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Annual Report 2006
To the European Commission

Regulatory Authority for Energy (RAE)

Athens - July 2006

1 Foreword

The last 12 months have brought a significant acceleration to the liberalization of Electricity and Natural Gas Markets, and the effective promotion of Renewable Energy investments. Following a meaningful and fruitful public consultation process that we believe established a new standard for Greece, a new Grid and Power Exchange code was enacted (May of 2005) and enhanced (June of 2006), and three new Laws on Electricity, Natural Gas and Renewable Energy Investment were voted by Parliament (December of 2005 and June of 2006). The foundation for the still pending completion of Natural Gas transportation tariffs and licensing was laid with ministerial decrees. Market monitoring and regulation implementation activities intensified, the unbundling of transmission and distribution networks was advanced, and competition enhancing domestic energy whole sale market and Cross Border Trade rules were clarified and initial achievements were observed. A summary of developments and next year's planned focus of activities is provided below.

1. Electricity Sector.

1.1 Unbundling of Electricity Networks. Dominant Company (PPC) accounting unbundling activity registered significant progress and 2002-2003 accounts were approved by RAE. Approval of the final methodology is still pending with a reasonable expectation of completion by the end of 2006. The new electricity law is promoting legal unbundling of the transmission system operator (TSO) who has been entrusted with the management of the mandatory wholesale market, and the distribution network operator (DNO) is planned to become independent of PPC by mid 2007. Ownership and the responsibility for maintenance and expansion of transmission and distribution network assets remain with PPC under contract with the independent joint TSO-DNO who proposes a rolling five year plan. The EU commission has sent a letter to the Greek government requesting clarifications on what it considers to be inadequate legal unbundling progress. The new Electricity law requires PPC to propose to RAE an effective functional unbundling plan which will enhance and supplement the legislated operational unbundling of electricity networks. RAE has yet to receive PPC's proposal which was due by June 2006. Although only minor problems have been observed in the connection of Independent Generators, significant progress has yet to take place in order to allow eligible customers to exercise their right to seek Independent Suppliers.

1.2 WholeSale Electricity Market and the Introduction of Independent Generators. Generators and Suppliers are obliged to realize all transactions through a mandatory day ahead energy market in which participation is mandatory and bilateral contracts are not allowed. Two independent generators (550MW or 5% of installed capacity) and independent importers (200MW) provide limited competition to PPC. Nevertheless, they are providing a benchmark of higher productivity. Their market participation and vocal identification of competitive market failures is promoting the debate for needed regulatory intervention to revise market rules so as to enhance competitive conditions and render new independent generator entry economically viable. RAE's market monitoring and code clarification has resulted in healthier day ahead market clearing prices, and a Power Code legislated capacity market that clears a long term (annual) capacity obligation of suppliers against capacity rights of generators is supplementing the day ahead income of generators. The TSO is currently in the process a risk mitigation tender that will result in the introduction of up to 1200MW of Independent Power Producer capacity by 2010. Finally, the TSO is already auctioning limited long and short term capacity rights for the import and export of electricity. A successful market based auction mechanism has resulted in congestion rents of 40.000 Euro per MW per year, and is promising to enhance cross border trade and promote the integration of the national energy market with that of the EU and South Eastern Europe.

2. Natural Gas Sector.

2.1 Unbundling. Despite the lack of maturity of the Greek Natural Gas sector, the new Gas Law has not only accelerated the eligibility of customers, but has also resulted in the legislation of the legal unbundling of the high pressure NG network through the mandated creation of a subsidiary transportation corporation that owns, maintains and manages the high pressure pipelines. Transmission tariffs have been proposed by RAE and approved by the minister, and a prospective independent supplier has been licensed and is actively seeking customers.

2.2 New Sources of Natural Gas and Domestic Suppliers. The imminent connection with the Turkish Natural Gas network (Spring of 2007) will allow a third source of supply that will augment the existing pipeline gas source at the Greek Bulgarian boarder and the LNG terminal in southern Greece.

2.3 Urban Distribution. The construction of low pressure networks in three urban centers is progressing and three new licenses are planned.

3. Renewable Energy Investment.

Wind parks and small hydro run of the river units are currently supplying close to 4% of the energy consumed in Greece, and installed capacity has reached 7%. Interest in further investment is accelerating significantly, and it is expected that by 2010, installed capacity will exceed 25%. The new Law passed recently is streamlining the licensing process, makes cogeneration and photovoltaic generation economically viable. Hybrid renewable energy investments are also promoted in order to supplement wind parks with pumped hydro projects that will be critical in making the implementation of the already proposed renewable generation investments viable without adverse effects on the efficiency of the conventional generation system and overall system stability.

4. *Planned Activities for 2007.*

The focus of RAE's activity during the next year will center on (i) promoting the unbundling effort in the electricity sector so as to allow the entry of independent generators and suppliers, (ii) working to remove cross-subsidies and distortions in retail rates charged by PPC, and quantify and allocate Public Service Obligations (PSO), (iii) Improving Electricity whole sale market rules to achieve economically efficient price signal through the day ahead market clearing prices, (iv) accelerating the transition period that will allow the full implementation of the Power Exchange code and the full operation of the day ahead market, (v) streamlining a reserves market that will supplement the energy market, (vi) studying the introduction of a balancing market that is closer to a real time market and will allow closer interaction and integration of the Greek National Market with EU and South Eastern Europe energy markets, (vii) promoting the interconnection of Greek Islands to decrease PSO costs in order to improve reliability and reduce oil consumption and emissions, and (viii) planning for the ability of the electricity system to absorb and realize the renewable energy generation potential.

Michael Caramanis

Chairman of RAE

July 2006

2 Summary \ Major Developments in the last year

2.1 Organizational structure and responsibilities of the regulatory agency

RAE is an independent administrative authority, which enjoys, by the provisions of the law establishing it, financial and administrative independence. RAE was established on the basis of the provisions of Law 2773/1999, which aimed to the harmonisation of the Hellenic legal order to the provisions of Directive 96/92/EC for the liberalization of the electricity market.

Pursuant to the provisions of Law 3377/2005 amending Law 2773/1999, RAE's board is composed of 7 members, so as to enhance effectiveness. The President and the two Vice-Presidents are appointed by a Decision of the Cabinet of Ministers acting on a proposal of the Minister of Development and following the opinion of the competent Parliamentary Committee. The other members are appointed by a decision of the Minister of Development.

The criteria for the selection of the members of the authority are scientific proficiency, professional capability and specialised experience in issues pertaining to the responsibilities of RAE. 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 are not obliged to comply with orders or directions issued by public or other institutions and organisations. In order to ensure such independence, RAE members may not be recalled during the term of their office and their revocation or suspension is permitted only in strictly 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 Law 2837/2000, through which it is anticipated that the Authority possesses its own resources, i.e. revenue fees for granting or amendment of licenses in the electricity sector, annual fees for the use of such licenses, annual fees from the companies of the natural gas and petroleum markets, 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 subject to ex-post auditing by Independent Auditors and the Court of Auditors.

For the accomplishment of its duties and responsibilities RAE is assisted by an administrative structure, namely the "Secretariat". The internal organization of the Secretariat is based on the aforementioned Presidential Decree No. 139/2001. According to that Decree, the Secretariat 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' s Administrative Support, Secretariat of RAE's Chairman and Members, and Press and Public Relations).

Currently the Secretariat of RAE consists of 38 experts (namely 13 engineers, 11 lawyers, 7 economists and 7 others) and 18 administrative staff.

In alignment with the provisions of the Directives 2003/54/EC and 2003/55/EC, particularly with respect to access tariffs to electricity and gas networks, the terms and conditions for the provision of balancing services in natural gas, as well as issues related to security of electricity and natural gas supply, RAE competencies and duties in the electricity and natural gas markets have been essentially strengthened through the provisions of new, recently adopted, laws (Law 3426/2005, 3428/2005 and 3468/2006).

Regarding the Electricity Sector, RAE provides advice to the Minister of Development, under the form of a simple opinion, for the adoption of the Authorisations Regulation and the Supply Code. On the other hand, RAE enjoys the right of a consenting opinion as far as the Electricity Grid Operation Code, the Power Exchanges Code and the Distribution Network Operation Code are concerned. Also, the tariffs for third party access to electricity networks are approved by the Minister of Development, following a consenting opinion of RAE, while RAE approves also the methodologies for the access tariffs to electricity transmission and distribution networks. Besides, RAE approves the decisions of the HTSO regarding the implementation details of the Grid Operation and Power Exchanges Code, the decisions of the Distribution System Operator regarding the implementation details of the Distribution Network Operation Code and the generation adequacy studies conducted by HTSO to establish whether HTSO should issue tenders for new generation capacity.

Moreover, the authority participates to the administrative procedure for granting, amending and revoking of licenses in the electricity sector, by providing a simple opinion. During the last four years RAE has issued almost 957 positive opinions for generation and supply licenses, 579 negative opinions (only for RES) and 87 opinions for revocation of licenses (only for RES).

Finally RAE's simple opinion is a prerequisite for the approval of electricity retail tariffs and 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.

Already prior to the natural gas market liberalization, RAE was entrusted with the duty to grant simple opinion for issuing technical regulations for internal and external natural gas installations and for the tariffs to be applied for TPA of electricity generators to the gas grid (Law 3175/2003). RAE is also responsible for supervising and monitoring 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).

According to the provisions of the new Gas Law, it is provided that the Authority gives a consenting opinion for the issue of the Operation Codes of the National Natural Gas System, as well as of Independent Natural Gas Systems, while it approves the appropriate methodologies and details for the implementation of such Operation Codes. Following a proposal by the responsible System Operator, RAE prepares the tariffs Regulation, which lays down the methodology used to calculate tariffs for the relevant activities and is approved by the Minister of Development. Finally, RAE regulates the terms and conditions for the provision of balancing services.

Regarding the Oil Sector, Law 3054/2002 granted to RAE relevant responsibilities and competences. Namely, RAE grant its opinion on the issuing of the Authorisations Regulation and the Oil Stockholding Regulation, collects and publishes statistical data regarding the petroleum products market, participates in the Emergency Response Committee for Oil Supply Crises. Besides, in exceptional cases, RAE grants opinion for the imposition of price caps in petroleum product prices.

