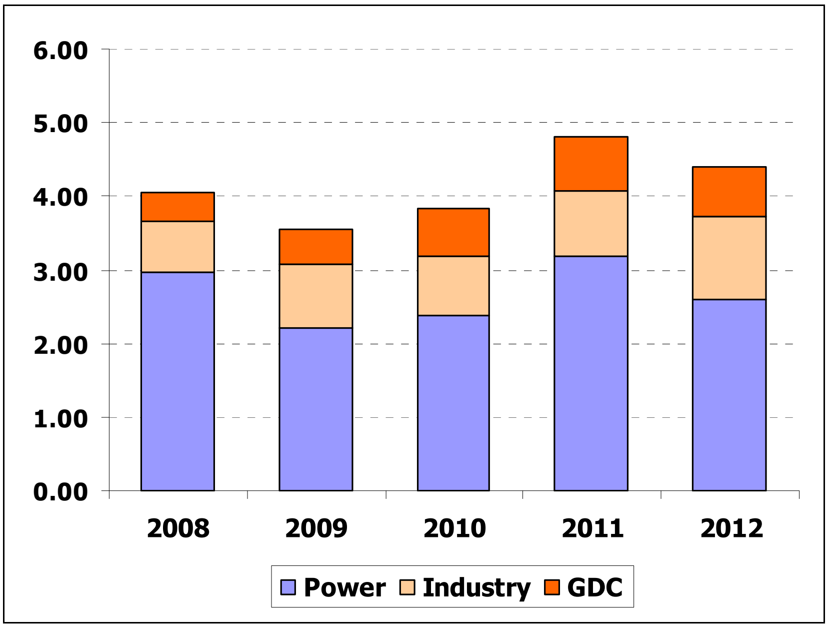

Figure 16. Gas demand per sector, 2008-2012

In 2012, there was no indigenous gas production in Greece. Gas was imported to the NGTS through its three (3) entry points. Figure 17 shows the Natural Gas sources and their participation to the total imported quantities in Greece in 2012, as reported by the TSO.

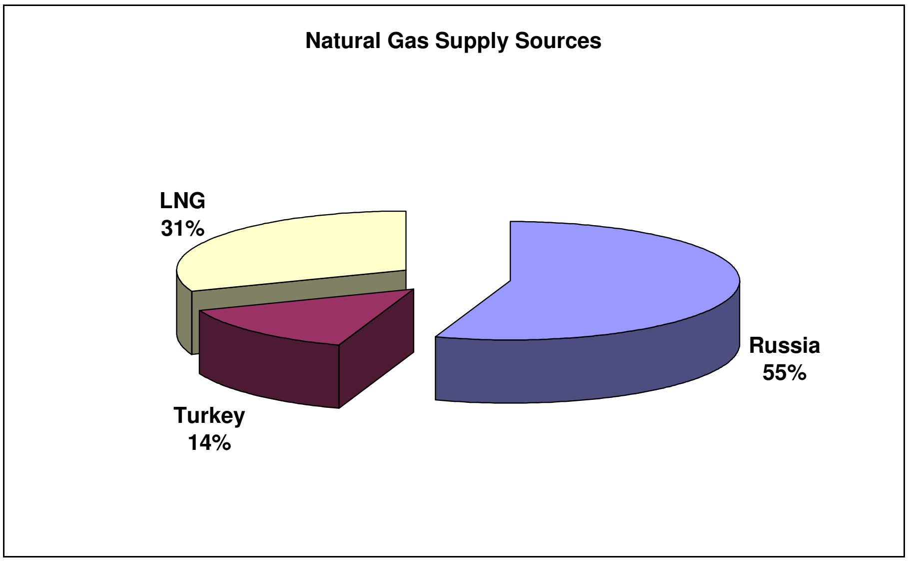

Figure 17. Natural gas supply sources in 2012

Figure 18 provides the share of imports from each source during the past five (5) years. The supply of gas through the existing long term contract with Russia lost a fraction of its share, in 2012, to LNG imports. LNG spot cargoes complemented the existing long-term contracts. LNG imports, in absolute numbers, increased by 9% in 2012 compared to 2011.

