2014 National Report to the European Commission

(Covering the period 01.01.2013 – 31.12.2013)

Regulatory Authority for Energy (RAE)

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1. Foreword

2013 was a milestone year for the Greek Regulatory Authority for Energy (RAE), as it marked the beginning of the implementation of its comprehensive package of measures for the overall reorganisation of the domestic energy market, which the Authority designed, put at a multi-phase public consultation, further detailed and, ultimately, instituted, in close and effective cooperation with the European Commission.

In this process, RAE's guide has always been the detailed Roadmap and Action Plan for the restructuring of the domestic energy market, in accordance with the provisions and requirements of the European Target Model, which the Authority had elaborated and published in December of 2011. After extensive studies and public consultation that followed in 2012, RAE proceeded in 2013 to issue a number of key decisions, that are already changing the map of the domestic energy market and are preparing Greece to participate, in a smooth, organised and efficient manner, in the ongoing integration process of the single European energy market. Some of these key RAE decisions concern:

- The phasing out, by mid-2014, of the transitional mechanisms and measures that had been applied in previous years in order to develop a level-playing field in the domestic wholesale electricity market competition (including the abolition of the Cost Recovery Mechanism and the so-called 30% rule, the concrete reform of the Capacity Adequacy Mechanism in accordance with the new EU directions and regulations).

- The revision of the methodology for determining the Use of System charges, for access to electricity networks, in accordance with the best European regulatory practice.

- The elaboration and institution of the Non-Interconnected Islands Code, which is a thorough and innovative regulatory piece of work, that sets up a detailed, unified legal framework for the development, operation and management of the tens of autonomous (island) electrical systems of the country.

- The elaboration of the new Electricity Supply Code, which deals, in depth and detail, with all the issues of the deregulated retail electricity market, with emphasis on consumer rights, and especially those of the vulnerable citizen groups.

- The second revision of the Network Code of the National Natural Gas System, which, combined with the new Tariff Regulation that RAE enacted in February 2013, introduced a full review of the rules governing access of users to the System, aiming to maximise the benefits from the development of competition and the creation of a modern, smoothly functioning domestic gas market, in accordance with the provisions of the Third Energy Package.

- The granting by RAE, in collaboration with the Italian and Albanian Energy Regulators, of an exemption from third-party access to the TAP pipeline, while imposing strict regulatory operating conditions. The choice of TAP, as the pipeline that will transport natural gas from Azerbaijan to Europe, is an important step forward in the drive to incorporate Greece into the integrated European gas market.

At the same time, RAE undertook several initiatives and measures to foster liquidity in the domestic energy market and to help create a financially viable environment, through effective management of the credit and market risk, created by accumulating consumer debts (unpaid bills) and the Market Operator’s lack of liquidity, in a very adverse economic and market environment.

RAE will proceed within the same framework for the next, very crucial, two-year period 2014-2015, that has a strong transitory nature, at all levels of energy and, in general, economic activity in Greece.

The Greek Regulatory Authority for Energy (RAE)

2. Main developments in the gas and electricity markets

2.1. Electricity

The Greek wholesale electricity market is still organised as a pure mandatory pool. However, during 2013, several rules and supplementary mechanisms, which exerted a substantial impact on market outcomes, were significantly revised so as to yield more competitive outcomes. More specifically, in July 2013, the following market changes were introduced:

- Immediate (11.07.2013) abolition of the "10% margin" of the cost recovery mechanism, which the generators dispatched by the TSO beyond the day-ahead schedule received above their declared minimum variable costs
- Abolition of 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, from 1.1.2014 onwards
- Abolition of the entire Cost Recovery Mechanism, from 1.7.2014 onwards
- Reform of the Capacity Adequacy Mechanism, by doubling the number of certificates issued for flexible plants (gas plants) until the end of the reliability year 2013-2014, and by abolishing the CAM remuneration of obsolete plants (which were about to be decommissioned, or potentially to enter into emergency reserve contracts with the TSO), while setting the unit CAM price paid by suppliers at 56,000 €/MW/year, from 1.8.2013 until 30.9.2014.

Regarding the market structure, PPC retained in 2013 its dominant position, having 80.4% in terms of conventional technologies (thermal and large hydro) in the interconnected system. The incumbent's market share drops to 60.5%, if renewable capacity is also taken into account.

Wholesale prices exhibited remarkably low levels in 2013, with a significant decline of 26.7% relatively to their average value in 2012, and lower even in comparison to their depressed levels in 2009 and 2010, two years of intense wet conditions and very large hydro production.

In the retail electricity market, stability was restored and no extraordinary events occurred in 2013, in sharp contrast to 2012, which was the year that four (4) electricity suppliers exited the market due to outstanding overdue payments. PPC remained by far the dominant supplier, as it held almost the entire retail market (99.60% of the total number of customers at the end of 2013, and about 98% of total electricity supplied).

LV tariffs were fully liberalised, as scheduled, on 01.07.2013. Following this, there were no more PPC tariff changes in 2013, in the LV customer categories, the tariffs of which still reflected some cross-subsidisation between certain categories (for instance, low consumption households continued to be subsidized, to some extent, by small commercial tariffs).

The growth of customer liabilities against their electricity suppliers continued in 2013 (PPC's estimated unpaid receivables of €1.2 billion at the end of 2013), reflecting the difficulties faced by consumers during the deep economic recession. The very large debt to the suppliers transferred throughout the electricity chain and on to the gas market.

2.2. Natural Gas

In 2013, the demand for natural gas shrank even further, by 11% compared to 2012, reaching only 3.92 bcm/year. This decrease followed a 10% decrease already observed in 2012 (vs. 2011) and was primarily a result of the continuing slow-down of industrial production because of the persistent recession, as well as of a very mild winter.

In the regulatory front, the second revision of the Gas Network Code was completed by RAE and put into effect in December 2013. Together with the new Tariff Regulation that RAE entered into force in February 2013, a fully-fledged entry-exit system is now in operation in the country. A Virtual Nomination Point (VNP), where transactions of natural gas quantities may take place between network users, has also been introduced. All necessary provisions for interruptible and reverse flow (backhaul) services have also been included in the revised Network Code.

In addition, the required regulatory framework set in the Security of Supply Regulation was completed, with RAE, as the national Competent Authority, publishing in 2013 the Preventive Action Plan and the Emergency Plan, developed in accordance with the provisions of Regulation (EU) 994/2010, after consultation with the Competent Authorities of the neighbouring countries.

Last but not least, in July of 2013, the three National Energy Regulatory Authorities of Italy, Albania and Greece issued their Joint Opinion on the exemption of the Trans Adriatic Pipeline (TAP) from third-party access rules and other provisions of the Third Energy Package. When completed, TAP will be a major Interconnector opening the Southern Gas Corridor for the supply of Europe with gas from Caspian sources, and shall contribute considerably to the maturity of the Greek gas market, establishing a market-based bridge between the Eastern gas resources and the Western gas markets. It should be emphasised that the acceptance of TAP AG's request for exemption has been accompanied by the enforcement of a strict set of regulatory terms and conditions by the three Regulators.

3. Regulation and Performance of the Electricity Market

3.1. Network Regulation

3.1.1. Unbundling

3.1.1.1. Certified Transmission System Operator - ADMIE S.A.

ADMIE S.A., the Independent Transmission Operator (ITO) since February 2012, is a 100% subsidiary of PPC S.A. and is responsible for the development, operation and maintenance of the national transmission system in Greece. According to the Energy Law 4001/2011, the market model applied in the Greek market for the Transmission Operator is the ITO one. In December 2012, RAE, with its final Decision 692A/2012 and after taking into consideration the Opinion of the European Commission, certified ADMIE as an Independent Transmission Operator (ITO).

In 2013, in accordance with the ADMIE Compliance Programme, which was also approved by RAE, ADMIE's Compliance Officer submitted to RAE the due half-year Compliance Reports, concerning the company's performance in fulfilling the legal and operational unbundling from the VIU. These reports provided evidence that during 2013 ADMIE applied the necessary procedures in order to perform independently in all three (3) areas covered by the Compliance Programme, namely (a) the independence of management, (b) the independence of financial resources, and (c) the independence of operational activities.

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

The Hellenic Electricity Distribution Network Operator (HEDNO S.A. or DEDDIE S.A.), which is the independent Distribution Network Operator since May 2012, 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."). HEDNO is also the Power System and Market Operator for the Non-Interconnected Islands of the country.

3.1.1.3. Accounting unbundling

According to the provisions of the Energy Law 4001/2011 and the European Directive 2009/72, integrated undertakings are obliged to keep separate accounts and report unbundled financial statements (Balance Sheet and Profit & Loss Account) for each activity. The Regulator approves the unbundling rules and methods, based on the company's proposal. During 2013, RAE issued the following decisions regarding accounting unbundling rules:

- Decisions 142/2013 and 178/2013: Based on RAE's Decision 86/2007 for the PPC's financial statements and unbundling methodology, the two RAE decisions of 2013 made some necessary amendments, mainly due to the transfer of Transmission and Distribution activities to the independent Operators, ADMIE S.A. and DEDDIE S.A., respectively.
- Decision 204/2013: RAE approved the proposal of the private energy company PROTERGIA S.A. for the adoption and implementation of unbundling rules for the first time in its 2012 Annual Report (financial statements).

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[1]. Following these instructions, the TSO published reports on the performance of the Transmission System for the years 2010, 2011 and 2012[2]. These 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 dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, in conjunction with the allowed revenue for 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. Review of the rules, procedures and data of PPC (that acted as the DSO until May of 2012), regarding QoS dimensions monitored to date, have been carried out by the Regulator since 2008. So far, this has allowed the Regulator to report on the overall service quality level

1 http://www.rae.gr/site/system/docs/misc/11012011.csp
2 March 2013 - http://www.admie.gr/fileadmin/groups/EDLES_DLS//PERFORMANCE_REPORT2012-IPTO.pdf

(SAIDI, SAIFI, connection times, service at customer centers), based on available, non-audited, data provided by the DSO and to formulate and publish its opinion on them, as well as on current DSO 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 demand users falls within the aforementioned initiative, undertaken by the Regulator over the previous years.

Concerning connection of new generation facilities, monitoring issues do arise for the DSO, as, in several circumstances, significant delays have been recorded in the DSO's responding to requests for connection offers to RES generators. However, the situation has notably improved in 2013, following the suspension, by law, of applications for connection of PV facilities in August 2012. 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 equal to 100%. Since 2011 (Law 4001/2011, article 140), RAE approves the tariffs for access to the national electricity networks (Transmission System and Distribution Network), one month before their entry into force, based on the proposals submitted to the Regulator by the Electricity Transmission System and Distribution System Operators (ADMIE and DEDDIE, respectively).

During 2013, there were no methodological changes with regards to network tariffs. In 2014, RAE intends to review network tariff-setting methodologies, and, for this reason, an international tender was issued in 2013, in order to appoint a consultant to assist with the review and development of a revised and improved methodology. The project is expected to be completed by the end of 2014. Due to time constraints and the need to move to an incentive-based regime with a longer regulatory period, RAE announced in December 2013 a public consultation regarding a methodology for setting the TSO revenue for the interim period of 2015 – 2017.The proposed amendments, in comparison with the existing methodology[3] for setting allowed transmission revenues, were:

- A multi-year regulatory period
- Calculation of the TSO's Allowed Revenue based on real terms and indexed to inflation
- Return on Capital Employed based on real pre-tax WACC

[3] RAE Decision 840/2012 - Article 275 of System Operating Code

- Calculation of depreciation using economic, instead of accounting, asset lives
- Smoothing of revenues within and between regulatory periods, in order to minimise the impact of fluctuations to consumers

The final decisions for the new methodology and the relative amendments to the System Operating Code were taken in April 2014[4].

The process for setting required revenue and network access tariffs for 2014 started in the autumn of 2013 and was completed in April 2014[5]. As a result, the 2013 network access tariffs remained in effect until 30.5.2014.

3.1.3.1. Transmission network tariffs for access

During 2012 and after conducting public consultation[6], RAE instituted[7] an amendment to the methodology of calculating the Required Revenue for the 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[8] as the sum of:

- the estimated annual Transmission Cost[9] ,
- the estimated annual cost of any work for the expansion of the System,
- the over-recovered funds /surplus (-) or under-recovered funds/shortfall (+)[10] from customers,
- the settlement for differences between forecasted and actual operating expenses (OPEX) and investments of previous years, and
- interconnection auction revenues[11].

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

[4] RAE Decisions 339/2014 και 340/2014.
[5] RAE Decisions 195/2014 (Transmission Network) and 196/2014 (Distribution Network).
[6] Public consultation took place from 17 May to 15 June 2012
[7] RAE Decision 840/2012
[8] RAE Decision 57/2012 (Government Gazette B' 103/31-01-2012) and subsequent amendments.
[9] According to article 275 of System Operating Code
[10] Deviations between the forecasted and the actual revenue from system users during previous years
[11] According to Regulation 714/2009, article 16. For 2012, the relevant amount was €21.4 m and for 2013 €26.9 m.

	2012 (million €)	2013 (million €)
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[12], 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 €1,413m (including €61.1m for new investments) and to €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 depreciation 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).[13]

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[14] in 2010.

Tariffs for HV-connected customers follow a €/MW structure, charged on the customer's average hourly demand during the 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 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 (the so-called KOT, see

[12] The under-recovery cost through the charges applied in 2010 (€16.1m) was taken into account in the Required Revenue of 2013.
[13] The revaluation was carried out by an independent firm of appraisers for accounting purposes (according to IAS 16).
[14] RAE Decision 2215/2010.

Section 3.3.2), 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% 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 the lack of appropriate meters and data on individual demand.

According to the above mentioned methodology, RAE approved the following customer tariffs for 2013:

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

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[15].

According to the methodology applicable at the end of 2012 (see previous National Report), the resulting Use of System (UoS) unit charges for Distribution in 2013, per customer category, are as presented in the table below. 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 3. Distribution Use of System (DUoS) charges for 2013

3.1.3.3. Transmission network connection tariffs

Only "shallow" connection costs, i.e. connection costs 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 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 yet been formally approved by the Regulator. According to the provisions of Law 4001/2011, a detailed pricelist is to be submitted by the TSO to RAE for final approval.

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

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 decreased in 2013, with the average NTC corresponding to exports decreasing from 1480 MW in 2012 to 1370 MW in 2013 (-7.4%), and the respective NTC for imports decreasing to 1475 MW in 2013, compared to 1500 MW in 2012 (-1.7%). The Winter-NTC for imports remained the same (1350 MW in 2013, as in 2012) and the Summer-NTC decreased at 1600 MW in 2013, compared to 1650 MW in 2012. Figure 1 displays the allocation of NTC in 2013 and its evolution compared to 2012.

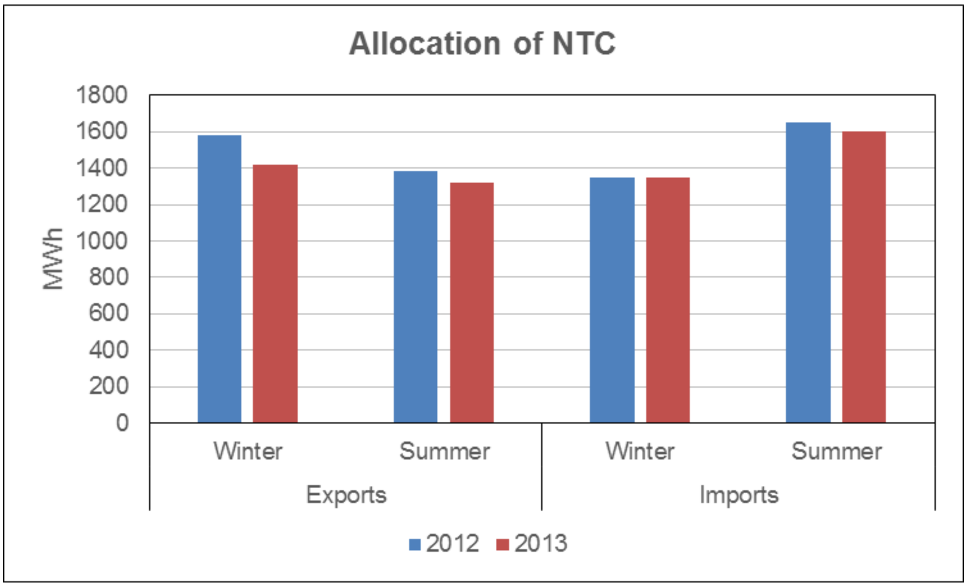

Figure 1. Comparison of Summer-NTC and Winter-NTC for Imports and Exports

Overall, the net interconnection balance increased significantly (+17.9%), from 1.8 TWh in 2012 to 2.1 TWh in 2013. Although net imports increased compared to 2012, the split into import and export patterns indicate a strong decline of the energy exchanged. Overall, imports declined by 21%, from 6 TWh in 2012 to 4.7 TWh in 2013, adding to the decline of 17% from 2011 to 2012, and exports decreased significantly, from 4.2 TWh in 2012 to 2.6 TWh in 2013 (-37.6%).

More specifically, exports to FYROM decreased significantly, from 0.15 TWh in 2012 to 0.05 TWh in 2013 (-63.2%). Albania recorded exports of 0.73 TWh in 2013, compared to 1.48 TWh in 2012 (-50.7%), while the decrease for exports to Italy was more moderate in terms of percentage share, but higher in volumes (35.4%, from 2.54 TWh in 2012 to 1.64 TWh in 2013). In contrast, exports to Turkey and to Bulgaria increased in 2013 by 4360% (from 0.004TWh in 2012, to 0.17 TWh in 2013) and by 86.7% (from 0.002 TWh in 2012, to 0.004 TWh in 2013), respectively, but the volumes remained at very low levels.

Imports from all countries, except from Albania, decreased. The percentage decline observed in the interconnection with Italy was 70.8% (from 0.33 TWh in 2012, to 0.1 TWh in 2013). Imports from Turkey and Bulgaria decreased by 52.7% (from 1.7 TWh in 2012, to 0.81 TWh in 2013) and by 24.2% (from 2.3 TWh in 2012, to 1.75 TWh in 2013), respectively. Imports from FYROM recorded a rather moderate decline, from 1.6 TWh to 1.49 TWh (-7%), while imports from Albania increased by 3157%, from 0.02 TWh to 0.57 TWh.

Figures 2 and 3 display the distribution of interconnection trading in 2013 and its evolution compared to 2012.

