ΡΥΘΜΙΣΤΙΚΗ ΑΡΧΗ ΕΝΕΡΓΕΙΑΣ
REGULATORY AUTHORITY FOR ENERGY

2011 National Report to the European Commission

(Covering the period 01.01.2010 – 31.12.2010)

Regulatory Authority for Energy (RAE)

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1. Foreword

Undoubtedly, 2010 was a milestone year for the development and opening of both the electricity and the gas markets in Greece.

The electricity wholesale market reached its final structural and operational pattern in September 2010, after a five (5) year transitional period. The final market design introduced a distinction between the day-ahead market and the balancing mechanism that follows, so as to reflect more clearly the factors influencing prices, the uncertainties involved and the implied risks in these distinct time scales. Considerable regulatory effort in 2010, also continuing in 2011, was placed on the gradual alleviation of market distortions and the resolution of technical issues related to the new market design.

For the first time, the electricity market had a significant supply surplus, with about 850 MW of natural gas-based capacity by IPPs coming into operation, as a result of strong incentives policy for a number of years, but also the financial crisis that shrank demand. This altered the wholesale market dynamics, to the extent that its structure permitted, and, in combination with a good hydraulic year, kept wholesale prices low.

This resulted in substantial potential margins in the retail market, at least for certain customer categories. Thus, activity in the retail market increased significantly during 2010. The important next step is to revisit the competitive components of the consumer tariffs, so as to remove all distortions due to cross-subsidisation, and to link tariffs to production costs, eventually removing regulation.

In distribution, the continuing non-existence of a legally unbundled DSO and the undertaking of the DSO duties by an organisational unit integrated within the incumbent, PPC S.A., prevented effective separation of the distribution network activities, in terms of decision making rights and functioning, from the competitive business of the integrated utility. On this issue, Greece received an infringement letter from the European Commission in June 2010.

Regarding cross-border trade, and following the second infringement letter received from the European Commissions in July 2009, significant improvements towards full compliance with Reg.1228/2003 took place during 2010, concerning cross-border trading arrangements over the interconnections with neighbouring countries, in areas such as available interconnection capacity, harmonisation of auction rules in CSE and overall market transparency.

Regarding renewables, at the end of 2010, wind parks and small hydro units were supplying about 3.9% of the electricity consumed in Greece, while installed RES capacity had reached 11.4% of the total power capacity in the interconnected system (12% on the non-interconnected islands). Interest in further RES investment has been growing, including photovoltaics and offshore wind, due to continuing strong financial incentives (feed-in tariffs) provided by the State (Law 3851/2010). Given the low SMP prices that prevailed in 2010 and the relatively high feed-in tariffs offered to electricity from renewables, the financial difficulties of the TSO in paying the RES producers, that started in 2009, intensified in 2010, and even more in 2011.

In the natural gas sector, following an unsuccessful attempt of a third-party to have access to the Revithoussa LNG terminal in December of 2009, RAE expedited the completion of the detailed rules for access to the market and launched a formal investigation on the circumstances of denial of access by the TSO and on the potential role of the incumbent, DEPA S.A. By the middle of 2010, all required secondary legislation was in place and a formal decision imposing a fine to the TSO for violation of national and EU legislation was issued. By the end of 2010, some 15% of eligible customers had changed supplier, while a strong interest for entering the domestic gas market had been recorded by many international players. Publication, for the first time, by RAE of weighted-average import prices was also very well received by the market in South East Europe and beyond.

The priorities of RAE in the gas sector for 2011 include a) the transposition of the Third Energy Package, b) the improvement of the TPA tariff system and TPA rules, in order to be compatible with a gas hub, and c) the fulfilment of the requirements of the Security of Supply Regulation.

The Greek Regulatory Authority for Energy (R.A.E.)

October 2011

2. Main developments in the electricity and gas markets

2.1. Electricity

While year 2010 was quite similar to 2009 in terms of key market parameters, mainly as far as the reduced demand levels and the significant surplus of hydro power were concerned, it witnessed significant changes in the market design, as well as in the capacity structure, and subsequently, in the level of competition in the wholesale market.

After a number of refinements and improvements, a transitional market-design model, gradually implemented over a five-year period, was finally put in place on September 30th, 2010. In essence, the new market design introduced a distinction between the day-ahead market and the balancing mechanism that follows, as is the case in other countries with mandatory pools. This structure reflects more clearly the factors influencing prices, the uncertainties involved and the implied risks in these distinct time scales. As the electricity market is evolving away from its previous rigid regime, the development of a forward market becomes essential for risk management, in parallel with other structural changes and the on-going restructuring of retail tariffs.

Furthermore, new capacity investments, which had been initiated as a response to past expectations about steady demand growth and to the strong incentives that were adopted, at that time, to counteract a (then) emerging tight supply, entered their final operational stage in 2010. The new capacity added made an impact on market dynamics, to the extent that the market design allowed. With two new CCGT plants of a total 857 MW capacity, starting commissioning trials in late April 2010, seven (7) IPP plants were overall active in the wholesale market by the end of the year, significantly reducing the market share of the dominant player, PPC S.A.

Given the above changes in the capacity structure, the electricity mix also changed significantly during 2010. Gas-based electricity production increased by 10.7%, partially counter-acting a 10% decline in lignite electricity production, while hydro electricity production increased by 35%, as inflows and reservoir levels reached very high values. The downward price effect of hydro generation counter-balanced, to a large extent, the upward price effect of the increasing gas share. As a result, wholesale prices fluctuated around an average value of 52.3 €/MWh, exhibiting an increase of about 10% relatively to 2009 prices (47.4 €/MWh).

In the new market regime, competition among gas plants has been rather intense, although a significant segment of the supply curve is covered by mandatory quantities (hydro, renewables, technical minima of thermal plants, etc). The effect of new capacity on wholesale prices becomes more apparent when IPP units undergo maintenance or return to regular operation. Still, the cost-recovery mechanism, a transitional compensation scheme which creates a safety net for generators, makes them rather indifferent to price levels, inducing an emphasis on quantities produced rather than on prices realised.

Regarding the market power of the dominant player, PPC S.A. covered 76.1% of total demand in 2010 (including exports), as opposed to 85.1% in 2009. Despite this significant decrease in market share, wholesale prices remained sensitive to PPC's bidding behaviour, given its exclusive access to a diversified portfolio of power plants and its flexibility to adjust hydro production – a critical parameter in price formation. In this direction, an extensive market inquiry was conducted by RAE in 2010, mainly relating to over-declarations of mandatory hydro quantities and other factors potentially suppressing wholesale prices, following a report/ complaint by a third supplier, claiming market-rule violations by the TSO. Over-declarations of hydro production were indeed verified and their average impact on prices was estimated, revealing a significant effect for most peak hours, as high as €16/MWh in certain (isolated) cases. Still, the extent to which those discrepancies were related to real safety constraints (the high-flood risk arising from the extreme hydro conditions in 2010), or to an acceptable, conservative TSO approach to hydro reserves, or, alternatively, to deliberate abusive bidding by PPC and the TSO's (unacceptable) tolerance to this, could not be conclusively deduced from the available, aggregated data. Over-declarations of hydro production were reduced substantially after the RAE investigation, which indicates either that the causal conditions of those deviations were temporary in nature (due to stochastic factors), or that the incumbent adjusted its bidding strategy, showing compliance.

Regarding interconnections, no significant changes occurred in the trading rules in 2010, compared to 2009. The net balance increased from 4.4 TWh in 2009 to 5.7 TWh in 2010, indicating an upward trend in cross-border trading. Imports increased by 12%, as the price spread with northern countries remained attractive and the interconnection with Turkey became operational. Exports were reduced by 13%, mainly reflecting the flow dynamics with Albania, as this neighbouring country had sufficient hydro power in 2010. Exports to Italy remained stable, despite some volatility and a moderate decline in spreads.

2.2. Natural Gas

During the first months of 2010, important items of secondary gas legislation were developed and put into force, completing the necessary regulatory framework for access to both the transmission system and the LNG Revithoussa terminal. In brief, the following regulations were put into place:

- The Network Code, following a public consultation and close collaboration between the Regulator and the TSO. The Network Code sets up all the necessary rules for TPA to the Transmission System and to the LNG facility on Revithoussa island.
- A Standard Transportation Agreement and a Standard LNG Agreement, which the TSO concludes with system users.
- The Measurements Regulation, that sets up the technical rules and procedures for measuring natural gas volumes at the entry and exit points.
- A National Natural Gas System (NNGS) Users Registry Regulation, that sets up the requirements and procedures for the registration of any legal or natural person as a gas shipper.
- The Authorisation Regulation, that sets up the rules for the granting of licenses for gas supply, as well as for the operation of independent gas infrastructure in the country.

Moreover, the TSO, following approval by the Regulator, introduced special tariffs for the short-term use of the Transmission System and the LNG facility. This development, as well as the completion of the above regulatory framework, strongly facilitated competition in the domestic gas market.

From the market side, the most important development in 2010 was the commencing of gas imports from suppliers other than DEPA S.A. Since April 2010, third parties (power producers) begun to import LNG on a spot basis, mainly for their own consumption.

Demand increased in 2010 by 8.4% compared to 2009, reaching a level of 3.6 bcm/year, mainly due to an increase in demand from gas-fired power plants and a relatively longer winter period. DEPA's market share in the wholesale market dropped, due to spot LNG imports from the new entrants.

A complaint against the TSO was officially submitted to RAE by an eligible customer, on a TPA refusal case that took place at the end of 2009. The eligible customer had attempted to import LNG for its own consumption, but the TSO had refused access, raising issues of contractual congestion and lack of sufficient regulatory tools to deal with the issue. RAE's position was that full TPA had to be granted to the interested party, and, accordingly, a strong recommendation to that effect was initially addressed to the TSO. Nevertheless, access was never realised and, following the said complaint submitted by the affected eligible customer, RAE launched a formal investigation. The outcome of this investigation was the imposition of a 250.000 € fine to the TSO. The case was also forwarded by RAE to the Hellenic Competition Authority for further investigation on possible infringement of competition laws by DEPA S.A., which was also involved in the case as the eligible customer's long-term supplier and shipper.

3. Regulation and Performance of the Electricity Market

3.1. Regulatory Issues

3.1.1. Management and allocation of interconnection capacity and mechanisms to deal with congestion

Internal Transmission System Congestion and Management

There has been no change in mechanisms to deal with congestion in the internal transmission system. Congestion management is inherent to the wholesale market mechanism (market splitting for generators), as described in detail in the 2010 National Report.

Cross-border congestion

During 2010, cross-border trade of electricity occurred with northern neighbouring countries (Bulgaria, FYROM and Albania) and with Italy (submarine, 400 kV DC link, 500 MW rated capacity). Congestion on northern interconnections predominantly appeared in the import direction, while the Greece-Italy link exhibited congestion in both directions. The newly built 400kV interconnection with Turkey was fully synchronised, and started trial operation in September 2010; commercial trading started in June 2011.

The main principles of interconnection congestion management rules in 2010 remained unchanged, as compared to 2009:

- 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 HTSO until 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 2010, 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	50	100
FYROM	50	100
Albania	50	100
Italy	0	100

Table 1. HTSO responsibility for capacity allocation on interconnections

Congestion on the Greece - Italy interconnection for the direction from Italy to Greece was managed by the Italian TSO for the entire NTC, through annual, monthly and daily auctions, according to the same auction rules. Note that on interconnections where congestion is managed entirely by one TSO (100% NTC), congestion revenue is split between adjacent TSOs on an equal basis. It should also be noted that an MoU was signed between all countries trading at the Italian borders, aiming at further harmonisation of auction rules at these borders and performing of the auctions by a single entity, namely CASC SA.

A significant change to improve compliance with Reg. EC/1228/2003 is that, during 2010, HTSO did not impose an aggregate constraint on the total export capability of the country. As a result, a separate auction is performed for each separate interconnection. Furthermore, HTSO discontinued its practice to curtail Long Term PTRs for reasons of adequacy of supply of the Hellenic system.

Integration of congestion management in wholesale market functioning

There has been no change compared to practices applied in previous years. The current scheme (explicit auctions of PTRs), however, does not establish effective integration of interconnection congestion management with the functioning of the wholesale market.

Congestion income

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 par. 3.1.2 below).

According to the TSO, total net income from CM (before any taxation) amounted to 14.21 MEuro in the period Jan-June 2010 and 11.09 MEuro in the period July-Dec 2010.

3.1.2. **The regulation of the tasks of transmission and distribution companies**

Network Tariffs

Transmission Network Tariffs

Transmission Network tariffs are calculated on the basis of the annual transmission system cost, which is defined in the Grid and Market Operation Code[1], as the sum of the annual rent owed by the HTSO to PPC SA (the network owner) and the annual cost of any work for the expansion of the System. The annual system cost is also adjusted to take into account the differences between the forecasted and the actual revenue from system users during the previous year. For 2010, estimated rent owed to the asset owner (PPC) was €277m (including 8% nominal, pre-tax Allowed Rate of Return), whereas total transmission costs to be recovered through the tariffs were €261.7m, accounting for the over-recovery of costs through the charges applied in previous years[2].

Following a Grid and Market Operation Code amendment in April 2009, transmission system costs are allocated 100% to load (previously, approx. 15% was allocated to generation). 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 and for the customers connected to

1 Ministerial Decision Δ5-ΗΛ/Β/8311/9-05-2005 and subsequent amendments.

2 RAE Opinion 501/2009 to the Ministry of Environment, Energy and Climate Change.

the Distribution Network (MV and LV) in a related Manual approved by RAE[3].

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 customer categories apply: Domestic, Agricultural (MV and LV), Public Lighting, Other MV, Other LV.
- Reduced or zero TUoS charges apply to some groups of customers (e.g. agricultural customer contracts include clauses for load reduction at peak hours, overnight demand in zonal tariffs is charged at 0).
- 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).
- For 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).

Following the above mentioned methodology, RAE concluded that the 2010 tariffs would be similar to the 2009 tariffs, and consequently proposed to the Ministry of Environment, Energy and Climate Change that the tariffs should remain unchanged for 2010.