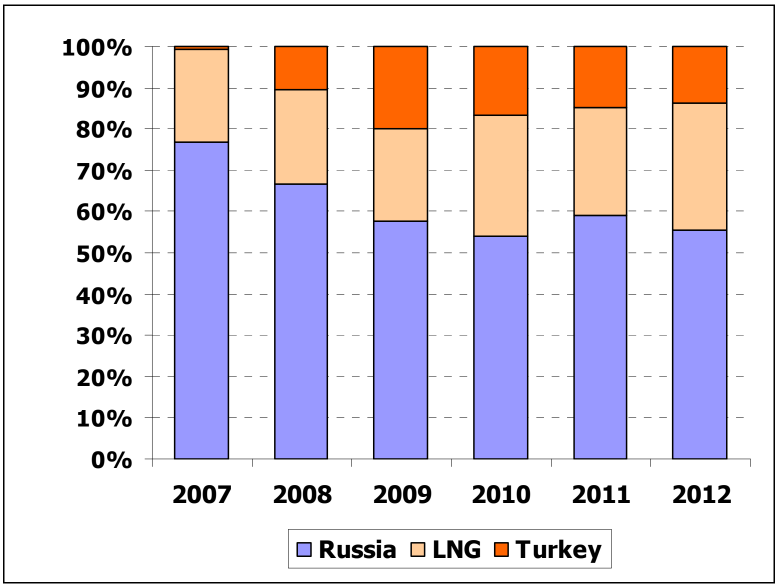

Figure 18. Share of natural gas import sources, 2007-2012

4.4.1.2. Projected demand

By the time this report was completed, DESFA had not released its updated demand projections for the years 2013-2015. All data provided thereon are based on 2012 projections. However, the 2013 consumption data so far, already indicate that demand may well be 20% lower than the figure provided in Table 23.

	2013		2014		2015	
	bcm	Mtoe	bcm	Mtoe	Bcm	Mtoe
Power Generation	3.15	2.87	3.02	2.75	3.31	3.02
Industry	1.20	1.09	1.25	1.14	1.26	1.15
Commercial & Domestic	0.60	0.55	0.65	0.60	0.73	0.66
Total	**4.95**	**4.50**	**4.92**	**4.48**	**5.30**	**4.83**

Table 23. Future natural gas demand (DESFA's 2012 estimates)

The demand outlook until 2020 has been significantly downsized, compared to previous projections. Below is the most recent projection by DESFA (2012), together with four (4) earlier projections.

Scenarios		2015		2020	
		bcm	Mtoe	Bcm	Mtoe
1	DEPA S.A.	8.50	7.80	9.30	8.50
2	LTPS (2007) 2nd scenario[1]	6.80	6.20	7.20	6.50
3	LTPS (2009) Base Case[2]	7.50	6.80	7.50	6.80
4	DESFA (2010)	6.33	5.76	6.92[3]	6.30[3]
5	DESFA (2012)	5.30	4.83	5.88	5.35

[1] *Increased RES and CO_2 abatement*
[2] *Annual Report on the Long-Term Energy Plan, 2009 (National Energy Strategy Council)*
[3] *Refer to the year 2019*

Table 24. Gas demand outlook in 2015 and 2020

4.4.2. Expected Future Demand and Available Supplies

During 2012, DEPA imported gas primarily through existing long-term contracts from three (3) different sources, namely Russia, Algeria (LNG) and Turkey, while several spot cargoes were also unloaded in Revithoussa. The aggregate of the contracted annual quantities, according to the three existing supply contracts, is shown in Table 25.

	bcm @ 15℃	Mtoe (HHV)
Up to 2016	4.4	4.0
After 2016	1.4	1.3

Table 25. Natural gas contracted annual quantities

Table 26 presents the anticipated supply – demand balance for the next three (3) years, based on the expected demand and the existing long-term supply contracts. The supply gap could rise to 0.9 bcm by 2015.

	2013		2014		2015	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	4.95	4.50	4.92	4.48	5.30	4.83
Supply Contracts	4.4	4.0	4.4	4.0	4.4	4.0
Supply Gap	0.55	0.5	0.52	0.48	0.9	0.83

Table 26. Expected natural gas supply-demand balance, 2013-2015

Figure 19 below shows the expected demand - supply balance projected to 2020, according to the scenarios presented in Table 24. The demand curve corresponds to the TSO's latest demand forecast of Table 24 (DESFA, 2012).