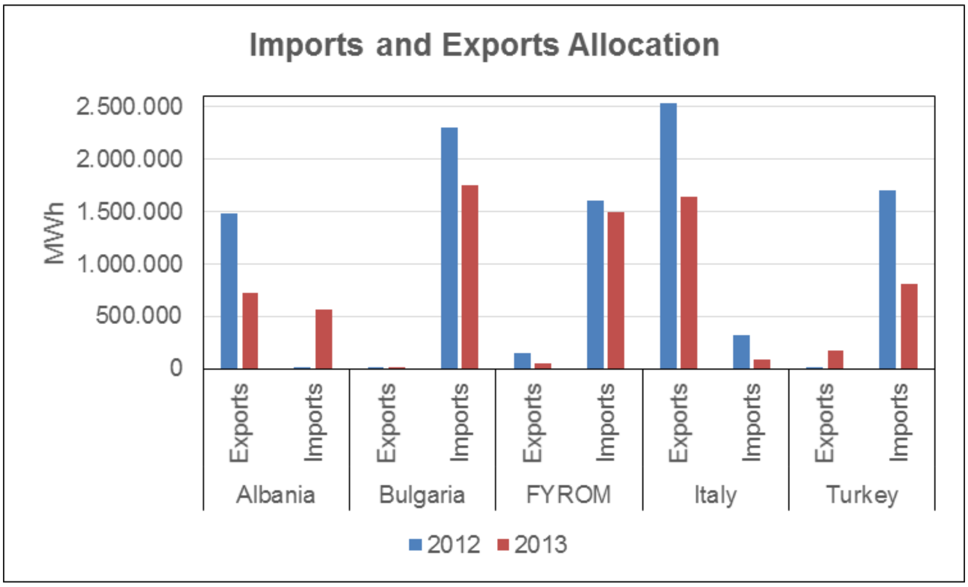

Figure 2. Distribution of import and export trading in 2013, compared to 2012

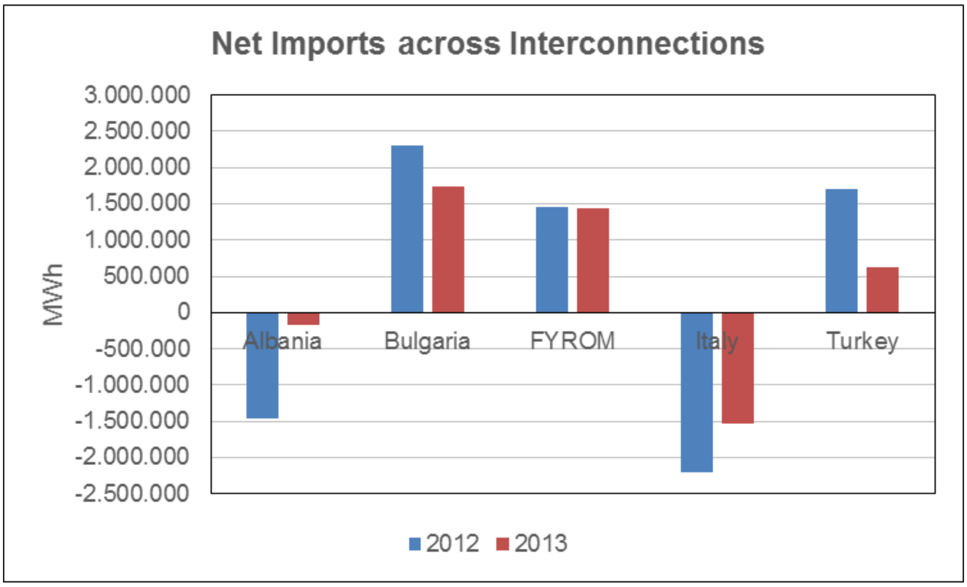

Figure 3. Net trading volumes across bordering countries (positive values for imports) in 2013, compared to 2012

Overall, the trading volume in all borders decreased by 2.8 TWh (-27.9%), with Italy having the higher percentage decrease (-39.5%, corresponding to 1130 GWh), and FYROM having the lowest (-11.7%, corresponding to 206 GWh).

The significant decrease of the trading volume in Italy could be partly attributed to the problematic operation of the interconnection. During the second half of 2013, the repeated forced outages led to long periods of limited, or no availability of the interconnector between Italy and Greece. Since October 22, 2013, the interconnection is not available and the reparation procedure is not expected to be completed before the end of the first semester of 2014.

The capacity allocation for the Italian borders, within the Central – South Europe (CSE) Region, is performed (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. During 2013, RAE approved (Decision 530/2013) new Capacity Allocation Auction Rules for the borders with Italy, with amendments for promoting the further harmonisation of auction rules. More specifically, provisions for the establishment of a Bulletin Board were added in the new version, in order to facilitate the transfer process in the context of the secondary market. Moreover, there was a change in the definition of equivalent days for the remuneration of participants in case of curtailments, as well as the introduction of tax gross-up, to address the different tax handling among the countries.

With Decision 561/2013, RAE approved the Auction Rules in the borders with Albania, FYROM, Bulgaria and Turkey. These Auction Rules will apply in the borders with Albania, FYROM and Turkey until the Auction Rules of South East Europe Coordinated Auction Office – SEE CAO take effect (mid 2014). The Bulgarian Transmission Operator (ESO EAD) decided not to participate in SEE CAO; therefore, the Auction Rules approved by RAE will remain unchanged in 2014.

Regarding the interconnections with Albania and FYROM, the main characteristics remained unchanged, with independent rules for the calculation of NTC in force. However, changes were introduced in the definition of the equivalent days, regarding the remuneration of participants in case of curtailments, as well as in the monthly resale deadline, limiting it to four, instead of five, working days, in order to increase the time period for the operators to complete the related procedures.

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 decision, incorporating the changes described above for Albania and FYROM, but also introducing provisions related to the remuneration of participants for curtailments of transmission rights due to Force Majeure, as well as other minor changes.

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, and rules that are the same as the ones for Albania and FYROM. 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). In April 2013, the ENTSO-E Regional Group Continental Europe (CE) decided to increase the capacities for commercial power exchanges between CE and Turkey. Hence, currently, the capacity for imports from CE to Turkey is 550 MW (up from 400 MW) and the capacity for exports from Turkey to CE is 400 MW (up from 300 MW). According to the relevant agreement, these capacities are split by a ratio of 2/3 for the Bulgaria-Turkey border and 1/3 for the Greece-Turkey border.

The main principles of interconnection congestion management rules in 2013 remained the same as in 2012, 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 ADMIE 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 2013, capacity allocation at the interconnections and directions as follows:

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

Table 4. HTSO responsibility for capacity allocation on interconnections

Income from congestion management has been used for purposes complying with the provisions of the Article 16 of European Regulation 714/2009 and its Annex with the Congestion Management Guidelines, namely to reduce transmission network tariffs (see also Section 3.1.3.1 above). This is reflected in the relevant report that RAE publishes annually, as required by the same Regulation.[16]

[16] http://www.rae.gr/site/file/system/docs/electricity/files/01081401

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 with regard to 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 Adequacy Mechanism (CAM), 2024 MW of new, IPP gas capacity was added to the system by the end of 2012, whereas in March 2013 a new CCGT plant by PPC also entered into commissioning status. However, early projections for strong and prolonged growth of demand (around 2.5% annually) 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.

Following the formation of the Market Operator (LAGIE) and the System Operator (ADMIE)[17] in February 2012, and the allocation of tasks between these two companies, the core of the market design and the settlement processed involved remained unchanged during 2013, while supplementary mechanisms were refined so as to lead to more competitive market outcomes and reduce operational inefficiencies that had emerged.

In essence, the current market design involves two distinct settlement processes:

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[17] In February 2012 (see National Report 2013), 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.

- 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 the System Marginal Prices (SMP), computed by LAGIE, and the 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, which exerted a substantial impact on market outcomes, remained in force in 2013, but were revised in crucial aspects so as to yield more competitive outcomes:

- A lower limit is imposed on generators' offers, equal to the minimum variable cost of each unit in each trading period. This limit had 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 so-called "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 margin. This margin had been set previously to 10%, but it was abolished in July 2013, being considered a market distortion, as generators used the mechanism as a way to get dispatched over prolonged time intervals, exhibiting stable profiles (of limited sensitivity to the demand level), but imposing unnecessary costs on the system. After this distortion was corrected, the mechanism expressed better its objective as a safety net that averts producers' losses when dispatched due to reserve requirements (not necessarily energy balance requirements) and inter-temporal technical constrains.

- 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 2013, the value of these certificates remained regulated, due to the very high market share of PPC in the retail market (>97%) and the consequent lack of liquidity and ability for contracting between suppliers and generators. The value of the capacity certificate was revised in July 2013 from 45,000 €/MW/year (a level set back in November 2010) to 56,000 €/MW/year.

More specifically, in the context of the reform package for the domestic wholesale electricity market, designed and elaborated by RAE, in collaboration with the European Commission, the Regulator issued Decisions 338 and 339/2013 (July 2013), introducing the following market changes:

- Immediate (11.07.2013) abolition of the “10% margin” of the cost recovery mechanism,
- Abolition of the “30% rule”, from 1.1.2014 onwards,
- Abolition of the entire cost recovery mechanism, from 1.7.2014 onwards,
- Reform of the Capacity Adequacy Mechanism, by doubling the number of certificates issued for flexible plants (gas plants) until the end of the reliability year 2013-2014, and by abolishing the CAM remuneration of obsolete plants (which were about to be decommissioned, or potentially to enter into emergency reserve contracts with the TSO),
- Setting the unit CAM price paid by suppliers at 56,000 €/MW/year, from 1.8.2013 until 30.9.2014.

The challenging issues that continued to arise in the domestic electricity market throughout 2013 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 vertically-integrated companies (with generation and supply portfolios), other than PPC. Vertical structures would enable firms to better manage 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 further emphasised by the fact that the two main alternative suppliers had exited the market in early 2012, creating a deficit of €172 million, and, hence, the incumbent, PPC, recaptured a market share close to 100% in the retail sector. The dominance of PPC in this respect changed only to a minor extent in 2013. In this context, RAE, already in 2011, 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 2013, the issue of excess capacity, to be assessed against declining demand levels, became even more evident. A new gas plant by PPC entered the system, intensifying, in theory, competition for mid and peak demand. In practice, however, the commissioning status of this unit, which ensured its dispatch, in combination with its higher efficiency and lower overall cost, exerted a downward pressure on the dispatch of IPP plants. Overall, it is notable that the total installed capacity of gas plants exceeded that of lignite plants. Due to this addition, PPC's share in the generation sector, which had been reduced substantially in previous years, increased slightly from 79% in 2012 to 80.4% in 2013, if calculated on conventional technologies (thermal and hydro) in the interconnected system, and from 53% to 60.5%, 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 in supporting the large-scale penetration of renewables through its flexibility, 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 were crucial for the revision of the capacity mechanism that RAE implemented in July 2013, but also for further plans to introduce a new capacity remuneration mechanism.

Liquidity problems continued throughout 2013. The deviation between the high feed-in-tariffs applied for renewable production and the suppressed reference price from the wholesale market, was reduced to some extent, as the reference price was revised in 2013. Effectively, the SMP price was substituted by a weighted-average value, reflecting the marginal cost of the plants actually being dispatched. This corrective action was important. Still, the structural reasons behind the debt in the Renewables Account remained, particularly as the addition of renewable capacity was substantial within 2013, evolving from 3668 MW in January to 4453 in December. In this context, the deficit of the RES account escalated to €550 million at the end of 2013 (compared to €340 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 2013. Simultaneously, consumers' debts (unpaid electricity bills) remained huge (exceeding €1 billion at the end of 2013), due to the severe economic recession and the incorporation, from autumn 2011 onwards, of a substantial property tax into the electricity bill, which bulged its total amount. Another concerning element of the liquidity crisis in 2013 was its eventual impact on the gas sector, as IPPs continued to accumulate substantial debts towards DEPA, and being subject to interest rates, because of the delays in their payments by the Market and System Operators.

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 elaborating the necessary market design changes, including the introduction of intraday and balancing markets.

Market Settlement

In 2013, the third year of the implementation of the revised market design that allowed for the settlement of imbalances, the remuneration through the day-ahead market represented 61% of generators' cash-flows. More specifically, the generators' annual revenues from the day-ahead market amounted to €1.8 billion, while ex-post settlements amounted to €1.2 billion. Hence, the turnover of the wholesale market reached €3.02 billion. The supplementary mechanisms of cost-recovery and capacity payments reached 556 and 546 million €, respectively, compared to €462 and €457 million in 2012. The escalation of the amount of the cost-recovery, which reached a monthly maximum level of €80 million in June 2013, reflected the extended dispatch of gas plants, achieved through the mechanism in combination with the 30% rule and the co-optimisation between energy and reserves. This observed inefficiency contributed to RAE's decision for the abolishment of the mechanism. The increase of the annual amount relating to the capacity mechanism reflected the increase of the value of the capacity certificate from August 2013. It is notable that over the last quarter of the year, as a response to regulatory changes, gas plants revised their operational status, aiming at operation over shorter time intervals during hours of higher prices, more closely reflecting their marginal costs. Having constrained their operational hours, the revenues of IPP plants from the market reduced, and availability, rewarded through the capacity mechanism, became a crucial parameter for their cash flows. For PPC, the day-ahead market reflected 69% of its income as a producer, while for IPPs the corresponding percentage was 37%. Hence, ex-post settlement amounts became crucial for the viability of the new independent plants.

In particular:

- The balancing cost remained a minor fraction of the total cost in the day-ahead market. More specifically, the generators' annual revenues from the day-ahead market amounted to €1.8 billion, while in total, their imbalance charges exceeded imbalance payments by a small percent, yielding a (negative) net amount of €1.3 million, with PPC contributing €35 million and independent producers receiving €33 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 €2 million, yielding less than 1% of total generators' revenues in 2013. 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 38% of the total generators' revenues in 2013. For the IPP producers, the cash-flows from the supplementary mechanisms represented 56% of their annual revenues, with their day-ahead market component being constrained to 37%. For PPC production, the day-ahead market represented 69% 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 2013, recapturing also the customers of the two alternative retailers that defaulted in early 2012. The cost-recovery component reached 40% 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 €336 million cost for PPC as a supplier in 2013, as opposed to €319 million in 2012 and 130 million in 2011, reflecting the changes 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 Figures 4 and 5. The excise tax imposed on natural gas is not displayed due to its different nature from the other streams.

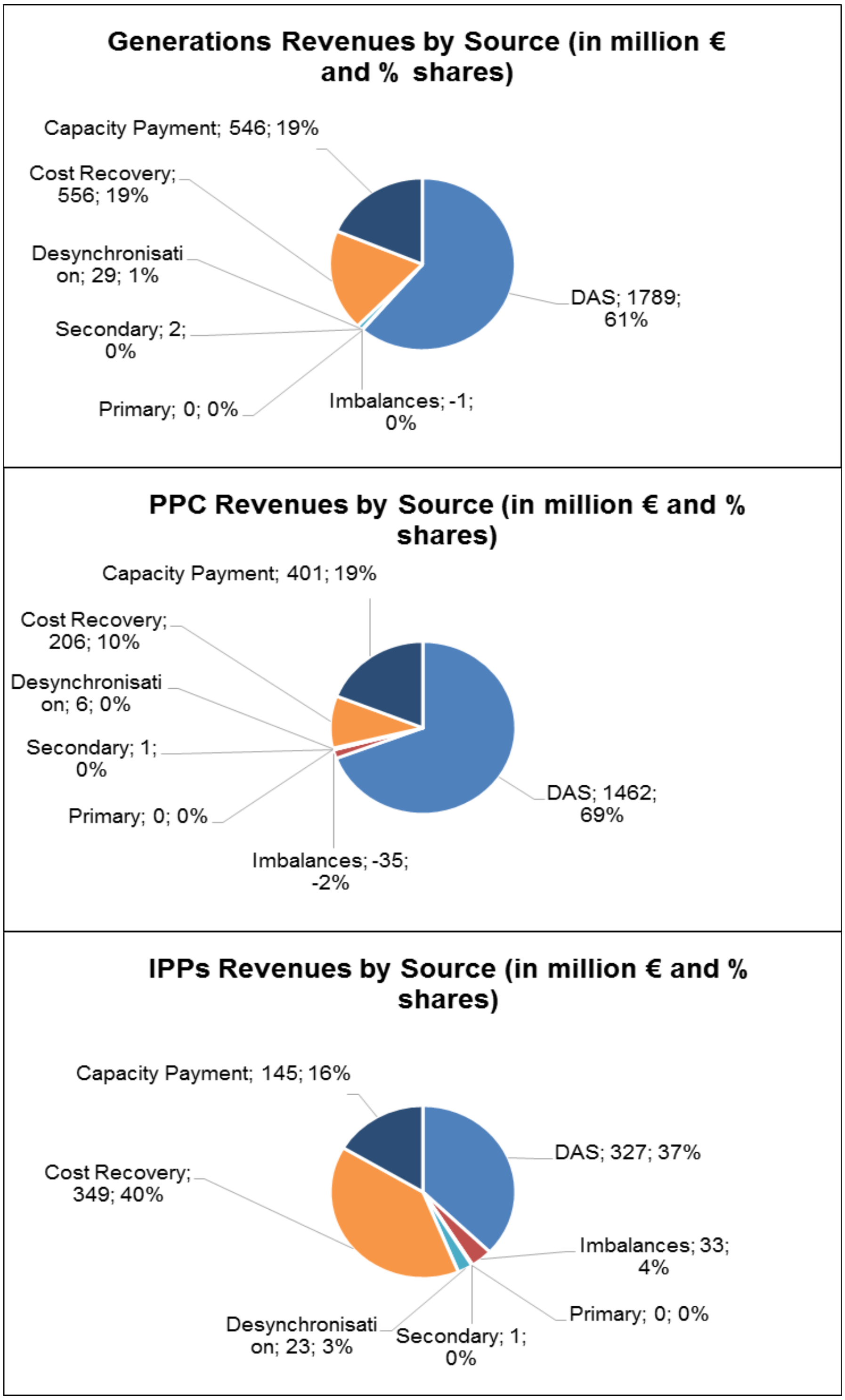


Figure 4. Generators' revenues from the day-ahead market and ex-post settlements in 2013

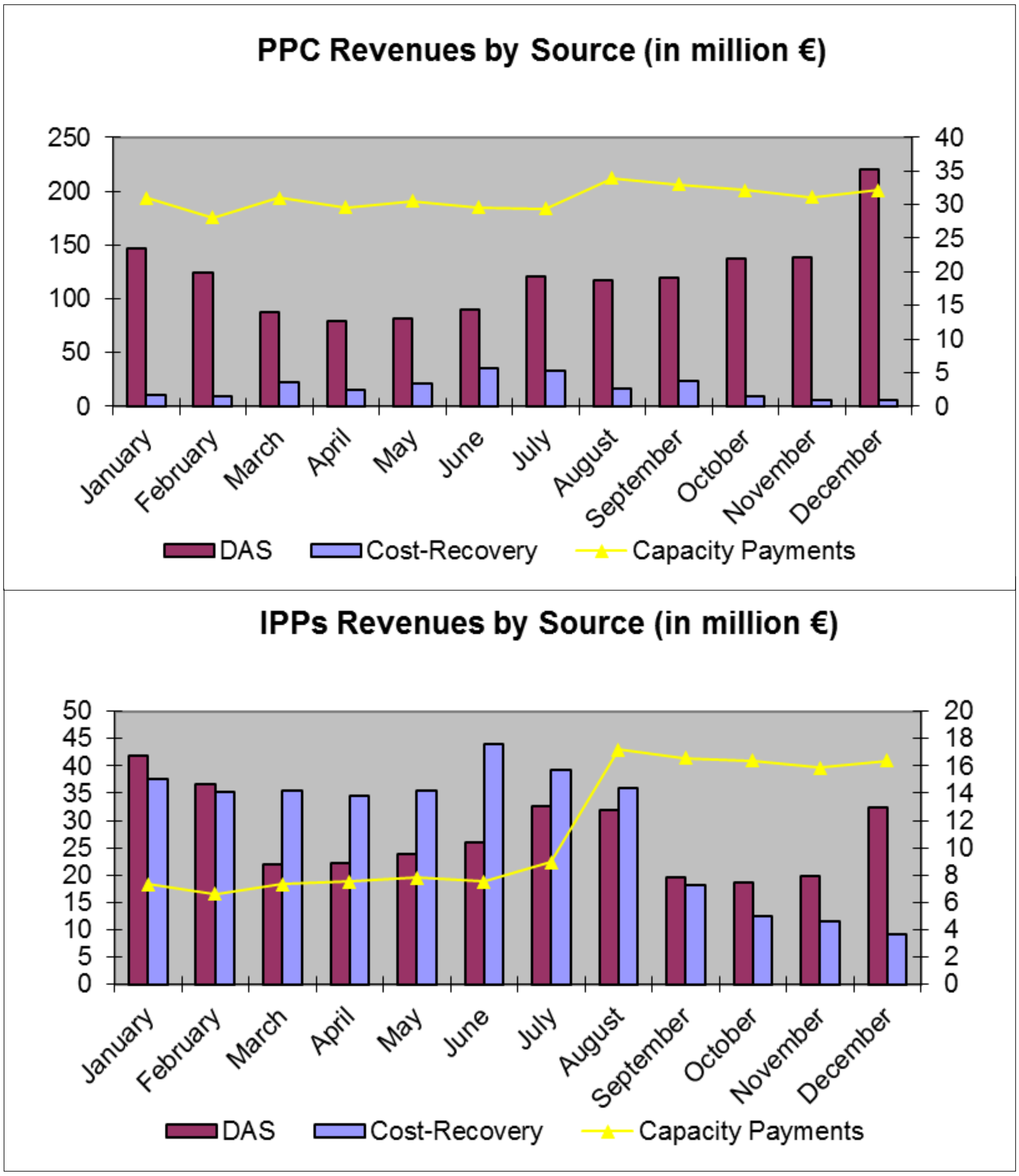


Figure 5. Generators' revenues from the day-ahead market and ex-post settlements, per month, in 2013

<u>Market Volume</u>

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 50,017,853 MWh in 2013, reflecting a decline of 0.97% relative to 2012.