Customer	Capacity Charge (€/MW or €/kVA)	Energy Charge (€/kWh)
HV	25,166 €/MW chargeable demand (3 coincident peaks)	-
MV (non agricultural)	2,025 €/MW max demand during peak hours	-
Domestic	0.33 €/kVA of Agreed Capacity per year	0.524*
Other LV (non agricultural)	0.70 €/kVA of Agreed Capacity per year	0.576*
Public lighting	0.70 €/kVA of Agreed Capacity per year	0.192

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

Table 2. Transmission charges for 2010

Distribution Network Tariffs

Regarding the allowed distribution revenue, there is currently no formal methodology set for its calculation, given that the Distribution Code (which will include the methodology for estimating the annual distribution costs) has not been adopted yet. As a transitional measure, the methodology

3 RAE Decision 1332/2009.

applied is the one currently used for the transmission system[4]. The elements of the distribution cost in 2010 were as follows[5]:

- Allowed operating expenses: €525.1 million. This is a reduced amount compared to the amount requested by PPC (€535.8 million), because it incorporates a 2% efficiency factor over the requested amount.
- Asset depreciation: €128.3 million.
- Capital employed: €2.605 million.
- Allowed Rate of Return (nominal, pre-tax): 8%.

As a result, the total allowed revenue for the distribution activity in 2010 was €863.4 million. Of this, about €86 million 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. These percentages for LV customers are 20% and 80%, respectively.

The final resulting Use of System unit charges for Distribution in 2010, per customer category, are presented in the following table. The unit capacity charge is applied on the customer *Subscribed Demand (*LV customers*)* and on the *Monthly Maximum Demand* registered at daily peak-hours (*MV customers*). The unit energy charge is applied to the metered energy, adjusted for the average power factor (assumed to be 1 for costumers without reactive power metering).

Customer Category	**Capacity Charge (€/kW of Monthly Maximum Demand at peak-period, per month)**	**Energy Charge (€/kWh)**
MV Customers	1,303	0.34
	Capacity Charge (€/kVA of Subscribed Demand per year)	**Energy Charge (€/kWh)**
LV Customers (subscribed demand >25 kVA) with reactive power metering	4.67	1.78
LV Customers (subscribed demand >25 kVA) without reactive power metering	3.76	2.02
LV Residential Customers	1.20	2.02
Other LV Customers (subscribed demand ≤ 25 kVA)	1.90	2.02

Table 3. Distribution Charges for 2010

4 Ministerial Decree of 31 Dec. 2007, following RAE opinion 294/2007
5 Ministerial Decree of 15 June 2010 following RAE opinion 505/2009

Network Performance and Quality of Service

In 2010, RAE prepared and published Regulatory Instructions for the reporting of the Transmission System performance[6]. Following these instructions, the TSO published a report on the performance of the Transmission System for the year 2010[7]. The report provides availability indices for overhead lines, underground cables and autotransformers, as well as indices for the impact of the system unavailability on 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 indicators. Relevant requirements are to be developed under the umbrella of the Distribution Network Code.

The proposal of RAE for the *Distribution Network Code*, which is yet to be adopted by the Ministry of Environment, Energy and Climate Change, envisages a penalty/reward scheme for quality of service regulation. In this context, the role of the Regulator encompasses the following:

i. Definition, 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 business (all the above are to be set by either a Regulatory or a Ministerial Decree, in the latter case following the Regulator's consenting opinion).

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

iii. Validation of data completeness and accuracy.

Quality of Service indicators – Distribution Network

As mentioned previously, DSO obligations in regard to Quality of Service (QoS) monitoring and the relevant details will be established in the Distribution Network Code. Review of 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 2009[8], to formulate and publish its opinion on these, but mainly on current PPC practices regarding service quality monitoring and reporting, as well as necessary improvements thereof. The work is considered preparatory in the context of the service quality regulation scheme, to be applied once the *Distribution Network Code* is finally enforced.

Balancing Market

Regarding the balancing market, a significant change in its design was introduced on September 30th, 2010 (Section 3.2.1). As opposed to an overall market settlement previously applied, the current market design involves two distinct settlement processes:

[6] http://www.rae.gr/site/system/docs/misc/11012011.csp
[7] May 2011 - http://newsite.desmie.gr/fileadmin/user_upload/Files/study/FINAL-PERFORMANCE_REPORT2010-HTSO.pdf
[8] Data on Quality of Service Indicators for 2010 will be available in the 4th Quarter of 2011.

- 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's dispatch orders.

It should be noted that market participants do not submit bids and offers for deviations from their day-ahead schedules, so as to formulate the imbalance prices, as is the case in the balancing mechanisms of other countries. Instead, the imbalance price is derived by re-solving the same cost-minimisation algorithm as in the day-ahead market, by inserting the actual values of the various inputs (demand, renewables output, plant availability), instead of day-ahead predictions.

Regarding the market concentration in this mechanism, balancing involves usually flexible units, such as gas plants, a significant portion of which is owned by private investors (48%). Hydro plants, owned exclusively by PPC, may also be used, depending on hydro conditions and storage levels.

3.2. Competition Issues

3.2.1. Description of the wholesale market

Market Design: Implementation of its Final Form

The Greek wholesale electricity market has been organised as a pure mandatory pool since its inception in 2005. After gradual refinements, the transitional market design[9], 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*.

In essence, the new market design introduced a distinction between the day-ahead market and the balancing mechanism that follows, as in other countries with mandatory pools. This structure reflects with more clarity 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. Zonal pricing, intended to reveal congestion problems and signal the location for new capacity, has not been activated yet, although two zonal prices (for north and south 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:

[9] See past Reports for a detailed description of the previous market design.

- 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.

Market Volume

The day-ahead market yields the reference price for the industry, as 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. to 52,365,777 MWh in 2010. Alternatively, one may consider imports and exports as distinct trading volumes in the market and add them to the local plant production. Adopting this last definition, the yearly trading volume attained the value of 57,988,243 MWh in 2010. A futures market has not been developed yet, while OTC trading has not been activated either.

New Entrants and Acquisitions

Two new CCGT plants (Elpedison Thisvi and Heron CC) commenced their regular operation in April 2010, while another one, Protergia, started in December (officially, in January 2011). As a result, stronger competition has been emerging in the generation sector, expected to become more intense in 2011.

Regarding acquisitions in the generation sector, Mytilinaios Group became the only owner of Endesa Hellas, after buying from Enel its 50.01% share in the company. The company was renamed "Protergia" and enhanced its market position, becoming the third largest player in terms of thermal capacity, after PPC and Elpedison.

Regulatory Progress in 2010

The regulatory focus in 2010 was mainly on the gradual alleviation of market distortions and on the resolution of technical issues relating to the implementation of the refined market design.

Indicatively, RAE tackled the following issues:

- Incorporating CO_2 emissions costs into the minimum variable cost of plants (i.e. the lower limit of their price offers). This cost would reflect, 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 (where free credits cease to apply).
- Introducing stricter definitions for mandatory hydro, making week-ahead declarations more binding, and deriving imbalance prices based on the maximum quantity between declared mandatory and actual, injected hydro.

- Creating incentives for accurate generation offers and load declarations (specification of parameters for imbalance penalties) and removing rules prone to abuse.
- Refining the marginal value of hydro generation, so as to reflect fuel prices, capacity surplus, and the deviations from the upper and lower levels of each reservoir.
- Drafting a credit cover mechanism for suppliers, in the presence of a deep national recession and the financial illiquidity arising from this. The required guarantees would be adjusted reflecting their volume, risk exposure and credit history.
- Refining the settlement timeframe of the day-ahead market (on a monthly, as opposed to weekly, basis for generators and importers, while suppliers are allowed to choose, as the settlement horizon is reflected upon the cost of their credit guarantees).
- Exemption of transit flows from uplift costs (including the cost of the balancing mechanism, of ancillary services, and of the cost-recovery mechanism) for competition reasons.
- Removal of certain constraints in the determination of available capacity for energy exports.

Regulatory measures regarding the above issues were either adopted during 2010 or carried over to 2011 via public consultations.

Emphasis was also placed on transparency and timely information diffusion by the TSO and PPC, the ex-monopoly and currently the dominant player in both the generation and the supply side. More specifically, the TSO was required to follow certain rules during its dispatch orders and to justify any deviations between the day-ahead schedule and the real operation.

Price Dynamics

Similarly to the price trend in 2009, wholesale prices retained remarkably low levels in 2010, consistent with market fundamentals. Influenced by the development of gas prices, the reduction of electricity demand, due to the economic recession, and a wet year, which boosted hydro production, wholesale prices fluctuated around an average value of 52.30 €/MWh. This level represents an increase of 10% relative to the price average in 2009 (47.40 €/MWh), an extremely yet year, and a decline of 40% relative to the price average in 2008 (87.22 €/MWh), the most recent dry year.

Price volatility in 2010 was retained fairly low, as in the previous year. Prices exhibited a standard deviation of 19.55 (19.63 €/MWh in 2009), reaching a maximum value of 150 €/MWh (the price cap) in 3 isolated instances and a minimum of 0 in a single case (of low demand, where price was set by imports, offered at a zero value). Figures 1 and 2 display the dynamics of SMP across the year, as well as its intra-day profile. Given the market design change introduced on September 30th, 2010, for homogeneity the ex-post SMP price is displayed as the relevant index for the entire year.

The seasonal variation of prices reflects mainly the dynamics of gas prices, maintenance schedules, the emerging competition, given the addition of new plants, and the annual pattern of rainfall. This last element is critical for price formation, as intense hydro conditions often imply severe flood risk and render water releases imminent. Hence, mandatory hydro quantities may easily escalate, particularly over the last quarter of the year. As these quantities enter the market in a compulsory, non-priced, way, the competitive part of the supply curve is reduced, suppressing the SMP.

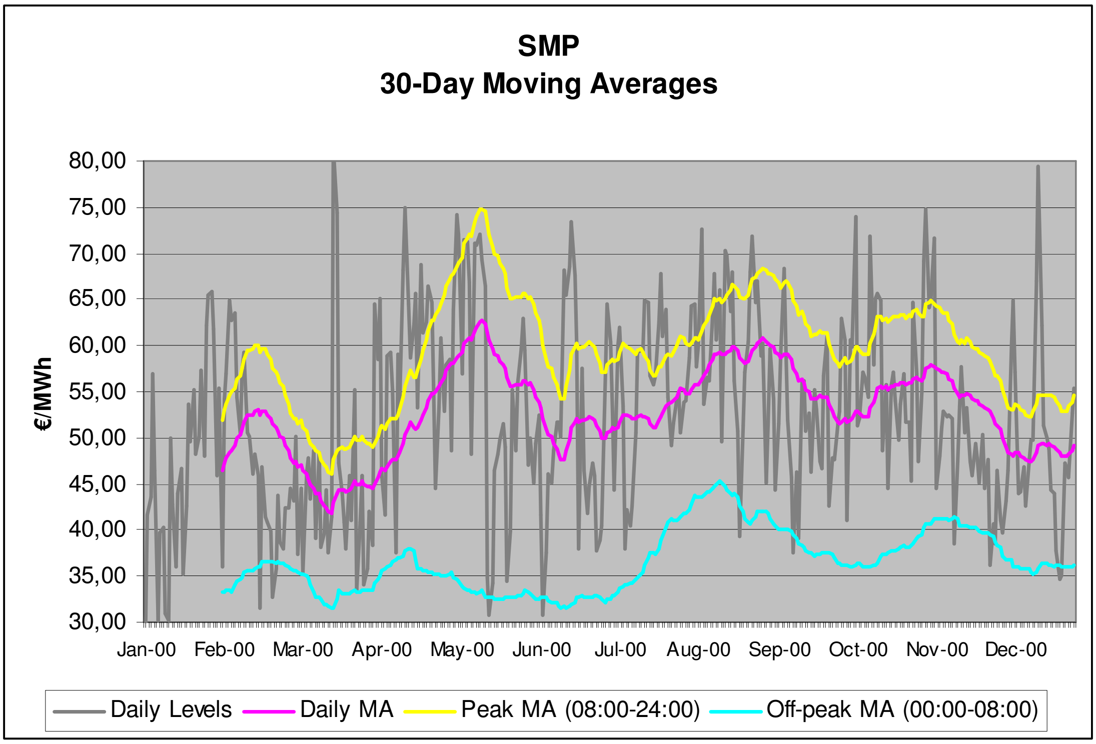

Figure 1. SMP dynamics (actual and smoothened levels) over 2010

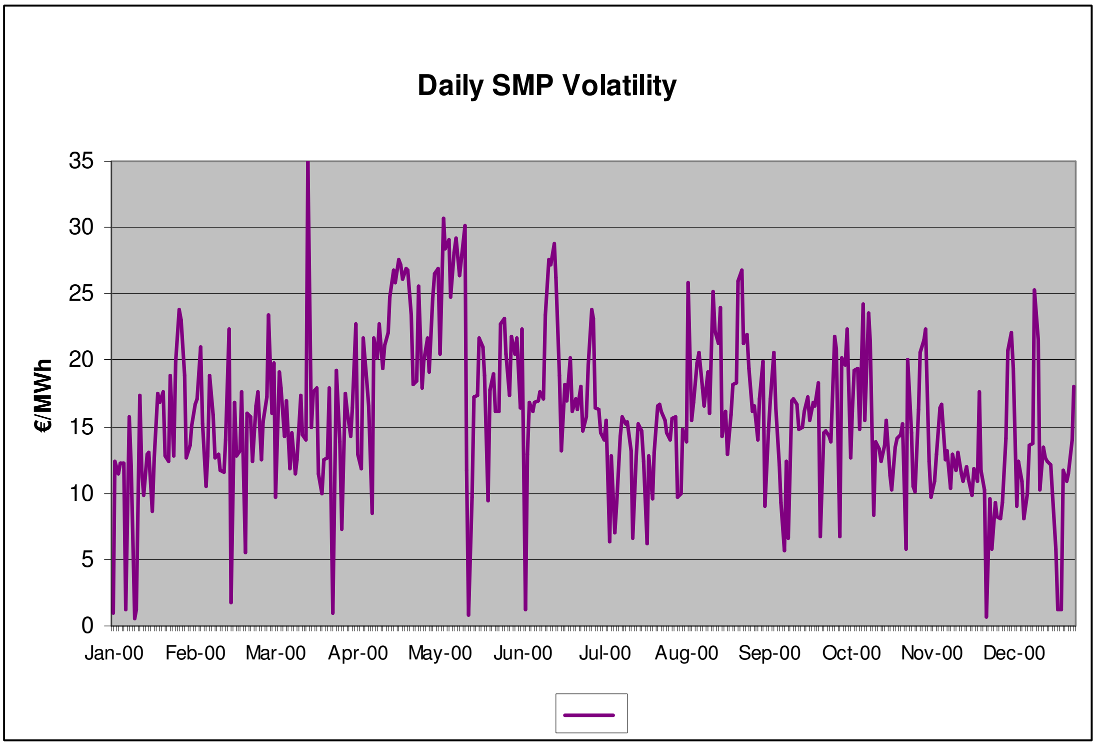

Figure 2. SMP volatility (st. deviation) over 2010

Incumbent's Influence on Price

Overall, given the highly concentrated market at both sides, wholesale prices remained sensitive to PPC's bidding behaviour over 2010. Given the substantial retail margins, the dominant objective of the incumbent seemed to be to suppress wholesale prices, in order to curtail the production of IPPs and reduce, effectively, the cost of energy purchases from renewables, independent generators and imports. Depending on import or export positions of PPC, wholesale prices could have been influenced to some extent by adjusting, appropriately, the bidding (quantities and offers) of hydro production.

