UNIVERSIDAD PONTIFICIA COMILLAS
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

MÁSTER OFICIAL EN EL SECTOR ELÉCTRICO

TESIS DE MÁSTER

GENERATION COSTS EVALUATION IN CENTRALIZED SYSTEMS
A contrast over market mechanisms

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“El saber y el valor contribuye
conjuntamente a la grandeza.
Hace al hombre inmortal
porque ellos lo son.
Tanto es uno cuanto sabe,
y el sabio todo lo puede.
Un hombre sin conocimientos
es un mundo a oscuras.
Es necesario tener ojos y manos,
es decir juicio y fortaleza.
Sin valor es estéril la sabiduría.”
Baltasar Gracián

ACKNOWLEDGEMENTS

This work reflects an almost two year's international experience. Uncountable moments and individuals have influenced these lines. And it represents in fact a very collective work. Fortunately more than I would ever expect.

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ABSTRACT

Master on the Electric Power Industry

Escuela Técnica Superior de Ingeniería (ICAI)

Pontifical University Comillas

GENERATION COSTS EVALUATION IN CENTRALIZED SYSTEMS
A CONTRAST OVER MARKET MECHANISMS

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From the late 70's, network industries and infrastructures are being liberalized and re-regulated across the world. It has been occurring a deep process of institutional, regulatory, economic and administrative change of network industries – notably on the electricity area, which is going through a strong transition to market and competition models. After approximately 15 years from the starting of liberalization processes, several studies have tried to balance the gains and losses of the electricity reforms worldwide, focusing on social cost-benefits to consumers, the evolution of costs, the result over the investments, innovation and quality of supply, and finally the effect on prices. The overall view indicates that, though pointing towards a relative welfare gain in liberalized markets, their results are not conclusive and several times divergent. Particularly in Spain there is much speculation about the affordability and the efficient gains from 1998 over this new system. This project has the purpose, with a formal and public study, to contrast both centralized and market-oriented generation prices on the ordinary regime between 2006 and 2009 for the actual Iberian power system. This work presents a methodology with optimization models to first study, model and replicate the actual centralized SEIE generation retribution mechanism. And then transpose and adapt the previous methodology to the SEP reality. The results are consistent. For the same operational and investment expansion decisions the theoretical centralized generation prices simulated and those from the current liberalized market in Spain seem to concur in the short term. Therefore, there is a strong indication the liberalized market has been working efficiently, setting prices in accordance with the most rational centralized decisions that would have been taken in a Reference Model. And short-term analysis points towards the necessity of future marginal prices at higher average levels, to reach the long term correct economic equilibrium for generators fixed costs compensation.

Index Terms: generation costs evaluation, centralized/market-oriented power systems, optimization models.

RESUMEN

Máster Oficial en el Sector Eléctrico

Escuela Técnica Superior de Ingeniería (ICAI)

Universidad Pontificia Comillas

EVALUACIÓN DE LOS COSTES DE GENERACIÓN EN SISTEMAS CENTRALIZADOS
UN CONTRASTE SOBRE MECANISMOS DE MERCADO

AUTOR: BRENO WOTTRICH

Desde finales de los años 70, industrias de red e infraestructuras están inmersas en una tendencia de liberalización y re-regulación en todo el mundo. Se está acometiendo un complejo proceso institucional, regulatorio, económico y administrativo - notablemente en la industria de electricidad, que viene atravesando una fuerte transición hacia modelos de mercado y competencia. Transcurridos aproximadamente 15 años desde el inicio de los procesos de liberalización, varios estudios han intentado medir el balance de pérdidas y beneficios de las reformas en todo el mundo, enfocando en el análisis de costes-beneficios para consumidores, la evolución de los costes del sistema, el efecto sobre las inversiones, la innovación y la calidad de suministro, y finalmente el efecto sobre los precios de energía. Una visión general demuestra que, aun mostrando incrementos relativos de los beneficios en sistemas de mercado, los resultados no son concluyentes y a veces señalan divergencias. En España, particularmente existen fuertes especulaciones sobre los impactos positivos en los costes y eficiencia desde la vigencia del nuevo marco regulatorio del sistema eléctrico en 1998. Este proyecto tiene el objetivo, con un estudio público y formal, de contrastar los precios de generación en régimen ordinario, 2006 a 2009, entre estructuras de mercado y centralizada para el actual sistema eléctrico Ibérico. El trabajo ofrece una metodología con modelos de optimización para en una primera estancia estudiar, modelar y replicar el mecanismo actual centralizado de retribución de costes de generación en el SEIE. Y a continuación transponer y adaptar la metodología anterior a realidad del SEP. Los resultados obtenidos son consistentes. Para las mismas decisiones operativas y de inversiones, los precios simulados del sistema teórico centralizado de generación y aquellos obtenidos del mecanismo de mercado vigente en MIBEL coinciden en un horizonte de corto plazo. Así, existe un fuerte indicio de que el mercado liberalizado está funcionando eficientemente, estableciendo precios de acuerdo con las decisiones centralizadas racionales y optimas que serian tomadas en un Modelo de Referencia. Finalmente, el análisis de corto plazo apunta la necesidad de que precios marginales futuros sufran incrementos significativos para alcanzar el correcto equilibrio en el largo plazo de compensación de costes fijos de generación.

Índices de Términos: evaluación de costes de generación, modelos de optimización, sistemas eléctricos centralizados/liberalizados.

GLOSSARY OF TERMS

ACG: Automatic Generation Control;

ATR: Third Party Access (*Acceso de Terceros a la Red*);

CCGT: Combined Cycle Gas Turbine;

CHP: Combined Heat and Power;

CNE: National Commission for Energy (*Comisión Nacional de Energía*);

CTC: Stranded Competition Costs (*Costes de Transición a la Competencia*);

DGPEM: General Direction of Energy Policy and Mines (*Dirección General de Política Energética y Minas*);

ENRESA: National Company of Radioactive Sediments (*Empresa Nacional de Resíduos Radioativos*);

EU: European Union;

GAMS: General Algebraic Modeling System;

GICC: Integrated Gasification in Combined Cycle (*Gasificación Integrada en Ciclo Combinado*);

INE: National Institute of Statistics (*Instituto Nacional de Estadística*);

IPC: Comsumption Prices Index (*Índice de Precios del Consumo*);

IPI: Industrial Prices Index (*Índice de Precios Industriales*);

LHV: Low Heating Value;

LNG: Liquefied Natural Gas;

LOSEN: Law for Restructuring the National Power System (*Ley de Ordenación del Sistema Eléctrico Español*);

MIBEL: Iberian Power Market (*Mercado Ibérico de Electricidad*);

MIP: Mixed Integer Problem;

MITC: Ministry of Industry, Tourism and Commerce (*Ministerio de Indústria, Turismo y Comércio*);

MLE: Legal and Stable Framework (*Marco Legal y Estable*);

OMEL: Iberian Power Market Operator – Spanish Pole (*Operador del Mercado Ibérico de Energía – Polo Español*);

OMIP: Iberian Power Market Operator – Portuguese Pole (*Operador do Mercado Ibérico de Energia – Pólo Português*);

PEN National Energy Plan (*Plan Energético Nacional*);

PNA: National Assignation Plan (*Plan Nacional de Asignación*);

REE: Spanish National Grid Company (*Red Eléctrica de España*);

REN: Portuguese National Grid Company (*Rede Elétrica Nacional*);

SEE: Spanish Power System (*Sistema Eléctrico Español*);

SEP: Peninsular Power System (*Sistema Eléctrico Peninsular*);

SEIE: Insular and Extra-Peninsular Spanish Power System (*Sistema Eléctrico Insular y Extra-Peninsular*);

SPSS: Statistical Package for the Social Sciences.