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 3.41 GWh in

2013. Hence, the “true” demand in 2013 was not 46.45 GWh, as the TSO reported, but 50.66 GWh, partly covered by PVs connected to the distribution network.

Figure 6 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.

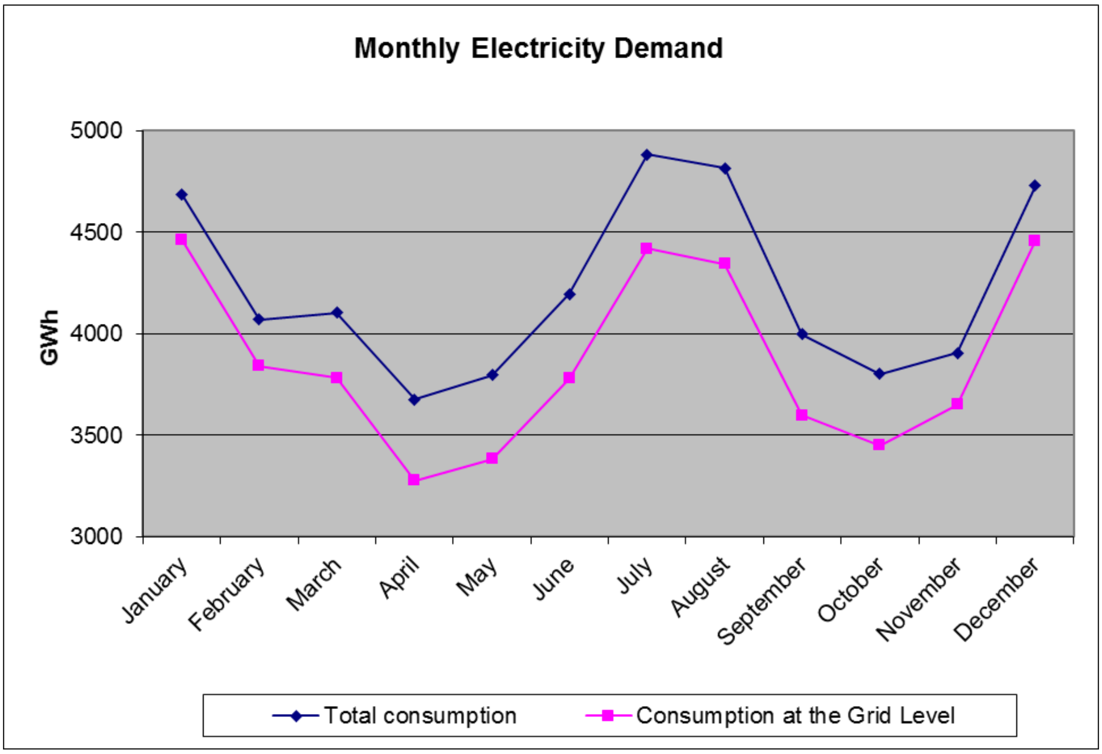


Figure 6. Electricity demand evolution during 2013

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 2013 its dominant position. On the generation side, reflecting the addition of a new CCGT, PPC’s market share remained almost stable, reaching a level of 80.4% (compared to 79.7% in 2012), in terms of conventional technologies (thermal and large hydro) in the interconnected system. The incumbent’s market share dropped to 60.5%, if renewable capacity is also taken into account. At the national level (including non-interconnected islands), PPC’s production covered 66% of total demand in 2013, the corresponding shares being 66.7% in 2012, 70.1 % in 2011 and 77.3% in 2010. In absolute terms, PPC’s production plus imports increased by 2616 GWh in 2013, adding to a reduction of 1083 GWh in 2012 and 4451 GWh in 2011. The import activity of PPC increased to 2153 GWh (+161 GWh relatively to 2012).

In the retail sector, the developments in 2013 were also minor, but in the opposite direction, as the incumbent's huge market share declined slightly to 98.2%, compared to 99.1% in 2012.

It should be emphasized that 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 two more IPP plants, and subsequently, in 2012, with the addition of a fifth plant, all being similar in terms of capacity and technology (gas CCGT of about 400 MW capacity each). In terms of thermal capacity, this direction of market evolution seems to converge towards an equilibrium point. More specifically, all private plants have now been completed, while, in terms of the incumbent's new capacity investments, a new CCGT plant (Aliveri V, 417 MW) entered the market in March 2013 and the last on-going CCGT project (Megalopoli V) is expected to become operational in the next few years. Although investment has reached a saturation point, given the suppressed demand levels, the market structure 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. The formation of a new vertical company, consisting of a portfolio of PPC's assets, will be reviewed in 2014. Apart from conventional generation, changes in market structure were enhanced by an almost explosive penetration of renewables, in which PPC's share remains minor. This tendency was constrained in 2013, after the imposition of "corrective" measures by the government in terms of lower feed-in-tariffs, taxes on revenues, and time limits in the completion of renewable investments.

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 S.A.
- Heron II (422 MW, CCGT) and Heron I (147.5 MW, OCGT) are owned by Heron Thermoelectric S.A. (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 2013, is owned by the Motor Oil refinery.

Moreover, as stated by the TSO in its most recent Ten-Year Network Development Plan (2015-2024), two (2) additional thermal units, of 851 MW total capacity, had also applied for connection by December 2013. This capacity includes the incumbent's new CCGT unit Megalopoli V (811MW), the materialisation progress of which is linked to the expansion of the gas network in the Peloponese central region. The above capacity of 851 MW does not include, however, the new lignite unit Ptolemaida V (660 MW), for which private investor involvement, along with PPC, has been discussed. In addition, seven (7) hydro units, of total capacity 1085 MW, have already been licensed, but not all of them have applied for connection yet. Two of these hydro units are pumping stations (231 and 403 MW). The hydro unit Ilarion (143 MW), on the Aliakmonas river, is expected to start commissioning in February

2014. Following the decommissioning of 250 MW of obsolete lignite units (Megalopoli I and II) in 2012, Ptolemaida II (116 MW) entered a cold reserve status in October 2013.

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

Electricity demand in the interconnected system was suppressed further in 2013, reaching a level of 46.45 TWh, hence exhibiting a decline of 7.6% relatively to 2012. At the national level, demand reached 50.66 TWh in 2013, relatively to 52.61 TWh in 2012, exhibiting a decrease of 3.7%. It is notable that demand declined over the third quarter of 2013 by 6.7% relatively to Q3 2012, 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).

Given the addition of production capacity in 2013, the incumbent's market share slightly increased in 2013. In the interconnected system, PPC's share, in terms of volume, increased to 82.6% of domestic production (excluding RES), while independent gas producers achieved a share of 17.4% (Elpedison 6.5%, Mytilinaios Group 7.3% and Heron Thermoelectric 3.5%). Renewables connected to the Grid, mainly wind, accounted for 7% of domestic production in 2013 vs 6.3% in 2012, reaching a total of 3381 GWh in 2013 vs. 3113 GWh in 2012. Taking into account this renewable output, PPC's overall market share reached 80%. In particular, PPC's gas production increased by 166% in 2013, i.e. to 3876 GWh, mainly due to the addition of the new plant (Aliveri V), hence restricting the space for IPP's production.

The HHI index for the wholesale market in 2013, a measure of market concentration, attained the value of 6553 in terms of volume, and 6597 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 these plants is higher 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 exhibited remarkably low levels in 2013, displaying a time-weighted average value of 41.47 €/MWh, hence exhibiting a significant decline of 26.7% relatively to their average value in 2012 (56.60 €/MWh). It is notable that prices remained lower, even in comparison to their depressed levels in 2009 and 2010, two years of intense wet conditions and very large hydro production, in which prices had collapsed to 47.40 €/ MWh and 52.30 €/ MWh, respectively. Focusing on monthly variations, depicted in Figure 9, the average price fluctuated between 30.55 €/MWh in March, due to the large increase in hydro production, while its levels were restored progressively over the last quarter of the year, reaching 62.81 €/MWh in December (+38% compared to December 2012).

Overall, the above price evolution in 2013 reflected a convolution of factors, including:

- the high penetration of renewables, which enter the day-ahead market as mandatory quantities, hence, 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 103% (+3887 GWh) compared to 2012.
- the capacity surplus of conventional plant, as 2100 MW of new CCGT capacity were added to the System over the last four (4) years, while demand declined by 11% over the same period, reflecting the deep economic recession.
- the large increase of hydro quantities in Q1 2013, that led to an overall increase in hydro production by 65% (+ 1906 GWh) compared to 2012.
- the trial operation of the new combined cycle gas plant of 420MW, Aliveri V, owned by PPC. Its trial operation started in March 2013 and the operation of the plant was stabilised in the second semester of 2013. Having reduced its imbalances and until some technical issues were solved, the mandatory dispatch of the unit suppressed to some extent the competitive segment of the load curve.

Following the declining trend in price levels, volatility of hourly prices decreased substantially in 2013. Prices exhibited a standard deviation of 13.17 €/MWh, compared to 27.22 €/MWh in 2012 and 23.18 €/MWh in 2011. Regarding extreme levels, the SMP did not reach its maximum value of 150 €/MWh (price cap) at any hourly trading period. The minimum level of zero (0) was attained in 674 hourly trading periods (compared to 97 periods in 2012), while prices exceeded 80 €/MWh in 7% of the trading hours. Zero levels occur during demand troughs (historically, over the Easter break in May), 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 7 to 10 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.

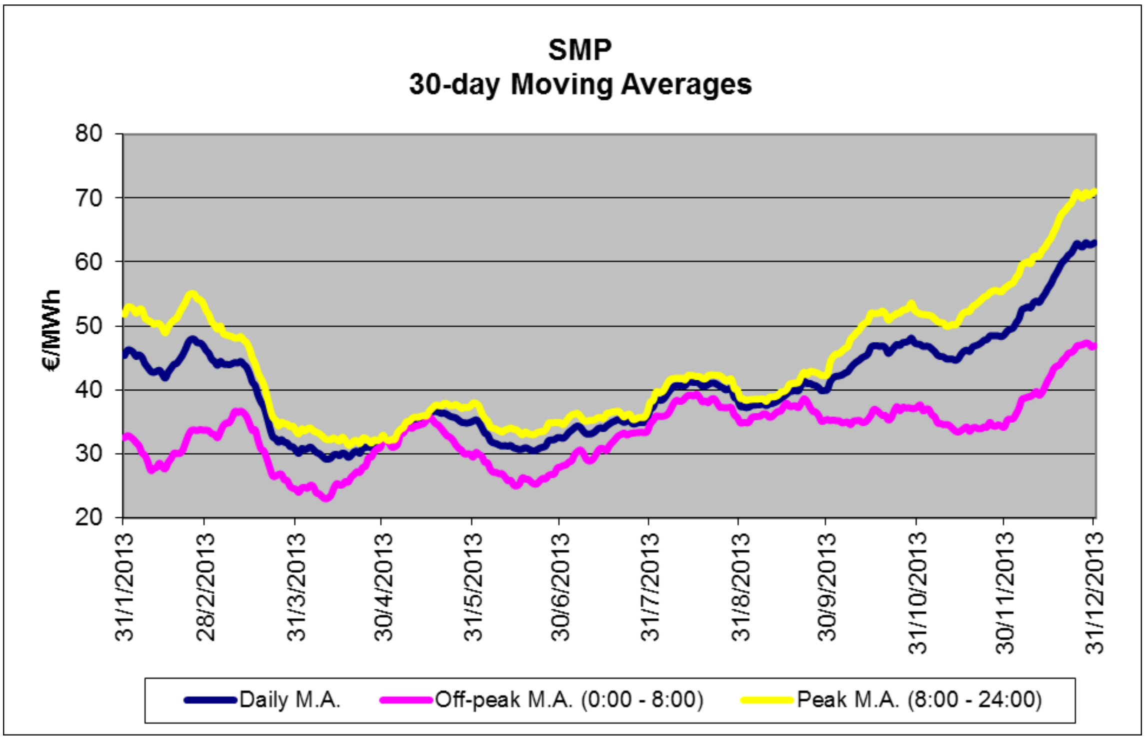


Figure 7. SMP dynamics (actual and smoothed levels) in 2013

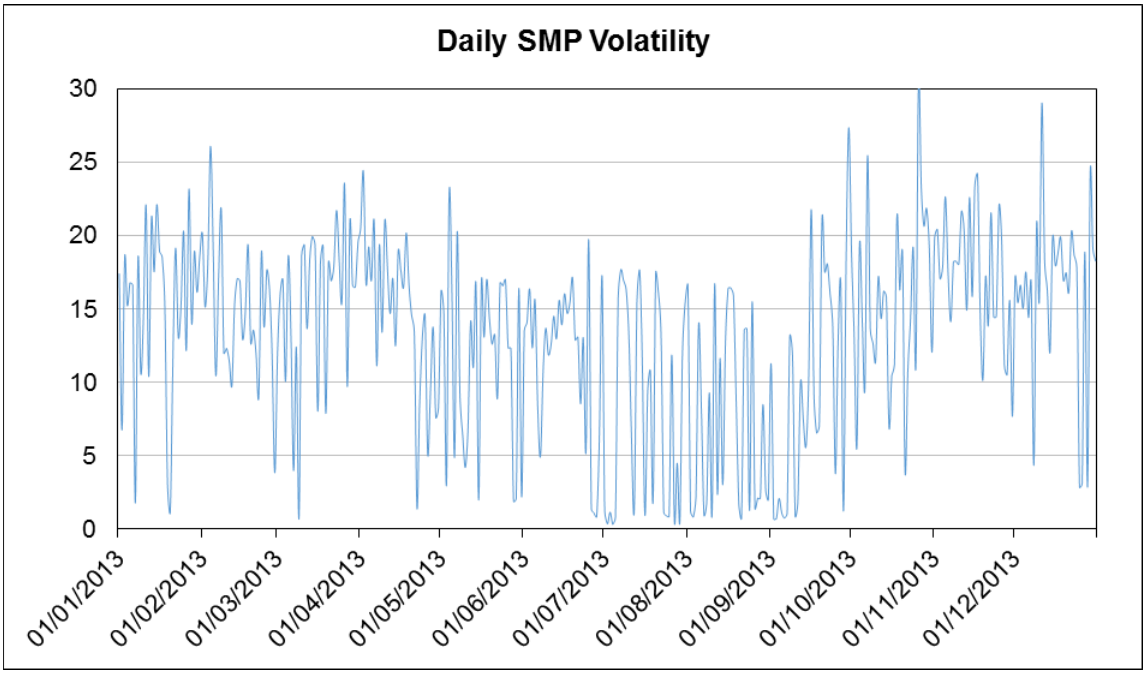


Figure 8. SMP volatility (st. deviation) in 2013

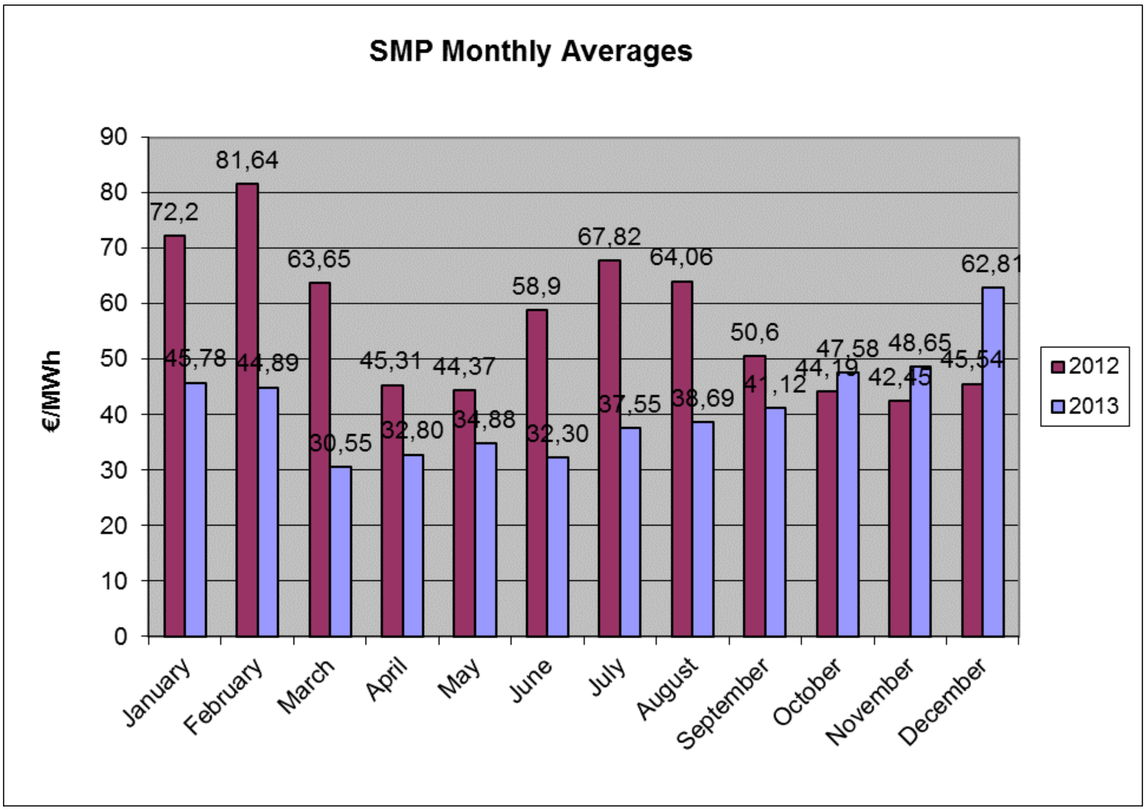


Figure 9. SMP intra-yearly pattern in 2013

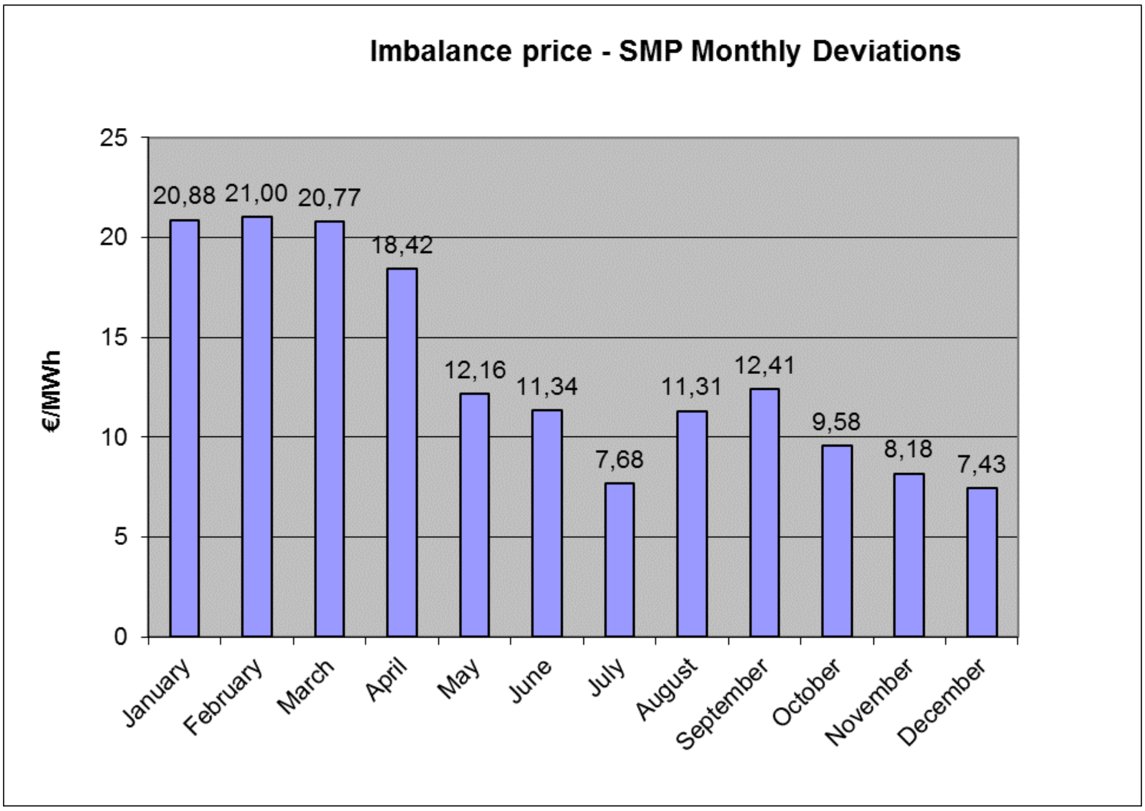


Figure 10. Imbalance Price - SMP: intra-yearly pattern of deviation in 2013

The declining market concentration at the generation side of the market, over the last few years, 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 retained its huge retail market share (98.2%) in 2013, 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. In 2012, PPC had chosen to shrink its gas production, and, hence, its expenses for the tax levy contribution. In 2013, the commissioning status of its new plant, Aliveri 5, incurred a substantial increase of its gas production, but simultaneously rendered more challenging the dispatch of IPP units.

