2015 National Report to the European Commission

(Covering the period 01.01.2014 – 31.12.2014)

Regulatory Authority for Energy (RAE)

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1. Foreword

The year 2014 has been an interesting year in the energy sector, as several changes had been already promoted or were underway. In the electricity market, measures such as the privatization of the TSO and the spin-off of part of the incumbent PPC to create a second, competitor company were underway, along with a large number of actions for the reform of the markets. In the gas market, a draft law for the opening of the retail market to competition - as opposed to concessions granted to distribution and supply regional monopolies - was under public consultation.

In the regulatory front, RAE was in the process of reviewing the regulatory framework that would effectively support the changing environment, designing the proper mechanisms that would implement the above changes, always in full alignment with the European Directives and Guidelines. At the same time, RAE undertook several initiatives and regulatory 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.

In the electricity sector, and following an extensive public consultation, RAE approved a new methodology for setting the TSO's allowed revenue. In the wholesale market, RAE worked towards removing market distortions and imposing measures for the alleviation of structural asymmetries, by eliminating the Cost Recovery Mechanism, while in the retail market continued work on formulation of NOME type auctions. Concerning the Non-Interconnected Islands (NIIs), RAE adopted the Operation Code of NIIs. In addition, the European Commission, acknowledging the unique conditions of NIIs, granted to Greece a derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs.

In the gas sector, after a successful cooperation with the Italian and Albanian energy regulators in the framework of the implementation of TAP project, the exemption decision was issued in June 2013. In the course of 2014 this collaboration continued as additional regulatory documents, including the compliance program of TAP AG and the Guidelines and invitation for the binding phase of the market test were approved by the Italian, Albanian and Greek energy regulators. Furthermore, in September 2014 the certification of the gas transmission system operator (DESFA SA) was completed. In view of an imminent change of DESFA's ownership regime, the "third-country clause" (under article 11 of the Gas Directive 2009/73/EC) was thoroughly assessed and specific obligations were put on both DESFA and SOCAR.

As a new challenging era is emerging and new priorities and governmental directions and decisions are shaping up, RAE will remain dedicated to its main objectives: to maintain the necessary security of the country's energy supply, both physically, and economically, and ensure affordable energy costs for the national economy and the Greek consumer, and, at the same time, to prepare the Greek energy market to participate, in a smooth, organised and efficient manner, in the ongoing integration process of the single European energy market.

2015 is expected to be both an interesting and crucial for the energy market year.

Dr. Nikolaos G. Boulaxis

President

2. Main developments in the gas and electricity markets

2.1. Electricity

Although no changes in the rules of the wholesale mandatory pool were introduced during 2013 and 2014, the supplementary mechanisms, which exerted a substantial impact on market outcomes, were revised in crucial aspects, in an effort to yield more competitive outcomes.

These reforms had an effect on the average System Marginal Price (SMP), which in 2014 increased substantially (close to 40% with respect to 2013); however, this may be partly viewed as a “self-correction” to reflect more realistically the variable cost of the dispatched units. However, at the same time, the incumbent, PPC, increased even further its share in the wholesale market, with the independent producers trying to limit their financial losses.

At the same time, RAE is proceeding with a power market restructuring and, especially, with the design of the implementation of Target Model in greek wholesale market.

Regarding the fuel mix, the sharp decrease of gas-fired production and a surge of net imports are worth noting. The contribution of RES was 17.9% of the total energy, although the rate of building new RES capacity had dropped drastically, due to changes in the legal framework during 2013 and 2014.

In the retail market, PPC also remained by far the dominant supplier, as it held almost the entire retail market (99.5% of the total number of customers and about 97.6% of total electricity supplied). Although 8 other suppliers were active, the switching rate remained very low.

The growth of customer liabilities against their electricity suppliers continued in 2014 (PPC’s estimated unpaid receivables of €1.5 billion at the end of 2014), reflecting the difficulties faced by consumers during the deep economic recession.

Regarding the non-interconnected islands, in February 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, setting the grounds for open competitive markets, in both the production and the supply activities on these islands. At the same time, the European Commission, acknowledging unique conditions, granted to Greece derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs: a) for the refurbishing, upgrading and/or expanding of PPC’s existing power plants until 1.1.2021, but not for new capacity, b) for a maximum of five years after the adoption of the NII Code, until the necessary infrastructure is in place, for the activity of supply.

2.2. Natural Gas

No structural changes of the gas market took place during 2014. However, in April 2014 the Greek State announced an ambitious plan for the reform of the market. The plan included, among others, changes at the level of the wholesale market, but, mainly, significant changes in the organization and operation of the retail market. The latter included a gradual termination of the concession that the three existing distribution and supply companies (EPAs) enjoy in the regions in which they operate, as well as an immediate reform of the supply regime for the rest of Greece, with an emphasis on setting eligible as many customers as possible. A law to this effect was put under public consultation and is expected to be introduced in 2015. RAE has already played an active role, as it will undertake the burden of the fast amendment of the secondary legislation.

In the meanwhile, in order to enhance competition and strengthen the liquidity of the gas market, the Competition Commission, in late 2012, with the active participation of the Regulator, established a gas release program. DEPA committed to offer volumes of natural gas (10% of the quantity supplied to its customers during the previous year) through electronic auctions to the market. Several amendments to the gas release program were introduced in 2014, especially following RAE’s suggestions regarding volumes, duration, auction price, delivery etc, that were important so that the gas release program can indeed offer better priced natural gas to the other players of the greek gas market.

In the purely regulatory form, RAE initiated the procedure for a third revision of the Gas Network Code, which will take place in 2015. A security of supply levy payable by all gas consumers was introduced, meant to finance the costs associated with the establishment of an incentive scheme designed for demand response by large customers and the readiness of availability of liquid fuel at power stations with dual fuel capability, in case of a gas security of supply crisis.

Last but not least, in September 2014 the certification of DESFA was completed. In view of an imminent change of its ownership regime, RAE examined the certification of DESFA as an ITO under both DEPA, as DESFA’s owner at the time, and SOCAR, as DESFA’s possible future owner. In close collaboration with the European Commission, the “third-country clause” (under article 11 of the Gas Directive 2009/73/EC) was thoroughly assessed and specific obligations were put on both DESFA and SOCAR.

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 ITO model has been applied in the Greek market for the Transmission Operator. 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). There was no change in the status of the TSO during 2014, despite plans to privatize ADMIE.

3.1.1.2. Distribution System Operator - 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. There was no change in the status of the DSO during 2014.

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 2014, RAE issued the following decisions:

- 266/2014 regarding accounting unbundling rules of PPC S.A. Based on Decision 178/2013, RAE approved necessary amendments, that mainly arose after the adoption of the Operation Code for the Non-Interconnected Islands (see Section 3.2.3). The key changes concerned: a) the way of reporting the transactions between PPC and its network subsidiaries ADMIE and DEDDIE, b) more transparent and analytical information for certain significant accounts, and c) the explicit reporting of income generated from the provision of Public Service Obligations (PSOs).

- 43/2014, approving the account unbundling rules for the company "Protergia Thermoelectric Saint Nikolaos A.E.", which is active both in generation and in supply.

3.1.2 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).

Developments regarding network company revenue regulation methodology

In June 2014, following extensive public consultation, RAE approved the new methodology[1] for setting the TSO's allowed revenue. The most critical changes, in comparison with the previous cost-plus methodology, are:

- A multi-year regulatory period (3 years for the interim period 2015-2017, and 4 year period thereafter).
- Calculation of the TSO's Allowed Revenue based on real terms.
- Detailed methodology for the calculation of Return on Capital Employed based on real, pre-tax WACC.
- 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.
- Additional incentives for the investment in projects of major importance, particularly those which offer a significant benefit to consumers.

Further details on the methodology can be found on RAE's webpage (http://www.rae.gr/site/en_US/categories_new/electricity/network/transport/costs.csp).

Furthermore, during 2014, RAE appointed a consultant in order to review the methodologies for setting user tariffs for access to transmission and distribution networks (connection and usage tariffs). Final results are expected during 2015. Main objectives of this work are:

- Evaluation of existing methodologies regarding Allowed Revenue for Networks, according to international experience and recommendations on the methodology to be applied in Greece.

[1] RAE Decisions 339/2014 και 340/2014.

- Comparative analysis of the international practice and the Greek current practice, relating to methodologies for tariff structures (usage and connection charges) and recommendations on the methodology to be applied in Greece.

The process for setting the required revenue (applying the previous methodology) and the network access tariffs for 2014 was completed in April 2014[2] as described further below. As a result, the 2013 network access tariffs remained in effect until 30.5.2014.

3.1.2.1. Transmission use of system tariffs

Based on the methodology in effect for 2014[3], tariffs were calculated on the basis of the annual Required Revenue for Greek Electricity Transmission System (ESMIE), which was defined in the System Operating Code[4] as the sum of:

- the estimated annual Transmission Cost[5],
- the estimated annual cost of investments financed by third parties,
- the revenue surplus (-) or shortfall (+)[6] from the application of the unit tariffs to final customer demand,
- the settlement for differences between forecasted and actual operating expenses (OPEX with a plus or minus 3% neutral band) and investments of previous years, and
- the revenues from the auctions for interconnection capacity rights as set by a RAE decision[7].

RAE, taking into account a proposal by ADMIE, issued Decision 195/2014 approving the Required Revenue for the Transmission System for 2014, as follows:

	2014 (mil €)
Operating Expenses	82.0
Annual Depreciation	56.0
Return (RAV*r)	118.8
Total Cost / Allowed Revenue	**256.8**
Other settlements (Under-recovered funds Interconnection revenues, Other Revenues)	**(51.3)**
Total Required Revenue	**205.5**

Table 1. Annual Transmission Cost and Required Revenue for 2014

[2] RAE Decisions 195/2014 (Transmission Network) and 196/2014 (Distribution Network).
[3] RAE Decision 840/2012.
[4] RAE Decision 57/2012 (Government Gazette B' 103/31-01-2012) and subsequent amendments.
[5] According to article 275 of the System Operating Code.
[6] Deviations between the forecasted and the actual revenue from system users during previous years.
[7] According to Regulation (EC) 714/2009, article 16. For 2014, the relevant amount was €30 m.

The approved return was based on the following values:

- Regulatory Asset Value (Capital employed) of €1,398 m (including an estimate of €121.7m for new investments).
- Allowed Rate of Return (nominal, pre-tax): 8.5%.

In approving the Allowed Revenue, RAE validates the TSO proposal against historic performance and future trends. No formal methodology or benchmarking has been used in the cost assessment.

The total required revenue is then allocated to the different consumer categories. The methodology for setting the Transmission Use of System (TUoS) tariffs for HV customers is set out in the System 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[8].

Tariffs for HV-connected customers follow a €/MW structure, charged on the customer's average hourly demand during the following three hours: system summer peak, system winter peak and the maximum of the two.

Transmission system cost is further allocated between MV and LV connected customers on the basis of the contribution of each class 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, as 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), Residential, Residential with Social Tariff (KOT)[9], Other Low Voltage (LV) and Public Lighting Use LV, excluding Agricultural MV and Agricultural LV that have zero TUoS charges.
- For MV customers, there is only a capacity charge (no energy charge for TUoS) based on the monthly maximum metered demand (MW) during peak hours (11am-2pm).
- Residential customers with Social Tariff (KOT) are charged a simple €/MWh energy charge (no capacity charge for TUoS).
- For Residential customers (except for Residential customers with Social Tariff), 10%[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 metered demand (MW), whereas the remaining is recovered through a simple €/MWh energy charge.
- For other LV customers, 20% of the allocated cost is recovered through capacity charges, which are charged on the basis of the connection capacity (kVA) given the

[8] RAE Decision 2215/2010

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

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

lack of metered demand (MW), whereas the remaining is recovered through a simple €/MWh energy charge.

According to the above mentioned methodology, RAE approved the following tariffs for 2014:

Customer Category	Capacity Charge (€/MW or €/kVA)	Energy Charge (c€/kWh)
HV	24,455 €/MW chargeable demand (3 coincident peaks)	-
MV (non agricultural)	1,279 €/MW of Monthly Maximum Demand at peak-period, per month	-
Residential	0.16 €/kVA of Subscribed Demand per year	0.563*
Residential with Social Tariff (KOT)	-	0.626
LV (non agricultural)	0.52 €/kVA of Subscribed Demand per year	0.454*
Public Lighting Use LV	0.52 €/kVA of Subscribed Demand per year	0.454

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

Table 2. Transmission Use of System (TUoS) charges for 2014

3.1.2.2. Distribution use of system tariffs

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, and is expected to be finalised and approved during 2015. As a transitional measure, the methodology applied is the one that was in effect for 2014 for the transmission system[11].

In accordance with its Decision 840/2012, RAE approved the total Required Revenue for Distribution Network (for the Operator and its parent company, as owner of the network assets) for 2014 (RAE Decision 196/2014) as follows:

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

	2014 (mil €)	
	PPC S.A. (Owner)	DEDDIE S.A. (Operator)
Operating Expenses	-	421.0
Annual Depreciation	131.3	6.8
Return (RAV*r)	232.4	19.9
Other settlements (asset rentals)	(12.0)	
	351.7	**447.7**
Total Cost	**799.4**	
Other settlements (over/under-recovered funds, actual vs forecast OPEX and investments, other revenues)	**(31.7)**	**(13.4)**
	320.0	**434.3**
Total Required Revenue	**754.3**	

Table 3. Annual Distribution Cost and Required Revenue for 2014

The approved return was based on the following values:

- Regulatory Asset Value (Capital employed) of €2,968m. (including an estimate of €292m. for new investments).
- Allowed Rate of Return (nominal, pre-tax): 8.5%.

Out of a total required revenue of €754.3m, €65m were set to be recovered by MV connected consumers and the remaining by LV connected consumers. Distribution network cost is allocated between MV and LV connected customers on the basis of the contribution of each class to the distribution network summer and winter peak demand.

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

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

The final resulting Use of System unit charges for Distribution in 2014, per customer category, are presented in the following table. The unit capacity charge is applied on the customer's subscribed demand for LV customers and on the Monthly Maximum Demand registered at daily peak-hours for the MV customers. The unit energy charge is applied to the metered energy, adjusted for the average power factor (assumed to be equal to 1 for costumers without reactive power metering).

Customer Category	Capacity Charge (€/MW of Monthly Maximum Demand at peak-period, per month)	Energy Charge (c€/kWh)
MV	1,170	0.30
	Capacity Charge (€/kVA of Subscribed Demand per year)	**Energy Charge (c€/kWh)**
LV (subscribed demand >25 kVA) with reactive power metering	3.85	1.67
LV (subscribed demand >25 kVA) without reactive power metering	3.27	1.90
Residential	0.56	2.14
Residential with Social Tariff (KOT)	-	2.37
Other LV (subscribed demand ≤ 25 kVA)	1.50	1.90

Table 4. Distribution Use of System (DUoS) charges for 2014

3.1.2.3. 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.

3.1.2.4. 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, and is expected to be finalised and approved by RAE, after conducting public consultation, during 2015.

3.1.3 Cross-border issues

3.1.3.1. Access to cross-border infrastructure including the procedures for the allocation of capacity and congestion management and the use of revenues for interconnectors

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 further in 2014, with the average NTC corresponding to exports decreasing from 1370 MW in 2013 to 1277 MW in 2014 (-7%), and the respective NTC for imports decreasing to 1157 MW in 2014, compared to 1475 MW in 2013 (-22%). The significant decrease in imports was mainly due to the cut by 36% of the Winter-NTC for imports (850 MW in 2014 compared to 1350 MW in 2013), which can be attributed to the scheduled maintenance of the DC interconnector in the border Greece-Italy, that took place in the first semester of 2014, and followed a series of severe outages during the second semester of 2013. These incidents have also affected Winter-NTC for exports, which decreased by 21%, reaching 1120 MW in 2014 (1420 MW in 2013). The Summer-NTC for imports decreased at 1444 MW in 2014, compared to 1600 MW in 2013, while the respective for exports increased by 9%. Figure 1 displays the allocation of NTC in 2014 and its evolution compared to 2013.

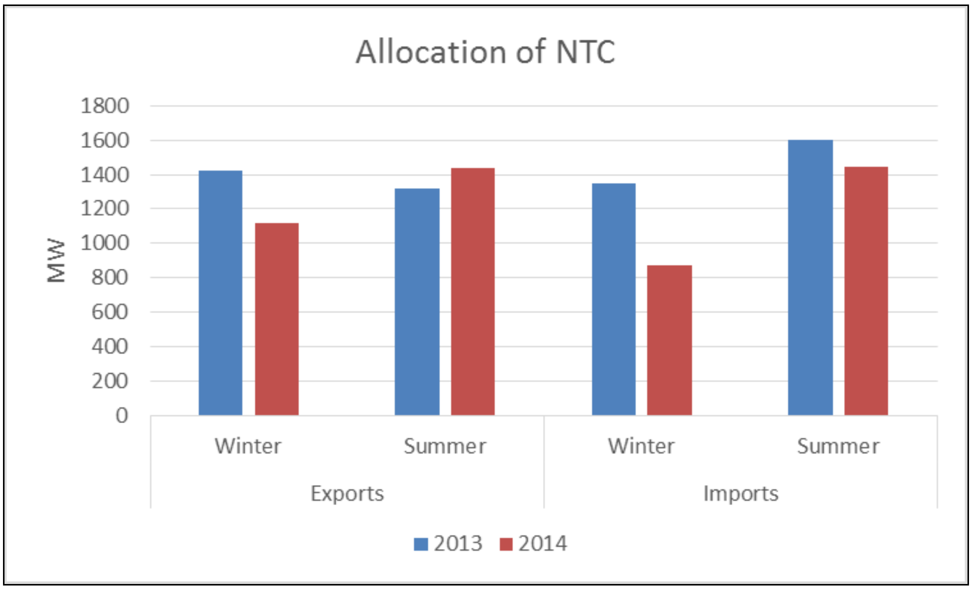

Figure 1. Comparison of Summer-NTC and Winter-NTC for Imports and Exports

Overall, the net interconnection balance increased significantly (+319%), from 2.1 TWh in 2013 to 8.8 TWh in 2014. Overall, imports increased considerably by 101%, from 4.7 TWh in 2013 to 9.5 TWh in 2014, whereas exports decreased reaching close to zero levels, from 2.6 TWh in 2014 to 0.6 (-75.3%), contributing to the increase of total net imports. It is worth mentioning that Italy is the only country with opposite interconnection balance from 2013 (net exporter) to 2014 (net importer).

More specifically, exports to FYROM decreased further with almost the same rate, from 0.05 TWh in 2013 to 0.02 TWh in 2014 (-64.6%), while Albania recorded the lowest decrease in exports (-30%), reaching 0.51 TWh in 2014 compared to 0.73 TWh in 2013. The highest decrease percentages were noted by Turkey and FYROM (-97.6% and -99.8%, respectively), but the volumes were relatively low. The exports to Italy decreased significantly (-93.4%), reaching really low levels in terms of volumes (0.11 TWh) in 2014, compared to 1.64 TWh in 2013 (more than half of the total exports).

Imports from all countries, except from Albania, increased, in contrast to last year's findings. The percentage increase observed in the interconnection with Italy was 1299.5% (0.1 TWh in 2013 to 1.34 TWh in 2014), placing it in the 4th position in terms of imports volume share. Imports from Turkey recorded the highest increase, by 136.9% (0.81 TWh in 2013 to 1.91 TWh in 2014), while imports from Bulgaria and FYROM increased significantly by 99.7% (from 1.75 TWh in 2013 to 3.48 TWh in 2014) and by 76.4% (from 1.49 TWh in 2013 to 2.63 TWh in 2014), respectively, accounting together for 65% of the total imports. Albania as already mentioned was the only exception in the total increase of exports, recording 81.5% decrease (from 0.57 TWh in 2013 to 0.1 TWh in 2014).

Figures 2 and 3 display the distribution of interconnection trading in 2014 and its evolution compared to 2013.