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Chapter 1. Introduction

Since the late 70's, network industries and infrastructures are being liberalized and re-regulated across the world. In fact, it has been occurring a deep process of institutional, regulatory, economic and administrative change of network industries – notably on the electricity area, which is going through a strong transition. Countries of the European Union, USA and South America show the trend of modifying the emphasis in regulatory politics to the regulation of natural monopolies.

The power industry was divided into two conceptual components during the reforms: generation, retailing, and metering activities were liberalized and opened to competition; and the transmission activities, due its natural monopolistic characteristics, remained deeply regulated. Even though reasons behind these changes could vary, the general motivations were normally correlated with: a) increase of security of supply; b) decrease of system costs; and c) improvement of system efficiency.

In the industrialized countries, included Spain, the main argument in favor of liberalization was that consumers would experience lower energy prices. The generation overcapacity during the 90's and the expensive investments in nuclear, coal and hydro units reflected in soaring generation prices. Initially, the power system liberalization has produced decreasing energy prices in many countries. *On the other hand, since the beginning of this decade, there is much speculation about the conclusiveness of this evidence. Therefore, the present work comes to fulfill this gap and to shed more light on the discussion. It presents a public and open study contrasting actual generation costs in two polar structures for the Spanish reality: centralized vs market oriented.*

1.1. The Recent Spanish Power Industry History and Regulatory Evolution

The SEE can be divided into two very divergent regulatory and operating frameworks. The first is the peninsular system where a market exists (and in the recent history moving towards an Iberian market with Portugal and Spain). And the Insular and Extra-Peninsular systems, strongly regulated by the Spanish Government, that consist of two cluster of islands and two autonomous cities.

1.1.1. The Spanish Power System

The response of the Spanish government over the soaring oil prices in 1973 was to protect the consumers. In this way, the Government absorbed a great portion of the impact over the oil derivative prices, mainly diminishing special taxes. In parallel, it started the first PEN in 1975, focusing on a growing demand, promoting the expansion of the nuclear and national coal energies to produce electricity. With the economic crisis and the excessive investment plans of the first program, it was adopted a second PEN (1978-1987), forecasting a growing demand at 6,5%, later in 1981 revised to lower standards to the period between 1981-1990. In 1982, with the socialist Government, took place the third PEN (1983-1992). It included, between others, the revision of nuclear expansion due to the low forecast demand and the others more favorable options. From more than 15.000 MW already approved, just six units already being built were authorized to be connected into the network (*Almaraz II*, *Ascó I* and *II*, *Cofrentes*, *Trillo I* and *Vandellós II*), totalizing in this way 7.800 MW of total nuclear installed capacity.

Important to mention also that in this period some regulatory measures were also necessary in order to find a solution to the high financial crisis of some power companies (derived fundamentally by their high debt linked, and not compensated, with the investment in new nuclear units, by the devaluation of the currency – *pesetas* – and their growing costs). In this way, a new regulatory framework came in 1987. The MLE management of the system was organized in a centralized way and compensated companies by their recognized costs. It successfully stabilized the global companies' debt to reasonable values, becoming not so dependent of external currencies.

The fourth PEN (1991) was focused on the period between 1991 and 2000, but was interrupted in the way by the restructuration and liberalization of the power sector. Its most insightful measures were related to: a) a forecast annual growth of demand in 3,5%; b) the promotion of indigenous generation – small hydro and coal; c) a greater focal point on gas technologies in comparison to fuel generation units; and d) enlargement of the lifetime of the existing generation plants and use of fuel units.

In the most recent period of the Spanish power system history, it was characterized by a strong expansion, liberalizations, restructuration of the companies, progressive integration, and harmonization with the other European Union countries. In the beginning of the 90's, the power companies were strongly regulated or intervened by the governments worldwide. In Spain, differently from almost all European countries and similarly to the USA, the companies were private, using their units in a centralized way, and were remunerated by the MLE framework. Within the imminent European directive to create a regional power market, the socialist Government approved in 1994 the LOSEN. This model, declaring a middle point between the traditional regulation and the free market, was never applied. But it created the National Power System Commission, which later on would be changed to the actual CNE. The new government, in the context of the [EC9296], agreed with the Spanish utilities in 1996 several conditions, what finally resulted into the important [L5497].

The [L5497] establishes the principle of access freedom to the network by all market agents (with a toll payment), and starts a competitive market, with bilateral contracts and an exchange market, managed by a new independent company, the OMEL. In this market, the suppliers submit bids at marginal prices, and the retailers demand energy at a specific price, resulting in a market price where all the energy is negotiated. The renewable energies and CHP are under a special regime by their environmental characteristics. The transmission and distribution lines are natural monopolies that continue to be regulated, what obliges the utilities to separate their regulated and competitive businesses. Spain in especial had a great advantage because it anticipated in more than ten years the creation of the REE, a separated and independent company, specialized in the activities of transmission and system operation. In this way, the vertically integrated companies just had to separate legally their regulated and no-regulated activities, but the property remained in the same holding. The consumers gradually obtained the possibility of choosing their supply company, in a way that in 2003 all the consumers had already this right recognized. In July of 2007, formally started the integration between the Spanish and Portuguese Market into the MIBEL, with a market splitting mechanism in the SPOT market of the Iberian Peninsula [ARRI07].

1.1.2. The Insular and Extra-Peninsular Spanish Power Systems

The small size and isolated power systems have several features that difficult operation and make their electricity costs higher. The generation units cannot be of large size, since a loss would represent a great impact in the overall system. This implies that it is not possible to exploit in an adequate way the scale economies of large and meshed power systems. In addition, the technical operation of the network to frequency and voltage control is complicated. In addition, the fuel transportation also helps to increase the costs in these kinds of structures. Because all these peculiar features, they require a different regulatory treatment. In the case of Governmental control, normally these structures pay the same electrical tariff, which must be financed by all the consumers (as in the Spanish case). For competition introduction, the isolated systems also face difficulties by its size, what has been leaded normally to traditional integrated companies. This model presents the additional advantage of considering explicitly the development of renewable energies. Finally, in some isolated systems, it was considered the introduction of physical bilateral contracts, what complements the operation of a traditional and regulated model [PERE07].

The [L5497] promoted in Spain a transition process from a traditional regulation regime to another structure introducing competition in the generation and retailing. In addition, it recognizes the necessity of a special regulation to the SEIE, due to its isolated features and the lack of possibility in the short term to interconnect their systems. Due to the constant complaints of the incumbent company because the system was not retributing properly its power services, it was finally approved in 2005 a new regulatory framework for the islands with [MITC91406] and [MITC91306] taking the principles published by the [ME174703]. Thus, from 2006, oficially REE was declared in charge to operate this very peculiar Spanish power structure, composed of two (systems of) islands and two autonomouns cities, namely Balearic and Canary Islands and Ceuta and Melilla cities. Because their singular structure (isolated and of small size), they have been operated effectively since then with a centralized generation dispatch mechanism (traditional scheme), bringing back from 1996, in part, the old MLE. This methodology brought transparency not just to generation activities, but also to transmission and distribution in the SEIE.

1.2. Technical Framework

The structure and operation of the electric sector after the implementation of modifications to the system in 1984, along with the financial returns system operating in the companies from 1998, meant a great change, which had important economic consequences for the Spanish electricity industry. It shall now be described the overall technical operation of the SEE and SEIE and their most relevant actual figures.

1.2.1. The Spanish Power System

The Spanish electricity sector from 1998 operates immersed in a liberalized framework, where competition in the generation and retailing activities has been gradually incorporated into the system. The basic principle of the SEE is the freedom for contracting by generators, retailers and consumers, declared by the [L5497] and further developed in the following years in accordance with the common European legislation.

