2012 National Report to the European Commission

(Covering the period 01.01.2011 – 31.12.2011)

Regulatory Authority for Energy (RAE)

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1. Foreword

Year 2011 was marked by the adoption of the new Energy Law 4001/2011, on 22.08.2011, that transposed the Third Energy Package into national legislation. The new law introduced major changes to the Greek electricity and natural gas markets, and strengthened the competencies of RAE regarding security of supply, licensing, monitoring of the energy market and consumer protection. Overall, the new law considerably improved the legislative framework for the regulation, monitoring and control of the domestic electricity and gas sectors.

In the electricity sector, the potentially positive effects of a) the stability in terms of market structure, b) the significant capacity surplus in the wholesale market, and c) the substantial increase in competition and supplier switching in the retail market, were largely cancelled out by the unfavourable economic conditions in the country, and, in particular, by the continuing decline in electricity consumption and the sharp increase in unpaid consumer bills and in business and credit risks, too.

Setting the basis at the end of 2011, and continuing its efforts throughout 2012, RAE has launched an intense public debate regarding the reorganisation and necessary structural reforms in all aspects of the Greek electricity market. The main objectives of the structural changes proposed by RAE include:

- To create the proper background in order to achieve harmonisation of the domestic electricity market with those of the neighbouring countries, in the framework of the single Internal European Market (Target Model).
- To ensure access of all participants, in a transparent, efficient and equal way, to the country's indigenous energy resources, mainly lignite and water, so as to create competitive portfolios of comparable energy costs.
- To further remove the distortions and cross-subsidies in the retail prices, with rational allocation of costs among the various consumer categories, so as to guarantee the long-term development of the energy sector, on the basis of the economic viability of the corresponding investments and infrastructure development.

In addition, RAE's priorities in the electricity sector for 2012 also include the certification of ADMIE SA, as the TSO following the ITO model, as well as the licensing of DEDDIE SA as the DSO, setting strict criteria for their independence from the mother company, PPC SA.

In the natural gas sector, 2011 was a year of solidification of the competitive conditions that were successfully introduced into the market in 2010. This was demonstrated by the increased number of new players entering the market, the price and overall contract renegotiations carried out by the incumbent with both its foreign suppliers and its large domestic customers, the first wholesale trading deals emerging between new suppliers and the expressed interest for new infrastructure development by third parties, including transit pipeline projects of the Southern Gas Corridor.

Strictly in the regulatory front, and besides its contribution to the transposition of the Third Energy Package into Greek legislation, RAE expedited and intensified its work towards: a) the transformation of the TPA regime to an entry-exit system, in compliance with the Gas Regulation, b) the monitoring and improvement of transparency and of the overall competitive conditions in the market, and c) the reform of the existing security of supply scheme, in compliance with the Security of Supply (SoS) Regulation. On the other hand, changing conditions on the privatisation and unbundling scheme of the incumbent, as decided by the Greek government in late 2011, have delayed progress in the TSO certification process.

Overall, RAE considers 2011 to be a successful year for the liberalisation and more efficient operation of the domestic gas market, since the competitive conditions proved to be sustainable, despite the harsh economic conditions in the country, and progress was indeed achieved in critical interim steps, towards full implementation of the Third Energy Package by 2014. The priorities of RAE in the gas sector for the next reporting period include: a) the establishment of entry-exit TPA tariffs, allowing for the full reform of the TPA regime, in order to be compatible with a gas hub, b) the timely completion of the security of supply scheme, in compliance with the SoS Regulation, and c) the establishment of a greater degree of integration with the neighbouring Member States, allowing for better competitive and SoS conditions in the entire SEE Region.

Last but not least, it is important to point out the serious steps backwards introduced by certain provisions in the new Energy Law 4001/2011, regarding the Regulator's resources and its independence in managing them. As an example, RAE's personnel was included in all fiscal measures applicable to the general public sector, which implied: a) an average reduction of 50% in their salaries, with the immediate effect of having several of its senior scientists leaving RAE, and b) RAE's inability/prohibition to hire any new personnel for an indefinite period of time. Under these circumstances, RAE will soon not be able to carry out, in any satisfactory way, the increased responsibilities and competences bestowed upon the Regulator by the Third Energy Package and Law 4001/2011, in a period when RAE's strong involvement is most needed by the market.

The Greek Regulatory Authority for Energy (RAE)

2. Main developments in the gas and electricity markets

2.1. Electricity

Following the passing of the new Energy Law 4001, in August 2011, PPC established a 100% subsidiary, ADMIE SA, which now owns and operates the transmission system, according to the ITO model. DESMIE SA, the former TSO, was for the most part absorbed by ADMIE and the rest was restructured to become the new wholesale Market Operator, LAGIE SA. The distribution network ownership remained with PPC, although its operation was assigned to another 100% subsidiary of PPC, DEDDIE SA. The official operation of these companies commenced in 2012.

In the wholesale market, the revised market design fully implemented in September 2010, after gradual evolution over the previous five (5) years, has completed in 2011 its first full year of application, remaining, for the first time, stable in terms of its structure and objectives. In addition, substantial new IPP capacity entered the system over two consecutive years, 2010 and 2011, reducing PPC's market share to 75% in 2011, relatively to 85% in 2009, and intensifying competition in generation, for medium and peak load demand.

The retail market was characterised, for the first time, by a substantial increase in supplier switching. Especially in the medium-voltage segment, nearly 10% (by eligible volume, i.e. MWh) of industrial and commercial customers had switched supplier by the end of 2011. Still, PPC's retail market share remained very high in 2011, at 92%, calculated with respect to eligible volume. Several problems were encountered in relation to procedures supporting the opening of the supply market, such as delays in supplier switching, data provision, disconnections and reconnections, market settlement, etc. These problems, while in part justified by the usual "arrhythmias" encountered during the first realisation of the retail market opening, were also a result of the DSO remaining, throughout 2011, an operational unit of the incumbent (PPC S.A.).

In June 2011, RAE issued a Decision on Tariff Guidelines for the non-regulated tariffs, applicable to all suppliers active in the electricity market. Regarding high-voltage (HV) tariffs, which have been deregulated since the end of 2007, negotiations between PPC and HV customers have not progressed significantly, the HV customers accusing PPC for not taking into account, in their tariff setting, their consumption volume, load profile and other specific characteristics. Several official complaints against PPC have been submitted to RAE since the last quarter of 2011, which are under investigation. At the end of 2011, all price regulation for the medium-voltage customers was removed too, while price regulation for the domestic and small-enterprise, low-voltage, customers remained in effect throughout 2011 and 2012, and is expected to be fully removed by mid 2013.

Debt problems, which have escalated in 2012, raised unprecedented challenges for the market participants, the TSO and the Regulator. Severe liquidity problems and credit risks started to emerge in the energy sector, partially reflecting the deepening economic recession, but also the effect of State policies regarding retail (domestic) tariffs and renewables feed-in prices. Costs were not correctly reflected or adequately transferred across the value chain, creating sustained debts, especially in the renewables account managed by the TSO, and gradually diminishing the Operator's liquidity.

Two other policy choices put into effect in 2011, namely the introduction of a tax levy on natural gas (including gas for electricity production) and the incorporation of a new property tax into the electricity bill, created severe adverse effects on competition and on consumers' ability to pay their bills.

This dire situation underscored the need for urgently defining and applying alternative ways to move forward, and has stimulated, with the initiative of the Regulator, discussions for serious structural reforms, consistent with the need for market adjustment and alignment to the EU Target Model, envisaged for 2015. To this effect, in December 2011 (and then in July 2012), RAE published its proposals for the reorganisation of the domestic wholesale electricity market, outlining a specific roadmap and action plan, in the framework of integration of the European electricity market.

2.2. Natural Gas

Law 4001/2011 assigned to RAE all the competencies provided for in the Gas Directive of the Third Energy Package, as well as the role of Competent Authority for the Security of Gas Supply. The law prescribed for ownership unbundling of the incumbent (DEPA S.A.). However, this decision was amended later in the same year, to allow both options to be available to the Greek State, either for ownership unbundling, or for the ITO model.

In August 2011, after a public consultation launched at the end of 2010, RAE approved the first revision of the Network Code, aimed at increasing the transparency and liquidity in both the LNG and the transmission-capacity markets, and setting the basis for virtual reverse flow and for gas resale transactions through the national grid. Furthermore, the Network Code introduced a complete set of new provisions regarding infrastructure development in Greece, in line with the provisions of the Third Energy Package.

In November 2011, RAE launched a public consultation on a TSO's proposal for a new Tariff Regulation, introducing a decoupled entry-exit tariff model in the domestic gas market. The consultation procedure (including a second round) and the approval by RAE of the new Tariff Regulation, as well as of the actual entry-exit tariffs were concluded in the summer of 2012. This development constitutes a major step on the way to a full reform of the Greek TPA system, towards a decoupled entry-exit regime, in full compliance with the Gas Regulation.

Furthermore, during 2011, RAE undertook a series of monitoring exercises that contributed to the TSO's efforts towards a substantial improvement in the level of transparency in the capacity market.

On the market side, an increasing number of third parties continued to independently import LNG and to perform wholesale transactions, maintaining an 11% market share in 2011, practically equal to their market share in 2010. Given that demand increased in 2011 by 25% compared to 2009, reaching a level of 4.8 bcm/year, it is evident that increased quantities of gas are being imported by new suppliers.

During 2011, RAE received three (3) applications for the development of new infrastructure in Greece by third parties ("Independent Gas Systems"), namely: a) the development of a new LNG terminal, b) the development of an underground storage (UGS) facility in an offshore depleted gas field, and c) the construction of the Trans-Adriatic Pipeline (TAP). The latter was accompanied by a request for exemption from certain third-party access and unbundling provisions, according to article 36 of the Gas Directive. The three regulatory authorities involved in the TAP application (RAE, AEEG of Italy and ERE of Albania) have approved, after close cooperation, the rules for the performance of the market test anticipated by article 36 of the Directive, which is currently (2012) underway. The LNG terminal application was granted a license in July 2011, while granting of a license for the development of the UGS is subject to pending government decisions regarding privatisations in the energy sector.

Last but not least, 2011 was a busy year regarding Security of Supply. The most prominent activity related to the implementation of EU Regulation 994/2010 was the Risk Assessment Study, which was completed on time and sent to the Commission on December 14th, after extensive consultation and collaboration with a) the Hellenic Gas Transmission System Operator S.A. (DESFA), b) the Hellenic Electricity Transmission System Operator S.A. (DESMIE), c) the Public Gas Corporation (DEPA), in its quality as supplier of gas to protected consumers under long-term gas import agreements, and d) representatives of the Ministry of Environment, Energy and Climate Change.

3. Regulation and Performance of the Electricity Market

3.1. Network Regulation

3.1.1. Unbundling

Within the context of the European Union's Directives and under the legislatory framework of Law 4001/2011, the spin-off (legal and operational unbundling) of the transmission activity from the vertically-integrated PPC S.A. took place in 2011. The Independent Power Transmission Operator, ADMIE S.A., a 100% subsidiary of PPC, was registered as Société Anonyme in November 2011, by having transferred to it all relevant transmission assets, activities and personnel, and reported its first financial statements on 31.12.2011. Its official operation started on February 1st, 2012.

In November 2011, RAE issued Decision 1412 on the "Guidelines for the Certification of Transmission System Operators", which describes the evaluation criteria and the documentation required for certification. The Transmission System Operator (TSO) candidate must document its legal and operational unbundling from the vertically-integrated enterprise, established on the grounds of (a) the independence of management, (b) the independence of financial resources, and (c) the independence of operational activities. The first phase (i.e. through the National Regulator) of the certification process for ADMIE SA was completed in July 2012, by the issuing of RAE's decision 672/2012, which was then forwarded to the European Commission for its further consideration and approval.

For the purpose of this Report, regarding the period 1.1.2011-31.12.2011, DESMIE SA had the role of both the TSO and the Market Operator (MO).

Referring to the Distribution Activity, the legal and operational unbundling took place in May 2012, with the establishment of DEDDIE S.A., as the Hellenic Electricity Distribution Network Operator, a 100% subsidiary of PPC, and the transfer of the entire distribution business unit to this new company. The network assets, however, still belong to PPC.

3.1.2. Technical functioning

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

<u>Network Performance and Quality of Service</u>

In December of 2010, RAE published an integrated set of Regulatory Instructions for the reporting of the Transmission System performance[1]. Following these instructions, the TSO published reports on the performance of the Transmission System for the years 2010[2] and

[1] http://www.rae.gr/site/system/docs/misc/11012011.csp
[2] May 2011 - http://newsite.desmie.gr/fileadmin/user_upload/Files/study/FINAL-PERFORMANCE_REPORT2010-HTSO.pdf

2011[3] . The reports provide availability indices for overhead lines, underground cables and autotransformers, as well as indices for the impact of the system unavailability to customers (system minutes).

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

i. Setting, per regulatory review period, of the regulated service quality dimensions, the corresponding overall and individual minimum quality standards, as well as the respective penalties/rewards, in conjunction with the allowed revenue of the distribution.

ii. Approval of rules, procedures and methodologies for monitoring, assessing and reporting service quality levels.

iii. Validation of data completeness and accuracy.

Until the Code is finally enforced, substantial preparatory work has already been carried out. Review of the PPC rules, procedures and data regarding QoS dimensions monitored to date has been established by the Regulator since 2008. So far, this has allowed the Regulator to report on the overall service quality level, based on available, non-verified, historical data up to 2010[4], and to formulate and publish its opinion on these data, as well as on current PPC practices regarding service quality monitoring and reporting and on necessary improvements thereof.

3.1.2.2. Monitoring time taken to connect and repair

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

Concerning connection of new generation facilities, monitoring issues do arise for the DSO as, in several circumstances, it takes significant time to respond to requests for connection offers to RES generators. Connection offers by the TSO do not exhibit significant delays, as the number of requests is by far smaller than the requests faced by the DSO.

3.1.3. **Network tariffs for connection and access**

In general, network access tariffs in Greece are of the ‘Postage Stamp’ type, with the ‘G’ component equal to 0% and the ‘L’ component equal to 100%.

[3] March 2012 - http://www.admie.gr/to-systima-metaforas/anaptyxi-systimatos/meletes/archeio/document/43280/doccat/detail/Document/

[4] Data on Quality of Service Indicators for 2011 will be available in the 4th Quarter of 2012.

3.1.3.1. *Transmission Network Tariffs for Access*

Transmission Network tariffs are calculated on the basis of the annual transmission system cost, which is defined in the *Grid and Market Operation Code*[5] as the sum of the annual rent owed to the network owner, now ADMIE S.A., plus the annual cost of any work for the expansion of the System. The annual system cost is also adjusted to take into account the difference between the forecasted and the actual revenue from system users during the previous year. For 2011, the estimated rent owed to the asset owner (PPC) was €264.9m, whereas the total transmission costs to be recovered through the tariffs were €261.7m, accounting for the interconnection auction revenues (€34.9m)[6] and under-recovery of costs through the charges applied in previous years (€31.7m)[7]. The elements of the transmission cost in 2011 were as follows:

- Allowed operating expenses: €82.4m.
- Asset depreciation: €746 million.
- Capital employed: €1,347 million, including €71.1m of new investments
- Allowed Rate of Return (nominal, pre-tax): 8%.

The Capital employed (RAB) and the Asset depreciation were determined, for the period 2010-2011, by excluding the effect of assets' revaluation in 2009 (the revaluation surplus for the Transmission Division was €340.4m).[8]

The methodology for the calculation of the Transmission Use of System (TUoS) tariffs for HV connected customers is set out in the *Grid and Market 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[9].

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. Demand is adjusted for losses depending on the connection voltage. Given the limited metering capabilities of consumers connected to the MV and LV networks (lack of measurements of coincident peaks), for the purpose of calculating TUoS charges, the transmission cost is further allocated to the two voltage levels based on their total energy consumption. The methodology, set out in the relevant manual, further specifies the following:

- For the purposes of TUoS charging, the following four (4) customer categories apply: Domestic, Domestic with Social Tariff (KOT)[10], MV and LV, excluding Agricultural MV and Agricultural LV that have zero TUoS charges.
- Only capacity charge (no energy charge for TUoS) is applied to MV customers, which is charged based on the maximum metered demand (MW) during peak hours (11am-2pm).

5 Ministerial Decision Δ5-ΗΛ/Β/8311/9-05-2005 and subsequent amendments.
6 RAE Opinion 371/2010
7 RAE Opinion 377/2010 to the Ministry of Environment, Energy and Climate Change.
8 The revaluation carried out by an independent firm of appraisers for accounting purposes (according to IAS 16).
9 RAE Decision 2215/2010.
10 In July 2010, a third public service was introduced, a Social Tariff for Domestic Customers, referred to as "KOT". This reduced tariff applies to vulnerable customers. The starting date for the implementation of the new tariff was set for the 1st of January 2011 (Ministerial Decision of September 2010 (Official Gazette, B 1614). See Section 3.3.2.

- Only energy charge (no capacity charge for TUoS) is applied to Domestic customers with Social Tariff (KOT).
- For Domestic customers (except for Domestic customers with Social Tariff), only 10%[11] 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).
- For other LV customers, only 20% of the allocated cost is recovered through capacity charges, which are charged on the basis of the connection capacity (kVA) given the lack of metered demand (MW).

According to the above mentioned methodology, RAE proposed the following tariffs to the Ministry of Environment, Energy and Climate Change for 2011 (the tariffs for MV and Other LV customers remained similar to those for 2010 and 2009):

Customer Category	Capacity Charge (€/MW or €/kVA)	Energy Charge (c€/kWh)
HV	26,365 €/MW chargeable demand (3 coincident peaks)	-
Domestic	0.16 €/kVA of Subscribed Demand per year	0.605*
Domestic with Social Tariff (KOT)	-	0.671
MV (non agricultural)	2,025 €/MW of Monthly Maximum Demand at peak-period, per month	-
LV (non agricultural)	0.70 €/kVA of Subscribed Demand per year	0.576*

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

Table 1. Transmission Use of System (TUoS) charges for 2011

3.1.3.2. Distribution Network Tariffs for Access

There is currently no formal methodology set for the calculation of the allowed distribution revenue, given that the *Distribution Network Code* (which will include the methodology for estimating the annual distribution costs) has not been adopted yet. As a transitional measure, the methodology applied is the one currently used for the transmission system[12]. The elements of the distribution cost in 2011 were as follows[13]:

- Allowed operating expenses: €459.2 million
- Asset depreciation: €140.8 million.
- Capital employed: €2,854.6 million.