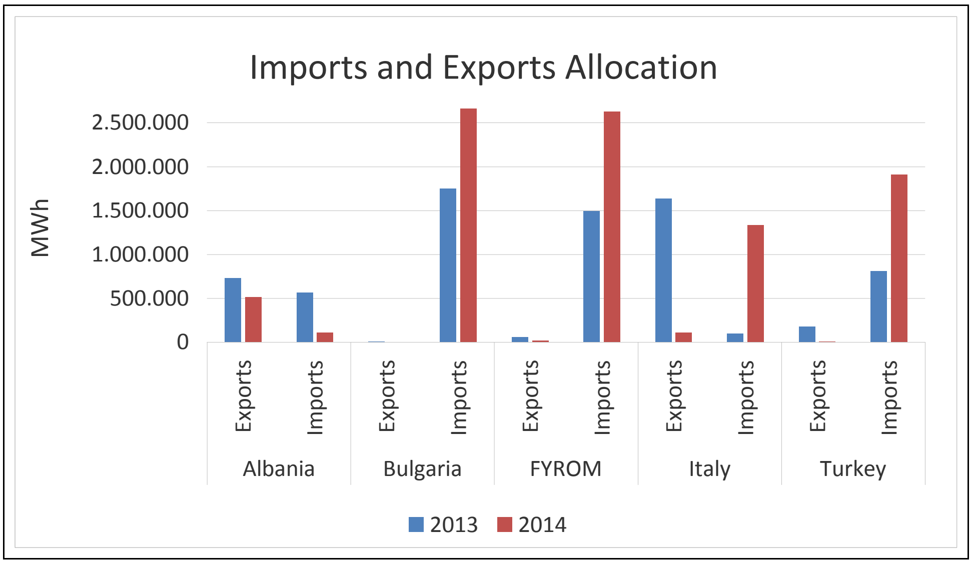

Figure 2. Distribution of import and export trading in 2014, compared to 2013

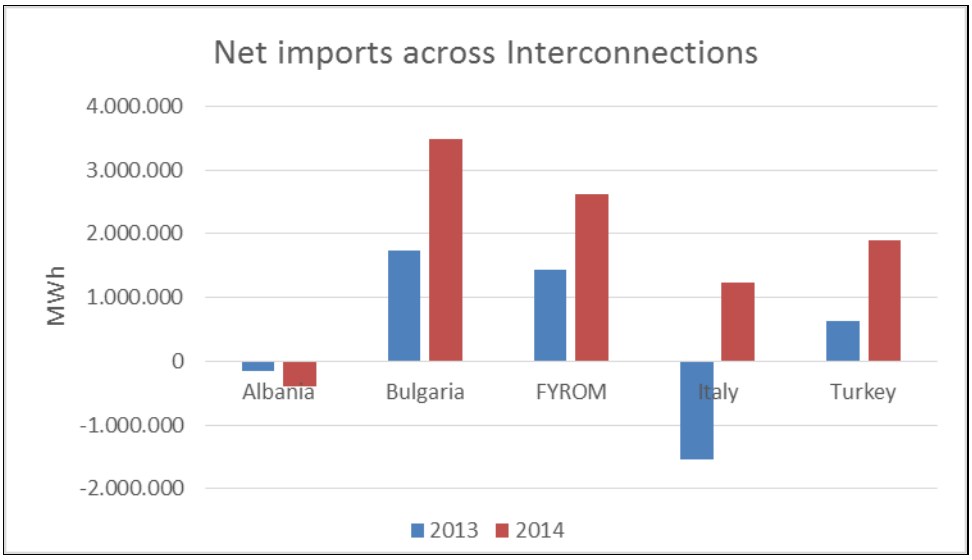

Figure 3. Net trading volumes across bordering countries (positive values for imports) in 2014, compared to 2013

Overall, the trading volume in all borders increased by 2.8 TWh (38.3%), with Bulgaria having the higher percentage increase (99.2%, corresponding to 1735 GWh), and covering one third (34.5%) of the total trading volume, and Albania having the highest percentage decrease (-52.5%, corresponding to 681 GWh).

As already mentioned, the operation of the interconnection with Italy during the second half of 2013 was problematic (the repeated forced outages led to long periods of limited, or no availability of the interconnector) and this led to a major reparation procedure that took place during the first semester of 2014. During that time the interconnection was not available to the market participants, hence the interpretation of the above figures should account for that fact.

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 2014, RAE approved (Decision 653/2014) new Capacity Allocation Auction Rules for the borders with Italy, with amendments for promoting the further harmonisation of auction rules.

With Decision 675/2014, RAE approved the Auction Rules in the borders with Albania, FYROM, Bulgaria and Turkey, which describe no significant change compared to the Auction Rules that were approved for 2014. These Auction Rules will apply to the borders with Albania and Turkey until the Auction Rules of South East Europe Coordinated Auction Office – SEE CAO, which have been approved by RAE with Decision 475/2014, take effect (mid 2015). The Bulgarian Transmission Operator (ESO EAD) decided not to participate in SEE CAO; therefore, the Auction Rules approved by RAE will remain unchanged in 2015. Similarly, MEPSO (the Transmission Operator of FYROM) has not made a definitive decision yet concerning the participation in SEE CAO, hence the Auction Rules for the interconnection with FYROM are expected to be valid for the whole 2015.

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 remained basically unchanged compared to the previous ones approved for 2014.

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, for 2014, the capacity for imports from CE to Turkey was 550 MW and the capacity for exports from Turkey to CE was 400 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 2014 remained the same as in 2013, 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, during 2014 ADMIE managed 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 5. 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 Regulation (EC) 714/2009 and its Annex with the Congestion Management Guidelines, namely to reduce transmission network tariffs (see also Section 3.1.2.1 above). This is reflected in the relevant report that RAE publishes annually, as required by the same Regulation.[12]

[12] 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 consumer 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. 2014 saw only a small increase in capacity given the commissioning of a new PPC 155MW hydro plant (Ilarionas). 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)[13] in February 2012, and the allocation of tasks between these two companies, the core of the market design and the settlement process involved remained unchanged during 2014, 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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[13] 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 to provide energy (and not reserves), 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, were revised during 2013 and 2014 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. The "30% rule" was abolished on 31.12.2013.
- 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 better expressed 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. Nevertheless, the mechanism was removed on 01.07.2014. In 2015 RAE will evaluate the implications of the mechanism abolition before reaching a final decision about its usefulness.

- 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 2014, 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 set in July 2013 from 45,000 €/MW/year (a level set back in November 2010) to 56,000 €/MW/year. The transitory regulated mechanism expired 31.12.2014. A new market-based methodology, in line with the recent European Guidelines, will be elaborated in 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

2014 was the fourth year of the implementation of the market design that allowed for the settlement of imbalances, and the first year of the reform package for the wholesale market, as described above. The remuneration through the day-ahead market represented 77% of generators' cash-flows, as compared to 61% in 2013. More specifically, the generators' annual revenues from the day-ahead market amounted to €2 billion, while ex-post settlements amounted to €0.7 billion. Hence, the turnover of the wholesale market reached €2.7 billion (€3.02 billion in 2013).

The supplementary Cost Recovery Mechanism, which was abolished on 30.6.2014, amounted to only €57 mil. in 2014 (essentially in the first half of the year), compared to 556 mil. € in 2013, i.e. decreased by about €500 mil. or 90%. Besides the abolition of this mechanism in the second half of 2014, an important parameter for the reduction of this amount was the more efficient operation of gas units, as early as October 2013, but mainly since the abolition of the "30% rule" on 01.01.2014. Indeed, only for the month of June 2013, the amount of the cost-recovery had reached €80 million, reflecting 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. It is notable that over the last quarter of the year, as a response to the 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.

The capacity payments amounted in 2014 to €565 million, compared to €546 million in 2013 (3.5% increase). This slight increase mainly reflects the higher unit CAM price (capacity certificate) that was adopted from October 2013, in the framework of RAE Decisions 338 and 339/2013.

For PPC, the day-ahead market reflected 79% of its income as a producer, while for IPPs the corresponding percentage was 44%. Hence, ex-post settlement amounts were still crucial for the viability of the new independent plants in 2014, contributing another 44% to their cash flows (40% coming from CAM, after the significant shrinkage of cost-recovery), as opposed to 19% for PPC. The differentiation regarding the allocation of cash-flows across PPC and IPPs is evident, reflecting various structural asymmetries, which although have blunted after the reforms of Decisions 338/2013 and 339/2013, are still present. Perhaps the most crucial factor is that, supplementary mechanisms translate into charges for suppliers and that PPC was the dominant supplier in 2014.

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. It amounted to €76 million in 2014, as compared to €148 million in 2013, which reflects the significant drop of gas-fired power production.

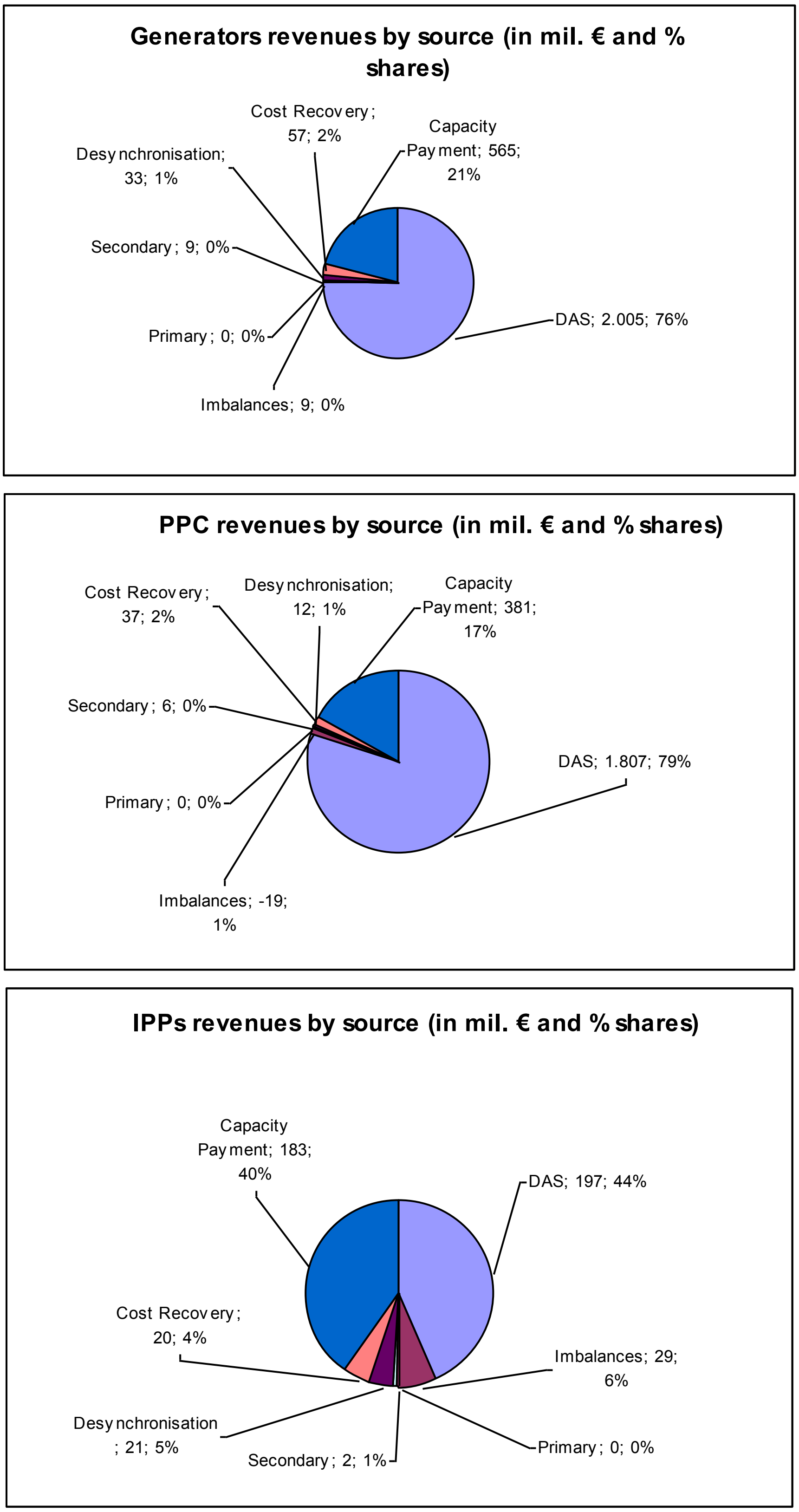


Figure 4. Generators' revenues from the day-ahead market and ex-post settlements in 2014

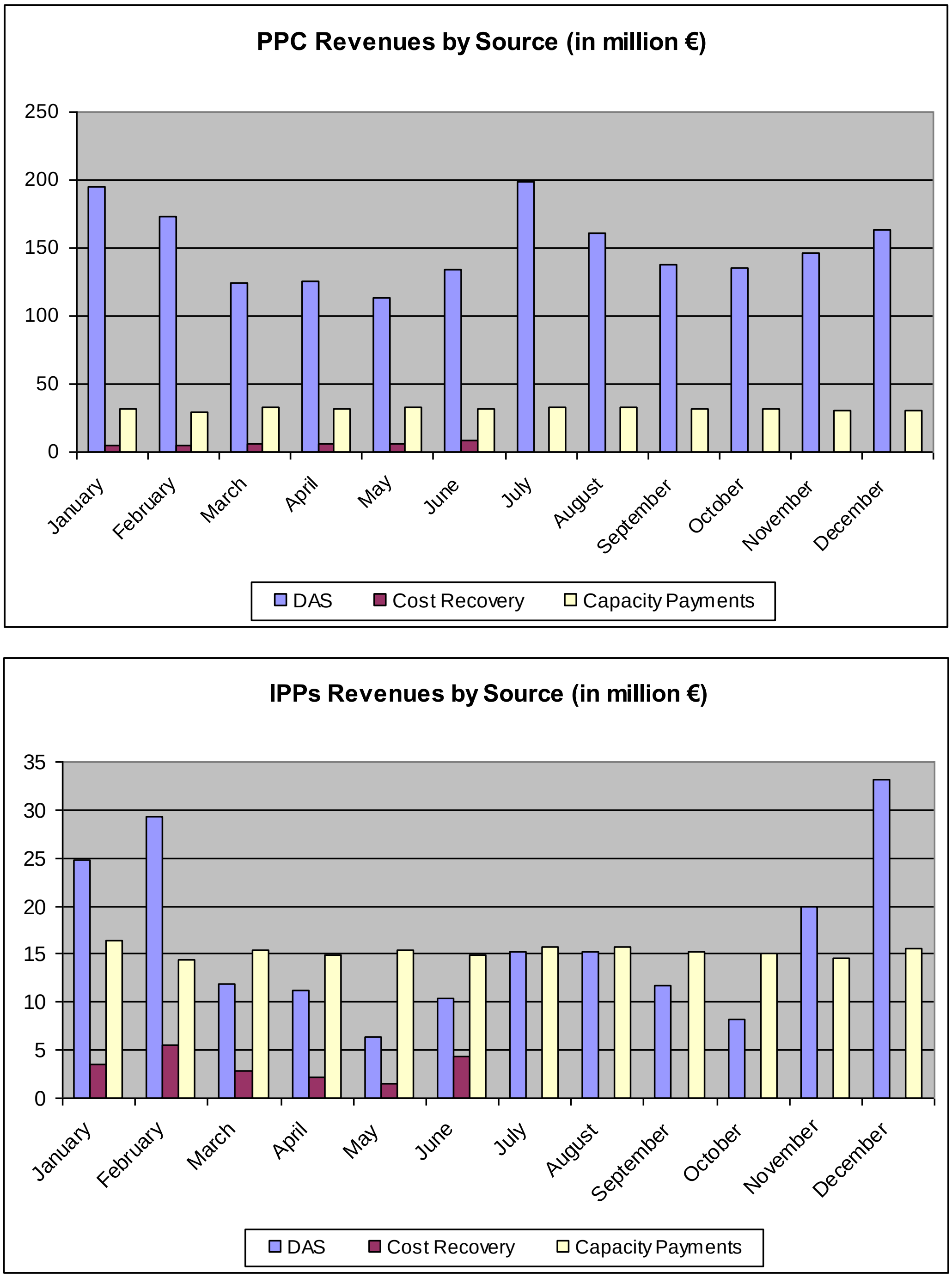


Figure 5. Generators' revenues from the day-ahead market and ex-post settlements, per month, in 2014

<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 (the DAS outcome) plus the net interconnection balance. This value was equal to 49,847,538 MWh in 2014, reflecting a marginal decline of 0.34% relative to 2013.

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. Hence, the "true" demand in 2014 was not 45.95 GWh, as the TSO reported (see Section 3.3.1), but 50.23 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.

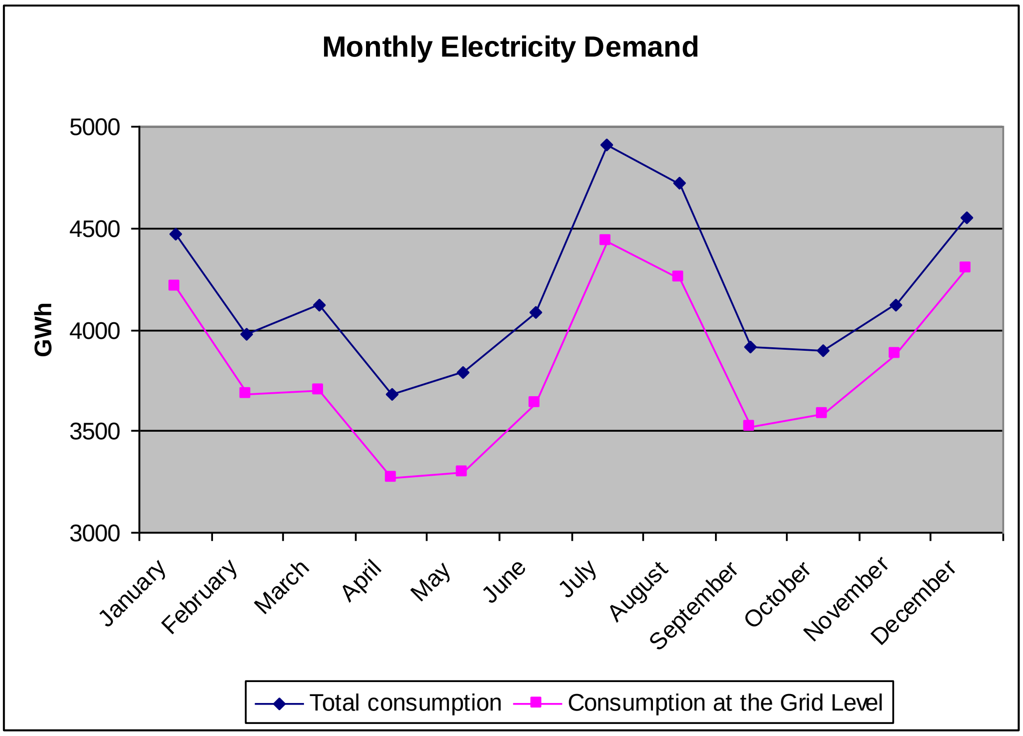


Figure 6. Electricity demand evolution during 2014

The installed capacity at the end of the year, as well as the annual production shares across fuels and imports, are presented in Sections 3.2.1.2 and 3.3.1.

3.2.1.2. Monitoring market shares

Regarding the market structure, PPC retained in 2014 its dominant position. On the generation side, reflecting the addition of a new hydro station of 155 MW, PPC's market share increased slightly, reaching a level of 80.6% (compared to 80.4% in 2013), in terms of conventional technologies (thermal and large hydro) in the interconnected system. The incumbent's market share was 60.3% (60.5% in 2013), if renewable capacity is also taken into account.

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 2015. 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 restrained in 2014, 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.

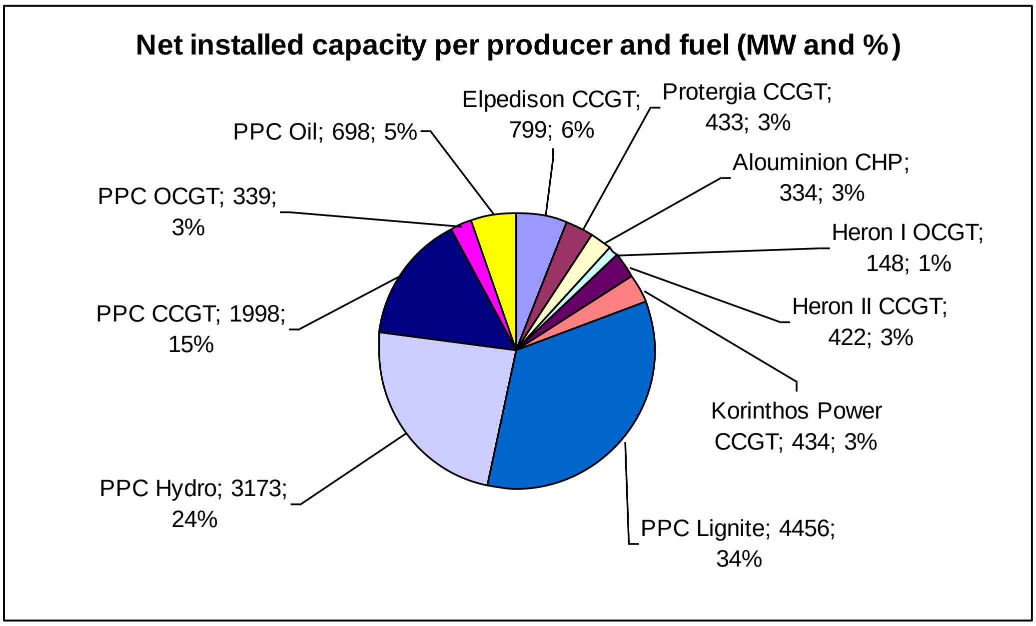
Summarising, eight (8) IPP gas plants are currently active in the wholesale market. Their ownership structure is presented below:

- 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 Peloponnese 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, the hydro unit Ilarion (143 MW), on the Aliakmonas river, started commissioning in February 2014, while six (6) other hydro units (two of which are pumping stations of 231 and 403 MW), of total capacity 940 MW, have already been licensed, but not all of them have applied for connection yet. 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. Finally, a fire in November 2014 set off Ptolemaida Units 3 and 4.