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 occasionally, 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, the addition of 2000 MW of IPP gas capacity over the last few years introduced elements of competition between PPC's gas plants and IPPs for mid and peak demand. The market dynamics changed as a result, but only to the extent that the details of the market design allowed and the severe pressure posed by the decline of the electricity demand. A critical factor for market outcomes was the market rule that allowed generators to offer 30% of their plant's capacity at a price below its minimum marginal cost. This rule allowed 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, as already noted, RAE decided to remove the 30% rule (which had turned out to be rather distorting) as of 1.1.2014. Furthermore, the extensive use of the cost-recovery mechanism rendered generators rather indifferent to the price levels and induced 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 by various units, with Lavrio 4 being the more flexible, as the only multi-shaft unit.

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 reserves (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, RAE requested from LAGIE and ADMIE to develop 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. The structure of these reports was designed in collaboration with RAE. LAGIE issued its first market report for the month November 2012, which was subject to revisions and additions, before its standardised format was finally approved by RAE in February 2013. This report is uploaded on LAGIE's website, on a monthly basis, from November 2012 onwards. ADMIE has been drafting and publishing an energy report, which is focused on the dynamics and allocation of energy quantities. RAE has also requested the addition of references to the cash settlements in which the TSO is involved, so that transparency is enhanced further.

3.2.1.4. *Regulatory progress in wholesale market issues in 2013*

The regulatory focus in 2013 was mainly on:

- Integrating the Regulations of the European Commission and national legislation into the Transmission Network Code and the Market Operation Code (and their Manuals),
- Proceeding with the power market restructuring and, especially, imposing measures for the alleviation of structural asymmetries, and
- Removing market distortions and mitigating the credit risk of the Market Operator, LAGIE, which derives from the day-ahead market cash flows.

Indicatively, during 2013, RAE worked on the following issues:

- The implementation of a methodology for the allocation of the payments (as well as the deficits), executed by LAGIE, among the producers that participate in the day-ahead market. Additionally, a mechanism was established, for the mitigation of LAGIE's financial risk, related to the operation of the day-ahead market, due to the economic difficulties that stem from the absence of a clearing house in the power market. The mechanism introduced some fundamental structural changes in the daily operation of the market, ensuring significant credit for LAGIE.
- Modifications in the Transmission Network Code regarding the inter-transmission System Operator compensation mechanism (ITC mechanism), and its proper integration into the existing framework, including arrangements for the transmission system losses compensation component.
- Modifications in the Capacity Assurance Mechanism (CAM), including adjustments in Capacity Obligation calculation, as well as in non-compliance charges. Moreover, two important decisions were taken, namely the deletion of old units from the CAM registry and the extra remuneration of the flexible natural gas units.
- With regards to the Cost Recovery Mechanism, the margin above the minimum variable cost was set equal to 0% (from 11.07.2013 onwards), and the full elimination of the mechanism itself was announced for mid 2014 (it entered into force on 01/07/2014), while the "30% rule", for the submission of bids below the minimum variable cost, was abolished on 01/01/2014. Additionally, extra provisions were made for the case of units with variable cost above the regulated price cap, which can be instructed by the TSO to operate, due to emergency situations, despite the low frequency in the emergence of such cases. These units are not able to recover their variable cost through the standard market operation, hence there is no economic

incentive for their availability. The aim of the extra provisions was to add such an incentive.

- In order to address the constantly increasing deficit in the RES account, modifications in the income of the account were introduced by law, which were integrated into the Codes. More specifically, the income from the market (both day-ahead and deviations) for RES (i.e. the amount paid by the suppliers) reflects at least the average variable cost of the thermal power plants on an hourly level.
- 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, was carried out in 2013 through a close collaboration between RAE and the Market Operator, LAGIE. The methodology initially submitted to RAE by LAGIE in November 2012 was subject to refinements, assessment of reservoir security issues and preliminary testing. More specifically, LAGIE performed daily simulations in a testing phase that covered four (4) months in the first semester of 2013, submitting monthly reports to RAE. However, due to the introduction of important regulatory measures in the market in 2013, that had already a significant impact on the marginal price, the use of its historic value as fundamental component in the above methodology is to be re-evaluated in 2014.

Regulatory measures regarding the above issues were either adopted during 2013 or carried over to 2014 via public consultations or reviewing processes. The implementation of market reforms, along with further elaboration of their key features, will continue in 2014.

<u>RAE's proposals on the restructuring of the domestic electricity market</u>

Following RAE's official proposals submitted to the government, concerning the restructuring of the domestic electricity market (November 2012), and after receiving the go-ahead from the relevant Ministry of Environment, Energy and Climate Change, three (3) Working Groups, as well as a Coordination Committee, were established and formed, in order to carry out the necessary processing and further specification of the RAE final proposals, concerning: a) changes in the institutional framework of the wholesale electricity market, b) auctions of lignite and hydro generation forward products, and c) details of the wholesale market restructuring towards the harmonisation with the European Union Target Model.

The result of the first Working Group, in the form of a document entitled "Final proposals of short-term transitional measures for the restructuring of the domestic electricity market" (19.06.2013), led to the relevant RAE Decisions of July 2013 (Decisions 338 & 339/2013 - see more details above). These Decisions detail specific regulatory measures aimed at the reduction of the weighted average production cost of the System, through the substitution of significant part of production from natural gas plants with lignite production. The design of these measures took into account the opinions expressed by PPC and other parties, namely that the prevailing rules at the time were the main reason for the compression of lignite production, given that they incentivised independent producers to maximise their production, and if this would change, then the reduction of the production of the natural gas fired independent producers would be translated into an increased production from lignite plants.

The above regulatory measures do not remove immediately the existing market distortions, they attempt, however, to reduce, to a certain extent, their negative impact.At the same time, they aim to provide the essential timeframe and steps for the development and implementation of new mechanisms and measures, that will gradually allow the establishment of fair and healthy competition, thus limiting the need for strong regulatory measures and intervention, which is necessary today to ensure the smooth operation of the market.

The said measures, as already stated, concern a short, transitional period, of about 1-1½ year, until the new mechanisms and measures that have been proposed by RAE, and concern mainly the access of third parties to the country's lignite and hydro production (through NOME-type auctions), are put in place. The objective of these transitional measures is on the one side to maintain a relevant economic equilibrium among the participants in the wholesale market, and on the other, to allow the continuing availability of the existing production infrastructure, so that it will still be available in the new conditions that will prevail, not only in the domestic but also in the international energy scene. Energy markets today are characterised by great uncertainty and fluctuation, and it is necessary that regulatory decisions take into account the possibility of significant and sudden changes in the existing conditions.

The work of the second and third Working Groups (on auctions of lignite and hydro forward products, and on amendments to the wholesale market rules aiming at harmonisation with the European Union Target Model, respectively) continued and are expected to lead to further elaboration and specification of the RAE proposals in 2014. In this context, RAE follows and supports the initiative of the System Operators and of the Power Exchange/Market Operators of the Central and South Europe, for the market coupling of the region, with the target of also coupling the Greek electricity market through Italy.

3.2.1.5. Market cash liquidity in 2013

In 2013, as in 2012, the conditions in the domestic energy market remained extremely critical, because of the continuing severe lack of credit, coupled with the overall adverse conditions in the Greek economy. The lack of a Credit House affected negatively the cash flows of all market participants, given the increased maturity and unpaid receivables from final consumers. At the same time, the continuing difficult position of the entire Greek banking sector considerably reduced the available credit for the electricity market, resulting in an increase of the short and long term cost of financing for all participants. More specifically:

- The utilisation of domestic suppliers of electricity to final customers as collection mechanisms for property tax (instead of the tax authorities), which started in the fall of 2011 and continued throughout 2012 and 2013, imposed a significant burden on the financial accounts and cash flows of all suppliers. PPC, especially, as the supplier with the highest market share in the retail market (>98%), was particularly affected, resulting again in a free fall in the company's receivables collections, despite its efforts to improve its collection procedures (estimated unpaid receivables of €1.2 billion at the end of 2013, which catapulted to almost €2 billion at the end of 2014).

- At the end of 2013, LAGIE remained in a dire financial position, the company owing around €1.1bn to RES producers and €109m to conventional Independent Power Producers. At the same time, LAGIE had receivables of €325m (of which €192m were overdue) from ADMIE and €201m from PPC.
- Power producers owed DEPA the amount of €280m in December 2013.
- The financial position of ADMIE was also problematic, since it had mature collectables of €419m and payments of €372m.

It must be noted that the current market structure and the consequences of the lack of a Credit House and a Clearing House, create serious problems in the efficient functioning of the market. Despite the repeated efforts of RAE, it has not been possible to establish these Credit and Clearing Houses, due to the existing adverse economic environment in the country and the severe pressure that the Greek banking sector is still facing. Therefore, in the meantime, the risk for the market transactions is undertaken primarily by the Market Operator (LAGIE) and the TSO (ADMIE). The Regulator has taken a number of decisions in order to reduce this financial risk, including:

- Continuous monitoring of debt for the main financial players (ADMIE, LAGIE, PPC).
- Tightening of rules on letters of guarantee provided by market participants.
- New credit risk management procedures introduced by LAGIE, in close collaboration with RAE, where the financial status (credit position) of participants is checked on a daily, rather than a monthly, basis, while payments are made weekly on a compulsory basis.

3.2.2. Retail market

3.2.2.1. Description of the retail market

Competition and market shares

Electricity consumption in the Interconnected System remained relatively stable throughout 2013, recording a small decrease in overall consumption of 1.9%, in comparison to 2012. This decrease is the result of years of continuing economic recession, which has caused an overall decline of about 5.7% in the total electricity demand of the Interconnected System, over the 4-year period 2010 - 2013.

In 2013, stability in the retail electricity market environment was restored and no extraordinary events occurred, in sharp contrast to 2012, which was the year that four (4) electricity suppliers exited the market due to outstanding overdue payments, including the two largest private electricity supply companies of 2011. Two new private suppliers entered the market in 2013, namely Protergia S.A. and Protergia Thermoelectric Agios Nikolaos S.A.

At the end of 2013, eight (8) electricity suppliers were active in the domestic retail market. PPC remained by far the dominant supplier, as it held almost the entire retail market (99.60% of the total number of customers at the end of 2013, and about 98% of total electricity supplied). Only a very small percentage of 0.27% (measured in terms of consumption volume) of the total LV and MV customers switched electricity supplier in 2013, a number significantly lower than that of the year before (3.6% in 2012), according to the data provided by the DSO. Overall, in the domestic electricity market for the interconnected system, the total number of customers in 2013 was 6,555,067 and their total consumption was 46,163,248 MWh (seeTable 5).

Another characteristic of the retail market in 2013, was the continuous growth of customer liabilities against their electricity suppliers, reflecting the difficulties faced by consumers during the deep economic recession. The excessive charges mounted on electricity bills as a result of high (and multiple) taxes on energy, combined with the inclusion in the electricity bill of other taxes and fees not related to electricity (e.g. property tax, local authority tax, television fee, etc), pushed a significant number of consumers to the edge of their budget constraints, thus resulting in either a reluctancy to pay, or an actual inability to do so.

By eligible meter points (31,12,2013)									
Customer type	**Total**	**PPC SA**	**WATT & VOLT SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**ELPEDISON ENERGY SA**	**VOLTERRA SA**	**HERON SA**	**PROTERGIA SA**	**PROTERGIA THERMO ELECTRIC SA**
Household customers	5,090,532	5,083,051	2,023	519	4,551	12	376	Ø	Ø
Small Industrial and Commercial customers	1,146,708	1,128,061	1,995	1,919	11,143	77	3,461	Ø	52
Other LV customers (eg, agricultural. public. traction)	307,723	307,723	Ø	Ø	Ø	Ø	Ø	Ø	Ø
Total LV Customers	**6,544,963**	**6,518,835**	**4,018**	**2,438**	**15,694**	**89**	**3,837**	**Ø**	**52**
Industrial and Commercial customers of MV	8,412	8,059	6	15	122	11	189	Ø	10
Other MV customers (eg, agricultural. public. traction)	1,654	1,654	Ø	Ø	Ø	Ø	Ø	Ø	Ø
Total MV Customers	**10,066**	**9,713**	**6**	**15**	**122**	**11**	**189**	**Ø**	**10**
Total HV Customers	**38**	**38**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**
Total Customers	**6,555,067**	**6,528,586**	**4,024**	**2,453**	**15,816**	**100**	**4,026**	**Ø**	**62**
Market Share (%)	**100%**	**99.60%**	**0.06%**	**0.04%**	**0.24%**	**0.00%**	**0.06%**	**Ø**	**0.00%**

By eligible volume (MWh)									
Customer type	**Total**	**PPC SA**	**WATT & VOLT SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**ELPEDISON ENERGY SA**	**VOLTERRA SA**	**HERON SA**	**PROTERGIA SA**	**PROTERGIA THERMO ELECTRIC SA**
Household customers	15,972,829	15,930,626	9,699	4,350	24,844	32	3,278	Ø	Ø
Small Industrial and Commercial customers	9,559,969	9,044,907	39,060	44,548	236,668	4,309	190,258	177	42
Other LV customers (eg, agricultural. public. traction)	3,639,741	3,639,741	Ø	Ø	Ø	Ø	Ø	Ø	Ø
Total LV Customers	**29,172,539**	**28,615,274**	**48,759**	**48,898**	**261,512**	**4,342**	**193,536**	**177**	**42**
Industrial and Commercial customers of MV	8,904,367	8,645,394	4,482	12,118	117,713	9,081	113,398	1,597	582
Other MV customers (eg, agricultural. public. traction)	1,487,292	1,487,292	Ø	Ø	Ø	Ø	Ø	Ø	Ø
Total MV Customers	**10,391,659**	**10,132,686**	**4,482**	**12,118**	**117,713**	**9,081**	**113,398**	**1,597**	**582**
Total HV Customers	**6,599,050**	**6,599,050**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**	**Ø**
Total Consumption	**46,163,248**	**45,347,010**	**53,241**	**61,016**	**379,225**	**13,423**	**306,934**	**1,774**	**624**
Market Share (%)	**100%**	**98.23%**	**0.12%**	**0.13%**	**0.82%**	**0.03%**	**0.66%**	**0.00%**	**0.00%**

Table 5. Market share of the active suppliers in the interconnected system, by eligible meter points and by volume, per consumer category in 2013

Electricity consumption on the interconnected system (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small Industrial and Commercial customers**	**Other** (eg. agricultural, public, traction)	**Total (GWh)**
LV	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**
	2013		15,973	9,560	3,640	**29,173**
MV	2010			9,674	1,447	**11,121**
	2011			9,125	1,397	**10,522**
	2012			8,471	1,513	**9,984**
	2013			8,904	1,487	**10,391**
HV	2010	6,355			1,191	**7,546**
	2011	6,613			1,536	**8,149**
	2012	6,507			1,361	**7,868**
	2013	6,599			1,168	**7,767**
Total	2010	6,355	16,477	21,931	5,443	**50,206**
	2011	6,613	16,116	19,660	6,459	**48,848**
	2012	6,507	16,714	18,594	6,608	**48,423**
	2013	6,599	15,973	18,464	6,295	**47,331**

Electricity consumption on 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	2010		1,750	1,804	509	**4,063**
	2011		1,771	1,720	461	**3,952**
	2012		1,815	1,682	484	**3,982**
	2013		1,671	1,607	478	**3,756**
MV	2010			873	220	**1,093**
	2011			855	210	**1,066**
	2012			874	208	**1,081**
	2013			865	188	**1,053**
Total	2010		1,750	2,677	729	**5,156**
	2011		1,771	2,575	671	**5,018**
	2012		1,815	2,556	692	**5,063**
	2013		1,671	2,472	666	**4,809**

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

Table 6. Evolution of the electricity consumption in the interconnected (mainland) system and the non-interconnected islands, 2010-2013

Supplier switching

Following the events of 2012 mentioned above, customer switching in 2013 plummeted, mainly as a result of the stabilisation of the market following the higher switching rates of 2012, due to the activation of the Supplier of Last Resort, but also possibly reflecting the negative experience of electricity customers that was combined with the exit of the largest independent suppliers. As a result, switching activity dropped down to near zero levels, as can be seen from the trends depicted in the following table:

Customer type	Total customers		Customers having changed supplier		% of customers having changed supplier	
	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	5,090,532	15,972,829	3,151	6,035	0.06%	0.04%
Small Industrial and Commercial customers	1,146,708	9,559,969	5,870	52,960	0.51%	0.55%
Other LV customers (eg. agricultural, public, traction)	307,723	3,639,741	0	0	0.00%	0.00%
Total LV customers	6,544,963	29,172,539	9,021	58,995	0.14%	0.20%
Industrial and Commercial customers of MV	8,412	8,904,367	187	47,326	2.22%	0.53%
Other MV customers (eg. agricultural, public, traction)	1,654	1,487,292	0	0	0.00%	0.00%
Total MV customers	10,066	10,391,659	187	47,326	1.86%	0.46%
Total LV & MV customers	6,555,029	39,564,198	9,208	106,321	0.14%	0.27%
HV customers	38	6,599,050	0	0	0.00%	0.00%
Total HV, LV & MV customers	6,555,067	46,163,248	9,208	106,321	0.14%	0.23%

Table 7. Switching rate per consumer category in 2013, by eligible meter points and by eligible volume (interconnected system)

Under the VaasaETT description scale of the levels of switching, the Greek electricity market, at the end of 2013, is considered a dormant market.

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

Following the completion of the competitive RAE procedure for the official designation of a Supplier of Last Resort (SoLR) and a Universal Service Supplier, the Regulator proceeded with the assignment of these services to PPC (which was, in fact, the only supplier who submitted an expression of interest and a bid to provide the services). The relevant RAEDecisions, No. 114 and No. 115/2013, respectively, stipulated the following conditions:

- The duration of the provision of the services of SoLR and USS is five (5) years.
- Every year, PPC is obliged to publish the tariffs applicable per customer category, or the methodology for the calculation of the service charge, in case that published tariffs don't exist for a specific customer category, for each of the two services provided (SoLR and USS).

- RAE has to consent on the implementation of these tariffs, with an aim to safeguard that the applied tariffs reflect prevailing conditions in both the wholesale and the retail market, throughout the 5-year period for which these services are to be provided.
- For the first year of the services provision, RAE approved the application of premium percentages on the regular tariffs offered by PPC to consumer categories, as follows:
    - 5% for HV customers over the wholesale market costs,
    - 12% for MV customers on PPC's published tariffs for MV customers,
    - 12% for LV customers on PPC's published tariffs for LV customers (applicable also for the USS).

New Supply Code

On 08.01.2013, RAE announced the completion of the new Electricity Supply Code, which was then sent (as a RAE Formal Opinion) to the Minister of Environment, Energy and Climate Change for the issuance of the relevant Ministerial Decision, according to the provisions of article 183, par. 1 of the Energy Law 4001/2011. The new Electricity Supply Code was officially published in the Government Gazzette in April 2013 (GG B' 832/09.04.2013).

Improvement of switching procedures and DSO reporting

Following the publication of the Ministerial Decision for the new Electricity Supply Code, RAE proceeded with the further improvement of the legal framework that applies to the functioning of the electricity supply activity, with the issuance, in 2013, of the amended "Manual for the Metering Management and Periodic Settlements of Distribution Network Suppliers" (RAE Decision 182/2013).