[11] Based on 2215/2010 RAE Decision, this cost percentage was reduced from to 20% to 10%.
[12] Ministerial Decree of 31 Dec. 2007, following RAE opinion 294/2007
[13] Ministerial Decree of 15 June 2010 following RAE opinion 378 /2010

- Allowed Rate of Return (nominal, pre-tax): 8%.

The Capital employed (RAB) and the Asset depreciation were determined, for the period 2010-2011, by excluding the effect of assets' revaluation in 2009 (the revaluation surplus for the Distribution Division was €421.9m).

As a result, the total allowed revenue for the distribution activity in 2011 was €828.3m, whereas the total distribution costs to be recovered through the tariffs were €818.3m (thus accounting for an estimated €10m for "Other Revenues" of the activity).

Of this, about €79m were set to be recovered by MV connected consumers and the remaining by LV connected consumers.

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 domestic 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 2011, 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	1,210	0.33
	Capacity Charge (€/kVA of Subscribed Demand per year)	**Energy Charge (c€/kWh)**
LV (subscribed demand >25 kVA) with reactive power metering	4.14	1.70
LV (subscribed demand >25 kVA) without reactive power metering	3.65	1.93
Domestic	0.59	2.17
Domestic with Social Tariff (KOT)	-	2.41
Other LV (subscribed demand ≤ 25 kVA)	1.80	1.93

Table 2. Distribution Use of System (DUoS) charges for 2011

3.1.3.3. *Transmission Network Connection Tariffs*

Only "shallow" connection costs, i.e. from the plant site to the appropriate connection point of the transmission system, are charged to producers. The charges are applied by the TSO, for specific activities carried out by the TSO 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 been approved by the Regulator yet. According to the provisions of Law 4001/2011, a detailed pricelist is to be submitted by the TSO to RAE for approval.

3.1.3.4. *Distribution Network Connection Tariffs*

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

3.1.4. **Cross-border issues**

3.1.4.1. *Access to cross-border infrastructure*

The relevant electricity market for Greece is, to a significant extent, the national market, as a regional market has not emerged yet. The total interconnection capacity in 2011 was 2000 MW. This level was reached in 2010, after the addition of a new interconnector eastwards, with Turkey[14] (500 MW). Following its full synchronisation in September 2010 and a trial operation period since then, commercial trading with Turkey started in June 2011. While trading volumes progressively increased, reaching 2.6 TWh by the end of the year, the impact of the interconnection on wholesale prices was not evident, as, simultaneously, imports from the northern borders were reduced due to economic substitution and portfolio diversification effects.

More specifically, interconnection with adjacent member states (namely Italy and Bulgaria) amounts to 1300 MW (500 MW and 800 MW, respectively), a sum which corresponds approximately to 13% of the annual peak demand (approximately 10,000 MW), while interconnections to Albania and FYROM are restricted to 200 MW total. Romania, another member state with an emerging, relatively liquid, power exchange, is also relevant for price comparisons, as it is indirectly connected, although not adjacent, to Greece. Nevertheless, various aspects of the transit flows through Bulgaria remain ambiguous, due to lack of transparency.

[14] A 400 kV interconnection between Greece and Turkey (nominal capacity 2000 MVA) was completed in 2008. Since then, the focus was on the synchronous operation of the two systems and, particularly, the fulfilment of UCTE network operation standards by the Turkish system.

Overall, the net interconnection balance declined from 5.7 TWh in 2010 to 3.2 TWh in 2011. This decline is better understood if split into import and export patterns. Overall, imports declined from 8.5 to 7.2 TWh (-15%), while exports increased from 2.8 to 3.9 TWh (40%). This net decline reflects the erratic dynamics of regional price spreads, an escalation of exports to Albania, due to severe hydro scarcity, and to some extent, to the removal of constraints in auction rules which had limited export activity in the past. The opposite condition occurred in 2010, when Albania experienced a surplus of hydro power, resulting in substantial flows to Greece (404 GWh).

A re-allocation of import quantities across adjacent countries also occurred, as commercial trading with Turkey developed, with corresponding imports increasing from 0.7 to 2.6 TWh. Exports to Italy declined from 2.3 to 1.7 GWh, in response to more erratic and less favourable price spreads, partially due to the impact of the economic recession on Italian prices and the simultaneous rise in Greek prices, two effects which were occasionally counter-acted. Still, the price differential between Italy and Greece strongly signalled exports to Italy over prolonged periods, with some reverse signs over off-peak periods (00:00-08:00), where pure imports were occasionally conducted. Imports from Italy remained low, but increased from 67 GWh in the previous year to 274 GWh, partially during temporal irregularities, such as a PPC strike in June, and the rising wholesale prices in Greece after a new tax levy was imposed on gas (including gas for electricity) since September 2011.

Imports from Bulgaria declined from 3.5 to 2.8 GWh, while imports from FYROM decreased as well, from 3.9 to 1.5 GWh, reflecting water scarcity in the Balkan region and, hence, reduced price spreads. Exports to Albania escalated from 0.4 to 2.1 TWh, reflecting the impact of a prolonged drought, given the 98% hydro share in the country's generation. For the same reason, quantities exported to FYROM remained marginal, but still increased from 8 GWh to 109 GWh.

Figures 1 and 2 display the allocation of interconnection trading in 2011 and its evolution relatively to 2010.

Focusing on price differentials, the premium of the Italian baseload retained substantial levels over 2011, mostly fluctuating between 15-30 €/MWh, and exceeding 50 €/MWh in some outstanding cases (August peak). These values imply substantial profits for exports to Italy over 2011, as well as potential profits for imports to Greece, whenever the sign reversal of the spread occurred and to the extent that this could be anticipated. As a representative price index in adjacent northern countries has not emerged yet, Romanian prices can be used as a plausible proxy. These prices exhibited a large discount relatively to Greek prices in 2011, which, given regional similarities, explains the large inflows to Greece from northern borders. More specifically, the premium of the Greek baseload relatively to the Romanian was quite erratic but substantial overall, often exceeding 25 €/MWh. Still, spread reversals were realised more often and with a higher persistence than in the previous year.

Usually, up to 15 companies were actively trading on the interconnection with Italy and significantly less, regularly around 5-10, at the northern borders and Turkey. As the constraint relating to security of supply in Greece was removed from the auction rules in 2010, and transit flows were exempted from uplift costs (reflecting the operation of the Greek wholesale market), cross-border trading was expected to become more efficient. Still, export activity was constrained in 2011, and the hydro shortage in Albania was only a temporal favourable condition.

The introduction of intra-day balancing in the Italian market since January 2011 allowed traders to adjust their positions after the closure of the Greek day-ahead market, eliminating this part of their uncertainty, while retaining their exposure to market conditions in Italy (prices, quantity, penalties). This change had an impact on the pricing of imports from Italy.

Import prices, which used to be zero in the past, so as to secure their flows, reflected now traders' predictions and, quite often, they were interpolations between the marginal costs of different plant technologies. In this context, certain strategies, typically of a reserve order to all others and of minor quantities, may occasionally influence the SMP in Greece and even reverse the price spread. The synchronisation of the two markets and the convergence of their imbalance penalties could avert such incidences.

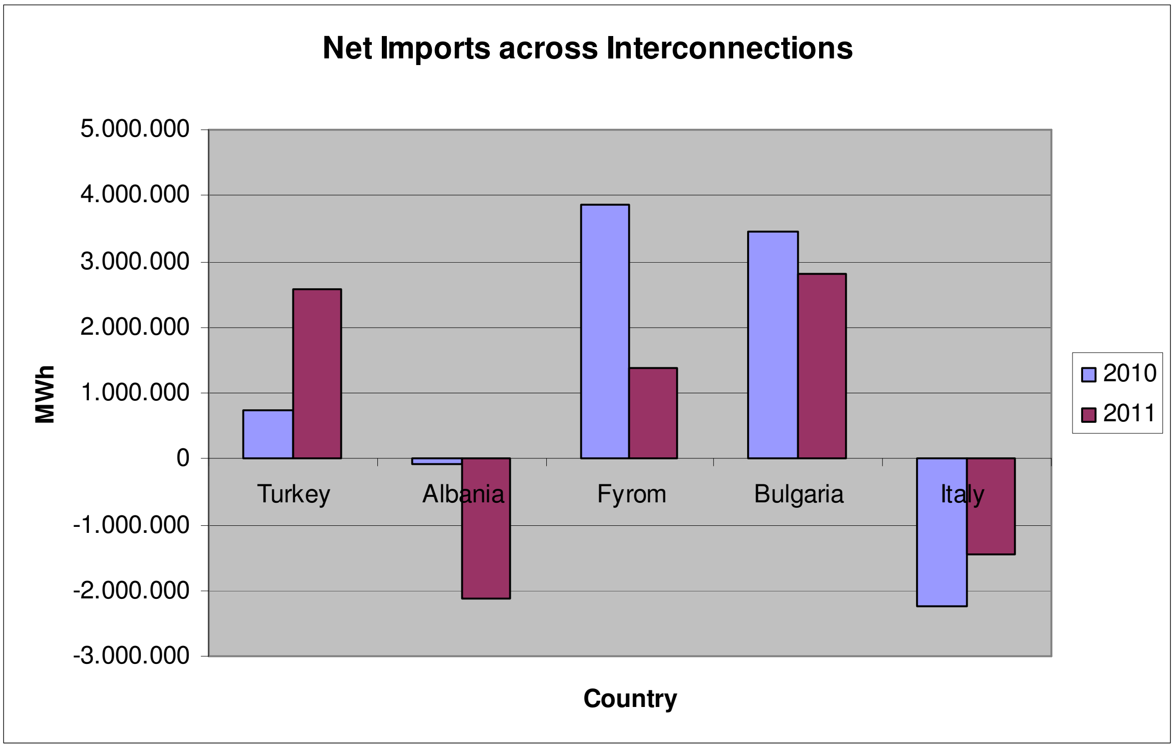

Figure 1. Net trading volumes across countries. Positive values represent net imports and negative values net exports.

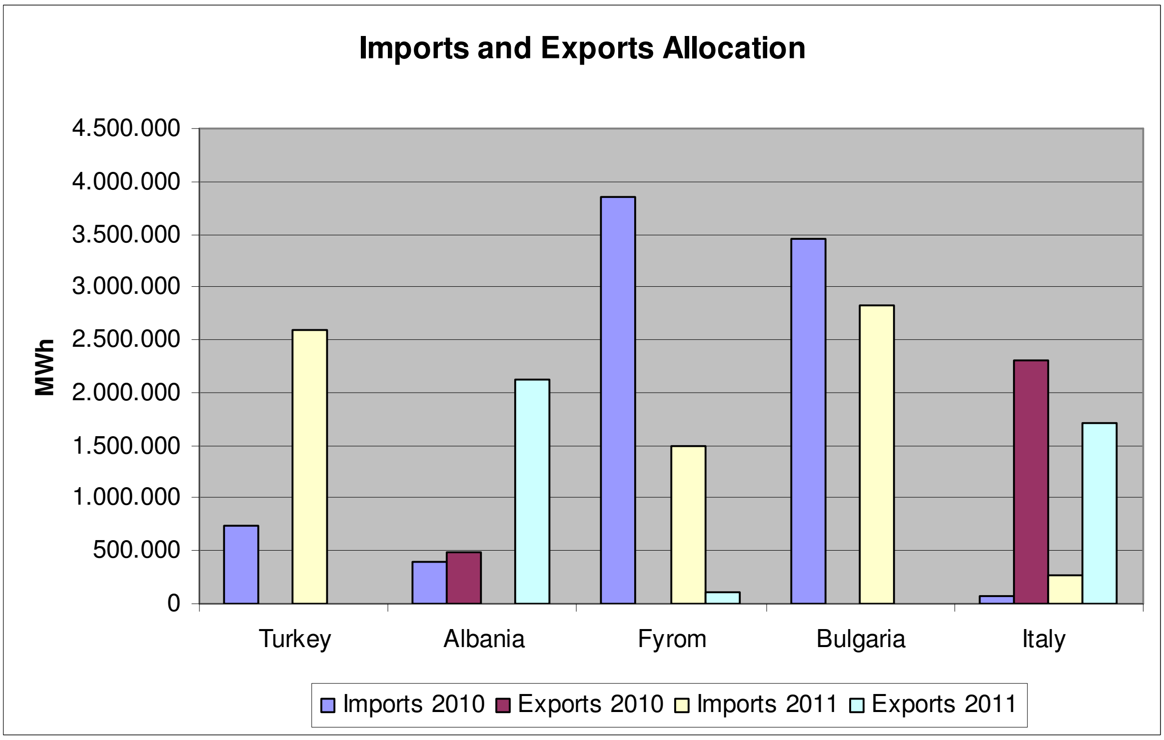

Figure 2. Profile of import and export trading in 2011, compared to 2010.

Significant changes also occurred in auction rules and auction implementation in 2011, both in the interconnection with Italy and with the Balkan countries. In order to facilitate market integration and harmonization of cross-border congestion management, capacity allocation for the Italian borders within the Central – South (CSE) region was performed, effective April 1st 2011, by the Capacity Allocation Service Company (CASC S.A.), the company which also performs the capacity allocation functions for the CWE region borders. The 2010 auction rules continued to apply for the period 1st January - 31st March 2011. This development enhanced compliance with the EC Regulations 1228/2003 and 714/2009. Points that now remain to be addressed are the ex-ante determination of the percentage fractions of capacity allocated across yearly, monthly and daily basis, and the intra-day allocation and management of capacity rights (which seems challenging in the absence of intra-day trading in the energy market).

In the past few years, integration with adjacent Balkan countries was subject to trading obstacles, due to the lack of appropriate implementation of Regulations 1228/2003 and 714/2009, especially regarding capacity allocation mechanisms and transparency issues. Following the second infringement letter issued by the European Commission in July 2009, significant improvements towards full compliance with Reg. 1228/2003 started to take place, from 2010 onwards. Significant changes that occurred in 2011 include: (a) the introduction of joint auctions for the allocation of the total capacity (with the Bulgarian TSO performing the monthly auctions and the Greek TSO the yearly and daily ones, along with the secondary market management), (b) common rules for the secondary market, and (c) a common clearing procedure for congestion revenues with equal allocation between the two system operators. A common approach regarding the determination of NTC between the two system operators (in accordance with 714/2009) has not emerged yet.

Regarding the interconnection with Albania and FYROM, the TSO's discretion to implement capacity rights curtailments, by claiming security of supply issues in the Greek market, was abolished. The auctions would be performed every day (including public holidays) and their time-framework was synchronized with CASC auctions. The concept "use it or sell it" (UIOSI) was re-introduced for the non-declared yearly or monthly rights in the daily auctions.

Regarding Turkey, the interconnection entered its commercial operation in June 2011. Due to sudden, non-scheduled changes in load flows at its initial stage, the full implementation of the 714/2009 Regulation has not been feasible yet.

The main principles of interconnection congestion management rules in 2011 remained unchanged, as compared to 2010:

- Annual, Monthly and Day-ahead (D-1): Explicit Auctions of Physical Transmission Rights (PTRs)
- UIOSI rule applied to long-term PTRs (reallocation by HTSO at Monthly and Day-Ahead Auctions) and UIOLI 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 2011, HTSO managed capacity allocation on the interconnections and directions as presented below.

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%

** Monthly auctions performed by the Bulgarian TSO (ESO-EAD)*

Table 3. HTSO responsibility for capacity allocation on interconnections

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

3.2. Promoting Competition

In 2011, the Greek wholesale market grew more mature, in the sense that substantial new capacity entered the system, intensifying competition for medium- and peak-load demand. However, severe liquidity problems and credit risks started to emerge in the domestic energy sector, partially reflecting the country's continuing economic recession, but also the adverse effects of "generous" policies regarding retail prices and renewables tariffs. The relevant implemented policies, although appealing to governments in the context of social policy and strong renewables growth, respectively, were internally inconsistent as revenue streams. Costs were not correctly reflected, or adequately transferred across the value chain, creating sustained debts in the renewables account, managed by the TSO, and gradually diminishing its liquidity. Two other policy choices applied in 2011, i.e. the introduction of a tax levy on natural gas and the inclusion of a new property tax in the electricity bill, also created adverse effects on competition and on consumers' ability to make payments, respectively. Debt issues, which continue to escalate in 2012, raised unprecedented challenges for the market participants, the TSO and the Regulator. This potentially explosive situation stimulated an intense discussion on alternative ways to move forward, which is likely to result in the introduction of substantial structural reforms in the coming months, consistent with the need for market adjustment to the EU Target Model envisaged for 2015.

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[15], so as to allow competition to emerge, in a context which, however, had a severe constraint: no structural reforms were implemented on PPC, the previous public electricity monopoly, such as plant divestures or release of consumers, as was the case in other European countries. In particular, the incumbent remained dominant in both the generation and the retail sectors, retaining exclusive access to cheap lignite and hydro resources, while retail prices, despite the gradual removal of cross-subsidies, remained unlinked to wholesale prices. This combination of unfavourable market conditions posed severe obstacles to new entrants in the early years of market liberalisation, resulting in capacity shortage over the subsequent years. The capacity certificate mechanism introduced in 2006 created incentives for new investment, which turned out to be adequate, as almost 2000 MW of new, IPP gas-fired capacity has been added to the system by the end of 2011. Still, projections for strong and prolonged demand growth (around 2.5% annually) were disrupted in 2009, when demand sank by 7%, due to the then erupting economic crisis, and has not recovered since. Hence, a substantial capacity surplus has emerged, with limited export possibilities and limited cost-reduction capability. 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 implicit in their gas-supply contracts.

[15] After gradual refinements, the transitional market design, implemented over a five-year period, was succeeded on 30th September 2010, marked as the "5th Reference Day", by its final provisional form. The revised market design thus reflects the full implementation of the 2005 *Grid and Market Operation Code*. See previous Reports for a detailed description of the transitional design.

Furthermore, wholesale prices remained low, not reflective of the full energy production cost. Their levels are suppressed due to significant amounts of compulsory quantities, including a) mandatory hydro, b) plants' minimum operational levels, and c) renewables, which currently constitute a fast escalating cost component. The widening difference between (depressed) wholesale price levels and high feed-in-tariffs applied to the reimbursement of renewables production has created a sustained (not temporal, but structural) debt in the renewables account, managed by the TSO, something that reduces its liquidity and hence, its ability to pay conventional generators and importers, too. At the same time, consumers' debt (unpaid electricity bills) escalated to €1.4 billion (estimated value) at the end of 2011, due to the severe economic recession and the incorporation of a property tax into the electricity bill, which catapulted the amount due. This convolution of adverse conditions and inconsistent policies has created severe financial problems to all market participants and to the TSO, which started to become more pronounced in 2011, and escalated drastically in 2012, signalling the urgent need for tariffs to be adjusted, or for new sources of financing to be found for stabilising the renewables account.