In terms of volume, the incumbent's share in 2014 in the interconnected system amounted to almost 90% of domestic production (excluding RES), while independent gas producers achieved only a 10% share, as the newly-added PPC's Aliveri V further shrunk IPP generation.

The net installed capacity and the produced volumes per fuel and producer in 2014 are depicted in the following Figures (see also Section 3.3.1).



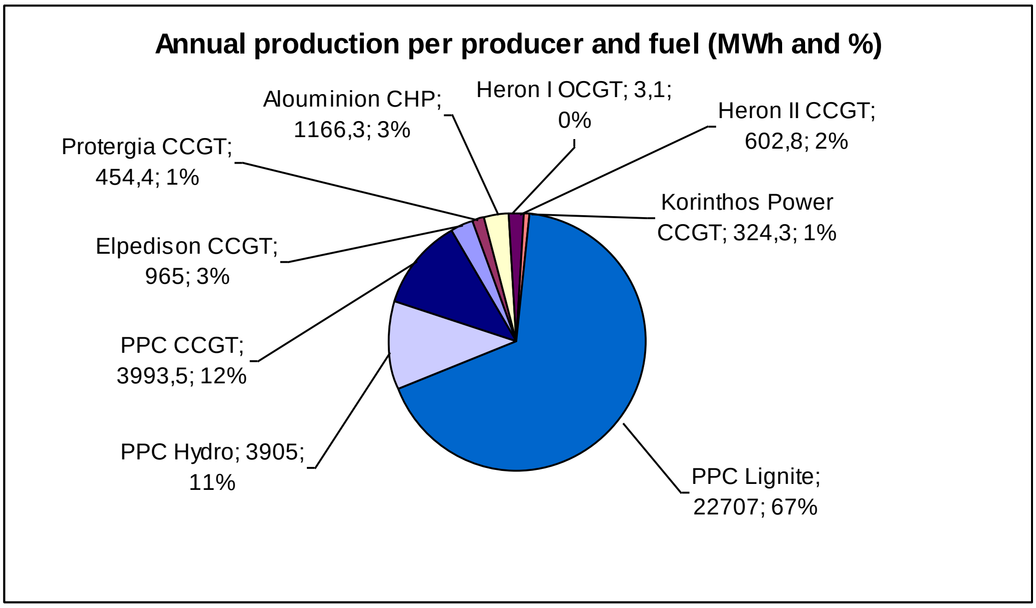


Figure 7. Shares in terms of installed capacity and produced volume per fuel and producer in 2014 (excluding RES)

The HHI index for the wholesale market in 2014, a measure of market concentration, attained the value of 8091 in terms of volume (production), and 6624 in terms of installed capacity; these values are to be compared with 6553 and 6597, respectively, in 2013.[14] The strongly increased concentration in terms of volume vividly illustrates the shrinkage of the production by the independent producers, in an effort to limit the financial losses suffered under the current conditions. Of course, it should not be overlooked that a long way has been travelled since 2009, when the HHI was close to the upper limit of 10,000. 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.

3.2.1.3. Price Monitoring

The average System Marginal Price (SMP) in 2014 amounted to 57.56 €/MWh, recording a noticeable increase (38.8%) compared with the previous year (41.47 €/MWh) and approaching the average level of 2012 (56.6 €/MWh). For the correct interpretation of this upward trend, it is important to clarify that it constitutes a partially correction of the SMP, more realistically reflecting the variable cost of the units dispatched in the DAS. This is because, up to September 2013, SMP levels had been strongly depressed, deviating systematically and significantly from the actual variable costs of production units.

Focusing on the monthly fluctuations, which are illustrated in Figure 10, it is notable that the average SMP showed a smooth profile in 2014, varying between 49.48 € / MWh in May and 65.75 € / MWh in July. The maximum monthly level of SMP arose primarily due to the strike in PPC for the period July 3-7, and not due to the weather, as temperatures in the month of July were below normal levels, with the maximum temperature of the year recorded eventually in August. In general, the SMP “correction” achieved, compared to nine months of compressed levels of 2013 varies on a monthly basis between 37% and 75%, while in the last quarter the monthly changes in the SMP was more limited (15% in October, 24% in November, while in December it dropped 1%), reflecting in part the constant adaptation of the behavior of producers in the DAS, which had already occurred since October 2013.

The variation of RES production had a smoother effect than in 2013, year in which, due to legal changes, RES had sharply increased, doubling in the end their participation in the DAS. With the exception of July that exhibited special circumstances, the highest monthly levels of SMP were recorded during January and February. The downward trend followed since March reflects the discount on the gas supply price charged by Gazprom to DEPA, which, for the electricity producers was around 10%. Finally, the increase of SMP in the last quarter of 2014 reflects issues in the availability of PPC units, such as extensive maintenance and faults of units (both lignite and natural gas units, particularly those of importance such as Aliveri V, Lavrio 4 and Lavrio 5), as well as sluggish production of RES and limited hydropower production.

[14] 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%.

The variability in the hourly levels of the SMP, as reflected in their standard deviation (Figure 9), showed a significant decrease, recording a mean daily value of 11.14 €/MWh in 2014, compared with 13.17 €/MWh and 27.22 €/MWh in 2013 and 2012, respectively. This reflects the more homogeneous price fluctuations around the most "reasonable" levels where it stood in 2014. The SMP exceeded 80 €/MWh for only 8% of the dispatching hours (compared to 7% of the hours in 2013 and 30% of the hours in 2012), determined in these limited cases mainly by gas units, and less often by exports or hydros.

The SMP touched the ceiling of 150 €/MWh at just one dispatching hour, as there were no extreme conditions which marked, even temporarily, potential power deficit, even during the period of the strike of the PPC personnel in July. Such cases had been observed in the previous years, and in particular 39 instances in 2012 because of a supply crisis in natural gas in February, and 14 hours in June 2011, due to a PPC personnel strike, but not in 2013.

It is noteworthy that the frequency of zero values dropped sharply during 2014 to only 31 dispatching hours, versus 674 hours in 2013 and 97 hours in 2012. Note that zeros occur predominantly at times of low demand, during which compulsory injections (hydros, renewable energy production, technical minimum thermal units, imports) exceed consumption. In these cases, imports are curtailed, due to the structure of the constraints incorporated in the DAS algorithm and, therefore, the SMP is determined by the import offer which was made with a zero value. 58% of these zero values (18 hours) were observed in March, when there were high and mandatory hydroelectric inflows due to weather conditions.

The dynamics of the day-ahead price, SMP, across the year, as well as its intra-day profile, as described above, are displayed in Figures 8 to 10.

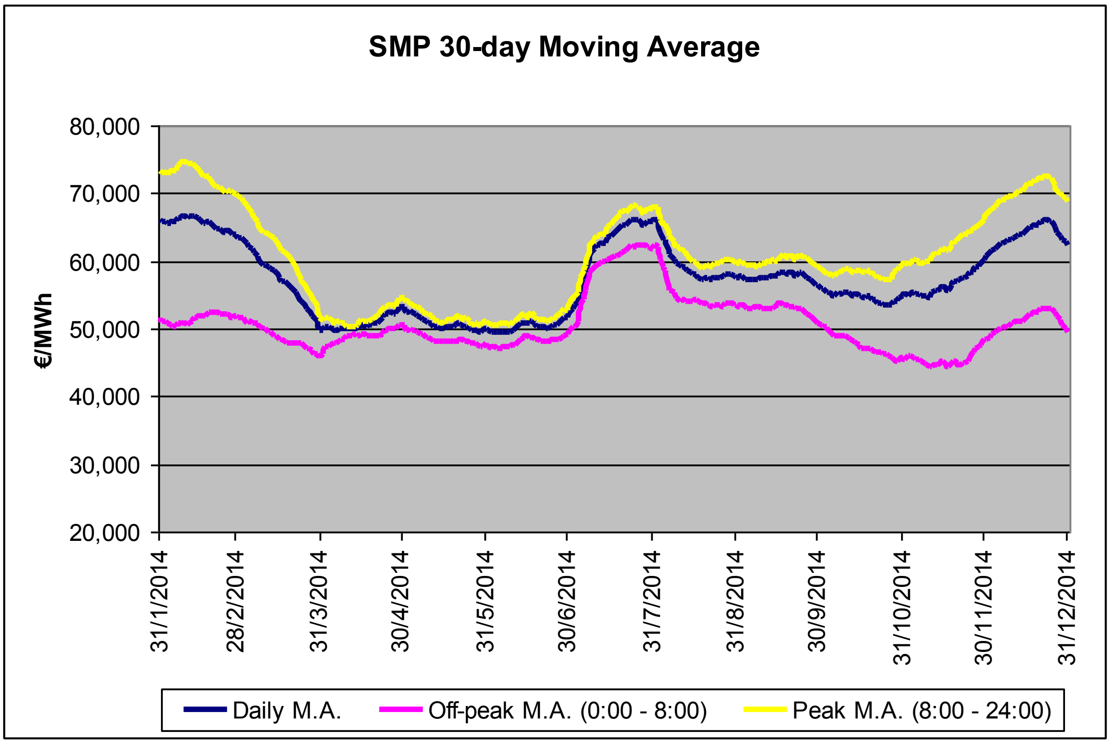


Figure 8. SMP dynamics (actual and smoothed levels) in 2014

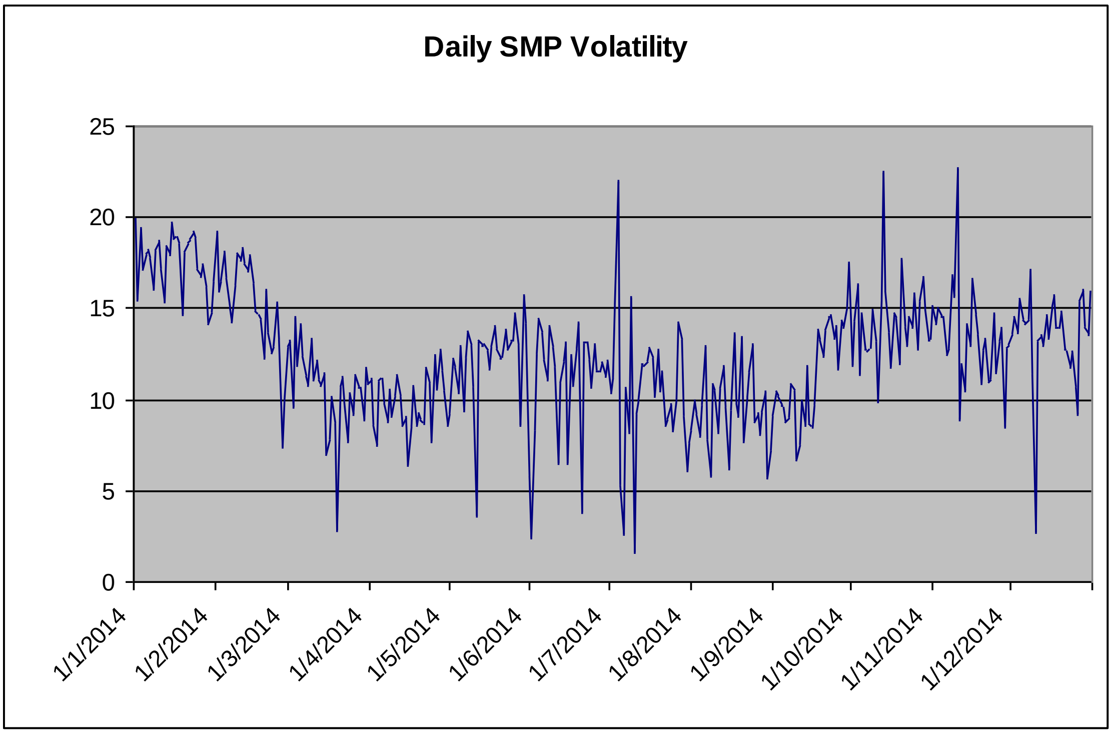


Figure 9. SMP volatility (st. deviation) in 2014

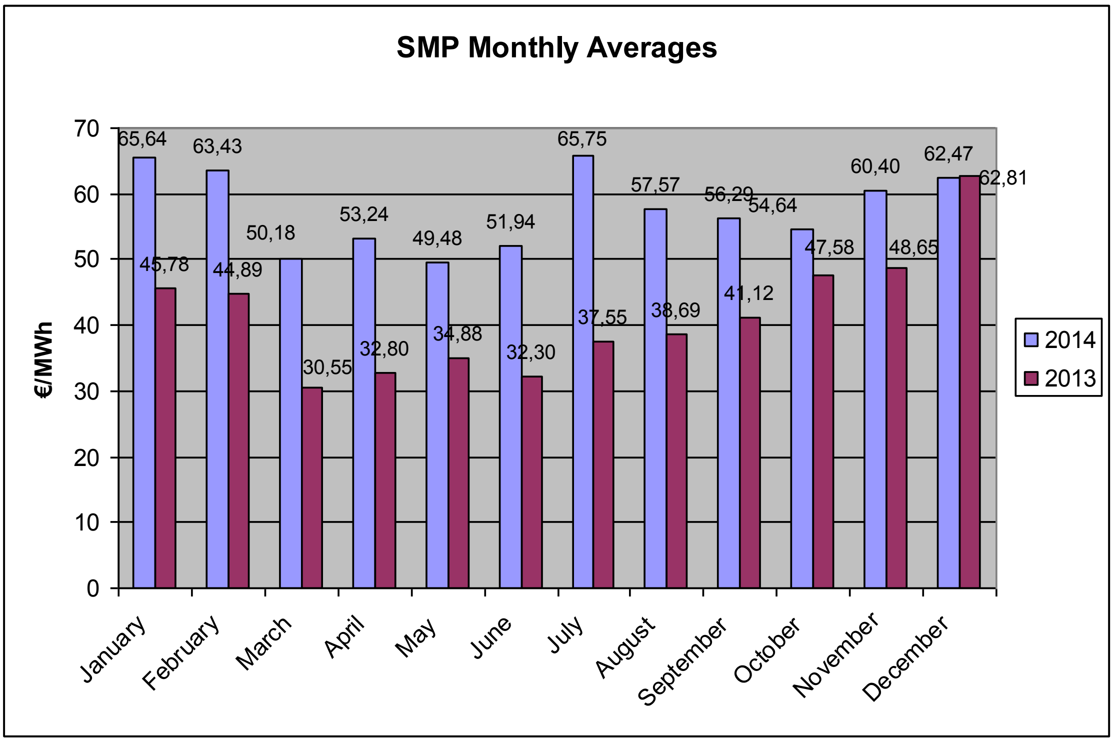


Figure 10. SMP intra-yearly pattern in 2014

The Imbalances Marginal Price (IMP) is a more realistic representation of the production cost, as it results from the solving of the DAS by entering the actual availability of units and the actual, metered quantities instead of forecasts (such as load, injections RES and cross-border flows). In 2014, the average IMP stood at 62.66 €/MWh, increased by 14.2% compared to 2013. To a large extent, the IMP was applied to the negative deviations (deficit) of lignite plants - which are in general less “available” than PPC declares to DAS - which were offset by positive deviations of hydro and gas plants.

The average hourly difference between IMP and SMP (Figure 11) was 5.1 €/MWh, compared with 13.43 €/MWh in 2013, fluctuating on a monthly basis between 0.19 €/MWh in December to 7,57 €/MWh in February. The sharp fall in the difference reflects the better correlation between the dispatching of the gas units and the level of demand and SMP, especially after the abolition of the 30%-rule on 1.1.2014, and the entire regulatory package decided in July 2013.

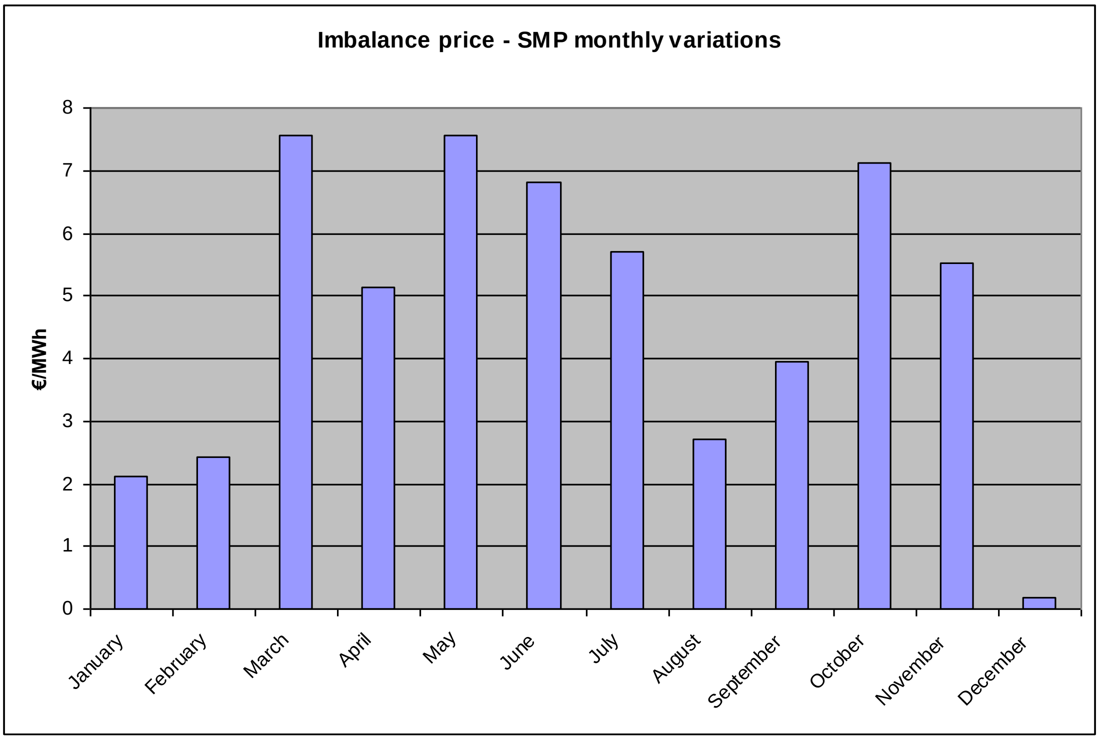


Figure 11. Imbalance Price - SMP: intra-yearly pattern of deviation in 2014

3.2.1.4. 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.

Furthermore, as the Greek NRA responsible for the application of REMIT Regulation in the energy wholesale markets in the country, we have worked with the Agency for the Co-operation of Energy Regulators (ACER) and with other European NRAs towards a common understanding on the administration and methodology to be followed regarding the identification, investigation and sanctioning of REMIT breaches. In parallel, RAE worked on capacity building among staff, especially with regard to market participants' registration process and data collection.

3.2.1.5. Monitoring of effectiveness of market opening and competition

As already mentioned, the most important barrier to market opening and competition is the structure of the Greek market characterized by the dominance of PPC in the generation market, and specifically in hydro and lignite generation, as indicated in Section 3.2.1.2 and Section 3.3.1. 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. The challenging issues that continued to arise in the domestic electricity market throughout 2014 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.

In 2011, RAE initiated an assessment of market design modifications, with the aim to stimulate structural market changes. These changes included Virtual Power Plant 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).

In 2014, excess capacity, to be assessed against declining demand levels, continued to be an issue. More new gas-fired capacity is expected to enter the system in 2015 (PPC Megalopoli 5 plant). Overall, it is notable that the total installed capacity of gas plants exceeded that of lignite plants. 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.

Below we discuss the progress achieved in 2014 on the above market restructuring and other issues regarding the wholesale electricity market.

Regulatory progress in wholesale market issues in 2014

The regulatory focus in 2014 was mainly on:

- Addressing market issues by removing market distortions and imposing measures for the alleviation of structural asymmetries.
- Proceeding with the power market restructuring and, especially, with the design of the implementation of Target Model in Greek wholesale market, and
- Clarifying and harmonizing the provisions of the Transmission Network Code and the Market Operation Code.

Indicatively, during 2014, RAE worked on the following issues:

- Regarding the harmonization of the wholesale market with the EU Target Model, RAE, in close cooperation with the Independent Transmission System Operator, ADMIE SA and the Market Operator, LAGIE SA, commissioned an international Consultant to develop the High Level Market Design for Reorganizing the Wholesale Electricity Market in Greece with a view to adopting to the requirements of the EU Target Model, as these are set through the corresponding ENTSO-E Network Codes. Under the proposed solution, the operation of a forward market, a day-ahead market and an intra-day market are foreseen. An Integrated Scheduling Process is also proposed accompanied by a Real Time Balancing Mechanism with a view to enabling the TSO to procure operating reserves and balance the system in the most cost-efficient way. The proposed design was set to public consultation which was concluded by the end of 2014.