The sector is regulated by the CNE, which is in charge of ensuring an effective competition and the objectivity of the market operation. Transmission and distribution activities remain deeply regulated, adopting legal unbundling[1] to separate regulated from competitive business in companies of the same holding group. The operation of the system is implemented by two independent entities: the market operator and the system operator. The REE is a necessary independent system operator responsible to manage the functioning of networks and real physical energy markets. There is also a day-ahead energy market operated by OMEL, where generators and consumers bid hourly their energy at marginal prices. Aggregated to this process, there exist forward markets with bilateral phisical and finantial contracts, as well as short term markets to cope with real time unbalances between load and supply. In addition, OMIP operates an organized forward market within the MIBEL arrangement.

Within the competitive generation side of the sector, there is distintiction between two regimes: the *special regime* and the *ordinary regime*. The first business activity includes electricity generation though small hydro, CHP, biomass and waste, and is used to boost distributed, renewable and low polluting ways of generation. It gives an economic incentive by a premium for the investors within this category, ensuring a correct and attractive retribution for their generation activities, both in the day-ahead market operation and with bilateral transactions. The ordinary regime works in normal market operation conditions and is composed by all the remaining installed capacity. Fig.1.1 and Fig.1.2 show actual data about the SEE generation structure. The ordinary regime was responsible in 2009 for producing the major part of the system energy needs (70% - 192.462 GWh; 66% – 61.902 MW). Interesting to note the high weight of CCGT units in the SEE ordinary regime, in both production (29% - 79.992 GWh) and installed capacity (24% - 22.243 MW). Due to technological improvements and approppriate market conditions, this technology has boosted since the liberalization of the sector[2].

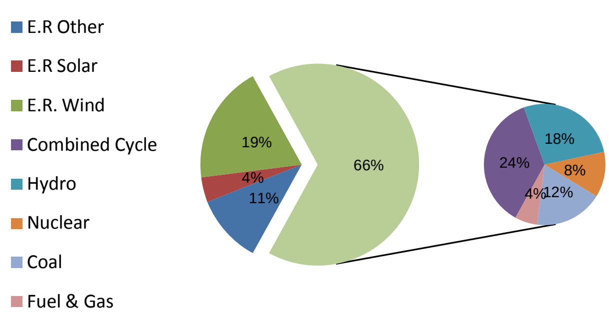

Fig. 1.1 - SEE installed capacity, 31/12/09

[1] In general, four different models of unbundling can be defined: administrative unbundling, management unbundling, legal unbundling, and ownership unbundling. As part of the liberalization of electricity markets, EU regulations [EC5403] require the legal unbundling of all networks from the remaining units in the electricity value chain.

[2] Basically, in the generation ordinary regime category just CCGT units have started operating from 1998 in Spain.

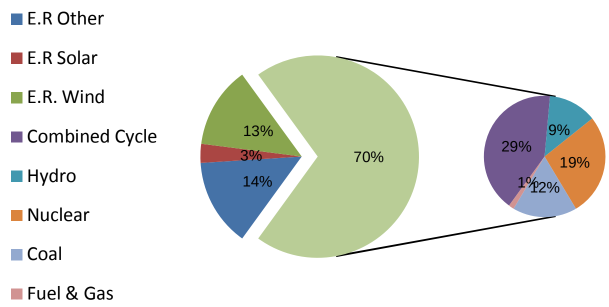

Fig. 1.2 - SEE energy production, 2009

The SEE is also characterized by its poor international connection capacity. It has corridors with Portugal, France, and Morocco, with a total of exports/imports capacity (MW) in peak hours of, respectively, 1.600/1.700, 400/1.400, and 700/600. Spain is typically a net export agent, with a total amount in 2009 of 1.766 GWh (France), -5.239 GWh (Portugal), and -4.925 GWh (Andorra/Morocco), where the negative sign represents net exports.

As a final point, in the context of security of supply, system efficiency and European integration scheme, Portugal and Spain have been closing relations to a common energy market, called MIBEL. In this structure, forwards markets have started in July 2006, while SPOT markets have been operating since July 2007. Energy financial transactions are managed by OMIP for physical and financial forward contracts and OMEL for the day-ahead energy transactions. And REN and REE are responsible for physical operations. Typically, the net balance of these connections tends to energy exports to Portugal, once prices are normally higher at that side of the border. So, according to the market splitting model for interconnection lines, there appears a price difference from the network congestions.

1.2.2. The Insular and Extra-Peninsular Power Systems

The SEIE are divided into two systems of islands and two autonomous cities, namely:

- Balearic Islands – Majorca-Menorca, Ibiza-Formentera;
- Canary Islands – Gran Canaria, Tenerife, Lanzarote-Fuerteventura, La Palma, La Gomera, and El Hierro;
- Ceuta y Melilla cities.

The sub-system Majorca-Menorca is linked by an interconnection line of 132 kV, and Ibiza-Formentera with a line of 30 kV. In the Canary Islands there is just one interconnection – Lanzarote-Fuerteventura of 66 kV. All the other systems are completely isolated. Actually, nowadays there is no possibility of changing this situation. The deep water depths impede to lay any submarine cable to interconnect their power structures.

Regarding the system operation, REE has exclusivity for the system transmission and is in charge for building, maintaining and maneuvering the components of their energy transmission network. In addition, it is responsible for the centralized generation economic dispatch of this traditional structure. The REE does not own the transmission facilities. The almost totality of the SEIE transmission and generation structure is property of the power company Endesa.

The generation arrangement is composed also of the ordinary and special regimes. Fig.1.3 and Fig.1.4 illustrates their relative percentages. Differently from the SEE, in the SEIE the almost totality of the energy production is with ordinary generation (94% - 15.403 GWh; 92% - 4.883 MW), with almost a half of fuel and gas technologies (49% - 8.016 GWh; 56% - 2.980 MW). As can be confirmed, due to the SEIE very peculiar layout, it represents a costly generation structure, with the predominance of fossil generations and few margins to benefit from interconnection lines. In this way, centralized operation would work more efficiently than market structures.

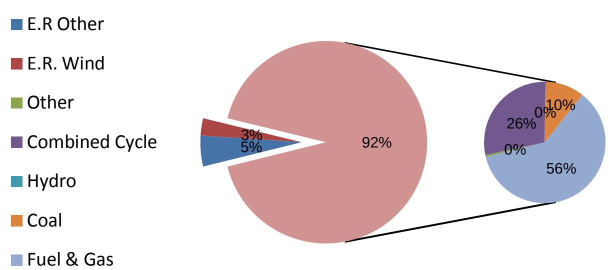

Fig. 1.3 - SEIE installed capacity, 31/12/09

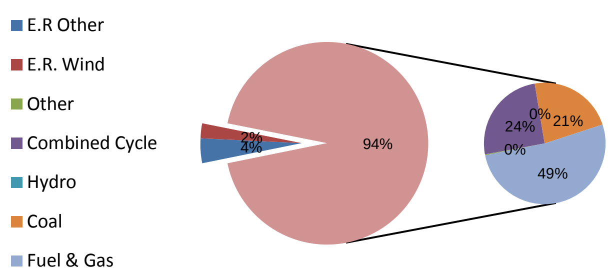

Fig. 1.4 - SEIE energy production, 2009

1.3. Motivations and Objectives of the Study

After approximately 15 years from the starting of liberalization processes, several studies have tried to balance the gains and losses of the electricity reforms worldwide. Some emphasize the analysis of social cost-benefits to consumers, governments and companies [NEWB97]. Several authors focus also on the effect on prices, using econometrics and statistical tools [GLOB05]. The evolution of costs is the second area that has been receiving more attention [FABR07]. And, to conclude the list, the affect over the investments, innovation and quality of supply were topics for many discussions on the specialized literature [DYNE07]. The overall view indicates that, even pointing towards a relative welfare gain in liberalized markets, their results are not conclusive and several times divergent.

