REGULATORY AUTHORITY FOR ENERGY
69, PANEPISTIMIOU STR. & AIOLOU, 105 64 ATHENS, GREECE
TEL.:+302103727400, FAX:+302103255460
E-mail : info@rae.gr, Website: www.rae.gr

Annual Report 2005

To the European Commission

Regulatory Authority for Energy (RAE)

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1 Foreword

This annual report summarizes the outcome of the monitoring activities of the Regulatory Authority for Energy (RAE) over the period from July 2004 to July 2005, according to the relevant provision of the Electricity and Gas Directives. It covers all issues reported in Articles 3, 4, 23(1) and 23(8) of the Electricity Directive 2003/54/EC and Articles 3, 5 and 25 of the Gas Directive 2003/55/EC according to the reporting structure approved by ERGEG.

The regulatory framework regarding the Electricity market in Greece has been significantly modified, aiming at facilitating the liberalization process and enhancing security of supply. More specifically, following the amendment in July 2003 of the Law 2773/1999 by the provisions of the Law 3175/2003, and after a long period of public consultation between RAE, the Ministry of Development and the stakeholders participating to the Greek electricity market, a new Grid and Power Exchange Code has been approved in May 2005. Through the provisions of this Code two major amendments regarding the organization of the Greek electricity market are introduced: Fist of all, a complete set of rules for the organization and the operation of a wholesale electricity market, with compulsory participation of all market players, has been established with a view to surpass the inefficiencies related to the previous market structure which was based principally on bilateral contracts between electricity generators and suppliers. At the same time, the role of the Hellenic Transmission System Operator SA (HTSO) is reinforced in so far as the System Operator is entrusted with the responsibilities of the Market Operator. Secondly, the Code introduces a capacity adequacy mechanism with a view to insuring the security of supply of the Greek power system, which, following a period of reduced generation investment activity, is suffering from the lack of adequate generation capacity. In this context the HTSO is preparing an international tender that will provide risk mitigation incentives to potential independent power producers. As the implementation of the new Code will start progressively in October 2005, no practical experience may be reported at this point. However, the initial response of the various market participants is optimistic and RAE's expectations regarding the development of competition are positive.

Furthermore, following the proposal of RAE, the Government launched in July 2005 a public consultation regarding further amendment of the Law 2773/1999 in order to fully transpose the provisions of the Directive 2003/54/EC into the Greek legal order.

Regarding gas, Greece has been granted a derogation as an emerging gas market regarding the implementation of the Directive 2003/55/EC. However, according to the provisions of the Law 3175/2003 from 1st of July 2005 gas-fired power producers and producers using co-generation with a consumption of more than 25 million m^3 of natural gas per year have become eligible customers, enjoying the right to choose their supplier. These two customer categories represent more than 70% of the current gas consumption in Greece. The conditions for the access of the eligible customers to the network, including network tariffs and balancing regimes, are currently under public consultation.

In parallel, a complete set of new primary and secondary legislation, fully implementing the Directive 2003/55/EC into the Greek legal order and taking into account the provisions of the forthcoming Gas Regulation, has been elaborated by RAE. Last April RAE launched a public consultation regarding the draft Law for the liberalization of the natural gas market in Greece. It is expected that this draft Law will be submitted to the Parliament within August 2005.

The Greek Regulatory Authority for Energy is committed to closely collaborate with the Government and the energy market participants for the successful implementation of the above, through a continuous and transparent dialogue. RAE is confident that it will realize concrete steps towards the efficient, non-discriminatory and sound operation of the energy markets in Greece. To this end, RAE is also in close collaboration, through CEER and ERGEG, with the other European Regulators and the European Commission and will continue to contribute to the efforts for the harmonization of the Regulatory Process throughout the European Union and beyond.

In conclusion I wish to thank all members of RAE's Secretariat for their contribution in the preparation of this report and their invaluable role in promoting the work of RAE.

Michael Caramanis

Chairman of RAE

2 Summary \ Major Developments in the last year

2.1 Organizational structure and responsibilities of the regulatory agency

The Regulatory Authority for Energy (RAE) is an independent administrative authority, which enjoys, by the express anticipation of the law establishing it, financial and administrative independence. RAE was established with the provisions of L.2773/1999, which was issued within the framework of the harmonisation of the Hellenic Law to the rules of Directive 96/92/EC for the liberalization of the electricity market.

RAE's board has 5 members, which are appointed by decision of the Minister of Development, following the simple opinion of the competent Parliamentary Committee, regarding the candidates for the positions of President and Vice President. According to a Law recently enacted by the Parliament, two more members will be added to the abovementioned structure so as to enhance effectiveness, and the number of Vice-Presidents is increased to two, while the President and the Vice-Presidents are appointed by a Decision of the Cabinet of Ministers acting on a proposal of the Minister of Development and following the simple opinion of the competent Parliamentary Committee.

The criteria for the selection of the members of the authority are scientific proficiency, professional capability and specialised experience in issues pertaining to the responsibility of the Authority. The members of RAE are considered senior civil servants enjoying personal and functional independence while exercising their duties. Within this framework, the members of RAE are subordinate only to the Constitution, the laws and their conscience, and do not take orders or directions from public or other institutions and organisations and may not be recalled during the term of their office; revocation or suspension of RAE members is permitted only in strict enumerated cases of serious criminal conviction or persecution. .

The financial independence of RAE, which is an essential condition in order to preserve the Authority's independence, was effectively ensured by the provisions of L. 2837/2000, through which it is anticipated that the Authority possesses its own resources, i.e. levies from the regulated industry, participation to research projects etc. These resources are managed in accordance with the Presidential Decree 139/2001 "Regulation for the Internal Operation and Administration of RAE", while financial management is only subject to ex-post auditing by Independent Auditors and the Court of Auditors.

Various responsibilities were assigned to RAE through L. 2773/1999, particularly in relation to the following subjects:

- Monitoring the operation of all sectors of the energy market (Electricity, Natural Gas, Oil Products, Renewable Energy Sources, Cogeneration of Electricity and Heat etc.).

- Collection and processing of information from every company of the energy sector while respecting the principles of confidentiality

- Participation in the pre-parliamentary legislative process through the capability to recommend to the Minister of Development measures RAE considers necessary pertaining to the observation of the rules of competition and the protection of the consumers in the energy market.

- Participation, under the form of a simple opinion, in the enactment of the secondary legislation issued by authorisation of L.2773/1999, that is the Codes and Regulations anticipated.

- Participation, under the form of a simple opinion, in the process for the granting and revocation of licences for the discharge of electricity activities.

- Follow up and monitoring of the way the rights arising from the licences are exercised and access to any information related to the parties involved in the energy sector.

- Participation, under the form of a simple opinion, in the procedure for the approval of electricity retail tariffs, wherever such an approval is required.

- Imposition of financial sanctions, particularly fines to the violators of the provisions of N. 2773/1999 as well as the regulatory acts issued by authorisation of this law.

- Arbitral resolution of disputes between the participants in the electricity market.

- Cooperation with equivalent Authorities of other countries, international Organisations and the European Commission.

- By the same law, the responsibilities of the abolished Energy Control and Planning Committee, which was established by L. 2364/1995, were "transferred" to RAE, according to which RAE holds responsibilities in the natural gas sector, however only limited to the distribution of natural gas in cities.

Finally, with L. 3054/2002 specific responsibilities were assigned to RAE regarding with the organisation and operation of the oil products market.

Although RAE is entrusted with different categories of responsibilities, it remains part of the Greek State administrative structure, as RAE is obliged to comply with the legality principle. The decisions of RAE that are not solely advisory are subject to judicial review by the Athens Administrative Court of Appeals. Finally RAE publishes and submits to the Parliament via the Minister of Development an annual report giving detailed information about its functioning and acts.

Regarding the Electricity Sector, RAE grants opinion for the Codes and Regulations of the electricity sector such as the Grid Operation Code, the Power Exchanges Code, the Distribution Network Operation Code, the Authorisations Regulation and the Supply Code, approves decisions of the HTSO regarding the implementation details of the Grid Operation and Power Exchanges Code, participates to the administrative procedure for granting, amending and revoking of licenses in the electricity sector. During the last three years RAE has issued almost 700 positive opinions for generation and supply licenses, 450 negative opinions and 50 opinions for revocation of licenses. Finally RAE's opinion is a prerequisite for the approval of electricity supply tariffs of the incumbent company (PPC), both for Eligible and Non Eligible Customers. Such an approval for PPC tariffs for eligible customers is required only for as long as PPC has a share of at least 70% of the eligible customers market.

Regarding the Gas Sector, RAE grants opinion for issuing technical regulations for internal & external natural gas installations, grants opinion for the tariffs to be applied for TPA of electricity generators to the gas grid (Law 3175/2003) and supervises and monitors the compliance of the three concession licensees for the distribution of natural gas (Approval of 5-year development plans, ex-post control of supply and connection charges, ex-post control for revenue cap violations and subsequent setting of tariffs and supervision of licensee and customer relationship).

Regarding the Oil Sector, Law 3054/2002 granted to RAE responsibilities and competences for the oil sector as opinion of RAE for issuing the Authorisations Regulation and the Oil Stockholding Regulation, collection and publication of statistical data regarding the petroleum products market, participation in the Emergency Response Committee for Oil Supply Crises and in exceptional cases, RAE grants opinion for the imposition of price caps in petroleum product prices.

The Secretariat of RAE is organized in five (5) operational departments (Monitoring of Markets and Competition Dept., Consumers' Protection and Environment Dept., Systems' Analysis Dept, Energy Planning and International Affairs Dept. and Decision Elaboration and Documentation Dept.) and of three (3) support departments (RAE'Administrative Support, Secretariat of RAE's Chairman and Members, and Press and Public Relations).

Currently the Secretariat of RAE consists of 40 experts (namely 14 engineers, 11 lawyers, 10 economists and 5 others) and 15 administrative staff.

As it is concluded from the above, RAE has mostly an advisory role to the Ministry of Development, with no major overlapping jurisdictions with other Governmental agencies and authorities.

However, RAE still does not have the full competencies assigned to it by Articles 23 and 25 of the Directives 54/03 and 55/03 respectively, since the transposition of the corresponding Directives into the Greek legislative framework has not been effected yet. This is expected to happen when the transposition of the new Directives into the Greek legal order will be effected (draft law currently under public consultation ending the 1st of August 2005).

2.2 Main developments in the gas and electricity markets

The regulatory framework regarding the Electricity market in Greece has been established by Law 2773/1999 and significantly modified by Law 3175/2003, aiming at facilitating the liberalization process and enhancing security of supply. Furthermore, following the enactment of the Law 3175/2003, after a long period of public consultation between RAE, the Ministry of Development and the stakeholders participating to the Greek electricity market, a new Grid and Power Exchange Code has been approved in May 2005. Through the provisions of this Code two major amendments regarding the organization of the Greek electricity market are introduced: Fistly, a complete set of rules permitting the organization of a wholesale electricity market, with compulsory participation of all market players, has been established with the view to surpass the inefficiencies related to the previous market structure which was based principally on bilateral contracts between electricity generators and suppliers. At the same time, the role of the Hellenic Transmission System Operator SA (HTSO) is reinforced in so far as the System Operator is entrusted with the responsibilities of the Market Operator. Secondly, the Code introduces a capacity adequacy mechanism with a view to increase the security of supply of the Greek power system, already suffering from the lack of adequate generation capacity, by providing appropriate financial incentives to facilitate the entry of independent power producers. As the implementation of the new Code will start progressively in October 2005, no practical experience may be reported for it yet. However, the initial response of the various market participants is optimistic and RAE’s expectations regarding the development of competition are positive.

In addition to the above, a major development for the proper operation of the electricity market in Greece is the progress towards a satisfactory unbundling of accounts. Following a lengthy period of dispute, PPC (the former Greek incumbent) has finally published in their Web Site accounts, for the exploration of lignite, generation, transmission and distribution activities for the period 2001 to 2003. However, RAE has expressed reservations regarding the compliance of the accounts published by PPC to the approved methodology, mainly due to the fact that the accounts of the distribution network have been published in a consolidated form with the accounts of PPC for the retail sales and generation in non-interconnected islands (excluding Crete and Rhodes), but also because the methodology for the allocation of the costs shared among various activities of PPC has not been clearly demonstrated. Therefore, RAE has not accepted the published accounts of PPC yet and has requested further clarifications from PPC on the above. Further work is currently underway, in order to have an updated full set of unbundled accounts of PPC up to 2005.