- Alongside the main work of the reorganization of the wholesale market, RAE proceeded with the development of specific regulatory measures, with a predetermined time horizon, to potentially create competitive conditions (contestable market), and to develop those long term requirements that will allow the effective participation of more players in the domestic market, will offer alternatives to the final consumers, and will promote the effective participation of the domestic market in the single market (at regional and European level). RAE worked on the formulation of the NOME type auctions, putting the basic design under public consultation in May 2014, and a more detailed design in August 2014. The proposal consists of the establishment and operation of a forward market that would ensure the access of the independent suppliers (i.e. excluding the incumbent PPC) to lignite and hydro resources held exclusively by PPC.

  An auction process with a regulatory-defined starting price that reflects the full cost of efficient lignite production is foreseen. The basic concept for the product design, as introduced in RAE's latest document, provides the opportunity for the whole spectrum of consumers to be supplied by alternative supplies as an alternative to PPC. The starting point is designed to be the current level of end-prices for all customer categories.

  The quantity to be auctioned concerns 1200 MW of baseload lignite and hydro generation. The first auction is expected to take place in the second quarter of 2015. The auctions are organized on an annual and quarterly basis for each year, for 4 years. The proposed auctions are transitional and designed so that they can "substitute" the results on the market of the operation of "Small PPC", the "New Electricity vertically integrated companies", but also with the new market arrangements expected to be in place by 2017 (EU Target Model), where similar products traded on market basis will provide the opportunities for suppliers and generators to manage in a long-term basis their positions.

- With regards to the Cost Recovery Mechanism, the full elimination of the mechanism itself was already announced in the context of RAE Decisions 338 and 339 of July 2013, to be effective from mid-2014. However, after the abolishment of the "30% rule" (for the submission by generators of bids below the minimum variable cost) in the aforementioned context from 01/01/2014, RAE has been monitoring the evolution of the mechanism during the first semester of 2014, conducting a relevant analysis and asking ADMIE as well as LAGIE to submit their comments on it, and particularly on four alternatives for the reform of the mechanism. Moreover, ADMIE was asked to conduct a special study on the impact and particular implications, the elimination of the

Cost Recovery Mechanism could have in the wholesale market, while the participants were invited to inform RAE, through specific reports, about any effects this elimination could have on their operation. In January 2015, ADMIE submitted the requested technical report and RAE will proceed in 2015 with the re-evaluation of the mechanism, taking also into account the reports sent by the market participants.

Additionally, with RAE Decision 713/2014, 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.

- With RAE Decision 474/2014 the Transitional Capacity Assurance Mechanism (CAM) was extended until 31.12.2014, in order to smoothly proceed in 2015 with the implementation of the new scheme, which was notified to DG Competition in December 2014. More specifically, at the end of July 2014, and in the context of restructuring the CAM, RAE launched a public consultation on a high-level proposal taking into account the new Guidelines on State aid for environmental protection and energy 2014-2020, as well as the relevant documents issued by the European Committee. The purpose of the CAM was described as twofold: a) to ensure long-term capacity availability, and b) to address market failures, due to structural issues and power concentration. Taking into consideration the high RES penetration, that is expected to increase further, and the special system needs that follow it, RAE's proposal was based in identifying the different capacity availability characteristics that are defined as system requirements. Integrating the comments from the first consultation as well as discussions with DG Competition, RAE launched a second public consultation in January 2015, with a proposal for a Transitional Flexibility Remuneration Mechanism (FRM), setting also the high-level design for the permanent auction-based FRM, while in parallel, the Greek Government notified the scheme of the Transitional FRM to DG Competition.
- The determination of the opportunity cost of hydro resources, explicitly linking this cost to reservoir levels and to the cost of the substitution fuel mix, as its main parameters. The development of a related methodology started in 2013 through a close collaboration between RAE and the Market Operator, LAGIE, and continued in 2014. The methodology, as modified in 2013, based on the results of LAGIE's simulations, was set to public consultation by RAE between 13.12.2013 and 20.01.2014. After evaluating the comments submitted during the public consultation, and taking into consideration additional analysis and comparative calculations, LAGIE adjusted the methodology, to account also for the recent regulatory reforms, and a second consultation was launched by RAE on 15.12.2014. A decision is expected in 2014.
- On 19.02.2014 ADMIE launched a public consultation for amendments in the Transmission Network Code regarding the implementation of a methodology for the allocation of the transaction deficits, born by ADMIE, among the market participants. Due to the limited participation in the public consultation and recognizing the

importance of the specific issue, RAE decided to launch a second public consultation, in order to highlight all the aspects of the methodology and its impact, which was conducted between 17.09.2014 and 20.10.2014. A decision is expected in 2014.

- The modification of the Transmission Network Code and the Market Operation Code was focused on: a) harmonizing them with the provisions of the Non-Interconnected Island Power Systems Management Code, particularly in regards with PSO charges as well as the special account of Article 143 of L.4001/2011 (RES Account), and b) clarifying their provisions with regards to the unit reimbursement, the calculation of critical hours, the availability estimation of dispatched High Efficiency Heat-Power Cogeneration Units, the parameter approval.
- Continuous monitoring of the cash liquidity across the electricity supply chain. In 2014, the liquidity conditions in the domestic energy market remained extremely critical, due to the overall adverse conditions in the Greek economy in general and the continuous severe lack of financing and credit for the energy industry in particular. The core problem remains the unpaid receivables of PPC: as the dominant supplier (retail market share >98%), the rate by which PPC collects its receivables has a major impact on the whole electricity value chain and the relevant cash flows. In 2014, despite its efforts to improve its collection procedures, eventually, PPC was not able to improve its rate and at the end of 2014 it estimated unpaid receivables of €1.9 billion (an increase of 44% from 2013).

Regulatory measures regarding the above issues were either adopted during 2014 or carried over to 2015 via public consultations or reviewing processes. The implementation of market reforms, along with further elaboration of their key features, will continue in 2015.

3.2.2 Retail market

3.2.2.1. Monitoring the level of prices, the level of transparency, the level and effectiveness of market opening and competition

Description of the retail market

The overall electricity consumption in the Interconnected System in 2014 recorded a small decrease of 1.8%, in comparison to 2013. This decrease is the result of years of continuing economic recession, which has caused an overall decline of about 7% in the total electricity demand of the Interconnected System, over the 5-year period of 2010 to 2014. This decreasing trend in the overall electricity demand is depicted at the following Table 6.

Electricity consumption at 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**
	2014		15.470	9.017	3.227	**27.714**
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**
	2014			8.212	1.456	**9.668**
HV	2010	6.355			989	**7.344**
	2011	6.613			1.536	**8.149**
	2012	6.507			1.361	**7.868**
	2013	6.599			1.168	**7.767**
	2014	6.773			1.243	**8.016**
Total	2010	**6.355**	**16.477**	**21.931**	**5.241**	**50.004**
	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**
	2014	**6.773**	**15.470**	**17.229**	**5.926**	**45.398**

Electricity consumption at 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**
	2014		1.685	1.627	466	**3.778**
MV	2010			873	220	**1,093**
	2011			855	210	**1,066**
	2012			874	208	**1,081**
	2013			865	188	**1,053**
	2014			919	204	**1.123**
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**
	2014		**1.685**	**2.546**	**670**	**4.901**

(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, 2010-2014

In 2014, stability in the retail electricity market remained and no extraordinary events occurred, with only one new company entering the market (NRG Trading House S.A.) and another one exiting the market, having essentially transferred its supply activity to an affiliated company ("Protergia S.A." exited the market, transferring its supply to its affiliate "Protergia Thermoelectric Agios Nikolaos S.A."). Overall, in 2014 there were no major events or developments that affected the representation of retail electricity consumers.

At the end of 2014, eight (8) electricity suppliers were active in the retail market:

1. PPC S.A.
2. ELPEDISON ENERGY S.A.
3. WATT & VOLT S.A.
4. HERON THERMOELECTRIC S.A.
5. GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.
6. VOLTERRA S.A.
7. PROTERGIA THERMOELECTRIC AGIOS NIKOLAOS S.A.
8. NRG TRADING HOUSE S.A.

Competition and market shares

PPC SA remained by far the dominant supplier on the interconnected system, as it held almost the entire retail market (99.5% of the total number of customers and about 97.6% of total electricity supplied, see Table 7). Only a very small percentage of 2.71% (measured in terms of metering points) of the total LV and MV customers switched electricity supplier in 2014, a number slightly better than that of the year before (1.86% in 2013), according to the data provided by the DSO. Overall, in the domestic electricity market for the interconnected system, the total number of customers in 2014 was 6,585,616 and their total consumption was 45,398,890 MWh. It must be noted that in the non- interconnected system, PPC remains the sole supplier of of electricity to all end consumers following an EU decision granting derogation from relevant articles of the Directive.

Another characteristic of the retail electricity market in 2014, was the continuous growth of consumers' 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. Moreover it must be noted that, although the special property tax was removed from electricity bills in 2014, this did not seem to improve the collection rates of the suppliers or the clearing of the previously accumulated bad debt.

By eligible volume (MWh)										
Customer type	**Total**	**PPC SA**	**WATT & VOLT SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**NRG TRADING SA**	**ELPEDISON ENERGY SA**	**VOLTERRA SA**	**PROTERGIA THERMO ELECTRIC SA**	**HERON SA**	**PROTERGIA SA**
Household customers	15,470,478	15,423,956	11,142	3,451	155	26,727	246	251	4,548	0
Small Industrial and Commercial customers	9,016,502	8,445,002	33,346	56,498	4,388	222,555	18,059	10,873	225,781	0
Other LV customers (eg, agricultural. public. traction)	3,227,222	3,227,222	0	0	0	0	0	0	0	0
Total LV Customers	**27,714,202**	**27,096,180**	**44,489**	**59,949**	**4,543**	**249,282**	**18,305**	**11,125**	**230,330**	**0**
Industrial and Commercial customers of MV	8,211,628	7,788,517	4,689	16,710	5,072	147,939	12,044	33,981	202,677	0
Other MV customers (eg, agricultural. public. traction)	1,456,060	1,456,060	0	0	0	0	0	0	0	0
Total MV Customers	**9,667,688**	**9,244,577**	**4,689**	**16,710**	**5,072**	**147,939**	**12,044**	**33,981**	**202,677**	**0**
Total HV Customers	**8,016,000**	**8,016,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Consumption	**45,397,890**	**44,356,757**	**49,177**	**76,658**	**9,615**	**397,221**	**30,349**	**45,106**	**433,007**	**0**
Market Share (%)	**100.00%**	**97.64%**	**0.11%**	**0.17%**	**0.02%**	**0.90%**	**0.07%**	**0.10%**	**0.98%**	**0.00%**

By eligible meter points (31.12.2014)										
Customer type	**Total**	**PPC SA**	**WATT & VOLT SA**	**GREEK ENVIRONMENTAL & ENERGY NETWORK SA**	**NRG TRADING SA**	**ELPEDISON ENERGY SA**	**VOLTERRA SA**	**PROTERGIA THERMO ELECTRIC SA**	**HERON SA**	**PROTERGIA SA**
Household customers	5,120,291	5,110,296	2,588	540	45	6,181	53	196	392	0
Small Industrial and Commercial customers	1,146,284	1,125,499	2,639	2,026	234	10,796	433	937	3,720	0
Other LV customers (eg, agricultural. public. traction)	308,623	308,623	0	0	0	0	0	0	0	0
Total LV Customers	**6,575,198**	**6,544,418**	**5,227**	**2,566**	**279**	**16,977**	**486**	**1,133**	**4,112**	**0**
Industrial and Commercial customers of MV	8,605	8,012	12	21	25	160	14	75	286	0
Other MV customers (eg, agricultural. public. traction)	1,652	1,652	0	0	0	0	0	0	0	0
Total MV Customers	**10,257**	**9,664**	**12**	**21**	**25**	**160**	**14**	**75**	**286**	**0**
Total HV Customers	**161**	**161**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Customers	**6,585,616**	**6,554,243**	**5,239**	**2,587**	**304**	**17,137**	**500**	**1,208**	**4,398**	**0**
Market Share (%)	**100.00%**	**99.52%**	**0.08%**	**0.04%**	**0.00%**	**0.26%**	**0.01%**	**0.02%**	**0.07%**	**0.00%**

Table 7. Market share of the active suppliers in the interconnected system, by eligible meter points and by volume, per consumer category in 2014

RAE monitors systematically, and with particular concern, the accumulation of consumer debt towards PPC, as it has a significant impact on the full market value chain cash flows, and tries to find effective ways to deal with the problem, while taking into account the social aspects of the phenomenon.

Supplier switching

Following the events of 2012 in the retail market, customer switching in 2014 continued to be very limited, possibly reflecting the negative experience of electricity customers that was combined with the exit of large independent suppliers, but more importantly structural problems of the domestic market, which is dominated by the incumbent supplier. The following table depicts the main figures of supply switching in the interconnected system in 2014:

	Total customers		**Customers having changed supplier**		**% of customers having changed supplier**	
Customer type	**By number of eligible meter points**	**By eligible volume**	**By number of eligible meter points**	**By eligible volume**	**By number of eligible meter points**	**By eligible volume**
Household customers	5,120,291	15,470,478	5.363	9,616	0.10%	0.06%
Small Industrial and Commercial customers	1,146,284	9,016,502	7.138	75,690	0.62%	0.84%
Other LV customers (eg, agricultural, public, traction)	308,623	3,227,222	0	0	0.00%	0.00%
Total LV customers	**6,575,198**	**27,714,202**	**12.501**	**85,306**	**0.19%**	**0.31%**
Industrial and Commercial customers of MV	8,605	8,211,628	278	94,197	3.23%	1.15%
Other MV customers (eg, agricultural, public, traction)	1,652	1,456,060	0	0	0.00%	0.00%
Total MV customers	**10,257**	**9,667,688**	**278**	**94,197**	**2.71%**	**0.97%**
Total LV & MV customers	**6,585,455**	**37,381,890**	**12.779**	**179,504**	**0.19%**	**0.48%**
HV customers	**161**	**8,016,000**	**0**	**0**	**0.00%**	**0.00%**
Total HV, LV & MV customers	**6,585,616**	**45,398,890**	**12.779**	**179,504**	**0.19%**	**0.41%**

Table 8. Switching rate per consumer category in 2014, 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 2014, is considered a dormant market.

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), continuously examines and intervenes with comments on relevant supplier material, including:

- Precontractual offer material
- Tariffs
- Standard terms and conditions of supply contract, with emphasis on the T&C offered to small customers (residential and small commercial)
- Standard bills and payment methods.

The main aim is to ensure transparency in the information provided to consumers and the avoidance of deceptive and abusive terms in contracts offered by the suppliers.

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

Within 2014, RAE exchanged detailed correspondence with each of the Suppliers, regarding RAE's comments and directions on the above contractual documents, especially focusing on, but not limited to, the minimum content of the provisions included in the supply contract, according to the provisions in Articles 15-18 of the Supply Code, the conclusion, entry into force and termination, the specific prerequisites for any amendment of the contract, especially on the adjustment and calculation of tariffs (competitive tariffs as well as regulated tariffs in the electricity bill), the form and content of the electricity bill, mainly insisting on transparency issues and other Supplier's policy and consumer protection issues.

The Suppliers have so far responded to this procedure, which is expected to be completed within 2015. An unofficial translation of the Supply Code can be found on the RAE website[15].

RAE's licensing activity

In December of 2014, RAE's electricity supply and trading registry included twenty-six (26) supply licenses and fifty (50) trading licenses. During the course of 2014:

- Three (3) new supply licenses were issued and another three (3) supply license amendment applications were completed,
- One (1) supply license renewal was issued,
- One (1) existing supply license was revoked, upon RAE's decision regarding non-compliance with the relevant provisions of Law 4001/2011,

[15] http://www.rae.gr/site/file/system/docs/misc1/14062013

- Four (4) supply license amendment applications were submitted within 2014, all of which were completed during the course of 2015,
- Three (3) new trading licenses were issued, one (1) was revoked following a request by the company due to liquidation, and one (1) license amendment was completed within 2014,
- Six (6) trading license amendment applications were submitted within 2014, all of which were completed during the course of 2015.

The relevant tables for the active supply and trading licenses at the end of 2014 are presented in Appendix I.

Price monitoring

This section concentrates on the prices offered by PPC in 2014, given that, for this particular year, PPC's market share in retail was over 97%. The PPC (average) prices by consumer category are presented in the table below, broken down by tariff element.

In the path to remove remaining cross subsidies in the PPC retail tariffs, amendments were made in July 2014 for the following categories:

- Increase of around 20% in prices for residential consumers with a consumption of 0-800 kWh/4-month period. In effect prices were increased to reach the same level of prices for the remaining residential consumers with a consumption up to 2000 kWh/4-month period.
- Small decreases to the commercial LV tariffs.

Prices have been fully liberalized since 01.07.2013. The only regulated tariffs are those under Public Service Obligations, i.e. the social tariffs and the prices offered under the Supplier of Last Resort and Universal Service Supplier services (see Section 3.4.6).

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.

	€/MWh	Energy	TUoS	DUoS	PSO	Other	Total	Δ(2013-2014) Energy only	Δ(2013-2014) Total
MV Commercial	2010	82.14	3.92	6.09	8.35	0.77	**101.26**	-2%	-2%
	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**		
	2014	80.10	3.61	6.00	17.90	0.44	**108.05**		
MV Industrial	2010	63.13	5.55	7.15	6.58	0.77	**83.18**	-5%	-5%
	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**		
	2014	79.44	4.21	6.47	6.91	0.44	**97.47**		
MV Agricultural	2010	36.90	0.00	0.00	3.24	0.77	**40.91**	8%	7%
	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**		
	2014	70.14	0.00	0.00	5.62	0.44	**76.20**		
LV Commercial	2010	94.28	16.01	16.51	11.51	0.83	**139.14**	1%	0%
	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**		
	2014	101.43	6.16	23.22	18.24	0.46	**149.51**		
LV Industrial	2010	79.03	10.39	23.66	10.34	0.83	**124.25**	3%	2%
	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**		
	2014	102.21	6.01	24.82	18.24	0.48	**151.75**		
LV Agricultural	2010	43.43	0.00	0.00	3.70	0.83	**47.96**	4%	4%
	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**		
	2014	69.06	0.03	0.08	7.07	0.48	**76.72**		
LV Pub. Lighting	2010	65.76	2.66	22.36	7.65	0.83	**99.27**	2%	2%
	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**		
	2014	81.81	3.89	20.23	13.71	0.46	**120.10**		
LV Residential	2010	67.78	5.89	22.43	8.06	0.83	**104.99**	2%	1%
	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**		
	2014	89.02	5.40	20.28	13.38	0.45	**128.53**		

Table 9. Average PPC retail electricity prices and tariff elements per consumer category (excluding taxes and levies), in €/MWh, for the 5-year period 2010-2014

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 residential and small commercial customers under the various tariffs on offer (both from PPC and from the active alternative suppliers). RAE continuously monitors suppliers' pricing information in order to ensure availability and clarity of information, to the benefit of final consumers, while the retail domestic market evolves and matures further.

Price-comparison tool

In order to provide clear price information for residential 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 estimates and publishes on a regular basis on its website the final electricity bill (€) for various consumption levels, for residential and small commercial consumers, and for all active electricity suppliers. RAE publishes a simple look-up table per company, with which the consumer can 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 best offer/ company very much depends on the particular consumption level and consumer category.

3.2.2.2. Tariff deficit

There is no tariff deficit regarding the competitive elements of electricity bills (i.e. which cover the activities of the wholesale market and retail business). Also, regarding network use of system costs, any revenue under-recovery is incorporated in the tariffs of following years. For PSO and RES levies, the case is different.

For the PSO levy, although the methodology foresees the same mechanism that applies for network tariffs (i.e. transfer of past under-recovery to tariffs of following years), this has not been implemented in practice as prices are set by law as a transitional measure following a relevant decision by the High Court. Therefore, although RAE has approved the total cost of compensation for the provision of PSOs up to and including the year 2013 (see section 3.4.5), this has not been reflected in the PSO levy.

Regarding the RES levy, the levels applied in the past were not sufficient to cover the total cost of the mechanism for supporting renewable generation (i.e. the feed-in tariff system). A deficit was created, which peaked at around €550m in 2013, but has since decreased significantly and is expected to become zero by the end of 2015.

3.2.3 Non-interconnected islands

All Greek Non-Interconnected Islands (NNIs)[16] 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 NII electricity production per year (not exceeding 15-20% for each NII).

In February 2014, RAE adopted the Operation Code for Non-Interconnected Islands (NII Code, Decision 39/2014, National Gazette B '304 / 02.11.2014), which largely completed the secondary legislation that regulates the operation and the transactions at the NII electrical systems, as provided for by Law 4001 / 2011. Therefore, with the NII Code in effect, the NII markets may be open to competition, for both the production and the supply activities.

In addition, on August 14, 2014, the European Commission granted to Greece (Decision 2014/536/EC) derogation from the provisions of Chapters III and VIII of Directive 2009/72/EC for the NIIs. This Decision followed the relevant applications of the Greek State in December of 2003, based on article 26 of Directive 2004/54/EC, and then in January of 2012, based on article 44 of Directive 2009/72/EC.