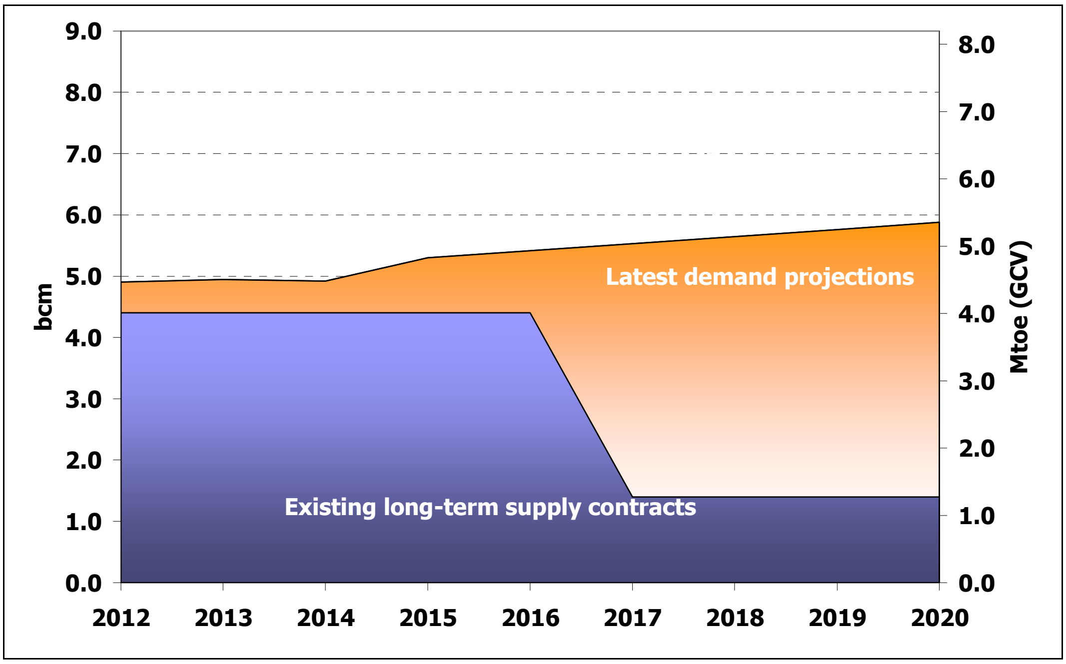

Figure 19. Expected natural gas supply-demand balance (forecast until 2020)

The Hellenic Gas Transport System has three (3) entry points, two at the North and North-eastern borders - Sidirokastro and Kipi - connecting with the Bulgarian and the Turkish gas networks, respectively, and one at the Southern part, where gas from the Revithoussa LNG terminal is injected into the System. Import capacity increased in 2012, by the addition of a new compressor station at the area of Nea Mesimvria.

Table 27 lists the current entry-point capacities. Annual quantities are derived from maximum hourly flow, considering a load factor of 90%.

Entry points	Bcm	Mtoe
Sidirokastro	3.9	3.6
Kipoi	1.7	1.5
AG. Triada (LNG Terminal of Revithoussa)	1.9	1.8
Total	**7.5**	**6.9**

Table 27. Natural gas entry-point capacities

The capacities listed are based on current capacity figures published by the TSO, based on upstream and downstream network constraints. The annual figures have been estimated based on a load factor of 90% for pipeline entry points, while the LNG terminal annual throughput is based on the assumption of an (annual) load factor of 40%, which corresponds to a ship arrival rate (with a capacity of 75,000 m3) of every 8 days. A new gas compressor started operation within the 4th Quarter of 2012.

Table 28 below lists the TSO's investment plans, which aim to add import capacity to the NGTS.

Project	Implemented by	Completion by
Revithoussa Terminal upgrade	TSO	Mid 2016

Table 28. Natural gas TSO investment plans

The Revithoussa LNG terminal upgrade will involve a storage capacity increase, through the addition of a 3rd LNG tank and an increase of the send-out rate by 40%. The project has already been awarded to an EPC contractor and its completion is expected by mid 2016.

4.4.3. Security of Supply crises

During 2012, two supply crises occurred, which threatened the security of supply of the Greek market with natural gas. The first crisis occurred during the period January - February 2012, and the second in December 2012.

RAE, under its responsibilities as a Competent Authority for the implementation of Regulation 994/2010, worked closely with all market participants, and in particular with the Transmission System Operators for both gas and electricity (DESFA and ADMIE, respectively), in order to minimise the impact on gas and electricity consumers.