In this challenging environment, the revised market design, fully implemented in September 2010, after gradual evolution over the previous five (5) years, has completed in 2011 its first full year of application, remaining stable in terms of its structure and objectives. Various design details got progressively more refined, so as to address technical or credit risk issues that emerged since then. In essence, this market design reflects the full implementation of the 2005 *Grid and Market Operation Code*. One of the key features that differentiates it from its previous transitional form is that it has introduced a clear distinction between the day-ahead market and the balancing mechanism that follows, as in other countries with mandatory pools. This structure reflects more clearly the factors influencing prices, the uncertainties involved and the implied risks at these distinct time scales. More specifically, during the transitory market regime, the Day-Ahead market provided an indicative plant-commitment schedule and a reference spot price (SMP forecast), which served purely as a signal. Cash-flows were based on ex-post SMP prices. These were derived by re-solving the same cost-minimisation algorithm as in the day-ahead schedule, by inserting actual metered values of the various inputs (mainly demand, plant availabilities and renewables' output), instead of day-ahead forecasts. These ex-post prices were applied to the actual quantities consumed or produced (the latter reflecting, to a large extent, the real-time dispatch orders of the TSO).

As opposed to an overall market settlement (through ex-post SMP prices), the current market design involves two distinct settlement processes:

- The settlement of the day-ahead market, in which generators' payments (suppliers' charges) are calculated, based on the SMP prices and the plant schedules derived from the day-ahead dispatch (load declarations submitted).
- The settlement of imbalances, in which deviations from day-ahead schedules are charged or compensated, depending on whether they are exogenous or reflect the TSO dispatch orders.
- There is also a provision for imbalance penalties, if certain limits are violated, regarding the magnitude and the frequency of the deviations.

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

The following rules or supplementary mechanisms still apply:

- A lower limit is imposed on generators' offers, equal to the minimum variable cost of each unit in each trading period. This has been introduced because, in the current structure, the incumbent has a strong incentive to suppress wholesale prices.
- A cost-recovery mechanism ensures that generators dispatched by the TSO, beyond the day-ahead schedule, are remunerated based on their declared minimum variable costs plus a 10% margin. This mechanism creates a safety net, which often makes participants rather indifferent to the price levels.
- A Capacity Adequacy Mechanism is applied for the partial recovery of capital costs, with suppliers being obliged to buy capacity certificates from generators. The value of these certificates was revised in November 2010, from 35,000 to 45,000 €/MW/year, in order to alleviate the impact of low demand on generators' revenues. This value was retained throughout 2011.

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 the differences between the day-ahead schedule and the real production or withdrawal of electricity – are settled through the Imbalance Settlement Mechanism.
- The timeframe for the imbalance settlement is one (1) hour.
- 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 according to the following rule: each imbalanced party pays or receives an amount, depending on whether it injected or withdrew energy from the system, equal to the product of the ex-post clearing price and its imbalance 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 has been included, aiming to ensure that generators will receive at least their marginal cost whenever they operate. The aim of the imbalance mechanism methodology is to minimise the total cost of system operation, by giving adequate incentives for "proper" behaviour to the market participants.

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.

Financial Outcomes

Over the first full year of its implementation (2011), the revised market design had an impact on market participants' cash-flows and on market conduct.

In particular:

- The balancing cost was a minor fraction of the energy cost in the day-ahead market. Indicatively, the generators' annual revenues from the day-ahead market added to €2.83billion, while in total, their imbalance charges slightly exceeded imbalance payments, yielding a (negative) net amount of €16.2 million. Suppliers' imbalance charges were €62 million in total, mainly reflecting under-predictions of demand by PPC, while most other suppliers received imbalance payments.

- The imbalance charges that PPC paid for its lignite plants, which tend to exhibit production shortage in real time, relatively to their day-ahead dispatch, were counter-balanced to a large extent by the imbalance payments received by its hydro plants.

- The provision of ancillary services yielded 1% of total generators' revenues over 2011. Given the capacity surplus and the co-optimisation of energy and ancillary markets, generators diminished their offers for reserve provision, so as to secure their dispatch even at their minimum operation level and receive subsequently a cost-recovery payment.

- The two supplementary mechanisms (cost-recovery and capacity certificates) yielded 20% of total generators' revenues over 2011

- The cost-recovery mechanism translated into a charge of €130 million for PPC in 2011, as opposed to 28.5 million in 2010, reflecting the increase in IPP production.

Market Volume

The day-ahead market yields the reference price for the industry, as it constitutes the major component on which generators' cash-flows are based. Due to the mandatory physical trading in this market, the traded volume of electricity is equal to the annual demand (including the interconnection balance), i.e. 51,872,288 MWh in 2011. This represents a decline of 0.94% relatively to 2010. A futures market has not been developed yet, while OTC trading has not been activated either.

Regulatory Progress in 2011

The regulatory focus in 2011 was on market adjustment to short- and medium-term challenges, varying from the specification of parameters related to the balancing mechanism, to the management of the credit risk issues that emerged, and the anticipated structural changes both in the TSO and in the market itself, as a way to alleviate asymmetries and become more compatible with the Target Model framework.

Indicatively, RAE worked on the following issues:

- The modification of the controversial excise tax imposed on natural gas from 1st September 2011 onwards, which yielded asymmetries among fuels. Initially added to the plants' fuel cost and hence, reflected on wholesale prices, this tax was transferred adversely to suppliers and eventually, consumers. RAE proposed this tax to be removed from the plants' offers and the corresponding amount to be recovered indirectly, through a specific market account (LP-3).
- The incorporation of CO_2 emission costs into the minimum variable cost of plants (i.e. the lower limit of their price offers), with effect from 8 June 2011 onwards. This cost reflects, at a transitional stage, the cost of covering a plant's emissions deficit (comparatively to free allocated credits) and the full emission cost from 2013 onwards (when free credits cease to apply).

- The systematic under-prediction of wind production, likely to influence the SMP. The TSO was required by RAE to refine its wind prediction model and to monitor its error structure.
- The incorporation of other renewables' production (those connected to the distribution network, not the high-voltage grid) into the market resolution. The TSO was required by RAE to develop a forecasting model, so that this generation is explicitly inserted into the market resolution, as an additive term to predicted wind production (instead of its implicit subtraction from load declarations made by PPC).
- The correction of an error by the TSO in the application of the formula computing secondary reserve payments and charges.
- The understanding of cogeneration dispatch issues, potential competition effects and reimbursement mechanisms.
- The calculation of losses in interconnections and TSO's potential reimbursement for loop flows.
- The clarification of the TSO's credit cover approach and the follow-up on its handling of suppliers' liquidity problems, in particular, as regards the guarantees required for their participation in the market (moving away from a "lenient" approach, towards a strict enforcement of the relevant Code).
- The provision of a two-month credit margin for charges relating to the RES levy, the PSO, the capacity certificates and the network and distribution use, so as to reduce the time gap between suppliers' energy payments to the TSO and their cash inflows from consumer payments.
- The adaptation of the ITO model (as opposed to ISO), since February 2012, and hence, the re-structuring of the former TSO into two discrete entities:
    - The Market Operator, which solves the day-ahead market, conducts its clearing, and engages into contracts with renewables producers.
    - The System Operator, which owns the network, as a 100% subsidiary of PPC, conducts the real time dispatch, the clearing of the imbalance market and the settlement of all other charges or payments.
- The determination of basic principles for the certification of the new ITO.
- The splitting of the Market Code into a) the Grid Code and b) the Transactions Code.
- The establishment of the Distribution Network Operator and the development of its compliance procedure.
- The assessment of the relevance and effectiveness of virtual plant power auctions, or measures similar to NOME as applied in France, to the domestic market, so as to allow portfolio diversification and cost reduction for IPP generators, facilitating their entry into the retail market and hence, enhancing gains for consumers.
- Understanding the type, cost and efficiency of the market re-organisation options, in order to become compatible with the Target Model framework (in particular, harmonisation of auction rules for cross-border trading).

Regulatory measures regarding all the above issues were either adopted during 2011, or carried over to 2012 via public consultations. Choices for structural reforms were also explored in more detail in 2012, and relevant RAE proposals were presented for public consultation first in July 2012, and then in November 2012, in their final form.

With the objective to increase transparency by clarifying market parameters and market conduct, a daily market report was developed by RAE and has been uploaded on its website since July 2011. The report displays and summarises the dynamics of market fundamentals and market outcomes, such as schedules, market shares, emissions, as well as deviations between day-ahead and real-time quantities. In this context, distortions, such as systematic over- or under-declarations in generation or supply, are illustrated in easy-to-follow graphs.

3.2.1.2. Price Monitoring

In contrast to collapsing wholesale prices in the previous two years (2009 & 2012), those prices reverted to higher levels in 2011, displaying an average value of 59.36 €/MWh, and, hence, a substantial increase of 13.5% relatively to the price average in 2010 (52.30 €/MWh). This price reversal was not a sign of economic recovery, but reflected, to some extent, the impact of market fundamentals, and mainly the scarcity of hydro, after two successive years of intensely wet conditions. While water scarcity exerts an upward pressure on wholesale prices, due to the need for substitution by more expensive energy, this effect was less pronounced than in previous years, due to the substantial capacity surplus in the market.

Furthermore, the price rise was also due to the new tax levy imposed on natural gas, from 1st September 2011 onwards. This controversial tax, which raised concerns about its asymmetric impact on gas-fired electricity production vs. lignite production and imports, implied an increase of 5.4€/MWh in the variable cost of the gas plants (assuming maximum plant efficiency). The effect of this tax counteracted the downward trend in prices that the seasonal decline of demand would be expected to induce in certain months (e.g. October). The imposition of this tax, combined with the shrinkage in hydro production, yielded a sustainable price increase, from September 2011 onwards. Indicatively, the daily average price increased from 55.66 €/MWh on 31th August to 73.09 €/MWh on 1 September (+31%), although the market fundamentals remained quite similar. At an aggregate level, the average price level escalated from 54.60 €/MWh prior to the tax levy to 68.83 €/MWh in the period after, while the average price in 2010 was 52.30 €/MWh.[16]

Price volatility in 2011 increased quite substantially. Prices exhibited a standard deviation of 23.18 €/MWh (19.55 €/MWh in 2010), reaching a maximum value of 150 €/MWh (price cap) in 14 hourly trading periods and a minimum of 0 in 35 periods, while in 5% of the trading hours, prices exceeded 100 €/MWh. Zero price levels occur during significant demand drops (typically the Easter break in April), when compulsory quantities (technical minima of plant generation, renewables and imports) may exceed consumption. Due to this surplus, imports, offered at a zero value, may get curtailed, setting the price to its minimum level. It is notable that this extreme case occurred only once in 2009, a fact that reflects the increasing penetration of wind generation.

Figures 3, 4 and 5 display the dynamics of the day-ahead price, SMP, across the year, as well as its intra-day profile. Given the revised market design introduced in September 2010, this price is the relevant market index, as it determines the largest part of participants' cash-flows.

[16] The methodology of inclusion of this tax into the variable cost of gas plants was modified by RAE in January 2012, so as not to be incorporated into the generators' offers in the electricity daily market (SMP); still, it had an adverse effect on industrial and export activity, diminishing the competitiveness of Greek products.

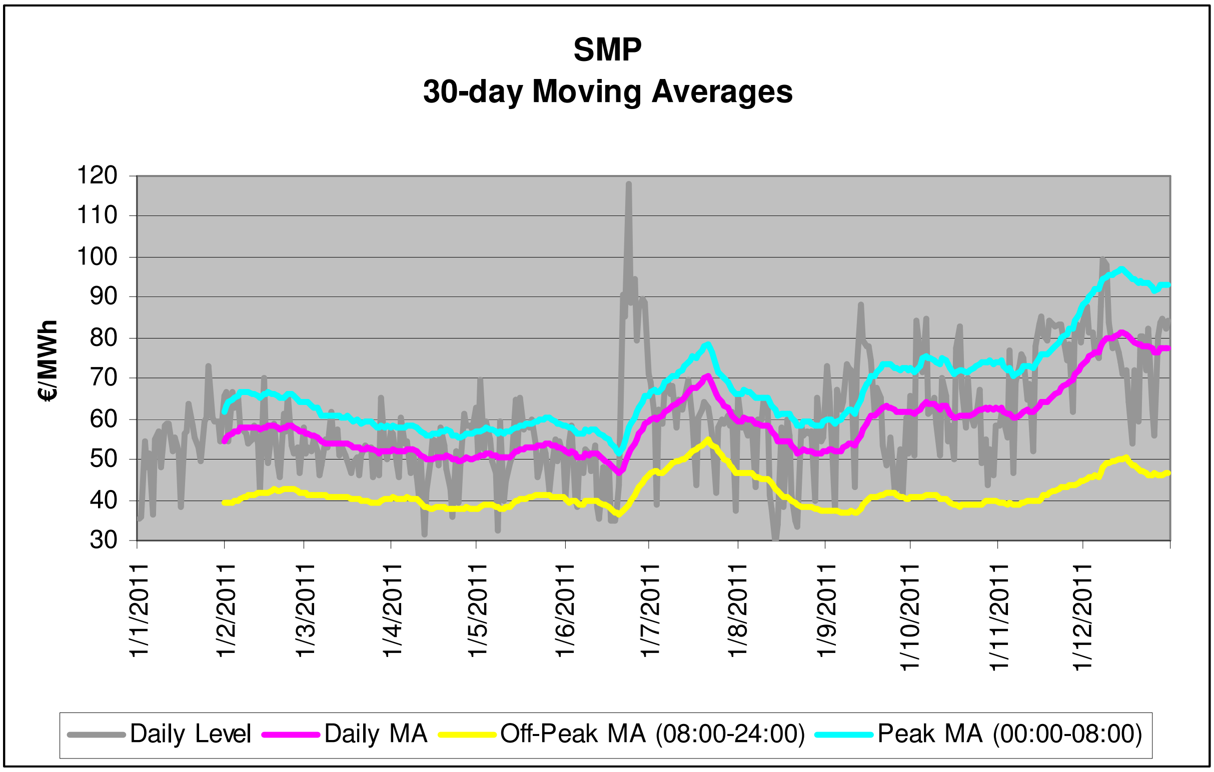

Figure 3. SMP dynamics (actual and smoothed levels) over 2011

The intra-yearly evolution of prices reflects the seasonal variation of the constrained hydro releases (diminished levels overall, but increased from June to August, for peak-shaving purposes), the dynamics of gas prices, maintenance schedules and outages. In particular, severe outages occurred in two gas plants towards the end of the year (Protergia, an IPP gas-fired unit, and PPC's Lavrio 5), rendering them unavailable over long periods of time (two and six months, respectively). At the end of June, a labour union strike at PPC, causing major capacity withholding (up to 20 plants), resulted in escalating prices (up to 108 €/MWh) over nine (9) days. It was also notable that in November 2011, demand showed an increase of 8% relatively to November 2010. It appears that air-conditioning units were used extensively for heating purposes at that time, as a substitute to heating oil, since the latter was perceived as a more expensive option for households. A secondary factor, which induced some price volatility in 2011, was the considerable trial-operation periods of new IPP plants. These plants induced occasional output variations from 300 to 4400 MWh on a daily basis. According to the market rules, their output entered the market as must-run generation, hence counteracting some of the upward pressure on prices, depending on the combination of other parameters, too.