The amendment was necessary following the Regulator's investigation into complaints by suppliers, which indicated problematic practices followed by the Distribution System Operator (DSO) in regard to customer switching, disconnection and reconnection procedures. In particular, the existing provisions of the Manual needed improvement and further expansion, in order to achieve: a) the acceleration of the supplier switching process for the benefit of final customers, b) the differentiation between a temporary disconnection due to unpaid debt and a permanent disconnection due to contract termination, c) the improvement of the quality of information that the DSO provides to the active suppliers, regarding the various procedures and their status/ outcome, thus resulting in greater market efficiency and customer protection. The changes are expected to facilitate non-discrimination/ equal treatment of final customers and their suppliers and, at the same time, to bring greater transparency to the numerous transactions carried out with the DSO.

RAE closely monitors the implementation of the new Manual for the Metering Management and Periodic Settlements of Distribution Network Suppliers, in order to achieve maximum effectiveness and to intervene when necessary, in order to provide further improvements.

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 2013, requiring the submission of detailed data related to their supply business activity throughout 2012.

Specifically, the required data included:

- Annual financial statements.
- Historic data on the volume and value of electricity sales by customer group.
- Total number of supply applications submitted per customer category, number of applications that were contracted, number of applications that were rejected and reasons for their rejection.
- Report on cases where suppliers were unable to complete switching procedures and related reasons.
- Report on delays in the switching process (more than 3 weeks, according to the provisions of article 51 of Law 4001/2011).
- Report on customer complaints submitted through any means available (letters, email, call-centre), with a distinction between complaint type, customer category and means of submission.
- Number of requests for disconnection and reconnection, related reasons and percentage that was actually completed.
- 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 customer and any other standard document which accompanies the Supply Agreement.
- Typical bill structure and description of payment methods, frequency of bill issuance and alternative payment methods available to customers.
- Updated information regarding the supplier’s organisational and administrative structure, representation, share capital, etc.

In addition to the above, and following the issuance of the new Electricity Supply Code, RAE invited all active electricity suppliers to change their supply contracts, in order to incorporate the provisions of the new Supply Code.

At the same time, RAE proceeded with the cross-examination of the suppliers’ websites, in order to check their compliance with the terms of their license and the new Supply Code provisions, particularly with regard to marketing practices, tariffs offered and related contractual terms, so as to investigate the possible presence of abusive terms or conditions and to effectively protect consumers from deceptive and abusive behaviours.

The aforementioned initiative was completed with RAE sending individual letters to all active suppliers, with specific amendments suggested to the terms and conditions offered by them to their customers, as well as with suggestions regarding their full compliance with the new Supply Code provisions, with respect to their supply contracts, electricity bills, tariffs and website content.

RAE's licensing activity

In December of 2013, RAE's electricity supply and trading registry included twenty-four (24) supply licenses and forty-eight (48) trading licenses. During the course of 2013:

- four (4) new supply licenses were issued
- ten (10) new trading licenses were issued
- three (3) applications for a trading license were rejected, for non-compliance with the provisions of Law 4001/2011 and the relevant Electricity Supply and Trading Licensing Regulation
- five (5) license amendment applications were submitted, of which two (2) were finalised and three (3) were still pending
- three (3) existing supply licenses and one (1) trading license were revoked, upon RAE's decision for non-compliance with the relevant provisions of Law 4001/2011
- one (1) supply license expired, without the submission of a renewal application.

The table in Appendix I presents the active supply and trading licenses, respectively, at the end of 2013.

3.2.2.2. Price monitoring

This section concentrates on the prices offered by PPC in 2013, given that, for this particular year, PPC's market share in retail was over 98%. 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(2012-2013) Energy only	Δ(2012-2013) Total
MV Commercial	2010	82.14	3.92	6.09	8.35	0.77	**101.26**	6%	3%
	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**		
	2013	81.59	4.46	5.98	17.90	0.44	**110.37**		
MV Industrial	2010	63.13	5.55	7.15	6.58	0.77	**83.18**	6%	3%
	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**		
	2013	83.49	5.35	6.62	6.91	0.44	**102.82**		
MV	2010	36.90	0.00	0.00	3.24	0.77	**40.91**	6%	6%

Agricultural	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**		
	2013	64.97	0.00	0.00	5.62	0.45	**71.04**		
LV Commercial	2010	94.28	16.01	16.51	11.51	0.83	**139.14**	14%	8%
	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**		
	2013	100.54	6.73	22.96	18.24	0.46	**148.93**		
LV Industrial	2010	79.03	10.39	23.66	10.34	0.83	**124.25**	14%	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**		
	2013	99.32	6.38	24.02	18.24	0.46	**148.42**		
LV Agricultural	2010	43.43	0.00	0.00	3.70	0.83	**47.96**	13%	12%
	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**		
	2013	66.10	0.00	0.00	7.07	0.46	**73.63**		
LV Pub. Lighting	2010	65.76	2.66	22.36	7.65	0.83	**99.27**	18%	10%
	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**		
	2013	80.51	2.80	20.05	13.71	0.46	**117.53**		
LV Domestic	2010	67.78	5.89	22.43	8.06	0.83	**104.99**	13%	8%
	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**		
	2013	87.46	5.46	20.26	13.90	0.45	**127.53**		

Table 8. Average PPC retail electricity prices and tariff elements per consumer category (excluding taxes and levies), in €/MWh, for the 4-year period 2010-2013

According to the "Second Economic Adjustment Programme for Greece, First Review - December 2012", the Greek government had to ensure that, at the latest by June 2013:

- the energy component of regulated tariffs for households and small enterprises reflects wholesale market prices, except for vulnerable consumers, and
- price regulation is removed for all but vulnerable consumers.

In view of the implementation of the above requirements by June 30th, 2013, PPC tariffs for LV customers were adjusted as of 01.01.2013, following:

- The submission of a PPC formal proposal to RAE, on 07.12.2012, with regards to LV-customer retail tariffs and underlying PPC budgeted costs for 2013. The total 2013 revenue requested by PPC for the competitive activities in the interconnected system was approx. € 4.8 billion, including return on assets and a supply margin. This would result in an increase of 28% of average PPC revenue (€/MWh), compared to the amount that RAE deemed acceptable for 2012. The requested increases were, according to PPC, mainly due to: a) new taxes previously not accounted for (special tax on natural gas as a fuel for power generation), b) introduction of the cost of CO_2 emissions, and c) higher average cost due to the acquisition, as a Supplier – by law – of Last Resort, of a large number of new customers following market exit of four alternative suppliers in early 2012, as well as due to the expected commissioning of three new PPC plants in 2013.

- RAE Opinion 13/20.12.2012: RAE considered some of the above PPC's cost estimates unjustifiably high, and proposed a reduction in OPEX, in order to incentivise the company to become more efficient, as well as a reduction in the level of return on assets and the supply margin, in view of the current economic situation. Overall, RAE proposed the reduction of PPC's revenue for 2013 to approx. € 4.27 billion, of which € 3.09 billion would be recovered through the LV customer tariffs in the interconnected system, thus limiting the average tariff increase to 13% (instead of the proposed 28%).
- Ministerial Decision of 07.01.2013 (GG B΄ 5/2013), which further reduced the revenue from LV customers in the interconnected system by another €200m, compared to the above RAE proposal.
- Submission by PPC of revised tariffs, to be applied for the 01.01.2013-30.04.2013 time period.
- RAE Opinion 1/10.01.2013, which confirmed that the PPC proposed revised tariffs were consistent with the Ministerial Decision of 07.01.2013.
- Ministerial Decision of 10.01.2013 (GG B΄ 20/2013), approving the PPC revised tariffs for the first half of 2013, with the possibility of a price review in the second quarter of 2013.

In summary, domestic tariffs (competitive element only) for 2013 increased by 11-34% over 2012, depending on the consumption category. As of 01.01.2013, there are only three (3) domestic customer (consumption) categories: 0-800, 801-2000 and over 2000 kWh/4-month period (the 801-1200 category was abolished). Consumers with a consumption of less than 800kWh during a 4-month period enjoy the lowest energy price (77.93 €/MWh), while consumers with a 4-month consumption of over 2000kWh are charged 102.52 €/MWh. The overall impact of tariff changes in 2013 (including changes in the regulated network tariffs and the RES levy) on the total domestic consumers' bill ranged between 5% for the higher consumption category, to nearly 18% for the consumers with 4-month consumption up to 800kWh.

Prices were fully liberalised, as scheduled, on 01.07.2013. Following this, there were no more PPC tariff changes in 2013, in the LV customer categories, the tariffs of which still reflected some cross-subsidisation between certain categories (for instance, low consumption households continued to be subsidized, to some extent, by small commercial tariffs).

Alternative suppliers offered lower tariffs, compared to PPC, only to certain customer categories. All alternative suppliers publish their tariffs on their websites, while RAE regularly publishes comparative estimates of the 4-monthly bill for domestic customers under the various tariffs on offer (both from PPC and from the active alternative suppliers). However, 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 domestic 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, the relevant practice that had been followed in the last few years, and in the first semester of 2013 for the last time, is described below.

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

Costs included:

- Fuel costs
- OPEX (personnel costs, third party contracting costs, materials, etc)
- Energy purchases from third parties (RES, pool, imports)
- Other costs arising from the 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 formed 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 remained with the Ministry of Environment, Energy and Climate Change. The retail tariffs were, therefore, set based on PPC's average cost, rather than the market marginal cost.

As already mentioned, price regulation was fully removed on 01.07.2013.

Monitoring and ex-post regulation of non-regulated prices

In 2013, only PPC LV tariffs were still regulated (until 30.06.2013), through a Ministerial Decision following a (non-binding) opinion by RAE. Regulation of HV and MV tariffs has been removed, since July 2008 and January 2012, respectively. 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 large 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 each particular customer.

Price-comparison tool

In order to provide clear price information for domestic and small commercial consumers, to enable them to avoid misleading marketing practices and choose the best price offer available to them in the retail market, RAE estimated and published on its website the final electricity bill estimate (€) for various consumption levels, for domestic and small commercial consumers, and for all active electricity suppliers in 2013. RAE published one simple look-up table per company, with which the consumer could estimate, on a comparable basis, what his/her final bill (over a four-month metering period) would be, under various offers by the different suppliers. The conclusion was that the best offer/ company very much depended on the particular consumption level.

Recommendations at the national level on supply prices and competition

In the autumn of 2013, a consultant was appointed by RAE, following an international tender, to study the cost benchmarking of PPC and its network subsidiaries. RAE's main goal was to obtain a detailed analysis of the cost baseline for each part of the value chain and to identify key areas of improvement, based on the results of a benchmarking study against internal best practices and international peers. The final aim was to explore the possibilities to eventually reduce PPC's cost of producing and supplying electricity to final customers. Within 2013, a significant part of the project was completed, concerning: a) gathering and processing of required information and data (cost and operational metrics, in order to calculate key performance indicators) for internal and external benchmarking, and b) the completion of the internal cost-analysis reports for the five (5) activities of the value chain (mining, generation, transmission, distribution and supply). The project will be completed in 2014 and RAE will evaluate the results, concerning the performance of PPC and its network subsidiaries. A possible improvement in the operational efficiency of PPC, currently the sole supplier of electricity to large industrial consumers, may positively affect the competitiveness of the whole Greek economy.

Experience with PPC's liberalised tariffs

During the course of 2013, and following official complaints by HV and large MV customers submitted to RAE, it was observed that PPC didn't comply with the Regulator's relevant decisions, through which PPC was instructed to continue its efforts for open and effective price negotiations with its MV customers. These negotiations should be based on customised tariff proposals by PPC, reflecting the load factor and consumption characteristics of the specific customer category. In addition, RAE had asked PPC to propose, by 01.01.2013, a sufficient number of alternative tariffs for MV customers (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.

The continuing disagreement on prices between PPC and major HV and MV customers escalated even further in 2013, due to the extra CO_2 emissions charge that was imposed by PPC, reflecting, according to the incumbent, the cost of purchase of CO_2 emissions rights, following the end of the period of free allowances. This new charge was imposed as a pass-through, with no link to the pending issue of the negotiations relating to the new tariffs to be proposed to these customers, or any other prior agreement on this particular issue. As a result, RAE was again the recipient of a large number of complaints by various large industrial customers of PPC.

As a result, RAE issued its Decision 307/2013 on 03.07.2013, following a hearing of PPC. The Decision imposed a 4.4 million € fine on PPC for abusive market behaviour, due to the company's non-compliance with RAE's Decision 895/2012, which called upon PPC to submit its new tariff proposals by 01.01.2013, and its overall refusal to provide alternative tariffs to its MV customers. Following the RAE decision, PPC proceeded with the submission of alternative tariff proposals to its MV customers, based on a relevant decision taken by its Board of Directors in August 2013. Until the end of 2013, a significant number of PPC customers had already proceeded to sign new supply contracts with PPC, based on the August tariff proposals.

3.2.3. Non-interconnected islands

All Greek Non-Interconnected Islands (NNIs)'[18] are electrified by autonomous electrical systems, which operate under the provisions of Directive 2009/72/EC. Until today, PPC S.A. remains effectively the only supplier and electricity generator from fossil fuels (oil products), in these islands. Renewable energy sources (wind parks and small photovoltaic stations), the majority of which are owned by independent producers (other than PPC S.A.), contribute with a significant percentage in the total NNI electricity production per year (not exceeding 15-20% for each NII).

In January of 2013, the final RAE draft of the Operation Code for Non-Interconnected Islands (NII Code), which sets the secondary legal operating framework for both producers and suppliers in the NIIs, was put in public deliberation. Following this deliberation, a joint team of RAE and the NII Operator, DEDDIE S.A., was set up, in order to formulate the final version of the NII Code, incorporating the comments received at the public deliberation and making all necessary adjustments for fine-tuning. By 31.12.2013, the NII Code was almost finished and it was finally approved by RAE in February of 2014 (RAE's Decision 39/2014, GG B' 304/11.02.2014). With the NII Code in effect, the secondary legal framework for operation in the NIIs is complete and, therefore, the NIIs market is open to competition for both the production and the supply activities.

[18] All islands that are not electrified via electrical interconnection to the mainland grid. NIIs consist of 32 autonomous electrical systems, covering 60 very small, small, medium-size and large islands in Aegean Sea (only two of these islands are in the Ionian Sea).

It is also noted that, based on the fact that all Greek non-interconnected islands, except Crete, are isolated micro-systems, according to the definition of the Directive 2009/72/EC, Greece has applied for derogation for all island micro-systems concerning the supply, as well as the generation from fossil fuels (except RES, CHP and autoproducers). The EC decision on the derogation application is expected in 2014.[19]

[19] The European Commission decision regarding the derogation was finally issued on August 14, 2014.

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 in 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).

There was no change in 2013 with regards to the definition and total cost of the Public Service Obligations, or the levy charged to final customers following Law 4067/2012 (Government Gazette A' 79/9.4.2012), as presented in the 2013 National Report.

3.3.2. Social Residential Tariff

The Social Tariff ("KOT") was applied for the first time on 01.01.2011, including the definition of vulnerable consumers for the purpose of the application of KOT, and specifying four (4) categories of beneficiaries. However, the escalating country's economic recession necessitated the amendment and expansion of the KOT measure. During 2013, KOT was expanded in terms of a) the number of consumers covered, by adding one (1) more category of eligible domestic customers, and b) the consumption limits, which were increased. The following five (5) categories of vulnerable customers are eligible for the Social Tariff:

1. <u>Families with Low Income:</u> Households with a) total annual income (salary or pension) below 12,000 Euros, and b) having an electricity consumption per 4-month period between 200 kWh and 1500 kWh. The income limit is increased by 6,000 Euros for residents of islands with population of less than 3,100 inhabitants. It is also increased by 3,000 Euros for each one of the first two dependent children. The prices of <u>KOT I</u> apply here (see Table 1).
2. <u>Families with 3 children:</u> Households with a) three children, b) total annual income (salary or pension) below 23,500 Euros and c) electricity consumption per 4-month period between 200 kWh and 1700 kWh. The income limit is increased by € 6,000 for residents of islands with population of less than 3,100 inhabitants. It is also increased by € 3,000 for each one of the first two dependent children. The prices of <u>KOT I</u> apply here (see Table 1).

3. Long-term unemployed: Unemployed people as of the 30th of November of each year, for a continuous unemployment period of at least 12 months, with a total annual household income (salary or pension) below € 12,000 - income from employment for the period preceding the unemployment period is not taken into account – and electricity consumption per 4-month period between 200 kWh and 1500 kWh. The income limit is increased by 6,000 Euros for residents of islands with population of less than 3,100 inhabitants. It is also increased by € 3,000 for each one of the first two dependent children. The prices of KOT II apply here (see Table 1).
4. Disabled people: Households having disabled persons with a) more than 67% disability (handicap), b) total household annual income (salary or pension) below € 23,500 and c) electricity consumption per 4-month period between 200 kWh and 1700 kWh. The prices of KOT II apply here (see Table 1).
5. People living on medical support: Households having individuals that their life depends on mechanical medical devices provided at home, with a) total household annual income (salary or pension) below € 30,000 and b) electricity consumption per 4-month period between 200 kWh and 2000 kWh. The prices of KOT II apply here (see Table 1).

The following table presents the prices per KOT category (as set by Ministerial Decision) which applied during 2013, for a) consumption up to 800kWh and b) consumption over 800kWh and up to the limit of each category (1500, 1700, 2000kWh), per 4-month period. If any 4-month consumption exceeds the limits, but the average 4-month consumption on a yearly basis is still within these limits, then for the excess consumption, regular domestic tariffs apply.

		Consumers with total consumption up to 800kWh		***Consumers with total consumption higher than 800kWh and up to the category limit***	
	Type of connection	***Energy Charge (€/kWh)***	***Fixed Charge (€/4-months)***	***Energy Charge (€/kWh)***	***Fixed Charge (€/4-months)***
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 9. Social Residential Tariff (KOT) prices for the first 800kWh of consumption and above 800kWh, per 4-month period

The following table presents a) the number of customers, b) the bills issued and c) the metered electricity consumption, to which the KOT tariff prices applied in 2013.

<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></tr>
<tr><th></th><th>Type of connection</th><th colspan="2">Total Energy (kWh)</th></tr>
<tr><td rowspan="2">KOT I</td><td>Single- phase</td><td>255,400</td><td rowspan="2">295,993</td><td>896,771,889</td><td rowspan="2">1,104,418,147</td></tr>
<tr><td>Three-phase</td><td>40,593</td><td>207,646,258</td></tr>
<tr><td rowspan="2">KOT II</td><td>Single- phase</td><td>97,762</td><td rowspan="2">116,890</td><td>376,132,548</td><td rowspan="2">478,085,371</td></tr>
<tr><td>Three-phase</td><td>19,128</td><td>101,952,823</td></tr>
</table>

Source: DEDDIE (DSO)

Table 10. Number of customers and metered consumption receiving the KOT tariffs, on 31.12.2013

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 decreased by more than 11% in 2013, compared to 2012. The number of electricity disconnections due to overdue amounts (arrears) declined by almost 4.7% in 2013, compared to 2012, and, correspondingly, the number of disconnections due to reasons other than overdue amounts (arrears) declined by almost 17.5% for the same time period. This decrease in the total number of disconnections in 2013 reflects, to a certain extent, the incumbent's initiative to further enhance and implement debt management – payment restructuring policies towards its customers.

Disconnections due to overdue payments accounted for 52% of the total number of disconnections and 53% of the total number of reconnections in 2013, reflecting the severe impact of the country's economic recession on customer's ability to pay. The situation is further compounded by the significant amount of taxes collected through the electricity bills, either directly or indirectly (such as a property tax, municipal taxes, radio & TV fees, etc). These taxes and levies, which are completely unrelated to the actual electricity supply activity, form, in many cases, the largest portion of the total amount to be paid through electricity bills. For 2014, prospects are better, since the Greek government has already announced its decision to withdraw the property tax element from the electricity bills and to continue its collection through direct tax imposition.

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

The following table depicts the relevant statistical data on customer disconnections/new connections.