Regarding natural gas market, the Law 3175/2003 provides for the eligibility, as of 1st July 2005, of the gas-fired power producers and of co-generators with an annual consumption of more than 25 million cubic meters of gas. Substantial work on the development of the use-of-the-network tariffs has already been concluded in due course of 2004 and 2005, which has resulted in a draft Ministerial Decree for the tariffs' setting, which is under public consultation until the 5th of August 2005. During the same period, substantial work has already been concluded for the development of the new Gas Law, which will transpose the provisions of the Directive 55/03 and the forthcoming Gas Regulation, along with the corresponding secondary legislation (Network Code, Supply Code and License Code). The proposal for the draft Gas Law is already under the third round of public consultation, until the 5th of August 2005 and will then be submitted to the Parliament for approval.

Beside the evolutions described above, regarding the legislative framework of the Greek electricity and gas markets, RAE has also been involved in the following major issues related to the operation of the Greek energy market:

- Strengthening of relations and cooperation with the Greek Competition Authority

  Following the corresponding evolutions at the European level, RAE and the Greek Competition Authority have initiated their collaboration, with the view to harmonize practices, exchange experience and coordinate their actions for the efficient monitoring of the liberalization process of the Greek energy market.

- International Activities

  International Affairs is one of the important fields of the activities of RAE. During the previous year, the efforts of RAE mainly focused on the process for the establishment of the Energy Community of South East Europe (ECSEE Process) and the ongoing work of CEER and ERGEG.

  - Energy Community of South East Europe

    RAE, along with the Italian Regulatory Authority, have been assigned the co-chairmanship of the working group of CEER for the South East Europe Energy Regulation (SEEER WG). In this capacity, RAE has been involved in all aspects of the development of the SEE Energy Market, in close collaboration with the other Regulatory Authorities of the SEE region and the neighbouring EU member states, the European Commission and the Donors Community and other market participants (SETSO, EFET).

  - Participation to the ongoing work of CEER and ERGEG

RAE actively participates, to the extend that its resources permit, to the work of the working groups established by CEER and ERGEG, with the view to enhance harmonisation of the regulatory practices in the European Union and accelerate convergence of the Greek energy legal framework to the corresponding best practice in the EU.

3 Regulation and Performance of the Electricity Market

3.1 Regulatory Issues [Article 23(1) except "h"]

3.1.1 General

The development of a liberalized electricity market in Greece suffered a significant delay due to ineffective market design adopted by Law 2773/1999, harmonizing the national legislation with Directive 96/92/EC. The Directive 2003/54/EC found the Greek electricity market development well behind, compared to the situation in other member states.

According to the provisions of the Law 3175/2003, which amended the previous Law 2773/1999, as of 1 July 2004, all non-household consumers of the interconnected system have become eligible, which accounts for almost 70% of annual electricity currently consumed in the country. Furthermore, as of 1 July 2007, all customers will become eligible. However, the Greek Government has filed with the European Commission a request for derogation in accordance to Article 26 of the Directive 2003/54/EC for the micro-systems on all non-interconnected islands (Crete and Rhodes not included). According to the request, there will be no eligible customers on these islands and the exclusive supplier and generator (with the exemption of RES, CHP and autoproducers) will be the incumbent PPC SA. This situation is presented in Table 3.1.1 below.

Table 3.1.1 Electricity Market Opening

Year	Threshold GWh/year	% Market Open
1995	N/A	0
1997	N/A	0
1999	N/A	0
2001	1 kV	34
2003	1 kV	34
2005	(1)	70
2007	(2)	92

(1) As of July 1st 2004, all non household customers except all customers in non interconnected islands
(2) All customers except those in non interconnected islands

The provisions of the Law 3175/2003 also allow for the development of new trading arrangements. In order to ensure practical applicability of the new provisions and after a long period of public consultation with the market participants during 2004, a New Grid and Power Exchanges Code was approved in May 2005 (2005 Grid Code).

The 2005 Grid Code allows for the development of an organized daily wholesale market, where all electricity injected to the System and absorbed from the System in Greece will be transacted. The Code will progressively be put into force over a period extending from

October 2005 till the end of 2007. All necessary infrastructures for the operation of the new electricity market will be developed within this time frame. It is expected that the arrangements of this Code will actually promote competition regarding generation and supply. For this transitional period, the provisions of the Grid Code currently in force (2001 Grid Code) will remain in force, until their gradual replacement by the corresponding provisions of the 2005 Grid Code, according to the time frame provided for in the latter.

3.1.2 Management and Allocation of interconnection capacity and mechanisms to deal with congestion

3.1.2.1 Interconnectors

Greece is electrically interconnected with its northern neighbouring countries (Bulgaria, FYROM and Albania) and with Italy (submarine, 400 kV DC link). With reference to the Northern Interconnectors, the meshed topology of the transmission systems in the associated regions precludes tracing of energy transactions between Greece and each of its northern neighbouring countries through individual interconnectors (each interconnection considered separately). In consequence, with regard to specifying and allocating transfer capacity, all Northern Interconnectors are considered as a single system and their capacity is allocated in an aggregated manner and not individually.

For the year 2004, the total net transfer capacity of the Northern Interconnectors has been determined by HTSO to 600 MW in each direction. The net transfer capacity of the Interconnector between Greece and Italy has been determined at 500 MW for imports to Greece and 300 MW for exports to Italy, due to internal congestion problems of the Italian system.

The Northern Interconnectors are congested for imports to Greece, while the interconnector between Greece and Italy is congested only for exports to Italy, with the exemption of the summer peak period when its full 500 MW import capacity is used.. Capacity allocation and management of congestion on the Northern Interconnectors (600 MW for imports) is, at the moment, performed unilaterally by the Greek HTSO, while the allocation of the capacity of the Interconnector between Greece and Italy is performed by HTSO for the 50% of the capacity in both directions (i.e. 150 MW for exports to Italy and 250 MW for imports to Greece), the remaining 50% being under the responsibility of the Italian HTSO (GRTN).

Capacity on interconnections is allocated to suppliers and eligible customers by explicit auctions on annual (long-term) and on daily (short-term) basis.. Any capacity not allocated on annual basis as well as any capacity allocated but not used (use-it-or-loose-it), is made available on the short term (daily) allocation procedure.

3.1.2.2 Congestion management of Interconnections according to the 2001 Grid Code

The procedure for the allocation of the import capacity at the Northern Interconnectors is set by decision of the Minister of Development, according to the provisions of the 2001 Grid Code. The procedure currently in force has been set in 2002 and will be effective until 31.12.2006.

According to this, 70% of the Net Transfer Capacity (with a minimum of 420 MW) is made available for long term (annual) reservation and is allocated on an annual basis. Out of this long term capacity, 52,4% (i.e. 220 MW) is directly allocated to the Public Power Corporation (PPC – the vertically integrated incumbent utility), while the remaining (200 MW) is made available to eligible customers (exclusively for their own use) and suppliers, by explicit auction.

The remaining 180 MW of the net transfer capacity on the Northern Interconnectors, increased by any part of the long term capacity which has not been allocated through the annual auction and including the long term capacity which has been allocated but is not used (nominated), is made available to Suppliers and eligible customers on a daily (short term) basis, with PPC however having priority on 83,3% of this daily allocated capacity.

The application of this procedure for the year 2004 resulted in the allocation of the entire 420 MW long term capacity on the Northern Interconnectors to PPC, to three eligible customers and to five Suppliers, following an explicit auction held in December 2003.The long term rights on the capacity of northern interconnections already allocated, will be valid until the end of 2005.

With reference to the Interconnector between Greece and Italy, according to the 2001 Grid Code only licensed generators in Greece have the right to export energy to Italy, or transit energy through Greece (not declared transit). Consequently, the 150 MW of interconnector capacity that was allocated for 2004 by the Greek side, have been entirely allocated to PPC, the only existing generator.

From June to August 2004, following the approval by RAE, no interconnection capacity was made available on a long term basis for exports from Greece to Italy , for reasons of security of supply of the Greek system.

However, for the interconnection between Italy and Greece, following the approval by RAE, HTSO applied a specific capacity allocation procedure for exports in 2005, with the view to accommodate the security of supply problems currently experienced in the Greek system, as follows:

- For January 2005 the allocation in force for 2004 was applied.
- For February and March 2005, the total available export capacity (300 MW) was made available for long term allocation, only for off-peak hours (23:00 – 07:00), while no long-term capacity was made available for exports for the rest of the hours of the day.
- For April and May 2005, the total available export capacity (300 MW) was made available for long term allocation, only for off-peak hours (23:00 – 07:00), while only 100 MW of the long-term capacity were made available for exports for the rest of the hours of the day.
- From June to August 2005, no capacity was available for long term allocation.
- A new explicit auction will be performed for the long term allocation of capacity for September 2005, while from October 2005 onwards the provisions of the 2005 Grid Code will be applicable, allowing also suppliers to participate in the explicit auctions' procedure.

From February to July 2005 additional capacity was also made available for the short term (daily) allocation (following the 50% rule for the two TSOs). The volume of this capacity was defined by HTSO according to the needs for the safe and secure operation of the Greek System.

3.1.2.3 Congestion management of Interconnections according to the 2005 Grid Code

Under the 2005 Grid Code, the right to export power from Greece (including transit through Greece) is granted to both generators and suppliers. This provision is applicable from 1 October 2005 onwards. Market based mechanisms (explicit auctions) are used for long-term interconnection capacity allocation, while interconnections' short term capacity nomination will be based on implicit auctions. Second order rules of good management like use-it-or-loose-it principle and imports-exports netting already provided by the 2001 Code shall continue to apply.

3.1.2.4 Transmission System (internal) Congestion and Management

Due to uneven distribution of supply and demand between the northern and the southern areas of the country, parts of the national transmission system connecting these areas experience system constraints especially in periods of high demand. According to the provisions of the 2001 Grid Code, congestion on the national transmission system is not managed through a market based mechanism (i.e. market split) and the market clearing price equals the price offer of the marginal unit of the real-time economic dispatch (merit order), without considering the effect of congestion and system constraints. However, due to system constraints (voltage stability and reactive power issues) the actual real-time unit dispatch may be different than the economic dispatch. Provisions exist for payments to generators for constrained-on and constrained-off operation due to system constraints, while their operation does not alter the market clearing price.

To help alleviate such physical system constraints, the level of use of system charges paid by generators for the use of transmission system varies between areas with capacity surplus and deficit. For year 2004, the continental (interconnected) system is divided in three zones; the zone with the largest generation deficit having a zero charge and the zone with generation surplus having the highest charge.

According to the provisions of the 2005 Grid Code, such constraints shall be dealt with via a market based mechanism (market split, with two zonal System Marginal Prices for generators and one uniform SMP for suppliers). The relevant provisions of the 2005 Grid Code shall come into force by January 2007. In parallel, the zonal differentiation of transmission use of system charges will be retained, although its effect will be reduced (see par. 3.1.3.1).

3.1.2.5 Provision of information by the HTSO

Information necessary to market participants regarding the long term and short term capacity allocation auctions (Total Transfer Capacity, Transmission Reliability Margin, Net Transfer Capacity, Long-term Reserved Capacity, Available Transfer Capacity) is provided by HTSO. Total Transfer Capacity, Transmission Reliability Margin and Net Transfer Capacity are determined by HTSO, in cooperation with neighbouring HTSOs, for each hour of the dispatch day and are announced by HTSO two days ahead. Available Transfer Capacity is also announced two days prior the dispatch day.

With reference to other information relevant to anticipating the situation of the national system regarding congestion (internal and on interconnections), HTSO provides the market with information on forecast demand, forecast capacity availability, system adequacy to meet forecast demand etc, in the context of the System Adequacy Forecast Study that is compiled at least every other year and extends over a 5 year period.