As far as energy markets in general are concerned, the main duties and responsibilities assigned to RAE relate 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.). RAE monitors in particular the management and allocation of interconnection capacity, the time taken by TSO and DSO for connections of users and repairs to the network, the publication of all appropriate information by the TSO and the DSO, the terms and tariffs for third party access, the unbundling of accounts, the level of transparency and competition in the energy market and the security of supply.

- Collection and processing of information from companies in the energy sector, while respecting the principles of confidentiality.

- Reporting every two years on security of supply both for electricity and natural gas. The said report is published and submitted both to the Minister of Development and the Commission.

- Participation in the pre-parliamentary legislative process through recommendation to the Minister of Development of the appropriate measures related to compliance with competition rules and to the overall protection of the consumers in the energy market.

- Monitoring of the exercise of the activities undertaken by licensees and access to information.

- Imposition of financial sanctions, namely fines to the violators of the primary and secondary energy legislation.

- Arbitral resolution of disputes between parties on electricity and natural gas legislation.

- Dispute settlement, with respect to complaints against electricity transmission or distribution system operators and the owner of the electricity network, as well as against Natural Gas System and Distribution Operators, on infringements of primary and secondary electricity and natural gas legislation.

- Cooperation with other countries' Regulatory Authorities, international Organisations and the European Commission.

- Reporting on an annual basis to the Commission on market dominance, predatory and anticompetitive behaviour, on the basis of the appropriate information submitted by the Competition Authority.

While exercising its duties, RAE is obliged to comply with the legality principle and its decisions, when not solely advisory, are subject to judicial review by the competent Administrative Courts. Finally RAE publishes and submits to the Parliament, via the Minister of Development, an annual report giving detailed information about its functioning and acts.

Finally, on February 2006 Law 3438/2006 was enacted, setting up a Council for Long-Term Energy Policy Planning, under the form of a consultative to the Minister of Development body, regarding the long-term planning of the country's energy policy. The above mentioned law, which is the statutory act of the Council, is explicitly providing that there is no overlapping of its jurisdictions with RAE jurisdictions and responsibilities.

2.2 Main developments in the gas and electricity markets

2.2.1 Main developments in the electricity market

New Electricity Law

The regulatory framework regarding the Electricity market in Greece has been established by Law 2773/1999, which was lately modified by law 3426/2005 with the view to transpose the provisions of the Directive 2003/54/EC, to accelerate the liberalization process and to enhance security of supply.

More specifically, the provisions of the new Law 3426/2005 may be summarized in the following:

- Further opening up of the market, with gradual deployment of eligibility rights to all customers. At first, since the entrance into force of the said law, all customers, except for domestic ones, are considered as eligible costumers and later on, by July the 1st, 2007, even domestic costumers become eligible, to the exception, though, on the basis of specific provisions regarding the Non-Interconnected Islands.

- Granting of Generation Authorization for thermal units in the Non-Interconnected Islands, under similar conditions and procedure as for the Interconnected System. A tendering procedure may be carried only in order to ensure security of supply in the Non-Interconnected Islands. On the other hand, regarding the Non-Interconnected Islands which constitute micro isolated systems and under the condition that a derogation has been granted according to the provisions of the new Electricity Directive, a generation authorization is granted exclusively to PPC, so as to ensure, at all times, the unobstructed supply of electricity.

- Further enhancement of the HTSO duties and responsibilities, regarding the maintenance and development of the Transmission System, as well as, reinforcement of TSO's independence vis-à-vis PPC's powers and competencies.

- Unbundling of the distribution system operation and assignment of this duty to the Transmission System Operator, becoming a Transmission and Distribution System Operator (T.D.S.O.), by July the 1st, 2007, with competences regarding the operation and the maintenance of a secure, reliable and efficient electricity distribution system. Until that time, there is a transitional period during which the distribution system operation is handled by PPC S.A., after dispatching of the competent internal Direction, which shall be independent in terms of organisation and decision making from other activities not relating to distribution.

- Further enforcement of the unbundling of accounts obligation of all electricity undertakings, according to which unbundled accounts should be kept and published for all different activities and controlling competences are provided for, in order to ensure the compliance of said undertakings.

- Clarification of the public service obligations of electricity undertakings, according to Directive 2003/54/EC provisions.

- Provision for the setting of the criteria for granting of authorisations to construct, own and operate direct supply lines to electricity producers, electricity supply undertakings and eligible costumers in the Authorisation Regulation.

- Enhancement of RAE's competencies and responsibilities, as already thoroughly described above (Chapter 2.1).

- Provision for the issuance of a Non-interconnected Islands' Operation Code, which shall include rules regarding the operation of the electricity generation units situated on such islands, as well as rules on dispatching and grid functioning, with a view to ensure reliability and economic performance. The operation of the electric system of the Non-interconnected Islands is held by a specific organisational unit of PPC S.A., which shall be independent in terms of organisation and decision making from other activities non-related to the Non-Interconnected Islands.

- Facilitation of the criteria for the granting of supply licenses. Namely, a supply license is granted to companies having the form of a "S.A." or of a "Ltd" with shares capital of at least 60,000 Euros, disposing an adequate organisational and administrative structure enabling reliable and good operation of the supply activity and possessing the necessary financial standing and solvency.

- Provision of a specific administrative procedure that will lead to effective functional unbundling of PPC's activities in the electricity sector.

New Grid and Power Exchange Code

Furthermore, on the basis of the provisions of Law 3175/2003, 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: A complete set of rules permitting the organization of a wholesale electricity market, consisting of a mandatory pool and a generation capacity assurance mechanism 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.

The daily wholesale energy market consists of four elements: day-ahead scheduling and market clearing; day-ahead/intra-day dispatch scheduling; real-time dispatch; and ex-post imbalance settlement. 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.

As mentioned before, the Code introduces also a generation 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 the appropriate financial instruments to manage efficiently the energy price volatility risk and facilitate the entry of independent power producers. In the framework of the capacity assurance mechanism, generators issue annual capacity assurance certificates (CACs) in one MW steps reflecting their available generating capacity and Suppliers have the obligation to purchase these CACs to cover their supply obligations plus a security margin. A summary of the 2005 Grid Code is given in Annex II.

The period from October 1st, 2005, until January 1st, 2008 when the new Code is to be fully applied, is transitional and the provisions of the new Code are to be progressively activated during this period. The deadlines for the stepwise enforcement of the provisions of the new Code during the transitional period are defined in this Code. During the transitional period, the participants of the electricity markets will gain relevant experience, while the Market Operator will acquire the necessary resources in terms of software and hardware, manpower and experience. At the same time RAE will have the opportunity to solve remaining problems relevant mainly to the former incumbent and decide on the necessary details or even amendments, for the effective application of the new Grid and Power Exchange Code. RAE has, actually, already issued its opinion for the first amendment of the new Code, following public consultation procedure and the Minister of Development adopted the relevant decision.

Security of supply and tendering procedures

Under the provisions of Law 3175/2003 and the new Code, in May 2006, after a long but very productive public consultation, the HTSO launched the first of three tenders for the installation of new generation capacity, for approximately 400 MW (the first trance) and up to 1200 MW in total which will be secured against debt capacity payment (corresponding up to 900 MW of the total capacity),. For reasons related to security of supply considerations, the auction is restricted to natural gas fired plants located in the south of Greece. The winning bidder will benefit from an income guarantee from the HTSO, to cover his fixed cost where he fails to obtain at least 70 per cent of those costs from his participation in the day-ahead market. According to the provisions of the Tender the maximum annual guarantee is set to €92,000 per available MW and year and the minimum to €75,000 per MW-Year and it will be given for 12 years. All bidders should submit their offers by the end of November, and the winner should construct and become commercially available within 27 months.

Accounting unbundling

In addition to the above, a major development promoting the development of the electricity market in Greece is the progress towards a satisfactory unbundling of the integrated company's, PPC, accounts for each of the electrical activities. RAE had launched in the past infringement procedures against PPC on the proper unbundling and publication of PPCs accounts for the years 2000, 2001 and 2002, and has imposed a fine on these grounds. Following this lengthy period of dispute, PPC 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.

The dispute between RAE and PPC regarding the aforementioned infringement procedures ended with the publication of the Court Decision in 2005 which ultimately decided on the non compliance of PPC with the legislation relevant to the unbundling of accounts. After a long period of consultation between RAE and PPC and following the decision by the Court, finally PPC re-submitted to RAE the accounts for 2001-2002 and 2003, separating the activities of distribution and supply as well as the activities in the mainland and the non-interconnected islands. RAE has accepted the submitted accounts for 2001-2002 and 2003, in December 2005, according to the provisions of Law 2773/1999, as it stood before the adoption of Law 3426/2005. Nevertheless, RAE stated that PPC should submit the unbundling methodology and its implementation for the Balance Sheet and Income Statement for 2004, 2005 and 2006 according to the provision of the Law 3426/2005. Further work is currently underway, in order to have an updated full set of unbundled accounts of PPC up to 2006.

New IPPs

An important development in the electricity market is the commercial operation of the new power station of T-Power, owned by a subsidiary of the Hellenic Petroleum S.A., i.e. the state controlled petroleum company. The T-Power plant, the first independent power station to operate in Greece (not having a contract with the HTSO for the provision of ancillary services), is a 400 MW gas fired CCGT , located in northern Greece.

2.2.2 Main developments in the gas market

Natural gas has been introduced to the energy mix of Greece in 1996. Due to this fact, Greece has been characterized an emerging gas market and was granted derogation from the implementation of the Directive 98/30/EC until November 2006.

In 2003, in the framework of the ongoing process for speeding up the liberalization of the Greek electricity market and the intertwining between gas and electricity markets, the Greek government took a first step towards liberalization of the gas market with law 3175/2003, despite the derogation. According to the provisions of said law, starting from the 1st of July 2005, natural gas-fuelled co-generators with an annual consumption exceeding 25 Mm3/year as well as all power producers were granted the eligibility right. At the same time, they were granted a right of access to the National Natural Gas System (NNGS) under a regulated TPA regime.