<u>Supply crisis during January - February 2012</u>

During the winter months of 2012, DESFA declared the NNGS at a state of emergency, in accordance with the provisions of the Gas Network Code, three (3) times: a) January 20-22, b) February 3-5, and c) February 10-19, 2012.

RAE kept the European Commission informed about the situation on a daily basis, and provided documented assessment regarding the level of crisis, as defined in Regulation 994/2010 (gas supply crises are divided into three levels, namely: early warning level, alert level, and emergency level). At the onset of the crisis, the drafting and adoption of the Emergency Plan measures laid down in Regulation 994/2010, had not yet been completed.

According to RAE's assessment, the first two crises were limited to the level of an alert, i.e. without requiring the imposition of any curtailment of natural gas supply to customers. On the other hand, the supply crisis that occurred during the period of 10-19 February 2012, gradually evolved into a state of emergency, as defined in the Directive, and required the imposition of gas supply cuts to power generation consumers.

This last crisis occurred gradually, as a result of a combination of negative events and conditions. The main reasons that contributed to the crisis were:

- the very high demand for natural gas for electricity generation.
- the stopping or limiting of the supply of gas from Turkey.
- the interruption of electricity exports from Bulgaria

- the very cold weather that prevailed, for several days, in the wider Balkan region.

On February 14th, due to the postponement of the arrival of the next LNG cargo at the Revithoussa terminal, DESFA upgraded the crisis to the level of emergency, as defined in Article 10 of Regulation 994/2010 and ESFA Network Code, instructing DEPA to limit the flow of gas to the power-producing plants. This extraordinary condition ended on February 18th, after the arrival and unloading of a new LNG cargo.

RAE directly informed the relevant Directorate of the European Commission on the grounds for the declaration of emergency, and maintained daily contact with all parties involved. After the end of the crisis, the Commission sent a formal request, pursuant to paragraph 8 of Article 10 of the Directive, asking for confirmation that the declaration of emergency was in accordance with the provisions of paragraph 3. In response, RAE produced a report that detailed the crisis conditions and the actions taken by the parties involved, including assessment of the demand curtailment as part of the emergency measures.

The Commission verified the satisfactory compliance with the provisions of the Directive during the crisis and made recommendations for the development of market mechanisms to manage future crises, to be incorporated in the Preventive Action Plan.

4.2.5.2 Supply crisis in the NNGS - December 2012

Following cancellation of a scheduled LNG cargo delivery, another supply crisis occurred during the period from 14th to 21th of December 2012. DESFA declared the NNGS in a state of emergency on December 14th, and RAE informed directly the relevant Directorate of the European Commission on the grounds of the declaration, as well as on the level of the crisis, in accordance with Article 10 of Regulation 994/2010.

The management of the crisis was handled by the market itself, through an increase of gas supply at the entry point Sidirokastro and a speeding-up of the arrival of the next LNG cargo ship on December 21st.

The level of crisis, in accordance with Article 10 of the Regulation, did not exceed level 2 (alarm), and the TSO did not have to resort to gas delivery curtailments. The new compressor in New Mesimvria, which allowed the flow of increased quantities of natural gas from the North, played a key role in limiting the crisis to level 2 and in its final resolution.

4.4.4. Measures to Cover Peak Demand or Shortfall of Suppliers

Under Law 4001/2011, RAE has been appointed as the Competent Authority to ensure the implementation of the measures set out in the European Regulation 994/2010. In this context, and as specified in this Regulation, RAE published in 2012 a *Risk Assessment Study*, prepared in accordance with the provisions of Article 9 of the Regulation, as well as a

Preventive Action Plan, developed in accordance with the provisions of Articles 4 and 5 thereof.

Risk Assessment Study

In March of 2012, RAE published the Risk Assessment Study[25], carried out in order to assess the risks to security of supply of gas to Greece and their implications. The Risk Assessment Study constitutes the basis for all future actions foreseen in the Regulation.

In this Study, the most significant threats to the supply of gas to the Greek NNGS were identified. Scenarios were then built to simulate the realisation of these threats. These scenarios were used as input to a mass-balance analysis, coupled with rules regarding the timing, the extent of the required load-shedding, as well as the interruption sequence of customers belonging to four (4) categories. The above analysis was then used to calculate a series of indicators for the estimation of the impact on the supply of gas to a) protected customers, b) large industrial customers, and c) power generation.