According to the Commission's above Decision:

- All NIIs except Crete are recognized as micro isolated systems according to art. 2 par. 27 of the Directive 2009/72/EC, while Crete is characterized as a small isolated system according to art. 2 par. 26 of the same Directive.

- Regarding conventional power generation:

    - The Commission acknowledges the distinct nature of the islands in terms of power production, i.e. that substantial problems exist for the operation of conventional power plants within the NII isolated systems. Derogation from Chapter III of Directive 2009/72/EC is granted for the refurbishing, upgrading and/or expanding of PPC's existing power plants until 1.1.2021, but not for new capacity. However, should the authorisation procedure for new capacity fail to provide for the satisfactory authorisation of new capacity for the isolated systems on the NIIs, the Greek authorities may consider using the provisions of Article 7(3) of Directive 2009/72/EC also for new small conventional capacity. Such new small conventional capacity may for instance include temporary generation capacity that may be made available on a long-term basis without permanent attribution to a specific location.

[16] 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 the Aegean Sea (only two of these islands are in the Ionian Sea).

    - Derogation from the provisions in Chapter III of Directive 2009/72/EC cannot be granted for Crete.

- Regarding electricity supply:

    - Derogation from market opening is granted for a period of 2 years after the entry into force of the NII Code, i.e. until 17 February 2016, in order for the registers, that are a necessary requirement for market opening, to be established, that may be extended to 5 years after the entry into force of the NII code, i.e. until 17 February 2019, for any of the NII isolated system. However, as the derogation can only be justified where substantial and material problems remain for market opening that are directly attributable to the non-completion of the infrastructure investment programme on the NIIs, it should be verified yearly whether such problems persist on a given NII isolated system.

    - By 17.02.205, the greek authorities shall prepare the infrastructure investment programme for each one of the NIIs separately, giving priority to Crete and Rhodes, and in accordance with the relevant provisions of the NII Code.

- The derogation decision takes effects from the date of notification of the initial application, i.e. from 5 December 2003.

3.3. Security of supply

3.3.1 Monitoring the balance of supply and demand

Table 10 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 2014 had a slight decrease of 1%, compared to 2013. 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 2014 was 50.23 TWh, showing a smaller decline of less than 0.6%, with respect to 2013 (50.71 TWh).

	2007	2008	2009	2010	2011	2012	2013	2014
Electricity consumption excluding pump storage (GWh)	55,253	55,675	52,436	52,329	51,492	50,289	46,451	**45,953**
Peak load (MW)	10,610	10,393	9,828	9,902	10,055	9,894	9,161	**9,263**

Source: HTSO

Table 10. Energy and peak power demand in the interconnected system, for the 8-year period 2007-2014

It is worth noting that, for the first time, the peak load was not observed in July, but on the 19th hour of December 31, 2014, due to bad weather conditions. For comparison to the previous years, the peak load in July 2014 was 8,667 MWh.

Fuel Shares

The decline in electricity consumption during 2014, along with the sharp increase of imports, significantly depressed electricity from conventional technologies. More specifically, the lignite production decreased by 2.2% (-522 GWh) in 2014 compared to 2013, falling to 22.7 TWh, compared with 23.2 TWh the previous year. The production from gas-fired plants was limited to 6.3 TWh, compared to 12.1 TWh in 2013, showing a sharp fall of 43%. Hydropower production also dropped significantly, falling to 3.9 TWh compared to 5.6 TWh in 2013. Production from renewables and CHP remained almost unchanged at 8.6 TWh, while oil production in the Interconnected System was 1 GWh (in the context of testings for the commissioning of new units) against zero level in 2013. Overall, domestic production decreased by 14.4%, reaching 41.6 TWh versus 48.6 TWh in 2013.

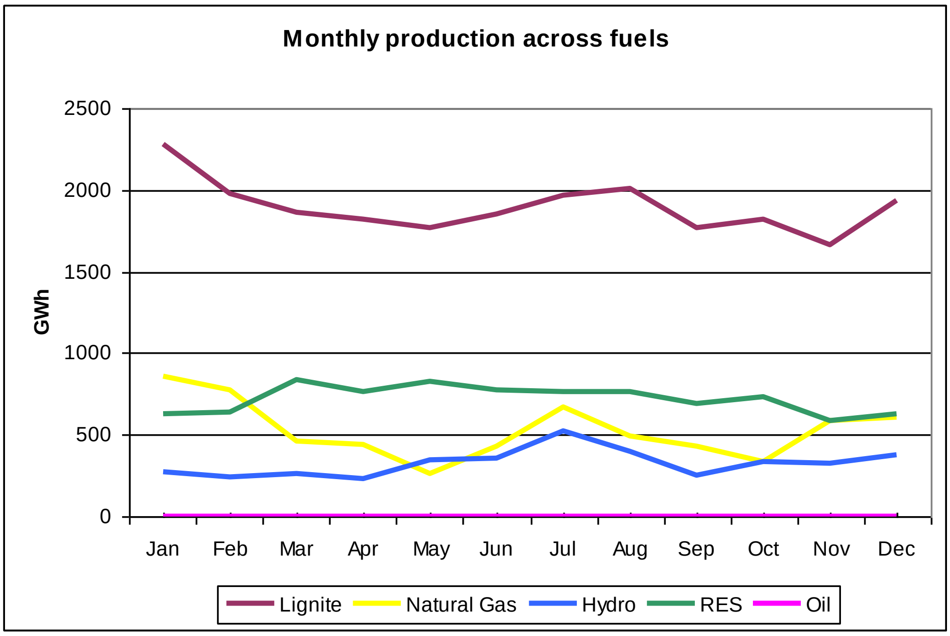


Figure 12. Production allocation across fuels at the monthly level, during 2014

Figure 12 shows the monthly variation of actual production by technology, reflecting the seasonal changes in demand, as well as the influence of stochastic factors, but also of regulatory measures. In general, the lignite production showed a smooth profile, following the fluctuations of demand, ranging between 1664 and 2280 GWh monthly. Noteworthy is the sharp decline in lignite production in November 2014 due to maintenance and technical problems at several plants, including emergencies, such as fire in Ptolemaida that set off Units 3 and 4.

The production from gas plants showed a significant decline in 2014, as well as strong volatility, with monthly levels between 262 and 856 GWh. The production decreased significantly from March 2014 onwards, temporarily boosted in July due to the strike of PPC personnel, and recovered only in the last two months of the year. The latest development is partly linked to the pursuit of natural gas producers to consume their contractual amounts, in order to prevent their exposure to the take-or-pay clause, in case it was activated by DEPA. It is also noted that the complete abolition of the Cost Recovery Mechanism as of 01.07.2014 led to a decrease of production of independent producers, since the dispatching of the units was since accompanied by insufficient cost recovery during the hours the SMP did not reflect the variable cost of the most expensive unit dispatched, but instead stayed well below this, resulting in significant money losses.

Hydropower production was in general at low levels because of limited inflows, ranging between 234 GWh in April and 523 GWh in July 2014. The production of renewable energy, as a stochastic quantity related to climatic factors, showed the expected seasonal variations, ranging between 586 GWh November and 841 GWh in March 2014, maintaining high levels between April and October.

A critical parameter is the surge of the interconnections balance by 2.1 TWh in 2013 to 8.8 TWh in 2014 (see Section 3.1.3.1), which reflects the lower prices prevailing in neighbouring countries. Characteristically, the months of July, August, November and December 2014, the interconnection balance was in the order of 1 TWh (see Figure 13).

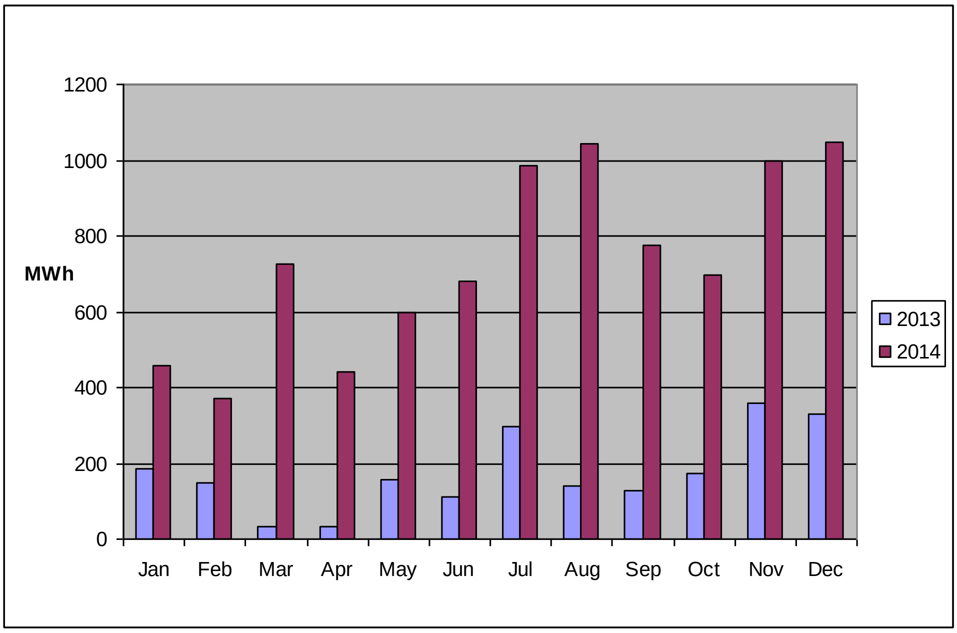


Figure 13. Monthly net imports during 2013 and 2014

Figure 14 depicts the annual share of fuels and net imports.

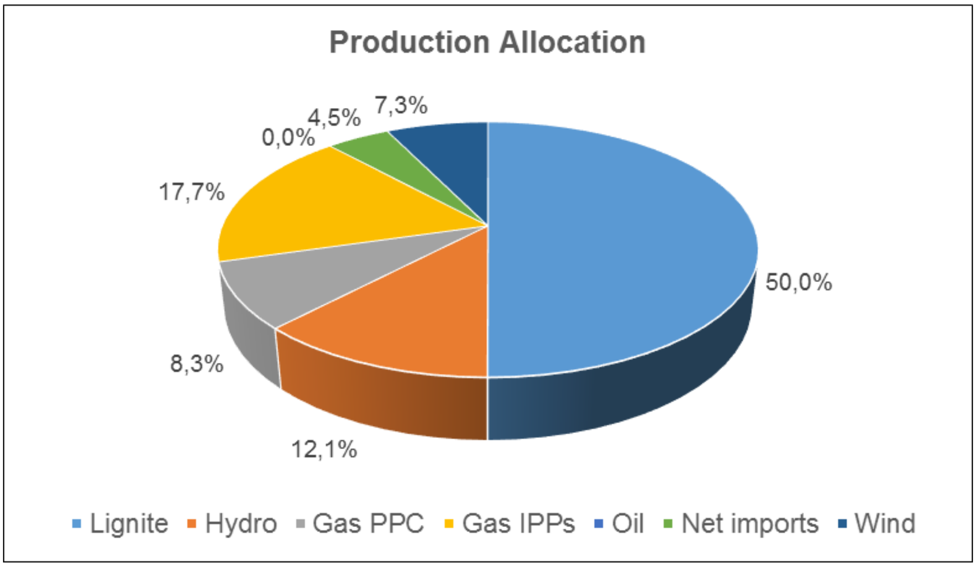


Figure 14. Annual shares of fuels and net imports

Finally, Table 11 depicts the changes in fuel mix in 2014, compared to 2013. 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.

	2014 (TWh)	2013 (TWh)	% difference
Lignite	22.71	23.23	-2.24
Fuel Oil	0	0	
Natural Gas	6.34	12.15	-47.82
Large Hydro	3.91	5.64	-30.67
RES	4.19	3.38	23.96
Net Imports	8.80	2.10	319.05
Total	**45.95**	**46.50**	**-1.18**

Table 11. Change in fuel-mix generation between 2013 and 2014 in the interconnected system

Installed capacity

During 2014, the market concentration in the field of conventional production increased marginally due to the entry of the new hydropower plant PPC, Hilarion, of 155 MW, which was put into trial operation on 15 February 2014. Thus, in terms of installed capacity, PPC's share of total conventional technologies (except RES) was 80.6%, against 80.4% in 2013. Note that the concentration of production than conventional technology sector had also strengthened in 2013, with the commissioning of the PPC gas unit Aliveri V (420 MW). The share of PPC to the total installed capacity, including renewables, decreased to 60.3% in 2014 from 60.5% the year before, as the increase of RES capacity outweighed the added strength Hilarion.

It is also worth noting that, in the interconnected system, the total installed capacity of the gas units now, for the first time, exceeds the installed capacity of lignite plants. This development is the result of strong investment incentives provided, since 2006, through the Capacity Adequacy Mechanism, in order to tackle the serious power deficit loomed at the time, before the onset of the economic crisis, as well as of the State decision not to invest in coal-fired units. The phasing out of obsolete lignite plants is expected, in the medium term, to significantly influence the mix of electricity production.

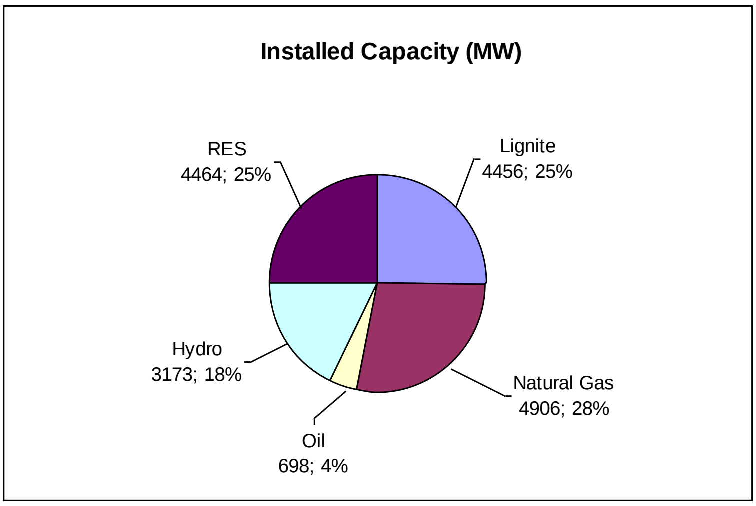


Figure 15. Installed capacity per fuel type in the interconnected system, at the end of 2014

	Ownership	Installed Capacity (MW)	Total Production (GWh)	Capacity Factor
Lignite	**PPC**	**4456**	**22707**	**58.17%**
Oil	**PPC**	**698**	**1**	**0.02%**
OCGT	PPC	339	0.4	0.01%
	Heron Thermoelectric	148	3.1	0.24%
	Total	**487**	**3.5**	**0.08%**
CCGT	PPC	1998	3990	22.80%
	Elpedison	799	965	13.79%
	Heron Thermoelectric	422	602.8	16.31%
	Protergia (Mytilineos)	433	454.4	11.98%
	Korinthos Power (Mytilineos + Motoroil)	434	324.3	8.53%
	Total	**4086**	**6336.5**	**17.70%**
Large-scale CHP	Alouminio (Mytilineos)	**334**	**1166.3**	**39.86%**
Total Thermal		**10061**	**30214.5**	**34.28%**
Large Hydro	**PPC**	**3173**	**3905**	**14.05%**
Small Cogeneration	**IPPs**	99	159	18.33%
Wind	**IPPs (mainly)**	1978	3689	21.29%
Small Hydro	**IPPs (mainly)**	220	701	36.37%
Biofuels – Biomass	**IPPs (mainly)**	47	207	50.28%
PVs & **PVs on buildings**	**IPPs (mainly)**	2221 375	3359 470	17.26% 14.31%
Total Renewables (Grid + Network)		**4940**	**8585**	**19.84%**
TOTAL		**18174**	**42704.5**	

Sources: ADMIE and LAGIE

Table 12. Installed capacity and capacity factor, by fuel and ownership, at the end of 2014

3.3.2 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 2014 to RAE, a Generation Adequacy Report for the period 2015-2024. 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, which was extended compared to the previous year's study from seven to ten years' time.

The 2014 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. For the first time and given the economic conditions in Greek power market, also scenarios for unit economic retirement were taken under consideration.

Two approaches, namely deterministic and probabilistic, were applied to calculate a series of reliability indicators based on hourly system simulations projecting the system to the future following various scenarios about demand and supply The indicators addressed issues of concern regarding generation adequacy in the future, including capacity adequacy and flexibility adequacy of the system, the latter being increasingly required due to developing variable renewables. In addition, the study reported on reliability indicators also by applying the standard approach of ENTSO-E (European Network of Transmission System Operators for Electricity).

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 600 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 16,82%) 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. Moreover, according to Decision 2014/536/EE of the European Commission, exemption has been granted for renovation, upgrading and expansion of thermal units on non-interconnected islands, in order to address security of supply issues, with special focus on the necessity of interconnections, which are anyway included in the medium-term planning of ADMIE.

3.4. Consumer protection

3.4.1 Compliance with the Directive provisions on consumer protection and consumption data (Annex 1, Articles 37(1)(n)&(p))

Articles 37(1)(n) and 41(1)(o) of Directive 2009/72/EC require that the Regulator, if necessary in collaboration with other Authorities, guarantee that the consumer protection measures taken, including those in Annex 1, are effective and applied. Table 13 illustrates the implementation status in Greece of the measures set out in Annex 1.

Directive measure		Implementation status
Par. 1(a)	*"Customers have a right to a contract with their electricity supplier that specifies a series of aspects".*	This obligation is covered by the Electricity Supply Code, which sets out the information that must be provided to the customer before the conclusion of a contract and the main clauses that must be included in a contract. The same Code also requires that the customer must be provided with the contract in printed form. With regards to the services and the service quality levels offered, they must be available to consumers through the Services Leaflet which is published on the Supplier's site. Currently compensation schemes, in case contracted service quality levels are not met, are not offered by Suppliers.
Par. 1(b)	*"Customers are given adequate notice of any intention to modify contractual conditions and they are informed about their right of withdrawal when the notice is given."*	The Electricity Supply Code requires that customers receive 60 days of notice prior to the application of the modifications to contractual terms, with the exception of price modifications where customers can be informed with the next bill after the price change. In any case, customers have the right to withdraw from the contract at no cost if they do not agree with the new terms.
Par. 1(c)	*"Customers must receive transparent information on applicable prices and tariffs and on standard terms and conditions in respect of access to and use of electricity services."*	The Electricity Supply Code stipulates that contracts must contain a section which clearly summarizes the costs borne by customers for the supply of electricity.
Par. 1(d)	*"Customers are offered a wide choice of payment methods."*	This obligation is derived from the Electricity Supply Code with the additional term that at least one payment method offered by each Supplier must be cost free.
Par. 1(d)	*"General terms and conditions shall be fair and transparent, and given in clear, comprehensible language. Customers shall be protected against unfair or misleading selling methods."*	The Electricity Supply Code contains the minimum "Principles of information and contact with clients" that cover all of the required obligations. Suppliers are obliged to introduce a Code of Contact based on at least the above referred principles.
Par. 1(e)	*"Customers are not charged for changing supplier."*	Supplier switching is free of charge according to the Electricity Supply Code.

Par. 1(f)	*"Consumers benefit from transparent, simple and inexpensive procedures for dealing with their complaints."*	The Electricity Supply Code stipulates that Suppliers must operate a Consumer Service department that handles customer complaints according to at least the minimum "Standards of complaints handling" included as a separate section of the Code. Written complaints / enquiries must receive a first or final response within 10 working days.
Par. 1(g)	*"Consumers benefit from information about their rights regarding universal service (electricity customers) of their right to be supplied at reasonable prices."*	The relevant information for consumers can be found on the Regulator's website (www.rae.gr).
Par. 1(h)	*"Consumers can have at their disposal their consumption data and shall be able to allow any registered supply undertaking to access, by explicit agreement and free of charge, their metering data."*	Consumers are adequately informed of actual consumption, monthly or every four months through their bills. In addition an application form is available at their Supplier's site and/or customer service centers, to request for historical consumption data.
Par. 1(j)	*"Consumers receive a final closure account following any change of supplier, no later than six months after the change of supplier has taken place."*	Energy Suppliers are obliged to issue a final closure account, within 6 weeks after the contract termination/change of supplier.
Par. 2	*"Member States shall ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity and natural gas supply markets."*	In the electricity sector, the timeframe for the roll-out of smart meters is set by Law no. 4001/2011 for the replacement of at least 80% of old meters by 2020.

Table 13. State of implementation of measures set out in Annex 1 (Directive 2009/72/EC)

3.4.2 Ensuring access to consumption data

Regulatory Decision in Gov. Gaz. no. B' 82/27.1.2006 ("Guide for management and periodic settlement of DSO measurements") requires that the DSO must collect consumption measurements at least every 6 months. In practice, the frequency of recording consumption data is every four months for LV customers. Consequently, small consumers are informed about their actual consumption at least every four months through their supplier bill. Furthermore, consumers can have access to historical consumption data through a simple application registered to their Supplier.