In December 2005, law 3428/2005 (the Gas Law) was adopted by the Greek Parliament, providing a coherent framework for the liberalization of the natural gas market in the light of and in full compliance with Directive 2003/55/EC (the Gas Directive). In summary, the Gas Law provides for (most Gas Law provisions will be presented in detail in the relevant sections of this report further below):

- Establishment of a National Natural Gas System Operator (NNGSO) with full competences regarding the operation, maintenance and expansion of the NNGS as well as the provision of TPA services under non-discriminatory terms. The NNGSO will be legally unbundled from the incumbent Public Gas Corporation S.A. (DEPA S.A.) and will hold ownership of the NGS assets. The Gas Law mandates for the completion of the unbundling by the end of 2006.

- A fully regulated regime for open access of suppliers, eligible customers and shippers to the NGS (including the LNG Terminal at Revythoussa as well as any storage facility that will be integrated to the NGS in the future). The access regime is based on (a) a Network Code regulating the operation, maintenance and expansion of the NGS as well as the provision of TPA services, (b) standard TPA contracts and (c) published regulated tariffs.

- Gradual opening up of the market, with deployment of eligibility rights to all customers by the end of 2009, taking into account the specific provisions (derogations) of the Gas Directive regarding existing gas distribution concessions in Greece. Independent suppliers can compete over the supply of eligible customers after being granted a relevant authorization. The general terms and conditions for the supply activity will be set by a Supply Code, while there is a provision for the adoption of additional customer protection measures, if deemed necessary. With the exception of supply to final consumers, all other commercial transactions regarding the imports, exports, sale and purchase of natural gas are free i.e. do not require any authorization.

- The obligation of all gas undertakings to keep and publish unbundled accounts for all different activities specified in the Gas Directive and assignment to the regulator of the competences to set the unbundling rules and control the compliance of said undertakings.

- An authorization or tendering procedure for the construction and exploitation of new infrastructures (Independent Gas Systems) by third parties. Independent Gas Systems are subject to the same rTPA regime applicable to the NNGS, unless applied for and being granted derogation, pursuant to article 22 of the Gas Directive.

- The regulation of the gas distribution sector, complementing the current legal framework for the operation of existing concessions and setting a new versatile regime for the future development of distribution networks in other parts of the country, in accordance with the provisions of the Gas Directive.

- Transitional measures for the effective opening up of the market even before the enactment of the Network Code and the relevant secondary legislation.

- A regulatory governance system in compliance with the Gas Directive, strengthening and extending regulatory powers to the setting of tariffs, balancing regime and access rules as well as security of supply, dispute resolution and unbundling of accounts.

In March 2006, following the enactment of the Gas Law, tariffs for TPA to the transmission system and the LNG terminal were set by the Ministerial Decision 4955/2006. According to the provisions of the Decision, access to the transmission system and LNG terminal is effected through separate standard contracts and is subject to different charges.

Until the enactment of the Network Code that will include the standard contracts for access to the NGS, the terms and conditions for access to and use of the transmission system and the LNG terminal will be set out in standard contracts that will be approved by the Minister of Development following the consenting opinion of RAE. Drafting of the both contracts is currently underway and is expected to be completed by the end of October 2006.

Following the recent developments described above, the first IPP in the Greek electricity market (see also point 2.2.1 above), has already exercised its eligibility right, launching an international tender for the selection of gas supplier. Apparently, there was at least one new supplier i.e. apart from the incumbent DEPA S.A, interested in providing the necessary gas quantities to the power plant. The tender procedure is still ongoing.

2.2.3 Major issues dealt with by the regulator

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:

- Amendment of the Grid and Power Exchange Code

  As the implementation of the new Code started in October 2005, providing for a transitional period of 2 years, since its full implementation is expected for the 1st January 2008, a number of crucial technical issues have arisen and lead to the amendment of a number of articles of the Code, approved by the Minister of Development after the opinion of RAE. These amendments can be summarized as follows:

  - Technical specifications and installation procedure of metering equipment
  - Methodology for the calculation of the obligation of the Suppliers to cover their supply obligations in the framework of the Capacity Assurance Mechanism.
  - Remuneration of generating capacity for providing ancillary services and during their testing period before the commencement of their commercial operation.

  Moreover, RAE provided clarifications concerning the methodology the System Marginal Price (SMP) is produced within the market clearing procedure with its decision of the 13-1-2006.

- Issue of RAE's opinion on details for the application of the Grid and Power Exchanges Code

  RAE has expressed its opinion on several issues regarding the application of the new Grid and Power Exchanges Code, among which mainly on the following:

  - In the framework of the capacity assurance mechanism, following the opinion of RAE, the price of the capacity assurance certificates (CACs) issued by the generators was set to 35,000 €/MW-year. This price will be applied during the transitory period of the implementation of the 2005 Codes, i.e. until the January 1st, 2008.

- In parallel with the decision on the regulated price of the capacity assurance mechanism, the maximum level of the System Marginal Price has been set to 150 €/MWh.

- Issue of the Handbook for the management of metering and the periodic reconciliation between Suppliers serving customers connected to the distribution network

  On the electricity distribution sector, RAE, exercising its power to decide on details for the application of the Codes for Power Exchange and Distribution Network Operation, approved in early 2006 the Handbook for the management of metering and the periodic reconciliation between Suppliers serving customers connected to the distribution network. A complete set of rules permitting customer switching on the distribution level has been established, consisting mainly of rules on the switching procedure, metering collection, analysis and verification, estimation of hourly consumption for customers with non hourly measurements based on load profiles, calculation of the total energy charged to each Supplier on an hourly basis taking into account network losses, and annual reconciliation between the suppliers based on the actual consumption metering which include a complete year. Although the Distribution Network Operation Code has not been established yet, the Handbook along with the decision of RAE on the distribution network losses factors, provides for medium and low voltage customers switching.

  RAE is currently working intensively on the Distribution Network Operation Code, in order to organise the public consultation and express its final opinion by the end of 2006.

- RAE actively supported the study and enforcement of measures alleviating security of supply problems during the summer of 2005, which where present due to voltage stability reasons (north-south congestion problem, see also par. 3.1.2) and marginal generating capacity adequacy. In this framework, RAE:

  - Participated in the development and enforcement (through its opinion to the Minister of Development) of incentives to customers in order to reduce consumption during peak hours, and

  - Supported technical committees chaired by the Ministry of Development, which studied measures for the improvement of consumption power factor and for the reinforcement of the transmission network.

- Issue of RAE's opinion on the publication of the TPA tariffs to the NNGS

  During the second half of 2005, RAE actively participated to the elaboration of the tariff structure as well as setting the actual tariffs for TPA to the National Natural Gas System. RAE also processed all comments received during the public consultation period and issued its opinion to the Minister of Development in February 2006.

- 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, as the co-chair of the working group of CEER for the South East Europe Energy Regulation (SEEER WG), has been involved in all aspects of the development of the SEE Energy Market and the implementation of the Energy Community Treaty entered into force on 1st of July 2006, 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 respect 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). As a consequence, with respect to the specification and allocation of transmission capacity, northern interconnectors are considered as a single system and their capacity is allocated in an aggregated manner and not individually.

For the year 2005, the total net transfer capacity of the northern interconnectors has been determined by HTSO to 600 MW on both directions.

Regarding the interconnector between Greece and Italy, although the physical transmission capacity is 500 MW on both directions, the total net available capacity for long term allocation of exports was reduced for 2005 by RAE following a proposal by HTSO, due to security of supply reasons.

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) was performed, for 2005, unilaterally by the Greek HTSO, while the allocation of the capacity of the interconnector between Greece and Italy was performed by HTSO for the 50% of the capacity in both directions, the remaining 50% being under the responsibility of the Italian TSO.

Capacity on interconnections is allocated on long-term and on daily (short-term) basis. Long term rights where allocated annually for imports using northern interconnections, and monthly for exports using the Greece – Italy interconnector. Any capacity not allocated on long-term 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 was first issued in 2002, reviewed in 2004, and will be effective by the end of 2006.

According to this decision, 70% of the Net Transmission 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 transmission 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 2005 resulted in the allocation of the entire 420 MW long term capacity on the northern interconnectors to PPC (220 MW by priority rights), to four eligible customers (149 MW in total) and to three suppliers (51 MW in total), following an explicit auction held in December 2004. For 2006, although the same allocation mechanism is applied, the interest of the eligible customers, as expressed in the auction, was reduced, mainly due to their obligations in the capacity assurance mechanism according to the new Grid and Power Exchanges Code.

With refespect to the interconnector between Greece and Italy, according to the 2001 Grid Code, solely licensed generators in Greece had the right to export energy to Italy, or transit energy through Greece (undeclared transit). These provisions where applicable until the end of September 2005. Consequently, the available capacity for exports to Italy during 2005, was allocated on the Greek side until September 2005 to PPC (mainly) and to one small generator (peaker). For October to December 2005, two suppliers allocated small part of the long-term rights (5 MW during peak hours) on the Greek side and exercised exports from Greece.

From June to August 2005, following the relevant decision of 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 (lack of generating capacity). For the rest of the year 2005, following the approval by RAE with the view to accommodate the security of supply problems currently experienced in the Greek system, the HTSO auctioned capacity for exports to Italy on a long term basis, under the following scheme:

- For January 2005 the allocation in force for 2004 was applied.
- For February and March 2005, 300 MW was made available for long term allocation during the 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, 300 MW was made available for long term allocation during the 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.
- For September 2005 to December 2005, 300 MW was made available for long term allocation during the off-peak hours (23:00 – 07:00), and 100 MW of the long-term capacity were made available for exports for the rest of the hours of the day.

HTSO allocated 50% of the above mentioned long-term rights and the Italian TSO the rest 50%.