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	26,055	282,626	254,928	184,610	162,964
Total LV & MV customers in the Non-interconnected System	3,915	27,184	27,878	21,815	17,480
Total LV & MV customers	**29,970**	**309,810**	**282,806**	**206,425**	**180,444**

Table 11. Statistical data on number of disconnections and re-connections of LV and MV customers in 2013

3.3.4. Handling of consumer complaints

The total number of consumer reports (complaints and inquiries) submitted directly to RAE during 2013 was 375, i.e. 27% lower than the corresponding one of 2012. However, the number of complaints registered to RAE through the Consumer Ombudsman has increased in the same year by 50%, compared to 2012. This is mainly attributed to the standard notification of the consumers appearing on their electricity bills, and providing relevant contact information for the Alternative Dispute Settlement Body, i.e. the Consumer Ombudsman.

RAE consumer reports of 2013 focused primarily (60.8%) on supply issues related to the dominant supplier (PPC). Moreover, the actual increase in 2013 of disconnection orders by the DSO, due to late or no payment as a result of the national economic crisis, doubled the percentage of consumer reports against the DSO, compared to 2012.

During 2013, the deteriorating economic situation and its adverse impact on the economically weaker groups of consumers, has been reflected in the consumer reports, through the increasing frequency of issues related to a) requests for facilitating payment of debts, b) avoiding disconnections, and c) reconnecting the electricity power.

More specifically, the complaints registered to RAE in 2013 focused primarily on the following issues:

1. Invoicing / billing issues (38%) related to (in ranking order): a) better settlement arrangements of debts (i.e. lower payment instalments), in order to avoid disconnection or to reconnect, b) transparency of regulated charges, especially those perceived to be excessively increased (such as the RES levy, the PSO fees, etc), c) correction of charges, d) difficulty to receive adequate information from the supplier on bill charges.
2. DSO issues (24.6%), related to (in ranking order): a) metering, such as mistakes in consumption recordings, delays in the meter installation / replacement, etc, b) disconnections, such as delays in satisfying disconnection requests, rejection of

reconnection requests due to no payment, etc, c) complaints on supply quality, related to unplanned electricity interruptions or voltage fluctuations, d) initial connections to the network, related to refusal of connection and delays in the connection works.

3. Rates and charges issues (23.1%), related primarily to disagreements / disputes on: a) charging the property tax fee through the electricity bills, reluctance of several local Tax Offices to accept the electricity bill receipt as proof of payment of the Property Tax fee, in the case of the main two alternative electricity suppliers that ceased their activity in early 2012, refusal of the consumer's right to pay the Property Tax fee directly to the tax office, instead of the electricity supplier, b) increase in the level of regulated charges, and especially those concerning the Network/Grid and the PSOs, c) insufficient transparency on the calculation of charges, d) delays on the return of the guarantee payment to their former customers by the suppliers that exited the market.

The statistics on the complaints/inquiries of electricity supply cases, registered to RAE in 2013, are summarised in Figure 11, by thematic category.

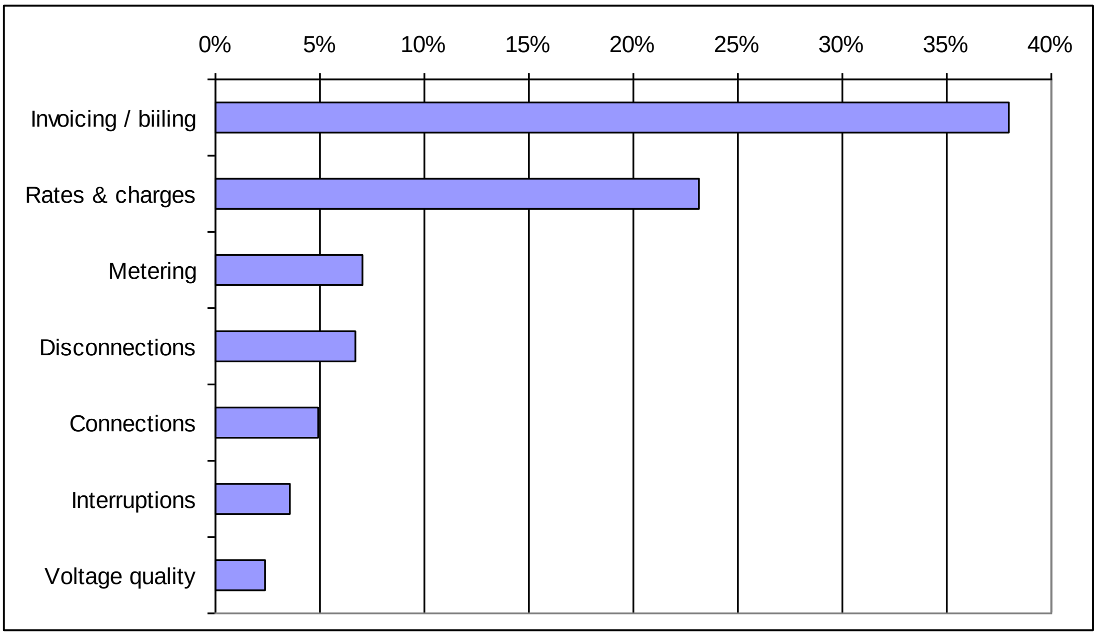


Figure 11. Complaints/inquiries registered to RAE in 2013, by thematic category of electricity supply cases

3.4. Security of supply

3.4.1. Monitoring the balance of supply and demand

Table 12 presents the evolution of annual electricity consumption in the interconnected system, since 2007, as reported by the TSO, ADMIE S.A. According to ADMIE's data, consumption in 2013 decreased by 7.6%, compared to 2012. 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 2013 was 50.66 TWh, showing a smaller decline of 3.7%, with respect to 2012.

	2007	2008	2009	2010	2011	2012	2013
Electricity consumption excluding pump storage (GWh)	55,253	55,675	52,436	52,329	51,492	50,289	**46,451**
Peak load (MW)	10,610	10,393	9,828	9,902	10,055	9,894	**9,161**

Source: HTSO

Table 12. Energy and peak power demand in the interconnected system, for the 7-year period 2007-2013

Fuel Shares

A critical factor for the allocation of fuel shares in the Greek electricity market is the level of hydroelectric 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 hydroelectric production, subsequently a dry year (2011), and then a year with moderate inflows (2012), water inflows increased significantly in 2013. 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. This 2013 increase was achieved over the first quarter of the year (+1552 GWh in Q1 2013 relatively to Q1 2012), driven by intense inflows over this period, which counteracted the conservative hydro output in later periods.

More specifically, in January 2013, inflows increased by four times compared to January 2012 (from 266 to 982 GWh), reaching 1285 GWh in March 2013 (compared to 652GWh in March 2012, 558 GWh in March 2011 and 1026 GWh in March 2010), even exceeding levels of the years with excessive water inflows. However, during the last quarter of 2013, the inflows started decreasing, compared to 2012, reaching 79 GWh in October 2013 (compared to 225 GWh in October 2012), and 317 GWh in December 2013 (compared to 665 GWh in December 2012), thus signaling the transition to a rather dry period.

Overall, domestic electricity generation decreased significantly in 2013, exhibiting a strong decline of 9% relative to 2012, with demand in the interconnected transmission system decreasing by 7.6%. Lignite production decreased by 15.7%, reaching 23.3 TWh. 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 four (4) years, being substituted by gas, became zero in 2013. 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, followed by a 14% decline in 2013 (amounting to 12.2 TWh), being partly counteracted by the hydroelectricity escalation over the first quarter of the year. Overall, hydro production in 2013 increased by 65% relatively to 2012, attaining a value of 5.6 TWh.

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 by 8.6% in 2013, following a significant increase of 22.81% in 2012, but its overall market share still remained low. Imports reached 5.6 TWh and exports 3.9 TWh, with the net balance (1.7 TWh) exhibiting a drop by 3% in 2013, relatively to 2012.

Figures 12 and 13 focus on the day-ahead market, presenting the allocation of production across the various technologies at the monthly level, while Figure 14 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 13 depicts the changes in fuel mix in 2013, compared to 2012. 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.

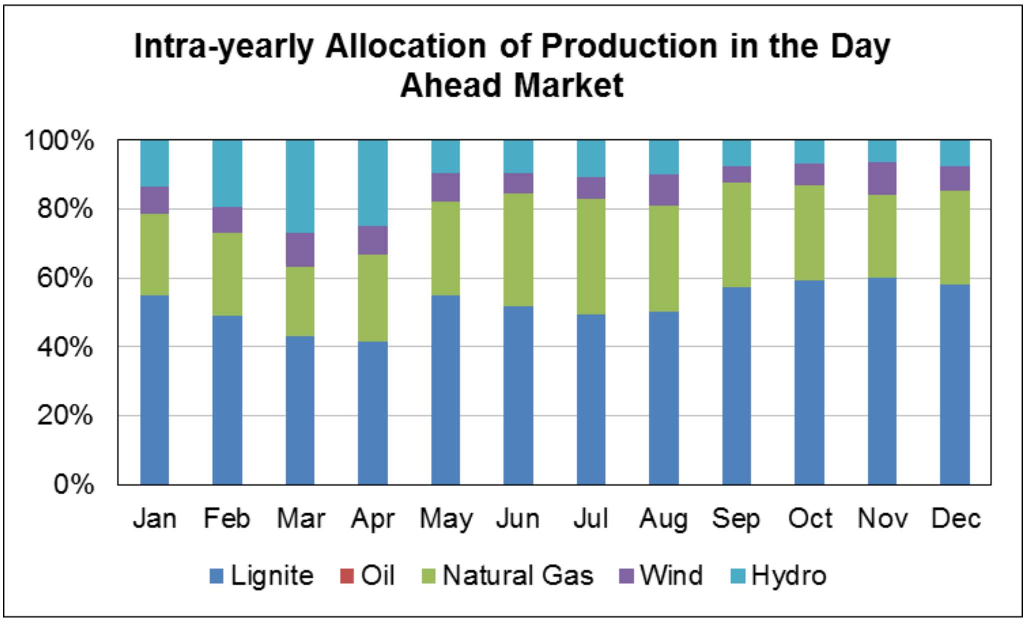


Figure 12. Production allocation across fuels at the monthly level, during 2013

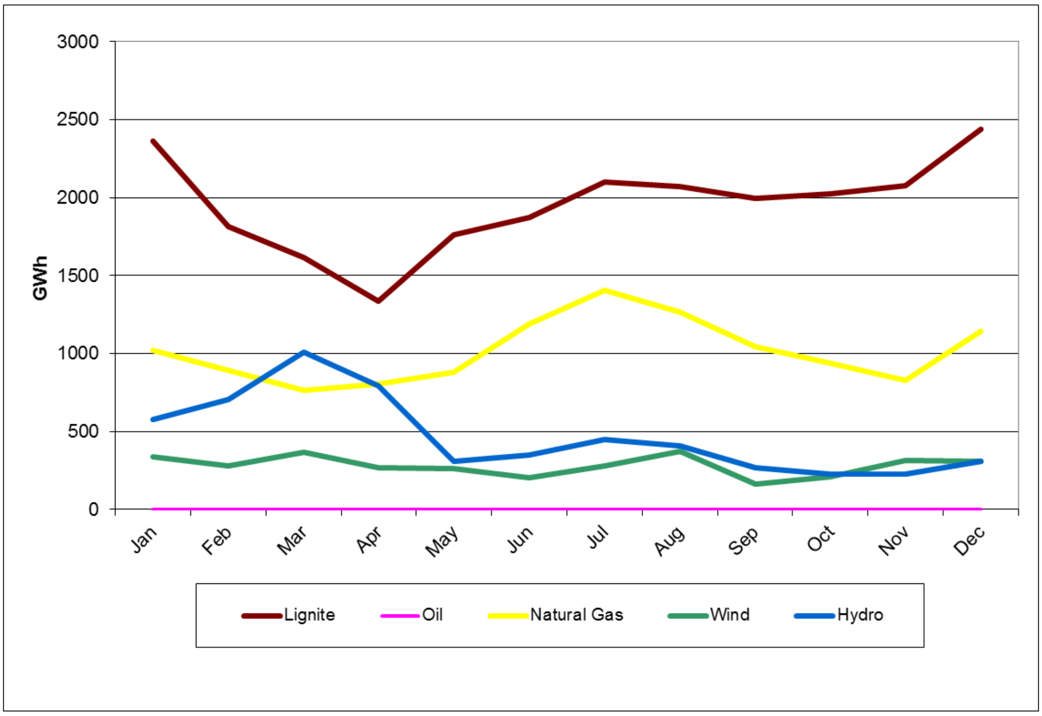


Figure 13. Production allocation across fuels at the monthly level, during 2013

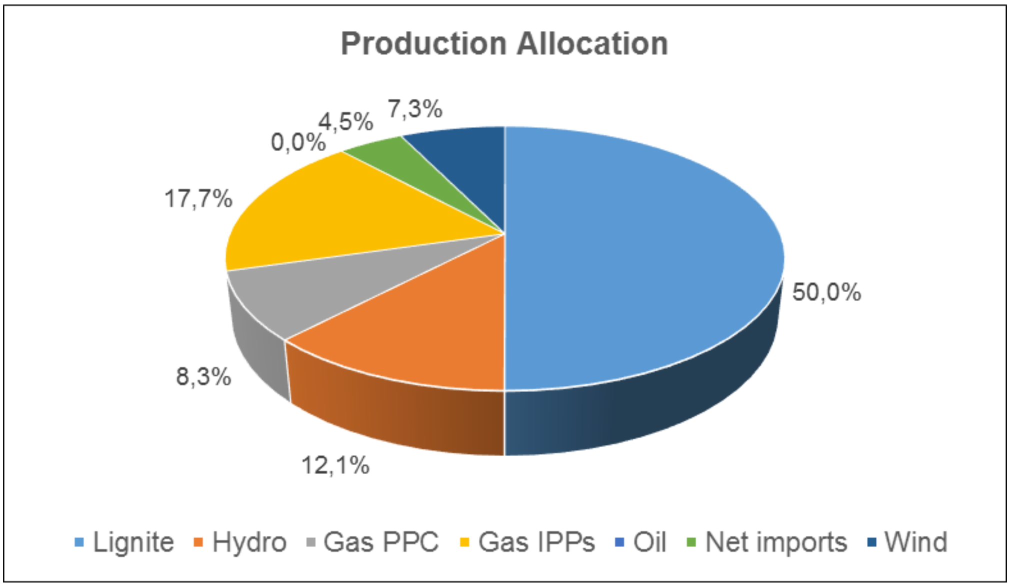


Figure 14. Annual shares of fuels and net imports

	2013 (TWh)	2012 (TWh)	% difference
Lignite	23.23	27.55	-15.7
Fuel Oil	0	0.078	100
Natural Gas	12.15	14.14	-14.07
Large Hydro	5.64	3.89	44.99
RES	3.38	3.11	8.68
Net Imports	2.10	1.78	-17.98
Total	**46.50**	**50.55**	**-8.01**

Table 13. Change in fuel-mix generation between 2012 and 2013 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 by private investors (52%). Hydro plants, owned exclusively by PPC, may also be used, due to their fast response rates, depending on hydro conditions and storage levels. Hydro quantities, in real time, exceeded their day-ahead dispatch schedules by 0.19 TWh, a rather negligible amount, compared to 5.45 TWh in day-ahead dispatch. These additional quantities implied additional payments to PPC for its hydro units, and slightly counter-acted the shortage of its lignite production (0.245TWh).

Installed capacity

Installed capacity in Greece at the end of 2013, by fuel, is depicted in Figure 15 and Table 14 below. The capacity of natural gas plants increased by 420 MW, compared to 2012, with the addition of a new gas plant, Aliveri V, owned by PPC. Finally, RES capacity increased significantly, by more than 1000MW, mainly due to new PV installations.

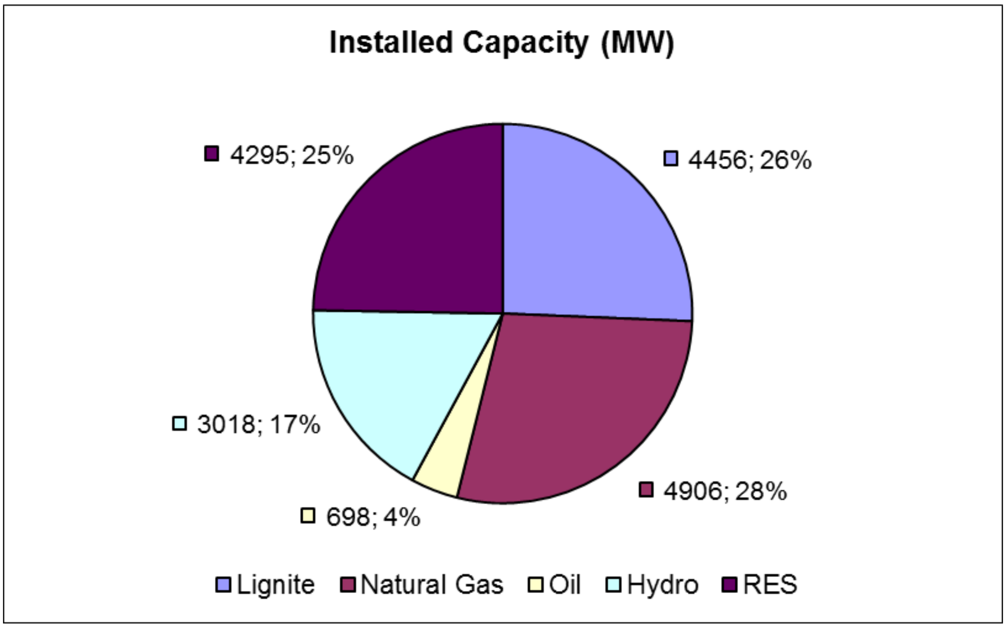


Figure 15. Installed capacity per fuel type in the interconnected system, at the end of 2013

	Ownership	Installed Capacity (MW)	Total Production (GWh)	Capacity Factor
Lignite	**PPC**	**4456**	**23231**	**59.51%**
Oil	**PPC**	**698**	**0**	**0%**
OCGT	PPC	339	1	0.03%
	Heron Thermoelectric	148	0	0.01%
	Total	**487**	**1**	**0.02%**
CCGT	PPC	1998	3875	22.14%
	Elpedison	799	2676	38.23%
	Heron Thermoelectric	422	1442	39.01%
	Protergia (Mytilineos)	433	1532	40.39%
	Korinthos Power (Mytilineos + Motoroil)	434	1457	38.32%
	Total	**4086**	**10982**	**30.68%**
Large-scale CHP	Alouminio (Mytilineos)	**334**	**1098**	**37.53%**
Total Thermal		**10061**	**35312**	**40.07%**
Large Hydro	**PPC**	**3018**	**5640**	**21.33%**
Small Cogeneration	**IPPs**	90	119	15.09%
Wind	**IPPs (mainly)**	1520	3392	25.48%
Small Hydro	**IPPs (mainly)**	220	771	40.00%
Biofuels – Biomass	**IPPs (mainly)**	46	210	52.11%
PVs & PVs on buildings	**IPPs (mainly)**	2070 349	2929 457	16.15% 14.95%
Total Renewables (Grid + Network)		**4295**	**7878**	**20.94%**
TOTAL		**17374**	**48830**	

Sources: ADMIE and LAGIE

Table 14. Installed capacity and capacity factor, by fuel and ownership, at the end of 2013

3.4.2. Generation adequacy in the interconnected and non-interconnected systems

According to regulatory instructions, and in the context of current legislation, the System Operator, ADMIE S.A., submitted in 2013 to RAE, for the first time, a Generation Adequacy Report for the period 2013-2020. The purpose of this report is to highlight potential future risks with regards to the ability of the interconnected power system to respond adequately to changes in electricity demand, foreseen for the time period under consideration.

The 2013 Generation Adequacy Report examined alternative demand and generation scenarios, which were formed based on relevant estimates-forecasts by the Transmission System Operator. Specifically, the assumptions concerned a) electricity demand projections (peak and annual), taking into account the relevant network development plans that are expected to be realised (e.g. the electric connections of the Cyclades islands and the island of Crete with the mainland electricity grid), and b) generation projections, taking into account the decommissioning of old existing plants, new generation plants that are expected to be commissioned, and the expected penetration of RES installations of various technologies.

The methodology that was used by ADMIE to calculate the risks to security of supply, combines a probabilistic approach with the calculation of de-rated capacity margins. The de-rated capacity margins were calculated according to the ENTSO-E (European Network of Transmission System Operators for Electricity) methodology for assessing the ability of the power system to serve the load.