3.1.3 The regulation of the tasks of transmission and distribution companies

PPC SA is by Law the exclusive owner of the electricity Transmission System, the interconnections and any future System expansion. The operation of the Transmission System is assigned to an Independent Transmission System Operator, namely ‘Hellenic Transmission System Operator S.A.’ HTSO SA (51% Greek State, 49% PPC S.A).

PPC SA is also the exclusive owner and operator of the electricity distribution network and of the grid and power plants operating at the non-interconnected islands.

As already mentioned in the previous chapter, the role of RAE in monitoring and measuring the performance of the Transmission and Distribution System Operators, as well as RAE’s competencies regarding the definition of the methodology for setting of tariffs and balancing arrangements are inferior to those specified under the Directive 2003/54 and the Regulation 1228/03. This should be rectified under the new Electricity Law, currently under discussion.

3.1.3.1 Transmission Network Tariffs

Network tariffs are calculated on the basis of the annual system cost, which is defined as the sum of the annual barter owed by the HTSO to PPC SA (i.e. the sum of the annual depreciation of the assets of the Transmission System, its operational and maintenance expenses and the return on the non-depreciated capital of the Transmission System, with the rate of return being approved by RAE) and the annual cost of any works for the expansion of the System, which are paid by the HTSO. The annual system cost is adjusted to also take into account the differences between the forecasted and realized transmission expenses during the previous year.

System charges are then allocated to generation -including imports- (G) and load –including exports- (L) according to a 30% - 70% split until 1 January 2006 (according to the 2001 Grid Code), which will then change to 15% - 85% (according to the 2005 Grid Code). Both G and L components are based only on the capacity of the corresponding user. The L component is uniform throughout Greece, while G has a zonal variation, according to the location of each generator. According to the 2001 Grid Code, Greece was split into three zones (Attiki-Viotia, where G was zero, Northern Greece, Western & Southern Greece), while the 2005 Grid Code provides for a two zones’ approach (Attiki-Viotia, where G is zero, and the rest of the interconnected system).

The operating expenses of the HTSO are not covered by the Transmission Network Tariffs. The annual budget of the HTSO, as approved by the Minister of Development, following the opinion of RAE, is debited in a regulated account which forms part of the Uplift Account. The Uplift Account is also used for the coverage of the cost of the ancillary services and for resolving system constraints. To balance the Uplift Account, a charge is imposed to all suppliers and self-supplied eligible customers in proportion to their share in total consumption.

A more detailed description of the methodology and procedures used for the definition of the Transmission Network Tariffs is provided in Annex I.

The role of RAE in the procedure of the definition of the Transmission Network Tariffs is mainly advisory. The final approval of the tariffs is performed by the Minister of Development, following the opinion of RAE. However, according to the Grid Code, RAE approves various elements of the cost base of the tariffs, such as the annual cost of the System, including the annual barter owed by HTSO to PPC SA and the annual operating cost of the System, and also the calculation of the use of the system charges.

3.1.3.2 Distribution Network Tariffs

Legal unbundling of the operation of the distribution network has not yet been established. Also, due to lack of the Distribution Network Code there is neither a methodology nor a procedure for the approval of the distribution system charges. Such charges are assumed to be incorporated into the retail tariffs of PPC, which are approved by the Minister of Development, following the opinion of RAE.

A set of charges for the use of the medium voltage distribution network were approved in April 2002 by the Minister of Development, following the opinion of RAE, to facilitate the opening of the market to eligible customers connected to this network. Due to the absence of adequate accounts unbundling, RAE performed the relevant calculations on the basis of best estimates. A new proposal has been submitted by RAE for the revision of the aforementioned charges, but this proposal has not been approved by the Minister of Development yet, so the previous charges still apply.

3.1.3.3 Estimated national average network charges

For the Transmission System, in 2004, the G charge was 0, 5.924,8 €/MW and 10.737,7 €/MW for the three zones respectively. According to RAE’s calculations, the average cost of transmission system use was 4,35 €/ MWh, based on the total energy consumption on the Interconnected Transmission System in 2004. Given the 30% G split, this cost led to an average G charge of 1,305 €/ MWh. The corresponding average L charge was 17.797 €/ MW.

For the Distribution Network, no tariff or estimation by RAE exists for low voltage distribution network charges. Supply to low voltage eligible customers is practically not possible, due to the absence of the Distribution Network Code and interval metering or other method for settlement of consumption by the DSO (PPC SA).

For a typical medium voltage customer: Annual transmission & distribution network charges = € 71,000 (transmission charges) + € 116,300 (distribution charges, estimated on the basis of Medium Voltage Distribution Network Tariffs proposed by RAE for 2002, adopted by decision of the Minister of Development –assuming that the subscribed demand is utilised fully for 11 months and 50% during the 12th month) = € 187,300 p.a.

3.1.3.4 Network performance and quality of service regulation

As regards the Transmission System, operating standards and HTSO obligations for securing and monitoring network performance following the UCTE rules are foreseen in the Grid Code. However specific procedures, indicators etc, for quality of service regulation are not stipulated, since it is rare for power quality on the Transmission System to become a ruling factor on service quality of downstream distribution networks and their customers. Such

regulation falls under the general authorities vested in the Regulator, with respect to monitoring and assessing the performance of HTSO in carrying out system and market operation.
Network performance and quality of service standards and obligations have not yet been set for the Distribution System Operator, due to the lack of the Distribution Network Code, which is currently under preparation.

Under the existing legislation, there is no procedure for the formal evaluation of the quality of service offered either by the Transmission or the Distribution system operators. However, according to information collected from the DSO, the following data are available:

Unplanned interruptions (Data provided by DSO, for 2003, concern Medium and and Low Voltage network only. There are no 2004 data available): In 2003 13,904 minutes were lost per customer per year (SAIDI). During the same year, the number of long interruptions (>3') per customer per year was 0,184 (SAIFI).

Planned interruptions (Data provided by DSO, for 2003, concern Medium and and Low Voltage network only. There are no 2004 data available): In 2003 8,081 minutes were lost per customer per year (SAIDI). During the same year, the number of long interruptions (>3') per customer per year was 0,047 (SAIFI).

All above data are as provided by the DSO (PPC SA), following their internally defined procedures, and, at present, their validity cannot be verified by RAE, since data collection and processing is not done by means of automated and certified systems and procedures (i.e. SCADA), following a methodology agreed with RAE.

Table 3.1.3 summarizes the data provided in the previous sections.

Table 3.1.3 Regulation of network companies

	Number of regulated companies	Approx network access charge (Euro/MWh)			Interruptions (min lost per customer per year
		Ig	Ib	Dc	
Transmission	1 (HTSO)	2,97	N/A	N/A	No data available
Distribution	1 (DSO - PPC SA)	4,85	N/A	N/A	13,904 (unplanned) 8,081 (planned)

3.1.3.5 User Connection to the Network and Publication of Data

Regarding user connection to the Transmission System, the Grid Code and the License of the HTSO provide that the HTSO publishes the General Terms and Conditions for connection to the Transmission System, which can be summarized as follows:

- Procedures for applying for a new connection to the Transmission System
- Overall criteria used by HTSO in selecting the suitable method of connection
- General description of connection works and associated equipment – Standards and specifications for connection works and equipment

- Typical connection examples
- Indication of budget connection costs (list of unit cost estimates for engineering/ equipment/works)
- Document specimen (connection application, connection contract)

The General Terms and Conditions document is currently under preparation by the HTSO and is not made available to the System users yet. This document will come into force by a decision of the Minister of Development, following RAE's opinion.

There are no legal obligations to the DSO for the publication of data, since neither the Distribution Network Code nor a Licence for the DSO are available.

The average time for connection to network and supply (additional data requested in Article 23 of the Electricity Directive 2003/54/EC) given below_includes time lapsed from the application by the customer until the completion of construction. Data is provided by the DSO to RAE following RAE's request, are not published by the DSO and their validity cannot be verified by RAE.

Type of Connection	**Average Connection Time (days)**	
	2003	2004
Simple Overhead Connection	25,96	30,28
Simple Underground Connection	43,91	46,96
Connection involving expansion of the Distribution Network	72,16	71,29

3.1.3.6 Balancing arrangements

The electricity market arrangements in Greece do not include a real-time balancing market. The whole balancing mechanism is based on the ex-post, administrative settlement of imbalances among the market participants. This concept was not altered by the 2005 Grid Code, since it was considered that the current stage of development of the electricity market in Greece, especially regarding the competition on the supply side, does not allow for the establishment of a properly functioning, efficient balancing market. This concept may be reconsidered in the future, should the market evolution and conditions permit.

The administrative balancing arrangements are closely linked to the operation of the mandatory Day Ahead Market, which, especially following the improvements introduced by the 2005 Grid Code, has been designed with the view to facilitate the needs of new entrants and small market participants.

The whole setup of the market operation, as provided for in the 2001 Grid Code, has been revised with the view to facilitate efficient market monitoring and increase the transparency of the market operation. The 2005 Grid Code, introduces a System of Power Exchanges, which consists of:

- The Day Ahead Scheduling (DAS) which includes the hourly transactions of the total energy injected and consumed by the system in the following day
- The Dispatch Procedure,

- The Imbalances Settlement which includes the settlement of energy deviations and the settlement of the services required for balancing of the system, and
- the Capacity Assurance Mechanism, through which part of the fixed costs of generating capacity are covered.

The supervision of the System of Power Exchanges is assigned to the Regulatory Authority for Energy (RAE). RAE is responsible for the supervision of the actions, with reference to rights and obligations, of the HTSO (in its revised capacity as a Market Operator and provider of all information necessary, as described below) and of the market participants (licensed generators, licensed suppliers and self-supplied eligible customers).

A more detailed, albeit concise, description of the provisions of the 2005 Grid Code, including detailed description of the settlement of imbalances, is presented in Annex II.

Indicators for balancing arrangements

According to the provisions of the 2001 Grid Code, the entire Interconnected System constitutes a single balancing area. The 2005 Grid Code does not alter this, however it virtually provides for economic separation between the zones of the System with generation deficit and surplus in cases of relevant system constraints, by differentiating both the Day Ahead Market and the Imbalance Settlement Clearing Price that generators are paid, whenever the Day Ahead merit order deviates from the economic merit order due to such System constraints. The Balancing interval is set to 60 minutes.

According to the 2001 Grid Code, Gate closure for all nominations is set to 11.00 a.m. of the day preceding the Dispatch Day. From 1.10.05 according to the provisions of the 2005 Grid Code, Gate closure for all nominations is set to 12:00 a.m. of the day preceding the Dispatch Day. Nominations can be submitted the earliest 48 hours prior to gate closure.

According to the 2001 Grid Code, intra-day trading is not foreseen. Nominations that are deemed unacceptable by the HTSO, can be resubmitted at the latest 2 hours following gate closure. With the above exception, revision of submitted nominations can be accepted only when special circumstances prevail, subject to HTSO's judgment. Such revisions may refer only to the technical part of the nomination (quantity) and not the price offer. According to the 2005 Grid Code: Intra-day trading is also not foreseen. From 1.7.06, nominations submitted to the Day Ahead Market can be revised up to 5 times prior to gate closure. Revisions are not allowed following gate closure.

According to the 2001 Grid Code, imbalances are not separately accounted for, since the market settlement and clearance are based on the ex-post calculated SMP, and the ex-ante SMP and generating units order are only indicative. Following these, there are not any special charges for imbalances, and the relevant cost cannot be estimated.

Provision of information

The HTSO must provide to market participants the following information regarding the balancing mechanism;.

According to the 2001 Grid Code, on the day before the Dispatch Day, HTSO provides participants with the following information regarding the Dispatch Day:

- Forecasted Hourly System Load
- Net and Available Transfer Capacity on interconnectors
- Information regarding Transmission System status & availability (scheduled operations and maintenance on transmission infrastructure, equipment outages, significant events, system alarms and emergency conditions)
- Day Ahead Dispatch Schedule for each generator (and changes thereof prior to the Dispatch Day) and Forecasted Hourly System Marginal Price.
- Changes in the Day Ahead Dispatch Schedule during the Dispatch Day due to congestion and system constraints.