The situation in Spain is not so different. There is much speculation about the affordability and the efficient gains from 1998 over this new system. And some even argument that prices are far more volatile in the actual market, with the tensions on fuel prices being internalized in a larger extent than in centralized markets. Within this dynamic environment, it is somewhat surprising the lack of public studies about the topic for the SEE. In this way, this project has the purpose, with a **formal and public study**, to contrast both centralized and market-oriented structures in the actual Iberian power system. As specific objectives, it can be mentioned:

- Study the current generation cost structure (regulatory, technical and economic) in centralized systems, particularly applied to the SEP;
- Reproduce the methodology used to pay the ordinary regime generation costs in the SEIE between the years 2006 and 2009;
- Contrast argumentatively current ordinary regime generation prices for the Iberian system between two polar structures: *centralized vs market-oriented* in the years 2006, 2007, 2008 and 2009.

1.4. Methodology Applied

This work can be split into two separated and interrelated parts. For both, the following four modeling steps are taken: *conceptual structure representation*, *data gathering and processing*, *model building*, and *simulations and validations*:

a) *study, model and replicate the SEIE generation prices structure;*
b) *transpose and adapt the previous methodology to the SEP reality.*

A number of main points must the highlighted. The methodology implemented in the SEIE was chosen to be used as a benchmark to the SEP, and not the one of the MLE. It may represent a more close and current approximation of traditional generation regulatory structure for the SEP than the MLE. Thus, the period of investigation converges with the time this structure has been operating in the SEIE – 2006 to 2009. The autonomous cities Ceuta and Melilla, for the sake of simplicity, are not indexed because their small power system characteristics. Just **Balearic and Canary Islands are modeled**. All the items that are going to be worked out in the following Chapters are only and always focused on the **ordinary generation regime** and the **Iberian market**. Special regime is not considered here because the regulatory stability. Nor transmission, trading, distribution or metering costs are taken into account. Finally, the main purpose along the assumptions implemented was always to use available and public data references, mainly from published regulatory documents and system operators and market agents' home pages.

1.5. Report Structure

The Chapter 2 presents the conceptual structure study based on mathematical relations to the fixed and variable generation costs computation in the SEIE. In the third Chapter all the data collection and processing part to fulfill the generation costs conceptual model of the SEIE is extensively elaborated. The fouth chapter works on all the modeling contruction part for the SEIE. It elaborates on the necessary assumptions and simplifications to adapt the gathered data to the most reasonable computational tools employed. Chapter 5 encloses the end of the first part of the work. It shows the output results from the models utilized and demonstrates the validity of the assumptions, comparing simulated generation prices with real published standards by the regulator. Once succesfully validated, the built SEIE structure can now be transposed to compute the SEP generation costs under a theorethical traditional regime. The Chapter 7 than adapts the conceptual structure and the model codes to several specificities and additional complexities of the SEE. Various economic hyphotesis for future discussions are also first introduced. In this way, the final quantitative results of the work are shown. They contrast the model outputs on generation prices with a realistic figure of the actual liberalized prices over several independent energy markets. With these graphical outcomes, together with stastistical tools, preliminary conclusions of the work are elaborated. The Chapter 8 is finally reserved to the last economic discussions and conclusions about the validity of previous postulations. It gives moreover some regulatory recommendations and points potential future studies.

Chapter 2. Generation Costs Conceptual Structure

Firstly, it is necessary to identify the factors that could have influence while replicating the generation costs inside the SEIE. This chapter therefore works on the calculus of both capacity payments and variable costs inside the SEIE. For the first case, the published [MITC91406] and its corrections [CMITC91406] are especially illustrative as reference. And for the latter, the [MITC91306] guides the general context for variable prices.

2.1. Mathematical Theory for Costs Computation

The generation costs in the ordinary regime for the SEIE can be decomposed as a sum of a fixed and a variable component:

$$gc(i,h) = gc_f(i,h) + gc_{var}(i,h) \tag{2.1}$$

Where:

$gc(i,h)$:	total cost of each unit *i* in the hour *h* [Euros]
$gc_f(i,h)$:	fixed cost of each generation unit *i* in the hour *h* [Euros]
$gc_{var}(i,h)$:	variable cost of each generation unit *i* in the hour *h* [Euros]

The final hourly generation price is therefore calculated as:

$$FPG(h) = \frac{\sum_i gc(i,h)}{\sum_i e(i,h)} \tag{2.2}$$

With:

FPG(h):	final hourly generation system price [Euros/MWh]
$e(i,h)$:	energy generated by the unit *i* in the hour *h* [MWh]

The next items develop the mathematical methodology and assumptions to compute each of the generation costs in the SEIE.

2.2. Capacity Payments

Generally, the non variable component of generation costs can be written as:

$$gc_f(i,h) = Gpow(i,h).Pavailable(i,h) \tag{2.3}$$

Being:

$Gpow(i,h)$:	hourly capacity payment of the unit *i* in the hour *h* [Euros/MW]
$Pavailable(i,h)$:	available power of the unit *i* in the hour *h* [MW]

The *capacity payment* concept compensates the investment and operation and maintenance costs, taking into account the necessary reserve level in the SEIE and the additional cost of each technology. And the a*vailable power* is defined by the difference between the installed capacity and power unavailable of the unit *i* in each hour.

In order to calculate the hourly capacity payment of each generator, (2.3) can be decomposed as follows:

$$Gpow(i,h) = \frac{Gpow(i)_n}{Hi} . fsea_h \qquad (2.4)$$

Where:

$Gpow(i)_n$:	annual capacity payment of the unit *i* [Euros/MW]
$fsea_h$:	hourly seasonality factor
Hi:	annual equivalent fired hours of the unit *i* [h]

The DGPEM establishes the *annual capacity payment* value before January 1th of each year. When the semester Government Bonds (10 years) moving average (January till June) vary 100 basis points in relation to the previous calculated average value, the next semester capacity payment value will be revised taking into account this variation.

The *hourly seasonality factor* is used to take into account the different year´s period (peak, shallow, and valley) on the hourly capacity payment. And the *annual equivalent fired hours* considers the unit standard annual hours of fail and maintenance.

For the computation of the annual capacity payment of each generation unit, it comes:

$$Gpow(i)_n = CIT_{in} + COMT_{in} \qquad (2.5)$$

With:

CIT_{in}:	annual investment cost of the unit *i* [Euros/MW]
$COMT_{in}$:	annual operation and maintenance fixed cost of the unit *i* [Euros/MW]

In turn, the annual investment cost is related with investments on amortization and a financial retribution for the unit:

$$CIT_{in} = A_i + R_{in} \qquad \forall \quad t_{op_i} < LC_i \qquad (2.6)$$

$$CIT_{in} = 0{,}5. CIT_{LC_i} \qquad \forall \quad t_{op_i} \geq LC_i \qquad (2.7)$$

Being:

A_i:	retribution for annual investment amortization of unit *i* [Euros/MW]
R_{in}:	financial retribution of the investment for unit *i* [Euros/MW]
LC_i:	lifecycle of the unit *i* [yr]
CIT_{LC_i}:	annual investment cost of unit *i* in last year of its lifecycle [Euros/MW]

In the equations (2.6) and (2.7), t_{op_i} reefers to the total operation time of the unit *i*, since it started operating. The *lifecycle* of a given generation unit is standardized. For the two different retributions of (2.6), it comes:

$$A_i = \frac{VI_{in}}{LC_i} \qquad (2.8)$$

$$R_{in} = VNI_{in}.Rr_n \tag{2.9}$$

With the following definition:

VI_{in}: recognized investment value of unit *i* [Euros/MW]
VNI_{in}: investment net value of unit *i* in the year *n* [Euros/MW]
Rr_n: financial retribution rate to be applied in year *n*

The *financial retribution* corresponds to the moving average value of the previous 12 months' 10-years Spanish Government Bonds, when implementing the tariff, more 300 fundamental points. To obtain the value for the recognized investment value - numerator of (2.8) - it come the following case condition:

$$VI_{in} = VI_{in_{real}} + 0{,}5.\left(VI_{in_{max}} - VI_{in_{real}}\right) \quad \forall \quad (VI_{in_{max}} - VI_{in_{real}}) \geq 0 \tag{2.10}$$
$$VI_{in} = VI_{i_{nmax}} \quad \forall \quad (VI_{in_{max}} - VI_{i_{nreal}}) < 0 \tag{2.11}$$

Where:

$VI_{in_{real}}$: real audited investment value of unit *i* [Euros/MW]
$VI_{in_{max}}$: maximum investment value of unit [Euros/MW]

The relation (2.10) implies that the real investment value of unit *i* is given by the *real audited investment* when starting operating more 50% of the difference between a maximum value set and the real one. These *maximum investment values* are defined by the DGPEM. They are updated each year with the annual variation of IPI (moved average of the last 12 months available when it is implemented the average tariff). If the real investments of the unit exceeds the allowed limits, (2.11) comes true and the recognized investment becomes just the maximum standard value.