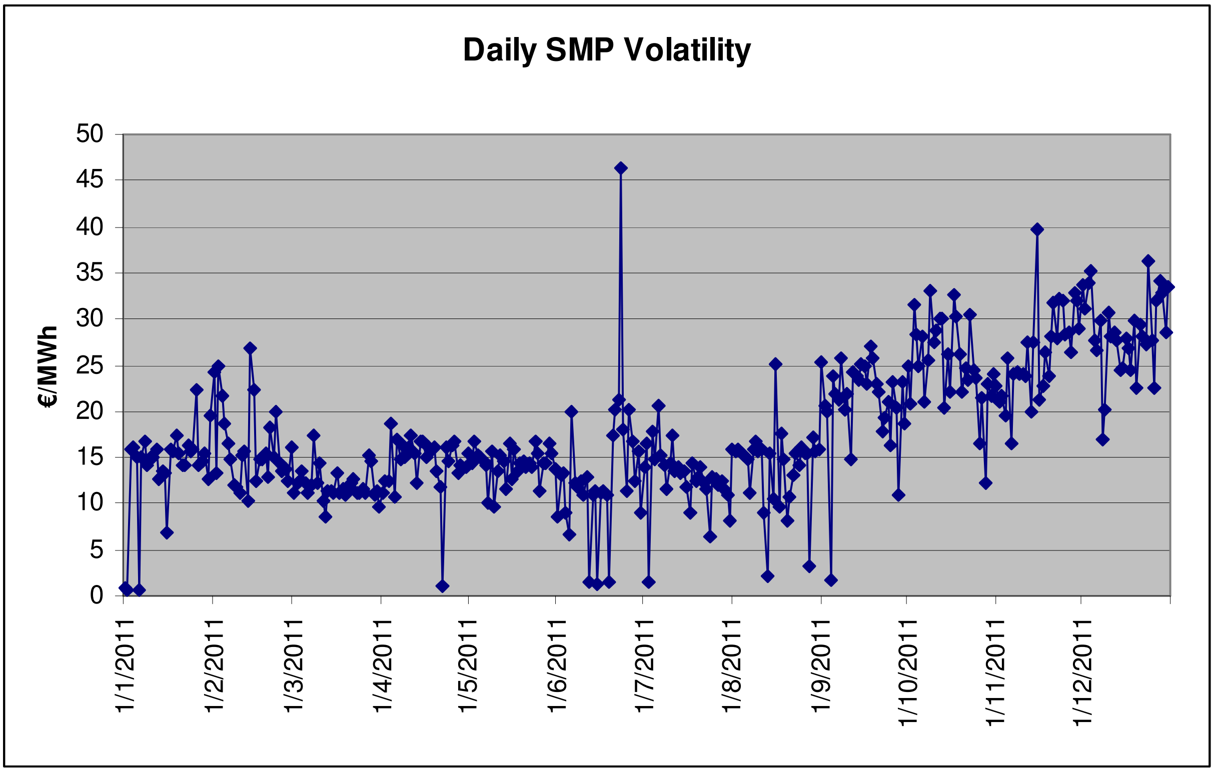

Figure 4. SMP volatility (standard deviation) over 2011

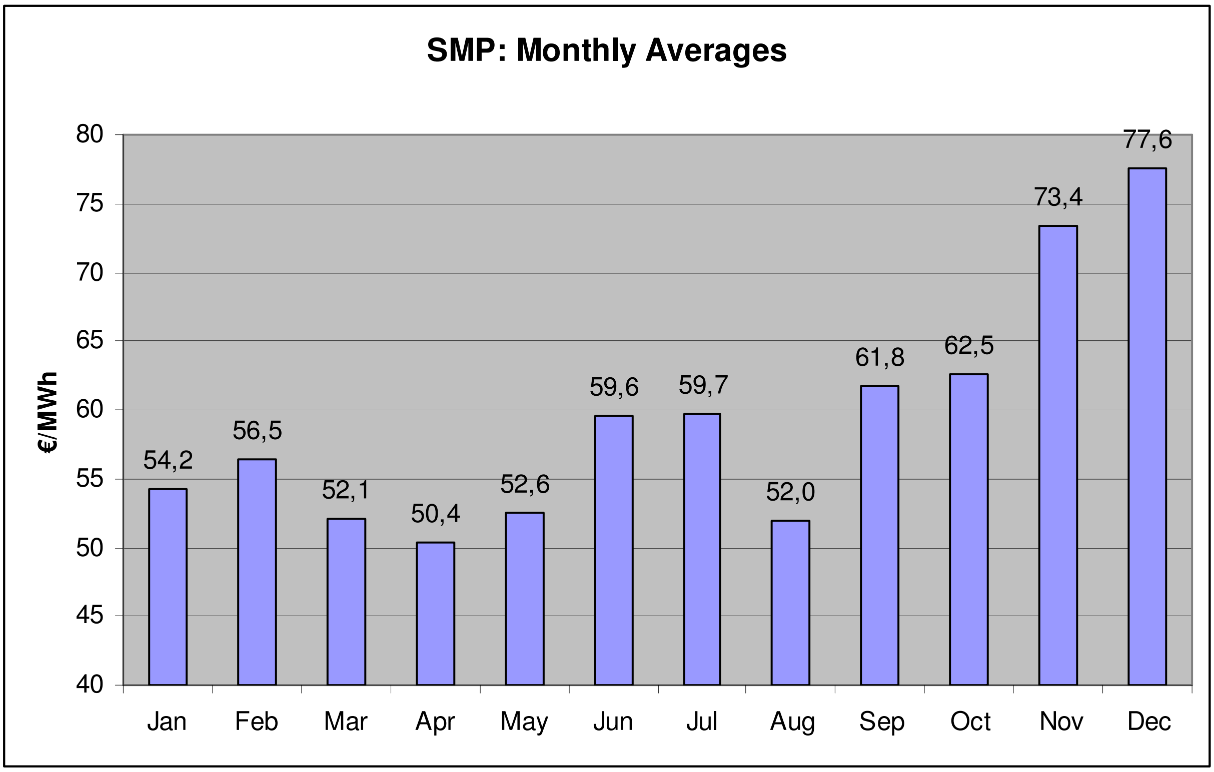

Figure 5. SMP intra-yearly pattern in 2011

Despite the declining market concentration at both sides of the market, wholesale prices remained sensitive to PPC's bidding behaviour in 2011. Given its vertically-integrated structure, and in the presence of substantial retail margins for certain customer categories in the past, the dominant objective of the incumbent in previous years seemed to be to suppress wholesale prices, in order to reduce its cost of energy purchases (effectively from renewables, independent generators and imports) and, possibly, to curtail IPPs' production and, thus, revenues.

In 2011, PPC's strategy could be possibly interpreted as being more concerned about retail losses rather than production losses. A critical factor in the formation of wholesale prices is the level and allocation pattern of hydro production, to which PPC retains exclusive access, along with lignite. In 2011, PPC implemented a conservative water management approach, which could be considered, ex-post, as over-restrictive in certain time periods, but counter-acted well the scarcity that emerged in Q4 2011. Simultaneously, this practice reduced the retail margin, in a period when PPC's retail volume decreased by 4.4% relatively to 2010, and its retail share declined to 92.3%. The exit of the two main alternative suppliers from the market, in the beginning of 2012, emphasised how sensitive the retail margin is and raised the question of how critical the restriction of hydro output was for this outcome.

In response to the above observations, RAE has proposed an integrated review of hydro management parameters, focused simultaneously on maximum daily quantities, prices reflective of the opportunity cost of water, and allocation patterns, linking these parameters explicitly to reservoir levels and to the cost of the substitution fuel mix.

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

Following the addition of two new CCGT plants in 2011, competition has intensified between PPC's gas plants and IPP units. Competition in this particular market segment has become more intense, given the continuing decline of electricity demand due to the economic crisis. The effect on prices becomes more apparent when independent units undergo maintenance, or get back to regular operation. Furthermore, the cost-recovery mechanism – a transitional compensation scheme – creates a safety net for them, which often makes IPP generators rather indifferent to the price levels and induces an emphasis on quantities produced, rather than on prices offered.

Competition in the reserves market has been particularly intense as well. In the provision of secondary reserve, which is crucial for renewables penetration, the only participating IPP unit, for most of 2010, was Enthess. Heron CC and Thisvi units got involved with this service towards the end of 2010. By the end of 2011, all new IPP units were active in secondary reserve provision, while PPC was represented only by the units Komotini and Lavrio 4.

An appropriate link between wholesale and retail prices is critical for the market to evolve in a more competitive direction. Hence, emphasis has been placed on the gradual adjustment of regulated prices, so that cross-subsidy distortions are reduced and retail prices reflect wholesale market costs.

3.2.1.3. *Monitoring the level of market opening and competition*

Regarding the market structure, PPC retained its dominant position in 2011, but its market share declined substantially, both in the generation and in the supply side. In the generation sector, a significant change towards a less concentrated structure occurred in 2010, as two new IPP units entered into commercial operation, and this change was reinforced in 2011, with the addition of two more IPP plants. In terms of thermal capacity, this direction of market evolution is not expected to persist in the future, as all private plants have now been completed, and the new plants expected to come on stream are all owned by PPC. This would change, however, if plant divestments, intensively discussed between the Greek government and the EU, or alternative measures of PPC's capacity allocation, are implemented in the coming years. Apart from conventional generation, changes in the market structure were enhanced by a steady, currently explosive, renewables' penetration (mostly PVs), in which PPC's share is marginal.

More specifically, regarding new capacity, significant additions occurred in 2011, intensifying competition for mid- and peak-load demand. The market dynamics changed as a result, but only to the extent allowed by the basic parameters of the current market design. A critical factor for market outcomes was the market rule that allows generators to offer 30% of their plant's capacity at a price below its minimum marginal cost. This rule allows the dispatch of various plants for reserve provision, which is crucial for the plants' viability in an era of capacity surplus, but suppresses prices to levels not reflective of the full production cost. In this context, RAE has proposed the removal of this rule, which, overall, had a rather distorting effect on the market.

Focusing again on market structure features, after the entry of two new CCGT plants (Elpedison Thisvi and Heron CC) in April 2010, two additional CCGT plants, Protergia (444.5 MW) and Korinthos Power (437 MW), entered the system in 2011. The former initiated its commercial operation in December 2011, after trial operation since January 2011. The latter started its trial operation in December 2011, with commercial operation commencing in April 2012. Both plants belong to the Mytilinaios Group. In particular, Korinthos Power is a subsidiary company of the Mytilinaios Group, owned jointly with Motoroil, with shares of 65% and 35%, respectively. Given the above developments, Mytilinaios Group became the largest IPP player in terms of installed capacity, followed by Elpedison with a total capacity of 812 MW.

Given the addition of substantial capacity over two consecutive years (2010 & 2011), the relevant market share of PPC declined significantly in 2011. In the interconnected system, PPC's generation share, in terms of volume, dropped to 75%, relatively to 85% in 2010, while independent gas producers achieved a share of 20% (Elpedison 8.9%, Mytilinaios 5.6% and Heron Thermoelectric 5.3%), and renewables captured 5.2% of production. While IPP's share more than doubled, PPC's gas production declined by 816 GWh (13.5%). It is interesting that, despite this decline, the annual gas cost for PPC increased by €10 million; due to an 18.4% increase in gas prices and a €21 million additional tax contribution due to the new levy imposed on gas.

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

- Enthess (395 MW) and Thisvi (422 MW), both CCGT plants, are owned by Elpedison.
- Heron II (432 MW, CCGT) and Heron I (147.5 MW, OCGT)[17] are owned by Heron Thermoelectric (GEK Terna- Gdf Suez).

[17] The Heron OCGT unit, previously contracted by the TSO for the provision of ancillary services, retained over a fourth consecutive year a long-term capacity availability contract with the incumbent, PPC. As noted by

- Protergia (444.5 MW, CCGT), Korinthos Power (437 MW, CCGT), and Alouminion (334 MW, large-scale CHP) are owned by the Mytilinaios Group.
- Motoroil has a cogeneration unit of 85 MW of net capacity, owned by the refinery.

At the national level (including the non-interconnected islands), PPC's production covered 70.1% of total demand in 2011, the corresponding share being 77.3 % and 85.6% in the previous two years. Subsequently, this market share was suppressed further, reaching 67.5% in Q1 2012. In absolute terms, PPC's production plus imports was reduced by 4451 GWh in 2011, while in 2010 this quantity had already been reduced by 5123 GWh relatively to 2009. The import activity of PPC was also reduced, by 18%. Regarding renewables generation, PPC's production remained low (246 GWh vs. 374 GWh in 2010), due to water scarcity affecting its small hydro units. Independent renewables production reached 3958 GWh in 2011. Wind parks connected to the HV system yielded 2535 GWh.

Due to the mandatory physical trading in the wholesale market, the traded volume of electricity is equal to the annual demand (including the interconnection balance), which reached 51,872,288 MWh in 2011. This represents a decline of 0.94% relatively to 2010. Alternatively, we may consider imports and exports as distinct trading volumes in the market and add them to the domestic plant production. Adopting the latter definition, the yearly trading volume reached 59.766.618 MWh in 2011, which represents an increase of 3% relatively to 2010.

The HHI index for the wholesale market in 2011 attained the value of 5764, dropping further from the value of 6844 in 2010. It is notable that this index exhibited substantially higher values in the past, close to the upper bound of 10000, in all years before 2010. The decrease indicates that the market is evolving towards a more competitive direction, with the current structural constraint being the lack of fuel diversification for IPPs, as well as the lack of physical hedging for them (consumers). As long as their fuel cost remains high and retail prices are not linked to wholesale prices, the entry of independent generators entry into the retail sector will not be an attractive option.

RES Levy

Renewable energy generation receives special feed-in tariffs (FIT), as set by law and relevant Ministerial Decisions. According to the provisions of Art. 143 of Law 4001/2011, which replaced Art. 40 of Law 2773/1999, the Market Operator (LAGIE) and the Distribution System Operator (DEDDIE) fully recover the sums paid to RES producers, through a Special RES Account managed by the Market Operator.

Five (5) different sources contribute income to this special account:

(a) The amounts that RES production would receive through operation in the wholesale market, in the interconnected system.

(b) The amounts that RES production would receive through operation on the non-interconnected islands, at the Average Variable Cost of Generation, as set annually by RAE.

Heron, this contract, similar to a tolling arrangement, increased its limited hours of operation, hence increasing the amount of gas used and reducing the average gas transportation charges. During the June 2011 PPC labour-union strike, this plant operated quite intensively and the same was true in the gas crisis of February 2012.

(c) The special RES levy, which is allocated uniformly throughout the Greek constituency, to every customer (including the independent autoproducers), based on the Equivalent Relevant Output method.

(d) The revenue derived from auctions of unused rights for emissions of greenhouse gases.

(e) Any other revenue that is foreseen by the existing legal framework (e.g., as of recently, part of the revenue coming from a television license fee, which is collected through the electricity bills).

The calculation of the Special RES Levy of Art. 143 of L.4001/2011 takes place on a regular (usually, annual or semi-annual), ex-ante basis, taking into account estimates of:

- the amounts to be paid to RES producers through the published feed-in tariffs, including assumptions made on the annual production of RES plants,
- the average variable cost of generation on the non-interconnected islands,
- the System Marginal Price in the wholesale market of the interconnected system,
- the total energy consumption in Greece, and
- the expected revenues derived from auctions of unused rights for emissions of greenhouse gases, as well as from other sources, such as part of the amount collected through electricity bills for the television license fee.

In 2006, the RES levy was set at €0.30/MWh, uniformly for all consumer categories. Due to the substantial increase in RES production in subsequent years and the decrease in the wholesale market price (SMP), an expanding deficit in the Special RES Account led, in June 2010, to an increase in the RES levy. RAE Opinion 236/2010 called for a uniform increase of this RES levy to the new level of 5.57€/MWh. The Ministerial Decision[18] diverged from RAE's Opinion, differentiating the RES levy and, in practice, applying its increase only to non-domestic customers. This Decision was enforced throughout the second half of 2010.

In December 2010, a new methodology was adopted for the allocation of the above-mentioned RES levy to different consumer categories. This methodology is similar to the one concerning PSO charges, i.e. the Equivalent Relevant Output method, based on the average revenue by category, according to the methodology approved by the Ministry of Environment, Energy and Climate change (MNEC)[19]. This methodology was applied for the first time to the charges applied in 2011, introducing a differentiation of the levy per customer category.

The total required revenue for the Special RES Account for 2012 was estimated in December 2011 at approximately €494m, of which €97.4m were necessary to cover part of the previous year's deficit (which at the end of 2011 reached €195m)[20]. Based on MNEC estimates, €201m of the aforementioned 2012 total cost (€494m) would be covered through anticipated revenues derived from a) auctions of unused emission rights of greenhouse gases (€116m), b) a lignite electricity levy (€55m) and c) revenues from a TV license fee (€30m), while the rest (€293m) would be recovered through the RES levy charges to consumers, as follows:

[18] Ministerial Decision June 2010 (Official Gazette, B 815).

[19] Ministerial Decision of December 2010 (Official Gazette B 1911), following RAE's Opinion 355/2010.

[20] RAE's Decision 1453/2011 (Official Gazette B 2967).

Category	RES levy unit charge July 2011 (€/MWh)	RES levy unit charge January 2012 (€/MWh)
HV and autoproducers' own consumption	1.04	2.96
Agricultural Use MV	0.74	2.29
Other Use MV	1.69	5.35
Agricultural Use LV	0.90	2.96
Domestic Use LV	1.95	5.99
Other Use LV	2.49	7.38

Table 4. RES levy charges for 2011-2012

During the first semester of 2012, the above MNEC estimates for 2012 revenues/expenses of the Special RES Account proved to be very optimistic, because of considerably lower revenues from various sources (auctions of emission rights, TV license fee, etc), combined with considerably higher-than-expected payments to RES producers, mainly due to the booming penetration of PV units in the system. This necessitated a new substantial increase in the RES levy, the third in the last 13 months, which was set, for the period of 01.08.2012-30.06.2013, at an average level of 4.6 €/MWh for HV and 8.7 €/MWh for domestic customers.

3.2.2. **Retail market**

3.2.2.1. Description of the retail market

Tables 5 and 6 present the consumption of end-use customers in 2011, by category and voltage level, for the interconnected system and for the non-interconnected islands, respectively. It should be noted that total consumption at the transmission system level, for the interconnected system only, was 47.3 TWh in 2011, 5.4% lower than the corresponding consumption in 2010.

Electricity consumption - Interconnected system (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small Industrial and Commercial customers**	**Other** (e.g. agricultural, public, traction, mines, pumping)	**Total**
LV	**2009**		16,368	11,432	3,608	**31,408**
	2010		16,477	12,257	2,805	**31,539**
	2011		16,116	10,535	3,526	**30,177**
MV	**2009**			9,273	1,425	**10,698**
	2010			9,674	1,447	**11,121**
	2011			9,125	1,397	**10,521**
HV	**2009**	6,007			1,358	**7,365**
	2010	6,355			989	**7,344**
	2011	6,613				**6,613**
Total	**2009**	6,007	16,368	20,705	6,391	**49,471**
	2010	6,355	16,477	21,931	5,241	**50,004**
	2011	6,613	16,116	19,660	4,923	**47,311**

Source: DSO. Data refer to metered consumption at the customer's site.

Table 5. Electricity consumption in the interconnected (mainland) system

Electricity consumption - Non-interconnected islands (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small Industrial and Commercial customers**	**Other** (eg. agricultural, public, traction)	**Total**
LV	**2009**		1,763	1,814	476	**4,053**
	2010		1,750	1,804	509	**4,063**
	2011		1,771	1,720	461	**3,952**
MV	**2009**			805	222	**1,027**
	2010			873	220	**1,093**
	2011			855	210	**1,066**
Total	**2009**		1,763	2,619	698	**5,080**
	2010		1,750	2,677	729	**5,156**
	2011		1,771	2,576	671	**5,018**

Source: DSO. Data refer to metered consumption at the customer's site.

Table 6. Electricity consumption in the non-interconnected islands

By the end of 2011, there was increased activity regarding supplier switching in the retail electricity market. More specifically, nearly 10% (by eligible volume) of industrial and commercial customers connected to the medium voltage network had switched supplier. The corresponding percentage in the low-voltage market segment was 3.35% for household customers (539.231 MWh out of a total of over 16.1 million MWh of eligible volume) and 12.25% for small industry customers (1.3 million MWh out of a total of over 10.5 million MWh of eligible volume). Thus, the market in the medium-sized industry sector and the low-voltage customers had become more active.

The HHI index for the retail market in 2011 was substantially higher than that for the generation sector, attaining a value of 8497, and hence, improving only slightly from the corresponding value of 8616 in 2010. Although suppliers in the past had been drawn in the retail market by high potential margins in certain customer categories, these margins are being reduced, as regulated prices are being progressively adjusted, removing cross-subsidies. In addition, retail margins turned out to be quite sensitive to the increase in wholesale prices observed in 2011, particularly towards the end of the year.