In general, price offers of the thermal plants of the incumbent appeared to be very close to the minimum variable cost, with large discontinuities across plant technologies. This translated into high risk exposures for other players, whenever marginal technologies were altered between the (indicative) day-ahead dispatch schedule and the ex-post one, which determined cash-flows. In addition, hydro bids were relatively variable, in response to the evolution of reservoir levels and perhaps, adapted, to some extent, to PPC's interconnection trading. In response to the above observations, RAE has been assessing valuation methodologies for the opportunity cost of hydro, by relating this explicitly to reservoir levels and to the marginal fuel. The derived values, updated on a seasonal basis, may form a lower limit on hydro offers, yielding an adaptive and more realistic proxy than the current limit of 53 €/MWh, which reflects past data on marginal plant costs (CCGT).

Following the addition of two new CCGT plants in April 2010, competition has been emerging between PPC's gas plants and IPPs. Competition at this particular market segment is currently more intense, given the 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, which often makes generators rather indifferent to the price levels and induces an emphasis on quantities produced, rather than prices shaped.

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 correction of regulated prices, so that cross-subsidy distortions are reduced and retail prices reflect wholesale market costs.

Fuel Shares

Given the evolution of market fundamentals in 2010, net generation declined by 3.7% relative to 2009. Lignite production exhibited a significant decrease, of 10%, possibly relating to the decommissioning of the Ptolemaida 1 plant and the environmental strategy of PPC, given its high exposure to carbon prices. Oil generation shrank substantially by 93%, in line with the previous year's trend, due to gas penetration. Gas production exhibited an increase of 10.7%, hence partly counteracting the lignite decline, while hydro production increased by 35%, as inflows and reservoir levels reached extremely high values. Renewable production increased moderately, by 8.2%, but its market share remained still low.

Imports increased by 12%, as the price spread with northern countries remained attractive and the interconnection with Turkey became operational. Exports were reduced by 13%, and this partially reflects fewer exports to Albania, possibly due to the gradual resolution of loop-flow issues and the hydro conditions in the neighbour country. Exports to Italy remained stable (2.3 TWh), as, despite some volatility and a moderate decline in spreads, their magnitude remained attractive.

Figure 3 presents the allocation of production across the various technologies, as well as net imports at the monthly level, while Figure 4 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 (see Section 5).

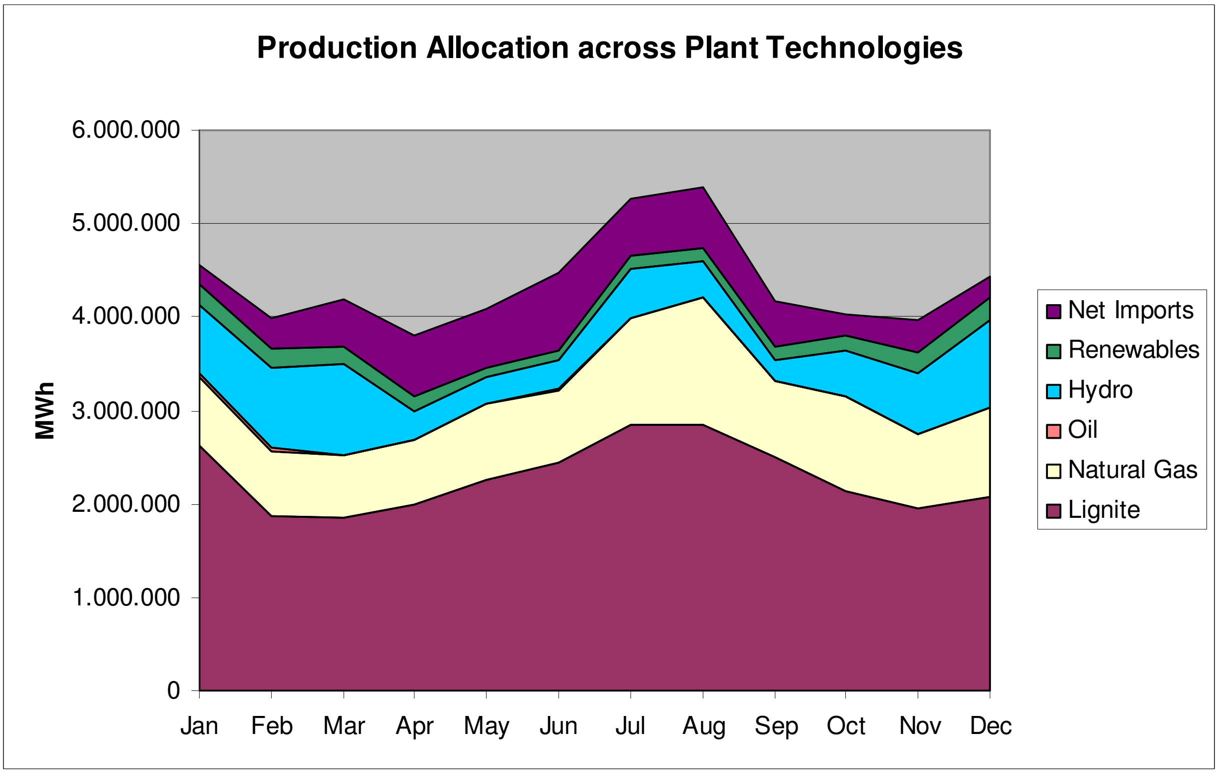

Figure 3. Production Allocation across Fuels and Net Imports at monthly level

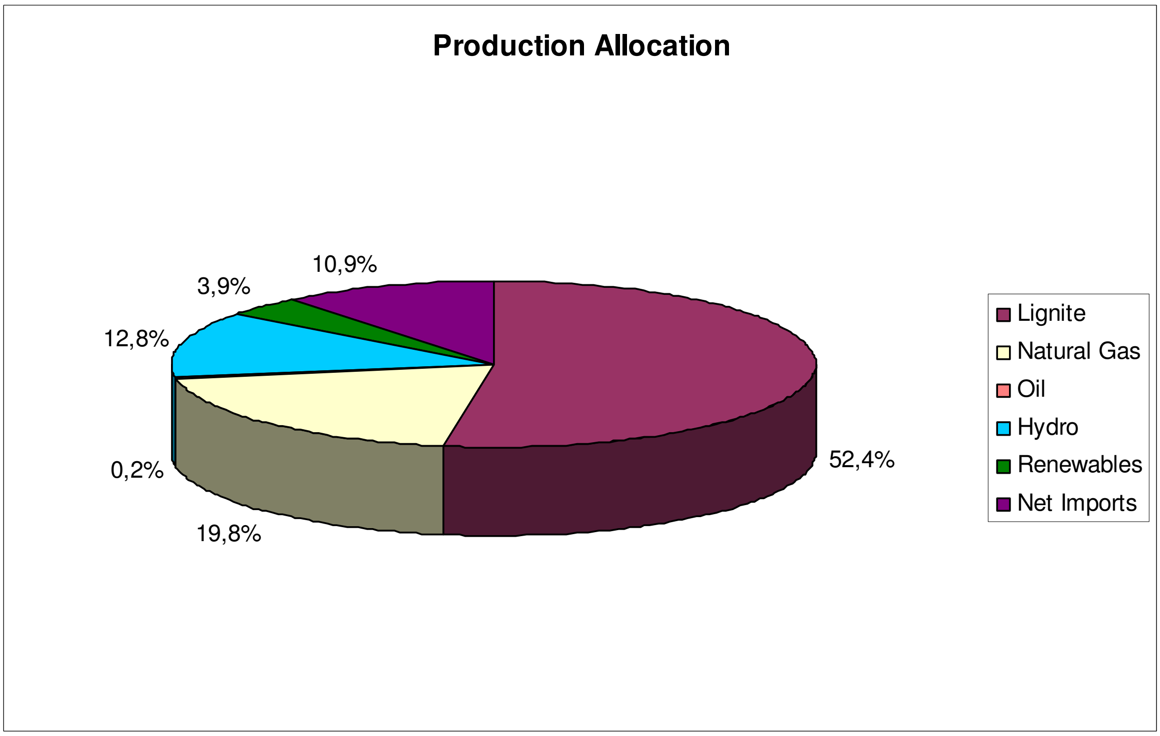

Figure 4. Annual shares of fuels and net imports

Market Structure

Regarding the market structure, PPC retained its dominant position over 2010. Still, its market share declined substantially, both in the generation and the supply side. This trend is expected to become stronger, through the commissioning of new thermal capacity as well as through the steady increase of renewable power generation.

Regarding new capacity, significant additions occurred in 2010, altering the market dynamics to the extent that the market design allowed. More specifically, two new CCGT units, Thisvi (422 MW), owned by Elpedison, and Heron II (435 MW), owned by Heron Thermoelectricity, started commissioning trials in late April 2010. Another CCGT unit, Protergia (previously known as Agios Nikolaos) (412 MW), owned by Mytilinaios Group (previously Endesa Hellas), started operation in December 2010. Hence, seven (7) IPP gas plants are currently active in the wholesale market, including, apart from the above units: Enthess (390 MW, CCGT), Alouminion (334 MW, large-scale CHP), Heron (150 MW, OCGT), and Motoroil. Heron, a 150MW OCGT unit, previously contracted with the TSO for the provision of ancillary services, retained over a third year a long-term capacity availability contract with the incumbent, PPC. As noted by Heron, this contract, similar to a tolling arrangement, increased substantially its hours of operation, hence reducing gas transportation charges.

Moreover, as stated by the TSO in the most recent Grid Development Study, six other thermal units, of total capacity 2700 MW, had also applied for connection until August 2009 (TSO's latest available data). Three of them are scheduled to connect to the 400kV system, whereas the others to the 150 kV. The incumbent's new units, Aliveri V (360-400MW) and Megalopoli V (850MW), both CCGT, have been contracted with the TSO. Upon their operation, the obsolete lignite units Megalopoli I and II, of capacity 250 MW, will be decommissioned. Two new hydro stations, Ilarionas (153 MW) and Mesochora (160 MW), have signed connection agreements, with the latter expected to operate over the coming years. The obsolete plant, Ptolemaida 1 (65 MW), which exhibited the highest emission factors among all plants, was decommissioned in June 2010, having completed fifty (50) years of operation.

After a significant decline of 6.9% over the previous year, electricity demand remained fairly stable over 2010 at 53.366 GWh (-0.87% relative to 2009) at the interconnected system. At the national level, demand was also unaffected, amounting to 61.817 GWh (relative to 61.842 GWh in 2009).

The market share of PPC declined significantly in 2010. In the interconnected system, PPC's share dropped to 85% of local production, while independent gas producers achieved a share of 8.8% and renewables generators of 6.4%. Taking its imports into account, PPC covered 76.1% of total demand in 2010 (including exports), as opposed to 85.1% over 2009. At the national level (including non-connected islands), PPC's production covered the 77.3% of total demand in 2010, with the corresponding share being 85.6% in 2009. In absolute terms, PPC's production plus import activity was reduced by 5.123 GWh. The import activity of PPC was also reduced, by 19%, while imports by other companies increased by 52%. Regarding renewables generation, PPC's production remained low (274 GWh), while IPPs produced 3.658 GWh (+9.8% compared to 2009).

The HHI index for the wholesale market in 2010 attained the value of 6844, as opposed to substantially higher values, much closer to the upper bound of 10,000 in previous years. This value indicates that over-concentration is still substantial in the market, but it also signals that competition is emerging. The HHI index for the retail market is even higher at 8616. Although suppliers were attracted by high potential margins in certain customer categories, these margins ought to be reduced as regulated prices are being progressively corrected, removing cross-subsidies.

Plans for new plant investments were explored with significant interest over recent years, both from PPC and private companies, including trading companies, which are seeking a physical hedge of their positions. Although some investment plans seem to be adjusted, given the deep economic recession, the renewables sector remains an attractive field, with the level of feed-in-tariffs being a major incentive, despite bureaucratic (licensing) obstacles. Given the targeted level of wind penetration (7500 MW by 2020) and its intermittent nature, stand-by reserve as well as secondary reserve is expected to emerge as a significant component of financial returns for thermal plants.

	Ownership	Installed Capacity (MW)	Total Production (MWh)	Capacity Factor
Thermal				
Lignite	**PPC**	**4,746**	**27,754,770**	**66.76%**
Oil	**PPC**	**698**	**114,549**	**1.87%**
OCGT	PPC	339	1,170,009	39.40%
	Heron	148	88,542	6.88%
	Total	**487**	**1,258,551**	**23.83%**
CCGT	PPC	1,578	5,087,350	36.80%
	Elpedison	812	2,156,639	30.32%
	Heron Thermoelectric	390	598,735	17.53%
	Mytilinaios	444	NA*	NA*
	Total	**3,192**	**7,842,724**	
CHP (Large-scale)	**Mytilinaios**	**334**	**1,272,616**	**43.50%**
Total Thermal		**8,759**	**38,243,210**	
Large Hydro	**PPC**	**3,018**	**6,888,214**	**26.05%**
Renewables				
Small Cogeneration	**IPP**	**125****	**114,560**	**1%**
Wind	**IPP (mainly)**	**1,039****	**2,039,108**	**24,17%**
Small Hydro	**IPP (mainly)**	**197****	**753,497**	**46.24%**
Biofuels – Biomass	**IPP (mainly)**	**44****	**193,933**	**54%**
PVs	**IPP (mainly)**	**153****	**131,951**	**16.46%**
Total Renewables		**1,558**	**3,118,489**	
TOTAL		**13,364**	**48,249,913****	

Table 4. Installed Capacity and Capacity Factor by Fuel and Ownership

** Although the plant started its commissioning in 12/2010, it entered the Scada system in 1/2011*

*** The capacities refer to the end of the year. Yearly average values were used for the calculations of capacity factors and market shares. Given this approximation, the total average capacity for renewable sources over 2010 was 1417 MW, while the overall capacity amounted to 12,475 MW.*

**** If losses are subtracted, total production is equal to 46.659.646 MWh, while quantities per technology are modified as follows: 27,439,614 MWh for lignite, 113,272 MWh for oil, 10,365,063 MWh for natural gas and 6,702,589 MWh for hydro.*

Source: Grid Development Study (TSO) and Scada Reports.