To conclude the computation of (2.9) and, consequently (2.6), it is necessary to calculate the investment net value defined as:

$$VNI_{in} = VI_{in} - Aai_{n-1} \tag{2.12}$$

With:

Aai_{n-1}: accumulated amortization of unit *i* until the year *n-1* [Euros/MW]

The accumulated amortization is calculated by a linear depreciation of the recognized investment value of the unit within its lifecycle. Continuing the formulation to obtain the value of the annual power guarantee (2.4), just the annual power guarantee term (2.5) is missing. Once the methodology to calculate the annual investment value (CIT_{in}) was already delineated, it is just omitted the annual operation and maintenance fixed costs, established with the conditions:

$$COMT_{in} = COMT_{in_{max}} + \varphi.VI_{in} \tag{2.13}$$

Being:

$COMT_{in_{max}}$: maximum annual operation and maintenance fixed costs of the unit *i* [Euros/MW]
φ: rate of unitary recurrent nature costs

The *annual operation and maintenance fixed costs* for each unit is set by the DGPEM. Its maximum unitary values are updated each year with the annual variation of the IPC (moved average of the last 12 months available when it is implemented the average tariff) minus one hundred basis points. Finally, to the monthly liquidation and to the generation dispatch, the *unitary recurrent nature costs* of each unit are defined provisionally by the regulator. The definitive values to be considered in each year are going to be the real audited recurrent expenses.

2.3. Variable Costs of a Generation Unit

The variable component of generation costs is broadly defined as follows:

$$gc_{var}(i,h) = e(i,h).\left[APP + PrF(i,h)\right] \tag{2.14}$$

Where:

APP:	average peninsular price [Euros/MWh]
$PrF(i,h)$:	premium for the generation unit *i* in the hour *h* [Euros/MWh]

The *average peninsular price* is defined annually by a Royal Decree (*Real Decreto*). This price includes the charge for auxiliary services delivered in the peninsular system and excludes the charge for secondary reserve. And the *premium* given for a generation unit complements the *APP*, in order to compensate the fuel costs, is calculated in hourly basis and can become negative.

Therefore, the *premium* of a generation unit in the SEIE ordinary regime is composed by the following five different costs concepts:

$$PrF(i,h) = \frac{C_{op}(i,h)+C_{st}(i,h)+C_{wu}(i,h)+C_{om}(i,h)+C_{reg}(i,h)}{e_{pow}(i,h)} - APP \tag{2.15}$$

With:

$C_{op}(i,h)$:	variable operating (fuel) costs of the unit *i* in the hour *h* [Euros/h]
$C_{st}(i,h)$:	variable start-up costs of the unit *i* in the hour *h* [Euros/h]
$C_{hs}(i,h)$:	variable hot standby costs of the unit *i* in the hour *h* [Euros/h]
$C_{om}(i,h)$:	variable operation and maintenance costs of the unit *i* in the hour *h* [Euros/h]
$C_{reg}(i,h)$:	variable secondary regulation costs of the unit *i* in the hour *h* [Euros/h]
$e_{pow}(i,h)$:	average hourly power of the unit *i* in the hour *h* [MW]

The *average hourly power* is of the same order of $e(i,h)$, refeered to hourly energy. The distinct costs of (2.15) are going to be explained in the next items.

2.3.1. Variable Operating Costs

It is the variable costs of each generator *i* associated to its fuel consumption and it is calculated by (2.16):

$$C_{op}(i,h) = \left[a(i) + b(i).e_{pow}(i,h) + c(i).{e_{pow}}^2(i,h)\right].pr(i,h) \tag{2.16}$$

Being:

$a(i)$: quadratic adjustment parameter [th/h]
$b(i)$: quadratic adjustment parameter [th/h.MW]
$c(i)$: quadratic adjustment parameter [th/h.MW^2]
$pr(i,h)$: fuel therm average price utilized by unit *i* in the hour *h* [Euros/th]

All the *quadratic adjustment parameters* are obtained with the hourly thermal consumption curve of each generator (gross consumption/power). They are set by the DGPEM and can be revised each four years. While the *average price of fuel* is determined using the relation (2.17):

$$pr(i,h) = \sum_c \frac{x(c,i,h).prf(c,i,h)}{lhv(c,i,h)} \tag{2.17}$$

Where:

$x(c,i,h)$: fraction of the total therm of fuel *c* utilized by the unit *i* in the hour *h*
$prf(c,i,h)$: price of fuel *c* utilized by the unit *i* in the hour *h* [Euros/t]
$lhv(c,i,h)$: low heating value of fuel *c* utilized by the unit *i* in the hour *h* [th/t]

The low heating values according to the fuel type are previously defined. If the acquired fuel has a value significantly different from these, the DGPEM can authorize other standards.

In turn, the *fraction of the total therms of fuel* is stipulated as:

$$x(c,i,h) = \frac{Q(c,i,h).lhv(c,i,h)}{\sum_c Q(c,i,h).lhv(c,i,h)} \tag{2.18}$$

With:

$Q(c,i,h)$: consumption of fuel *c* by the unit *i* in the hour *h* [t/h]

The *price of fuel* is composed by: the product price (CIF international value on the spot market); and the logistic costs (unload, port services, intermediate storage, transmission to the central cistern, ships and trucks, quality control and adequacy, commercialization tariffs and costs).

$$prf(c,i,h) = prp(c,i,h) + log(c,i,h) \tag{2.19}$$

Where:

$prp(c,i,h)$: product price of fuel *c* by the unit *i* in the hour *h* [Euros/t]
$log(c,i,h)$: logistic cost of fuel *c* by the unit *i* in the hour *h* [Euros/t]

The *product price* is established according to geographic zone and fuel package for each SEIE. They are fixed each six months by the DGPEM, in January and July, and are calculated as the average of monthly prices, corresponding to the previous six months, depending of the fuel type. In case of new fuels, the MITC approves a new method to compute the fuel price. For the conversion from USA dollars to Euros, it is taken the average of the daily USA-Euro exchange types published by the European Central Bank and corresponding to the period of combustible price calculus. Also, the six-months calculated fuel prices used to the variable dispatch of generation costs are regularized each January and July by the real average values (from the last six months). Finally, the fuel costs are going to be revised in the end of each year to take into account the internalization of emissions price rights by the generation units. Regarding the *logistic costs*, they are actualized annually with the IPC foreseen in the tariff minus one-hundred basis points. The DGPEM could revise these values each four years.

It is convenient at this point, to avoid any possible misunderstanding, to make clear the distinction between three conceptual prices types defined by the regulator and extensively mentioned along the work. The **product price** (prp) is always associated with the average fuel quotation prices, calculated with various sources (international or national markets). On the other hand, the **price of fuel** (prf) takes into account *all* the fuel cost (product plus logistics). Finally, The **fuel therm average price** (pr) gives the thermal average value of the fuels used by a given generation unit.