RAE provided comments/observations on the Generation Adequacy Report to the TSO, with a view to incorporating them in the next submitted reports. The objective of the Regulatory Authority is to establish a systematic reporting and evaluation procedure of the generation adequacy, so that the security of electricity supply in the country can be monitored in the best possible way.

As far as the non-interconnected (island) system is concerned, there are 32 autonomous electricity systems in Greece today, with an annual maximum demand (peak) ranging from a few tens of kW (e.g. the Antikythera island, peaking around 100 kW), up to several hundreds of megawatts (e.g. Crete, peaking around 700 MW). Currently, the energy demand on these islands is covered primarily by local power stations, consisting of conventional thermal power plants using heavy fuel oil or diesel, while a part of this (up to 20%) is covered by RES (wind and photovoltaic plants). The sole producer of electricity from conventional units in these non-interconnected systems is currently PPC, while RES power stations on the islands are predominantly privately owned.

The inability of existing RES plants to provide guaranteed power to the local island systems inevitably leads to continued strengthening of the conventional power resources of each island, with new thermal units designed to meet both peak demand and the necessary reserve capacity. In particular, it is noted that to ensure sufficient resources and minimise the risks to security of supply, especially in the event of power loss, in each autonomous island system, and in addition to the required power to meet the maximum demand (peak), reserve conventional capacity is also installed and kept at standby status, in order to cover the possibility of loss of the largest power unit in each autonomous system.

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 Third Energy Package, and for both the electricity and gas TSOs.

The Energy Law 4001/2011 that entered into force in August 2011 and transposed 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 introduced 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 Law 4001/2011, enacted by two consecutive Government Legislative Acts, took place in November of 2012, in order to introduce more specific provisions on the implementation of either the Ownership Unbundling or the ITO model, to accommodate the DEPA/DESFA S.A. privatisation process (tender).

Consequently, the TSO's 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).

During the first quarter of 2013, RAE thoroughly examined the certification application of DESFA, in order to check whether the effective legal and functional unbundling of DESFA from DEPA had indeed taken place, based on – according to the Gas Directive - its independence in terms of governance, financial resources and operation.

At the same time, under the Gas Directive provisions relating to the certification of Independent Transmission Operators, DESFA prepared and submitted to RAE for approval the following documents and information:

- The Compliance Programme, which sets out the specific obligations of DESFA's employees to achieve and ensure: a) independence of DESFA from the vertically-integrated undertaking, b) equal treatment of users of the National Natural Gas System, and c) transparency and safeguarding of the confidentiality of commercially sensitive information.
- Information on the appointment of the members of the Supervisory Board of DESFA and of the Compliance Officer.

After a thorough examination of the above, RAE adopted the following decisions on the preliminary TSO Certification of DESFA, under the ownership of DEPA:

- Decision 184/2013 on the "Approval of DESFA's Compliance Programme, in accordance with the provisions of Law 4001/2011".
- Decision 199A/2013, on the "Approval of the Supervisory Board and of the Compliance Officer of the Company «Hellenic Gas Transmission System Operator (DESFA) SA» ".
- Decision No. 199B/2013, on the "Certification of the Company «Hellenic Gas Transmission System Operator (DESFA) SA», as an Independent Natural Gas Transmission Operator", which was the preliminary certification decision, in accordance with Article 10 of Directive 2009/73/EC and Article 64 of Law 4001/2011. With this preliminary decision, RAE considered a positive certification of DESFA, setting, however, a deadline until July 1, 2013 to the Operator in order to fulfil three (3) specific conditions (this deadline was extended until July 31, 2013, with RAE's Decision 277/2013). DESFA responded promptly providing evidence on the fulfilment of these conditions.

However, before the completion of the DESFA certification procedure, as defined in Article 10 of Directive 2009/73/EC, i.e. before the notification of the preliminary decision of RAE to the European Commission, significant new developments took place. More specifically, DESFA, under the circumstances defined in Article 65 par. 2 of Law 4001/2011, informed RAE, in December 2013, on the pending acquisition of 66% of the share capital of the company by the State Oil Company of Azerbaijan (SOCAR), which had emerged as a successful bidder in the international tender process that had taken place for the sale of that share. In this context, DESFA informed RAE that a new request for certification would be submitted to RAE for evaluation under this imminent change of its ownership regime and in relation to its acquisition by a third country-entity, according to the provisions of articles 9, 10 and 11 of the Gas Directive (2009/73/EC) (i.e., Articles 63a, 64 and 65 of Law 4001/2011). This new certification request was submitted to RAE by DESFA on 27/01/2014.

B) DSO Unbundling

During 2013, 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.

4.1.2. Technical functioning

According to the provisions regarding gas balancing services, as set in the relevant Greek legislation, DESFA S.A. prepares and submits every year to RAE for approval an annual balancing plan. The balancing plan includes the TSO estimates regarding balancing gas needs, as well as an evaluation of possible balancing gas supply sources for the next 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).

With its Decision 636/2013, RAE approved an amendment to the annual balancing plan for the year 2013, with regards to the methodology used to estimate the capacity reserved each year by the TSO for balancing purposes. Based on the new methodology, the capacity reserved by the TSO for balancing services takes into account the seasonality observed in the monthly capacity used for balancing during the period 2008-2012. Therefore, the TSO fulfils its obligation to provide balancing services to the system users, but at the same time, the capacity that remains available for network users, to book for their own transportation needs, is maximised.

RAE also approved in 2013 the annual balancing plan submitted by DESFA S.A. for the year 2014, which included the estimates of the TSO regarding balancing gas needs, as well as an evaluation of possible balancing gas supply sources for 2014. According to this plan, the TSO proposed to acquire balancing gas (in the form of LNG) for the balancing needs of 2014 through an international tender procedure, according to the main provisions of the Greek 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 2013 balancing plan, the TSO had estimated that the balancing gas needs for that year would amount to 5.2% of the total gas consumption, while the year-end data indicated that this figure actually amounted to 2.2%.

In 2013, 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[20].

4.1.3. Network and LNG Tariffs for Connection and Access

A. Transmission System and LNG terminal access tariffs

Up to January 2013, the Third-Party Access (TPA) tarification system was set by the Ministerial Decision 4955/2006. In July 2012, RAE approved a new Tariff Regulation (RAE's Decision 594/2012, Government Gazette B' 2093/5.7.2012), which established entry-exit tariffs, in line with the provisions of Regulation (EC) 715/2009. Subsequently, through its Decision 722/2012 (GG B' 2385/27.8.2012) entitled "Approval of the National Natural Gas System Tariffs", RAE approved the entry-exit tariffs to be applied as of the 1st of February 2013, in accordance with the provisions of the new Tariff Regulation.

The actual tariff coefficients for the year 2013 are presented in the tables below (for January 2013 and for the rest of the year, respectively):

Tariff (1.1.2013 – 1.2.2013)	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh)
Transmission	631.297	0.31059
LNG	26.487	0.019985

Table 15. Coefficients of TPA tariffs for one-year duration contracts, January 2013

Tariff 1.2.2013-31.12.2013	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh)
Entry Sidirokastro	135.5148	0.1204
Entry Kipi	124.2238	0.0924
Entry Ag. Triada	25.6193	0.0519
Exit Northeast Zone	67.2695	0.1349
Exit North Zone	260.5188	0.4132
Exit South Zone	367.5513	0.5010
LNG Terminal	58.3032	0.1180

Table 16. Coefficients of TPA tariffs for one-year duration contracts, as of February 1st 2013

As of February 2013, 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

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

reduced proportionally to the part of the year, calculated in days, during which the contract is in force, and are multiplied by a factor (B) which corresponds to the total duration of the contract.

The coefficients B are calculated according to the following formula, as set in RAE's Decision 722/2012:

$$B_{(d)} = a * e^{-bd}, (B_{d>=365} = 1)$$

where a and b are fixed parameters, and d is the duration of short-term services, in days, for the use of the Transmission System or the LNG terminal. The specific parameters used for calculating the coefficient B are defined as: a = 1.794793, b = 0.001602. Thus, the values of Factor B range from 1,791919 for a 1-day contract down to 1 for a 365-day contract.

DESFA S.A. publishes on its website the current and historical TPA tariffs, as well as a relevant calculator, in both Greek and English[21].

B. Distribution System access tariffs

During 2013, 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. EPAs are operating under a regime of exclusive rights for both the activities of distribution (DSO) and the supply of gas in their areas.

According to article 82 of the Greek Gas Law, access to EPAs 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 licenses. 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 System

As mentioned above, 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 Energy Law 4001/2011.

This development constituted a major step forward in reforming the TPA system, towards a decoupled entry-exit regime, in full compliance with the EU 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 was, therefore, set in place in 2013.

In 2013, RAE also completed a major revision of the Gas Network Code (2nd Revision), which was published in the Official Gazette in December of 2013 (RAE's Decision 526/2013), after

[21] http://www.desfa.gr/default.asp?pid=552&la=1

carrying out two public consultations. The main new elements of the Gas Network Code include, among others:

- Operation of a fully-fledged entry-exit system. Introduction of a Virtual Nomination Point (VNP), where transactions of natural gas quantities may take place between Network Users.
- Inclusion of all CMP provisions to be applied at the interconnection points between Greece and Bulgaria, as well as Greece and Turkey, in line with the provisions of Annex I of Regulation (EC) No. 715/2009.
- Inclusion of all necessary provisions for interruptible and reverse flow (backhaul) services.
- Necessary additions in the LNG terminal access provisions, to allow for efficient terminal access, auction procedures for the monthly and daily allocation of the additional temporary storage, and secondary market development, including within-tank LNG exchange of quantities.
- Elaboration of new provisions in the Gas Network Code, to allow for the effective implementation of the recently approved Emergency Plan, in line with the provisions of Regulation 994/2010 on Security of Supply (RAE's Decision 122/2013, Official Gazette 691/26.3.2013).

4.1.4. Cross-border issues

According to the provisions of the Energy Law 4001/2011, RAE has been assigned as the Competent Authority on ensuring the implementation of the measures foreseen in EU Regulation 994/2010 regarding security of supply. During the course of the year, a bilateral meeting took place in Bulgaria, following a meeting 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.

Following the above cooperation between the Greek and Bulgarian Competent Authorities, Regulators and TSOs, the Greek and Bulgarian TSOs submitted a joint proposal to the Competent Authorities on the realisation of physical reverse flow in the interconnection point Kula-Sidirokastro.

In September 2013, RAE accepted the joint proposal of the two TSOs (RAE's Decision 452/2013) on the realisation of physical reserve flow at the above point. According to this proposal, reverse flow capacity during normal operation of transmission networks in Greece and Bulgaria would amount to one (1) mcm of natural gas per day (on a continuous basis), and up to three (3) mcm of natural gas per day (on an interruptible basis). The cost of the investment related to the activation of reverse flow capacity of the National Natural Gas

System would be about 1 million €, and, according to the results of the market test conducted by the two TSOs in the formulation of their common proposal, it is expected to be repaid by users through capacity reservation in that interconnection point.

In October of 2013, the final recommendation of DESFA S.A. on the Ten Year Network Development Plan 2013-2022 (TYNDP 2013-2022) was officially submitted to RAE for approval, after being put into two public consultations, one run by the TSO and the second by RAE. RAE approved the TYNDP 2013-2022 (Decision 525/2013, Official Gazette B 3003/26.11.2013), according to the provisions of the Greek legislation and the Gas Network Code, and submitted a copy of the approved plan to ACER.

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 Greek 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 16 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 January 2011 through December 2013. Data are published on RAE's website[22] 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 time period of 01.04.2011 to 31.12.2013, the price of procuring balancing gas only includes a proportionate charge, which incorporates the fixed amount paid out by the Transmission 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.

[22] http://www.rae.gr/site/en_US/categories_new/gas/market/wholesale_gr.csp

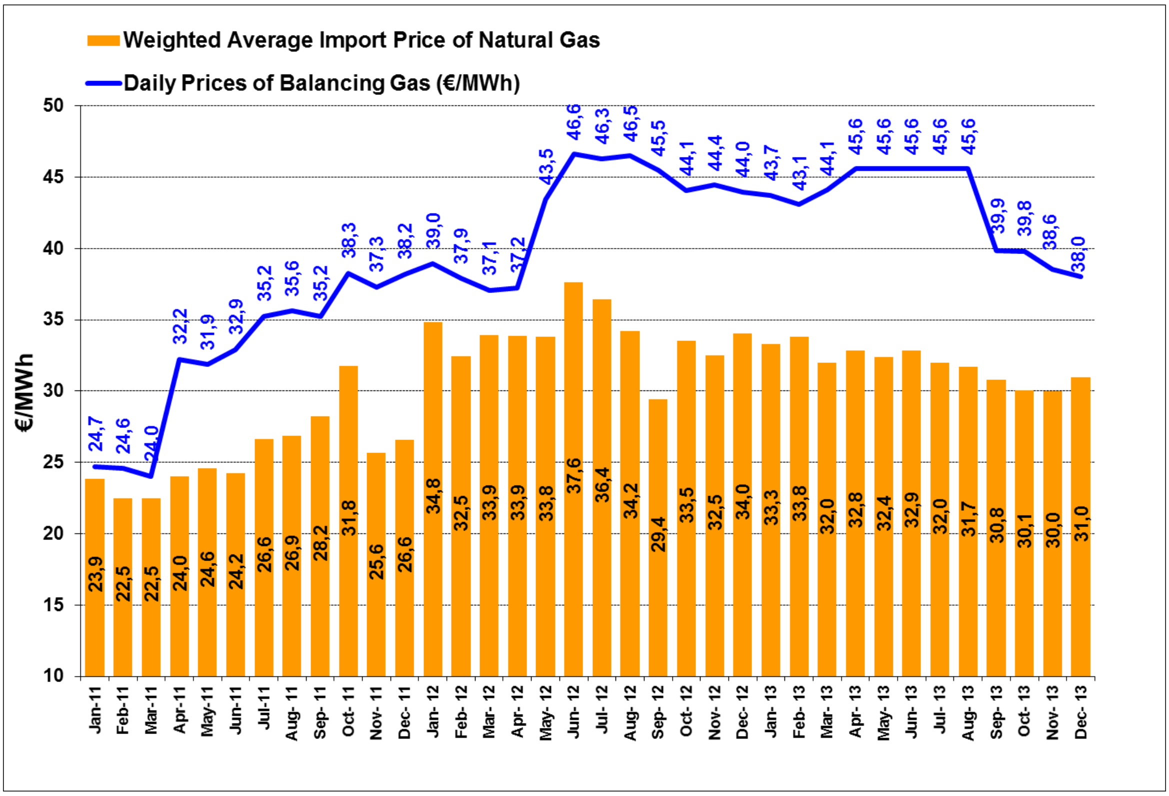


Figure 16. Monthly weighted-average import price (WAIP) against the price of balancing gas (Jan. 2011-Dec.2013)

4.2.1.2. Monitoring the level of transparency

Level of Transparency

Following a series of monitoring exercises that RAE carried out in the 2011-2013 period, the TSO Operator established a separate section on its homepage, regarding the publication of all information that is required to be published by the TSO in line with the provisions of the Third Energy Package. Therefore, network users can find in one place all the information necessary for third-party access to the NNGS, including historical data of use, as provided for in the Annex of Regulation 715/2009.

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2013. 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 was fully confirmed in 2013, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market.

During the 2010-2012 period, when there was considerable competition in imports of natural gas in Greece, the share of DEPA gas imports corresponded to about ninety percent (90%) of total annual imports. However, in 2013, the share of DEPA gas imports reached ninety-nine percent (99%) of total annual imports. Only two (2) other companies (one gas supplier and one big industrial consumer), beyond DEPA, imported natural gas in the country in 2013, representing the remaining one percent (1%) of total imports.

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

The companies that have been granted a Gas Supply Authorisation are 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.
10	GUNVOR INTERNATIONAL B.V.

Table 17. 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 2013, twenty six (26) companies were officially registered as potential users of the NNGS, five (5) of which were active in 2013. 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
22	ELVAL S.A.	Eligible Customer
23	SOVEL S.A.	Eligible Customer
24	SIDENOR STEEL INDUSTRY S.A.	Eligible Customer
25	FULGOR GREEK ELECTRIC CABLES S.A.	Eligible Customer
26	HELLENIC HALYVOURGIA S.A.	Eligible Customer

Table 18. Companies officially registered as NNGS users during 2013

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 at the retail level the same share as in the wholesale market.

In October 2011, the EPA Attica changed its methodology for setting customer tariffs, the previous one linking natural gas prices to the price of oil. From 1 October 2011, the EPA Attica pricing methodology is cost-based and is 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 end-user prices in 2013 were lower than the corresponding prices in 2012. This reduction in prices is attributed mainly to the discount achieved by DEPA in its long-term LNG import contract with SONATRACH, Algeria. This discount in price was passed on to EPAs and, subsequently, to the final consumer.

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

Year	Average end-user price (€/MWh)*			
	EPA Attica domestic	EPA Attica commercial	EPA Thessaloniki domestic	EPA Thessaloniki commercial
2009	36.37	40.73	45.88	47.34
2010	45.59	52.13	47.63	49.10
2011	57.54	62.22	51.95	53.49
2012	62.96	63.96	61.40	63.01
2013	57.66	58.66	57.19	58.82

** Net of VAT*

Table 19. Indicative, annually-averaged, natural gas prices in distribution, 2009-2013

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 of EU Directive 2009/73/EC

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 on their websites all necessary information regarding offered services and end-user prices, per customer category. 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 yet been fully adopted by the three EPAs, in terms of compliance with a) the categories of vulnerable groups, and b) economic protection schemes.

The Distribution License of each EPA, which operates under a regime of exclusive right for both the activities of distribution and supply of gas in its geographical area, 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 such customers, these 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 (people with 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 the above 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 special needs customers, 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).

4.3.3. Handling of consumer complaints

Only a very small number of complaints (34) were filed to RAE in 2013 regarding the distribution and supply of natural gas in the EPA areas, amounting to 9.1% of all consumer reports submitted to RAE in the same year.

4.4. Security of Supply

This section provides information in accordance with Directive 2009/73/EC. All data referring to gas quantities are provided in both units of Mtoe (based on gas with a HHV of 9600 Kcal/Nm^3) and bcm (at 15°C).

In the first quarter of 2013, the Emergency Plan and the Preventive Action Plan, as required by the relevant provisions of Regulation 994/2010 on Security of Supply, were adopted by RAE. Furthermore, the process of implementing the short-term strategy of the Preventive Action Plan was initiated. More specifically, a scheme for incentivising demand response, as well as key legislative provisions for ensuring dual-fuel availability of power stations were prepared and, following a public consultation, were put in place by Law 4203/2013.

4.4.1. Monitoring Balance of Supply and Demand

4.4.1.1. Current demand

The demand for Natural Gas in 2013 amounted to 3.92 bcm, out of which approximately 66% came from the power generation sector, as shown in Table 20.

Year 2013	bcm @ 15°C	Mtoe (HHV)
Power Generation	2.64	2.40
Industry & HP customers	0.72	0.66
GDCs (Primarily Commercial & Domestic)	0.57	0.52
Total	**3.92**	**3.57**

Table 20. Natural gas demand by sector in 2013

As depicted in Figure 17, gas demand in 2013 further decreased from the demand levels of 2011 and 2012, primarily due to the very mild winter and the continuing economic recession.