3.4.3 Consumer empowerment

Amongst the main priorities of the Regulator in 2014 was consumer's protection, regarding easy access to significant information on energy developments and the upgrading of the quality of electricity distribution services.

3.4.3.1. *Access to information*

In order to strengthen the consumer's position in the retail market, in 2014, the Regulatory Authority, in cooperation with the competent department of the Ministry of Administrative Reform and E-Governance, prepared and distributed to consumers 228.000 pieces of three different thematic brochures through all the "Single Point of Contact" centres located in the area of Attica that represent at least 40% of total population. The aim was to inform energy consumers on their rights related to electricity supplier switching, out of court dispute resolution and the low electricity tariff for vulnerable consumers. Of course the electronic form of the brochures can be found also on the Regulator's site.

Additionally to the above, the Regulator's site offers a wide selection of information, guidelines and advices on important topics to consumers for their empowerment and protection.

3.4.3.2. *Quality of DSO Services*

Another key direction of RAE was related to the improvement of the customer services provided by the electricity DSO, DEDDIE S.A. After at least one year of negotiation, the DSO's program of Guaranteed Distribution Services with individually guaranteed standards was redesigned, upgraded and came into force in April 2014, by adapting the following main modifications:

1. In addition to the ten services already included in the previous program, the following four new guaranteed services have been introduced:
    1) The construction of a new electricity supply that requires simple network extension, within 40 working days.
    2) Electricity interruptions for medium voltage consumers due to network failure or planned interruptions should be restored within a maximum of 12 hours.
    3) Meter inspection after a client's request is concluded within 20 working days.
    4) Written consumer complaints about the quality of voltage, are replied within 30 working days.
2. The penalty of 15 € for exceeding the deadline set for each service, shall be credited to consumers automatically through their bills, without the previous requirement of submitting a written application to the DSO. In the case of medium voltage clients the penalty for failed planned interruptions recovery within 12 hours is 150 €.

Based on the annual data provided by the DSO, on the minimum quality requirements for individual users, the Guaranteed Distribution Services program has been evaluated by the Authority for 2013:

Service	Guaranteed level	% of failed cases				
		2009	2010	2011	2012	2013

Instrumentation - connection of meter	3	Working days	12.23%	11.34%	10.25%	13.58%	12.44%
Connection offer with network extension	25	Working days	5.94%	3.89%	3.93%	4.86%	3.68%
Reconnection after client's request	2	Working days	3.16%	2.89%	3.39%	3.25%	3.47%
Reconnection after settlement of debt	Same day		1.96%	1.58%	1.58%	1.59%	1.80%
Intervention for fuses replacement	4	Hours	0.75%	1.50%	1.48%	1.56%	1.77%
Connection offer for simple works connection	15	Working days	1.55%	1.68%	2.97%	4.52%	1.35%
Observance of appointment time	3	Hours	9.46%	5.92%	2.89%	2.05%	1.20%
Response to written requests-complaints, that require visit	15	Working days	1.66%	1.11%	0.79%	0.60%	0.66%
Response to written requests/complaints, without visit	10	Working days	0.54%	0.26%	0.11%	0.12%	0.64%
Construction of simple connection	30	Working days	0.51%	0.38%	0.53%	0.54%	0.46%
Total No of applications			**807,527**	**808,513**	**880,673**	**912,692**	**848,430**
Total % of failure on GS			**3.76%**	**3.33%**	**3.22%**	**3.20%**	**3.04%**

Table 14. Performance of Guaranteed Services (GS): Consolidated figures, 2009-2013[17]

There is a decreasing trend during 2009 – 2013 on the total percentage of non-performed cases identified by the DSO. In terms of individual services, there has been a significant improvement in the ratio of performed cases nationally for the following two services, Observance of appointment time, Connection offer with the requirement for network extension.

3.4.4 Vulnerable Customers and Energy Poverty

In 2014, RAE introduced targeted measures in order to mitigate energy poverty. In addition to the Social Residential Tariff presented in detail in the 2014 National Report, that has been applied since 01.01.2011 to five (5) categories of vulnerable customers (families with 3 children, families with low income, invalid consumers, long term unemployed consumers and people living on medical mechanical support), the following additional measures were introduced:

1) The Social Residential Tariff has been extended to include the short-term unemployed consumers (those who can prove to be unemployed for more than three (3) months) and

[17] The evaluation of the performance of the new program of Guaranteed Distribution Services for 2014 will be available later in 2015.

the consumers that have been disconnected from the network in the past, due to their inability to pay their electricity debts and they rely on the social structures of the Church and municipalities for their food.

2) In case of a public alert for short-term emission reduction measures from combustion in order to reduce the atmospheric pollution, the electricity consumption (competitive part) for Social Residential Tariff consumers, is free of charge during double the time of the above short term measures.
3) A low rate Social Solidarity Tariff was introduced to reduce the expenses for electricity of certified non profitable institutions that provide social care services.

At the end of 2014, 522,760 consumers were under the Social Residential Tariff (KOT) scheme (see Table 15), compared to 412,883 consumers, which was the corresponding number at the end of 2013 (an increase of 26.6%). Also, at the end of 2014, 19,996 consumers were under the Large Family Tariff scheme, showing a reduction of 4.4% in comparison to the end of 2013, when 20,925 customers were under the same scheme. Since the total number of residential consumers for 2014 throughout the country amounted to 5,746,273, compared to 5,712,515 in 2013, the estimated number of residential consumers who were under both the Social Residential Tariff and the Large Family Tariff schemes, at the end of 2014, amounted to 9.4% of all household customers, an increase of 1.8% compared to 2013 (7.6% the corresponding number for 2013).

Table 15 presents the number of customers and the metered electricity consumption to which the KOT tariff prices applied in 2014, while Table 16 presents the number of customers and total electricity consumption of the Residential Social Tariff.

Social Residential Tariff Category		Connection Type	Number of meter readings	Energy Consumed (MWh)	Number of Customers
KOT I	Category 1	Single Phase	722,437	666,585	**358,513**
		3 Phase	109,521	103,782	
	Category 2	Single Phase	49,783	62,099	**77,004**
		3 Phase	16,883	21,457	
KOT II	Category 3	Single Phase	116,616	111,884	**52,399**
		3 Phase	26,225	25,492	
	Category 4	Single Phase	173,212	181,102	**27,395**
		3 Phase	32,355	34,401	
	Category 5	Single Phase	20,840	37,671	**7,449**
		3 Phase	3,727	6,735	
Total			**1,271,599**	**1,251,208**	**522,760**

Source: DEDDIE (DSO)

Table 15. Household customers under the Social Residential Tariff at the end of 2014

Year	Number of customers	Total Energy (kWh)

2011	247.666	548.006.275
2012	250.568	404.333.772
2013	412.883	1.582.503.518
2014	522.760	1.251.208.124

Source: DEDDIE (DSO)

Table 16. Social Residential Tariff: number of customers and total consumption, 2011-2014

3.4.5 Public Service Obligations

Public Service Obligations (PSOs), which have been set by Ministerial Decrees since 2007 (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) ,

while with article 17 of law 4203/2013, the Tariff of Solidarity Services was also set as a PSO.

Suppliers that offer the above-mentioned services should be compensated completely, while if, by any chance, deficit or surplus occurs from the provision of such services, the respective amounts should be included in the calculation of the PSOs of the following years. The methodology for the calculation of the annual return to suppliers for the provision of PSO services, as well as the cost for the provision of these services by suppliers, are determined by RAE according to the provisions of article 56 paragraph 2 of law 4001/2011.

In June 2014, RAE issued Decision 356/2014, with which it estimated the annual compensation to suppliers who provided PSO services in 2012 and 2013. More specifically, the decision determined:

a. the compensation to PPC as the sole supplier of the Non-Interconnected Islands (NII) for the application of a uniform tariff for all consumers for the years 2012 and 2013 based on the methodology developed by RAE. The amount of compensation to PPC was estimated at € 784 m. and € 771 m. for 2012 and 2013 respectively.

b. the compensation to PPC for the provision of the special tariff for large families (€ 11.5 m. for year 2012 and € 10.9 million for year 2013).

c. the compensation to suppliers for the provisions of the Social Residential Tariff (KOT), taking into account the actual data provided by suppliers that offered the Social Residential Tariff throughout 2012 and 2013 and on the basis of a) the existing methodology, b) the tariffs that were in effect during that specific time period, as well as c) the reference competitive price element for years 2012 and 2013. The amounts for 2012-2013 are as follows:

Year	Company	Annual Compensation for Social Residential Tariff (€)
2012	PPC S.A.	15,092,094
	WATT & VOLT S.A.	709
2013	PPC S.A.	33,633,251
	WATT & VOLT S.A.	1,905
	ELPEDISON S.A.	1,493

Table 17. Compensation for the provision of the Social Residential Tariff during 2012-2013

The total amounts of Public Service Obligations for the years 2012 and 2013, according to RAE Decisions 356/2014 and 357/2014 respectively, are presented in the following table:

	2012 (€)	2013 (€)
PSO for the provision of a uniform tariff to the consumers connected to the distribution network in the non-interconnected islands	783,974,665	771,200,756
PSO for consumers/families with more than three (3) children	11,480,000	10,900,000
PSO for the provision of the Social Residential Tariff	15,092,803	33,636,648
PSO for Supplier of Last Resort (SoLR) services	33,164,433	
Total PSO return	**843,711,901**	**815,737,404**

Table 18. Compensation for the provision of PSOs during 2012-2013

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

In 2013, RAE proceeded with the assignment of the Supplier of Last Resort (SoLR) and the Universal Service Supplier (USS) services' to PPC (who was, in fact, the only supplier who submitted an expression of interest for the provision of the services) issuing Decisions, No. 114 and No. 115/2013, respectively. Under law 4001/2011:

The role of the SoLR is to temporarily supply customers who lost their previous supplier due to:

- Planned exit of supplier: a supplier exits the market by its own free will.
- Unplanned exit of supplier: a supplier exits the market due to insolvency.

- Serious breach of license: a supplier's license is revoked, following repeated serious breaches of its license conditions.

The SoLR supply period cannot exceed three (3) months, during which the customers are obliged to conclude a contract with a supplier of their own choice.

The Universal Service Supplier is a more permanent service to supply customers who do not choose a supplier of their own:

- either because they have neglected it or are unable to negotiate with such a supplier, or
- they are unable to conclude a new contract with a supplier, e.g. because of their poor payment record.

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

RAE Decisions 114 and 115/2013 on the assignment of the services to PPC following an open invitation for expressions of interest, also approved the application of premium percentages on the regular tariffs offered by PPC to consumer categories for the first year, 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).

By virtue of RAE's decisions 673 and 674/2014, respectively, the above tariffs remained stable for the second year of the provision of the above services.

The services of PPC as SoLR were not activated during 2014. Statistics on the USS services are presented below:

Date	Residential Connections	Non- Residential Connections	Total Connections
March 2013	10,673	14,183	24,856
December 2013	9,965	12,465	22,430
December 2014	8,487	10,649	19,136

Source: PPC

Table 19. Number of customers, under the Universal Service Supplier arrangements, for the period March 2013-December 2014

	2013	**2014**

Residential Use	56,400,804	41,761,017
Non Residential Use	104,889,494	74,619,955
Total	**161,290,298**	**116,380,972**

Source: PPC

Table 20. Total customer consumption (kWh), under the Universal Service Supplier arrangements, for the period 2013 and 2014

The number of customers under the arrangements of USS is reducing. Most of these customers were initially included under the USS automatically, following the expiration of the 3 month period under SoLR services, which had been activated after the default of four independent electricity suppliers in 2012. Apart for these consumers, roughly an additional 4,300 connection points entered the service, mainly due to disconnections caused by bad debts. At the same time, about 10,300 connections left the service and re-entered contracts with electricity suppliers, probably due to the higher cost associated with the USS (a 12% surplus is added to regular PPC tariffs).

3.4.7 Statistics on customer disconnections and new connections

RAE monitors customer disconnection and reconnection data provided by the DSO (DEDDIE). Table 21 displays the total number of disconnections that occurred during 2014 due to a) payments in arrears and b) other reasons, as well as the respective number of reconnections due to a) settlement of arrears or b) other reasons.

Total number of electricity disconnections decreased by more than 33% in 2014, compared to 2013. The number of electricity disconnections due to overdue amounts (arrears) declined by almost 40% in 2014, compared to 2013, and, correspondingly, the number of disconnections due to reasons other than overdue amounts (arrears) declined by around 26% for the same time period. This decrease in the total number of disconnections in 2014 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 47% of the total number of disconnections and 42% of the total number of reconnections in 2013, reflecting the severe impact of the country's economic recession on customer's ability to pay. 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.

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	24,935	168,750	189,469	121,428	171,496
Total LV & MV customers in the Non-interconnected System	3,396	18,671	19,557	13,950	18,240
Total LV & MV customers	**28,331**	**187,421**	**209,026**	**135,378**	**189,736**

Table 21. Statistical data on number of disconnections and re-connections of LV and MV customers in 2014

3.4.8 Handling of consumer complaints

Consumers are free to submit enquiries and complaints to RAE in writing through personal visit to the offices, by sending an email to info@rae.gr, by post or by fax. They can also call Regulator's telephone centre for simple information enquiries.

During 2014, RAE also introduced on its site an online electronic form for consumer complaints and enquiries, which can be filled in and automatically sent to RAE together with all necessary supporting documents.

The total number of consumer reports (complaints and enquiries) submitted to RAE during 2014 is 303, revealing a gradual decline in absolute numbers since 2012, remaining however at higher levels compared to the previous of 2012 figures. The vast majority of consumer reports received by RAE were complaints and disputes (85.8%) rather than enquiries/information requests.

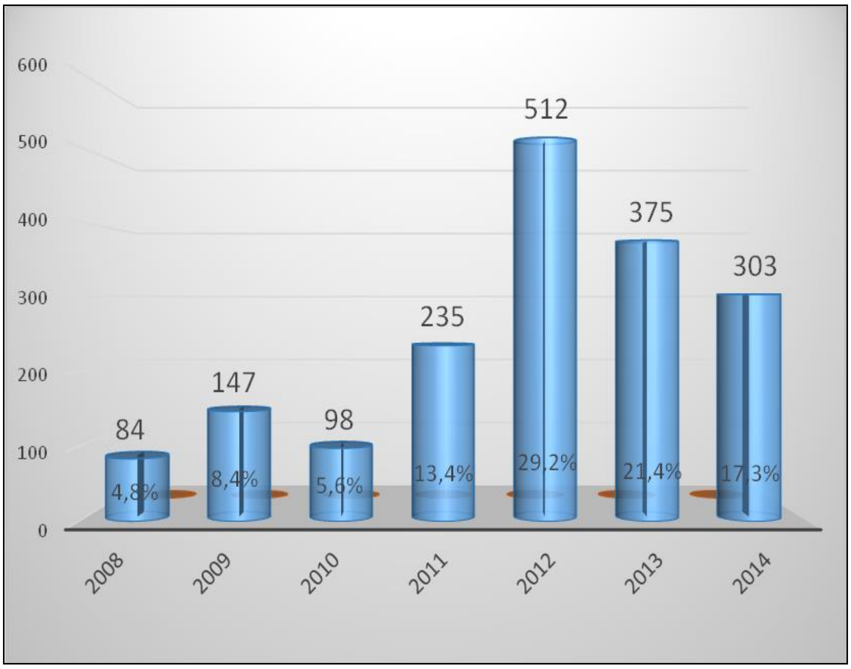


Figure 16. Number of written consumer reports registered to RAE by year

Concerning Suppliers' issues, 2014 percentage number of consumer reports has declined slightly, approximately 4%, reaching a rate of 68.0% instead of 72.2% in 2013. As shown in Figure 17 below, the consumer reports concerning Suppliers' issues were focused primarily on cost and electricity expenses matters, revealing the country's continuing economic crisis. In particularly, consumers seem to be now more cautious in paying their invoices than before. These consumer reports included complaints about:

1. Invoicing/billing (59.2%), which is related to the following issues:

    a) transparency/clarity of the bill with respect to listed charges and rates (24.2%),

    b) disputed calculation of charges (12.5%),

    c) requests for more favorable payment settlements of accumulated electricity debt (9.7%), and

    d) excessively high bills (6.3%)

2. Prices and rates (19.9%), which is related to the following issues:

    a) insufficient information on the calculation of charges (6.8%),

    b) disputed calculation of either supply charges or other surcharges

3. Favorable terms on debt payments

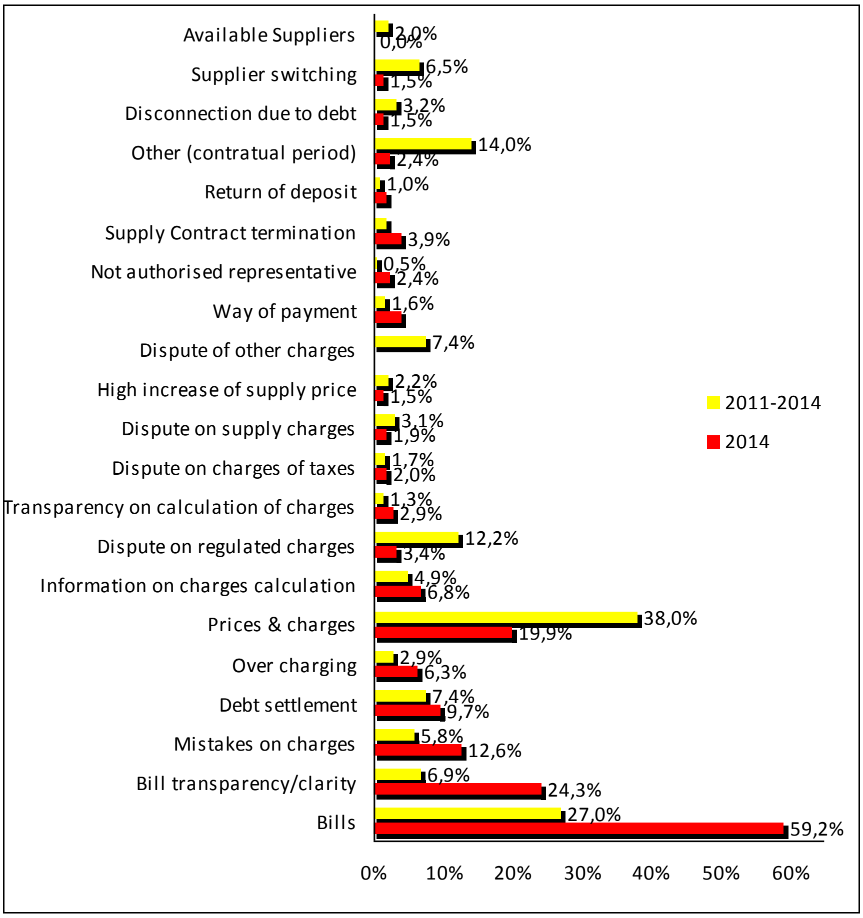


Figure 17. Complaints concerning Suppliers by thematic category

Concerning Distribution Network issues, 97 consumer reports were filled in 2014. They are presented in Figure 18 below, in comparison to the corresponding consumer reports of years 2011 to 2014. There is a 7% increase in reports concerning the DSO, reaching a rate of 21.8% in 2014 instead of 14.9% in 2013. According to this, the percentage of complaints on disputed/fault meter/consumption readings (10.3%) resulting to high bills, has doubled compared to the previous years. This is an observation that requires further attention and investigation, as it affects the reliability of the DSO and burdens the financial situation of consumers. The rest of consumer reports are related to the constantly recorded complaints regarding the financial compensation for damaged electric appliances after unplanned electricity interruptions, voltage fluctuations (9.3%), delays on disconnection request (5.2%), rejection of reconnection requests due to no payment (4.1%).