HTSO also publishes daily on its Web Site the updated information regarding the Transmission System Loss Factors and the Maintenance schedule for the Transmission System and the Interconnectors

In due course of the Dispatch Day, the HTSO provides market participants with the following information:

- Actual Hourly System Load.
- Hourly Ex-post System Marginal Price (market clearing price).
- Information regarding the actual operation of the system at least on a weekly basis.
- Bids submitted by generators are disclosed to all parties concerned every six weeks.

According to the 2005 Grid Code, HTSO must provide participants with the following information:

- Weekly schedule of Reliability-Must-Run hydro units (ex-ante) and actual dispatch program (ex-post)
- Net and Available Transfer Capacity on interconnectors
- Information regarding Transmission System status & availability (scheduled operations and maintenance on transmission infrastructure, equipment outages, significant events, system alarms and emergency conditions)
- Forecast of the Hourly System Load, the Ancillary Services Requirements and the Transmission System Status (forecast regarding onset of congestion and/or constraints)
- Bids submitted by HTSO regarding injection of energy from units under priority dispatch regime (renewable & cogeneration, units under trial operation)
- Ex-post data concerning the previous dispatch day and particularly as regards forecast deviations from actual system operation
- Computed System Marginal Price, total System Load, Imports – Exports Schedule accepted in the Day Ahead Market.
- Provisional Dispatch Schedule for generators and suppliers, as it is accepted in the Day Ahead Market.
- Ex-post statistical information regarding the operation of the Day Ahead Market

HTSO must also publish any updated information regarding the Transmission System Loss Factors, historical data and statistics regarding the accuracy of its forecasts and the Scheduled Outages of the Interconnections.

In the context of Dispatch Scheduling, HTSO must also provide to participants a report on any system constraints that were taken into consideration and affected the solution of the Dispatch Schedule problem.

In the context of Imbalance Settlement, HTSO must publish the Imbalance Marginal Price and keep relevant records available to participants for a period of 5 years.

3.1.4 Effective unbundling

3.1.4.1 Transmission and Distribution System Operators

PPC SA is the owner of the Transmission System according to the, Article 12 of Law 2773/1999. A separate company, the “Hellenic Transmission System Operator” S.A. (“DESMIE” or HTSO, www.desmie.gr), established by Ministerial Decree 328/12.12.2000 is the Transmission System Operator responsible for the operation and exploitation of the Transmission network and for ensuring its maintenance and development (article 14 of Law 2773/1999). The HTSO is 51% state owned and 49% owned by the generators; at the moment the only generator being PPC SA, therefore PPC controls 49% of the shares of the HTSO and appoints members to the Board of Directors of HTSO. The HTSO is located separately from PPC in its own premises. Nevertheless, most of the employees of the HTSO are coming from PPC, and are members of PPC’s trade union.

Legal unbundling has not yet been implemented for the Distribution System Operator. PPC SA, the integrated company and the exclusive owner of the Distribution Network, is appointed as the Distribution System Operator under the legislation in force (article 21 of Law 2773/1999). The DSO is part of the integrated company, sharing the same premises.

3.1.4.2 Unbundling of accounts

Article 30 of Law 2773/1999 lays down that the rules for the allocation of assets, liabilities, expenditure and income which are followed in drawing up the separate accounts by vertically integrated undertakings are specified in the annex of the annual accounts of the undertakings, and these rules can only be modified following RAE’s approval. The wording of the abovementioned provision which provides that RAE is responsible for approving any modification to these rules, leads to the conclusion that RAE has the authority to co-operate and approve the methodology used for the unbundling of accounts of vertically integrated undertakings. In this line, RAE has issued on 04-01-2002 a detailed methodology for the implementation of the unbundling of accounts by PPC, including the activities for which separate accounts should be kept, the methodology for the cost allocation between the abovementioned activities, the balance sheets, profit and loss accounts for the separate activities etc.

Following a lengthy period of dispute, PPC SA has finally produced unbundled accounts in their Web Site, for the exploration of lignite, generation, transmission and distribution activities for the period 2001 to 2003. However, RAE has expressed reservations regarding the compliance of the accounts published by PPC to the approved methodology, mainly due to the fact that the accounts of the distribution network have been published in a consolidated form with the accounts of PPC for the retail sales and generation in non-interconnected islands (excluding Crete and Rhodes), but also because the methodology for the allocation of the costs shared among various activities of PPC has not been clearly demonstrated. Therefore, RAE has not accepted the published accounts of PPC yet and has requested further clarifications from PPC on the above. Further work is currently underway, in order to have an updated full set of unbundled accounts of PPC up to 2005.

A separate audit for the unbundled accounts from a certified accountant is not laid down in the legislation in force. However, this obligation is laid down pursuant to the legislation in force (Law 2190/1920 with respect to joint stock companies – societes anonymes) for the annual consolidated accounts of companies which operate under the legal form of 'societe anonyme'.

The costs of the legally unbundled HTSO only reflect its administrative costs and, therefore, are not shared with other affiliated companies of the owner of the Transmission System, i.e. PPC SA.

On the contrary, since the unbundling of the Distribution System has not been completed yet, the accounts of the DSO are consolidated with the accounts of retail sales and generation in non-interconnected islands (excluding Crete and Rhodes) of PPC and, therefore, it is not possible to estimate the proportion of the costs of the DSO shared with other business units of PPC.

In case of failure to comply with the provisions of Law 2773/1999, or with secondary legislation issued as specified in the Law 2773/1999, RAE can impose fines pursuant to article 33 of Law 2773/1999.

Table 3.1.4 Summary Information on Unbundling (Electricity)

	Transmission	Distribution
Separate Headquarters	Y	N
Separate corporate presentation	Y	N
Unbundled regulatory accounts with guidelines	N(1)	N
Audit of unbundled accounts	Y	Y
Publication of unbundled accounts	Y(2)	N
Separate board of Directors without Directors from other group companies	N (3)	N

(1): The accounts published do not fulfil the requirements of the methodology set by RAE. The unbundling refers to the accounts of PPC as the owner of the Transmission System, and not the HTSO as the operator of the Transmission System.

(2): PPC has published the accounts for 2002 and 2003, seperately for the Transmission System. Pending for 2004

(3): Although HTSO, as a separate joint-stock company, has a separate board of Directors, two Directors are General Managers of PPC SA

3.2 Competition Issues [Article 23(8) and 23(1)(h)]

The development of a liberalized electricity market in Greece suffered a significant delay due to ineffective market design adopted by Law 2773/1999, harmonizing the national legislation with Directive 96/92/EC.

Due to the inadequacy of the legal and regulatory framework, with the exception of renewables and small CHP which enjoy a special regime through PPAs (feed-in tariffs and investment support), only one independent power plant (natural gas peaking unit of 150 MW) not owned by PPC SA has been constructed and began to operate as late as in 2004. The investment decision for the construction of this plant was facilitated by the fact that at the end of 2003 and due to tight capacity margins especially for the summer peak, the HTSO launched a tendering procedure for the provision of ancillary services (reserve capacity). Therefore, the abovementioned plant benefits from a special contract with the HTSO, with a duration of almost 3 years.

In addition, the construction of new thermal power plant, owned by Thessaloniki Energy SA - an affiliate of the partially state owned Hellenic Petroleum SA- also began in 2004,. The commercial operation of this power station, currently under commissioning, is expected to start before the end of 2005.

In so far as the market organization was principally based on bilateral contracts between power generators and suppliers and due to the absence of any measures introducing a virtual IPP mechanism or other capacity release measures, competition regarding the retail market was limited to imports. However, the capacity of the northern interconnections of the Greek Transmission System is limited, compared to the size of the market. Furthermore, as already described, significant part of this capacity is allocated directly to PPC (for the purposes of ensuring supply to non-eligible customers).

All these factors resulted in the very poor development of competition in the Greek wholesale electricity market, without, at the same time, to provide any incentives for the development of new generation capacity. This could have very severe effects on the security of supply of the Greek electricity system and called for immediate remedial actions. This resulted in the new electricity Law 3175/2003 and the 2005 Grid Code, as mentioned above.

The 2005 Grid Code allows for the development of an organized daily wholesale market, where all electricity generated and consumed in Greece will be transacted. The Code is progressively put in force over a period extending from October 2005 till the end of 2007. All necessary infrastructures for the operation of the new electricity market will be developed within this time frame. It is expected that the arrangements of this Code will actually promote competition regarding generation and supply.

3.2.1 Description of the wholesale market

According to the provisions of the 2001 Grid Code, a daily market determines the economic merit order of the units to be used to cover next day's load, as forecast by the HTSO, based on short-run marginal cost declarations for each technically available generating unit. Power stations are obliged to offer their short-run marginal cost. All transactions are settled after the day, and all ancillary and balancing services are included, since there is no separate market for these services. From the daily market the generators receive the System Marginal Price which effectively covers their fuel cost and they have to recover their capital cost through bilateral contracts with suppliers or self supplied customers. Under these arrangements, the wholesale market is very closely linked with retail, since technology and fuel competition is the only possibility in the wholesale market.

In 2004 total consumption of 51,7 TWh (including losses) and a load peak of 9370 MW have been measured in the interconnected System, which refers to the mainland of Greece (plus interconnected islands). It has to be noticed that the peak load might have been higher since the maximum demand was measured just before the brown out on the 12th of July. HTSO's estimates show that the peak demand might have been 9500 – 9600 MW on the 12th of July, if the brown out had not happened. On the non interconnected islands the total amount of energy consumed is around 4,4 TWh.

The total installed capacity in the interconnected system is 11350 MW, of which 5288 MW lignite fired power plants, 1841 MW natural gas, 836 MW fuel oil fired plants, 3039 MW hydro plants and 346 MW small hydro, RES and CHP plants, not participating in the wholesale market (Dec.2004). The total capacity installed on the non interconnected islands is 1605 MW, of which 140 MW RES and 1465 fuel oil fired plants.

PPC owns 97% of the installed capacity and the competitors (IRON THERMOILECTRIKI, RES-CHP-autoproducers) the remaining 3%. IRON THERMOILECTRIKI started its commercial operation in the very end of December 2004 and operates under a contract with HTSO to offer ancillary services. RES, CHP and autoproducers are under a special protective regime, consisting of the obligation of HTSO or DSO to adsorb electricity generated from renewables and small CHP under a regulated feed-tariff regime.

In 2004, lignite-fired plants accounted for 61 % of total gross electricity production, followed by natural gas (15%), oil (13%), hydro (9%) and RES (2%). At base load almost 5288 MW (lignite fired plants) are used, at mid load additional 1970 MW (thermal) and at peak load additional 3570 MW (Hydro plants, "Agios Georgios" gas-fired units and "IRON THERMOILECRTIKI" gas-fired unit) are used.

During 2004 it was only PPC that has provided the total of requested ancillary services.(HHI equals 10.000 indicating the monopoly situation)

There are no specific measures for demand side management in Greece. The demand side participation in the wholesale market is minimal and can only be effected indirectly, through the minimization of the use of electricity by a limited number of industrial customers during the peak hours, where the price of electricity is high.

The relevant electricity market for Greece is the national market, since the interconnection capacity with neighbouring member states (namely Italy) is limited. Nevertheless, a number of traders, apart from PPC, are active in the region and supply energy in Greece, bought in the Balkans area. The price differentiation between the Balkans area (estimate of 33€/MWh) and Greece (wholesale price from the daily market is around 35€/MWh, but the full energy price, based on PPC tariffs, is estimated on average base 52€/MWh) and Italy (above 65 €/MWh) creates favorable conditions for electricity trading. Nevertheless, trading arrangements over the interconnections were not sufficient to enhance trading activity during 2004.

There is no activity related to mergers and acquisition, since most of the independent companies participating in the electricity market are in the very beginning of their development and the market is still very concentrated. Nevertheless, one of the major companies, active in the area of RES and especially wind farms, ROKAS SA, has concluded an agreement with Iberdrola for the 21% of its shares. ROKAS SA owns and operates a number of wind power parks with total installed capacity of 190 MW, which is almost 40% of the total installed wind plants' capacity. It has to be noted that RES are not participating in the competitive market, and a specific tariff is applied for the payment of the energy produced by RES. A special levy is applied to all load to support the RES scheme.