Customer Category	Total number of eligible meter points	Total eligible volume (MWh)	Number of eligible meter points that changed supplier	Eligible volume that changed supplier (MWh)	% of eligible meter points that changed supplier	% of eligible volume that changed supplier
Household customers	5,160,681	16,115,532	94,482	539,231	1.83	3.35
Small industrial and commercial customers	1,184,583	10,535,223	65,552	1,290,748	5.53	12.25
Other LV customers (eg agricultural, public, traction)	306,625	3,526,234	6	70	0.00	0.00
Total LV customers	6,651,889	30,176,989	160,040	1,830,049	2.41	6.06
MV Industrial and commercial customers	7,449	9,124,539	559	1,051,682	7.50	11.53
Other MV customers (eg agricultural, public, traction)	1,589	1,396,502	0	0	0.00	0.00
Total MV customers	9,038	10,521,041	559	1,051,682	6.18	10.00
Total LV and MV customers	6,660,927	40,698,030	160,599	2,881,731	2.41	7.08
HV customers	35	6,613,402	0	0	0.00	0.00
Total LV, MV and HV	6,660,962	47,311,432	160,599	2,881,731	2.41	6.09

Table 7.Switching rate per consumer category in 2011, by eligible meter points and by eligible volume

PPC remained the dominant supplier in 2011, with 92% share of the total volume. Nevertheless, some noticeable activity in the retail market was evident during 2011. Specifically, 15 out of 45 independent electricity suppliers (see Appendix I) in the country were active and two (2) of them, namely “Energa Power Trading S.A.” and “Hellas Power S.A.”, represented 3.8% and 3.6% of total volume, respectively.

Market Share (%)		PPC S.A.	HELLAS POWER S.A.	ENERGA POWER TRADING S.A.
Households customers	By metering points	98.50	0.90	0.60
	By eligible volume	99.00	0.60	0.40
Small industry (LV)	By metering points	94.51	2.58	2.61
	By eligible volume	82.50	8.00	8.70
Medium-sized industry (MV)	By metering points	90.27	2.70	4.92
	By eligible volume	89.20	4.50	4.70
Large industry (HV)	By metering points	100.00	0.00	0.00
	By eligible volume	100.00	0.00	0.00
Total retail market	By metering points	97.60	1.28	1.03
	By eligible volume	92.00	3.60	3.80

Table 8. Market share (%) of the three (3) largest retailers on 31.12.2011, by consumer category

The procedure for issuing electricity supply and trading licenses followed Article 24, paragraph 1 of Law 2773/1999, and covered both the activities of electricity supply and trading. However, Law 4001/2011, which went into effect on 22.08.2011 (National Gazette 179 A'), introduced new provisions, under which separate licenses were to be issued for the activity of Supply and the activity of Trading. In this context, and in accordance with the provisions of paragraphs 2 and 4 of Article 134 of Law 4001/2011, different criteria apply for the issuing of the two separate licenses. The most importance difference concerns the minimum amount of the required share capital. More specifically, the minimum capital required for a Supply license is €600,000, whereas for a Trading license is €60,000.

Under the transitional provision of paragraph 12 of Article 196 of Law 4001/2011, applications regarding Supply licenses which were submitted before the adoption of Law 4001/2011, were to be processed according to the provisions of the new Law. Existing supply licenses which do not meet the minimum required share capital criterion under the new Law, should be treated as trading licenses; thus, according to the new provisions, RAE is in the process of converting these licenses to trading licenses. By the end of 2011, trading licenses had been granted to 24 companies, while 45 companies were still holders of supply licenses, 15 of which were active suppliers (see list in Appendix I).

3.2.2.2. Price monitoring

PPC retail tariffs to MV and LV customers remained regulated in 2011. Prices for 2011 were set by a Ministerial Decision, following two (2) RAE Opinions regarding the regulated PPC retail tariffs (Opinions 237/2010 and 353/2010). In the first Opinion, RAE approved a new consumer categorisation proposed by PPC, as well as a new tariff structure. In the second, RAE set the level of the average, cost-reflective, revenue per consumer category, which assumed the removal of all cross-subsidies, and which was reduced by approx. 5% compared to the average revenue requested by PPC in its original proposal. In this second Opinion, the overall average revenue was set below SMP prices realised in the wholesale market, taking into account PPC's cheaper fuel mix (high level of hydro output, combined with free access to lignite). This approach was taken as a short-term measure, in the transition to fully cost-reflective tariffs and removal of all cross-subsidies, with the aim to pass on to the final consumers part of the benefit stemming from the lower cost of generation to which PPC has the exclusive right (large hydro, lignite). RAE also proposed that the relevant cost data need to be reviewed every six (6) months, so that the retail tariffs can be regularly adjusted to reflect future wholesale costs.

The Ministry of Energy, Environment and Climate Change (MEECC), taking into account the two RAE Opinions, introduced transitional steps towards the removal of all cross-subsidies, maintaining, to a certain extent, some of them, in order to avoid sharp price increases to any single consumer category. Small domestic customers (with a 4-month consumption of up to 800kWh) experienced the most significant price increase, percentage-wise, with an average increase of 11% in their total bill (including taxes). At the same time, large domestic consumers (over 3000kWh of 4-month consumption) saw, on the average, an 8.5% reduction in their total bill (including taxes). Total bills to agricultural customers were increased by about 6-8%, while industrial MV customers also experienced an average increase of around 8.8% in their total bill (including taxes). Estimated reductions to commercial MV and LV customer bills were around 5-10%. The final regulated tariffs for 2011 were approved through a Ministerial Decision on December 28, 2010 (National Gazette B 2031). Prices remained constant during 2011, as the Ministry did not adopt RAE's Opinion on mid-year price revision.

At the end of 2011, all price regulation for the MV customers was removed. Price regulation for domestic and small enterprise LV customers remained in effect throughout 2011 and 2012, and is expected to be fully removed by mid 2013.

Regarding prices offered by alternative suppliers, price reductions (compared to PPC) were concentrated mainly in the MV and commercial LV categories. New retail products were offered in the domestic market, with a fixed monthly price for consumption up to a certain level. These "packages", resembling products of the mobile phone market, offered savings mainly to customers with consumption levels near the package limits.

Table 9 shows the average PPC retail prices in 2010 and 2011, by consumer category, broken down by the various tariff elements. Average data for other suppliers was not available on a comparable basis. A significant step towards removing cross-subsidisation between different consumer categories was achieved, with agricultural, domestic and industrial customers experiencing the most significant increases, while commercial customers, who traditionally subsidised other consumer categories, saw a significant reduction in the energy component of their bill.

		Energy (€/MWh)	TUoS (€/MWh)	DUoS (€/MWh)	PSO (€/MWh)	Other (€/MWh)	Total (€/MWh)	Δ(2010-2011) Energy only	Δ(2010-2011) Total
MV Commercial	**2010**	82.14	3.92	6.09	8.34	0.77	**101.26**	-17.5%	-10.4%
	2011	67.76	4.92	6.35	11.29	0.44	**90.75**		
MV Industrial	**2010**	63.13	5.55	7.15	6.58	0.77	**83.18**	8.8%	6.3%
	2011	68.69	6.19	7.19	5.90	0.44	**88.42**		
MV Agricultural	**2010**	36.90	0.00	0.00	3.24	0.77	**40.91**	37.6%	27.5%
	2011	50.76	0.00	0.00	0.95	0.44	**52.15**		
LV Commercial	**2010**	94.28	16.01	16.51	11.37	0.83	**139.00**	-5.8%	-5.4%
	2011	88.82	6.75	22.57	12.99	0.42	**131.55**		
LV Industrial	**2010**	79.03	10.39	23.66	9.86	0.83	**123.77**	7.1%	3.1%
	2011	84.63	6.50	24.23	11.77	0.43	**127.55**		
LV Agricultural	**2010**	43.43	0.00	0.00	3.70	0.83	**47.96**	33.7%	24.2%
	2011	58.05	0.00	0.00	1.10	0.44	**59.59**		
LV Public Lighting	**2010**	65.76	2.66	22.36	7.65	0.83	**99.27**	7.6%	-4.2%
	2011	70.73	2.46	19.39	2.10	0.41	**95.09**		
LV Domestic	**2010**	67.78	5.89	22.43	8.06	0.83	**104.99**	11.7%	1.7%
	2011	75.68	4.96	17.83	7.90	0.38	**106.76**		

Source: PPC.

Table 9. 2010 and 2011 average PPC retail electricity prices and tariff elements per consumer category (excluding taxes and levies), €/MWh

Retail price regulation

Under the new Energy Law 4001/2011 that transposed the 3rd Energy Package into national legislation, only LV tariffs are currently being regulated (until June 2013), through a Ministerial Decision following a (non-binding) Opinion by RAE. This means that all regulation of HV and MV (since 01.01.2012) tariffs has been removed. Under the same Law (Art. 140, par. 6), RAE monitors the deregulated retail prices and may intervene ex-post, if an abusive behaviour is identified (prices are either too high, therefore abusive towards consumers, or too low, therefore abusive towards competitors).

In Decision 692/2011, RAE set the general principles for tariff setting in the deregulated retail 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 choices to consumers and, where possible, provide incentives for the efficient use of electricity. Special guidelines were provided for large industrial (and commercial) consumers, where it is possible to offer tailor-made prices rather than a published general tariff, in order to take into account the specific load profile and other special characteristics of the given customer. It is intended that these principles be included in the new version of the *Supply Code*, expected to be adopted within 2012, and in accordance with the relevant requirements set out by Law 4001/2011.

In any case, measures adopted by RAE in terms of price regulation will have to take into account the latest developments in the retail market and the level of competition, or the existence of market power dominance in the relevant market segments.

<u>Progress with regard to HV tariffs</u>

PPC finally submitted, in late March 2011, a proposal for three (3) different electricity tariffs for HV customers, referring only to the competitive element of the total tariff. Earlier, PPC had asked RAE to specifically comment on the proposed supply contract (including tariff) for its largest HV customer, Aluminum of Greece (AoG).

As a response to both requests, in June 2011, RAE issued a Decision on Tariff Guidelines for the "non-regulated tariffs", which apply to all suppliers active in the electricity market. This Decision states that suppliers should provide their customers with a sound justification of the level of the price or tariff offered, quantifying the customer parameters that may have an impact on their offered price, such as the load profile of the end user, interruptibility, volume etc. RAE also asked PPC to reevaluate its tariff proposals to HV customers, including AoG, in order to take into account the said RAE Guidelines.

Nevertheless, PPC resubmitted the same tariff proposals and did not provide any data regarding its underlying costs, that would justify the price levels offered to HV customers. PPC insisted that its cost data have already been provided to RAE and the Ministry of Energy during the procedure for approval of its regulated tariffs for MV (before these tariffs were deregulated) and LV customers in 2011, not recognising that this is a separate procedure and that the cost of electricity supply to different customer categories with different load profiles and characteristics cannot be the same.

The fact that PPC is the only vertically-integrated company, thus able to hedge its position and provide longer-term stability to prices offered to customers, explains why HV customers are highly dependent on a supply contract with PPC. On the other hand, PPC claims that HV customers demand very low prices, driven by benchmark prices in other Member States or countries with different market and generation characteristics (e.g. nuclear generation, state subsidies in the case of non-EU countries, etc), which, if adopted by PPC, would lead to cross subsidisation and to PPC selling below cost to HV customers.

Following PPC's proposals, negotiations between PPC and HV customers were initiated, but were slowed down by the introduction of a new natural gas consumption tax in September 2011, which had a significant impact on the wholesale electricity market and prices. The negotiated prices had to be reviewed again, to take into account the effect of this new tax. Given the considerable negative impact of the tax on the electricity market, RAE proposed to the government the removal of this tax from natural gas and the introduction of an alternative tax measure, of equivalent fiscal results.

In October 2011, one of the major industrial electricity consumers submitted an official complaint to RAE against PPC, claiming abusive monopolistic behaviour and lack of negotiations regarding HV tariffs on the part of PPC. The examination of the complaint continued into 2012.

Supply Code

RAE continued in 2011 the drafting of the new *Supply Cod*e. Issuing of this Code has been delayed, partly due to the adjustments necessary to include provisions of the new energy law issued in August 2011 (Law 4001).

During the summer of 2011, RAE conducted a public consultation on the management of customer debt. The main issue examined was the option of debt blocking or debt flagging. The results of the public consultation were taken into account in the drafting of the new *Supply Code* (which was announced for a second public consultation during the spring of 2012). RAE proposed a debt-flagging approach, allowing suppliers the option to refuse to submit an offer to supply a customer that had a bad payment history with their previous supplier. The option of debt blocking was considered to be too severe for consumers, under the current economic conditions. Proposals also include the option for the supplier to charge a higher deposit / advance payment to consumers with a bad payment history.

3.2.2.3. Monitoring the level of transparency

Monitoring electricity supplier practices

RAE requests, on an annual basis, detailed information from all suppliers, concerning their practices in regard to the services offered in the electricity market, their activity and financial data. Information includes prices offered to consumers per category, marketing material, standard contractual terms and conditions, information on number of customers and volumes of sales by customer group over the past year, company financial data, etc.

In 2011, RAE reviewed the contractual terms that all suppliers offered, with particular emphasis on those concerning smaller customers (LV). Letters were sent to most suppliers, starting with the three largest ones, with specific recommendations on areas for improving the terms offered, to the benefit of the final consumer, as well as to fully comply with the existing legal requirements (Energy Law, Supply Code, etc).

Price comparison tool

In order to provide clear and easy-to-understand information to domestic consumers, so as to enable them to avoid misleading marketing practices and to choose the best offer available to them in the retail market, RAE calculated the final bill at various consumption levels for domestic consumers, for the three major electricity suppliers in 2011 (PPC, Energa and Hellas Power). RAE presented on its website one table per company, which was a simple look-up table, where the consumer could estimate, on a comparable basis, what the final bill (over a four-month metering period) would be, under various offers by the three (3) suppliers above. The general conclusion was that the best offer / company very much depended on the specific consumption level.

Removal of barriers for supplier switching

RAE received numerous reports and letters of complaint from alternative suppliers, with regards to practical problems during supplier switching:

- Early in 2011, it was reported that during the supplier switching procedure, and when combined with a change of the name of the account holder, PPC, acting as the Network Operator, also requested a safety certificate for the installation. On many occasions, the consumer decided not to switch, in order to avoid the additional cost of having this certificate issued, and, therefore, this was considered as a barrier to supplier switching. When investigating the matter, RAE found out that, although it is indeed a requirement by law that such a certificate is renewed periodically (every few years, the exact number depending on the consumer category), in order to ensure the safe operation of an installation, the DSO had not ensured a way for the periodic checking of the validity of such certificates, and attempted to do so at the time of supplier switching. RAE instructed the Network Operator to proceed with supplier switching regardless of whether the certificate was valid or not, and to put in place separate, independent procedures for monitoring compliance with the installation safety regulations.
- In September 2011, the government introduced a special tax on property for 2011 and 2012, to be collected through the electricity bills. The rules for the implementation/collection of this tax seemed to prohibit supplier switching, if outstanding payments of the property tax existed. This was seen by alternative suppliers as a barrier to competition in the retail market and they requested the assistance of RAE in interpreting the rules. RAE cooperated with the suppliers and with the Network Operator in an effort to remove this barrier. Proposals were submitted by RAE to the relevant ministries for the issuing of an official clarification note and for the redrafting of the relevant ministerial decisions, in order to avoid conflict with the electricity market-opening legislation, i.e. the 3rd Energy Package and Energy Law 4001/2011. The problem seemed to be resolved temporarily in 2011, although reappeared in 2012.

Practices of the Distribution System Operator with regards to supporting the supply market

During 2011, the Distribution System Operator remained a unit of PPC. Problems experienced in the past, in relation to procedures supporting the opening of the supply market, such as delays in supplier switching, data provision, disconnection and reconnection, market settlement, etc, continued, although some improvement was observed.

In July 2011, RAE issued Decision 670/2011 on an official complaint submitted in November 2010 by an independent supplier against the Distribution System Operator. Problems reported in the complaint included:

- Lack of provision of historic data for customers wishing to switch supplier
- Delays in the date when supplier switching becomes effective
- Delays in the provision of market settlement data
- Lack of data on the next metering date
- Lack of up-to-date data on meter representation

RAE imposed a total fine of €900,000 on the DSO for non-compliance with procedures supporting the opening of the retail market, as set out in the relevant Code and Manuals. Furthermore, the DSO was requested to improve specific terms and procedures, and to report back on actions and measures taken within a set timetable. The DSO submitted an appeal, which was rejected by RAE in December 2011 (Decision 1598/2011).

3.3. Consumer protection

3.3.1. **Compliance with Annex 1**

RAE Decision 771/2011 on "General principles and standards for the proper marketing and sales of services in the electricity supply market"

Following reports and complaints on misleading information and abusive behavior and sales practices of electricity suppliers and their representatives, while marketing/selling their products to consumers, RAE issued Decision 771/2011, which set out proper marketing guidelines (covering both general advertising and direct contact with consumers), as well as minimum information that should be available to consumers, in order to enable them to compare offers by various suppliers and to choose the best offer available to them. Minimum information includes the offered contract terms and conditions, particularly in regard to prices, advance payments/ deposit, services offered, minimum contract duration, special terms attached to the particular offer, the existence of penalties, and information on billing and payment methods. More importantly, the supplier is required to provide an estimate of the annual bill taking into account the demand characteristics of the particular consumer, and when a comparison is made with prices offered by another supplier, the comparison has to be made on an annual, total bill basis; otherwise, the offer is considered misleading.

It is intended that the above principles and standards will be included in the new version of the *Supply Code*, expected to be adopted within 2012, and in accordance with the relevant requirements set out by Law 4001/2011.

Supplier of Last Resort and Universal Service Supplier

New regulations regarding the Supplier of Last Resort (SoLR) and the Universal Service Supplier (USS) were implemented through law 4001/2011. According to article 57 of the law, the Supplier of Last Resort must supply customers who are not represented by any other Supplier, due to an event for which the customer is not responsible (e.g., ex-Supplier's license revocation, voluntary exit, or involuntary exit due to insolvency). The supply period under SoLR cannot exceed three (3) months, so that the customers have enough time to negotiate a contract with a new supplier of their choice. On the other hand, according to article 58, the Universal Service Supplier must supply "small" customers, i.e. all domestic customers and small businesses with a connection up to 25kVA, who have neglected or are unable to negotiate a contract with a supplier, or are unable to find a supplier (e.g. due to a bad payment record).

Regarding price regulation for SoLR and USS services, general principles are set as follows: given that in a SoLR event it is, practically, the "Supplier's fault", the customer should not be penalized. Nevertheless, the SoLR must be compensated for the extra costs encountered (e.g. extra energy purchases, cost of service and communication), and the cost will most probably be covered by Public Service Obligations (PSOs), to be split among all consumers. On the other hand, prices for USS must be reasonable, transparent and directly comparable to tariffs offered in the competitive market. Nevertheless, a higher tariff is justified by the higher expected cost of service for these customers and also to give them an incentive to ultimately choose a supplier in the competitive market.