The time-horizon of the Study is until the end of 2014, and its main results are summarised as follows:

1. Based on the current data, household consumers, small and medium enterprises that are connected to the distribution network, as well as district-heating installation companies without alternative heating fuel, are not expected to suffer an interruption of their supply, under any of the risk scenarios examined, if the appropriate measures for demand-side management in power generation and in industry are adopted.
2. From the impact analysis of eighteen (18) such scenarios, it is concluded that two (2) scenarios will have no effect, eight (8) scenarios are of low risk, ten (10) scenarios are of medium risk, while one (1) scenario is of high risk.
3. The maximum daily and weekly demand can be satisfied with the existing infrastructure, within the time horizon considered, i.e. until the end of 2014.
4. The “N-1 Rule” is not satisfied with the existing infrastructure. This means that, in order to satisfy this rule within the next 3 years, in case of non availability of the Revithoussa LNG terminal, there will be a need for demand-side management, in the order of 3-5 millions of cubic meters per day, or equivalent capacity increase of gas injection (new or enhanced pipeline gas or LNG import capacity, or building of gas storage facilities with adequate injection capacity).

Preventive Action Plan

In November of 2012, RAE published the “*Draft Preventive Action Plan for enhancing security of supply of gas in the Greek National Natural Gas System (NNGS)*”[26], under its competency as the country's security of gas supply Competent Authority. For the preparation of the Plan, RAE established a working group, which included the Operator of the National Natural Gas

[25] http://www.rae.gr/site/file/system/docs/misc1/20102011/01032012_1
[26] http://www.rae.gr/site/file/system/docs/natural_gas/05112012_3

System, DESFA SA, the Operator of the Greek Electricity Transmission System, ADMIE SA, the Public Gas Corporation, DEPA SA, in its capacity as the Supplier of Protected Customers, as well as representatives of the Ministry of Energy, Environment and Climate Change. Participants in the gas market, large gas consumers and electricity producers also contributed their views through a broad consultation process.

Having the Risk Assessment Study as its starting point, and using the same methodology and the same initial conditions with regard to demand scenarios, the Preventive Action Plan contains a short-term and a medium-term strategy composed of actions aiming to mitigate the specific risks identified in the Risk Assessment Study, through the implementation of appropriate actions. The list of alternative actions examined in order to reduce risks, include the development of new infrastructure and the improvement / upgrading of the existing one, but also market-related measures or obligations on suppliers, or agreements with neighbouring TSOs. Cost estimates for the examined actions or measures are based on independent assessments, and on published information, where available. The adoption of the Plan is gradual, as it includes actions designed to be implemented in the short (1-2 years) and the medium (3-6 years) term.

The provisions of Law 4001/2011 concerning several aspects of the above required actions are not in line with Regulation 994/2012. To remedy this, and following consultation with stakeholders, a legislative amendment has been proposed by RAE to the Ministry, containing all necessary provisions to fully implement the short-term strategy contained in the Preventive Action Plan. If accepted by the Ministry, this legislative amendment can be enacted by the third quarter of 2013.

The Preventive Action Plan has been sent to the European Commission and to the Competent Authorities of the neighbouring countries, in accordance with the exchange process outlined in Article 4 of the Regulation, for their comments before its final adoption.

Appendix I - List of licensed electricity Suppliers and Traders at the end of 2012