In addition to the summer months, 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 1st of 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, although, as already mentioned, more of these provisions will be activated starting from January 1st, 2007. 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 generation 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 2005, 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 integrated with the functioning of the daily energy wholesale market. In general, when the HTSO predicts that the unconstrained Day-Ahead schedule, as revealed by the unconstrained wholesale market, violates physical flows rules (mainly due to voltage stability limits, and secondary due to thermal limits) a solution will be determined that is constrained by physical transmission system limitations. In these cases, the market is spitted, two different zonal System Marginal Prices are calculated for generators, and one uniform SMP for suppliers is determined as the weighted average of the zonal generators' SMPs. The relevant provisions of the 2005 Grid Code will come into force by July 1st, 2007. In parallel, the zonal differentiation of transmission use of system charges is 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 Transmission Capacity, Long-term Reserved Capacity, Available Transmission Capacity) is provided by HTSO. Total Transfer Capacity, Transmission Reliability Margin and Net Transmission 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 Transmission 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). According to the provisions of Law 3426/2005 (approved on December 2005) amending the basic electricity Law 2773/1999, PPC SA, as the exclusive owner of the transmission system, is responsible for the development of the transmission system, following the relevant 5-year statement studied by the HTSO and approved by the Minister of Development following RAE's opinion. Moreover, according to the provisions of the abovementioned Law, PPC is responsible for planning and carrying-out the maintenance, daily operation and actual functionality of the transmission system, while the HTSO is responsible for developing the relevant switching program. PPC and HTSO have to conclude contracts on these issues.

PPC SA is also the exclusive owner of the electricity distribution network. According to the provisions of Law 3426/2005, a special department of PPC undertakes currently the responsibilities of the Distribution System Operator, which consequently will be transferred to the HTSO (along with the special unit of PPC), by July 1st, 2007. The Distribution System Operator, according to the provisions of the same Law, is responsible for ensuring the reliability, functionality and efficiency of the distribution network, and for third party access to the distribution network. The Distribution System Operator is responsible for the distribution network that is interconnected with the mainland's transmission system.

For the non-interconnected islands, the operator of the relevant network (different department of PPC) is also the generation dispatcher. The owner of the distribution network, i.e. PPC for the distribution network of the entire country, is responsible for receiving connection applications, maintaining the functionality and efficiency of the network, as well as developing and maintaining the network according to the relevant program developed also by the owner of the distribution network, i.e PPC. PPC and the Distribution System Operator have to conclude contracts with reference to the development and maintenance of the distribution network of the mainland and the interconnected islands.

RAE is responsible for monitoring the compliance of the network operators and the networks owner with the provisions of the Codes. With reference to the decision of the relevant rules, RAE gives a consenting opinion for the approval of the Codes by the Minister of Development, and decides on the details of the application of the Codes, as already mentioned. The following issues are covered (or should be covered since the Distribution Network Code has not been approved yet), by the network Codes:

- methodology for setting the network tariffs,
- performance measurement and quality regulation,
- provision of information by the network operators to the interested parties.

Network tariffs are approved annually by the Minister of Development, following a simple opinion by RAE.

The Distribution Network Code has not been approved yet. RAE is planning soon the relevant consultation procedure on the technical aspects of the Code, as well as on the quality regulation aspects. The Distribution Network Code is expected by RAE to be enforced by mid-2007. Until then, PPC, as the distribution network owner and operator, follows internally defined rules and procedures.

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 is changed 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 a simple opinion of RAE. According to the Grid Code, RAE gives its opinion for 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, as performed by the HTSO.

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. RAE, taking into account the progress achieved in 2005 – 2006 with the unbundling of the accounts of PPC, will formulate its opinion for the distribution network charges to be approved by the Minister of Development, based on the methodology applied for the Transmission System Charges.

3.1.3.3 Estimated national average network charges

According to the network tariffs for 2006, as approved by the Minister of Development after the opinion of RAE, the network charges for Suppliers is set to €20.335 MW/Year, for generators in southern Greece €514MW/Year and for generators in northern Greece €6.900 MW/Year.

According to RAE's calculations, the average cost of transmission system use was 4,65 €/ MWh, based on the total energy consumption on the Interconnected Transmission System in 2005. Given the 15% G split, this cost led to an average G charge of 0,70 €/ MWh. The corresponding average L charge was 3,95 €/ MW/h..

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).

Moreover, since the unbundling of PPC accounts has not yet been completed, the end-user tariffs are still unbundled, providing only a unified charge including energy, transmission, distribution, PSO and metering charge. An estimate is only possible to be given for the transmission system tariffs, for a typical consumer of the Ib category is calculated to €1.016,75 per year or 20,35 €/MWh, and for the Ig category is €81.344 per year, or 3,38 €/MWh. It has to be noted that since the transmission charges are only capacity related, in some consumers' categories, especially those with very low load factor, the energy reported charge seems to be very high.

For a typical medium voltage customer: Annual transmission & distribution network charges = € 81.340 (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) = € 197.640 p.a. As said, the distribution charges remain on the levels set by the decision of 2002.

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.

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. RAE estimates that the final decision on the General Terms and Conditions for connection to the Transmission System is to be taken in the following months.

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

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 assessment. 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.
- Information regarding the actual dispatch of each unit, for the previous 15 days.

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 Transmission 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

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). Nevertheless, PPC SA is the owner of the Transmission System according to Article 12 of Law 2773/1999. The HTSO is 51% state owned and 49% owned by PPC, according to Article 16 of Law 2773/199 as amended by Law 3426/2005; until the adoption of Law 3426/2005, it was provided that the share of PPC will be reduced to allow a proportionate ownership share of the HTSO for other generators. The new law annulled this provision, and it is now expected that the 49 per cent share will remain with the PPC regardless of the increase of non-PPC power generation.

The HTSO is located separately from PPC in its own premises and is presenting itself through its corporate logo and web site.

To safeguard the independence of the HTSO, the members of the board of directors should not be related in any way to a generation or a supply company, while PPC appoints up to two members of the board.

The headcount of the HTSO is currently 200 employees, while a total 320 employees are expected to staff the HTSO according to its organizational chart. Nevertheless, most of the employees of the HTSO come from PPC, and are members of PPC's trade union. According to the new Law 3426/2005, PPC's staff seconded to the HTSO is under the obligation to choose, approximately by the end of 2006, either to be return to PPC or to remain with HTSO by resigning from PPC. It has to be noted that PPC occupies 1700 employees in the Transmission Network business. All maintenance and expansion works, decided and planned by the HTSO, are executed by PPC staff.

As far as the DSO is concerned under law 3426/2005, article 12, PPC has the task, to set up, not later than 22 June 2006, within its organizational structure a unit that will be assigned all responsibilities of the distribution network operator outlined below. This unit will be transferred to the HTSO by 1 July 2007, and the HTSO will be assigned not later than 1 July, 2007 with the role of the Distribution Network Operator.

PPC will retain ownership of the network and per Article 11 of Law 3426/2005 will continue to receive applications for connection to the network, run the network, ensure the technical integrity of the network, develop and maintain the network according to the plan developed by PPC. In general, the HTSO will be responsible for monitoring the activities of the owner of the distribution networks connected to the transmission system of the mainland. The distribution network of the non-interconnected islands will be operated by a separate department of PPC ("Non-interconnected islands operator"), which will also be responsible for the dispatching of the generating units..The responsibilities of the HTSO regarding the distribution system connected to the mainland transmission system, will be to safeguard the:

- Security of network
- Technical soundness and economic efficiency of network
- Quality of voltage and supply reliability
- Access to network
- Connection to network
- Metering system and metering
- Flow of Information to network users
- Cooperation with the airport operator
- Contracting with the network owner (PPC) for the development of the network

The number of employees that will be working in the DSO is not known as yet, but preliminary estimates count for about 100 employees needed to undertake these tasks. These employees will be probably transferred from PPC to the HTSO (DSO), in a similar way with the first group of employees of the HTSO for the Transmission System Operations. It is noted that more than 8200 employees are occupied in PPC's distribution network business, and these personnel will be serving all new connections and maintenance and expansion works, as planned by PPC.

As far as the unbundling of the accounts of the HTSO are concerned, all costs of the legally unbundled HTSO reflect its administrative costs and, therefore, are not shared with any other affiliated companies of the owner of the Transmission System, i.e. PPC SA.

Moreover, although the legal unbundling of the Distribution System has not been completed yet, the cost of the DSO will only reflect its administrative costs, in the same manner as for the HTSO.

Nevertheless, the accounts of the transmission and distribution businesses within PPC should be audited by the certified accountant responsible for the auditing of PPC according to the provisions of article 30 of Law 3426/2005.

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.

3.1.4.2 Unbundling of accounts

Article 30 of Law 2773/1999, laid down that the rules for the allocation of assets, liabilities, expenditure and income which should be implemented for the compilation of the separate accounts by vertically integrated undertakings should be 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 provided that RAE is responsible for approving any modification to these rules, lead to long period of dispute between RAE and PPC, concerning the competences of RAE to approve not only the modifications but also the development of the methodology, was amended by Law 3426/2005, which clearly assigns to the RAE 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 uploaded 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 raised reservations regarding the compliance of the accounts published by PPC with 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.

RAE sent a letter on 28.2.2005 raising again the methodology of the accounts unbundling, where it restated the basic principles to be followed for the development of the unbundling methodology, pointing out the necessity of presenting, mining, generation, transmission, distribution and supply businesses separately, as well as the requirement of separating the accounts of all businesses for mainland and non-interconnected islands.

RAE had launched in the past infringement procedures against PPC on the proper unbundling and publication of PPCs accounts for the years 2000, 2001 and 2002, and has imposed a fine on these grounds. The infringement procedures ended with the publication of the Court Decision in 2005 which ultimately decided that PPC did not comply with the relevant provisions on the unbundling of accounts. The Court stated that under the relevant legislation RAE has the duty to monitor the operation of the liberalized market and to impose fines to undertakings which fail to comply with the relevant legislation. The Court stated further that RAE’s decision to impose a fine on PPC was justified taken that PPC had not complied with the relevant provisions nor with the detailed methodology issued by RAE on the unbundling of accounts due to the following grounds: The accounts for lignite mining exploitation activities carried out by PPC has to be separated from the accounts related to the electricity production activity taken that lignite mining represents a separate activity and cannot therefore be incorporated in the electricity production. Separate accounts should be kept for the supply and distribution activities of PPC. The cost for the provision of the ancillary services should not be incorporated to the accounts for electricity generation of PPC since this cost is invoiced separately and the ancillary services are paid separately by the HTSO. The cost for distribution and supply of electricity in the non-interconnected islands (undertaken solely by PPC) should be separate from distribution and supply activities in the mainland (which are open to competition) for transparency reasons. PPC should indicate important transactions with associated undertakings, affiliated undertakings or undertakings belonging to the same owner in the annex of the annual accounts.