Cross-border trading activity remained stable over 2010, with, usually, up to 15 companies active in the interconnection with Italy and significantly less, regularly around 5, in the northern borders. In the past, some demand involvement in the market could be manifested indirectly, e.g. through curtailment arrangements with industrial customers during peaks, which entailed some form of demand response to high prices, even in the context of adequacy measures. Given the economic crisis, which influenced industrial production, the potential of such indirect demand-response effects appeared more restricted in 2010. Still, within a recession period, and under the assumption of a link between wholesale and retail prices, demand elasticity to price can emerge as a significant driver for market changes in the near future.

Integration with neighbouring member-states

The relevant electricity market for Greece is, to a significant extent, the national market. The total interconnection capacity of the country in 2010 was 2000 MW, a significant increase compared to 2009, due to the addition of a new interconnector eastwards, with Turkey[10] (500 MW), which was fully synchronised in September 2010. The trial operation period for the new line is expected to be completed in May 2011, when commercial trading is scheduled to start, exerting an impact on wholesale prices.[11]

Currently, interconnection with adjacent member states (namely Italy and Bulgaria) amounts to 1300 MW, which corresponds approximately to 13% of annual peak demand (approximately 10,000 MW), while interconnections to Albania and FYROM are restricted to 200 MW. 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.

Overall, the net interconnection balance increased from 4.4 TWh in 2009 to 5.7 TWh in 2010. This indicates an upward trend in cross-border trading and also reflects the impact of the factors below.

- In the interconnection with Albania, a significant change occurred in the direction of flows. Imports increased substantially, while exports shrank, as the neighbour country had sufficient hydro power over 2010.
- The activation of the new interconnection line with Turkey resulted in energy imports of 0.7 TWh. This quantity refers to flows through the new line and does not indicate Turkey as the country of origin of the energy.
- The higher volatility of the price spread with Italy influenced export activity. 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.

As a result, imports increased from 7.6 TWh to 8.5 TWh (+12%), while exports declined from 3.2 TWh to 2.8 TWh (-13%). Imports from Bulgaria and Fyrom remained stable. Figure 5 displays the allocation of interconnection trading in 2010 and its evolution relatively to 2009, which reflects the conditions previously described.

Focusing on price differentials, the premium of the Italian baseload retained substantial levels over 2010, despite its higher volatility. On average, the premium fluctuated as follows: 22.2 €/MWh in Q1, 12.9 €/MWh in Q2, 20.0 €/MWh in Q3 and 18.8 €/MWh in Q4. These values imply substantial profits for exports to Italy over 2010, as well as potential profits for imports to Greece, whenever the

[10] 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.

[11] Commercial trading started in June 2011; up to date, the trading volumes remain low and have not influenced OTC.

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 2010, 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, often exceeding 25 €/MWh. On average, the price differential varied as follows: 2.2 €/MWh in Q1, 12.7 €/MWh in Q2, 14.2 €/MWh in Q3 and 7.6 €/MWh in Q4 2010.

Usually, up to 15 companies were actively trading on the interconnection with Italy and significantly less, regularly around 5, in the northern borders. Despite its substantial growth over previous years, export activity from Greece had not reached its full economic or technically feasible potential, as the Auction Rules for determining ATC for exports posed a constraint relating to security of supply in Greece. In a recession period, where business activity needs to expand beyond the country border, and given the sustained spreads with Italy, such obstacles should be reduced as much as possible. This constraint on exports was indeed removed in 2010. In the same direction, transit flows are expected to be exempted from uplift costs that relate to the operation of the local wholesale market. No significant changes occurred in the rules for cross-border electricity trading in 2010.

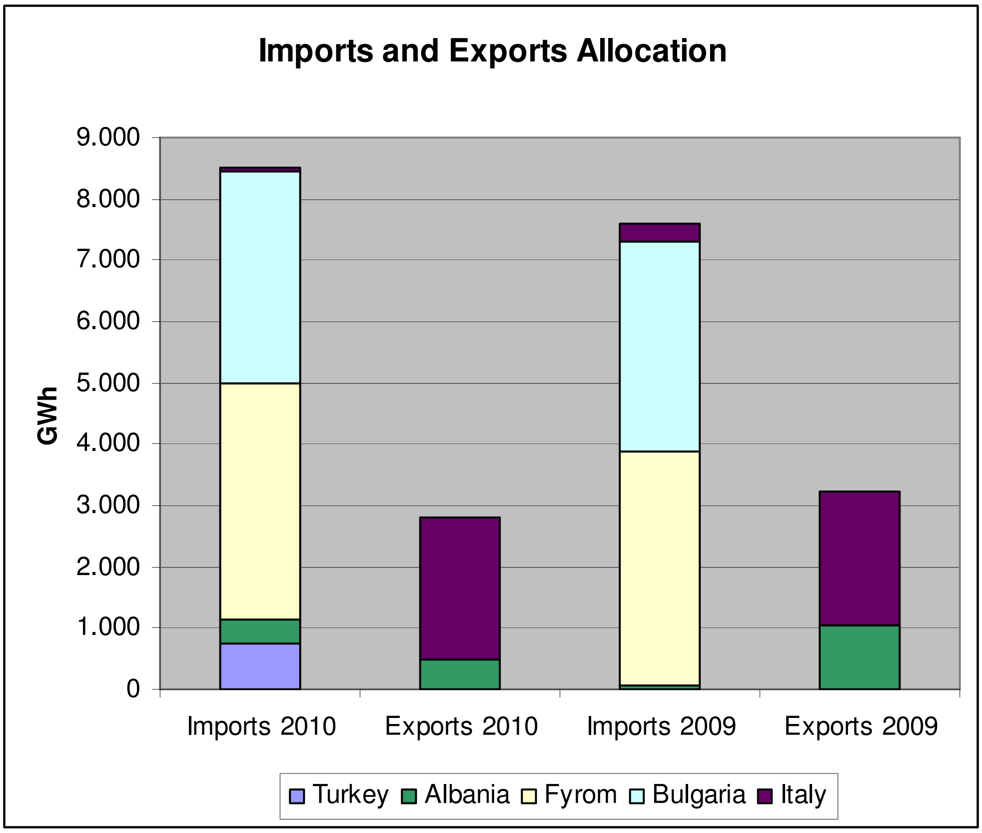

Figure 5. Profile of import and export trading in 2010 compared to 2009

In the past few years, integration with adjacent Balkan countries was subject to trading obstacles, due to the lack of appropriate implementation of Regulation 1228/2003, especially regarding capacity allocation mechanisms and transparency issues. Following the second infringement letter received from the European Commissions in July 2009, significant improvements towards full compliance with Reg.1228/2003 took place during 2010, concerning cross-border trading arrangements over the interconnections with neighbouring countries, in areas such as available interconnection capacity, harmonisation of auction rules in CSE and overall market transparency.

3.2.2. Description of the retail market

Tables 5 and 6 present the consumption of end-user customers in 2010 by category and voltage level, for the interconnected system and for the non-interconnected islands, respectively.

Electricity consumption - Interconnected system (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small and Medium Industrial and Commercial customers**	**Other (eg. agricultural, public, traction, mines, pumping)**	**Total**
LV	**2009**		16,368	11,432	3,608	**31,408**
	2010		16,477	12,257	2,805	**31,538**
MV	**2009**			9,273	1,425	**10,698**
	2010			9,674	1,447	**11,121**
HV	**2009**	6,006			1,358	**7,364**
	2010	6,355			989	**7,344**
Total	**2009**	6,006	16,368	20,705	6,391	**49,469**
	2010	6,355	16,477	21,931	5,241	**50,004**

Source: TSO & DSO. Data refer to metered consumption at customer site. Losses at HV system were 1.5TWh

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

Electricity consumption - Non-interconnected islands (GWh)						
Voltage	**Year**	**Large Industrial customers**	**Household customers**	**Small and Medium Industrial and Commercial customers**	**Other (eg. agricultural, public, traction, mines, pumping)**	**Total**
LV	***2009***		1,763	1,814	476	**4,054**
	2010		1,750	1,804	509	**4,062**
MV	***2009***			805	222	**1,027**
	2010			873	220	**1,093**
Total	***2009***	0	1,763	2,619	698	**5,081**
	2010	0	1,750	2,677	728	**5,155**

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

Table 6. Electricity consumption in the non-interconnected islands

Total consumption at the transmission system level (for the interconnected system only) was 52.4TWh, very close to the 2009 level (0.87% reduction).

Despite increased activity in the retail market by new entrants, PPC remained the dominant supplier (93.7% of the total volume in the interconnected system). Eleven (11) out of 62 electricity supply licence holders were active in the retail market. Two of those independent suppliers, namely "Energa Power Trading AE" and "Aegean Power S.A.", represented 3.1% and 2.7% of total volume in the interconnected system, respectively. During 2010, nearly 7% of industrial and commercial customers connected to the medium voltage network (representing a volume of 8.42%) had switched supplier. PPC's share in this market dropped to approximately 89%, while the shares of Energa and Aegean were 4.2% and 4.9%, respectively. The second most active market segment was the industrial and commercial customers connected to the low voltage network, where approx.

5% of the customers (approx. 15% of volume) switched supplier during 2010. PPC's share in this market dropped to approx. 84%, while the shares of Energa and Aegean were 8.8% and 6.8%, respectively. The switching percentages in the remaining low-voltage market remained insignificant.

At the end of 2010, apart from PPC SA, supply licenses had been granted to 61 other companies (see list in Appendix I). None of these companies are affiliated to the TSO or DSO businesses. It should be noted that, until recently, independent suppliers were mainly active in trading, rather than in retail supply. 2010 saw increased activity in the retail market, demonstrated by the volumes purchased by suppliers in the wholesale market.

Switching procedures did not change in 2010. However, given the increased activity in supplier switching, suppliers reported problems in the implementation of these procedures. An official complaint by an independent supplier was submitted to RAE against the Distribution System Operator (still a part of the vertically integrated PPC) in November 2010, which reported problems and market obstacles relating to:

- 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

The RAE inquiry on the above complaint continued in 2011.

During the spring of 2010, RAE conducted a public consultation on the new Electricity Supply Code. The draft code covers issues including:

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

The issuing of the new Supply Code will follow the recent adoption (August 2011) of new national legislation, incorporating the provisions of the 3rd Energy Package (Law 4001/2011).

Retail price developments

There was no change in the regulated retail tariffs of PPC in 2010 (although related taxes and levies did change, applying to all suppliers). Average prices per voltage and consumer category can be seen in Table 7. Independent suppliers were able to offer discounts over PPC regulated tariffs, in the range of 5-15%, in specific retail market segments, demonstrating higher levels of profitability, due to cross-subsidies in the regulated tariffs (mainly tariffs for medium and large commercial customers, as well as large domestic customers).

Voltage	Domestic	Industrial	Commercial	Agricultural	Public Lighting	Total average
LV	104.95	123.70	139.70	47.88	99.22	**113.53**
MV		83.11	100.86	40.80		**90.36**
HV		61.02				**61.02**

Table 7. 2010 Average PPC retail electricity prices per consumer category, €/MWh (excluding taxes and levies)

Consumer complaints

In the absence of a formal (legal) definition, RAE recognises and treats a consumer complaint as the written expression of a consumer's dissatisfaction, which is addressed to the electricity provider (supplier or distributor), or to any other third party, and to which the consumer expects a response or resolution. On the other hand, a consumer inquiry is any written request for information or clarification or advice, submitted by a consumer or any other third body, in relation to the provision of electricity or gas or any other subject within the responsibilities of the Authority.

A total number of 69 discrete cases[12] on complaints/inquiries concerning electricity were registered to RAE, either directly by individual consumers or through other responsible consumer bodies/organisations. Although RAE does not have a legal mandate to act as a dispute settlement body, between service providers and individual consumers, its policy is to investigate all complaints submitted directly by individual consumers and to respond to all inquiries addressed to RAE. In this context, RAE investigated 35% of the documents, i.e., 24 cases, pertaining to electricity.

Complaint evaluation process involves two main stages: in the pre-hearing stage, RAE may request information and relevant documents from service providers. Due to the continuing lack of a Distribution Network Code and to the inadequacies of the outdated Supply Code still in force, usually a certain change in behaviour or action may be recommended as a result of the evaluation. A hearing stage could follow, when there is a clear violation of the electricity law, that affects a significant number of consumers, according to which RAE may:

- issue an order to the service provider, to cease any behaviour violating consumer rights
- impose a financial penalty to the service provider for non-compliance with regulations or with the above mentioned order.

In the context of energy market monitoring, RAE's main role is to collect and analyse data and information on complaints, in order to identify any underlying market malfunctioning, in an effort to set up or improve rules and regulations for better protecting consumers. Other bodies, directly responsible for the dispute settlement of consumer complaints, are: a) the Greek Ombudsman, b) the Hellenic Consumer's Ombudsman, which is a public Independent Authority with an institutional role in dispute resolution, c) the General Consumer's Secretarial of the Ministry of Employment & Social Security and d) local non-governmental consumer organisations. Unfortunately, the decisions and recommendations of those bodies, with the exception of the General Consumer's Secretarial, are not legally binding to service providers, and complaints are often not settled.

A table of statistics on consumer cases registered to RAE, regarding electricity, follows:

[12] Please note that in comparison to 2009 data, starting in 2010 RAE reports the number of discrete consumer cases and not the number of incoming documents related to consumer cases.