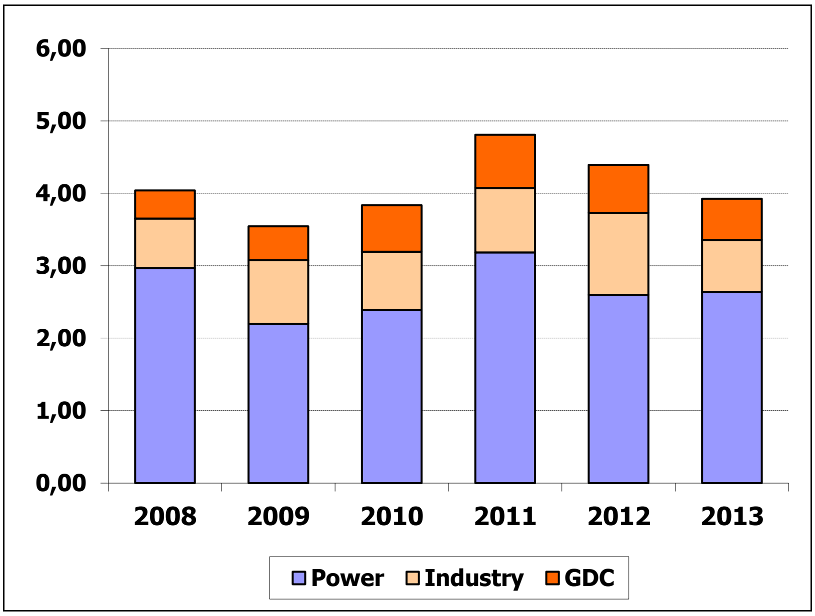


Figure 17. Gas demand per sector (bcm @ 15°C), 2008-2013

There is no indigenous gas production in Greece. In 2013, natural gas was imported in the National Natural Gas System through three (3) entry points. As shown in Figure 18, more than 66% of the gas imported into the country came from Russia and 18% was imported from Turkey. The remaining 16% was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point.

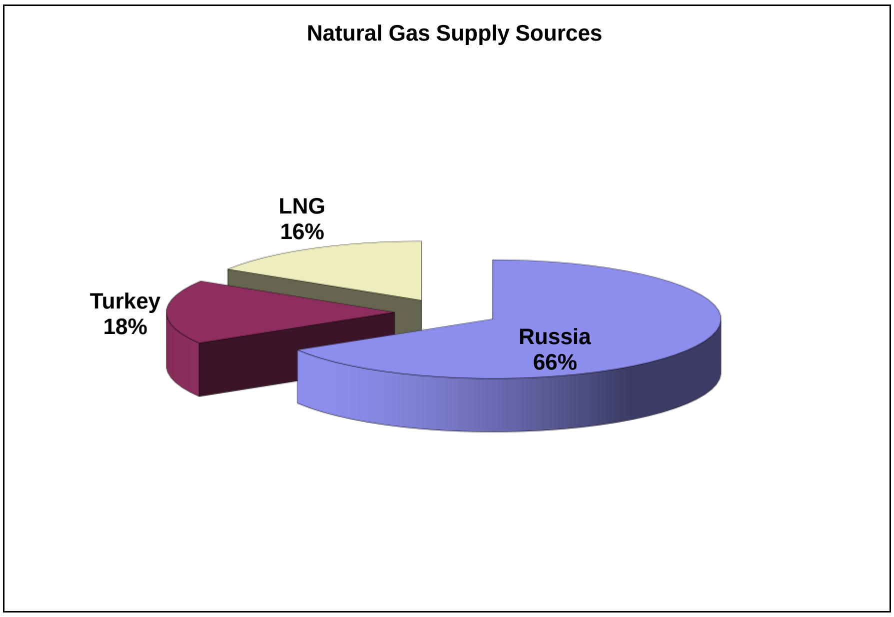


Figure 18. Share of natural gas supply sources in 2013

Figure 19 provides the share of imports from each source during the past seven (7) years (2007-2013). The supply of gas through the existing long-term contract with Russia lost a fraction of its share, in 2012, to LNG imports. However, in 2013, high spot prices limited LNG imports to quantities procured through DEPA's long-term contract with Sonatrach, Algeria; thus, the associated share of Russian supplies increased to 66%.

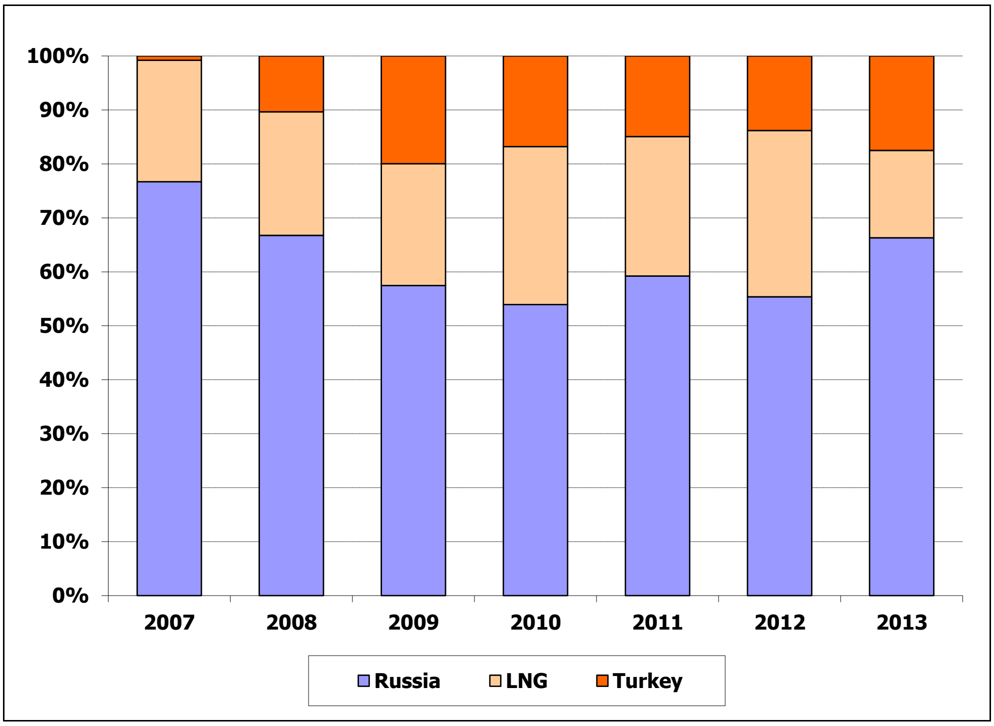


Figure 19. Share of natural gas import sources, from 2007 to 2013

4.4.1.2. Projected demand

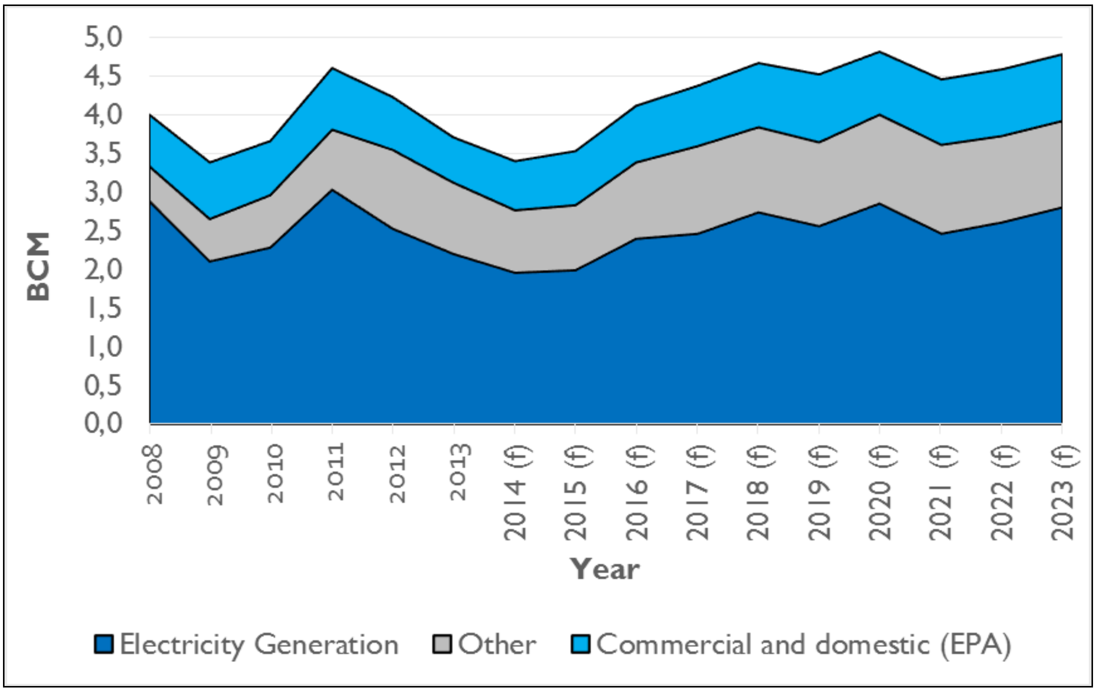
All data provided hereon are based on DESFA's projections in the latest TYNDP (study) 2014-2023. The 2014 consumption data so far indicate that demand may well be 10% lower than the figure projected in Table 21.

	2014		2015		2016	
	bcm	Mtoe	bcm	Mtoe	Bcm	Mtoe
Power Generation	2.07	1.88	2.10	1.91	2.53	2.31
Industry	0.83	0.76	0.88	0.80	1.01	0.92
Commercial & Domestic	0.69	0.63	0.74	0.67	0.79	0.72
Total	**3.59**	**3.27**	**3.72**	**3.38**	**4.33**	**3.94**

Table 21. Future natural gas demand (DESFA's estimates)

According to the full ten-year demand outlook for the period 2014-2023, as depicted in DESFA's 2014-2023 TYNDP (study), gas demand is expected to reach the 2011 plateau from

2018 onwards. New uses of gas have not yet been included in the demand forecast, but are expected to influence demand in the years to come.



[1] Source: Ten-Year Network Development Study 2014-2023, DESFA S.A. (June 2014)

Figure 20. Ten-year gas demand outlook

4.4.2. Expected Future Demand and Available Supplies

During 2013, 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.

Table 22 presents the anticipated supply-demand balance for the next three (3) years, based on the expected demand and the existing long-term supply contracts. It becomes evident that the existing contracts (that are in effect up to 2021) are sufficient to cover the anticipated demand. A very limited supply gap could appear in 2016, if growth returns as projected.

	2014		2015		2016	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	3.59	3.27	3.72	3.38	4.33	3.94
Supply Contracts	4.06	3.69	4.06	3.69	4.06	3.69
Supply Gap	0	0	0	0	0.27	0.25

Table 22. Expected natural gas supply-demand balance, 2014-2016

Figure 21 below shows the expected demand - supply balance up to 2020. The demand curve corresponds to the TSO's latest demand forecast of Figure 20.

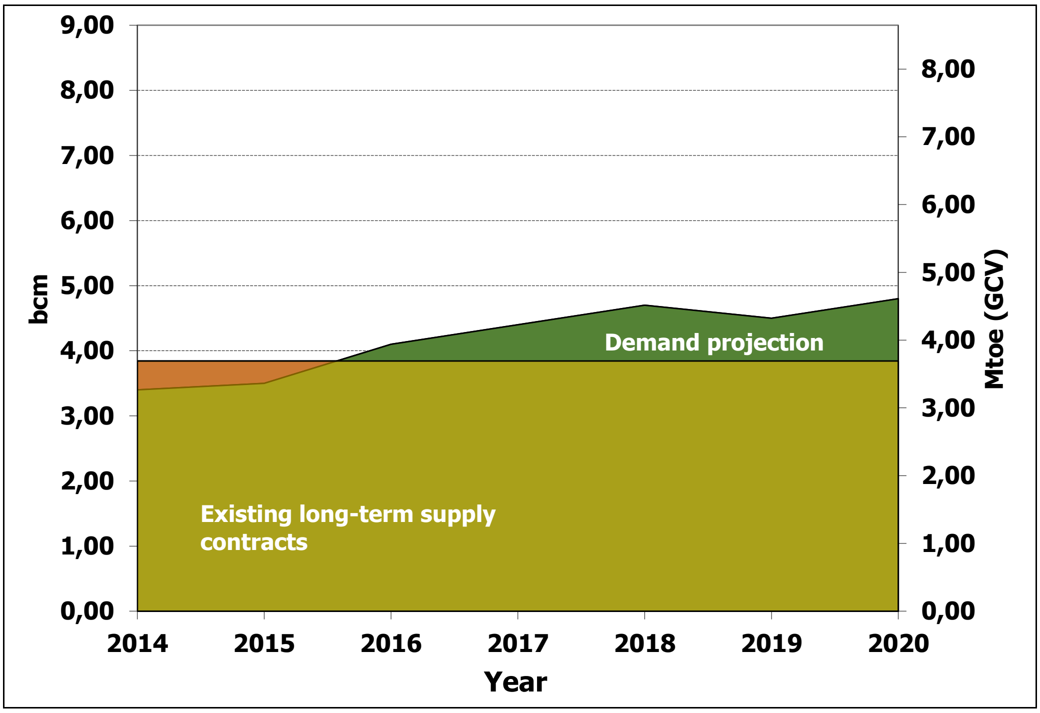


Figure 21. Expected natural gas supply-demand balance (forecast to 2020)

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.

Table 23 lists the current entry-point capacities. These capacities reflect current figures published by the TSO, based on upstream and downstream network constraints. The annual figures have been estimated based on a load factor of 100% for all entry points.

Entry points	Bcm
Sidirokastro	3.94
Kipoi	1.57
AG. Triada (LNG Terminal of Revithoussa)	4.55
Total	**10.06**

Table 23. Natural gas entry-point capacities

Table 24 below lists the TSO's investment plans, which aim to add import capacity to the NGTS. The plans are based on the Revithoussa LNG terminal upgrade, including a) the upgrade of the docking/marine facilities, b) the increase of the terminal's storage capacity by the addition of a third storage tank, c) the increase of the regasification capacity, and d) the upgrade of the Agia Triada M/R to match the upgraded regasification capacity.

The project for the construction of the third storage tank has already been awarded to an EPC contractor and its completion is expected by 2016. Once the terminal upgrade is completed, the total import capacity into the NNGS by the three (3) existing entry points will increase from 10 bcm/year to 12.5 bcm/year.

Project	Implemented by	Completion by
Revithoussa Terminal upgrade	TSO	End of 2016

Table 24. Natural gas TSO investment plans

4.4.3. Security of Supply crises

A series of events occurred that triggered a crisis at an early warning level, as defined in article 10 of Regulation 994/2010, from December 12 to December 18, 2013.

Supply from Turkey had been unstable since December 3, with pressure and deliveries consistently below the contractual level. On December 11, deliveries were halted. Greek gas demand was relatively high (in the range of 170,000 MWh per day) due to low temperatures, while the next confirmed LNG shipment was due for January 2, 2014. The crisis was triggered according to the provisions of the Emergency Plan, following the loss of more than 20% of gas supply from Turkey, through the Kipi entry point, for two consecutive days. The early warning was lifted on December 18, after deliveries through Kipi were restored. In the meantime, the LNG shipment due on January 2, 2014 had been rescheduled for December 25, 2013.

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 the Regulation, RAE published in 2013 the Preventive Action Plan and the Emergency Plan, developed in accordance with the provisions of Articles 4, 5 and 10 thereof.

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)*"[23], under its competency as the country's security of gas supply Competent Authority. For the preparation of the Plan, RAE had established a working group, which included the Operator of the National Natural Gas System, DESFA S.A., the Operator of the Greek Electricity Transmission System, ADMIE S.A., the Public Gas Corporation, DEPA S.A., 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 RAE Preventive Action Plan contains a short-term and a medium-term strategy, aiming at mitigating 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, obligations on suppliers and/or agreements with neighbouring TSOs. Cost estimates for the examined actions/measures were 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.

Following consultation with stakeholders, a legislative amendment was proposed by RAE to the relevant Ministry of Energy, Environment and Climate Change, containing all necessary provisions to fully implement the short-term strategy contained in the Preventive Action Plan. RAE's proposals were adopted by the Ministry and the legislative amendment was put in place in the third quarter of 2013, thereby setting the legal background for:

1. Ensuring the availability of dual fuel capability at approximately 1.7 GWe of gas-fired capacity.
2. Incentivising the participation of large customers in demand-response schemes that may be activated during a supply crisis.

Emergency Plan

The Emergency Plan was drafted by RAE in accordance with: a) Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010, concerning measures to safeguard security of gas supply and repealing Council Directive 2004 /67/EC (L 295) (the "Regulation") and, in particular, Articles 8 and 10 thereof, and b) the provisions of Articles 12 and 73(1) of Law 4001/2011, as in force.

In particular, the Plan aims to:

[23] http://www.rae.gr/site/file/system/docs/natural_gas/05112012_3

a) Define the responsibilities, obligations and actions of the State, RAE, Natural Gas System Operators, the Independent Power Transmission Operator (ADMIE S.A.), natural gas undertakings and major natural gas customers, in order to effectively address supply disruption or exceptionally high gas demand, which results in a significant deterioration of the supply situation in the Greek natural gas market, in accordance with Article 10(3) of the Regulation;

b) Establish procedures and measures to be followed for each crisis level, in accordance with Article 10(3) of the Regulation; and

c) Establish the information obligations imposed on natural gas undertakings.

The Preventive Action Plan and the Emergency Plan were 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 their final adoption by RAE.

Appendix I - List of licensed electricity Suppliers and Traders at the end of 2013

	Trading Licences		Supply Licences
1	4E ENERGEIAKI TWO (2) S.A.	1	ALPIQ ENERGY S.A.
2	A2A TRADING S.R.L.	2	ATHENS INTERNATIONAL AIRPORT S.A.
3	ALPIQ ENERGY HELLAS S.A.	3	COMPAGNIE NATIONALE DU RHONE
4	AXPO ENERGY ROMANIA S.A.	4	EDELWEISS ENERGIA S.P.A.
5	AXPO HELLAS S.A.	5	ELECTRADE S.P.A.
6	CEZ A.S.	6	ELEKTROPARAGOGI SOUSSAKI S.A.
7	DANSKE COMMODITIES A/S	7	ELPEDISON ENERGY S.A.
8	DENCO S.R.L.	8	ENI S.P.A.
9	DEUTSCHE BANK A.G.	9	EVN TRADING SOUTH EAST EUROPE E.A.D
10	DUFERCO ENERGIA S.P.A.	10	GREEK ENERGY SA (ELLINIKI ENALLAKTIKI) S.A.
11	EDF TRADING LIMITED E.D.F.T.	11	GREEK ENVIROMENTAL & ENERGY NETWORK S.A.
12	EDISON TRADING S.P.A.	12	HERON II VOIOTIA S.A.
13	EFT HELLAS S.A.	13	HERON THERMOELECTRIC S.A.
14	EHOL HELLAS S.A.	14	KAFSIS ENERGEIAKH S.A.
15	EL. EN. TRADING L.T.D.	15	NECO TRADING S.A.
16	ELEKTRICNI FINANCNI TIM D.O.O.	16	NRG TRADING HOUSE S.A
17	ELLINIKH TEXNODOMIKI ENERGEIAKH S.A.	17	PPC S.A.
18	ENEL TRADE S.p.A.	18	PROTERGIA AGIOS NIKOLAOS POWER S.A.
19	ENER S.A.	19	PROTERGIA S.A.
20	ENERGY MT E.A.D.	20	REVMAENA L.T.D.
21	ENERGY SUPPLY E.O.O.D.	21	RWE SUPPLY & TRADING GmbH
22	ENERGY TRADING L.T.D.	22	TINMAR-IND S.A.
23	ENSCO S.A.	23	VOLTERRA S.A.
24	EUNICE TRADING S.A.	24	WATT & VOLT S.A.
25	EUROPEAN ENERGY TRADE S.A. GIOUZELIS-CHATZIDIMITRIOU		
26	EZPADA S.R.O.		
27	GALA S.P.A.		
28	GAZPROM MARKETING & TRADING		
29	GEN I ATHENS L.T.D.		
30	GUNVOR INTERNATIONAL B.V.		
31	HSE D.O.O.		
32	IBERDROLA GENERACION S.A.U.		
33	NECO A.E.		
34	NOVEL ENERGY L.T.D.		
35	OET HELLAS S.A.		
36	OET UNITED ENERGY TRADERS L.T.D.		
37	REPOWER TRADING CESKA REPUBLIKA S.R.O.		
38	ROSEVELT L.T.D.		

39	RUDNAP ENERGY L.T.D.		
40	SEMAN S.A.		
41	SENTRADE S.A.		
42	STATKRAFT MARKETS GmbH		
43	STELLA GAVRIIL L.T.D.		
44	SUN CURE S.A.		
45	TERNA ENERGY S.A.		
46	VERBUND A.G.		
47	VIVID POWER E.A.D.		
48	TEI HELLAS S.A.		

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
GG	Government Gazette
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

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