2.3.2. Variable Start-up Costs

It is related to the start-up costs of a generation unit, both to the fuel consumption and other variable costs, with formulation as follows:

$$C_{st}(i,h) = a'(i).\left[1 - \exp\left(-\frac{t}{b'(i)}\right)\right].pr(i,h) + d \tag{2.20}$$

Being:

t:	time period since the last unit stop [h]
$a'(i)$:	exponential adjustment parameter [th]
$b'(i)$:	exponential adjustment parameter [h]
d:	additional operation and maintenance costs [Euros]

The *exponential adjustment parameters* are obtained with the consumption/stop hours curve. The DGPEM approves the parameters values (*a'*, *b'* and *d*) for each SEIE with a report of the CNE. The *additional operation and maintenance costs* are established for each unit start-up and are actualized annually with the forecast tariff IPC minus one hundred basis points.

2.3.3. Variable Warming-up Costs

To avoid the stop and start-up of a generation unit, the System Operator can decide to set a unit to the condition of warming-up. In this way, instead start-up costs, it will be applied the operation and maintenance costs of this state:

$$C_{wu}(i,h) = Q_{wu}(i,h).prf(i,h) \tag{2.21}$$

With:

$Q_{up}(i,h)$:	fuel consumption of unit *i* in the hour *h* during hot standby [t/h]

It is understand as warming-up of a steam thermal unit when it maintains the thermal boiler conditions to be able to connect immediately in the network with its minimum technical. The *fuel consumption* values are approved provisionally by DGPEM.

2.3.4. Variable Operation and Maintenance Costs

It corresponds, basically, to material and the planned maintenance costs of each generation unit. This expenditure also includes the working capital costs. It is formulated as follows:

$$C_{om}(i,h) = a''(i) + \frac{b''(i)}{100} . C_{op}(i,h) \tag{2.22}$$

Where:

$a''(i)$: O&M functioning hour's parameter [Euros/h]

$b''(i)$: fungible material and working capital's parameter [%]

The DGPEM approves the parameters values (*a''* and *b''*) for each SEIE with a report of the CNE. The *O&M functioning hour's parameter* is actualized annually with the forecast tariff IPC minus one hundred basis points.

2.3.5. Secondary Regulation Costs

It refers to the generation over cost due to the assigned band regulation (up and down) by the system operator in order to regulate the equilibrium between the load and supply, as well to guarantee a reserve margin for system security, being formulated as:

$$C_{reg}(i,h) = a'''(i,h) . p_{reg}(i,h) \tag{2.23}$$

Where:

$a'''(i,h)$: secondary regulation price [Euros/MW]

$p_{reg}(i,h)$: assigned secondary regulation of the unit *i* in the hour *h* [MW]

Finally, the *secondary regulation price* is fixed only to units having an assigned regulation band and included in the AGC:

$$a'''(i,h) = 0{,}05 . Gpow(i,h) \tag{2.24}$$

Chapter 3. SEIE: Data Collection and Processing

After the conceptual model has been described, it must be specified in terms of these concepts. This has been done by data collection, processing, and model construction. The two first steps are worked out in this chapter, specifying all the indexes, parameters, and values necessary to replicate generation costs inside the SEIE.

3.1. Constraints and Main Assumptions

For the SEIE, data searching have been necessary in order to get an accurate replication of the methodology used by REE in the ex-ante generation dispatch and ex-post price calculation. Due to the new regulatory framework for the islands, many of the necessary information were already published. They gave a nice start point to look for. The major difficulties while trying to access the information can be resumed as:

- hourly energy generated by generation units: $e(i,h)$ or $e_{pow}(i,h)$;
- hourly available power of generation units: $Pavailable(i,h)$;
- recognized investment values of generation units: VI_{in};
- average peninsular price: APP;
- time period since the last unit stop: t;
- assigned secondary regulation of the generation units: $p_{reg}(i,h)$;
- hourly fuel consumed by generation units: $Q(c,i,h)$.

For these points, some coherent hypotheses have been taken.

3.1.1. Hourly Energy Generated by Generation Units

Regarding the hourly energy generated by generation units, the most precise information in public technical documents for the islands were in the daily power schedule published by the REE on its website[3]. It is possible to access the daily outputs by technology (namely coal, fuel and gas, CCGT, hydro). Also, it is possible to find the generation of the units in special regime and the overall consumption of their auxiliary services. In addition, there are data available for each islands' power system. But for the variable energy price computation, the output power for individual units would be needed. Therefore, to find this output it was implement a simplified economic dispatch taking the technology generation as a residual demand for a group of units. And additionally it was used the islands' demand as a restriction to take into account the transmission limitations between the power systems. In centralized power systems, the power dispatch of units is first scheduled by an optimization problem purposing to minimize the overall system costs. Therefore, the idea was that the daily simulated output would be precise and realistic enough for the objective of this work. This step will be extensively elucidated in Chapter 4.

[3] www.ree.es

3.1.2. Hourly Available Power of Generation Units

For capacity payments calculation, there is no published data in hourly basis about available power of generation units. The only source was in the new monthly report, available in the official website of REE, for the Canary and Balearic Islands. It gives the average monthly generation availability by technology (coal, fuel and gas, and CCGT can be found). And there are published, till the middle of 2010, just seven reports for each system, with information from January to August of 2009. Thus, it was defined a standard and fixed hourly availability, by technology, taking a simple average of the monthly percentage. And this value was used as standard for all simulated years (2006 till 2009). For hydroelectric generation, it was considered as 100% available. In reality, the only hydro unit in the islands – *El Mulato* – has not been operating. It is important to say that all these simplifications are expected to cause just a minor impact on the final energy prices output, once the units availability normally varies very little in real systems and is usually above the 90%. Table 3.1 below resumes what was justified on the previous lines.

Table 3.1 - Power availability in the SEIE

Generation Availability 2009 (%)									
Technology	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**AVERAGE**
Balearic Islands									
Coal	98,09	98,89	83,31	86,82	98,20	99,86	97,21	99,77	**95,27**
Fuel + Gas	95,52	94,40	84,65	89,81	89,23	97,48	94,77	93,42	**92,41**
CCGT	96,12	93,17	95,06	97,88	95,92	94,64	98,63	99,25	**96,33**
Canary Islands									
Coal	--	--	--	--	--	--	--	--	**--**
Fuel + Gas	95,05	95,75	94,62	93,97	90,23	87,83	91,55	92,64	**92,71**
CCGT	92,45	100,00	92,45	99,62	80,78	93,26	99,69	94,88	**94,14**

Source: SEIE monthly reports, own elaboration.

3.1.3. Recognized Investment Values of Generation Units

The recognized investment values of units operating on 31/12/05 were calculated and published in [MITC91406]. On the other hand, for units starting from 2006, there is not any mention about them. Neither any readjust of values accorded. Thus, it was taken the investments documented in the Order as standard. For new capacity installed, the maximum allowed investment published every year, by technology, was used as reference. In fact, the final recognized value under this new regulatory framework inside the SEIE is always very close from the maximum allowed limits given as incentive to minimize fixed investment costs. The Appendix 1 resumes the main inputs of generation units for capacity payment estimation in Canary and Balearic Islands.

3.1.4. Average Peninsular Price

Less difficult was the determination of the average peninsular price. In theory, it would be obtained and clearly defined by a Royal Decree that approves the tariff for a given year for the SEE. Working out on (2.14) and (2.15), it is possible to observe that, in reality, this variable does not influence the calculation of variable generation costs, once it is annulated when adding up the equations. The main purpose of defining a "premium" by the regulator is to get a clear image of the extra-cost of the SEIE when comparing it with the SEE. This additional system expenditure was ruled by [L5497] and distributed between all the consumers, purposing an equal tariff in the Spanish power system. Now, the management of this topic is being transferred to the Government Budget[4]. In this way, this price does not affect the results of the model.