PPC SA retains its 97% share of electricity generation as the power projects of new entrants are proceeding slowly despite a high annual increase in electricity demand, because the existing market structure, established according to the first electricity liberalisation law 2773 of 1999, inhibits their financing on a project finance basis. Since 2001, when the Greek electricity market was liberalized, 12 generation licenses have been granted to anticipated gas-fired non-PPC producers for a total capacity of 4153 MW. However, only the 400 MW CCGT power plant, owned by Hellenic Petroleum, is under construction (expected to be operational by the second half of 2005) financed on corporate basis and the gas-fired power station (147 MW) of IRON THERMOILEKTRIKI in Viotia is in operation under a contract to provide ancillary services to HTSO.

Table 3.2.1 summarizes the situation of the Greek electricity wholesale market, while Table 3.2.1a reveals the fact that all trading is performed through bilateral contracts.

Table 3.2.1 Development of wholesale market

	Demand		Installed capacity (GW) (1), (3)	No. of companies with >5% generation	Share of largest three generation companies	HHI (where available)	
	Total (TWh) (1)	Peak (GW) (1)				All plant, by capacity	All plant, by volume
2001	45,9	8.598	9.846	1	100%	Not Available, however too high (close to 10,000)	
2002	46,9	8.924 (2)	10.526	1	98%		
2003	49,7	9.042 (2)	10.857	1	98%		
2004	50,9	9.370 (2)	11.004	1	97%		

(1) Interconnected System only, where wholesale market is organized
(2) Not taken into account the black out in 2004, and agreed load shedding programmes
(3) Not including Small Hydro, RES, CHP not participating in the wholesale market

Table 3.2.1a

Volume of electricity traded (TWh)

	Total consumption	traded in spot PX market	traded in forward PX market	bilateral OTC trading
2002	46,9	NA	NA	46,9
2003	49,7	NA	NA	49,7
2004	50,9	NA	NA	50,9

3.2.2 Description of the retail market

In Greece 29% of electricity is consumed in the industrial sector, 36% in the commercial agricultural and public sectors and 34% in the domestic sector.

Practically, all consumers connected to the medium and low voltage system are supplied by PPC. A number of eligible industrial consumers, connected to the high voltage system, have been supplied with electricity from the interconnections either as self-supplied customers or through independent suppliers. The electricity volume traded outside PPC is around 1 TWh (approx. 2% of the total electricity volume consumed in 2004), including the electricity produced by autoproducers and RES and the imported electricity.

Since the 97% of the energy sold to the consumers is supplied by PPC, regulated retail tariffs are applied. During 2004, and because of the fact that the unbundling of PPC accounts had not been completed, PPC retail tariffs remain bundled, without explicit reference to energy, transmission, distribution and other costs. It is only the levy for RES that appears separately on PPC's bills, and of course VAT (8%, from February 2005 it is 9%).

In 2003, practically 100% of the electricity supply belonged to PPC SA. Only two (2) suppliers besides PPC were active and imported 8 GWh, which is less than 0,02 % of the total energy consumption on the Interconnected Transmission System. In 2004, four (4) suppliers imported in aggregate 398 GWh, which corresponded to 0,78% of the total energy consumption on the Interconnected Transmission System. All the above suppliers are non-national companies expanding their business into the Greek market. These companies supplied energy mostly to customers in the commercial and the light industrial sectors.

Up to 2004, supply authorizations had been granted to 10 companies corresponding to a total potential supply of 2.471 MW. None of these companies are affiliated to the HTSO or DSO businesses. Out of these authorized suppliers, only four (4) were active during 2004 and two (2) in 2003.

In 2004 the licensed suppliers were the following:

ATEL HELLAS SA
ENEL TRADE S.p.A
CINERGY GLOBAL TRADING LTD
EDF TRADING LIMITED

E.ON SALES & TRADING GMBH
RWE TRADING GMBH
ENTRADE GMBH
VERBUND AUSTRIAN POWER TRADING AG
EDISON TRADING S.P.A
IRON THERMOILEKTRIKI SA

3.2.2.1 Customers' switching of supplier

In 2004, three (3) eligible customers (heavy industrial sector) have covered a small part of their load (approx. 790 GWh, corresponding to 1,55 % of the total energy consumption on the Interconnected Transmission System and to 10,6% of the electricity consumption of the relevant sector) through imports, while covering the rest of their needs from PPC. In addition, four (4) suppliers were active, importing in total 398 GWh (0,78% of the total energy consumption on the Interconnected Transmission System). This energy was supplied mostly to customers in the commercial sector (less than 15 customers and 100 metering points). Energy imported by suppliers other than PPC and by self-supplying consumers in 2004, amounted to 2,33 % of the total energy consumption on the Interconnected Transmission System.

In 2003, only two (2) out of approximately 7.000 eligible customers covered a small part of their load (approx. 321 GWh) through imports. Two (2) suppliers were active, importing in total 8 GWh. Energy imported by suppliers other than PPC and by self-supplying consumers in 2003, amounted to 0,65 % of the total energy consumption on the Interconnected Transmission System.

Cumulatively, since 2003 a total of 406 GWh (0,4 % of the total energy consumption) was imported by suppliers other than PPC and were supplied to commercial and a few industrial customers, whereas 1.111 GWh (1,1% of the total energy consumption) was imported by self-supplying consumers (heavy industrial sector).

Issues related to the procedure of customers switching of suppliers are regulated by the Supply Code and the Power Exchanges Code which are approved by the Minister of Development after simple opinion of RAE and published in the Official Gazette.

Article 9 of the Supply Code (Official Gazette B' 270/2001) provides that following the conclusion of a supply contract between an eligible customer and a supplier, the latter notifies the HTSO, submitting in addition an authorisation by the eligible customer which enables the HTSO to register the corresponding entry in the Trading Arrangements Registry, update the registry records relevant to the representation of the eligible customer's meter so as to reflect the modified status of supply, and notify the suppliers affected by the modifications.

Eligible customers may be supplied simultaneously by more than one supplier. In this case an agreement needs to be executed between the suppliers, defining the allocation rules among the suppliers of the supplied energy. The HTSO approves these agreements as regards compliance with the law, the codes and the terms of the suppliers' authorisations, ensuring that the entire metered energy consumption is allocated to the suppliers and/or the eligible customer, in case of customers procuring part of their consumption directly from the market.

The procedures followed by HTSO with respect to supplier switching, the set of information that needs to be provided by the parties involved and all matters relevant to the representation of end-user consumption by suppliers for the purposes of settlement are dealt with in more detail in the 2005 Grid Code where provisions exist for further elaboration by the HTSO in the Metering Handbook. These provisions come into effect on 1.10.2005.

Provisions regarding the above do not exist for the DSO yet, due to lack of a Distribution Code. However the 2005 Grid Code includes a provision stipulating that the abovementioned procedure shall apply also to the customers connected at the medium voltage Distribution Network. Furthermore, the 2005 Grid Code provides for the DSO to draft and RAE to approve by 1.10.2005, detailed rules regarding switching of suppliers by customers connected at the low voltage Distribution Network.

Table 3.2.2 summarizes the concentration of the Greek electricity retail market.

Table 3.2.2 Development of retail market

				Market share of three largest companies			Cumulative % customers having changed suppler (by volume)		
	Total consumption (TWh)	No. of companies with >5% retail market	Number of fully independent suppliers (1)	large and very large industrial	small-medium industrial and busines	very small business and household	large and very large industrial	small-medium industrial and business	very small business and household
2001	45,9	1	0	100	100	100			
2002	46,9	1	0	100	100	100			
2003	49,7	1	4	99	100	100	0,65%	0,016%	0
2004	50,9	1	10	98	99	100	1,55%	0,78%	0

(1) i.e. fully independent from network companies

3.2.2.2 Retail Price Levels

According to the provisions of the Supply Code in force, all retail supply tariffs of a company which covers more than 70% of the energy supplied to Eligible customers are regulated.

Currently, the average level of the (all inclusive) regulated PPC tariff ranges from 0.05 €/kWh for high voltage industrial customers to 0.08 €/kWh for medium voltage commercial customers and 0.11 €/kWh for low voltage commercial customers. Since 2002 only increases due to inflation have been approved, amounting to around 8.85%.

Since no unbundling of the accounts of PPC has been approved, yet, it is not possible to present in detail all components of the aforementioned retail prices (such as network costs, levies included in network costs, energy cost plus supply margin and taxes).

3.2.3 Measures to avoid abuses of dominance

According to the provisions of the Supply Code in force, suppliers are obliged to publish information regarding the structure of applicable tariffs, the charges applicable and the principles governing calculation of such charges, and the terms governing the supply contracts with customers. The Code also includes the general terms of supply contracts, while no special term may be contractually agreed in contradiction to such general terms. Further to that, the same Code provides for specific obligations regarding supply offers and contracts between big suppliers (i.e. suppliers with a market share of more than 40% of the total electricity consumed by Eligible customers in Greece) and Eligible customers. Such obligations refer to the exclusion of liability limitations. Finally, the Code includes special provisions for dominant suppliers with a market share higher than 70% of the total electricity consumed by Eligible customers in Greece. However, all these requirements have been proven of very limited practical importance for the Greek electricity market, since the failure of the previous market arrangements to promote the entry of independent power producers other than the incumbent, the limited interconnectors' capacity as well as the absence of the Distribution Network Code obstructed also the development of competition on the supply side.

As far as the information flow is concerned, the 2001 Grid Code includes provisions for a number of reporting requirements by the generators, related to the availability of the generating units and unplanned outages. However, the information provided by the generators has little effect in the wholesale market, at least as far as the bidding behaviour of the generators is concerned, since it is only used by the HTSO for the physical balancing of the transmission system. The same accounts for the suppliers, whose contracts with the end costumers are not linked with the System marginal price.

The 2005 Grid Code provides a number of additional procedures in order to prevent market abuse and protect the integrity of the market and strengthen the public confidence in the electricity market.

In particular , according to the 2005 Grid Code, a number of reports and declarations have to be submitted by the participants and especially the generators to the Market Operator (i.e. the HTSO), in order to be eligible to participate in the day-ahead energy market.

A techno-economic declaration has to be submitted by all generators giving all technical characteristics for each generating unit as well as information on fuel cost and other operations' costs. According to this declaration certain compensation items are calculated in the balancing mechanism, if the generating unit offers some services during the day. The techno-economic declaration is compulsory, and there is a penalty clause for non or false submission of the declaration. The HTSO is responsible for collecting the penalty, the level of which is decided by the HTSO after RAE's approval.

Generation license holders are obliged to submit for each generating unit they own declaration of partial or total non availability due to technical reasons, as well as declaration of major outages, that is unavailability for more than 10 continuous days during the summer period and 3 continuous months the rest of the year. The availability declaration is compulsory, and there is a penalty clause for non- or false submission of the declaration. The HTSO is responsible for collecting the penalty, the level of which is decided by the HTSO after RAE's approval.

All the information related to the availability of a generating unit is considered as "significant incident" and the HTSO is obliged to publish all incidents, protecting nevertheless the confidentiality of the information related to each participant.

Under the 2005 Grid Code, the organization responsible for market supervision is the Market Operator (HTSO). In parallel, RAE has the general responsibility to monitor the development of the electricity market and the market behaviour of all participants. RAE has the authority to ask any participant to submit to RAE published or confidential information, as RAE may require, in order to investigate actions and practices followed by the participants. In case of violation of the provisions of the 2005 Grid Code, RAE has the authority to impose administrative sanctions (e.g. fines) against the licensees, including an opinion to the Minister of Development to revoke the license.

RAE has issued special decisions regarding application details of the Codes, with the view to facilitate the competitive position of new entrants and enhance the security of supply of the electricity system. More specifically:

- Suppliers having obtained long term import rights in the Interconnectors have, according to the Codes (monthly use-it-or-loose-it mechanism), specific obligations to exercise these rights, otherwise they should declare their intention not to use part of their allocated capacity, which would then be available for short-term allocation and, most probably, would be allocated to PPC. RAE relaxed some of these obligations, when security of supply problems were not pressing..
- New suppliers in practice mostly supplied their imported energy for the partial coverage of the load of large customers. These customers were also supplied by PPC, creating, thus, the need for an agreement between PPC and the new supplier for the sharing of the meters. Problems have been faced regarding delays of signing the necessary, since PPC insisting on imposing the terms of these agreements. Following RAE's intervention, such problems were resolved.
- Moreover, problems arose during the periods of interconnectors' maintenance, when it was questionable whether the customers of the importers should buy energy from PPC (the only active generator in the country) being exposed to penalties for exceeding contracted power limits, or the importers should continue supplying their customers buying energy from the daily market. RAE promoted the second solution to solve the problem.