After a long period of consultation and following the decision by the Court, PPC finally re submitted to RAE in November 2005 the unbundled accounts for 2001-2002 and 2003, separating the activities of distribution and supply as well as the activities in the mainland and the non-interconnected islands. The methodology followed by PPC was based on the principles set by RAE, but the unbundled accounts were not compiled in a detailed manner, due to the fact the appropriate and necessary data to separate the distribution and supply businesses for those fiscal years were not available. RAE has accepted the submitted accounts for 2001-2002 and 2003, in December 2005, according to the provisions of Law 2773/1999, and in order to progress on the unbundling of the accounts. Nevertheless, RAE stated that PPC should submit the detailed methodology for the unbundling of the accounts and its implementation for the Balance Sheet and Income Statement for 2004, 2005 and 2006 according to the provisions of the Law 3426/2005. Further work is currently underway, in order to have an updated full set of unbundled accounts of PPC up to 2006.

A separate audit for the methodology followed for the compilation of the unbundled accounts from a certified accountant is now laid down according to the provision of Law 3426/2005. According to article 30, the certified accountant verifies that the rules for allocating the assets and the liabilities and equity as well as the revenues and expenses for each electrical activity were implemented correctly.

Moreover, this obligation is laid down pursuant to the legislation in force (Law 2190/1920 with respect to joint stock companies – sociétés anonymes) for the annual consolidated accounts of companies which operate under the legal form of 'société anonyme'.

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.

Although the new Grid Code provides the legal framework for the development of a competitive electricity market, with the exception of renewables and small CHP which enjoy a special regime through PPAs (feed-in tariffs and investment support), the interest by potential investors is restrained due to the existence of a dominant company in both the generation and supply businesses, and the low System Marginal Prices recorded in the day-ahead market 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, which was contracted by the HTSO to provide ancillary services. 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). Nevertheless, this contract ends at the end of 2006, with the option from HTSO side to extend it for 3 more months. A second power station, owned by Thessaloniki Energy SA - an affiliate of the partially state owned Hellenic Petroleum SA, stared its commercial operation in December 2005, (400 MW CCGT). The ENTHES project was financed on a corporate basis, and is expecting to achieve acceptable return on its investment through its participation in the day ahead market..

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 or energy 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

The wholesale electricity market operated in 2005 according to the provisions of the 2001 Grid Code, and it is expected that the same provisions will continue to regulate the market by the end of 2006. According to these provisions, 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. Although the 2001 Grid Code provided for bids based on short-run marginal cost declarations for each technically available generating unit, as from the 1st of October 2005 the short-run marginal cost of each unit was set to be the lower limit of the bids submitted, in parallel with the uniform upper limit of 150 €/MWh of the System Marginal Price as described above. 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 at least their fuel cost and they have to recover the rest of their capital cost through their participation in the Capacity Assurance Mechanism.

In 2005 total consumption of 53,4 TWh (including losses) and a load peak of 9.635 MW have been measured in the interconnected System, which refers to the mainland of Greece (interconnected islands not included). The peak demand value should be increased by approximately 160 MW that is the estimated load shedding at the time of peak demand. On the non interconnected islands the total amount of energy generated is around 5,0 TWh.

In 2005 the total maximum net generation capacity on the mainland's interconnected system was 10.268 MW (10.833 total nominal generating capacity). On late December 2005 one 390 MW CCGT power plant, owned by Hellenic Petroleum (T-Power), started its commercial operation.

The total 10.268 MW of total maximum net generation capacity is distributed as follows:

- lignite plants: 4.808 MW,
- HFO plants: 718 MW,
- natural gas plants: 1.684 MW (2.074 MW including T-Power station), and
- hydro plants: 3.058 MW.

Another 400 MW gas fired CCGT power plant owned by PPC S.A. has been constructed and is currently under commissioning tests. 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.

Furthermore, by December 2005 the following additional generating capacity from RES was injecting energy to the interconnected system:

- 412 MW wind generators,
- 48 MW small hydro, and
- 20 MW biomass and biogas.

In addition, 163 MW of CHPs are connected to the mainland's interconnected system.

Regarding the interconnected mainland's system, PPC owns 90% of the installed capacity and the competitors (T-Power, IRON THERMOILECTRIKI, RES-CHP-autoproducers) the remaining 10%. 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 2005, lignite-fired plants accounted for 64,2 % of total gross electricity production, followed by natural gas (15,9%), oil (6,6%), hydro (10,9%) and RES (2,4%).

During 2005 it was only PPC that has provided the total of requested ancillary services.Taking into account the percentage of PPC in the ownership of generating capacity the HHI index is estimated to the upper bound of 10,000.

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, when the price of electricity is high. Nevertheless, these measures do not reveal any elasticity of the consumers to the high prices during peak hours, but are more considered as security measures.

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 39 €/MWh) and Greece (wholesale price from the daily market is around 52€/MWh, but the full energy price, based on PPC tariffs, is estimated on average base 55 €/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 2005.

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.

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, apart from the 395 MW

CCGT power plant, owned by Hellenic Petroleum, that came into commercial operation on late December 2005, no other licences have been exercised for building independent generating plants. Due to lack of investments in generating capacity, and within the framework of the provisions of Law 3175/2003, the HTSO in May 2006 tendered for guarantying the minimum annual income of new generating capacity up to 400 MW. The submission of offers is expected on November 2006.

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 nominal capacity (GW) (1), (3)	Installed net 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	9.860	9.340	1	100%	Not Available, however too high (close to 10,000)	
2002	46,9	8.924 (2)	10.355	9.816	1	100%		
2003	49,7	9.042 (2)	10,685	10.108	1	100%		
2004	50,9	9.370 (2)	10.833	10.256	1	98,6%		
2005	53,4	9.635 (2)	10.833	10.256	1	98,6%		

(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
2005	52,0	NA	NA	52,0

3.2.2 Description of the retail market

Total energy consumption in Greece in 2005 was 53,4 TWh, of which 1,34 TWh were transmission system losses. This energy volume applies for the consumption on the mainland interconnected system. Of the total volume, 27% accounts for the consumption in the industrial sector taking into account the consumption in the high and medium voltage connected customers, 39% to commercial agricultural, public and small industrial customers, and 34% to households.

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 transacted outside PPC is around 1,47 TWh (approx. 2,8% of the total electricity volume consumed in 2005), of which 1,2 TWh was consumed by self-supplied large industrial customers and the rest was supplied by independent suppliers to medium voltage connected commercial customers. In 2005, four independent suppliers and four self-supplied industrial consumers were active in the supply business.

Since the 97,2% of the energy sold to the consumers is supplied by PPC, regulated retail tariffs are applied. During 2005, 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 VAT (9%).

Up to today, supply authorizations had been granted to 16 companies. None of these companies are affiliated to the HTSO or DSO businesses. Out of these authorized suppliers, only four (4) were active during 2005. Today the licensed suppliers are 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

NECO S.A.

EFT HELLAS S.A

HELLENIC PETROLEUM S.A.

EGL HELLAS S.A.

INTERNATIONAL ATHENS AIRPORT SA

MYTILINEOS ELECTRICITY GENERATION AND SUPPLY SA

3.2.2.1 Customers' switching of supplier

In 2005, four (4) eligible customers (heavy industrial sector) have covered a part of their load (approx. 1.213 GWh, corresponding to 2,3 % of the total energy consumption on the interconnected transmission system and to 18% of the electricity consumption on the industrial high voltage sector) through imports, while covering the rest of their needs from PPC. In addition, four (4) suppliers were active, importing in total 260 GWh (0,5% of the total energy consumption on the interconnected transmission system). This energy was supplied mostly to customers in the commercial sector.

Issues related to the procedure of customers switching of suppliers are regulated by the 2005 Grid and Power Exchanges Code. Nevertheless, the absence of the Distribution Code that will regulate in detail the switching procedure for medium and low voltage customers, lead RAE to develop a Handbook for the management of metering and the periodic reconciliation between Suppliers serving customers connected to the distribution network. Provisions of this Handbook arrange the customer switching procedure until the enforcement of the Distribution Code. In this context, RAE decided on the distribution network losses factors which are required to calculate the volume of energy supplied by independent suppliers. Nevertheless, distribution system charges have not yet been approved due to the lack of accounting unbundling between the activities of PPC and especially the lack of information on the cost of medium and low voltage networks. Since an older (2002) decision on the cost of medium voltage network is still applied, customer switching is practically possible for the medium voltage customers but not for the low voltage customers.

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 ensures that the entire metered energy consumption is fully allocated to the suppliers and/or the eligible customer.

The procedures followed by the 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 and Power Exchanges Code where provisions exist for further elaboration by the HTSO in the Metering Handbook. These provisions came into effect on 1st of October, 2005.

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

Table 3.2.2

Development of retail market

	Total consumption (TWh)	No. of companies with >5% retail market	Number of fully independent suppliers (1)	Market share of three largest companies			Cumulative % customers having changed suppler (by volume)		
				large and very large industrial	small-medium industrial and business	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%	0,780%	0
2005	52,0	1	14	82 (2)	99,5	100	18% (2)	0,50%	0

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

(2) refers to high voltage connected self-supplied customers

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 0,12 €/kWh for low voltage commercial customers. Since 2002 only increases due to inflation have been approved, amounting to around 11,35%.