3.1.5. Time Period Since the Last Unit Stop and Secondary Regulation

The time period since the last unit stop and the hourly secondary regulation are another unknown parameters. The first is used to determine the costs due to the start-up of units. And the second takes place to calculate de costs for generation units included in the AGC. Because of these difficulties they had not been considered. The solution for the time constant was to transform the exponential equation (2.20) in a linear relation in a way that the time between units stops does not need to be considered in a horizon of 24 hours (modeling horizon). In this way it is obtained a linear expression that reduces considerably execution times. Actually, this linearity is necessary when working with linear and binary integer problems, as it will be discussed in the modeling part. For the hourly secondary regulation, it was decided, as a valid simplification, not to consider this cost. If several units are participating in the AGC system, more start-ups and shut-downs would be necessary to supply a given demand. On the other hand, for the sake of simplicity and low overall impact, this expenditure is often neglected while simulating optimization problems for economic dispatch of generation units. And in the case of SEIE, it represents only 5% of the hourly capacity payment costs per assigned megawatt (2.24).

3.1.6. Hourly Fuel Consumed by Generation Units

Concerning the hourly fuel consumed by generation units, the information available is about which fuel to consider in each SEIE and the methodology to obtain their price. And the task becomes more complex if we take into account that the CCGT units, because availability and regulatory reasons, have been not burning natural gas until the moment. They are using until the moment any fuel possible to be gasified. On the other hand, this situation is going to change soon. The recent proposal [MITC10] regulates different aspects of the SEIE. It suggests the calculus of a new framework for gas prices in the islands due to the start of operation of a submarine pipeline to Balearic Islands. In this way, CCGT units and gas turbines in open cycles are going to be allowed to burn the new fuel. In fact, the gas pipeline connected to Balearic Islands has been operating for tests since the end of 2009. The process for adapting units for the new fuel takes on average 2 months by plant. In this way, all the system is expected to be fully running with natural gas from the end of 2010.

Thus, given all this uncertainty, it was considered that each unit just work with one type of fuel – (2.18) equals to one - and the average price of fuel (2.17) is equal to

[4] The [RDL609] establishes that the over cost of the SEIE is going to be incorporated in the Law of General Budgets (*Ley de Presupuestos Generales*). In the year 2009, this compensation was in 17%. For 2010, 2011, and 2012, the rates are going to be, respectively, 34%, 51% and 75%. And from this year, all the cost is going to be financed (100%). The remaining amount that has not been included in the Government Budget, together with any possible values deviations, between 2009 and 2012, is going to be financed by access tolls and is going to be considered a permanent system cost.

the average price of all fuels that could be utilized by that unit. Table 3.2 illustrates which fuels must be considered for each SEIE.

Table 3.2 - Fuels to be considered for each SEIE by technology

Balearic Islands		Canary Islands	
Technology	**Fuel**	**Technology**	**Fuel**
Coal	Imported Coal	**Gas**	Fuel Oil BIA 1,0% Fuel Oil BIA 0,3% Diesel Oil Gas Oil
Gas	Fuel Oil BIA 1,0% Fuel Oil no 1 Gas Oil	**Fuel (Oil)**	Fuel Oil BIA 1,0% Fuel Oil BIA 0,3%
Fuel (Diesel)	Gas Oil	**Fuel (Diesel)**	Diesel Oil Gas Oil
CCGT	Fuel Oil BIA 1,0% Fuel Oil no 1 Gas Oil	**CCGT**	Fuel Oil BIA (sulfur 1,0%) Fuel Oil BIA (sulfur 0,3%) Diesel Oil Gas Oil

Source: [MITC91306], own elaboration.

3.2. Indexes, Fuels Data and other Technical Parameters

The seven items listed in the prior items were the main difficulties faced when collecting data. More minor hypotheses were also made to face the lack of data. The information about units start operating and ending their operation from 2006 is public, published, but somewhat fuzzy. There are annual reports available in the website of REE, in the end of each year, establishing the main parameters of generation units and the transmission system for the Spanish power structure, including the SEIE. When no information was available, the first and last day of the year were taken respectively to the units' starting and ending operation. Also, a mathematical approximation was implemented to estimate net power of CCGT units working with different layouts (1x1, 2x1, 3x1) and those thermal units that only the gross power was accessible.

After solving all the problems when gathering data above mentioned, the rest of values were relatively easy to obtain in regulatory documents. Table 3.3 shows, for example, the seasonality factors to be used. Most of the data is established on the basis of a given year, and readjusted forwards based on specific indexes. All are defined annually, with exception of product prices published in a six-month basis (there is a distinction between ex-post and ex-ante prices). In addition, especially concerning technical parameters of units for variable dispatch, they were recognized and standardized for each individual generator in 2002 basis and readjusted each year. For new units, indicative ordinary values by technology were published in the same year with a similar annual readjustment. Appendix 2 and Appendix 3 show, respectively, the standards maximum unitary investment and the O&M values. They are updated with the annual variation of the IPI and IPC minus one hundred basis points. Appendix 4 illustrates the fixed indicative consumption curve parameters for units starting operating from 2002. Appendix 5 provides all the necessary data regarding fuel parameters. It goes from methodology to define product prices, low heating values, logistic costs, till product prices values. In the Appendix 6 and Appendix 7 it is possible to find the start-up parameters and O&M cost parameters for units built from 2002. Finally, Appendix 8 gives all the published data of [MITC91306] by generation unit for the variable cost computation.

Table 3.3 - Seasonality factors

PERIOD	Balearic Islands		Canary Islands	
	Applied Months	Seasonality factors	Applied Months	Seasonality factors
Peak	June, July, August, September	1,15	August, September, October, November	1,05
Shallow	January, February, May, October	1	February, March, July, December	1
Valley	March, April, November, December	0,85	January, April, May, June	0,95

Source: [MITC91406], own elaboration.

The historical moved average of the previous 12 months series for the IPI and IPC can be found on the official Spanish homepage of INE[5] and are showed in the Fig.3.1. Table 3.4 resumes the published indexes.

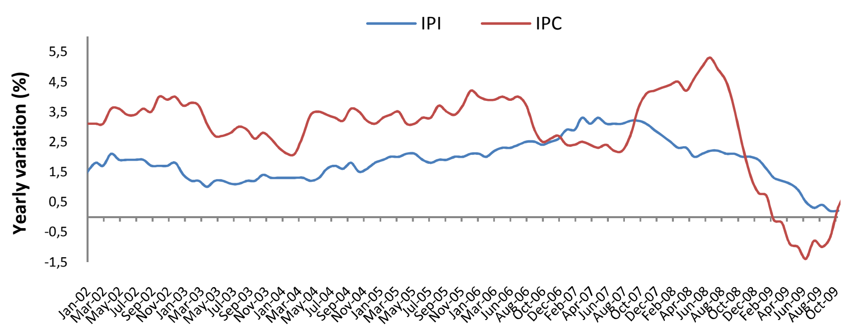

Fig. 3.1 - Yearly variation of IPC and IPI

Table 3.4 - Indexes

Index	Year				
	2006	2007	2008	2009	2010
IPI (%)	N/A	2,4	3,2	2,1	0,2
IPC (%)	N/A	2,5	3,6	3,6	-0,7
Foreseen IPC (%)	N/A	2,0	2,0	2,0	1,0
10-year Government Bonds (%)	3,39	3,79	4,31	4,42	4,01

Source: INE, [DGPEM08], [DGPEM09], [DGPEM10], own elaboration.

The product prices of each fuel to be considered (Table 3.2) are given in the Appendix 5. Fig.3.2 illustrates the historical variation of these prices, from June, 1999. They were calculated based on internal database of fuel stock prices of **Iberdrola**.