Further regulations on the provision of SoLR and USS services were developed by RAE during 2012, as the Regulator is responsible by law for the setting of relevant terms and conditions, and has the obligation to publish a call for interest for the provision of these services until 31.7.2012. If no supplier expresses interest to become SoLR or USS, the supplier with the largest market share per customer category is appointed as such, through a RAE decision. The call for interest must set specific criteria for the selection of the SoLr and USS suppliers, such as the minimisation of the relevant cost to the consumer and/or the minimisation of market distortions. Until the conclusion of the above procedure, PPC SA has been assigned by law (4001/2011) as the SoLR and USS provider, being the supplier with the largest market share.

3.3.2. **Definition of Vulnerable customers**

The definition of vulnerable consumers, for the purpose of the application of the reduced Social Residential Tariff (referred to as “KOT”, pursuant to the Greek acronym), includes the following four (4) categories (electricity consumption limits apply to consumption during the day, for those with zonal metering devices):

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

The Social Residential Tariff (KOT) was applied for the first time on 01.01.2011. Table 10 presents the prices per KOT category, as set by the Ministerial Decision, which apply for the first 800kWh of consumption in the 4-month period. For the remaining consumption, and up to the set category consumption limit, the supplier’s regular domestic prices for the equivalent category apply. KOT(I) applies to categories 1&2 and KOT(II) to categories 3&4, as above.

		Consumers with a total consumption of up to 800kWh/4 months		Consumers with a total consumption above 800kWh/4 months	
	Type of connection	**Energy Charge (€/kWh)**	**Fixed Charge (€/4Months)**	**Energy Charge (€/kWh)**	**Fixed Charge (€/4Months)**
KOT(I)	**Single- phase**	0.06452	2.77	0.07885	11.13
	Three-phase	0.06904	7.88	0.07885	22.20
KOT(II)	**Single- phase**	0.05735	2.77	0.07009	11.13
	Three-phase	0.06137	7.88	0.07009	22.20

Table 10. Social Residential Tariff (KOT) prices for the first 800kWh per 4-month period.

3.3.3. Public Service Obligations

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

(a) consumers connected to the distribution network of the non-interconnected islands and to remote micro-grids, at tariffs equal to those of the mainland (interconnected) system,

(b) consumers / families with more than three (3) children, at special, reduced tariffs, and

(c) vulnerable consumers, at the Social Residential Tariff (KOT).

The methodology for calculating the annual cost of provision of the PSOs was set in November 2007, through a Ministerial Decision[21], following RAE's Opinion 233/2007. Specifically, the methodology for estimating the cost of providing uniform tariffs to the non-interconnected islands introduced a five-year regulatory period, expiring at the end of 2012, with the cost indexed to inflation and to oil-prices, minus a required efficiency index (2% per annum). In 2011, this methodology was revised (RAE's Decision 1525/2011), in order to incorporate a new element for the allowed revenue for the Special Residential Tariff (KOT) cost, as well as an allowance for the recovery of unforeseen changes in generation costs on the non-interconnected islands. The cost of providing the reduced tariff to large families is estimated as the difference between the reduced tariff and the regulated PPC domestic tariffs. The methodology was applied for the last time in 2011, in order to determine the cost for the provision of the PSOs in 2011, to be recovered through PSO levies in consumer bills in 2012. A new methodology will apply after the Non-Interconnected Island Distribution and Operation Code is enforced, most probably in late 2012.

The estimated annual cost for covering PSOs is allocated to consumer categories using the Equivalent Relevant Output method, based on the average revenue by category, according to the methodology approved by a Common Decision of the former Ministries of Development and Economy[22]. This methodology was subsequently revised by the MEECC, in order to allow for differentiation of charges (i.e. of discounts) to encourage better environmental and efficiency performance of electricity consumers.

In 2011, the cost of providing PSOs was estimated at approx. €714m[23], significantly higher than the €448m in 2009[24] and the €529m in 2010[25], as a result of steep increases in the excise taxes

[21] Ministerial Decision of September 2007 (Official Gazette, B 2353), following RAE's Opinion 233/2007.
[22] Joint Ministerial Decision of May 2009 (Official Gazette, B 932), following RAE's Opinion 310/2008.
[23] RAE's Decision 1526/2011 (Official Gazette, B 2991).
[24] Ministerial Decision of February 2010 (Official Gazette, B 189), following RAE's Opinion 502/2009.
[25] Ministerial Decision of December 2010 (Official Gazette, B 2045), following RAE's Opinion 370/2010.

imposed on the fuels used for electricity production on non-interconnected islands. This amount will be recovered in 2012 through the PSO charges and the amount equivalent to the Transmission Use of System (TUoS) charge, recovered from the consumers on the non-interconnected islands through the application of the uniform (national) retail tariff. The PSO charges for 2010, 2011 and 2012 are as follows:

Category	2010 PSO Charges (€/MWh)	2011 PSO Charges (€/MWh)	2012 PSO Charges (€/MWh)
Agricultural Use LV	3.70	1.15	7.07
General Use LV	11.51	14.37	18.24
Industrial Use LV	10.34	13.22	18.24
Public Lighting Use LV	7.65	2.32	13.71
Night-Time Use LV	0.00	1.45	8.89
Agricultural Use MV	3.24	0.95	5.46
General Use MV	8.35	11.41	17.9
Industrial Use MV	6.58	5.87	6.91
HV and autoproducers' own consumption	4.21	3.88	4.14

Table 11. PSO charges per customer category, 2010-2012

Sub category / consumption (kWh per 4-month period)	2010 PSO Charges (€/MWh)	2011 PSO Charges (€/MWh)	2012 PSO Charges (€/MWh)
0-800	0.00	0.20	6.99
801-1600	8.70	5.28	6.99
1601-2000	9.30	11.37	15.70
2001-3000	16.60	31.57	39.87
>3000	22.20	36.08	44.88

Table 12. PSO charges for domestic customers, 2010-2012

It is RAE's intention to gradually eliminate any differentiation between charges for different domestic consumer categories.

3.3.4. Statistics on disconnections and new connections

Approximately 340,000 electricity customers were disconnected in 2011 due to bad debt, of which less than 52% (174,000) were reconnected after settlement of their outstanding bills. Once a bill has not been paid, the supplier has the right to send a notification to the customer, with a 14-day deadline to settle the payment, after which the supplier may ask the Distribution System Operator to disconnect the customer.

Regarding disconnections, it is worth mentioning that almost 52% were due to payments in arrears, a fact that highlights customers' financial difficulty to pay their electricity bills. Only 26% of the disconnections were finally reconnected. The following table depicts relevant statistical data.

Customer Category	Number of new connections	Number of disconnections due to payments in arrears	Number of disconnections for other reasons	Number of re-connections after settlement of payments in arrears	Number of re-connections for other reasons
Interconnected system	58,029	305,714	284,003	154,267	144,266
Non-interconnected islands	9,423	33,340	30,757	20,441	16,030
Total	67,452	339,054	314,760	174,708	160,296

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

Customer Category	Number of new connections in the interconnected system	Number of new connections in the non-interconnected islands	Total number of new connections
Household customers	35,040	5,446	40,486
Small Industrial and Commercial customers	20,341	3,478	23,819
Other LV customers	2,326	448	2,774
Total LV customers	57,707	9,372	67,079
MV Industrial and Commercial Customers	311	50	361
Other MV customers	11	1	12
Total MV customers	322	51	373
Total LV and MV customers	58,029	9,423	67,452

Table 14.Statistical data on new connections

3.3.5. **Handling of consumer complaints**

Since 2011 was the first year of substantial activity of alternative electricity suppliers and, hence, of the opening of the retail market, an increased number of complaints was to be expected. Indeed, the total number of complaints registered to RAE during 2011 was 42% higher than in 2010.

It is interesting to note that almost one third of all complaints registered to RAE were against PPC SA as the Distribution System Operator, mainly regarding delays in supplier switching procedures.

Statistics on consumer cases registered to RAE, regarding electricity supply are as follows:

Complaints against a specific supplier (or the DSO)	% of total
PPC SA, as a supplier	37.95
PPC SA, as the DSO	32.82
Energa Power Trading S.A.	14.36
Hellas Power S.A.	13.85
Other suppliers	1.03
Total	**100.00**

Table 15.Percentage of complaints (% of total) against electricity suppliers and the DSO

Thematic Categories of Electricity Cases/Complaints	%
Dispute on consumption charges	29.4
Problems with suppliers during pre-contractual period (eg information on contractual terms, pricing transparency, insufficient information for pricing methods)	7.4
Damages on appliances after electricity reset	10.6
Dispute of regulated and other charges	9.4
Damages on appliances caused by a cut-off of the neutral conductor or a disturbance of the electricity voltage	6.8
Problems on supplier switching procedures	6.3
Problems with metering	4.2
Bad debt settlement	3.9
Unfair commercial practices	3.9
Payment delays	1.5
Frequency of electricity voltage disturbances	1.5
Double billing from different suppliers	1.3
Violation of the right for withdrawal from a new contract	1.0

Frequency/duration of electricity interruptions	1.0
Delays in the activation of a new connection	1.0
Delays in billing program after request	1.0
Misleading commercial practices	0.5
Disconnection delays	0.5
Delays in the return of guarantee payment	0.5
Delays in contract termination request	0.5
Other	7.8

Table 16. Complaints/inquiries by thematic category of electricity supply cases

3.4. Security of supply

3.4.1. Monitoring balance of supply and demand

Electricity demand remained fairly stable over 2011 at 51,872 GWh, exhibiting a minor decline of 0.94% relatively to 2010 at the interconnected system. At the national level, demand was also unaffected, amounting to 61,834 GWh (relatively to 61,817 GWh in 2010). It is notable that demand recovered over the last quarter, exhibiting an increase of 2% relatively to Q4 2010, as air-conditioning was used quite intensively for heating, perceived by consumers as a less expensive option than oil.

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

Source: HTSO

Table 17. Energy and peak power demand 2007-2010 for the interconnected system

Overall, local generation increased by 4.2% relatively to 2010, reversing the previous year's downward trend (-3.7%). Lignite production remained stable, with a minor increase of 0.5%, as no decommissioning occurred over 2011. Due to its base-load nature, lignite production followed closely the demand fluctuations, peaking in July, August and the winter period (November up to February). Oil generation shrank substantially, by 93%, in line with the previous two years' trend, being substituted by the more economic gas, increasingly penetrating the market. Gas production exhibited an increase of 43.3% (relatively to 10.7% in 2010), hence partly counteracting the hydro decline. Hydro production in 2011 shrank by 45% relatively to 2010. This was consistent with limited water inflows, which dropped to 2721 GWh, exceeding only by 13% the worse-case (driest) scenario predicted at the end of 2010.

Renewable generation connected to high-voltage, which mainly involves wind parks, peaked over the months January to April, August and December, a pattern which is rather typical of wind dynamics. Renewable production increased substantially, by 24.3%, but its market share remained still low. Imports declined by 16%, as the price spread with northern countries showed signs of reduction, and quantities were reallocated across interconnected countries, since the interconnection with Turkey became operational. Exports increased by 40%, and this mainly reflects substantial exports to Albania, given its hydro scarcity, which caused severe energy shortage in this country. The prolonged drought caused an escalation of exports to Albania to 2.1 TWh, a level which represents 54% of total exports from Greece. Exports to Italy got reduced by 26% (1.7 TWh), being adjusted to the higher volatility and the moderate decline in spreads, the magnitude of which remained still attractive.

	Interconnected system		Non-interconnected islands		Total	
	TWh	**%**	**TWh**	**%**	**TWh**	**%**
Lignite	27.57	53.15	-	-	27.57	47.98
Fuel Oil	0.009	0.02	4.76	85.15	4.77	8.30
Natural Gas	14.85	28.63	-	-	14.85	25.84
Large Hydro	3.68	7.09	-	-	3.68	6.40
RES	2.53	4.88	0.83	14.85	3.36	5.85
Net Imports	3.23	6.23	-	-	3.23	5.62
Total	**51,87**	**100.00**	**5.59**	**100.00**	**57.46**	**100.00**

Source: TSO and PPC's Island Network Operations Department

Table 18. Generation fuel mix in 2011

	2010 (TWh)	2011 (TWh)	% difference
Lignite	27.44	27.57	0.47
Fuel Oil	0.11	0.009	-91.82
Natural Gas	10.36	14.85	43.34
Large Hydro	6.70	3.68	-45.07
RES	2.04	2.53	24.02
Net Imports	5.70	3.23	-43.33
Total	**52.35**	**51,87**	**-0.92**

Table 19. Change in fuel-mix generation between 2010 and 2011 in the interconnected system

Figure 6 presents the allocation of production across the various technologies, as well as net imports at the monthly level, while Figure 7 displays the annual market shares across fuel and net imports. Both figures refer to the interconnected system, to which the wholesale market relates. If the production on the non-interconnected islands is taken into account, the oil share would rise significantly.

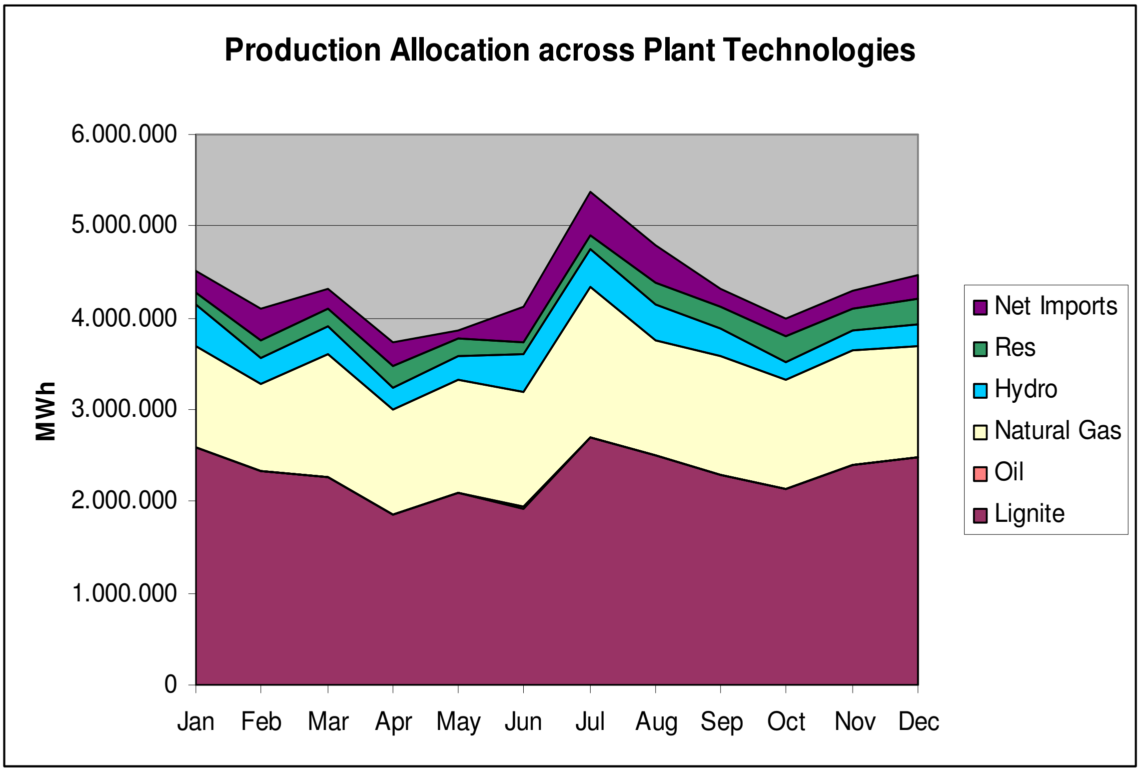

Figure 6. Production Allocation across Fuels and Net Imports at monthly level

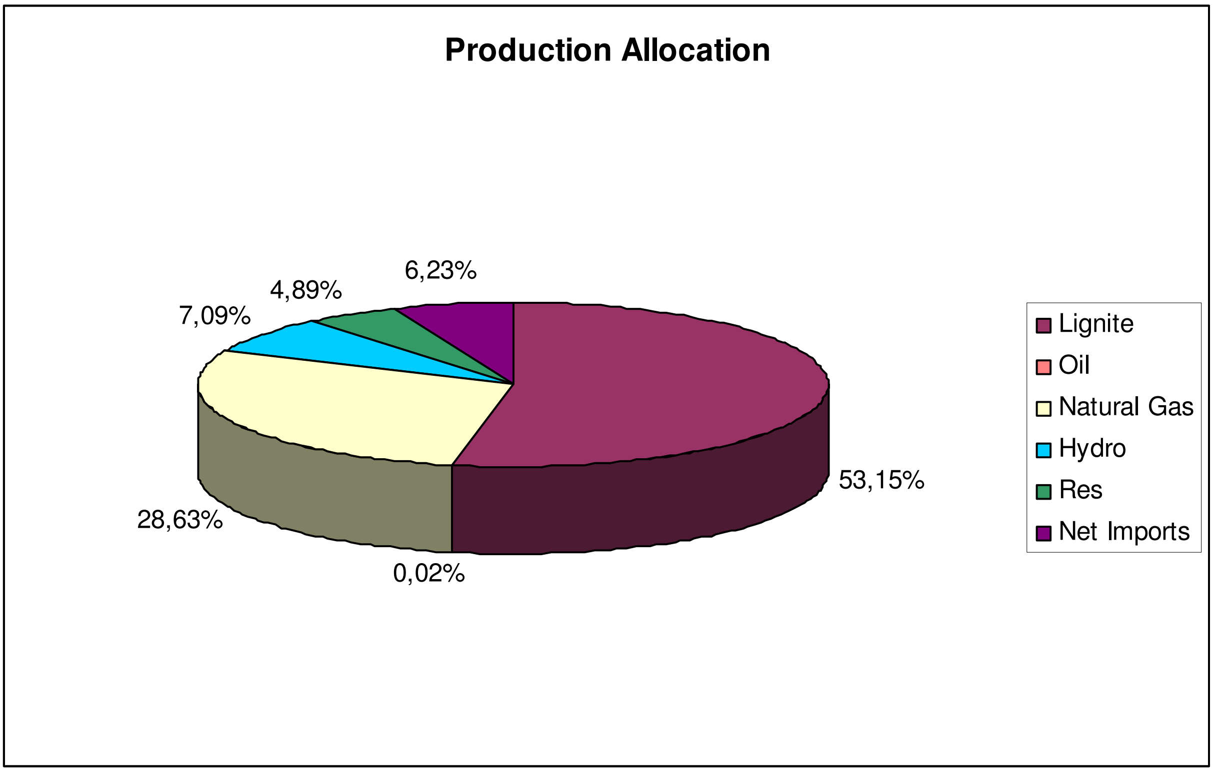

Figure 7. Annual shares of fuels and net imports

Installed capacity in Greece is depicted in Table 20 below.