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 already included 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

4.1.1.1 Market structure

The structure of the Greek gas market until July 2006 has been largely similar to what was described in the National Report 2005. Following the enactment of the Gas Law, major changes in the market structure are expected for the period August 2006-July 2007 as explained in the section 2.2.2 above, driven by the establishment of the NNGSO, the elaboration of the Network Code and the most important pieces of secondary legislation and the fact of new eligible customers (independent power producers) seeking for gas suppliers.

4.1.1.2 Market Opening

Pursuant to article 28.3 of the Gas Directive and due to the ten-year derogation period granted to Greece in November 1996, the full opening of the market has to be realized three years at the latest after the expiry of the derogation period (i.e. November 2009), subject to the milestones set therein. In addition, existing concessions in Greece have been exempted from certain provisions of the Gas Directive, including the eligibility rights of their customers, for the whole duration of the concession (article 28.4).

As explained in section 2.1.1 above, since the 1st of July 2005, all power producers have been granted the eligibility right. Since the enactment of the Gas Law (December 2005), this right has been extended to co-generators with an annual consumption of more than 9 Mm^3/year.

Currently, these eligible customers represent approximately 67% of the gas demand in Greece (based on actual 2005 and forecast 2006 demand data).

According to the provisions of the Gas Law eligible customers will be:

1. As of 15.11.2008:
    a. Non-household customers located outside the geographic areas served by regional gas distribution companies under a concession regime (EPAs), irrespective of their annual consumption.
    b. Non-household customers located in the EPA areas, purchasing natural gas for final use in vehicle motors in the form of Compressed Natural Gas.
    c. Large customers i.e. customers with an annual consumption of over 9 Mm^3/year, located in the EPA areas.
    d. The existing EPAs of Attica, Thessaly and Thessaloniki, for natural gas quantities exceeding the annual contract quantity specified for year 2010 in their respective contract with DEPA SA and up to the expiry of each contract (2016). After the expiry of said contracts, existing EPAs will have the right to choose their supplier for the whole of the natural gas quantities they purchase.

2. As of 15.11.2009, household customers not located in the geographic areas of the three EPA companies or the geographic area of any newly formed EPA that will be granted a derogation, pursuant to articles 28(4) and (5) of Directive 2003/55/EC.
3. As of the expiry of existing concession licenses (ca 2030) for the EPAs of Attica, Thessaly and Thessaloniki, all the customers of those EPAs.
4. All EPAs which will be formed after the entry into force of the Gas Law.

The estimated market opening by the end of 2008 and 2009 is in the order of 80% of the total gas demand.

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

Currently, there is no interconnection of the Greek NGS 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. This is also the case for the transit pipelines upstream of Bulgaria. Therefore, the Greek NGS so far is commercially isolated from the neighbouring TSO regions. For information on planned interconnections pls see section 5.2.3 below.

There is no physical (or contractual) congestion experienced in the NGS, 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 3.0 Gm3/year.

According to the provisions of the Gas Law, the Network Code will include all necessary congestion management and capacity allocation rules, in accordance with the provisions of both the Gas Directive and the Gas Regulation. RAE is entrusted has been assigned the responsibility of monitoring and supervising the actual application of such rules, in cooperation with the Regulators of the region.

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

4.1.3 The regulation of the tasks of transmission and distribution companies

4.1.3.1 Network Tariffs

A. TPA tariffs

According to the provisions of law 3428/2005, the tariff setting methodology for TPA to both the transmission system and the LNG terminal will be defined in a Tariff Regulation, which will be drafted by RAE, following a recommendation by the TSO and a public consultation. Actual tariffs will be set on the basis of the Tariff Regulation by the TSO and will be approved by RAE. Both the Tariff Regulation and the actual tariffs will be submitted by RAE to the Ministry of Development for formal approval.

Until the elaboration and entry into force of the Tariff Regulation, TPA tariffs are set by the system operator and approved by the Minister of Development, after RAE expresses an opinion.

Current tariffs for TPA to the transmission system and the LNG facility were set by the Ministerial Decision 4955/2006 (Government Gazette B 360/27.3.2006). The methodology for the calculation of tariffs is based on rate-of-return regulation. For each year over a certain period, the annual required revenue of the TSO is calculated taking into account both capital and operating expenses. The Weighted Average Cost of Capital (WACC) used in the calculation of capital expenses is 10,06% nominal pre-tax or 6,56% real pre-tax. Due to the considerable uncertainty regarding the utilization of the Revithoussa LNG terminal over the next few years (for balancing and/or TPA purposes) a provisions has been made to recover 95% of the required revenue for LNG terminal, through the transmission tariff applied for natural gas transportation via the high pressure pipeline running through mainland Greece and only the remaining 5% is recovered from the LNG tariff. In a largely underutilised facility with high capital costs, this was considered necessary for the initial stage of the market opening, in order to reduce the access charges and thus to provide incentives for the increased utilization of the terminal.

The unit tariff for both the transmission system and LNG terminal use is derived by dividing the required revenue by the projected volumes which are expected to be transported through the transmission system or regasified in the LNG terminal respectively. The unit tariff is split in a capacity/commodity charge by a 90/10 ratio.

Transmission tariffs refer to booking and use of pipeline capacity. The transmission tariff coefficients are as follows:

Year	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
1.1.2006-31.12.2006	693,285	0,341087
1.1.2007-31.12.2007	625,589	0,307781
1.1.2008-31.12.2008	541,121	0,266224
Future years	CPI adjustment	

The capacity charge is applied to the maximum daily booked/used transportation capacity during the respective year, while the commodity charge is applied to each MWh of gas being transported during the year.

LNG tariffs refer to booking of and use of vaporization capacity and –implicitly- to the respective LNG reception services and temporary storage. There is no tariff for long-term storage services as yet.

The tariff coefficients are as follows:

Year	Capacity Charge (€/peak day MWh/year)	Commodity Charge (€/MWh/year)
1.1.2006-31.12.2006	29,088	0,021947
1.1.2007-31.12.2007	26,247	0,019804
1.1.2008-31.12.2008	22,703	0,017130
Future years	CPI adjustment	

The capacity charge is applied to the maximum daily booked/used send-out capacity during the respective year, while the commodity charge is applied to each MWh of LNG regasified during the year.

B. Distribution tariffs

Local distribution companies (EPA) set there tariffs under a revenue cap which is adjusted every year according to CPI. The tariff is bundled (i.e. there is no separate charge for transmission and distribution of gas) and each EPA follow a different methodology in order to calculate there tariffs (market value or cost plus).

C. Average charges

The estimated national average network charges for typical customer I4-1 are as follows:

Year	Average Charge (€/MWh)
2006	3,11
2007	2,81
2008	2,43
Future years	CPI adjustment

The other two types of typical customers (I1 and D3) are supplied by Local distribution companies. An indicative charge for transmission and distribution of gas (no cost of gas included) in the area of Thessaloniki is presented below:

Typical customer	Average Charge (€/MWh) 1.1.06-31.5.06
D3	13,44
I1	12,68

D. Storage charges

Greece has no storage facilities except from the LNG tanks in the Revythoussa LNG terminal. So far TPA to the terminal is related only to the offloading, temporary storage and regassification of LNG i.e. no storage service is provided.

4.1.3.2 Balancing

Balancing arrangements and the respective charges will be defined in the Network Code, pursuant to article 8 of the Gas Law.

4.1.4 Effective Unbundling

So far, DEPA S.A., the integrated incumbent in the Greek gas market, was performing both the system operator and supply activities and was obliged to keep separate internal accounts for those activities. The existing gas distribution companies (EPAs), owned by DEPA and independent investors by a respective share of 49/51 %, had no obligation to keep unbundled accounts for their DSO, supply, or other activities. RAE had no competence to set the rules for the unbundling of DEPA accounts.

According to the provisions of the Gas Law:

- A legally unbundled NNGSO being also the owner of NNGS assets will be formed by the end of 2006 at the latest (see also section 2.2.2).
- Management and functional unbundling of the NNGSO will be required by the terns of its authorization. Additionally, the law provides for a Compliance Code which shall specify the obligations of the staff and management of the NNGSO so as to avoid any discriminatory behaviour regarding TPA to the NNGS, the measures for the implementation of the Code and a control of compliance system. Until the 31st of January of each year, the NNGSO shall submit to RAE a report describing the measures taken in relation to the observance of the Compliance Code. This report shall be published by the NNGSO. On the basis of that report, RAE shall evaluate annually the extent of independence of the NNGSO and may propose measures for further safeguarding of independence.
- All integrated natural gas undertakings should keep and publish unbundled accounts for the activities of transmission, LNG installation, storage, distribution and other natural gas activities, as well as other activities not related to natural gas as if those activities were operated by different companies. Furthermore, all companies

exercising natural gas activities are obliged to keep and publish unbundled accounts for the activities of supply of natural gas to eligible customers and supply of natural gas to non-eligible customers as well as for the cost of provision of public service obligations. Unbundled accounts should be audited by an certified accountant. The audit should address all the requirements set by the law and its outcome should be submitted to RAE. RAE has the right to conduct inspections in order to maintain these requirements. Finally, RAE has the right to impose a fine to any company that violates the relevant provisions of the Gas Law.

- Existing gas distribution concessions are exempted from functional unbundling requirements (article 28 of the Gas Directive) but are obliged to keep separate accounts for their gas distribution and supply activities. For new gas distribution concessions, the Gas Law provides for the application of the "100.000 customers" rule regarding functional unbundling, and the obligation for accounting unbundling.

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

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

4.2.1 Description of the wholesale market

4.2.2 Description of the retail market

5 Security of Supply

5.1 Electricity [Article 4] [1]

5.1.1 Supply versus Demand

In 2005 the measured peak demand in the interconnected system reached 9.635 MW, occurred in July. This peak value should be increased by approximately 160 MW that is the estimated load shedding at the time of peak demand. At the same year, the total energy consumption, including transmission system losses, was 53.400 GWh. The evolution of energy and peak power demand is forecasted for the years 2006-2010 in the five-year statement on the development of the transmission system. According to the baseline scenario of the HTSO (average annual energy demand increase 3,5%), the evolution of energy and peak power demand is forecasted as follows:

[1] This section may make reference to supply demand forecasts compiled by TSOs where appropriate

Year	Forecasted Peak Demand (MW)	Forecasted Energy Consumption (GWh)
2006	10.130	54.586
2007	10.500	56.496
2008	10.880	58.473
2009	11.270	60.519
2010	11.660	62.636

Regarding the non-interconnected islands, the synchronised peak-demand is not calculated since the corresponding load profiles are quite different between the islands. The total energy generated in 2005 by PPC on these islands was 4.995 GWh, from which 2.644 MWh were generated on Crete. In general the total energy consumption on the non-interconnected islands is increased annually by 3.5% - 4%.