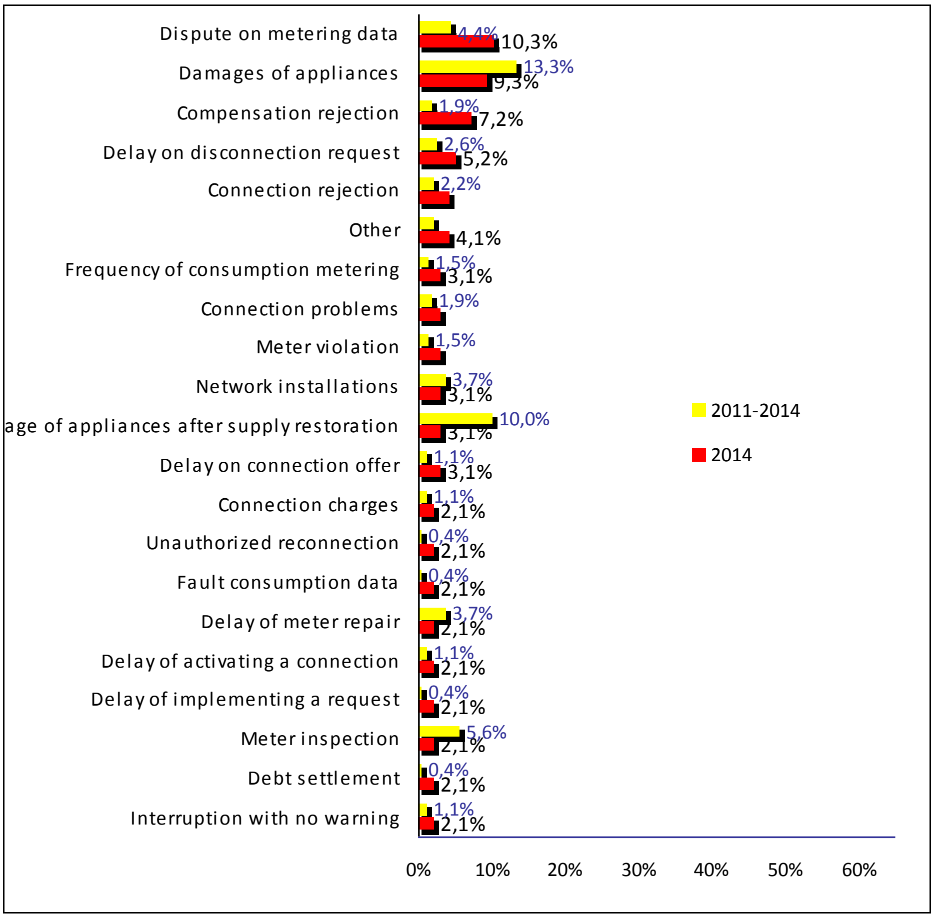


Figure 18. Complaints concerning DSO by thematic category

<u>Major concerns</u>

In 2014, written complaints mainly concerned energy bills with regards to clarity, comprehensive calculation of charges, incorrect tariff calculations and debt settlement. They were also related to lack or poor information on the justification of supplier’s and/or system operator different charges.

It is a fact that the continuous economic crisis makes consumers more concerned on increasing bill expenses. It is also true that an energy bill, especially the electricity bill, includes various charges and levies, which are associated with difficult and rather technical terminology and calculations that makes the bill quite complicated for the middle educated consumer to understand.

Experience also shows that a large number of customers attempt to resolve their complaints directly with their supplier or distribution system operator. However in many cases they are not happy with the explanations provided, because the explanations are not convincing, due to either lack of trust, or insufficient training of suppliers’ personnel. Hence the consumers apply directly to RAE in order to get proper and trustful advice and/or resolution to their problems.

In any case, energy service providers should focus on improving the information given to consumers with regards to invoicing and related explanations.

3.4.9 Dispute Settlement

The Consumer's Ombudsman is the legally responsible authority for dispute settlement between consumers and companies including energy service providers.

As a mediator, the Consumer's Ombudsman draws conclusions, makes recommendations and/or proposals to the companies after following a hearing process, but is not authorized to impose sanctions. However, if any of the involved parties does not accept the authority's recommendation, the Consumer Ombudsman may disclose the case in public.

RAE also handles all complaints addressed in written to the Authority, investigates the cases and tries to resolve the disputes or makes recommendations to the companies or draws regulations and/or imposes sanctions to the companies, if a significant number of consumers is affected. Some of the most characteristic cases handled and resolved by the RAE during 2014 follow:

1. Electricity bills based on unreasonably high estimated consumption

   After a number of consumer complaints on unusually high total amount of electricity bills, issued by one supplier, RAE investigated the cases in cooperation with the company involved and the DSO. The Authority concluded that an incorrect assessment of estimated electricity consumption for LV Customers resulted to high charges of the interim bills sent prior to the clearing bills. The problem was resolved by facilitating the communication between the DSO and the supplier and persuading the latter to implement correctly the relative provisions of the Manual for Measurements and Periodic Settlement of DSO.

2. Review and editing of electricity Suppliers template contracts for LV and MV Customers

   Under the scope of monitoring the proper adoption of the provisions of the Electricity Supply Code, related to Customers protection (Decision of the Deputy Minister of Environment, Energy and Climate Change No. D5-HL / B / F1.20 / oik.6262 / 29.3.201, Gov. V832 / 04.09.2013), RAE reviewed and edited the electricity supply template contracts and all other related forms (applications, general terms & conditions, Services Electricity leaflet, site information etc.). In some cases addressed, apart the main issues, RAE intervened by giving specific guidance to suppliers for necessary corrections and/or further proper inclusion of provisions.

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).

However, before the completion of the DESFA certification procedure, as defined in Article 10 of the Gas Directive, 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 specified in Article 11 par. 2 of the Gas Directive and 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 the 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. This new certification request was submitted to RAE by DESFA on 29/01/2014.

RAE examined the request to certify DESFA as an ITO under both DEPA, as DESFA's owner at the time, and SOCAR, as DESFA's future owner, and within the four months from the date of the above notification deadline, issued its draft certification decision on 26/05/2014. This draft certification decision was made according to the provisions of articles 9, 10 and 11 of the Gas Directive and Articles 63a, 64 and 65 of Law 4001/2011.

More specifically, RAE's assessment revolved around three main questions:

1. Whether the choice of the ITO model for DESFA was legitimate.

   RAE considered that DESFA did belong to a VIU on 3 September 2009, and thus according to Article 9(8) Gas Directive the choice of the ITO model was legitimate.

2. Whether DESFA complied with the requirements of unbundling rules.

   RAE concluded that based on the application file DESFA complied with the ITO rules vis-à-vis both DEPA and SOCAR, as it was both autonomous and independent from its Vertically-Integrated Utility (VIU).

3. Whether granting the certification would put at risk the security of energy supply of either Greece or the European Union.

   Based on Article 11(3)(b) of the Gas Directive, RAE took into account in its assessment the following elements: (i) the rights and obligations of the European Union with respect to the Republic of Azerbaijan arising under international law, including any agreement which addressed the issues of security of energy supply; (ii) the rights and obligations of Greece with respect to the Republic of Azerbaijan arising under agreements concluded with it, insofar as they were in compliance with European law; and (iii) other specific facts and circumstances of the case and the third country concerned. More in particular, following also Recital 22 of the Gas Directive, RAE considered: (a) the level of the European Union's and Greece's dependence on energy supply from third countries; (b) the role of SOCAR in the production, transmission and supply of the Republic of Azerbaijan in the European Union; and (c) the capacity of SOCAR, having the sole control of DESFA, to deny access to the NNGS.

After thorough investigation, RAE concluded that:
(a) the natural gas of the Republic of Azerbaijan on the one hand was not likely to put at risk the security of supply of Greece or the European Union as the volumes of Azeri gas delivered to Greece and the European Union were small, especially in comparison to volumes coming in from other third countries, and on the other hand an increase in Azeri gas supplies would actually improve the security of supply situation in Greece and the wider region given that it would reduce the dependence on gas from other sources and routes; and
(b) RAE was in any case well equipped to impose adequate penalties and regulatory

measures on DESFA to prevent, deter or sanction any misapplication of the rules stemming from the 3rd Energy Package, if needed.

RAE promptly notified the above draft certification decision to the European Commission, together with all the relevant information with respect to that decision. Pursuant to Article 3(1) of Regulation (EC) No 715/2009 and Article 10(6) and 11(6) of the Gas Directive, the European Commission assessed the certification file and delivered its opinion to RAE on 28/07/2014. In its opinion, the European Commission:

(a) agreed with RAE about the choice of the ITO model for DESFA;
(b) considered that DESFA complied with the unbundling rules, although it recommended RAE firstly to closely cooperate with DESFA and its owners, following the change of control over DESFA, to develop a plan aimed at reducing the leasing of personnel, and secondly to ensure that DESFA in carrying out services for TAP AG does not discriminate in favor of the latter and to the detriment of other network users;
(c) expressed some concerns about the potential risks for the security of supply of Greece or the EU following certification.

In particular with regard to possible security of supply risks stemming from SOCAR's acquisition of sole control over DESFA, the European Commission pointed out the following:

- The risk of governmental acts by the Republic of Azerbaijan or acts by SOCAR and companies affiliated to them that render it impossible or more difficult (such as by creating legal uncertainty or conflicts of law between Azeri and EU legislation) for SOCAR or DESFA to comply with EU energy law, other relevant EU law or Treaty obligations. This includes in particular acts that would impair the development of DESFA's network, such as not providing DESFA with the appropriate financial resources to carry-out necessary investment projects, notably those contained in DESFA's ten-year network development plan, including those concerning the Revithoussa LNG terminal and the future interconnections with the TAP, in accordance with Article 22 Gas Directive;
- The risk that the Republic of Azerbaijan could exercise its ownership rights in SOCAR in a manner that could result in SOCAR or DESFA acting contrary to EU energy law, other relevant EU law or Treaty obligations, including the exercise of investigative powers and enforcement action;
- The risk of acts by the Republic of Azerbaijan, SOCAR and/or companies affiliated to them that directly or indirectly sanction the enforcement of EU law against SOCAR or DESFA, including by-measures regarding the supply of natural gas to the EU or the terms and conditions of such supplies.

Based on the above remarks, the European Commission took the view that certification should only be granted once it is established that RAE has the power to suspend, on its own initiative or upon request of the European Commission, all voting rights attached to the shares that SOCAR holds in DESFA, should SOCAR and/or the Republic of Azerbaijan take a decision or action that negatively affected the security of supply of Greece and/or the European Union.

Implementing the European Commission's suggestion, the Greek government introduced a new article in Law 4001/2011 (art. 65A – Official Gazette A' 194/19.09.2014) to accommodate the needs and alleviate the concerns expressed therein by the European Commission regarding possible security of supply risks stemming from SOCAR's acquisition of sole control over DESFA.

Within two months of receiving the opinion of the European Commission, RAE adopted its final certification decision, having taken the utmost account of that opinion. Decision No. 523/2014 of 25/09/2014 certified DESFA as an ITO and imposed two additional obligations on DESFA: (i) six (6) months after the change of control over DESFA, and after having consulted both RAE and its owners, to develop and submit to RAE for approval a plan aimed at reducing the leasing of personnel in DESFA; and (ii) to submit to RAE for approval every service agreement entered into with TAP AG as counterparty or related to TAP pipeline.

It should be noted that the change of control over DESFA has not taken place yet, as the merger clearance, which is another prerequisite for the closing of the deal, is still pending before the Directorate-General for Competition of the European Commission.

Finally, within the context of monitoring the provision of services from DESFA to its current VIU (DEPA S.A.) pursuant to Article 63B Law 4001/2011 and Article 17 (1)(c) Gas Directive, RAE approved in 2014 the terms and conditions of three (3) standard service agreements. More in particular, RAE assessed and approved that the provision of those services did not discriminate among system users, were available to all system users on the same terms and conditions and did not restrict, distort or prevent competition in production or supply. The three (3) standard service agreements submitted by DESFA and approved by RAE where the following:

- Provision of natural gas odorization services for gas distribution systems (RAE Decision n. 375/2014)
- Technical study on the cathodic protection system of EPA Thessalia and EPA Thessaloniki gas distribution systems in order to assess the associated risk indicators
- Consulting services to EPA Attiki, EPA Thessaloniki and EPA Thessalia (subsidiaries of DEPA functioning both as the DSOs and retailers for the areas of Attiki, Thessaloniki and Thessalia, respectively) on regulatory and technical issues.

Following the approval of the terms and conditions of those standard service agreements, DESFA can offer these services to any other interested part, outside the VIU.

B) DSO Unbundling

During 2014, 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 422/2014, RAE approved the annual balancing plan submitted by DESFA S.A. for the year 2015, which included the estimates of the TSO regarding balancing gas needs (approximately 1.310.000 MWh), as well as an evaluation of possible balancing gas supply sources for 2015. According to this plan, the TSO proposed to acquire balancing gas (in the form of LNG) for the balancing needs of 2015 through an international tender procedure, according to the main provisions of the Greek Gas Law. Furthermore, RAE with the same Decision, approved the monthly capacity reserved by the TSO for balancing services.

In the 2014 balancing plan, the TSO had estimated that the balancing gas needs for the year would amount to 3.8% of the total gas consumption, while the year-end data indicated that this figure actually amounted to 6.9%. According to the annual report issued by DESFA on the operation of the NNGS in 2014[18], this significant deviation was the result of considerable imbalances presented mainly at the exit points of the National Natural Gas System where gas-fuelled power plants are connected. For the year 2015, TSO estimates that the balancing gas needs will amount to 4.3% of the total estimated gas consumption.

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 2014, RAE[19] approved the balancing cost allocation scheme and the relevant shippers' charges, which include all costs arising from the provision of balancing services for the years 2013 and 2014. 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).

[18] http://www.desfa.gr/files/ΔΙΕΥΘΥΝΣΗ%20ΔΙΑΧΕΙΡΙΣΗΣ%20ΡΟΗΣ%20ΑΕΡΙΟΥ/Αναλυτική%20Έκθεση%20για%20τη%20Λειτουργία%20του%20ΕΣΦΑ%20για%20το%20Έτος%202014-final.pdf

[19] RAE Decisions 75/2014 and 486/2014

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].

In the course of 2014 the Greek TSO, DESFA S.A., informed RAE that they intend to submit an interim measures report to RAE within the year (and according to the provisions of Chapter X of the European Network Code on Balancing) as the lack of liquidity in the Greek natural gas market is not conducive to the full application of the provisions of the European Network Code on Balancing in 2015 or 2016. RAE is expected to evaluate the report according to the provisions of articles 46 and 27 of the European Network Code on Balancing and issue a decision within six months following the receipt of the complete report.

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 (Government Gazette 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. 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.

The actual tariff coefficients for the year 2014 are presented in the table below.

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

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh)
Entry Sidirokastro	134.2952	0.1193
Entry Kipi	123,1058	0.0916
Entry Ag. Triada	25.3887	0.0514
Exit Northeast Zone	66.6641	0.1337
Exit North Zone	258,1741	0.4095
Exit South Zone	364,2433	0.4065
LNG Terminal	57.7785	0.1169

Table 22. Coefficients of TPA tariffs for one-year duration contracts in 2014

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 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

The three EPAs, EPA Attikis, EPA Thessalonikis and EPA Thessalias are operating under a regime of exclusive rights for both the activities of distribution (DSO) and the supply of gas in their areas. In addition, DEPA, the main gas supplier in Greece, is the owner and operator of three (3) distribution networks in three (3) areas known as new-EPA areas. According to article 82 of the Greek Gas Law (law no. 4001/2011), access to EPAs' and DEPA's networks is granted to other suppliers serving eligible customers. According to the Greek Gas Law Eligible Natural Gas Customers were customers with annual natural gas consumption, for two consecutive years, of more than 100 GWh GCV of natural gas. In 2014, in order to cope with reduced gas consumption by many eligible customers due to the continued recession of the greek economy, two laws were passed which redefined the term Eligible Natural Gas

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

Customers. Law no.4254/2014, redefined Eligible Customers inside the EPA areas customers who used to be eligible as of 31 December 2012. In other areas (outside EPAs' areas), Law 4301/2014 redefined Eligible Customers all non-domestic customers.

Tariffs for TPA in EPAs' distribution networks are currently those set in their concession licenses. New TPA tariffs will be set by the EPAs and DEPA 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.

3nd Revision of the Gas Network Code

At the end of 2014, after receiving a series of proposals from the TSO and requests from the participants in the Greek natural gas market, RAE initiated the procedure for a third revision of the Gas Network Code. Based on DESFA's proposals put under public consultation on RAE's website in December of 2014, the main new elements of the Gas Network Code will include, among others:

- Replacement of the standard contracts for the delivery of either transmission of natural gas service (on a firm or interruptible basis) or usage of the LNG terminal with two framework agreements for the transmission of natural gas LNG facility usage, respectively. Every User will sign only one Framework Agreement with the TSO, under which requests for services will be executed.
- Inclusion of all necessary provisions for the delivery of natural gas on a firm reverse flow basis.
- Elaboration of new provisions for guarantees provided to the TSO from the counterparty to a Framework Agreement in order to fulfil the obligations derived from the Agreement.
- Introduction of specific procedures regarding the interruption of Natural Gas Delivery to a Customer upon transmission system User request and obligatory LNG gasification covering exclusively protected customers' needs, in case of National Natural Gas System Crisis.

4.1.4 Cross-border issues

RAE is actively involved in regular cross-border cooperation with several Regulatory Authorities, Governmental bodies and TSOs, in order to foster activities related to the creation of an internal energy market in Europe and the implementation of major infrastructure projects.

First and foremost, RAE is working closely with the adjacent Regulatory Authority of Bulgaria focusing on the cross-border implementation of the Network Codes on capacity allocation and congestion management, on balancing and on interoperability, as well as on issues related to the European Regulation 347/2013.

In order to exchange best practices and know-how in market regulation including gas hub developments RAE and the operator of the Greek natural gas system (DESFA) and their

Belgian counterparts, the Commission of Regulation for Electricity and Gas (CREG) of Belgium and the operator of the Belgian natural gas system (Fluxys) have agreed to foster cooperation between Belgium and Greece in the natural gas sector.

In November of 2014, RAE and CREG signed a memorandum of understanding (MoU) in order to cooperate in facing the important role national energy regulatory authorities are called upon in the implementation of the EU legislation and national regulatory issues. Pursuing synergies will undoubtedly have a positive impact on the development of the energy market and the economy of both countries. By signing this agreement, CREG and RAE endorsed the objective to promote effective market opening for all customers and suppliers and to ensure appropriate investment conditions, taking into account long-term objectives. Timely and meaningful exchange of information and views regarding all sectors of their competence are expected to contribute to integrated and effective regulatory decisions.

At the same time, Fluxys and DESFA have signed an agreement with a view to creating a virtual trading point in Greece. Through its subsidiary Huberator, Fluxys operates the Zeebrugge Beach (first physical trading point on the European mainland, created in 1999) and the Zeebrugge Trading Point (virtual trading point established in 2012 in the wake of the entry into force of the Belgian entry-exit model). The agreement aims at conducting a feasibility study for the creation of a liquid wholesale gas market in Greece, which entails the setup of a notional point where market players can exchange gas commodity and contribute to a well functioning market-based balancing regime in line with the European legislation.

In addition to the above, RAE has an excellent cooperation with the Italian and Albanian energy regulators in the framework of the implementation of TAP project. The exemption decision issued in June 2013 is the result of a continuous, often daily, excellent cooperation between the three energy regulators. In the course of 2014 this collaboration continued as additional regulatory documents, incl. the compliance program of TAP AG and the Guidelines and invitation for the binding phase of the market test were approved by the Italian, Albanian and Greek energy regulators.

Last but not least RAE, in its role as the Competent Authority on ensuring the implementation of the measures foreseen in EU Regulation 994/2010 regarding security of supply is also cooperating with the Ministry of Energy of Bulgaria.

During the course of the year 2014 the final recommendation of DESFA S.A. on the Ten Year Network Development Plan 2014-2023 (TYNDP 2014-2023) 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 2014-2023 (Decision 681/2014, Official Gazette B 3310/2014), according to the provisions of the Greek legislation and the Gas Network Code, and submitted a copy of the approved plan to ACER. The consistency of the TYNDP 2014-2023 has been checked against both the regional and the European TYNDP.

4.2. Promoting Competition

4.2.1 Wholesale Markets

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 19 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 2012 through December 2014. 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 31.12.2014, 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

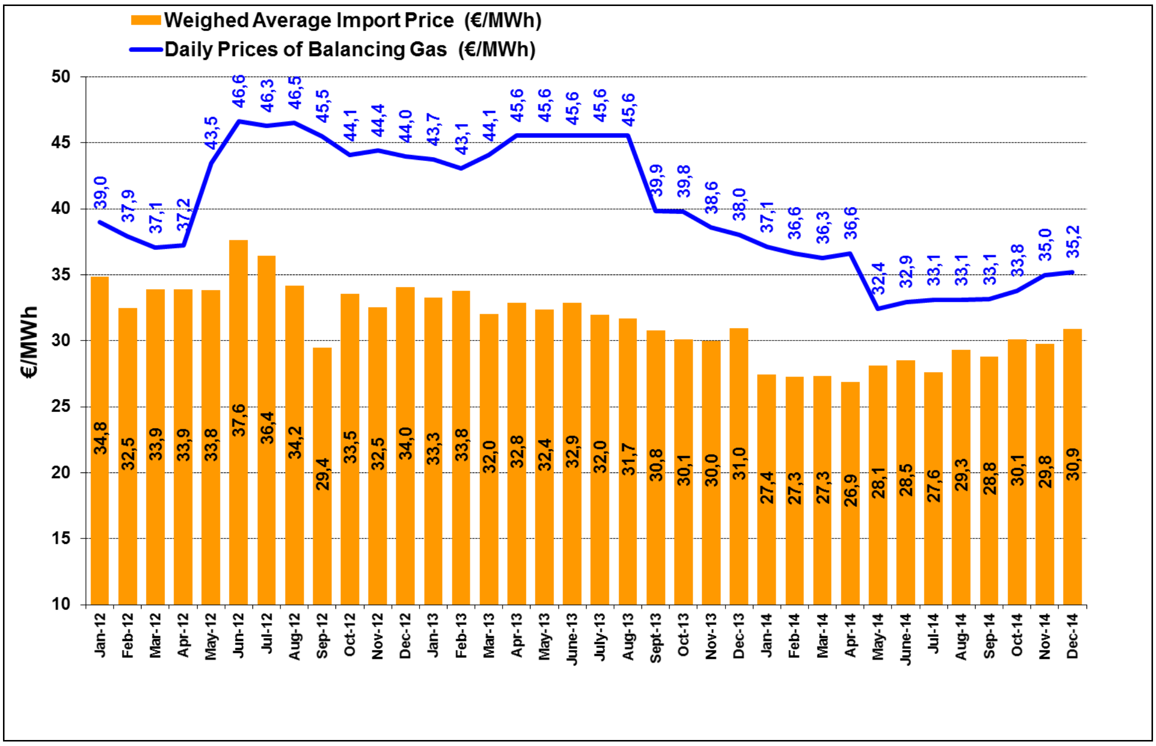


Figure 19. Monthly weighted-average import price (WAIP) against the price of balancing gas (Jan. 2012-Dec.2014)

4.2.1.1. Monitoring the level of transparency

Level of Transparency

There was no major development towards transparency in the year 2014 as the actions taken in the years 2011-2013, as described in previous National Reports, have resulted in the TSO establishing a separate section in its homepage for transparency reasons. 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 2014. 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 2014, the Revithoussa LNG terminal remains the main channel/opportunity for new entrants in the Greek gas market. The second upgrade of the Revithoussa LNG terminal is progressing in order to be commissioned by the end of 2016.