	Ownership	Installed Capacity (MW)	Net Installed Capacity (MW)	Total Production (MWh)	Capacity Factor (%)
Lignite	**PPC**	**4,930**	**4,456**	**27,570,155**	**63.84**
Oil	**PPC**	**730**	**698**	**8,201**	**0.13**
OCGT	PPC	360	339	201,612	**6.39**
	Heron Thermoelectric	148.5	147.8	19,787	**1.53**
	Total	**508.5**	**486.8**	**221,399**	**4.98**
CCGT	PPC	1,606	1,578	5,024,577	35.71
	Elpedison	817	799	4,351,081	60.80
	Heron Thermoelectric	432	422	2,553,609	67.48
	Mytilinaios	444.5	433	1,346,305	34.54
	Korinthos Power	437	434	35,507	0.93
	Total	**3,737**	**3,666**	**13,311,079**	**40.66**
CHP (Large-scale)	**Mytilinaios**	**334**		**35,507**	**45.05**
Total Thermal		**10,239**		**41,146,341**	**47.30**
Large Hydro	**PPC**	**3,018**		**6,888,214**	**26.05**
Small Cogeneratio	**IPP**	89		199,102	25.52
Wind	**IPP (mainly)**	1,363		2,595,849	21.74
Small Hydro	**IPP (mainly)**	205		580,628	32.28
Biofuels – Biomass	**IPP (mainly)**	44.5		141,636	36.31
PVs	**IPP (mainly)**	439		441,553	11.48
Total Renewables		2,140.5		3,958,768	21.11
TOTAL		**15,397.5**		**51,993,323**	

Source: 10-year Grid Development Plan (TSO) and Verified Metered Data.

Table 20. Installed Capacity and Capacity Factor by Fuel and Ownership

3.4.2. **Monitoring investment in generation capacities in relation to SoS**

3.4.2.1. Monitoring investment in generation capacities in relation to SoS

As stated by the TSO in its ten-year Grid Development Plan, six thermal units, of total capacity 2476 MW, had also applied for connection until December 2011. This capacity included the incumbent's new CCGT units and more specifically, Aliveri V (417MW), projected to be completed by Autumn 2012, and Megalopoli V (811MW), which seemed to be progressing in terms of the expansion of the gas network in the region. The above capacity does not include, however, Ptolemaida V (660 MW), for which private involvement along with PPC has been discussed. In addition, five hydro units, of total capacity of 335 MW, had applied for connection by the end of 2011, while αvother 287 MW got licensed, but not applied for connection yet (including Mesochora). The obsolete lignite units Megalopoli I and II, of capacity 250 MW, were decommissioned.

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

4. The Gas Market

4.1. Network Regulation

4.1.1. Unbundling

A) TSO Unbundling

The unbundling regime regarding the Greek TSO (DESFA S.A.) under the Second Energy Package has been described in detail in the previous National Reports (2008 – 2010). In brief, the TSO of the National Natural Gas System (NNGS) 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 SA, the incumbent and vertically-integrated gas company in Greece. DESFA SA 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 SA has exclusive rights for the operation, maintenance, development and exploitation of the NNGS and is currently the only gas system operator in the country.

Law 4001/2011 that entered into force in August 2011, transposing the Third Energy Package into the national legislation, provided for ownership unbundling of DESFA S.A. from DEPA S.A..

In September 2011, RAE published on its website detailed guidelines regarding the certification procedure and the relevant data requirements for both the electricity and the gas TSOs, for all three (3) unbundling models provided for in the Directive.

However, Law 4001/2011 was subsequently amended in December 2011, by a Government Legislative Act, to allow for either model, Ownership Unbundling or ITO, to be able to apply in the case of DEPA S.A. and DESFA S.A.. This amendment was carried out in view of the government’s intent to privatise the incumbent and to allow potential investors to express their interest in acquiring one or both of the above companies.

Therefore, the certification procedure has not yet started, in anticipation of the results of the tender that is underway, or any subsequent decision of the Greek Government.

B) DSO Unbundling

During 2011, there was no change in the unbundling regime of the three distribution companies currently active in Greece (hereinafter “EPAs”), which has been presented in detail in the previous National Reports (2008-2010).

4.1.2. Technical functioning

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

In 2011, RAE approved the annual balancing plan for 2012 submitted by DESFA SA, which included the estimates of the TSO regarding balancing gas needs and an evaluation of possible balancing gas supply sources for 2012. In the 2011 balancing plan, the TSO had estimated that the balancing gas needs for that year would amount to 4.8% of the total gas consumption. The year-end data indicated that the percentage of balancing gas to total consumption amounted to 4.0%.

In 2011, there was a major change in the scheme for balancing gas, as it was described in the 2011 National Report. As approved by RAE, while for the first four (4) months of 2011 DESFA S.A. acquired balancing gas directly from the long-term LNG contract of the incumbent, then for the next eight (8) months DESFA S.A. purchased required balancing gas quantities through a contract with the incumbent, which was the result of an international tender procedure, run for the first time by DESFA S.A.

According to the annual balancing plan, DESFA S.A. has also proposed to acquire balancing gas (in the form of LNG) for the balancing needs of 2012 through an international tender procedure, according to the main provisions of the Gas Law.

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

In 2011, RAE also approved the balancing cost allocation scheme and the relevant shippers' charges, which include all costs arising from the provision of balancing services. The corresponding charges include:

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

All balancing charges and the methodology of their calculation, as well as the Daily Balancing Gas Price, are published on DESFA's website, in both Greek and English[26].

4.1.3. **Network and LNG Tariffs for Connection and Access**

A. Transmission system and LNG terminal access tariffs:

During 2011, there was no change in the third-party access (TPA) tariffication system, which has been presented in detail in the previous National Reports (2008-2010). Therefore:

- Tariffs for contracts of a standard duration of one (1) year were simply adjusted for inflation, compared to the previous year (2010), and the actual tariff coefficients for 2011 are as follows (Table 21):

[26] http://www.desfa.gr/default.asp?pid=408&la=1

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
Transmission	602,1000	0,296225
LNG	25,2620	0,019061

Table 21.Coefficients of TPA tariffs for one-year duration contracts, for the year 2011

- 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 presented above, are reduced proportionally to the part of the year, calculated in days, in which the contract is in force, and are multiplied by a factor (B) which corresponds to the total duration of the contract, according to the following table:

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

Table 22. Coefficients of TPA short-term tariffs

DESFA S.A. publishes on its website: (a) the Ministerial Decision 4955/2006 establishing the tariffs, (b) the current and historical TPA tariffs, and (c) a relevant calculator, in both Greek and English[27].

B. Distribution system access tariffs:

There were no changes in the scheme of gas distribution, as described in the previous National Reports (2008-2010), which is carried out by the three (3) distribution companies currently active in Greece (hereinafter "EPAs"). EPAs are operating under a regime of exclusive rights for the activities of both distribution (DSO) and supply of gas in their areas.

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

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

C. Development of an entry-exit TPA Tariff System:

In November 2011, after extensive talks with the TSO that lasted for several months, RAE launched a public consultation on a TSOs proposal for a new Tariff Regulation, introducing, for the first time, a decoupled entry-exit tariff model in the Greek gas market. The consultation procedure (including a second round) and the approval by RAE of the new Tariff Regulation and the actual

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

entry-exit tariffs were concluded in the summer of 2012. This recent development constitutes a major step on the way to a full reform of the TPA system, towards a decoupled entry-exit regime, in compliance with the EU Gas Regulation.

4.1.4. **Cross-border issues**

During 2011, there was no change regarding interconnection infrastructure of the Greek transmission system with neighbouring gas systems, namely Bulgaria and Turkey. Furthermore, no physical or contractual congestion was experienced in both interconnectors during 2011.

It has to be noted that there is still no integration between the Greek and the Bulgarian natural gas markets, mainly due to the fact that the pipeline transporting gas to Greece through Bulgaria is a dedicated transit pipeline, exempted from the TPA rights that apply to the rest of the Bulgarian national network. This is also the case for the transit pipelines upstream of Bulgaria. Furthermore, there is no integration between the Greek and the Turkish markets, since there is no clear TPA regime in the latter.

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

The five-year network development plan (TYNDP) compiled by DESFA S.A. in September of 2010 was approved by a Decision of the Minister of Development in June of 2011, following an opinion by RAE (RAE’s Opinion 97/3.2011). Starting in August of 2011, the provisions of the Network Code were revised to incorporate necessary changes, so that the monitoring of the TSO’s investment plan can be assessed against the Community-Wide TYNDP. The TSO is, therefore, obliged to submit to RAE a ten-year network development plan, instead of a five-year network development plan, by the 30th of June every year, and not every two years. The plan must be approved by RAE, according to the revised provisions of the Network Code, and in line with the provisions of the Third Energy Package, as has been incorporated into national law.

4.2. Promoting Competition

4.2.1. **Wholesale Markets**

4.2.1.1. *Price monitoring*

RAE, within the framework of its competences regarding monitoring of the energy market, published, 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 8 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 2009 through December 2011. Data are published on RAE's website[28] 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 procurement, which constitutes the basis for the calculation of HTAE. Based on the contract signed by the TSO for procuring balancing gas for the period of 1.4.2011 to 31.12.2011, the price of procuring balancing gas includes only a proportionate charge, which incorporates the fixed amount paid out by the TSO 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.

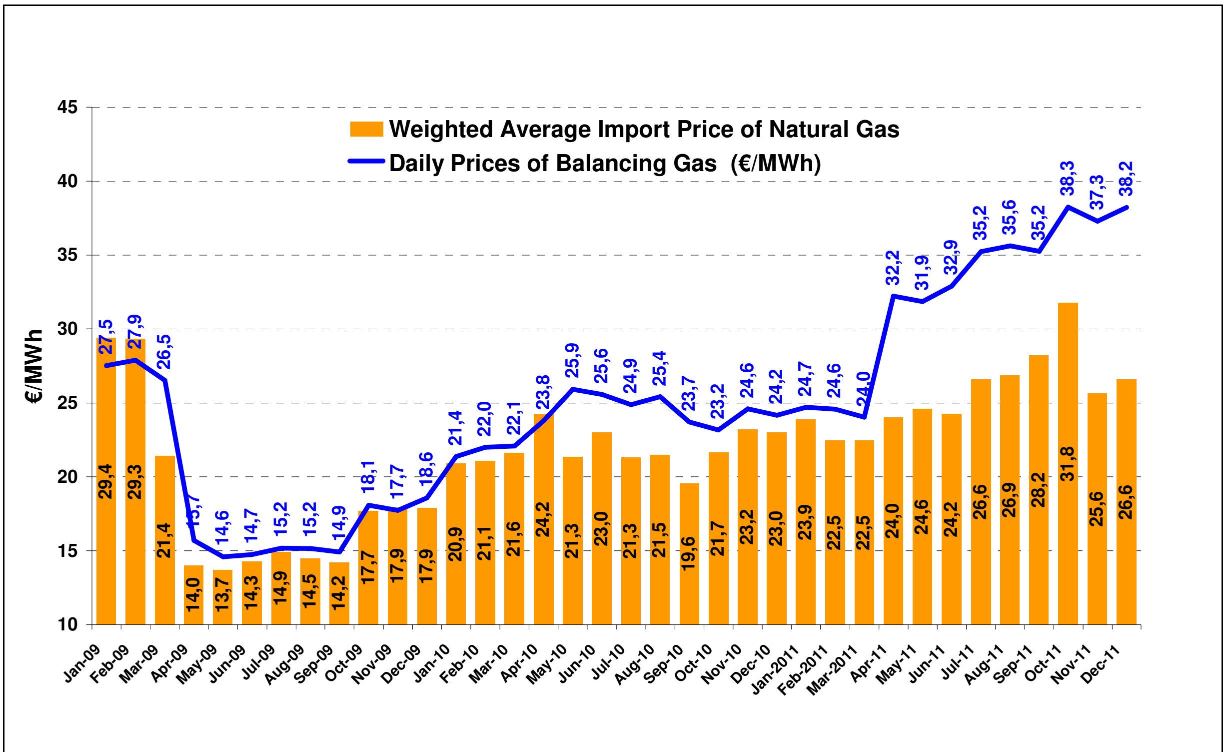

Figure 8. Monthly weighted-average import price (WAIP) against the price of balancing gas

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

4.2.1.2. *Monitoring the level of transparency*

Level of Transparency

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

Furthermore, during 2011, RAE undertook a series of monitoring exercises that contributed to the TSO's efforts towards substantially improving the level of transparency in the capacity market.

Market Opening and Competition

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2011. As explained in previous National Reports, there is no indigenous gas production in Greece. Furthermore, there are no storage facilities, and the LNG storage tanks are used exclusively for temporary LNG storage. Therefore, as has been noted in the past, and fully confirmed in 2011, the Revithoussa LNG terminal remains the main opportunity for new entrants in the Greek gas market.

Following importation of natural gas by third parties, other the DEPA S.A., in 2010, the same pattern was observed in 2011. Two power generators, one large industrial consumer, and one supplier imported LNG quantities for their own consumption and trading. Out of the 13.5 TWh of natural gas imported in the Revithoussa LNG Terminal in 2011, 61% were imported by DEPA S.A. and 39% by the other importers.

In fact, the entering of new gas importers in the domestic market decreased the market share of the incumbent DEPA S.A. in the wholesale level, from 100% to 89.1%. Therefore, for 2011, HHI stands at 7887.

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

The suppliers that currently hold a Gas Supply License are presented in Table 23 below:

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

Table 23. Companies currently holding gas authorisations (supply licenses)

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. After the publication of the NNGS Registry Regulation in 2010, twenty one (21) companies have been registered as potential users of the NNGS, five (5) of which were active in 2011. 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 & M GAS CO	Natural Gas Supplier
13	KORINTHOS POWER S.A.	Eligible Customer
14	E.ON RUHRGAS AG	Third Party
15	STATOIL ASA	Third Party
16	EDISON HELLAS S.A.	Natural Gas Supplier

17	TRANS ADRIATIC PIPELINE A.G.	Third Party
18	GASTRADE S.A.	Third Party
19	LARCO S.A.	Third Party
20	ELPE S.A.	Third Party
21	TERNA S.A.	Natural Gas Supplier

Table 24. Companies registered as NNGS users during 2011

4.2.2. **Retail Markets**

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

There were no developments regarding the pricing methodologies used by EPAs in setting end-user prices for the various customer categories. Overall, average retail gas prices in 2011 were higher than the corresponding 2010 prices, due to the increase of oil-product prices in the last quarter of 2010 and the first quarter of 2011. From September 2011, an excise tax of 5.4 €/MWh was imposed on the retail price of natural gas. Some indicative annual average prices for EPA Attica and EPA Thessaloniki, are presented in Table 25:

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

** Net of VAT and excise tax*

Table 25. Indicative, annually-averaged, natural gas prices in distribution, 2007-2011

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

EPAs provide all the necessary information regarding end-user prices per customer category in their own websites. Moreover, they provide telephone lines, through which the customers can obtain information regarding prices, connection fees, connection details, etc.

4.3. Consumer Protection

4.3.1. **Compliance with Annex 1**

Consumer protection provisions, as described in Annex 1, par. 1 of Directive 2009/73/EC, have been partially incorporated in the Distribution Licenses of the three EPAs. EPAs provide all necessary information regarding offered services and end-user prices, per customer category, on their websites. Moreover, they provide telephone lines through which customers may obtain information regarding prices, connection fees, connection details, etc. They are also obliged to handle customer complaints and 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 the definition of vulnerable consumers of Law 4001/2011 have not been fully adopted by the EPAs, in terms of compliance with the categories of vulnerable groups and economic protection schemes.

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

Under the absence of a relative Ministerial Decision for the provision of conditions and economic protection schemes, customers “with Special Needs” are currently defined by each distribution company, based on transparent criteria according to their Distribution Licenses. These include the following categories of consumers:

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

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

- Prohibition of disconnection due to overdue debt between November to February.
- Transfer of the consumption meter in order for the customer with special needs to have easy access to meter readings.
- Telephone service for blind consumers to be informed on meter readings
- Free visit to special needs customers in order to be informed on security measures in case of an emergency
- Provision for the customer with special needs to assign another person for communication purposes (receiving bills, messages etc).

4.4. Security of Supply

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

Year 2011 was a busy year regarding Security of Supply. The most prominent activity related to the implementation of Regulation 994/2010 was the Risk Assessment Study, which was completed on time and was sent to the Commission on December 14th. To elaborate the Study, RAE established a working group formed by experts from (a) the Hellenic Gas Transmission System Operator (DESFA S.A.), (b) the Hellenic Electricity Transmission System Operator (DESMIE S.A.), (c) the Public Gas Corporation of Greece (DEPA S.A.), in its quality as supplier to protected consumers under long-term gas import agreements, and (d) representatives of the Ministry of Energy, Environment and Climate Change (MEECC).

Interim results of the Study were presented to representatives of the electricity production (E.P.) sector and the industry, as well as to the Natural Gas Undertakings (NGU) that supply minor consumers connected to the Greek transmission system. Remarks submitted by the participants have been taken into account in formulating the final Study.

The analysis conducted within the Risk Assessment resulted in the following conclusions:

1. Under the current conditions, household consumers, small and medium-sized enterprises connected to a distribution network, as well as district heating installations that are not able to switch to alternative fuels, are not expected to suffer impacts on their supply, in any of the scenarios examined, as long as proper measures for managing the demand by EP and Industry are applied.
2. The analysis of 18 scenarios and their sub-cases (a, b), entailing different impacts (21 in total), shows that 2 scenarios will have no impact at all, 8 scenarios are considered as low-risk, 10 scenarios are considered as medium-risk, and one (1) scenario is considered as high-risk.
3. The maximum daily and weekly demand may be satisfied by the current infrastructures.
4. The N-1 standard is not met by the current infrastructures. It is expected that this standard could be satisfied through the application of market-based, demand-side management, measures, in the range of 3-5 mcm per day, during the next three (3) years.

4.4.1. Monitoring Balance of Supply and Demand

4.4.1.1. Current demand

The demand for Natural Gas in 2011 was 4.80 bcm, out of which approximately 66% concerned the power generation sector, as shown in Table 26.

Year 2011	bcm @ 15℃	Mtoe (HHV)
Power Generation	3.18	2.90
Industry & HP customers	0.89	0.81

GDCs (Primarily Commercial & Domestic)	0.74	0.67
Total	4.81	4.38

Table 26. Natural gas demand by sector in 2011

Gas Demand, after the dip observed in 2009, is again on the rise, driven primarily by the power sector (see Figure 9).