5.1.2 Generation Capacity and Licensing

In 2005 the total maximum net generation capacity on the mainland's interconnected system was 10.256 MW (10.833 total nominal generating capacity). On late December 2005 one 390 MW CCGT power plant, owned by Hellenic Petroleum (T-Power), started its commercial operation.

According to historical data on the reliability, operation and availability of the generating units in the framework of the implementation of the capacity assurance mechanism, it is calculated that the average long term cumulative availability of the generating units is 90% of the total net capacity. In this calculation the generating units under maintenance or other long outages due to major failures are not taken into account. This figure can be summarised as the capacity that is statistically expected to be available as percentage of the total generating capacity declared to be available[2].

The total 10.268 MW of total maximum net generation capacity is distributed as follows:

lignite plants: 4.808 MW,

HFO plants: 718 MW,

natural gas plants: 1.684 MW (2.074 MW including T-Power station), and

hydro plants: 3.058 MW.

Another 400 MW gas fired CCGT power plant owned by PPC S.A. has been constructed and is currently under commissioning tests. According to the respective generation license, this plant shall substitute equal capacity from old PPC plants that will be retained as cold

[2] This percentage cannot be applied for sort term forecasts, since different emphasis is given by the generators to the reliability of their units on peak or off-peak hours.

(emergency) reserve. Additionally a number of RES generation licence holders have proceeded to the construction of RES plants.

On the non-interconnected islands, the total maximum available net generation capacity was about 1.410 MW, all coming from HFO and LFO units. In addition, 164 MW of wind generators are connected to the distribution network of the non-interconnected islands.

Since 2001, when the Greek electricity market was liberalized, 15 generation licenses have been granted to anticipated gas-fired non-PPC producers for a total capacity of 5816,8 MW, and a large number of licenses (432 Wind + 249 Hydro) to RES plants (for a total capacity of (5225,9 + 490,8 = 5716,7MW) (see Table RES Generation Licenses' below).

Table RES Generation Licenses granted

Technology		2001	2002	2003	2004	2005	2006	Sum
Wind	Total capacity (MW)	936,9	556,6	1612,6	551,6	663,3	904,9	5225,9
	Number of Licenses	113	67	102	62	47	41	432
Biomass	Total capacity (MW)	39,4	19,8	0,6	0,3	3,5	26,4	90,0
	Number of Licenses	7	3	2	2	3	2	19
Geothermal	Total capacity (MW)	0,0	0,0	8,0	0,0	0,0	0,0	8,0
	Number of Licenses	0	0	1	0	0	0	1
Small Hydro	Total capacity (MW)	135,6	96,0	113,9	45,9	73,6	25,8	490,8
	Number of Licenses	73	36	68	22	36	14	249
Solar	Total capacity (MW)	1,1	0,6	0,5	0,0	0,0	0,0	2,2
	Number of Licenses	6	32	2	0	0	0	40
Total Capacity in MW		1113,0	672,9	1735,6	597,8	740,4	957,1	**5816,8**
Total number of generation licenses		199	138	175	86	86	57	**741**

Note: The above Table presents the Generation Licenses granted on the basis of the year when the licenses were initially granted and the final capacity (as it is after any license modifications). The relevant Table of the Annual Report 2005 presented the Generation licenses granted on the basis of the year when the license were modified and the final capacity (as it is after any license modification).

In May 2006, the HTSO launched the first of the three tenders for the installation of new generation capacity, for approximately 400 MW (the first trance) and up to 1200 MW in total which will be secured against debt capacity payment (corresponding up to 900 MW of the total capacity), under the provisions of law 3175/2003. All bidders should submit their offers by the end of November, and the winner should construct and become commercially available within 27 months. The second tender is expected to be launched in December 2006, and the third one is expected for the mid of 2007. The necessity of the two tenders will be evaluated on the basis of the production licence granted in the meantime and the construction of new power station outside the “guaranteed income” mechanism.

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

RENEWABLE ENERGY (LAW 3468/2006)

In order to comply with the prerequisites of the EU Directive 77/2001 regarding the promotion of electricity produced from Renewable Energy Sources (RES) in the Greek Electricity Market and to establish an attractive environment for investors in the RES sector, the law 3468 was introduced by the Greek Government in June 2006. The law regulates the electricity generated by RES and Combined Heat and Power (CHP) units and transports the contents of the above mentioned Directive in the Greek legal framework. More specifically the law foresees:

- Definitions applying to renewables according to the definitions in article 2 of the EU Directive 77/2001.

- Implementation of a mechanism issuing guarantees of origin of electricity produced from RES and designation of competent bodies independent of generation and distribution activities to supervise the issue of such guarantees of origin, as indicated in article 5 of the EU Directive.

- Introduction of a new set of Feed-In Tariffs (FITs) for electricity generated by renewables and CHPs, aiming at contributing to the achievement of the national indicative target, set by the EU Directive 77/2001, at 20,1% share of renewables with respect to the national gross electricity consumption. The new FITs system takes into account the characteristics of different sources of renewables, different technologies, the cost of electricity generation in different geographical areas as well as the current situation regarding the development of renewables in Greece (85% of the installed capacity comes from wind farms) and focuses on the promotion of solar and PV technologies, where substantial increases are given. The new FITs for power generated by renewables constitute an integral part of the law (prices are stated in the law as shown in Table 1 below) and are no longer connected to electricity retail tariffs. Higher tariffs apply to the non-interconnected islands compared to these applying in the interconnected system covering the mainland of Greece.

- Measures and incentives to encourage greater penetration and thus greater consumption of electricity produced from renewables, in conformity with the national indicative target, such as:

-Allowing for the licensing of off-shore wind farms and hybrid plants on the non-interconnected islands, for which the existing legal framework was inconsistent;

-Launching a programme for the development of PVs with a perspective of 200 MW and 500 MW installed capacity in the non interconnected island and the mainland respectively, by 2020;

-Elimination of the 50 MW upper limit in the capacity of a renewable plant that could get priority dispatch be the Hellenic Transmission System Operator (HTSO), according to the law 2773/1999;

-Exemption from the obligation of acquiring the Generation, Installation and Operation permits for lower capacity renewable energy plants (PVs up to 150kW, geothermal plants up to 500 kW; biomass up to 100kW e.t.c), thus encouraging dispersed energy generation with minimum administrative involvement.

- Measures for the reduction of administrative barriers to renewables development, establishment of clear guidelines for authorisation procedures with a clear attribution of responsibilities to all bodies involved (in order to accomplish this two Ministerial Decrees were issued in parallel with the law 3468, regulating procedures for obtaining environmental permits), simplification of the licensing procedures with a view to decrease the time needed for obtaining all the necessary permits. Up to now in Greece, a multi-layered approval system and complex bureaucratic processes lead to lengthy licensing procedures. A number of ministries and local or regional authorities were required to give their consensus to a proposed development, in some cases requiring that prior assent from another body has already been received before the abovementioned bodies even begin to consider an application. Thus, the licensing process lasted from 2 to 3,5 years and in some cases licensing has taken so long that the technology on which the original application was based was no longer available, due to rapid technological progress especially in wind turbine manufacturing.

- Creation of special cross-ministerial committees aiming at the coordination between different administrative bodies as regards deadlines, reception and treatment of applications for authorisations to RES and CHP projects and at streamlining and expediting procedures at the appropriate administrative level.

Greek renewables projects show a low realisation rate. According to most recent statistics, only 13% of projects that had received a generation license from the Ministry of Development had started to generate, and a further 5% had begun construction. Administrative, technical, and cultural barriers have a negative impact on the completion rate of licensed projects, and the licensing of new projects.

These administrative barriers are compounded by the absence of sufficient grid infrastructure and capacity, especially in areas with good RES potential, and the absence of a Special Spatial Plan for RES covering the entire country, setting priority zones and specifying rules and conditions for installing RES depending on the land use and other environmental issues. The absence of such a Special Spatial Plan for RES is used as an argument by the local resistance against new developments, in particular wind, which is conducted both through political and judicial means. A number of rulings on challenges brought against proposed developments at the Greek Supreme Council of State (SCS - the highest court in Greece) were issued against renewable and other energy developments such as grid extensions. Appealing to the SCS usually has the immediate effect of halting any work on a development, even if all licenses and permits have been obtained, until a decision by the SCS has been reached. This takes on average three years, resulting in many cases in the project being abandoned with the complete loss of funds invested in the development stage.

The new law 3468/2006 may remedy some of the problems faced by investors in the renewables sector, mostly these related to administrative barriers, however it should be clearly stated that increased renewables penetration may only be accomplished provided that:

- Grid access and infrastructure availability is ensured.
- Pre-planning mechanisms such as the Special Spatial Plan for renewables are enabled as soon as possible.

Feed-in tariff for renewable electricity in Greece in EUROs per MWh

Electricity Produced from:	**Energy Price (€/MWh)**	
	Interconnected System	**Non-Interconnected Islands**
(a) Wind Farms	73	84,6
(b) Off-shore Wind Farms	90	
(c) Hydroelectric energy (plants with less than 20MW of installed capacity)	73	84,6
(d) Solar energy generated by Photovoltaic Units (with less than 100kW of installed capacity)	450	500
(e) Solar energy generated by Photovoltaic Units (with more than 100kW of installed capacity)	400	450
(f) Solar energy generated by other than Photovoltaic Units (with less than 5MW of installed capacity)	250	270
(g) Solar energy generated by other than Photovoltaic Units (with less than 5MW of installed capacity	230	250
(h) Geothermal energy, biomass or biogas	73	84,6
(i) Other RES	73	84,6
(j) CHP (High Yield)	73	84,6

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.