4 Regulation and Performance of the Natural Gas market

4.1 Regulatory Issues [Article 25(1)]

4.1.1 General

Natural gas has been introduced to the energy mix of Greece in 1996. Due to this fact, according to the provisions of the Gas Directives, Greece is an emerging gas market and has been granted derogation from the implementation of the Directive 55/03 until November 2006. Therefore, the Greek gas market is currently operating in a monopolistic way, under the provisions of law 2364/1995.

In 2003, in the framework of the ongoing process for the liberalization of the Greek electricity market and the intertwining between gas and electricity markets, the Greek government took a first step towards liberalisation of the gas market, despite the derogation. According to the provisions of law 3175/2003, natural gas-fuelled co-generators with annual consumption over 25 million cubic meters as well as all power producers are eligible to choose their supplier, starting from July 1st, 2005. At the same time, they have been granted a right of access to the National Gas Transmission System (NGTS) under a regulated TPA regime. The aforementioned customer categories represent approximately 70% of the current level of annual gas consumption in Greece.

The draft Ministerial Decision for the use-of-system tariffs, is currently under public consultation by the Ministry of Development. However, in order to ensure the exercise of the eligibility rights, a complete regulatory framework and detailed market rules need to be put in place.

In this context, in August 2004, RAE published its proposal for the liberalisation of the gas market, comprising a complete set of the primary and secondary legislation required for the full transposition the Directive 2003/55/EC and -to the greatest possible extent- the forthcoming Gas Regulation into the Greek legal framework.

The Ministry of Development recently launched a public consultation on the new draft law for the transposition of Directive 2003/55/EC to the Greek legal system and the gradual liberalization of the market beyond the level introduced by law 3175/2003. By the completion of the public consultation, in early August 2005, the draft law will be forwarded to the Greek Parliament for ratification. Following the parliamentarian approval, the draft secondary legislation proposed by RAE in September 2004 will be finalized and approved through a similar procedure.

4.1.1.1 Description of the Market Structure

Under the current monopolistic market organisation, DEPA SA, the vertically integrated, state-controlled gas company is the owner and operator of the NGTS. Currently, the Greek State owns 65% of the shares of DEPA, while the remaining 35% belongs to Hellenic Petroleum S.A., in which the Greek State has also a share of approximately 35%. Until 01.07.2005, DEPA also had the exclusive right to import and supply natural gas in Greece.

There are three regional gas distribution companies (EPAs) in Greece, operating in the urban areas of Attiki, Thessaloniki and Thessaly (Larissa/Volos). In accordance with the provisions of the current gas law, EPAs were established jointly by DEPA SA and private investors following an international tender. The management of each EPA and 49% of its equity belong to the private investors, while DEPA controls the rest 51% of the shares through its corresponding affiliate companies, EDAs (100% owned by DEPA). The private investors are Italgas for EPA Thessaloniki and Thessaly and the joint venture of Cinergy Global Power Inc. and Shell Gas B.V. for EPA Attiki.

Each EPA has been granted a 30-year concession license, under which it has the exclusive right to develop and operate the gas distribution system and supply all domestic, commercial and industrial consumers that do not exceed a certain annual consumption threshold (10 million cubic meters p.a.), within the area specified in its license. DEPA S.A. has the right of access to the distribution network for supplying customers that lie within the EPA territory but exceed the aforementioned consumption threshold.

Therefore, EPAs are vertically integrated gas undertakings, exercising both the distribution system development, operation, exploitation and supply functions. It is worth mentioning that, according to the provisions of paragraph 8, article 28 of the Directive 2003/55/EC, the vertical integration of these EPAs and the monopolistic concession regime under which they operate will be preserved for the whole duration of the concession licences, irrespectively of the liberalisation of the market.

Gas distribution in other areas of Greece is currently limited to a small number of industrial consumers and is carried out by DEPA S.A., regarding both operation of the relevant distribution network and supply to customers.

4.1.1.2 Description of the existing Gas Supply and Demand

In 2004 the total gas consumption in Greece was 2,5 bcm. There is no domestic production.

DEPA imports pipeline gas from Russia (contracted quantity 2,8 bcm/year) and LNG from Algeria (0,68 bcm/year) under long-term, take-or-pay agreements. DEPA has also announced the conclusion of a long-term, take-or-pay contract with Turkish Botas for the provision of 0,75 bcm/year from Turkey.

There is no interconnection of the Greek NGTS to the networks of other Member States. The only interconnection that currently exists is with Bulgaria to the North. There is actually no integration between the Greek and the Bulgarian natural gas markets, mainly due to the fact that the pipeline transporting gas to Greece through Bulgaria is a dedicated transit pipeline, exempted from the implementation of a TPA regime which applies to the rest of Bulgarian national network and also to the fact that no TPA regime is applied to the Greek market yet (except for the gas-fired electricity producers and CHP, as mentioned above). This is also the case for the transit pipelines upstream of Bulgaria. Therefore, the Greek NGTS is commercially isolated from the neighbouring HTSO regions, a situation which is not expected to improve dramatically, even after the expected connection to the Turkish gas network, which is currently under construction.

The maximum importing capacity of the entry point from Bulgaria is currently of 379,800 Nm^3/h, extendable to 691,000 Nm^3/h. The current send out rate of the LNG Terminal is 293,000 Nm^3/h, and will be expanded to 580,000 Nm^3/h, while the net storage capacity of the LNG tanks is 130,000 m^3 of LNG, while the unloading capacity of the Terminal equals 3,500 m^3 of LNG per hour.

4.1.1.2 Description of the existing retail market

The only retail suppliers currently active in the Greek gas market are:

1. DEPA SA which supplies gas to all consumers, except those with an annual consumption of less than 10 million cubic meters that are located in the area of an EPA.

2. The three gas distribution and supply companies (EPA Attiki, EPA Thessaloniki and EPA Thessaly) which -within the area specified in their respective license- hold the exclusive right to supply all domestic, commercial and industrial consumers with an annual consumption of less than 10 million cubic meters.

As mentioned above, since the 1st July 2005 power generators are eligible customers irrespective of their annual consumption and location . So far, all such customers (currently there are only two of them, PPC SA and IRON THERMOILECTRIKI SA) are supplied by DEPA SA.

Gas quantities currently supplied by DEPA are mostly under contracts the duration of which varies between 3 and 5 years for industrial and commercial customers and goes up to 15 years for power generators (PPC) and 16 years for the supply of the three EPAs.

The tariffs for the supply of customers not belonging to EPAs are set by DEPA SA without any involvement of the Regulator, or the government. The end-user tariffs for the customers of the EPAs are set by the corresponding EPA, with only an ex-post control performed by RAE, regarding the violation of the annual revenue cap (as defined in the corresponding licence of each EPA), implementation of discriminatory pricing for customer categories, etc. All tariffs are bundled, without any indication of cost for the use of the transmission or distribution networks.

4.1.2 Management and allocation of interconnection capacity and mechanisms to deal with congestion

There is no physical (or contractual) congestion experienced in the Greek Natural Gas Transmission System, either nationally or on the interconnection points, since the total capacity of the Greek Natural Gas Transmission System is estimated at around 6.5 to 7 billion cubic meters per annum, while the existing market size is approximately 2.5 bcm per annum.

As already mentioned, the legal framework for the transposition of the Directive 55/03 is not in place yet, therefore no mechanisms for the management and the allocation of the interconnection capacity are in force, since the system operates under the bundled control of DEPA SA.

For the time being there is no gas transit through Greece.

4.1.3 The regulation of the tasks of transmission and distribution companies

There is no regulatory framework in place for the transmission and distribution companies (with the exemption of the role of RAE in monitoring the fulfilment of the obligations of the three EPAs, according to their License, which is described above) and, therefore there are not either regulated tariffs or regulated balancing arrangements in place.

4.1.4 Access to Storage, Linepack and other ancillary services

Non Applicable

4.1.5 Effective Unbundling

Under the current (monopolistic) regime of the Greek gas market, DEPA S.A. is obliged to keep accounts for its activities as HTSO separate from the accounts regarding its gas supply or other activities. However, there is no legal requirement for publishing unbundled accounts.

EPAs have no obligation to keep unbundled accounts for their DSO, supply, or other activities.

No competences are currently assigned to RAE to set the rules for unbundling of accounts of DEPA.

4.2 Competition Issues [Article 25(1)(h)]

As described above, there is no competition in the Greek natural gas market, therefore completion of the following paragraphs is not relevant for the case of Greece.

4.2.1 Description of the wholesale market

See section 4.1.1.2 above

4.2.2 Description of the retail market

See section 4.1.1.3 above

5 Security of Supply

5.1 Electricity [Article 4]

5.1.1 Supply versus Demand

The overall picture of the supply and demand pattern of the Interconnected System is provided in Table 5.1 below.

In 2004 the peak demand in the Interconnected System reached 9.370 MW. It has to be noticed that the peak load might have been higher since the maximum demand was measured just before the brown out on the 12th of July. HTSO's estimations shows that the peak demand might have been 9500 – 9600 MW on the 12th of July 2004, if the brown out had not happened.

According to the Baseline scenario of the HTSO and an average annual demand increase of 3,9%, the evolution of peak demand is forecasted for the years 2005-2008 as follows:

Year	Peak Demand (Interconnected System) in MW
2005	10.100
2006	10.550
2007	11.050
2008	11.550

There are no data available for the peak-demand on the non-interconnected islands.

5.1.2 Generation Capacity and Licensing

In 2004 the total available generation capacity was 12.956 MW (estimation by RAE), 1.605 MW of which belong to the autonomous systems on the non-interconnected islands.

Since 2001, when the Greek electricity market was liberalized, 12 generation licenses have been granted to anticipated gas-fired non-PPC producers for a total capacity of 4153 MW, and a large number of licenses (583) to RES plants (for a total capacity of 4566 MW) (Please see Table 'RES Generation Licenses' below). However, only one 400 MW CCGT power plant, owned by Hellenic Petroleum, is currently under construction (expected to be operational by second half of 2005) financed on corporate basis and the gas-fired peaking power station (147 MW) of IRON THERMOILEKTRIKI in Viotia is in operation under a contract with HTSO for the provision of ancillary services. Another 400 MW gas fired CCGT power plant is currently under construction by PPC S.A., scheduled for its initial synchronous operation by mid 2006. According to the respective generation license, this plant shall substitute equal capacity from old PPC plants that will be retained as cold (emergency) reserve. Additionally a few number of RES producers, who are under a protected regime, have proceeded to the construction of RES plants.

The overall situation of the installed power generation capacity in Greece, including RES generation licenses is provided in the following tables.