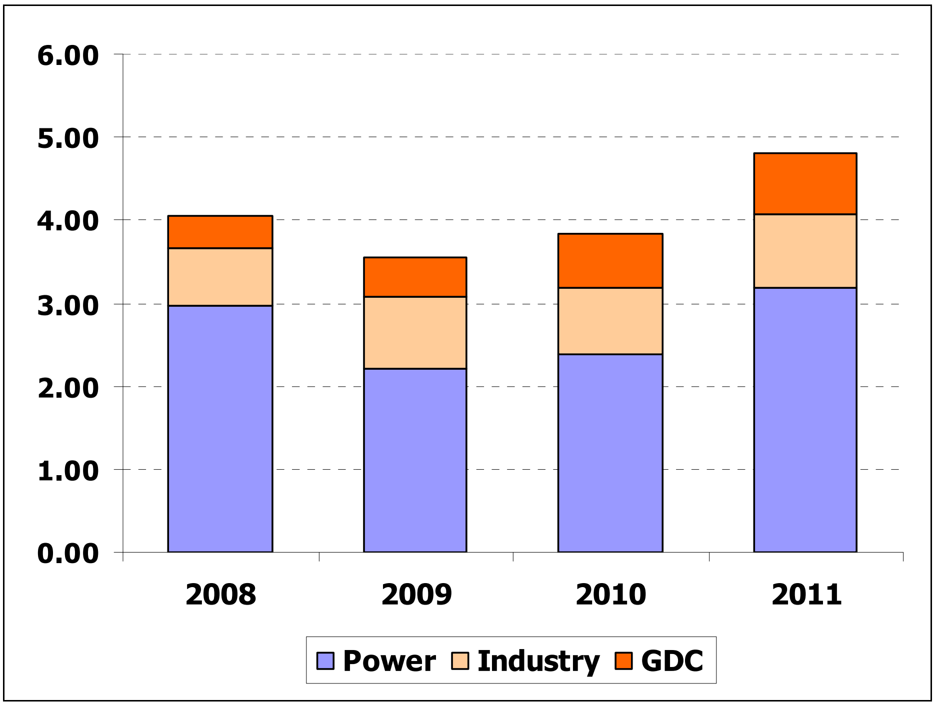

Figure 9. Gas demand per sector, 2008-2011

During 2011, there was no indigenous gas production in Greece. Gas was imported to the NGTS through the three (3) entry points. Figure 10 shows the Natural Gas sources and their participation to the total imported quantities in Greece, as reported by the TSO.

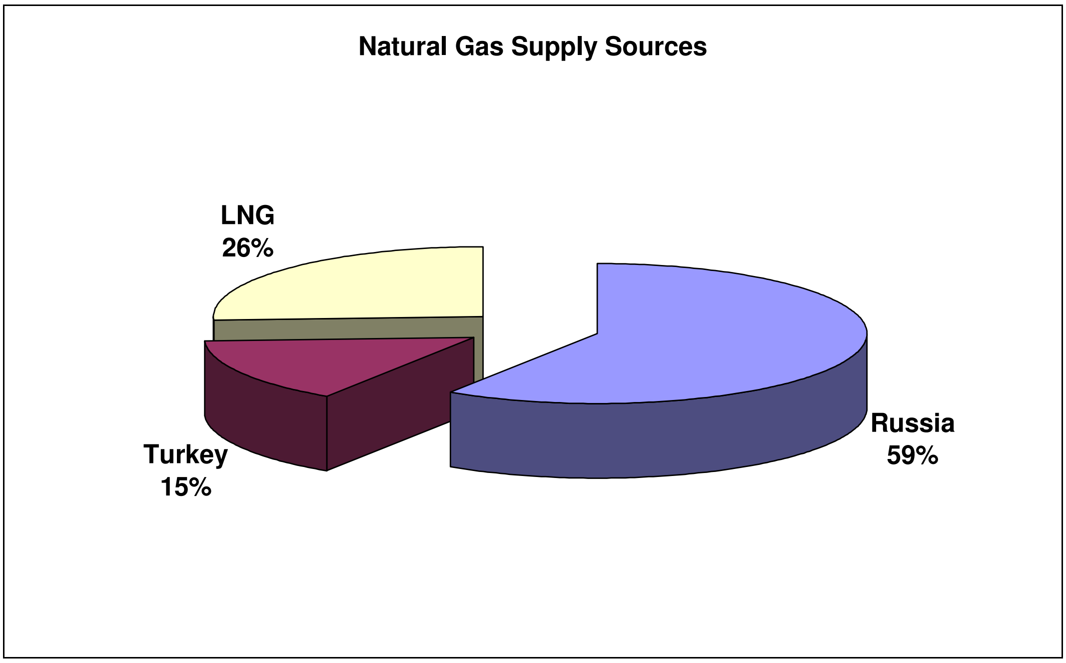

Figure 10. Natural gas supply sources

Figure 11 provides the share of imports from each source during the past five (5) years. The supply of gas through the existing long term contract with Russia increased its share during the past year, in order to cover demand. LNG spot cargoes complemented the existing long term contracts. It is notable that LNG imports, in absolute numbers, increased by 10% compared to 2010.

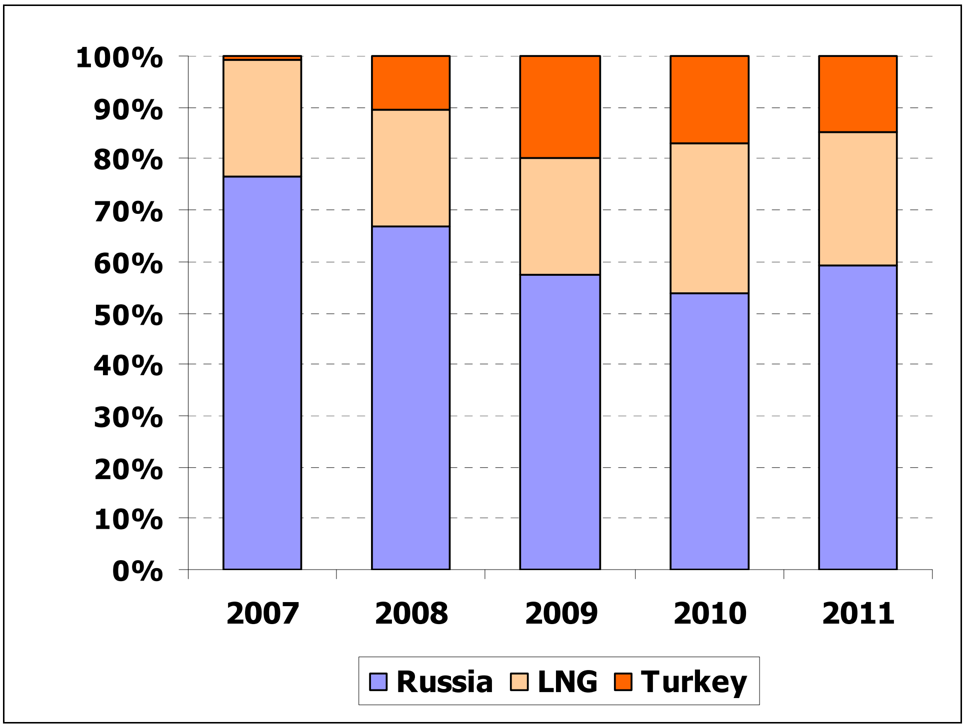

Figure 11. Share of natural gas import sources since 2007

4.4.1.2. *Projected demand*

Projections for the current year (2012) show demand stabilizing just below 5 bcm, as shown in Table 27. Commercial and domestic demand is expected to increase steadily, according to the expansion plans of the Gas Distribution Companies (EPAs). Expected national demand for the next three (3) years is presented below in Table 27 (DESFA's estimates).

	2012		2013		2014	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**Bcm**	**Mtoe**
Power Generation	3.15	2.87	3.15	2.87	3.02	2.75
Industry	1.20	1.10	1.20	1.09	1.25	1.14
Commercial & Domestic	0.55	0.50	0.60	0.55	0.65	0.60
Total	**4.90**	**4.47**	**4.95**	**4.50**	**4.92**	**4.48**

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

The demand outlook for the next ten (10) years has been significantly reduced compared to previous projections. We provide the latest projection by DESFA, alongside four (4) earlier assessments.

Scenarios		**2015**		**2020**	
		bcm	**Mtoe**	**Bcm**	**Mtoe**
1	DEPA S.A.	8.5	7.8	9.3	8.5
2	LTPS (2007) 2nd scenario[1]	6.8	6.2	7.2	6.5
3	LTPS (2009) Base Case[2]	7.5	6.8	7.5	6.8
4	DESFA (2010)	6.33	5.76	6.92[3]	6.30[3]
5	DESFA (2012)	5.3	4.83	5.88	5.35

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

Table 28. Ten-year gas demand outlook

4.4.2. **Expected Future Demand and Available Supplies**

During 2011, DEPA imported gas primarily through existing long-term contracts from three (3) different sources, namely Russia, Algeria (LNG) and Turkey, while several spot cargoes were also unloaded in Revithoussa. The aggregate of the contracted annual quantities, according to the three existing supply contracts, is shown in Table 29.

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

Table 29. Natural gas contracted annual quantities

Table 30 presents the anticipated supply – demand balance for the next three (3) years, based on the expected demand and the existing long-term supply contracts. The supply gap is expected to be in the range of 0.5-0.6 bcm through 2014.

	2012		2013		2014	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**bcm**	**Mtoe**
Demand	**4.90**	**4.47**	**4.95**	**4.50**	**4.92**	**4.48**
Supply Contracts	4.4	4.0	4.4	4.0	4.4	4.0
Supply Gap	0.50	0.47	0.55	0.5	0.52	0.48

Table 30. Expected natural gas supply-demand balance, 2012-2014

Figure 12 below shows the expected demand - supply balance projected to 2020, according to the scenarios presented in Table 28. The demand curve corresponds to the TSO's latest demand forecast of Table 28 (DESFA 2012).

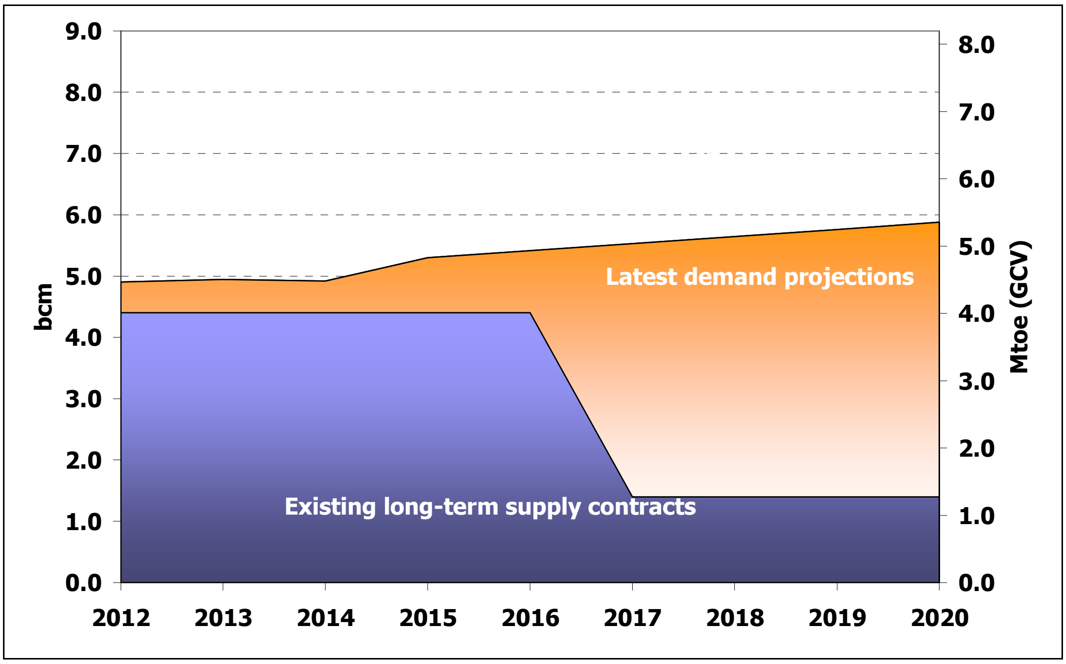

Figure 12. Expected natural gas supply-demand balance (10-year forecast)

Import capacity has remained unchanged throughout 2011.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 to the System.

Table 31 lists the current entry capacities. Annual quantities are derived from maximum hourly flow, considering a load factor of 90%.

Entry points	**Current**		**2nd half of 2012**	
	Bcm	**Mtoe**	**bcm**	**Mtoe**
Sidirokastro	3.2	2.9	3.9	3.6
Kipoi	0.9	0.8	1.7	1.5
Ag. Triada (LNG Terminal of Revithoussa)	1.9	1.8	1.9	1.8
Total	**6.0**	**5.5**	**7.5**	**6.9**

Table 31. Natural gas entry-point capacities

The capacities in column [1] above are based on current capacity figures published by the TSO, based on upstream and downstream network constraints. The annual figures have been estimated based on a load factor of 90% for pipeline entry points, while the LNG terminal annual throughput is based on the assumption of an (annual) load factor of 40%, which corresponds to a ship arrival rate (with a capacity of 75,000 m^3) of every 8 days. A gas compressor initially scheduled to start operation within the 1st Quarter of 2012, is delayed and is expected to become operational in late 2012. This will relieve internal bottlenecks and will increase capacities to the values reported in the column "*2nd half of 2012*".

Table 32 below lists the TSO's investment plans, which aim to add import capacity to the NGTS.

Project	**Implemented by**	**Completion by**
Compressor Station	TSO	2012
Revithoussa Terminal upgrade	TSO	End of 2014

Table 32. Natural gas TSO investment plans

The previously mentioned compressor station is expected to come on line in late 2012. The Revithoussa LNG terminal upgrade will involve a storage capacity increase, through the addition of a 3rd LNG tank and an increase of the send-out rate by 40%. This project has been officially approved and completion is expected by the end of 2014.

4.4.3. **Measures to Cover Peak Demand or Shortfall of Suppliers**

Load shedding is the primary measure foreseen in the event of an emergency. According to the provisions of Law 3428/2006, the TSO enters into contracts with customers which choose to be interruptible, and, by default, with all dual-fueled power plant operators.

RAE, as the Competent Authority, in cooperation with Stakeholders, is preparing a Preventive Action Plan, according to articles 4 and 5 of EU Regulation 994/2010, which aims to identify the most cost effective actions, in order to mitigate the risks identified in the Risk Assessment Study. Alternative options, across the following three (3) axes, are investigated:

1. Demand side management
2. Emergency gas supplies
3. Gas storage and other related infrastructures.

Appendix I - List of licensed electricity Suppliers and Traders at the end of 2011

Trading Licences	Supply Licences
1. A2A TRADING SRL	1. ALPIQ ENERGY S.A.
2. ALPIQ ENERGY HELLAS S.A.	2. ATHENS INTERNATIONAL AIRPORT S.A.
3. CEZ a.s.	3. BLACK PEARL ENERGY S.A.
4. DANSKE COMMODITIES A/S	4. COMPAGNIE NATIONALE DU RHONE
5. EDF TRADING LIMITED (EDFT)	5. DEUTSCHE BANK A.G.
6. EFT HELLAS S.A.	6. E.ON ENERGY TRADING AG
7. EGL HELLAS S.A.	7. EDELWEISS ENERGIA S.P.A.
8. EHOL HELLAS S.A	8. EDISON TRADING S.P.A
9. ELEKTRICNI FINANCNI TIM, PRODAJA ELEKTRICNE ENERGIJE d.o.o. LJUBLJANA	9. EL.EN. LTD
10. ELLAKTOR S.A. (HELLENIC TECHNODOMIKI)	10. ELECTRADE SRL
11. ENERGY MT EAD	11. ELECTRICITY TRADING COMPANY HELLAS S.A.
12. EZPADA S.R.O	12. ELEKTROPARAGOGI SOUSSAKI S.A.
13. HELLENIC PETROLEUM S.A.	13. ELPEDISON S.A.
14. NOVEL ENERGY LTD	14. ELPETRA ENERGY A.E
15. OET HELLAS S.A.	15. ENEL TRADE S.p.A
16. POWER SHARE S.A.	16. ENER SA
17. ROSEVELT LTD	17. ENERGA POWER TRADING S.A.
18. SEMAN S.A.	18. ENERGA TRADING OF ELECTRIC POWER S.A.
19. STATKRAFT MARKETS GMBH	19. ENERGY DANMARK A/S
20. STELLA GAVRIIL LTD	20. ENI SPA
21. TEI HELLAS S.A.	21. ENTRADE GMBH
22. TERNA ENERGY S.A.	22. EUROPEAN ENERGY TRADE S.A. GIOUZELIS-CHATZIDIMITRIOU
23. VERBUND AG	23. EVN TRADING SOUTH EAST EUROPE EAD

24. VIVID POWER EAD	24. GAZPROM MARKETING & TRADING
	25. GEN I ATHENS LTD
	26. GREEK ENERGY SA (ELLINIKI ENALLAKTIKI) S.A.
	27. GREEK ENVIROMENTAL
	28. HELLAS POWER S.A.
	29. HERON THERMOELECTRIC S.A.
	30. HSE D.O.O
	31. IBERDROLA GENERACION S.A.U.
	32. ITA ENERGY TRADE ΕΝΕΡΓΕΙΑΚΗ S.A.
	33. NECO S.A.
	34. NECO TRADING S.A.
	35. OET UNITED ENERGY TRADERS LTD
	36. PPC S.A.
	37. PROTERGIA S.A.
	38. REPOWER TRADING CESKA REPUBLIKA s.r.o
	39. REVMAENA LTD
	40. RUDNAP ENERGY LIMITED
	41. RWE SUPPLY & TRADING GMBH
	42. THRACE ELECTRICITY S.A.
	43. TINMAR-IND S.A
	44. UNIT HELLAS S.A.
	45. VOLTERRA 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
GHG	Greenhouse Gases
HGTSO	Hellenic Gas Transmission System Operator
HTSO	Hellenic Transmission System Operator
HV	High Voltage
IGI	Italy-Greece Interconnector
INGN	Independent Natural Gas Network
IPP	Independent Power Producer
LAGIE	The Greek Market Operator as of 01.02.2012
LV	Low Voltage
MEECC	Ministry of Environment, Energy and Climate Change
MO	Market Operator
MV	Medium Voltage
NGS	Natural Gas System
NNGS	National Natural Gas System
NTC	Net Transfer Capacity
PPC	Public Power Corporation, S.A.
PSO	Public Service Obligation
PTR	Physical Transmission Rights
QoS	Quality of Service
RAE	(Hellenic) Regulatory Authority for Energy
SoLR	Supplier of Last Resort

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

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