Category Cases	%
Complaint	78.2
Inquiry	8.6
Combination of the above	11.6
Other	1.6

Table 8. Electricity complaints/inquiries by category case

Thematic Categories of Electricity Cases	%
Dispute on consumption charges	13.0
Meter readings	13.0
Damages on appliances after electricity reset	10.1
Damages on appliances caused by a cut-off of the neutral conductor	7.2
Problems related to electricity network installations	5.8
Social tariff	5.8
Dispute on charges (other than consumption)	4.3
Damages on appliances due to bad quality of electricity	4.3
Delay on meter repair	4.3
Connection / disconnection	4.3
Electromagnetic radiation	2.9
Supplier switching	1.4
Connection refusal	1.4
Increased price	1.4
Arrangements for payment of debts	1.4
Dispute on charges (“closed” distribution nets)	1.4
Double charges	1.4
Information on pricing policy	1.4
Damages after network installations	1.4
Delay to connection	1.4
Quality of electricity	1.4
Green electricity certificates	1.4
Frequency of interruptions	1.4
Over-charges	1.4
Other	5.8

Table 9. Electricity complaints/inquiries by thematic category

In the electricity sector, the majority of dissatisfied consumers were concerned with: a) compensation claims for damage sustained to electric and electronic home appliances, due to problems in the quality of supply and b) issues of unjustifiably high bills. The Distribution Network Operator has formulated, in cooperation with RAE, a compensation scheme, according to which the DNO pays up to a fixed amount to consumers, whose electric appliances are damaged after the random cut-off of the network neutral conductor. Most of the consumers expressed their satisfaction for this new compensation measure, that is applied through a simple process.

3.2.3. **Measures to avoid abuses of dominance**

Wholesale Market Inquiry

An extensive market inquiry was conducted by RAE in 2010, mainly relating to over-declarations of mandatory hydro quantities and other factors potentially suppressing wholesale prices, following a report/ complaint by a supplier for market rule violations by the TSO. Hydro over-declarations were indeed verified and their average impact on prices was estimated, revealing a significant effect for most peak hours, which peaked at €16/MWh on isolated occasions. Still, in the presence of strong technical inter-relations among hydro stations, which may have a magnifying effect even on small deviations, the extent to which these discrepancies were, indeed, related to security constraints (the high flood risk arising from the extreme hydro conditions in 2009), or to a conservative (but quite acceptable) TSO approach to reserves, or alternatively, they were related to deliberate abusive bidding by PPC and TSO's tolerance to this, could not be inferred from the available, aggregated data. In addition, over this transitional market stage, in the presence of market distortions, generators' payments were based on ex-post, rather than on day-ahead, prices, and it was found that the implied premium in this settlement counteracted the suppressing effect on prices that over-declarations could induce (irrespective of their source, which remains unclear). While the TSO could have been more proactive, reporting systematic patterns to the Regulator and assessing potential remedies, it was still clear that it operated within various security and plant constrains and fulfilled its fundamental obligations, despite the rather extreme hydro conditions. Hydro over-declarations were reduced substantially after this inquiry, which indicates either that the causal conditions of the deviations were temporal (due to their stochastic nature), or that the incumbent adjusted its bidding strategy, showing compliance.

Retail market – marketing practices

Activity in the retail market in 2010 increased significantly. In order to protect consumers from aggressive and misleading marketing behaviour by the new entrants, RAE issued Guidelines[13] towards supply companies, concerning their practices when communicating with customers, with emphasis on the provision of important, mandatory information, such as supplier/ agent identity, contact details, clear description of the services offered, specific terms and conditions, etc.

Competitive tariffs for HV customers

Although retail prices to HV customers have been deregulated since 2008, PPC had not proceeded with the unbundling of the tariffs and with the renegotiation of contracts with customers connected to the HV network. As a result, the estimated competitive component of the retail tariff for each HV customer exhibited great variation, between 45 and 85 €/MWh, which does not reflect the different load characteristics, but is mainly due to the differences in the application of the regulated tariff components (charges for Use of the Transmission System and charges for Public Service Obligations).

[13] RAE's Decision 81/2010.

In order to remove this distortion, RAE requested that PPC proceed immediately with HV tariff unbundling and setting of separate prices for the competitive component of the tariff, based on customer/ group load characteristics, the latest by the end of 2010. This was not completed by PPC on time, but was carried over into 2011.

Mechanisms for Market Monitoring

To assess ex-post generators' conduct or to predict future behavioural patterns, the Regulator introduced the systematic use of specialised software, mainly:

- a market simulator, which allows the testing of counterfactual and future scenarios, and

- a market monitoring platform, which displays various ex-post metrics of market performance.

RAE has also set up procedures for regular updates by the TSO of various relevant parameters, both technical and economic, at the plant level.

More specifically, the Regulator receives ex-post extensive hourly data from the TSO on a regular monthly basis, including plant availability declarations and possible modifications after the closure of the day-ahead market. Hourly bidding data are also obtained, usually with a time lag of a few months, partially due to the more complex structure of these data (dimensionality) and the frequent adjustments in the TSO's software (in response to subtle changes in the market rules). An effort is made to assess these data regularly. The Regulator has the right to conduct an investigation, if patterns of improper or alarming behaviour are detected.

To assess the price impact of certain market parameters or patterns of generators' behaviour, a market simulator is used, in which the technical and economic data received from the TSO are fed. This simulator has been used to assess certain diverging responses, for instance to assess the price effect of hydro over-declarations, wind forecast errors, or incorrect fuel costs. The next technical challenge for RAE is to create a more efficient interface with the data sent by the TSO, linking efficiently the two different structures.

In addition, RAE developed a market monitoring software in 2010, which generates consistently a daily market report, upon which a market commentary is based. This report displays various market fundamentals and market outcomes on an hourly basis, including prices, dispatch, mandatory production (hydro and renewables), plants' deviations between day-ahead schedules and real time operation, emissions, market shares, cash-flows, marginal technologies and interconnection activity.

Hence, significant aspects of market performance are clarified, while indications for patterns of improper or alarming generators' conduct may also emerge. For instance, due to the critical role of mandatory hydro on price formation and the suppressing effect of over-declarations on prices, a part of the report focuses on the deviations between declared mandatory quantities by PPC and actual production. If substantial or persistent deviations arise, the Regulator requests detailed justification.

Overall, the market outcome is assessed on a regular basis and investigation is conducted when points of concern are detected, such as capacity unavailability over crucial periods. After a trial period, the report will be uploaded on the Regulator's site within 2011, so as to enhance transparency and market understanding.

Data Requirements and Transparency

- Generators are required to submit technical and economic data, including their cost components (e.g. fuel costs, estimated carbon costs, etc), so that the TSO can verify, on a daily basis, that the level of their hourly energy offers exceeds their minimum variable cost.

- Regarding capacity schedules, the TSO publishes annual maintenance schedules (for the period starting in October of the current year up to, and including, September of the following year), which are revised according to changes in plant declarations.

- Apart from capacity availability forecasts, short- and medium- term predictions for significant market inputs are published by the TSO. These include week-ahead declarations of mandatory hydro, made by PPC, demand forecasts of baseload and peak for each week of the next two months (a practice first implemented in July 2010) and indicative weekly forecasts of NTC over the next 12 months (a practice first implemented in March 2010).

4. Regulation and Performance of the Natural Gas market

4.1. Regulatory Issues

4.1.1. Management and allocation of interconnection capacity and mechanisms to deal with congestion

During 2010, there was no change regarding interconnection infrastructure of the Greek transmission system with neighbouring gas systems, namely Bulgaria and Turkey.

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 TPA rights, which 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.

Therefore, no physical or contractual congestion was experienced in both interconnectors during 2010.

4.1.2. The regulation of the tasks of transmission and distribution companies

Network Tariffs

A. TPA tariffs

A major development during 2010 was the introduction of detailed provisions regarding short-term TPA services tariffication, in order for the tariff system to be fully in line with the provisions of the Network Code regarding short-term transmission and LNG contracts (minimum 1 day and 1 month respectively). Therefore:

1. Tariffs for contracts of a standard duration of one year were simply adjusted for inflation compared to the previous year (2009), and the actual tariff coefficients for 2010 are presented in the Table below:

Tariff	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
Transmission	575.070	0.282927
LNG	24.128	0.018205

Table 10.Coefficients of TPA tariffs for one-year duration contracts

2. In case of a short-term contract for the use of the Transmission System or the LNG System, the capacity coefficients of the 1-year contract as presented below, 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 11. Coefficients of TPA short-term tariffs

DESFA S.A. publishes on its website the Ministerial Decision 4955/2006 and the current TPA tariffs, in both Greek and English[14].

B. Distribution tariffs

There were no changes in the scheme of gas distribution, performed by the three distribution companies currently active in Greece (hereinafter "EPAs"). EPAs are operating under a regime of exclusive right for both the activities of distribution (DSO) and supply of gas in their areas.

According to article 24 of the Gas Law, access to EPA's networks may be granted to other suppliers serving eligible customers with annual consumption of more than 100 GWh GCV of natural gas. The tariffs for accessing the EPA's distribution systems are approved by the Regulator (article 31 of the Gas Law), in full compliance with the provisions of the Directive.

Tariffs for TPA in EPA's distribution systems are currently set in accordance with the terms of their concession license. By the completion of accounting unbundling, TPA tariffs will be set by the EPAs and approved by RAE.

Balancing

There was no change in the scheme for balancing energy, as it was described in the 2010 National Report.

RAE approved in 2010 the annual balancing plan 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 the year. For 2010, the TSO estimated that the balancing gas needs for the 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%. According to the balancing plan, and in line with an interim provision of the Gas Law, the necessary quantities of balancing gas (in the form of LNG) were purchased from DEPA SA, the incumbent company.

In the balancing plan of 2010, DESFA S.A. announced its intention to activate a market-based approach for acquiring balancing gas to cover balancing gas needs for the year 2011, in line with the main provisions of the Gas Law. To this effect, RAE provided its consent.

RAE also approved the balancing cost allocation scheme and the relevant shipper's charges for the year 2010, which include all costs arising from providing balancing services. The corresponding charges include:

[14] http://www.desfa.gr/default.asp?pid=1&la=2

- 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 contract, which is 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[15].

4.1.3. **Effective Unbundling**

The unbundling situation in Greece, as well as the relevant provisions of the Gas Law and the Authorisation Regulation, have been presented in detail in the previous two National Reports, regarding years 2008 and 2009.

[15] http://www.desfa.gr/default.asp?pid=196&la=1

4.2. Competition Issues

Summary of regulatory developments and market entry

As already mentioned in paragraph 2.2, during 2010 the regulatory framework was completed with the publication of the Network Code, the Authorisations Regulation and other items of secondary legislation, therefore setting the stage for the development of real competition in the market.

The Network Code sets the rules and procedures for TPA in the Transmission System and the LNG facility. Among others, the Code deals with capacity allocation and congestion management, scheduling, nominations, balancing and NNGS infrastructure development. The subsequent publication of the Standard Agreements for the use of the Transmission System and the LNG facility completed the TPA regime. According to the Network Code, capacity in the Transmission System or the LNG terminal at Revithoussa is available on a short-term basis; the minimum contract duration is one day for transmission and one month for LNG.

The scope of the Authorisations Regulation covers the granting, the amendment and the revocation of the Independent Natural Gas System (INGS) License, the INGS Operation License, the Natural Gas Distribution License (Distribution License), the Natural Gas Supply License (Supply License), and the Ownership and Operation of the National Natural Gas System License, granted to DESFA S.A.

During 2010, after the publication of the Authorisations Regulation, RAE received the following applications for granting an authorisation:

	Company	Type of license applied for
1	DEPA S.A.	NATURAL GAS SUPPLY AUTHORISATION
2	DESFA S.A.	AUTHORISATION FOR THE OWNERSHIP AND OPERATION OF THE NNGS
3	PROMETHEUS GAS S.A.	NATURAL GAS SUPPLY AUTHORISATION
4	EGL HELLAS S.A.	NATURAL GAS SUPPLY AUTHORISATION (the company withdrew the application)
5	EGL HELLAS S.A.	NATURAL GAS SUPPLY AUTHORISATION
6	TRANS ADRIATIC PIPELINE AG (TAP AG)	INGS AUTHORISATION
7	M & M GAS Co S.A.	NATURAL GAS SUPPLY AUTHORISATION
8	AEGEAN POWER S.A.	NATURAL GAS SUPPLY AUTHORISATION
9	ENIMEX S.A.	NATURAL GAS SUPPLY AUTHORISATION
10	GASTRADE S.A.	INGS AUTHORISATION

Table 12. Companies' applications for gas authorisations

According to the provisions of the Gas Law 3428/2005 and the Authorisations Regulation, the Minister of Environment, Energy and Climate Change is responsible for granting the licenses, following an opinion by the Regulator. During 2010, RAE gave a positive opinion for the granting of four (4) supply licenses (DEPA S.A., PROMETHEUS GAS S.A., EGL HELLAS S.A., M&M GAS co S.A.). The final positive Decisions by the Minister, granting these first four supply licenses, were taken in January 2011.

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, eleven (11) companies were registered as potential users of the NNGS, four (4) of which were already active in 2010. 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

Table 13. Companies registered as NNGS users during 2010

The effects of those major developments are presented in section 4.2.1

<u>Cases of anti-competitive behaviour brought to the Regulator's attention</u>

A case of refusal of access to the network took place at the end of 2009, when an eligible customer attempted to import LNG for his own consumption. The TSO raised issues of contractual congestion and lack of sufficient regulatory tools to deal with the issue. RAE's position on the issue was that full TPA had to be provided to the interested party, and, accordingly, a strong recommendation was addressed to the TSO as a first step. Nevertheless, access was never granted and, following a complaint submitted by the affected eligible customer, RAE initiated a formal investigation in the beginning of 2010.

RAE reached a decision in June 2010, concluding that indeed there had been violation of both national legislation and Regulation 1775/2005 on the side of the TSO, DESFA SA, and imposed a 250.000 € fine on the Operator. RAE's investigation also included the issue of possible anti-competitive behaviour of the incumbent (DEPA S.A.) and, based on the preliminary findings, the case was sent to the Hellenic Competition Commission for further investigation and action. The decision of the Hellenic Competition Commission is expected within 2011.

4.2.1. **Description of the wholesale market**

Infrastructure for entering the Greek natural gas market

There was no new major infrastructure, such as new entry points, LNG or storage facilities, commissioned in 2010. 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.