INSTALLED ELECTRIC POWER GENERATION CAPACITY (MW)

	2000	2001	2002	2003	2004	annual % change 01/00	02/01	03/02	04/03	MAGR 00/04
Mainland and Interconnected Islands										
Thermal Power Plants										
Coal	4908	4933	4958	5288	5288	0,5	0,5	6,7	0,0	1,9
HFO	777	771	836	836	836	-0,7	8,4	0,0	0,0	1,9
Natural Gas	1100	1103	1693	1693	1841	0,2	53,5	0,0	8,7	13,7
Total Thermal	**6785**	**6807**	**7488**	**7818**	**7966**	**0,3**	**10,0**	**4,4**	**1,9**	**4,1**
Hydroelectric Plants										
small (1-10 MW)	24	31	35	38	38	29,2	12,9	8,6	0,0	12,2
large (>10 MW)	3039	3039	3039	3039	3039	0,0	0,0	0,0	0,0	0,0
Hydroelectric	**3063**	**3070**	**3074**	**3077**	**3077**	**0,2**	**0,1**	**0,1**	**0,0**	**0,1**
Other RES	**137**	**199**	**217**	**308**	**308**	**45,7**	**8,6**	**42,4**	**-0,1**	**22,5**
Total	**9985**	**10076**	**10778**	**11203**	**11350**	**0,9**	**7,0**	**3,9**	**1,3**	**3,3**
Non Interconnected Islands										
Thermal Power Plants										
Coal	-	-	-	-		-	-	-	-	
HFO & LFO	1290	1315	1365	1365	1465	1,9	3,8			3,2
Natural Gas	-	-	-	-		-	-	-	-	-
Total Thermal	**1290**	**1315**	**1365**	**1365**	**1465**	**1,9**	**3,8**	**0,0**	**7,3**	**3,2**
Hydroelectric Plants										
small (1-10 MW)	0	0	0	0	0	0,0	0,0	0,0	0,0	0,0
large (>10 MW)	-	-	-	-		-	-	-	-	-
Hydroelectric	**0**	**0**	**0**	**0**	**0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
Other RES	**76**	**79**	**83**	**107**	**140**	**3,3**	**5,3**	**29,0**	**30,7**	**16,4**
Total	**1367**	**1394**	**1448**	**1472**	**1605**	**2,0**	**3,9**	**1,7**	**9,0**	**4,1**
TOTAL	**11351**	**11470**	**12226**	**12675**	**12956**	**1,0**	**6,6**	**3,7**	**2,2**	**3,4**

Source : RAE

Table RES Generation Licenses granted (until 31.5.05)

Technology		2001	2002	2003	2004	2005	Sum
Wind	Total capacity (MW)	414,2	436,8	1810,3	1054,2	372,6	4088,1
	Number of Licenses	70	39	120	95	26	350
Biomass	Total capacity (MW)	16,8	10,6	0,6	26,7	9,7	64,3
	Number of Licenses	3	3	3	6	1	16
Geothermal	Total capacity (MW)			8,0			8,0
	Number of Licenses			1			1
Small Hydro	Total capacity (MW)	79,2	45,1	124,7	129,7	24,8	403,6
	Number of Licenses	49	20	73	51	11	204
Solar	Total capacity (MW)	0,8	0,5	0,5	0,1		1,9
	Number of Licenses	6	3	2	1		12
Total Capacity in MW		511,0	493,1	1944,1	1210,7	407,0	**4565,9**
Total number of generation licenses		128	65	199	153	38	**583**

However the needs for generation capacity remain high, since according to the forecasts, 400 MW of new generating capacity will be needed per year. The main challenge will be to develop this capacity under the new market arrangements which exist in Greece since May 2005.

The Law 3175/2003 enables the HTSO, following a call for tender, to contract for the provision of ancillary services. Also the same law provides for the HTSO to contract for generation capacity in order to ensure that the availability of sufficient capacity and adequate reserve capacity margins is secured on a long term basis. The total capacity volume up to which the System Operator is each time allowed to conclude such generation capacity contracts is specified following a specific study with regards to the electrical capacity sufficiency and the adequate reserve capacity margins. This report is periodically carried out by the System Operator in the context of the approved long term energy planning and is validated by the Minister of Development following an opinion issued by RAE. For the first application the maximum volume of generation capacity contracts has been set at 900 MW with a supplementary option of another 400 MW; PPC is eligible to bid only for capacity contracts up to 200 MW of these supplementary 400 MW. The same Law also provides for PPC the possibility to renew and substitute a total capacity of 1600 MW from its old plants.

According to the Law, the general criteria applied for the granting of generation licenses are:

a) The safe and sound operation of the Electricity System, including the network, the generation installations and all relevant equipment.

b) The protection of the consumers and the environment

c) The efficient production and use of electricity

d) The primary source of energy and the technology used

e) The technical, economical and financial capacities of the investor

f) The maturity of the project

g) The provision of public service obligations

h) The long-term energy planning of the country

j) Information received from other public authorities regarding issues of national security

For granting a license to a hydro power station, the integrated development planning and energy management of the affected hydrological potential is also taken into consideration.

Table 5.1 Security of supply evolution

	Peak electricity demand (GW) (1)	Available capacity (GW) (1)	Forthcoming new plant (GW)		Plant completed minus plant closed in the year (GW)				
			authorised	under construction	coal and oil	gas	RES	CHP	nuclear
2001	8.598	10.076	Gas fired non-PPC producers 4.153 MW, RES 4.566 MW						
2002	8.924	10.778							
2003	9.042	11.203							
2004	9.370	11.350							
2005	10.100			0,4 (2)					
2006 est	10.550			0,4 (3)					
2007 est	11.050								
2008 est	11.550								

(1) Interconnected system, including small hydro, RES and CHP.
(2) Hellenic Petroleum 400 MW CCGT power plant
(3) PPC SA 400 MW CCGT power plant

5.1.3 Generation Capacity Assurance Mechanism

In October 2003 RAE estimated that the reserve capacity margin for the years 2003-2006 is considerably lower than 15%. The third EU benchmarking report (based on the UCTE Adequacy Forecast 2004-2010 report) indicates that the amount of reserve generation capacity in July 2004 is -0.3 GW.

In the 2005 Grid Code which will come into force gradually from October 2005 to January 2008, a generating capacity assurance mechanism is included. This mechanism is designed to reduce business risk of the investors of the new power plants, by providing guarantees for covering part of their capital cost. On the other hand, by the same mechanism suppliers can ensure restricted volatility of the wholesale prices.

Every generator issues capacity certificates, which correspond to the actual generating power availability of his units. Each supplier or self-supplying customer, is obliged to hold capacity certificates covering his total load (plus some reserve margin), and, for this purpose, he buys capacity certificates under terms negotiated with the corresponding generator.

In the 2005 Grid Code, the generating capacity assurance mechanism and the daily market mechanism are economically linked, in order to achieve both long-term capacity assurance and total cost efficiency.

5.1.4 Planning of network development

HTSO establishes and publishes, at least every two (2) years, a regular 5 year estimate of the generating and transmission capacity that is likely to be connected to the Transmission System, the interconnection needs to other Systems or Networks, the transmission capacity needs and the electricity demand. The manner in which these estimates shall be published, as well as any other necessary detail to the implementation of the plan, are defined by decision of the Minister of Development after opinion by RAE.

The set of criteria applied by HTSO in planning the development of the transmission system aim to achieving, at all times, the transmission of electricity in a secure, reliable and most economic manner, while taking into account the principle of providing unrestricted access to any third-party wishing to connect to the transmission system.

As far as congestion is concerned, the steady state system security is evaluated for scenarios with forecast demand over a 5 year period, in order to assess the ability of the system to serve the expected load, to identify potential weak points and determine the necessary system development to secure reliable and economic operation.

5.1.5 Interconnection projects

The major interconnection projects underway are the following:

Interconnection with Turkey: Consists of a 100 km EHV line (400 kV, nominal capacity 2000 MVA), with 40 km in the territory of Greece. Power flow analysis and route survey have been completed. Environmental licensing is currently under way. Project completion is expected in the 2nd semester of 2006. Other enhancements of the Greek transmission system in the area, relevant to the particular project, are a new EHV substation and a 160 km EHV line to connect the new substation with the EHV transmission system of northern Greece. Regardless of the interconnection with Turkey, this infrastructure is also necessary in order to reliably absorb power generated by wind farms and a licensed gas fired plant in north-east Greece. All new infrastructure in the Greek territory will comprise assets of the transmission system and its cost will be recovered though transmission use of system charges.

Upgrade of interconnection with FYROM: Upgrade of the existing 150 kV line between Greece and FYROM, to 400 kV. Completion time cannot be determined due to financing issues on the part of the FYROM HTSO.

New interconnection with Bulgaria: The construction of a new line between Greece and Bulgaria has been studied but no agreement has been signed so far between the two countries for the construction of the project. The Bulgarian HTSO has requested to investigate the alternative construction of an alternative tie-line to connect to the new EHV substation that will be built close the Greek-Turkish border.

All new infrastructure in the Greek territory will form part of the assets of the transmission system and its cost will be recovered though transmission use of system charges.

5.2 Gas [Article 5]

As has already been mentioned, Greece is an emerging market for gas. This is reflected in the existing and forecasted level of gas consumption, as presented in the table below:

Table 5.2 Security of supply evolution (gas)

	Total gas demand (bcm)	Production capacity (bcm)	Pipeline import capacity (bcm)	LNG import capacity (bcm)	Forthcoming new capacity (bcm)	
					authorised	under construction
2004	2.511	0	3.4(1)	2.6(3)		
2005	2.838	0	3.4(1)	2.6(3)		
2006 est	3.503	0	3.4(1)	2.6(3)		
2008 est	4.981	0	9.4(2)	5.0(4)		
2010 est	5.688	0	N/A	N/A		

(1) Estimation based on the nominal import capacity of the Border Metering Station at the Greek-Bulgarian border
(2) Estimation based on the forecasted nominal import capacity of the Border Metering Station at the Greek-Turkish border and the assumption that the new interconnection with Turkey is going to be operational in 2007.

(3) Estimation based on the nominal send-out rate of the LNG Terminal in Revythoussa, without taking into account the import capacity of the terminal and the storage capacity of the LNG tanks.

(4) Estimation based on the expansion of the send-out rate of the LNG Terminal, already under implementation

The corresponding figures for the gas consumption in the territories of the three existing EPAs are presented in the table below:

Year	**Gas consumption in bcm**
2004	0,218
2005	0,392
2006	0,532
2007	0,659
2008	0,777

Source: RAE

Currently, there are no specific provisions for the security of gas supply in the Greek legislation. The issue is covered by the general provisions of the Greek Law 2773/99 regarding overall security of energy supply, in the context of the long-term energy planning of the country.

The two major gas infrastructure projects currently underway are: (1) the Interconnector Turkey-Greece and (2) the increase of the regasifying capacity of the Revithoussa LNG terminal from the current 270 cubic meters of LNG per hour to 1000 cubic meters of LNG per hour. In addition, a feasibility study for an interconnector between Greece and Italy was launched in March 2004 and it is expected to be finalized within 2005. A Protocol of Intent between Italy and Greece has been signed in June 2005 for the development of the project, following a corresponding Letter of Understanding signed between DEPA and Edison in April 2005.

6 Public Service Issues [Article 3(9) electricity and 3(6) gas]

6.1 Public Service Obligations

A. Electricity

According to the provisions of the Law 2773/1999, the Minister of Development can impose public service obligations to market participants (authorised generators, suppliers, network operators and network owners), in order to ensure security and continuity of supply, quality of service, consumer protection, protection of the environment. Market participants are required to abide by such ministerial decisions for the provision of public services, as per the terms and conditions of their license.

No obligation for primary energy source labelling exists so far. Consumers located in non-interconnected islands enjoy electricity supply service at the same rates that are valid for PPC customers in the interconnected system.

In addition, a discount tariff is granted to families with more than three children, as a measure of social support. There are also special discount tariff regimes for consumers in the agricultural sector and for the employees of PPC.

B. Gas

There are no explicit provisions regarding PSO for Gas.

6.2 Supplier of Last Resort

A. Electricity

PPC is obliged to supply eligible customers who will not be supplied by other suppliers. In such cases, PPC has the right to charge fees to recover potential additional cost caused by the fact that the customer was previously not supplied by PPC. These fees are set by decision of the Minister of Development following an opinion by RAE and are calculated by PPC for each customer category.

B. Gas

There is no supplier of last resort for Gas.

6.3 Measures to guarantee eligible customers' ability to switch to a new supplier and the provision of information regarding supply contracts

A. Electricity

According to the current Supply Code, each supplier following the granting of a supply license, must publish the supply terms that he applies to eligible customers (structure of tariffs, charges imposed and the principles applied for the estimation of these charges and the Supply Contract terms) in at least two (2) national daily newspapers and in one (1) local newspaper. Additionally the licensee should publish any modifications on the terms and conditions (tariffs, method or pricing, terms of the contract etc). The publication takes place one month prior the date of granting of the supply license and one month prior to the date of any modification of the supply license.

Offers of service to customers are made in written from, are binding on the part of the Supplier and stipulate all charges imposed and pricing, as well as the general and any special terms of the supply contract.