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, the share of DEPA gas imports in 2013 reached ninety-nine percent (99%) of total annual imports, and ninety-five percent (95%) in 2014. Only one (1) other company (big industrial consumer), beyond DEPA, imported natural gas in the country in 2014, representing the remaining five percent (5%) 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 are the result of the following mechanisms: a) wholesale trading of LNG quantities in-tank, b) resale of gas between eligible customers, and c) the gas release programmes run by DEPA on a quarterly basis since December 2012 according to the provisions of the Hellenic Competition Commission (HCC) Decision 551/VII/2012.

RAE has repeatedly stressed that, under the current operating conditions of the Greek gas market (inability to find alternative suppliers of natural gas, limited storage capacity and adverse conditions in the LNG market), DEPA's commitments for gas release programmes are currently, and for the foreseeable future, the main alternative option for gas supply for third parties - consumers and suppliers - and hence, currently, the only way possible to develop competition in the wholesale gas market in Greece. During 2014, RAE provided an extensive opinion to HCC on ways to optimize the functioning of the gas release programmes in the framework of an extensive consultation run by HCC whereby all major gas market players participated in.

As a result, in order to offer Suppliers and Customers the ability to put together a flexible portfolio for the supply of natural gas and in addition to the current system of quarterly auctions, DEPA has undertaken to make natural gas available on an annual basis in the electronic auctions, i.e. with an absorption period of one calendar year (annual auctions). Additionally, to further reduce dependence of DEPA Customers by DEPA and to equally treat all participants in the auctions, irrespective of the supply contract that they have concluded with DEPA (with or without transmission services), DEPA undertook (as of 01.01.2015) to make all quantities available through the annual and quarterly auctions solely at the Virtual Trading Point (VTP) of the National Natural Gas System (NNGS).

Any - very small - administrative burden that this process causes to the participants is easy to compensate, especially since the reform of the whole action process strengthens the involvement of new and existing suppliers, as they will take over the management of the consumers they will serve. RAE considers that the suggested measures will promote sustainable competition and create a more liquid gas wholesale market.

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	AXPO 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.
11	GREEK ENVIRONMENTAL & ENERGY NETWORK S.A.
12	GASELA GmbH
13	HELLAS EDIL S.A.
14	GREENSTEEL – CEDALION COMMODITIES S.A.

Table 23. 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 2014, forty (40) companies were officially registered as potential users of the NNGS, sixteen (16) of which were active in 2014. 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
27	PROTERGIA S.A.	Eligible Customer
28	GREEK ENVIRONMENTAL & ENERGY NETWORK A.E.	Natural Gas Supplier
29	YIOULA GLASSWORKS S.A.	Eligible Customer
30	ANOXAL S.A.	Eligible Customer
31	ERLIKON WIRE PROCESSING SA	Eligible Customer
32	FITCO METAL WORKS SA	Eligible Customer
33	HALCOR METAL WORKS SA	Eligible Customer
34	ALUMAN S.A.	Eligible Customer
35	PAPYROS PAPER MILL S.A.	Eligible Customer
36	GREENSTEEL - CEDALION COMMODITIES S.A.	Natural Gas Supplier
37	SONOCO PAPER MILL AND IPD HELLAS S.A.	Eligible Customer
38	EP-AL-ME S.A.	Eligible Customer
39	DAIRY INDUSTRY OF XANTHI SOCIETE ANONYME	Eligible Customer
40	INOTEX PRIVATE COMPANY	Third Party

Table 24. Companies officially registered as NNGS users during 2014

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 2014 were lower than the corresponding prices in 2013. The most important drivers of gas cost plus tariffs are international fuel prices (FO, GO, Crude) and inflation. This reduction in prices is attributed mainly to the discount achieved by DEPA in its long-term LNG import contract with SONATRACH, Algeria, in 2013, and an amendment which incorporated a new supply formula from Gazprom to DEPA in 2014. 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
2014	54.59	55.59	48.87	50.51

** Net of VAT*

Table 25. Indicative, annually-averaged, natural gas prices in distribution, 2009-2014

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. The 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 (28) were filed to RAE in 2014 regarding the distribution and supply of natural gas in the EPA areas, amounting to 9.2% of all consumer reports submitted to RAE in the same year.

A complaint that seemed to be recurring was regarding the amount of reconnection charges imposed by one of the gas supply companies. RAE, in cooperation with the gas provider involved and after thorough investigation of the relevant costs, concluded that reconnection fees must be reasonable and reflect actual costs. The Authority’s view was accepted by the gas company that agreed to change reconnection costs within 2015 in favour of consumers.

4.4. Security of Supply

The extension of the definition of protected customers and the introduction in the last quarter of 2014 of a security of supply levy payable by all gas consumers were the major developments during 2014 as regards security of supply (SoS). The aim of the security of supply levy is to finance mechanisms that incentivise demand response from large consumers and ensure dual-fuel availability of power stations.

The gas quantity data provided in this section are expressed in both units of Mtoe (based on gas with a HHV of 9600 Kcal/Nm^3) and bcm (at 15°C). All demand projections provided hereon are based on DESFA's projections in the 2015-2024 TYNDP report.

4.4.1 Monitoring Balance of Supply and Demand

4.4.1.1. Current demand

The demand for Natural Gas in 2014 amounted to 2.99 bcm, out of which approximately 56% came from the power generation sector, as shown in Table 27.

	bcm @ 15°C	Mtoe (HHV)
Power Generation	1.66	1.51
Industry & HP customers	0.76	0.69
GDCs (Primarily Commercial & Domestic)	0.57	0.52
Total	**2.99**	**2.72**

Table 26. Natural gas demand by sector in 2014

As depicted in Figure 17, gas demand in 2014 decreased dramatically, by twenty five percent (25%) compared to the demand level of 2013, primarily due to the new rules in the electricity Day Ahead Market and the continuing economic recession.

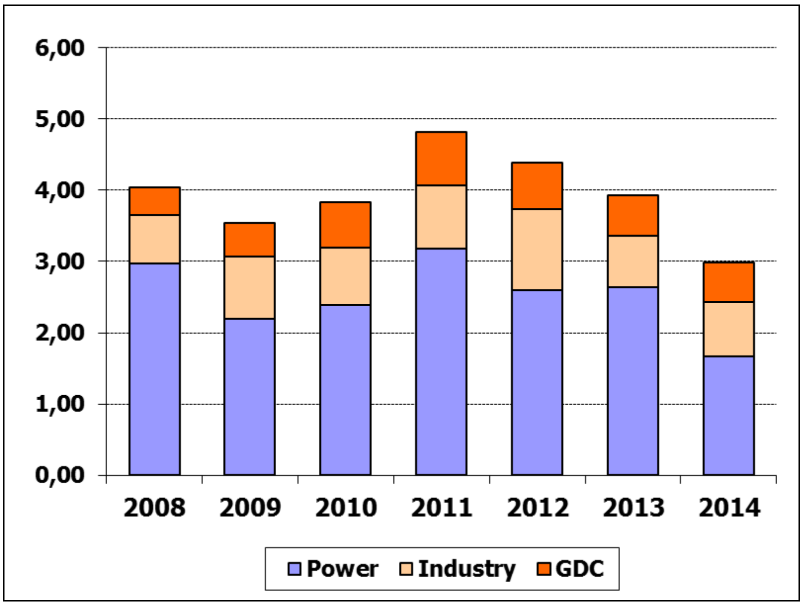


Figure 20. Gas demand per sector (bcm @ 15°C), 2008-2014

There is no indigenous gas production in Greece. In 2014, natural gas was imported in the National Natural Gas System through three (3) entry points. As shown in Figure 21, approximately fifty eight percent (58%) of the gas imported into the country came from Russia and twenty two percent (22%) was imported from Turkey. The remaining twenty two percent (22%) was imported as LNG at the island of Revithoussa and was injected into the transmission system from the Agia Triada entry point.

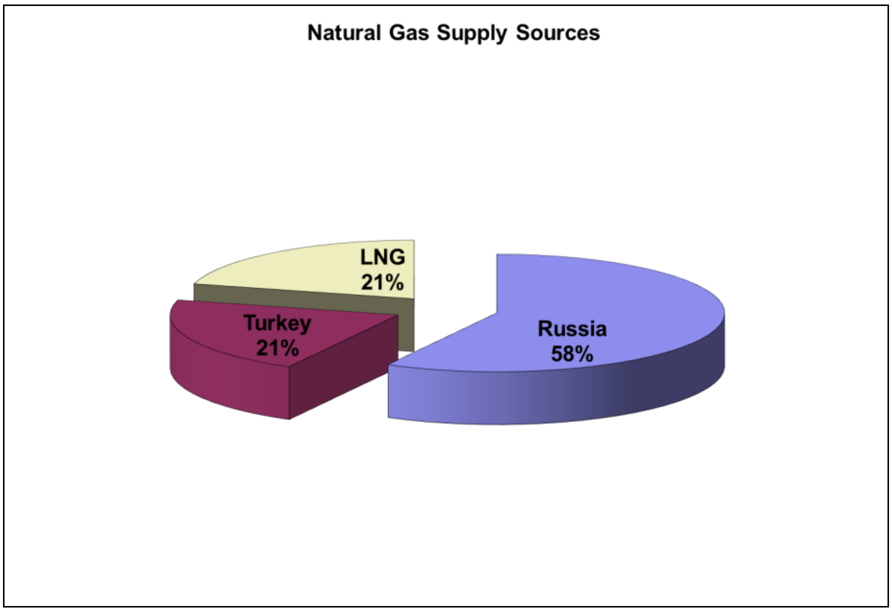


Figure 21. Share of natural gas supply sources in 2014

Figure 22 provides the share of imports from each source during the past eight (8) years (2007-2014). The supply of gas through the existing long-term contract with Russia appears to stabilize at around sixty percent (60%).

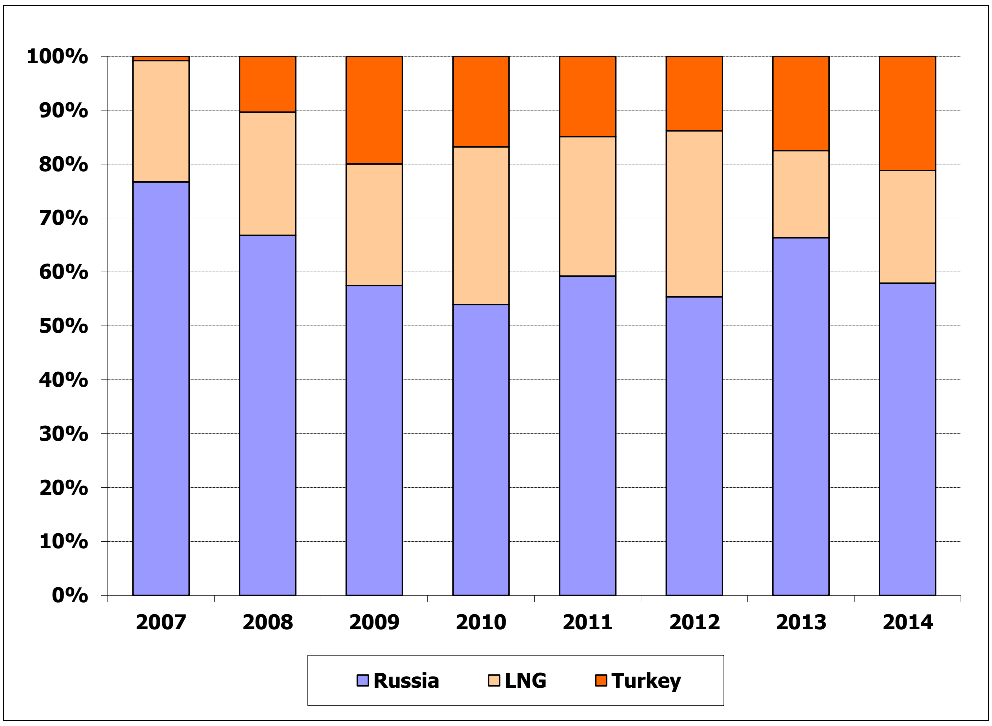


Figure 22. Share of natural gas import sources, from 2007 to 2014

4.4.1.2. Projected demand

Demand is expected to rise in the next three (3) years (2015 to 2017) compared to demand of 2014. However, this is largely influenced by power market conditions and in particular the energy available for imports and hydro production.

	2015		2016		2017	
	bcm	Mtoe	bcm	Mtoe	Bcm	Mtoe
Power Generation	1.80	1.64	2.45	2.23	2.19	2.00
Industry	0.83	0.76	0.94	0.85	0.93	0.85
Commercial & Domestic	0.65	0.59	0.68	0.62	0.72	0.66
Total	**3.28**	**2.99**	**4.07**	**3.71**	**3.85**	**3.50**

Table 27. Future natural gas demand (DESFA's estimates)

4.4.2 Expected Future Demand and Available Supplies

During 2014, DEPA imported gas primarily through existing long-term contracts from three (3) different sources, namely Russia, Algeria (LNG) and Turkey, while several spot cargoes sourced from Norway and Spain were also unloaded at Revithoussa.

Table 28 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 (the first of which expires at the end of 2021) are sufficient to cover the anticipated demand.

	2015		2016		2017	
	bcm	Mtoe	bcm	Mtoe	bcm	Mtoe
Demand	3.28	2.99	4.07	3.71	3.85	3.50
Supply Contracts	4.06	3.69	4.06	3.69	4.06	3.69
Supply Gap	0	0	0	0	0	0

Table 28. Expected natural gas supply-demand balance, 2015-2017

Figure 23 below shows the expected demand - supply balance up to 2024. The demand curve corresponds to the TSO's latest demand forecast.

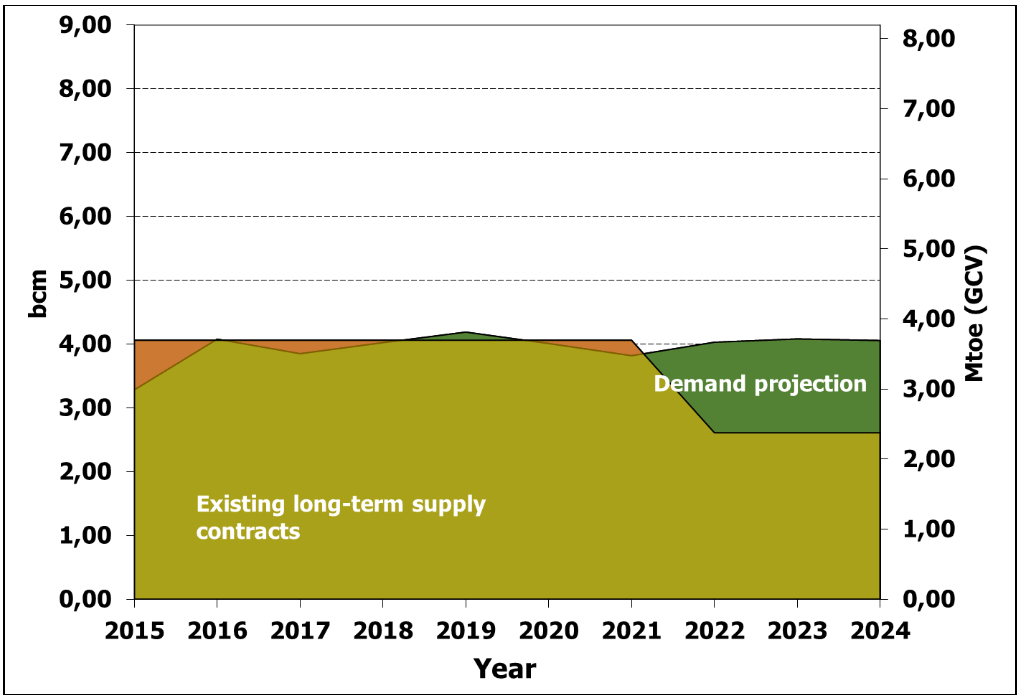


Figure 23. Expected natural gas supply-demand balance (forecast to 2024)

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 29 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 (15°C)**
Sidirokastro	4.16
Kipoi	1.66
AG. Triada (LNG Terminal of Revithoussa)	4.80
Total	**10.62**

Table 29. Natural gas entry-point capacities

Table 30. 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 the 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 30. Natural gas TSO investment plans

4.4.3 Security of Supply crises

Year 2014 was uneventful.

4.4.4 Measures to Cover Peak Demand or Shortfall of Suppliers

During 2014 the legislative framework was further aligned with the Preventive Action Plan strategies, by applying the extended definition of protected customers according to article 2 of Regulation 994/2010 and with the introduction of a security of supply levy required to finance the demand response contracts and the costs associated with maintaining dual fuel capability at five gas fired power plants.

Protected Customers

According to the provisions of the Ministerial Decree no. D1/B/10233/13-6-2014 (Government Gazette B' 1684/24.6.2014), Protected Customers in Greece include the following categories of customers (in line with article 2 of European Regulation 994/2010):

a) Households;
b) Social services, as follows:
    - Hospitals,
    - Schools,
    - Public sector buildings,
    - Airports, and
    - Gas refueling stations serving public transport and municipal services vehicles.
c) Small and medium commercial and industrial companies connected on distribution grids which have contracted less than 10.000 Mwh annually, and
d) District heating installations provided they do not have fuel switching capability.

The only gas-fired district heating installation in Greece that has been licensed with dual fuel capability is not included in the protected customers list.

The total gas demand stemming from categories b, c and d does not exceed twenty percent (20%) of the total gas demand in Greece.

Security of Supply Levy

On September 2014, a security of supply levy payable by all gas consumers was introduced, according to the provisions of article 73 of Law 4001/2011. The levy is meant to finance the costs associated with:

- The establishment of an incentive scheme designed for demand response by Large Customers at the level of around 1.5 mcm/day.
- The readiness of availability of liquid fuel at power stations with dual fuel capability and the regular testing of the Power Plants on liquid fuel.

The SoS levy is set at a different level for each one of the following four customer categories: a) interruptible customers, b) gas-fired power plants, c) protected customers, and d) all other types of customers. The level of differentiation in the actual levy per customer category captures the different level of protection each customer category is offered according to the procedures foreseen in the national emergency plan.

The actual levy for each customer category as set by RAE Decision 344/2014 (Government Gazette B' 2536/9.2014) is shown in Table 11 ranging from a value of 0 €/MWh for interruptible customers to 0.48 x C €/MWh for protected customers.

Customer Category	**SoS Levy (2014)**
Interruptible	0
Gas-fired power plants	0.16 x C
Protected customers	0.48 x C
All other customers	0.18 x C

Table 31. Security of Supply Levy per customer category

The constant C may take a value ranging from zero (0) to one (1) and is set once a year by the Greek TSO, DESFA, according to a transparent, ex-ante approved by RAE formula. The constant C is adjusted annually at the level necessary to pay off all predicted outflows from the Security of Supply account (managed by DESFA) during the year taking also into account the inflows to the account. The value of C is currently set at 0.7224.

Appendix I - List of licensed electricity Suppliers and Traders at the end of 2014

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

39	ROSEVELT L.T.D.		
40	RUDNAP ENERGY L.T.D.		
41	SEMAN S.A.		
42	SENTRADE S.A.		
43	STATKRAFT MARKETS GmbH		
44	STELLA GAVRIIL L.T.D.		
45	SUN CURE S.A.		
46	TERNA ENERGY S.A.		
47	VERBUND A.G.		
48	VITOL GAS AND POWER B.V		
49	VIVID POWER E.A.D.		
50	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
VIU	Vertically-Integrated Utility
WAIP	Weighted-Average Import Price

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