Trading Licences	Supply Licences
1. A2A TRADING SRL	1. ALPIQ ENERGY S.A.
2. ALPIQ ENERGY HELLAS S.A.	2. ATHENS INTERNATIONAL AIRPORT S.A.
3. CEZ a.s.	3. BLACK PEARL ENERGY S.A.
4. DANSKE COMMODITIES A/S	4. COMPAGNIE NATIONALE DU RHONE
5. DEUTSCHE BANK A.G.	5. EDELWEISS ENERGIA S.P.A.
6. EDF TRADING LIMITED (EDFT)	6. EDISON TRADING S.P.A
7. EFT HELLAS S.A.	7. ELECTRADE SRL
8. EGL HELLAS S.A.	8. ELECTRICITY TRADING COMPANY HELLAS S.A.
9. EHOL HELLAS S.A	9. ELEKTROPARAGOGI SOUSSAKI S.A.
10. EL.EN. LTD	10. ELPEDISON S.A.
11. ELEKTRICNI FINANCNI TIM, PRODAJA ELEKTRICNE ENERGIJE d.o.o. LJUBLJANA	11. ENI SPA
12. ELLAKTOR S.A. (HELLENIC TECHNODOMIKI)	12. EVN TRADING SOUTH EAST EUROPE EAD
13. ENEL TRADE S.p.A	13. GREEK ENERGY SA (ELLINIKI ENALLAKTIKI) S.A.
14. ENER SA	14. GREEK ENVIROMENTAL & ENERGY NETWORK S.A.
15. ENERGY MT EAD	15. HERON THERMOELECTRIC S.A.
16. ENSCO S.A.	16. NECO TRADING S.A.
17. EUROPEAN ENERGY TRADE S.A. GIOUZELIS-CHATZIDIMITRIOU	17. PPC S.A.
18. EZPADA S.R.O	18. PROTERGIA S.A.
19. GALA SPA	19. REVMAENA LTD
20. GAZPROM MARKETING & TRADING	20. RWE SUPPLY & TRADING GMBH
21. GEN I ATHENS LTD	21. THRACE ELECTRICITY S.A.
22. GUNVOR INTERNATIONAL B.V.	22. TINMAR-IND S.A
23. HELLENIC PETROLEUM S.A.	23. UNIT HELLAS S.A.
24. HSE D.O.O	24. VOLTERRA S.A.
25. IBERDROLA GENERACION S.A.U.	
26. NECO S.A.	
27. NOVEL ENERGY LTD	
28. OET HELLAS S.A.	
29. OET UNITED ENERGY TRADERS LTD	
30. REPOWER TRADING CESKA REPUBLIKA s.r.o	
31. ROSEVELT LTD	
32. RUDNAP ENERGY LIMITED	
33. SEMAN S.A.	
34. STATKRAFT MARKETS GMBH	

35. STELLA GAVRIIL LTD	
36. TEI HELLAS S.A.	
37. TERNA ENERGY S.A.	
38. VERBUND AG	
39. VIVID POWER EAD	

i. List of Acronyms

ADMIE	The Greek Electricity Transmission System Operator, as of 01.02.2012
AoG	Aluminum of Greece S.A.
ATC	Available Transfer Capacity
CAC	Capacity Availability Contract
CAT	Capacity Availability Ticket
CPI	Consumer Price Index
CSE	Central-South Europe
CWE	Central-West Europe
DAES	Day-Ahead Energy Schedule
DEDDIE	The Greek Electricity Distribution System Operator, as of 01.05.2012
DEPA	Public Gas Corporation S.A.
DESFA	Hellenic Gas Transmission System Operator
DSO	Distribution System Operator
EPA	Gas Distribution Company
FIT	Feed-in Tariffs
GDC	Gas Distribution Company
GHG	Greenhouse Gases
HGTSO	Hellenic Gas Transmission System Operator
HTSO	Hellenic Transmission System Operator
HV	High Voltage
IGI	Italy-Greece Interconnector
INGN	Independent Natural Gas Network
IPP	Independent Power Producer
LAGIE	The Greek Market Operator as of 01.02.2012
LV	Low Voltage
MEECC	Ministry of Environment, Energy and Climate Change
MO	Market Operator
MV	Medium Voltage
NGS	Natural Gas System
NNGS	National Natural Gas System
NTC	Net Transfer Capacity
PPC	Public Power Corporation, S.A.
PSO	Public Service Obligation
PTR	Physical Transmission Rights
QoS	Quality of Service
RAE	(Hellenic) Regulatory Authority for Energy
SoLR	Supplier of Last Resort

SoS	Security of Supply
SMP	System Marginal Price
STA	Standard Transportation Agreement (for access to the gas transmission system)
TDSO	Transmission and Distribution System Operator
TPA	Third-Party Access
TSDS	Transmission System Development Study
TSO	Transmission System Operator
TUoS	Transmission Use of System
TYNDP	Ten-year Network Development Plan
UCTE	Union for the Co-ordination of Transmission of Electricity
UIOLI	Use it or lose it
UIOSI	Use it or sell it
UGS	Underground Storage
USS	Universal Service Supplier
WAIP	Weighted-Average Import Price

ii. List of Figures

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