Supplier switching is allowed following unilateral termination by the part of the customer of the previous supply contract and cannot be impeded by reason of unsettled debt towards the previous supplier. Suppliers may exercise their lawful rights for claims against clients related to unsettled debt. Dispute settlement regarding outstanding debt are referred, from either parties, to arbitration by RAE. Suppliers are obliged to provide customers with all information needed to complete the switching process (i.e. meter readings), as well as any information needed by the System or Network Operators, within 14 days of customer's notice.

B. Gas

There are no corresponding provisions for gas.

6.4 Supply contract terms

A. Electricity

According to the provisions of the Supply Code and with reference to consumer protection, the following general terms and conditions apply to supply contracts with eligible customers:

- Customer right to request meter accuracy check, with the relevant costs borne by the Supplier in case of failure to meet accuracy standards.

- Contract prepayments are limited to an amount corresponding to payment for services rendered over a period of 3 months.

- Unilateral contract termination is foreseen with a minimum notice of 3 months (termination by the part of the customer) and 12 months (termination by the part of the supplier).

- Unilateral termination of the contract by the supplier with less than 3 months notice is possible a) in case of unsettled debt (45 days following payment date expiration) and b) in case of breach of contract terms by the customer.

The standard terms and conditions of the Supply code that apply to the supply contracts have not yet been established in PPC's supply contracts. The same holds for the minimum standards of the commercial quality. So far PPC SA has not unbundled its contracts in a Connection Contract and a Supply Contract.

According to the current PPC supply contracts, which are not yet harmonised with the Supply Code requirements, the customer can withdraw from the contract no later than 30 days and not earlier than 10 days from each cycling period (ie the cycling period is renewed every 12 months, from the contract date, for another year). In addition if the customer withdraws earlier than 5 years, he should pay the rest fixed fees. However those terms have not been applied in practice, since the Greek legislation protects the consumer from the terms of Adhesion contracts.

B. Gas

There are no harmonized conditions for the supply of customers connected to the Transmission System. Currently, supply to the NGTS customers is performed under contracts negotiated between DEPA and such customers.

For the customers of the Distribution Network, the standard terms and conditions of the supply contract, imposed by the Distribution licence, include the obligations, rights of the supplier to the customer (with regards to the supply according to the “General Terms and conditions”, the invoices (frequency, structure, pricing principles), the procedure on meter reading disputes, duration/renewal of contract) and the obligations, rights of the customer to the supplier (responsibility for the protection of the network on his premises and the meter, payment of the bills, disputes on charges and meter readings, connection fees). The customer can withdraw from the contract at any time without charge. There is one year duration of the contract with automatic renewal.

6.5 Regulation of end user prices

A. Electricity :

In so far that PPC retains at least a 70% market share of the supply to eligible customers, all its supply tariffs to eligible customers are regulated and fixed by the Minister of Development after opinion by RAE. The approval of the supply tariffs is based on total cost-plus calculations. PPC provides evidence of annual growth of cost elements, as for example inflation rates and changes in energy fuel prices and then the decision takes the form of allowed percentage change of all tariff levels and parameters. The tariffs are defined per category of customer (e.g industrial, commercial, domestic, etc.) and are not related to eligibility or not of the customer.

B. Gas :

Until today, the tariffs for the supply of customers not belonging to EPAs are set by DEPA SA without any involvement of the Regulator, or the government. The end user tariffs of the EPAs are set by the distribution companies (EPA) and controlled by RAE for compliance to the terms of their license.

ANNEX I

Methodology for computation of Transmission Network Tariffs

The methodology and procedure for setting transmission network tariffs (according to the 2005 Grid Code) is as follows:

I. Annual System Cost

The HTSO calculates the annual System cost using the following formula:

$$E = E1 + E2 \pm \Pi1 \pm \Pi2$$

where

E is the annual System cost,
E1 the annual barter owed by the HTSO to the Owner of the System (PPC SA), which is calculated below,
E2 is the annual cost of System Works paid by HTSO,
Π1 is the non recovered cost (+) or surplus (-) from generators (including importers) during the current fiscal year and
Π2 is the non recovered cost (+) or surplus (-) from Load (customers and exporters).

The barter owed to the Owner of the System by the HTSO on a yearly basis and which corresponds to variable E1 is calculated as follows:

$$E1 = O + A + (V - D) * \rho$$

Where

O is the annual operation and maintenance expenses and also the indirect expenses, borne by the Owner of the System (PPC SA), as are budgeted using the accounts unbundling rules. These expenses include also the maintenance expenses of users connection assets.

A is the annual depreciation of transmission assets, as are budgeted using the accounts unbundling rules;
V is the budgeted average initial value of the initial System assets based on acceptable evaluation methods and the budgeted average value of operating capital of transmission;
D is the budgeted average value of aggregated depreciation for the System assets
ρ is the nominal pre tax rate of return of invested capital in total capital which is approved by RAE, according to regulation policy and international practice and experience.

II. Method for the allocation of the cost of the System to the users

The HTSO allocates the Annual System Cost to all System users (injecting and absorbing energy) and calculates a charge for each user.

The charge corresponding to each user is calculated on an annual basis as the product of the user's chargeable output multiplied by the unit charge corresponding to such user category. The unit charge shall be in Euro/MW. The charge for generation units for using the System does not change due to scheduled shut down of such units due to maintenance or fault.

The annual System cost shall be allocated to all generation units including imports (G), and load including exports (L) as follows:

a) 2 % of the sum of E1 and E2 increased or decreased by Π1 shall be allocated to all G.
b) 13% of the sum of E1 and E2 increased or decreased by Π1 shall be allocated to G connected to system nodes in the Prefectures of Evros, Rodopi, Xanthi, Drama, Kavala, Thessaloniki, Halkidiki, Kilkis, Serres, Pieria, Grevena, Florina, Pella, Imathia, Kastoria, Kozani, Larissa, Trikala, Karditsa, Magnisia, Fthiotida, Thesprotia, Preveza, Ioannina, Arta, Kefallinia, Lefkada, Zakinthos and Corfu.
c) 85% of the sum of E1 and E2 increased or decreased by Π2 shall be allocated to L.

The unit charge for each of the cases a and b of the previous paragraph is calculated by dividing the annual transmission cost allocated to G for each case by the sum of chargeable outputs for G included in each case.

The unit charge allocated to Load is uniform throughout the territory and is calculated by dividing the annual transmission cost allocated to Load by the sum of chargeable outputs for customers.

III. Approval of Annual System cost and unit charges

By September 30th each year, the HTSO drafts the budget for the following year, which shall include:

a) the annual cost of the System
b) the budgeted income of HTSO from the use of the system charges for the next fiscal year, based on the use of the system unit charges and the expected total demand of electricity.
c) any differences between the sum collected by the HTSO from G and L for use of the System and the real transmission cost during the current fiscal year, which shall be credited or debited to the transmission cost budget for the following year.

The operating expenses of the HTSO are not included.

The budget of the annual cost of the System, including the annual barter owed to the Owner of the System, the annual cost of the System and the calculation of the use of the system charges are approved by RAE.

Following approval of the budget, the HTSO shall calculate if necessary, until 31st of October each year, the unit charge corresponding to customers and generation units for each charge zone for the following fiscal year.

The unit charges are approved by the Minister of Development following RAE's opinion.

ANNEX II

Balancing Arrangements under the 2005 Grid Code

A System of Power Exchanges is introduced, which consists of the Day Ahead Scheduling (DAS) which includes the hourly transactions of the total energy injected to the system and consumed daily, the Dispatch Procedure, the Imbalances Settlement which includes the settlement of energy deviations and the settlement of the services required for balancing of the system and the Capacity Assurance Mechanism, through which part of the fixed costs of generating capacity are covered.

The supervision of the Power Exchange System is assigned to the Regulatory Authority for Energy (RAE). RAE is in charge of supervising the actions, with reference to rights and obligations, of the System Operator (the HTSO) and the Participants, as far as the System and the Market are concerned.

Participants in Power Exchange System are the Producers who are production license-holders enlisted in the Unit Register, the Suppliers who are supply license-holders, representing their customers' load, importers and exporters of electricity and Self-Supplying Customers, who are Eligible Customers choosing to absorb electricity from the Power Exchange System exclusively for their own use.

Day Ahead Schedule (DAS)

DAS constitutes the first stage of the electricity transactions process, aiming at the daily minimization of the total cost that is required for serving the load and meeting ancillary services requirements (primary & secondary reserves), taking Transmission System Constraints into consideration, in order to arrive at a solution that closely approximates the Real Time Unit Dispatch. In order to achieve this target, the System Operator prepares on a daily basis the Day Ahead Schedule, where the total load is contrasted to the economic injection offers for energy. All procedures and transactions concerning the DAS are concluded within the day that precedes that Dispatch Day, referred to as "Day Ahead", that is the day of the physical delivery of energy. Charges and payments for the energy scheduled to be absorbed or injected in accordance with the DAS Schedule, are calculated and settled within the day ahead. Charges and payments for reserves and ancillary services are calculated and settled through the Imbalances Mechanism.

Real Time Dispatch

The objective of the Dispatch Procedure is scheduling of the operation of Dispatchable Units, Contracted Units and Cold Reserve Units, as well as the issuing of Dispatch Instructions in real time from the System Operator, in order to ensure that the total absorption of energy from the System, according to the forecasts and the measurements of the System Operator, is carried out according to terms of good faith, reliable operation of the System, capability of facing emergency events and minimization of the total cost. The Dispatch Instructions are issued according to the Dispatch Schedule.

Imbalance Settlement

The Imbalances Settlement includes clearing of transactions with respect to energy deviations (due to Imbalances, forced and unforced production changes), Ancillary Services and Uplift Accounts. For this purpose, during the Imbalances Settlement and for each Dispatch Day, the System Operator estimates:

- The quantity of energy corresponding to Imbalances, forced and unforced production changes, which are thereby attributed to each Participant for each Dispatch Period.
- The debit or credit corresponding to the Imbalances of each Participant for a Dispatch Day, as well as the additional debit or credit corresponding to the forced and unforced production changes of each Participant for the same Dispatch Day.
- The payment of each Participant for the provision of Ancillary Services, the readiness to provide Supplementary System Energy and Cold Reserve Services, through the Uplift Accounts.
- The debits and credits of the Uplift Accounts.

In order to achieve higher availability of the generating units and to properly allocate the imbalance costs to those who cause them in the context of Imbalances Settlement, the following rules are used:

- Imbalance is defined, separately for each Injection Offer and Load Declaration, and separately for each Dispatch Period. It is the difference between the scheduled energy in the DAS and the measured energy.
- Unforced production change of a Unit for a Dispatch Period is defined as the difference between the energy quantity as given by the Dispatch Instructions for injection into the System and the measured energy.
- Forced production change of a Unit for a Dispatch Period is defined as the difference between the scheduled energy in the DAS and the energy quantity as given by the Dispatch Instructions for injection into the System. The forced production changes of a Unit are due to Dispatch Instructions that were issued by the System Operator, principally for the adjustment of production of the Unit and the provision of Ancillary Services and Supplementary Energy.

In the above framework, calculation of energy deviations is performed separately for every Participant, with separate calculations for each Load Declaration and Meter, each Production Unit and each Interconnection. In every case a specific tolerance margin is taken into consideration when calculating energy deviations.

The Imbalances Settlement procedure is defined as an administrative procedure which does not correspond to an Imbalances Market. In this context:

- The Imbalances Settlement clears at a uniform price, the Imbalances Marginal Price, which is calculated in such a way so that it will encourage the availability of the units.
- The System Operator (HTSO), in its capacity as Market Operator too, should aim that the cost of the Imbalances is allocated to the partiers that cause them.
- The System Operator (HTSO) should aim towards the minimization of the total Imbalances Settlement cost.

The Imbalances Marginal Price is calculated hourly in correspondence to the DAS Solution Mechanism, considering the actual availability of the Units and actual load that was absorbed. Regarding forced and unforced production changes, each Unit can be debited or credited an amount additional to the Imbalances Settlement debit or credit, depending on the circumstances.

The Imbalance Settlement procedure is completed within 4 days following the Dispatch Day.