Moreover, 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 TPA rights. 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.

Therefore, as has been noted in the past and fully confirmed in 2010, the Revithoussa LNG terminal remains the main opportunity for new entrants in the Greek gas market.

Market entry, structure and reference prices

The main development of 2010 regarding competition was the importation of natural gas by third parties, other than the incumbent, DEPA S.A. Two power generators and one large industrial consumer imported LNG quantities for their own consumption and trading, taking advantage of the opportunities presented by low spot LNG prices and supported by the recently completed regulatory framework.

In fact, the entrance of new gas importers in the market decreased the market share of the incumbent DEPA S.A. in the wholesale level, from 100% to 88.6%. Therefore, the HHI for 2010 stands at 7910.

The gas market is still organised on the basis of bilateral contracts between suppliers and eligible customers and no organised wholesale market exists yet.

However, following the aforementioned developments in market entry, RAE, within the framework of its competences regarding monitoring of the energy market, publicised, for the first time, 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 6 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 March 2008 through March 2011. Data are published on RAE's website[16] and updated on a regular basis.

[16] http://www.rae.gr/site/categories_new/about_rae/factsheets/03082011_1.csp

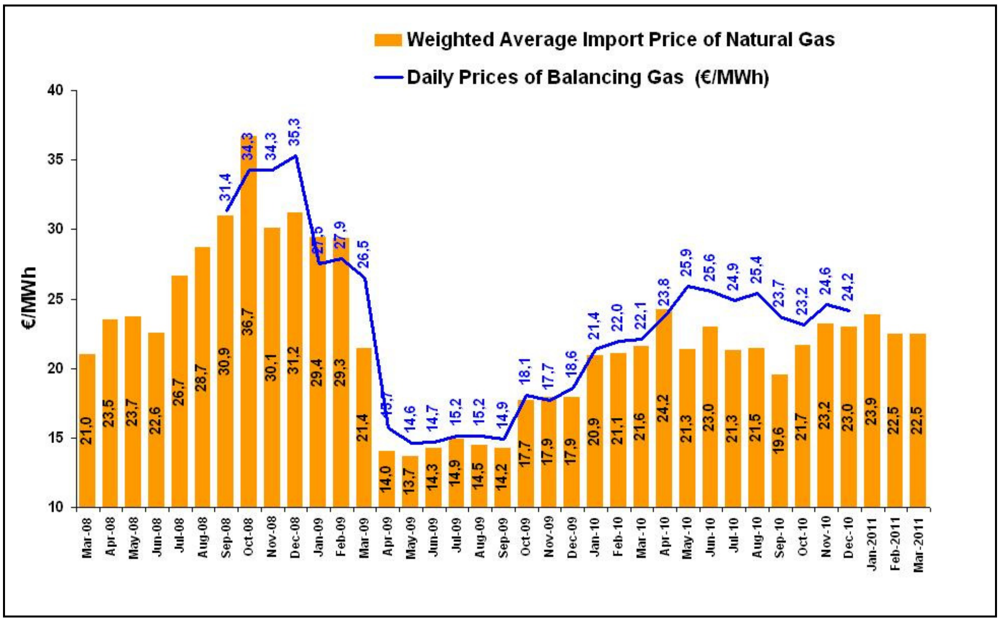

Figure 6. Monthly weighted-average import price (WAIP) against the price of balancing gas

4.2.2. **Description of the retail market**

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 prices in 2010 were higher than 2009 prices, following the increase in the prices of oil products. Some indicative annual average prices for EPA Attica and EPA Thessaloniki, are presented in Table 14:

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

** Net of VAT*

Table 14. Indicative, annually-averaged, natural gas prices in distribution, 2007-2010

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.

Consumer complaints

A total number of 29 discrete cases[17] on complaints/inquiries concerning gas were registered to RAE, either directly by individual consumers or through consumer bodies/organisations. Although RAE does not have a legal mandate to act as a dispute settlement body, between service providers and individual consumers, it investigates all complaints submitted directly by individual consumers and responds to all inquiries addressed to RAE. In 2010, RAE investigated 18 such cases pertaining to gas.

The 29 complaint documents registered to RAE are categorised as follows:

[17] Please note that in comparison to 2009 data, starting in 2010 RAE reports the number of discrete consumer cases and not the number of incoming documents related to consumer cases.

Complaints/inquiries by category cases	%
Complaint	60.7
Inquiry	21.4
Combination of the above	17.9

Table 15. Natural gas complaints/inquiries by category case

Complaints/inquiries by thematic category	%
Information on pricing policy	14.3%
Internal network installations	14.3%
Connection / disconnection	10.7%
Payment delay	10.7%
Dispute on charges	7.1%
Connection refusal	7.1%
Gas Meter check	3.6%
Social tariff	3.6%
Pricing transparency	3.6%
Misleading advertising on prices	3.6%
Contractual terms	3.6%
Other	7.1%

Table 16. Natural gas complaints/inquiries by thematic category

5. Security of Supply

5.1. Electricity

5.1.1. Supply - Demand Balance

The incentives for new capacity investments in the generation sector during the past few years proved to be more than adequate; as a result, currently there is a substantial capacity surplus in the Greek market. This surplus partially results from the current recession and debt crisis, which have totally reversed the demand growth rate anticipated four (4) years ago. More specifically, in 2007, the TSO had predicted persistent demand growth over the subsequent four years with an annual growth rate in the range of 2.5% - 3.5%. Based on these predictions, the annual electricity demand for 2010 was expected to be 59.5 - 61.3 TWh. Instead, actual demand in 2010 was only 52.4 TWh, which is 12% lower than even the "pessimistic" (worst-case) scenario that the TSO had predicted in 2007. Peak demand reached 9902 MW, while net generating capacity reached 13332 MW by the end of 2010. The installed capacity of renewables amounted to 1555 MW, with wind capacity contributing 1039 MW. Even if wind generation is totally excluded, due to its intermittent nature, the evolution of market fundamentals yields a capacity surplus of 24% over peak demand. This surplus becomes even more pronounced, if net capacity is compared to the average hourly demand of 2010, i.e. to 5978 MW.

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

Table 17. Energy and peak power demand for the interconnected system, 2007-2010 (Source: HTSO)

In terms of generation volumes, the market shares of the various technologies in 2010 are presented in Section 3.2, Figures 3 and 4. It is also interesting to note the difference in fuel-mix generation (TWh) between the years 2009 and 2010 (Table 18). In terms of net generating capacity, the market shares attained the following values: 38.04% lignite, 5.6% oil, 29.49% natural gas (OCGT: 3.9%, CCGT: 25.59%), 2.56% large CHP, 24.19% hydro and 11.36% renewables. Given the intra-yearly variation of generating capacities, their average annual values were used in the above calculation.

	2009 (TWh)	2010 (TWh)	% difference
Lignite	30.54	27.44	-10.15
Fuel Oil	1.70	0.11	-93.53
Natural Gas	9.38	10.36	10.45
Large Hydro	4.96	6.70	35.08
RES	1.88	2.04	8.51
Net Imports	4.37	5.70	30.43
Total	**52.83**	**52.35**	**-0.91**

Table 18. Change in fuel-mix generation between 2009 and 2010 (Source: HTSO)

Regarding thermal capacity commissioned or retired over 2010:

- New gas capacity reached 1269 MW. More specifically, two CCGT units, Thisvi (422 MW), owned by Elpedison, and Heron II (435 MW), owned by Heron Thermoelectric, started commissioning trials in late April 2010. Another CCGT unit, Protergia (previously known as Agios Nikolaos) (444 MW), owned by the Mytilinaios Group (previously Endesa Hellas), started its operation in December 2010.

- The obsolete lignite plant, Ptolemaida 1 (65 MW), which exhibited the highest emission factors among all power plants in Greece, was decommissioned in June 2010, having completed fifty (50) years of operation.

Regarding non-thermal capacity, its penetration rate remained low, with 386 new MW being installed in 2010, of which 122 MW was wind capacity, 44 MW was small hydro, and 107 MW was PV. Biofuels and biomass remained the same, while small cogeneration was reduced from 141 to 125 MW.

RES TYPE	**Commercially operating***		**Additional capacity with installation licence**		**Additional capacity with generation license**		**Licenses revoked**		**Applications for generation license**	
	MW	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
WIND	1183.6	84.1	1282.2	72.2	14373.4	81.3	653.9	84.1	61795.1	84.2
BIOMASS	33.9	2.4	21.2	1.2	243.4	1.4	24.5	3.2	1462.0	2.0
GEOTHERMAL	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	340.5	0.5
SMALL HYDRO	166.3	11.8	79.2	4.5	886.3	5.0	98.0	12.6	2220.9	3.0
PVs	23.8	1.7	321.7	18.1	1564.6	8.8	0.7	0.1	4256.2	5.8
OTHER	0.0	0.0	72.2	4.1	604.9	3.4	0.0	0.0	3290.0	4.5
TOTAL	1407.6	100.0	1776.5	100.0	17680.6	100.0	777.1	100.0	73364.7	100.0

Table 19. Licenced RES plants as of 31.12.2010 in the interconnected system

** Does not include: a) plants under 1MW which are exempted from applying for a license, b) plants in trial operation, which do not receive the feed-in tariff.*

In summary, at the national level, i.e. including the non-interconnected islands, the generation fuel mix in 2010 was as follows:

	Interconnected system		Non-interconnected islands		Total	
	TWh	%	TWh	%	TWh	%
Lignite	27.44	52.41	-	-	27.44	47.32
Fuel Oil	0.11	0.21	4.96	88.00	5.07	8.74
Natural Gas	10.36	19.79	-	-	10.36	17.87
Large Hydro	6.70	12.80	-	-	6.70	11.55
RES	2.04	3.90	0.68	12.00	2.72	4.69
Net Imports	5.70	10.89	-	-	5.70	9.83
Total	**52.35**	**100.00**	**5.64**	**100.00**	**57.99**	**100.00**

Table 20. Generation Fuel Mix in 2010 (Source: HTSO & PPC's Islands Network Operations Department)

5.1.2. Transmission

Transmission system projects

Major new projects in the transmission system, scheduled for construction in the next few years, according to the TSO's plan, are:

– Expansion of the 400 kV national interconnected transmission system to the south. Three (3) new EHV substations will be erected for this purpose in the Peloponnesus region. By the year 2012, a large part of this project is expected to be operational. The power reinforcement of this region will provide increased security of electricity supply, as well as additional transmission capacity for new RES projects in Peloponnesus.

– Connection of the Cyclades Islands to the mainland interconnected system, through a DC or AC submarine link. The aim of this project, apart from increasing the security of electricity supply to these islands, is also to reduce the PSO costs for their supply and to transfer the power from local wind parks to the interconnected system (see next section).

In addition, major transmission projects interconnecting other Aegean islands to the mainland electricity system are currently under study. The interconnection of Crete Island has received priority consideration.

Interconnections

The interconnection with Turkey (400 kV transmission system), in the northeast part of the Greek interconnected system, will also accommodate generation by new wind parks and thermal power stations. The full project became operational in October 2010.

Non-interconnected islands

All Greek non-interconnected islands operate as autonomous electrical systems, under the provisions of Directive 2009/72/EC. However, given that the *Operation Code for Non-Interconnected Islands* is pending approval, PPC S.A. still remains effectively the only supplier and electricity generator from fossil fuels on these islands.

All Greek non-interconnected islands, except Crete, are isolated micro-systems, according to the definition of Directives 2003/54/EC and 2009/72/EC. Based on this fact, Greece had applied for a derogation for all micro-systems, except Rhodes, according to Art. 26 of Directive 2003/54/EC, covering both the supply and the generation from fossil fuels (except RES, CHP and autoproducers). This derogation has not been granted yet.

Supply - Demand Balance

In 2010, the total demand in the non-interconnected islands amounted to 5,637.5 GWh.

The generation capacity and the fuel mix in the non-interconnected islands for 2010 is presented in the following table:

	Installed Capacity (MW)	% Installed Capacity	Fuel Mix (GWh)	%
Fuel Oil	1,598.0	84.37	4,959.8	87.98
RES	296.1	15.63	677.7	12.02
	1,894.1	**100.00**	**5,637.5**	**100.00**

Table 21. Installed power capacity & fuel mix in the non-interconnected islands as of 31.12.2010

	Nominal Power (MW)	Operating power (MW)
Generating units installed in power plants	1,609	1,471
Portable power generators	146	127

Table 22. Capacity of thermal power plants in the non-interconnected islands as of 31.12.2010

The following table presents the new capacity licensed to PPC, which is to be installed within the next five (5) years.

Non-Interconnected System	Power (MW)	Expected year of operation
Rodos		
New Thermal Station	120	2014
Lesvos		
New Thermal Station 1 GT unit	120 20	2016 2013
Samos		
2 IC units	2x 8,25	2011, 2013
Mikonos		
1 GT unit 1 IC unit	20 8	2012 2010
Kos-Kalimnos		
2 IC units 2 IC units	2x8 17, 25	2011,2013 2014
Thera		
2 IC units	2x10	2014
Paros		
1 IC unit 1 GT unit	10 20	2014 2012
Lemnos		
2 IC units	2x8	2013 - 2014
Ikaria		
3 IC units	3x3,5	2013
Nisiros		
1 IC unit	1,277	2010
Tilos		
1 IC unit	1,277	2010
Serifos		
2 IC units	2x1	2012
Kithnos		
2 IC units	2x1	2012
Karpathos		
3 IC units	3x4	2013, 2015

Table 23. Licensed capacity for new thermal units or thermal plants in the non-interconnected islands as of 31.12.2010

Concerning RES, the licensing mix per technology as of 31.12.2010 (excluding projects with an interconnection proposal) is presented in Table 24. It is worth mentioning that there are 2,505 MW of applications for offshore wind parks (of which 63 MW cover areas on-shore), located close to non-interconnected islands and, therefore, affecting the TSO's strategic development plan of interconnecting autonomous electrical systems.