5.1.3 Generation Capacity Assurance Mechanism

In the 2005 Grid Code which will come into force gradually from October 2005 to January 2008, a Generation Capacity Assurance Mechanism is included. The Generation Capacity Assurance Mechanism aims to ensure long-term capacity availability and is based on the obligation of the suppliers to present sufficient guarantees in that direction. Moreover, the mechanism aims to reduce the generator's business risk, by guaranteeing part of his fixed costs, and the smooth fluctuation of prices in the wholesale market, due to the reduction of the short term risk of the generators.

According to this Capacity Assurance Mechanism, generators and importers are issued annual Capacity Availability Tickets (CATs) in one MW steps reflecting their total net generating capacity and import rights. CATs are submitted to the CAT Register kept by the TSO and constitute an offer to the suppliers for the conclusion of Capacity Availability Contracts (CACs). Suppliers have to conclude these CACs to cover their supply obligations plus a security margin.

When capacity shortage is foreseen and is not expected to be covered by IPP initiatives, the TSO can proceed to a tender for the pre-purchase of CACs, corresponding to new generating units. The CACs pre-purchase is done on behalf of the future suppliers and customers, to whom the TSO should transfer the CACs as soon as possible via an auction and aims to guarantee the minimum required income for the new units - for the part of the capacity contracted by the TSO, facilitating their financing.

During the Transitional period, until January 2008, and due to the possible difficulty in the conclusion of CACs between suppliers and generators, the following alternative mechanism is offered:

- Generators may conclude CACs with the TSO.
- The capacity obligations of suppliers can be covered by the above CACs, upon conclusion of a "Contract for Participation in the Transitional Capacity Assurance Mechanism" between the suppliers and the TSO.
- A regulatory defined uplift is charged to all participating suppliers, according to their customers' peak loads, and is received by all participating generators depending on their unit availability.

- The value of the uplift has been set at 35.000 €/MW, based on the costs of unit installation and of keeping units at the highest levels of operational availability.

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 estimation procedure, are defined by decision of RAE.

Moreover, the HTSO is responsible for the development of the transmission system on the mainland and the interconnected with this system islands. 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, applying transparent, unbiased and non-discriminatory criteria, while taking into account the principle of providing access to anyone wishing to connect to the transmission system[3]. In this framework, the HTSO elaborates and publishes annually the five-year plan for the development of the interconnected transmission system, which is approved by the Minister of Development following RAE's opinion and the views of the owner of the transmission system (PPC). The procedure for the elaboration of the five-year plan for the development of the transmission system is specified in detail in the 2005 Grid Code. In this plan, the development projects are specified, as well as the progress timeframe and the estimated costs.

The projects that are necessary for the reinforcement of the existing transmission system are entrusted to PPC as the owner of the transmission system, with the exception of the cases when a third party can undertake a project when PPC invokes inability either to respect the time schedule or to finance the project.

The projects that refer to extensions of the transmission system in order to connect new facilities, can be executed either by the interested for the connection party or by the owner of the transmission system. These projects are promoted even when they are not included in the approved five-year plan.

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.

[3] According to the provisions of the new Law 3426/2005, the HTSO may refuse connection to the system where it lacks the necessary capacity. Duly substantiated reasons must be given for such refusal, in particular having regard to the necessary system reinforcements

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 2007. However, full operation of the interconnection should be expected following the official procedure for the interconnection of the Turkey transmission system with the UCTE system. Relevant studies are to be concluded in the beginning of 2007.

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 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]

5.2.1 Ongoing Supply-Demand Situation

In 2005, the total gas consumption in Greece reached 2.67 Gm3. The gas demand forecast for the period 2006-2008, is presented in the following table, broken down in consumer categories:

Gas Demand (Mm^3/year)	**2005**	**2006 (f)**	**2007 (f)**	**2008 (f)**
Electricity Generation	1.812	2.115	2.528	2.918
Large Industries	537	573	784	837
Small Industries	147	173	338	370
Commercial and domestic	157	273	386	518
Other	13	14	25	30
Total	**2.667**	**3.148**	**4.061**	**4.672**

Greece has no domestic gas production. So far, gas is supplied by means of the following long-term, take-or-pay contracts held by DEPA:

1. A contract for the supply of pipeline gas from Russia (2,80 Gm^3/year).
2. A contract for the supply of LNG from Algeria (0,68 Gm^3/year)

DEPA has also announced the conclusion of a new long-term, take-or-pay contract with Turkish Botas for the provision of 0,75 Gm^3/year from Turkey, anticipated to be effected after the completion of the Greece-Turkey interconnector, due by the end of 2006.

5.2.2 Currently available import capacity

The maximum importing capacity of the entry point from Bulgaria is currently 360,000 m^3/h, corresponding to an annual throughput of approximately 3.2 Gm^3/year. The current capacity is extendable with relatively minor investment to 691,000 m^3/h, corresponding to an annual throughput of approximately 6.0 Gm^3/year.

The second entry point to the NGS is the Revythoussa LNG terminal. The current send out rate of the LNG Terminal is 270 m^3 LNG/hour (approx. 160,000 m^3/h) corresponding to an annual throughput of 1.4 Gm^3/year. 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 LNG/hour.

5.2.3 Forthcoming import investment for the next three years

The two major new infrastructure projects currently underway are:

- The Turkey-Greece Interconnector, due to be completed by the end of 2006. The initial import capacity of the Interconnector is estimated to 3.5 Gm^3/year.
- Expansion of the capacity of the Revithoussa LNG terminal, due to be completed by the end of 2008. The project refers to: (1) Increase of the regasification capacity from the current level of 270 m^3 LNG/hour to 1000 m^3 LNG/hour, corresponding to an

annual throughput of 5.0 Gm^3/year. (2) Increase of the unloading capacity of the terminal from the current level of 3,500 m^3 LNG/hour to 7,250 m^3 LNG/hour.

5.2.4 Other infrastructure projects

In November 2005, Italy and Greece signed an intergovernmental agreement for the development of the Interconnection Italy Greece (IGI) project. The project involves the construction of both an onshore and offshore pipeline linking the two countries and thus enabling the flow of gas through Greece to Italy and Europe. The initial capacity is estimated to 8 Gm^3/year, extendable to approx. 10 Gm^3/year in the future. The project is sponsored by DEPA S.A. and Edison S.A. The final investment decision is estimated to be taken within 2007 and if positive, the project will be completed by 2010.

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, as amended by law 3426/2005, 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.

According to the provisions of the Law 3426/2005, the Minister of Development defines the PSO's categories and the providers of those services within 6 months from the publication of the Law. Then, in three months time from the decision of the PSO's categories, the Minister of Development after RAE's opinion, approves the methodology for the allocation of PSO costs, within each category of consumers. The level of the levy required for the provision of PSO's is annually approved by the Minister of Development after the opinion of the RAE. The providers of PSO's are obliged to maintain separate accounts for PSO costs and charges. These accounts include in a transparent way the economic rent owed to the PSO provider as well as the charges allocated to their customers concerning PSO expenses.

Consumers located in non-interconnected islands enjoy electricity supply service at the same tariffs as any other customer regardless of the cost of their connection and supply. The difference between the cost of providing electricity on the non interconnected islands and tariffs applied to the consumers of the islands is considered as provision of public service, and should be compensated by a special PSO levy. Currently this levy is incorporated in the unbundled PPC tariffs. The decision to apply the same tariffs in the whole of the country is taken as a measure to promote social .

In addition, groups of vulnerable customers under certain specified conditions (e.g. families with more than three children) enjoy a discount tariff by PPC, 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.

No obligation for primary energy source labelling exists so far. Nevertheless, recent Law 3468/2006 provides for a procedure that all producers are able to issue energy source certificates by applying to the HTSO or to the operator of the non interconnected islands network. The mechanism is monitored and controlled by the RAE.

B. Gas (Gas Law 3428/2005)

According to the provisions of the Gas Law, public service obligations may be imposed by the Minister of Development to the NNGSO and all other authorization holders. More specifically, PSOs related to security and continuity of supply, quality and price of service and environmental protection (including climate protection and energy efficiency) can be imposed to the NNGSO by means of a Ministerial Decision. Recovery of the NNGSO's cost for providing the PSOs will be recovered through separate charges.

In addition, according to the provisions of the regulation for granting, amending and revoking authorizations in the gas market, PSOs can be imposed to all authorization holders by means of a Ministerial Decision issued after RAE's opinion. Additional obligations can be imposed to such entities in cases of extreme and adverse climate conditions as well as for national and public security reasons.

These provisions will be effected after the establishment of the NNGSO (by the end of 2006) and the enactment of the secondary legislation provided for in the Gas Law,.estimated to be completed by the first half of 2007.

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

According to the provisions of Law 3428/2005, in emergency situations, all supply authorisation holders that supply gas to small consumers (i.e. consumers with consumption less than less than 9 Mm^3/year) are obliged to continue the supply of gas to all such consumers i.e. irrespectively if they are their customers, following the instructions of NNGSO. For the provision of last resort gas supplies, supply authorisation holders will be fully compensated, in accordance with the terms of their authorisation.

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

The subject is relevant to the provisions of the Supply Code to Eligible Customers. The Supply Code is part of the Gas Law's secondary legislation and is estimated to be enacted by mid-2007.

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

As far as eligible customers are concerned, the subject is relevant to the provisions of the Supply Code to Eligible Customers (see also section 6.3 above).

For non-eligible customers supplied by the gas distribution companies (EPAs) under a concession regime, standard terms and conditions of the supply contract are imposed by the Distribution Licence and include:

1. Obligations of the supplier regarding invoicing (frequency, structure, pricing principles), settlement of disputes over meter readings, duration/renewal of contract etc.)

2. Obligations of the customer regarding access of the company to his premises and to the meter, due payment of bills, connection fees etc.).

The duration of the supply contract is one (1) year and is automatically renewed unless the customers notifies the company otherwise. The customer can withdraw from the contract at any time without any charge.

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 are controlled ex-post 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:

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

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.

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