RES Type	Commercially operating		Additional capacity with installation licenses		Additional capacity with generation licenses		Applications for generation licenses	
	MW	%	MW	%	MW	%	MW	%
Wind	257.1	86.8	80.2	100.0	598.9	57.2	178.5	4.8
Offshore Wind	0.0	0.0	0.0	0.0	0.0	0.0	2,505.0	66.8
Biomass	0.2	0.1	0.0	0.0	0.4	0.0	25.0	0.7
Geothermal	0.0	0.0	0.0	0.0	8.0	0.8	5.0	0.1
PVs	38.2	12.9	0.0	0.0	180.5	17.3	0.0	0.0
Solar-Thermal	0.0	0.0	0.0	0.0	98.0	9.4	321.0	8.6
Hybrid	0.0	0.0	0.0	0.0	160.0	15.3	717.7	19.1
Small Hydro	0.6	0.2	0.0	0.0	0.6	0.1	0.0	0.0
Total	**296.1**	**100**	**80.2**	**100.0**	**1,046.4**	**100.0**	**3,752.2**	**100.0**

Table 24. Licensed RES plants in the non-interconnected islands, excluding projects with an interconnection proposal, as of 31.12.2010

About 88% of the electricity in non-interconnected islands is produced by HFO and LFO units. PPC S.A. is the only supplier and the only generator (from thermal plants) in these islands. On the other hand, the percentage of RES generation has grown to over 12% in the non-interconnected islands. About 87% of the RES installed capacity in these islands concerns wind plants. As explained extensively in last year's Report, RAE strongly favours the interconnection of, at least, a number of these islands to the mainland grid, an investment which, according to relevant studies, can be paid back within a few years. Through the interconnection, the islands' long-term security of supply will be ensured, while their rich RES potential will be fully exploited.

Interconnections to the mainland system

The interconnection of the autonomous systems of the islands to the mainland grid is considered to be the optimal solution for the long-term security of electricity supply to these islands.

RAE has conducted two technical/economic studies, regarding the feasibility of interconnections through DC or AC submarine links.

Apart from the point of view of the security of supply, island interconnections to the mainland system are expected to substantially increase RES penetration in the national energy balance, due to the high RES potential of the islands that still remains unexploited and unable to be integrated in the (weak) autonomous systems, due to technical constraints.

To this effect, Law 3851/2010 introduced the responsibility of the HTSO to conduct strategic planning studies for the interconnections of islands to the mainland, in order to select optimal sizes and technologies, primarily to serve the long-term security of supply, and, where possible, to integrate the RES potential of these islands to the mainland system. The same law also introduced an increased feed-in tariff for RES plants that would be installed on autonomous islands, in the particular case that an interconnection to the mainland would be constructed by the plants' owners.

The following table depicts the licensed wind projects with an interconnection to the mainland grid (generation license granted). Some 4235 MW of additional applications for generation license in various islands, encompassing a proposed interconnection to the mainland system, are still pending.

Island	Licensed wind plants with interconnection to the mainland (MW)
Cyclades	517.6
Crete	844
Lesvos	306
Lemnos	250
Chios	150
Skyros	333
TOTAL	**2,400.6**

Table 25. Licensed wind plants with interconnection to the mainland as of 31.12.2010 (generation license granted)

In addition, a total of 200 MW of new RES plants can be installed on the Cyclades Islands, on top of the 518 MW mentioned above, due to the interconnection project already in progress by the HTSO. The project of the connection of the Cyclades Islands to the interconnected (mainland) system, through a DC or AC submarine link, commenced in 2010. The HTSO, in cooperation with PPC (the owner of the transmission system), conducted a public consultation, regarding mainly the technical specifications of the project. The Strategic Transmission System Planning Study, that is conducted by the HTSO and approved by a Ministerial Decree, was modified accordingly, based on the outcome of the consultation.

Upon completion of the project, the Cyclades Islands (Andros-Tinos-Syros-Mykonos-Paros-Ios-Sikinos-Folegandros-Koufonisi-Schinousa and Iraklia) will be fully interconnected to the national grid system, and, therefore, the local thermal plants will cease to operate.

For the island of Crete, a joint working group from RAE, the HTSO and the PPC (as the owner of the transmission system) has been formed, in order first to examine the alternative interconnection scenarios of the island to the mainland system, and then to compare the optimal interconnection scenario to the alternative of continuing the development of Crete's autonomous system through thermal plants (oil and natural gas).

5.2. Natural Gas

This section provides information in accordance with Directives 55/2003/EC and 2004/67/EC. All data referring to gas quantities are provided in both units of Mtoe (based on gas with a HHV of 9600Kcal/Nm^3) and bcm (at 15°C).

5.2.1. Current levels of gas consumption and expected future demand

The demand for Natural Gas in 2010 was 3.83 bcm, out of which approximately 75% concerned the power generation sector, as shown in Table 26.

Year 2010	bcm @ 15°C	Mtoe (HHV)
Power Generation	**2.39**	**2.18**
Industry & HP customers	**0.80**	**0.73**
GDCs (Primarily Commercial & Domestic)	**0.64**	**0.58**
Total	**3.83**	**3.49**

Table 26. Natural gas demand by sector in 2010

During 2011, gas demand from the power generation sector started rising, as also projected in Table 27 below. This is primarily attributed to reduced hydro production. Commercial and domestic demand is expected to increase steadily, according to the expansion plans of the Gas Distribution Companies (GDC's). Expected national demand for the next three (3) years is presented below in Table 27 (DESFA's estimates).

	2011		2012		2013	
	bcm	Mtoe	bcm	Mtoe	Bcm	Mtoe
Power Generation	3.02	2.75	3.09	2.82	3.43	3.12
Industry	1.10	1.00	1.20	1.10	1.25	1.14
Commercial/Domestic	0.56	0.51	0.63	0.58	0.72	0.66
Total	**4.67**	**4.26**	**4.93**	**4.49**	**5.39**	**4.91**

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

The demand outlook for the next ten (10) years cannot be predicted with adequate accuracy, particularly due to substantial uncertainties in global issues, such as the EU ETS and the international oil prices, as well as domestic issues, such as the degree of participation of coal and renewable energy sources into the national energy mix, within this time frame. Given these uncertainties, we provide four (4) different assessments, the latest one coming from the TSO. The other three come: a) from DEPA S.A., assuming business-as-usual and increased sales, b) from the Long-Term Planning Study (LTPS) published in 2008 by the Ministry of Development, and c) from the *Annual Report on the Long-Term Energy Plan*, published in 2009 by the *National Energy Strategy Council*. The data refer to five-year intervals, extending to 2020.

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]

Table 28. Ten-year gas demand outlook

[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*

5.2.2. **Supply - Demand Situation**

There was no indigenous gas production in Greece during 2010. In March 2010, a TPA scheme for the Revythousa terminal was implemented in the Grid Code, which, given the LNG market conditions at that time, provided users with an opportunity to import spot LNG cargoes. This has resulted in a 35% increase in the share of LNG, compared to the previous year. DEPA S.A., which lost its status as the sole gas supplier, 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. Figure 7 shows the Natural Gas sources and their participation to the total imported quantities in Greece, as reported by the TSO. The aggregate of the contracted annual quantities, according to the three existing supply contracts, is shown in Table 29.

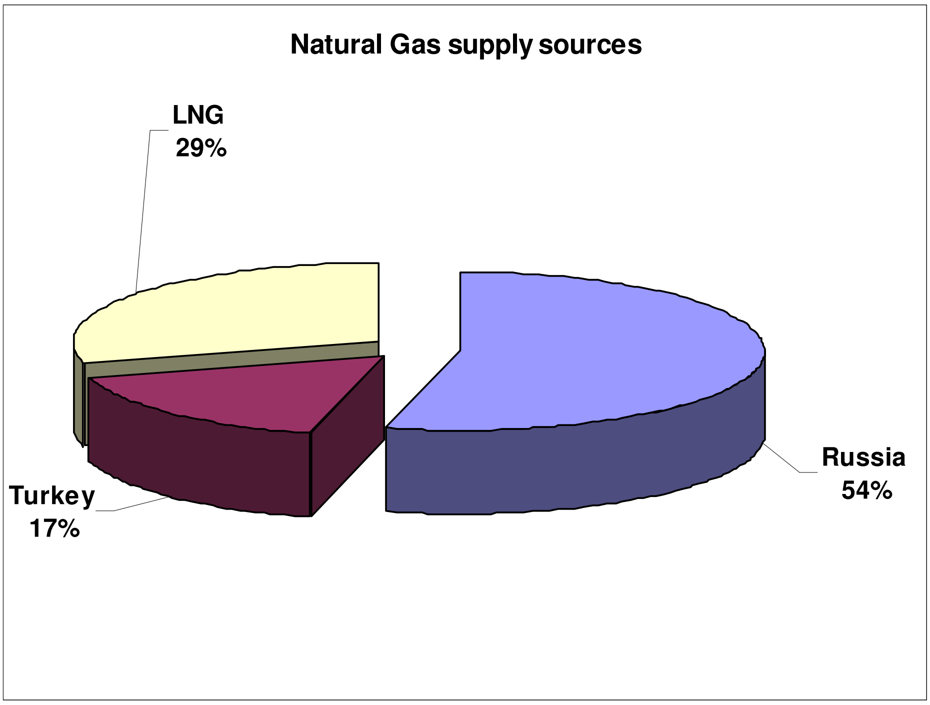

Figure 7. Natural gas supply sources

	bcm @ 15°C	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. Because of the revised, significantly lower, gas demand forecasts, existing supply contracts are expected to fully meet demand through 2011.

	2011		2012		2013	
	bcm	**Mtoe**	**bcm**	**Mtoe**	**bcm**	**Mtoe**
Demand	4.7	4.3	4.9	4.5	5.39	4.91
Supply Contracts	4.4	4.0	4.4	4.0	4.4	4.0
Supply Gap	0.3	0.3	0.5	0.5	0.99	0.89

Table 30. Expected natural gas supply-demand balance, 2011-2013

Figure 8 below shows the expected demand - supply balance projected to 2020, according to the scenarios presented in Table 28. The demand curve corresponds to DEPA's demand forecast of Table 28.

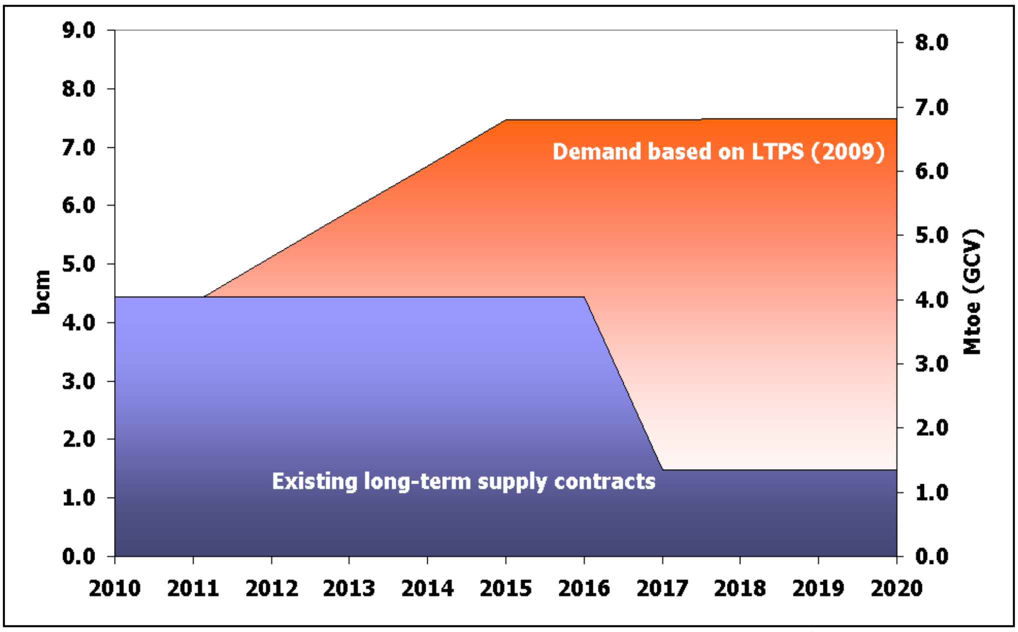

Figure 8. Expected natural gas supply-demand balance (10-year forecast)

5.2.3. **Quality and level of maintenance of the networks**

The TSO, being responsible for operating, maintaining and developing the NGTS, follows a regular cleaning and internal inspection programme for the pipeline network, by means of cleaning pigs, in order to ensure the good operating condition of the network. Meter runs and the LNG terminal feature redundant systems, minimising the impact of component malfunction.

5.2.4. **Emergency measures**

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.

Load shedding is implemented according to a priority list. On top of the list, which includes all customers, are power plant installations with dual-fuel capability and other interruptible customers that have entered into supply-interruption contracts with the TSO. Last on this list, are the domestic customers. This, being a demand measure, is primarily aimed at satisfying peak demand, as well as covering an eventual short-term supplier shortfall.

Security of supply provisions will be re-examined on the basis of the provisions of Regulation 994/2010. RAE, as the Competent Authority, is leading an effort to conduct the Risk Assessment with input from the TSOs, both electricity and gas, and the industry. Following the completion of this task, and based on the results obtained, options will be examined, in order to address, to the extent possible, the identified security shortfalls. This task is expected to take place within the process of preparing the preventive action and the emergency plans.

5.2.5. **Import capacity**

Import capacity has remained unchanged throughout 2010.The Hellenic Gas Transport System has three (3) Entry Points, two at the North and North-eastern borders - Sidirokastro and Kipoi - 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	**Present**		**2nd Quarter 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 is scheduled to start operation within the 1st Quarter of 2012, which will relieve internal bottlenecks and will increase capacities to the values reported in the column "*2nd Quarter 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 early 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.

5.2.6. Security of supply standards

No new measures were introduced during 2010 and the implementation of the supply-interruption contracts has been delayed by the TSO, while awaiting the final provisions of the new Security of Supply Regulation. Our conclusions, expressed in the 2009 National Report are still valid, and the whole set of provisions is planned for a review following the results of the Risk Assessment and the ensuing preparation of the preventive and emergency action plans.

The applicable provisions present no impact to gas market players, since none is directed to gas suppliers. Instead, they are targeted towards gas customers. The whole set of provisions is pending review, based on the results of the Risk Assessment.

5.2.7. Storage capacity

There are no underground storage sites in the NGTS. The storage capacity is limited to the existing LNG terminal on Revithoussa Island, which features two (2) tanks with a total capacity of 130,000 m^3 of LNG, equivalent to approximately 0.08 bcm.

The export capacity of the LNG terminal is limited by its re-gasification capacity, which, unlike the storage capacity, is significant (approximately 14 mcm/day).

5.2.8. **Extent of long-term gas supply contracts**

As already mentioned in Section 5.2.2, DEPA has three (3) long-term contracts if effect for the supply of Natural gas from Russia, Algeria (LNG) and Turkey. The figure below shows the contractually available gas quantities in the 2014-2022 time period.

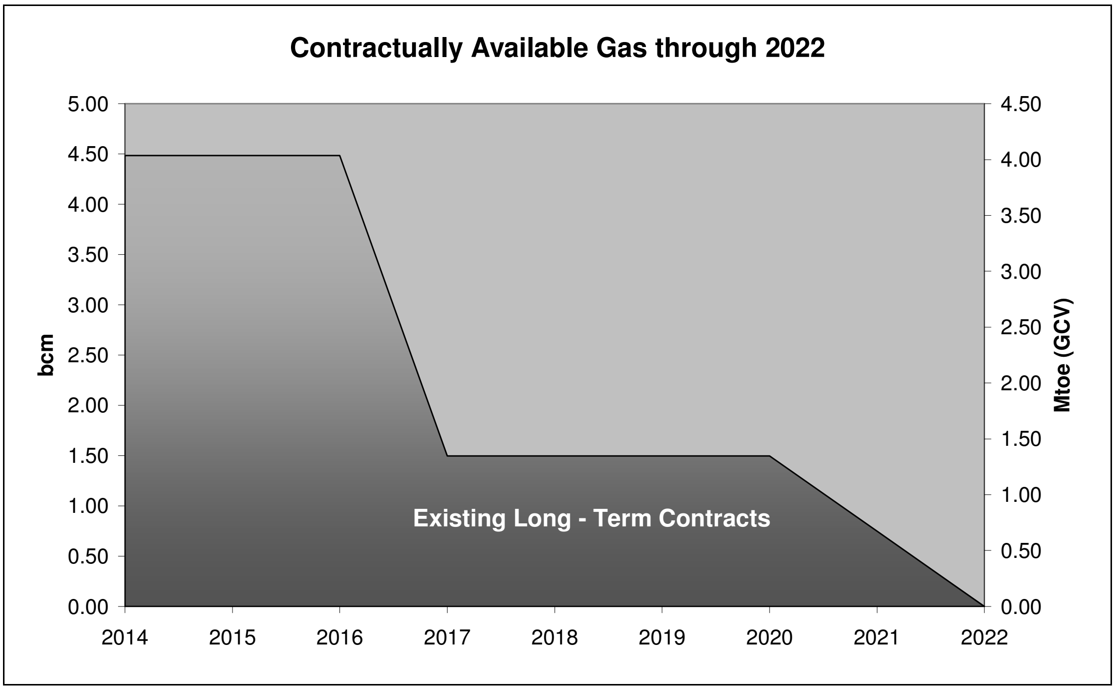

Figure 9. Contractually available Natural Gas quantities through 2022

6. Public Service Issues

6.1. Electricity

Public Service Obligations (PSOs)

According to Law 3426/2005 (Ar.28), the Minister for Development defines the public services in the electricity sector for which an obligation to serve exists. In June 2007, the following services were defined as public services by a Ministerial Decision[18]:

(a) supply of electricity to non-interconnected islands and to remote micro-grids, with tariffs equal to those of the mainland interconnected system, and

(b) reduced tariffs for the supply of electricity to consumers / families with more than three (3) children.

In July 2010, a third public service was introduced, a Social Tariff for Domestic Customers referred to as "KOT", pursuant to the Greek acronym. This reduced tariff applies to vulnerable customers, i.e. low income households, families with three (3) children, unemployed or disabled consumers, all within set limits of electricity consumption.[19] The starting date for the implementation of the new tariff was set for the 1st of January 2011.[20]

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 in 2012, with the cost indexed to inflation and to oil-prices, minus a required efficiency index (2% per annum). The cost of providing the reduced tariff to large families is estimated as the difference between the reduced tariff and the published PPC domestic tariffs. Regarding the cost of providing the Social Tariff ("KOT", in Greek), the methodology was not in place in 2010, but a provision for 20 €m was taken into account in the calculation of the cost for 2011, in order to avoid a significant increase in PSO charges, due to the addition of this new PSO.

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].

In 2010, the cost of providing PSOs was estimated at approx. €497m[23], compared to €417m[24] for 2009. This amount will be recovered in 2011 through the PSO charges and the amount equivalent to the TUoS (Transmission Use of System) charge, recovered from the consumers on the non-

18 Ministerial Decision of June 2007 (Official Gazette, B 1040).

19 Ministerial Decision of September 2010 (Official Gazette, B 1614).

20 Ministerial Decision of August 2010 (Official Gazette, B 1403), following RAE's Opinion 237/2010.

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 Ministerial Decision of December 2010 (Official Gazette, B 2045), following RAE's Opinion 370/2010.

24 Ministerial Decision of February 2010 (Official Gazette, B 189), following RAE's Opinion 502/2009.

interconnected islands through the application of the uniform (national) retail tariff. The PSO charges for 2010 and 2011 are as follows:

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

Table 33. PSO charges per customer category, 2010-2011

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

Table 34. PSO charges for domestic customers, 2010-2011

RES Levy

Renewable energy generation receives special feed-in tariffs, as set by law and relevant Ministerial Decisions. According to the provisions of Art. 40 of Law 2773/1999, the Transmission System Operator and the Distribution System Operator fully recover the sums paid to RES producers, through a Special RES Account managed by the Transmission System Operator.

Until recently, the income of this Account came from three (3) sources:

(a) The amounts that the RES production would receive through operation in the wholesale market, via the procedure of settlement of Supply-Demand Imbalances of Art. 20.

(b) The amounts paid by PPC, as the (de-facto) exclusive supplier on the non-interconnected islands, for the electricity supplied to those islands, according to Articles 36, 37 and 38 of the same Law, at the Average Variable Cost of generation in Non-Interconnected Islands, as approved by RAE.

(c) The special RES levy, which is allocated uniformly throughout the Greek constituency, to every customer (including the independent autoproducers, pursuant to a methodology determined through a Ministerial Decision, which is issued following RAE's opinion).

A fourth source of income for the Special RES Account was added with Law 3851/2010, as follows:

(d) the revenue derived from auctions of unused rights for emissions of greenhouse gases, allocated for the period up to and including 2012.

The calculation of the Special Levy of Art. 40 of L.2773/1999 takes place on an annual and 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.

In 2006, the RES levy was set at €0.30/MWh. Due to the substantial increase in RES production in subsequent years and the decrease in the wholesale market 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 the RES levy to the new level of 5.57€/MWh. The Ministerial Decision[25] 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)[26]. This methodology was applied to the calculation of the RES levy for 2011, and, for the first time, it introduced a differentiation of the levy per customer category.

The total required revenue for the Special RES Account for 2011 was estimated at approximately €350m, of which €100m were necessary to cover the deficit of the previous year (which resulted from the said partial increase of the levy in the second half of 2010). Based on the estimation of the Ministry (MNEC), €200m of the aforementioned 2011 total cost (€350m) will be covered through the anticipated revenues derived from auctions of unused emissions rights of greenhouse gases, while the rest (€150m) will be recovered through a) the SMP revenues and b) the RES levy charges, set as follows:

Category	**RES levy unit charge (€/MWh)**
HV and autoproducers own consumption	1.04
Agricultural Use MV	0.74
Other Use MV	1.69
Agricultural Use LV	0.90
Domestic Use LV	1.95
Other Use LV	2.49

Table 35. Special RES levy charges for 2011[27]

25 Ministerial Decision June 2010 (Official Gazette, B 815).

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

27 Ministerial Decision December 2010 (Official Gazette B 2095), following RAE's Opinion 379/2010.

Regulated Retail Tariffs

PPC retail tariffs to MV and LV customers remain regulated. There was no change in these tariffs during 2010, and the mechanism to revise tariffs through an indexation to fuel prices was suspended indefinitely in July 2010[28].

In order to remove the existing price distortions in the retail market, in November 2007 PPC was requested by RAE and the Ministry of Development to submit, within 2008, specific proposals for regulated tariff structures, in order to achieve:

- unbundling of the various services (generation, transmission, distribution, supply)
- cost reflectivity and removal of cross-subsidisation between consumer categories
- choice of tariff structures which better match consumer load characteristics in the most economic way
- incentivisation of consumers to improve their load characteristics
- transparency in order to remove barriers to new entrants
- maximisation of the long-term benefit to consumers
- optimisation of the use of the existing assets
- coverage of Public Service Obligations (PSOs)
- continuous security of supply.

The PPC proposal was finally submitted in November 2009, and included new consumer categories and new structures for the competitive element of the retail tariffs, in order to meet the required unbundling of the tariffs. Given that the analysis was based on cost data of previous years, RAE requested that PPC resubmit its proposal, taking into account cost estimates for 2010 and 2011. Submission of these data and subsequent discussions led to RAE issuing two (2) opinions on the regulated PPC retail tariffs (237/2010 and 353/2010). In the first opinion, RAE accepted the proposed consumer categorisation and new tariff structures. 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 was based on a reduction of approx. 5% compared to the average revenue requested by PPC in its original proposal.

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, to assist in the transition to fully cost-reflective tariffs and to the removal of all cross subsidies, as well as to pass on to the consumers the benefit of the lower cost of generation, to which PPC has the exclusive right (large hydro, lignites). At the same time, RAE proposed that the cost data need to be revisited every six (6) months, in order for the retail tariffs to be adjusted so as to reflect future wholesale costs.

The Ministry of Energy, Environment and Climate Change, taking into account the two RAE Opinions, introduced transitional steps towards the complete removal of all cross subsidies, while 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-monthly consumption) saw, on the average, an 8.5% reduction in their total bill (including taxes). Average bills to agricultural customers increased by about 6-8%. Industrial MV customers also

[28] Ministerial Decision July 2010 (Official Gazette B 1158), following RAE's Opinion 338/2010.

experienced an average increase of around 8% in their total bill. Estimated reductions to commercial MV and LV customers were around 5-10%. Final regulated tariffs for 2011 were approved through a Ministerial Decision on December 28, 2010 (Official Gazette B 2031).

Price regulation is expected to be fully removed by the end of 2011, with the exception of domestic and small enterprise customers, for which regulated tariffs will continue to apply until mid 2013.

Other issues

Approximately 283,000 customers were disconnected in 2010 due to bad debt, of which less than 50% (131,000) 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 Operator to disconnect the customer.

Details on the regulations governing the Supplier of Last Resort have not been set up yet.

6.2. Natural Gas

There were no developments regarding the legal framework for imposing PSOs, compared to 2009.

Appendix I - List of licensed electricity suppliers at the end of 2010

1. A2A TRADING SRL
2. AEGEAN POWER S.A.
3. ALPIQ ENERGY SE
4. CEZ a.s.
5. CINERGY GLOBAL TRADING LTD
6. COMPAGNIE NATIONALE DU RHONE
7. DANSKE COMMODITIES A/S
8. DEUTSCHE BANK A.G.
9. E.ON ENERGY TRADING AG
10. EDELWEISS ENERGIA S.P.A.
11. EDF TRADING LIMITED (EDFT)
12. EDISON TRADING S.P.A
13. EFT HELLAS S.A
14. EGL HELLAS S.A.
15. EHOL HELLAS S.A
16. ELECTRABEL ΕΝΕΡΓΕΙΑ HELLAS S.A
17. ELECTRADE SRL
18. ELECTRICITY TRADING COMPANY HELLAS S.A.
19. EL.EN EMPORIO ILEKTRIKIS ENERGEIAS LTD
20. ELLINIKI TECHNODOMIKH ENERGEIAKI S.A.
21. ELPEDISON S.A.
22. ELPETRA ENERGY S.A
23. ENALAKTIKH ENERGEIAKI S.A.
24. ENEL TRADE S.p.A
25. ENER S.A.
26. ENERGY DANMARK A/S
27. ENERGY MT EAD
28. ENI SPA
29. ENRON POWER LTD
30. ENTRADE GMBH
31. EVN TRADING SOUTH EAST EUROPE EAD
32. EZPADA S.R.O
33. EUROPEAN ENERGY TRADING GIOUZELIS A. - CHATZIDIMITRIOU A.
34. GAZPROM MARKETING & TRADING
35. GEN I ATHENS LTD
36. GREEK ENVIROMENTAL & ENERGY NETWORK S.A.
37. HELLENIC PETROLEUM S.A.
38. HERON ILEKTRIKI S.A

39. IBERDROLA GENERACION S.A.U.
40. ILEKTRIKI THRAKIS S.A.
41. INTERNATIONAL ATHENS AIRPORT S.A.
42. ITA ENERGY TRADE ENERGIAKI S.A.
43. NECO TRADING S.A.
44. NECO S.A.
45. OET HELLAS S.A.
46. OET UNITED ENERGY TRADERS LTD
47. POWER SHARE
48. PPC S.A.
49. PROTERGIA S.A.
50. REPOWER TRADING CESKA REPUBLIKA s.r.o
51. REVMAENA LTD
52. RWE SUPPLY & TRADING GMBH
53. SEMAN S.A.
54. STATKRAFT MARKETS GMBH
55. TINMAR-IND S.A
56. TEI HELLAS S.A.
57. TERNA ENERGY S.A.
58. TRESEN S.A.
59. UNIT HELLAS S.A.
60. VERBUND AUSTRIAN POWER TRADING AG
61. VIVID POWER EAD
62. VOLTERRA S.A.

i. List of Acronyms

ATC	Available Transfer Capacity
CAC	Capacity Availability Contract
CAT	Capacity Availability Ticket
CPI	Consumer Price Index
DAES	Day-Ahead Energy Schedule
DEPA	Public Gas Corporation S.A.
DESFA	Hellenic Gas Transmission System Operator
DSO	Distribution System Operator
EPA	Gas Distribution Company
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
LV	Low Voltage
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
RAE	(Hellenic) Regulatory Authority for Energy
SMP	System Marginal Price
STA	Standard Transportation Agreement (for access to the gas transmission system)
TSDS	Transmission System Development Study
TDSO	Transmission and Distribution System Operator
TPA	Third-Party Access
TSO	Transmission System Operator
UCTE	Union for the Co-ordination of Transmission of Electricity
UIOLI	Use it or lose it
UIOSI	Use it or sell it

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