[5] www.ine.es

To end the data collection and processing part, just few terms are missing. The lifecycle of units is standardized in 25 years for thermal units and 65 years for hydro ones. The value of operating hours is set to 7.709 hours (normal years) and 7.730 hours (leap years). Finally, the rate of unitary recurrent costs is defined provisory as 1,5%.

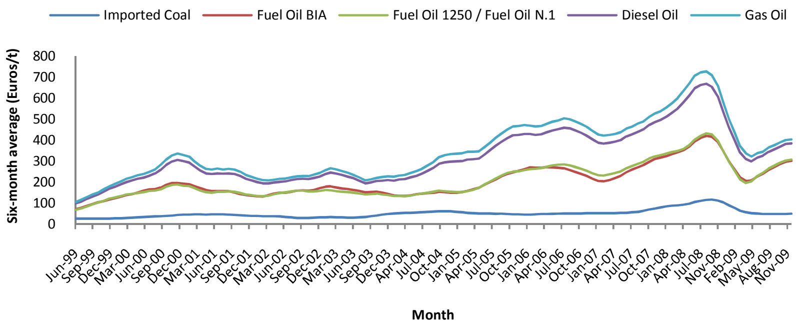

Fig. 3.2 - Six-month average of product prices

Chapter 4. SEIE: Model Construction

The next step in the models' progress is to calculate and validate energy prices in the SEIE. In this context, to choose appropriate computational tools are essential. The model construction can be divided into two distinct and interrelated parts: capacity payments calculation and variable costs assessment. For the first case, straightforward spreadsheets were used. For the latter, an optimization system for economic dispatch of generation units was modeled.

4.1. Fixed Costs Representation

For computing these costs, it could be checked that the methodology published follows simple linear relations (see item 2.2), without any feedback loops. Also, the objective is to analyze quantitatively the outputs and not their dynamic over time. In addition, the necessary input data is available and is relatively not so extensive. Based on these justifications, to handle this step with spreadsheets models would be the most suitable way of working.

Because only start-operating months of generation units are defined on official documents, it was considered the first day of the month as indication to the linear depreciation within the units' lifecycle – needed to estimate their net investment value. Furthermore, the cost of investment in the last operating year for those units already amortized in 2006 was estimated based on the yearly published values (the DGPEM establishes the annual capacity payment value before January 1st of each year). It is important to note that the capacity payment concept for a certain generation unit is constant for almost all hours of the year - just changes between shallow, peak and valley months according to the seasonality factors.

4.2. Variable Costs Model

While collecting the necessary input data for the five cost concepts that guide the variable retribution in the SEIE, it was observed, as introduced in the item 2.1, the need of estimating the hourly output power by generation unit in the system. In fact, there is no public information of units output. The most accurate records about generation were found in the daily power schedule published by the REE on its website. There, it is possible to access the daily outputs by technology (coal, fuel and gas, CCGT, hydro). Also, it is possible to get the generation of the units in special regime and the overall consumption by auxiliary services. In addition, there are data available by power systems of islands (e.g. Ibiza - Formentera and Majorca – Menorca for Balearic Islands). Based in the previous comments, the more realistic way of estimating the individual output power was to build an optimization model to find the best dispatch strategy minimizing the yearly system costs, taking the daily generation by technology as a virtual demand for a group of units. Once in centralized power systems the unit commitment is obtained also by this kind of structure, the idea was that the daily simulated output would be precise and realistic enough for the objective of this work.

In this context, the tool GAMS[6] is specifically designed for modeling linear, nonlinear and mixed integer optimization problems. The system is particularly useful with large, complex, one-of-a-kind problems which may require many revisions to establish an accurate model, like the one in the perspective of the SEIE. Furthermore, the computational tool was used not just to obtain the power of units, but also to directly calculate their variable costs. To handle all the interactions and parameters in this step with spreadsheet models would be complex and time consuming. Thus, just the data manipulation part of input and output data was implemented with worksheets.

Based on what has been presented, a number of plausible and realistic considerations were applied with the intention of dealing with simplified and often unknown input data. It is clearly defined that, in order to implement the economic generation dispatch of each generation unit in the SEIE, REE considers, specially, the following items:

- Start-up costs and time;
- Warming-up costs;
- Operating variable costs (fuel and other operating and maintenance costs);
- Secondary regulation capacity.

Because there is no clear available information about secondary regulation, this item was neglected. For the warming-up expenditure, it is only defined for base (coal) units. And since these units are expected to operate mostly with high load factors, this expenditure was also omitted. Therefore, for the generation unit's economic dispatch, three distinct variable cost concepts were considered: *variable operating costs*, *variable start-up costs*, and *variable operating and maintenance costs*. The next points work extensively on the explanation of the code design and main hypothesis elaborated. For a full view of the GAMS code applied specifically to Balearic Islands, year 2008, the Appendix 9 should be checked.

4.2.1. Project set-up

Ideally, information in hourly basis would be needed to run the model in a more accurate way. Unfortunately, the only numbers available are the daily generation by technology. Thus, it was decided to use a daily aggregation representation to compute variable costs – start-ups and shut-downs decisions only occur in the end/beginning of each day. Thus, final day by day energy prices could be viewed, in reality, as averages of the 24-hour values. Regarding the time horizon for simulations, it corresponds to the beginning of the new regulatory framework in the SEIE (January 2006) until the end of the year 2009. Without prejudice to the results, the runs were made independently and annually, in order to simplify the structure of code design and reduce simulation times. And the CPLEX solver was used to work out the MIP. Finally, no network restrictions were taken into account. In fact, by using the real ex-post generation information by technology in part already minimizes the impact of network constraints on simulations. Therefore, the generation system is modeled as a single bus.

[6] www.gams.com

4.2.2. Objective Function

The main target in a traditional (centralized) generation system dispatch is to minimize the total costs. Therefore, within the simulation year, the intention is to:

$$min \sum_i \sum_d Cop(i,d) + Cst(i,d) + Com(i,d) \tag{4.1}$$

Where *Cop(i,d)*, *Cst(i,d)*, and *Com(i,d)* represent, respectively: variable operation, startup, and operation and maintenance costs of the generation unit *i* in the day *d*.

4.2.3. Variable Operating Costs

This component is generally defined in (2.16). It could be noted that the equation is not linear, with quadratic terms. Since linear relations are easier to manage by mathematical programming solvers (nonlinearities yield longer solution times), it was necessary, before all, to transform the equation to be used. In this way, it can be rewritten as:

$$C_{op}(i,h) = pr(i,h).\{a(i) + [b(i) + c(i).Pnet(i)].e_{pow}(i,h)\} \tag{4.2}$$

Where *Pnet* represents the net power of each unit *i* in MW. The Fig.4.1 shows the curves related with the real equation (Equation) and the linearization (Linear). It is associated to Ibiza 15 gas generation unit in Balearic Islands, technical parameters adjusted for the year 2006. As can be checked, (4.2) represents a very close approximation and is nothing more than a linear calculation of quadratics terms. One more important manipulation is necessary before entering the equation in the optimization model. The published parameters *a*, *b*, and *c*, as well as e_{pow}, are defined in hourly basis, and the model is run in daily schedules. Thus it comes:

$$C_{op}(i,d) = pr(i,d).hr(i,d).\left\{u(i,d).a(i) + [b(i) + c(i).Pnet(i)].\frac{energy(i,d)}{hr(i,d)}\right\} \tag{4.3}$$

The *u(i,d)* is the binary variable indicating whether the unit *i* in the day *d* is connected {1} or disconnected {0}. In turn, *hr(i,d)* is defined as the number of functioning hours of a unit *i* in the day *d*. Because we consider all units could operate the entire day, this value is set to 24 hours. Also important, the price of fuel *pr(i,d)* is calculated in the first and second semesters (based in published standards). Thus, for the economic dispatch, the provisional (ex-ante) product prices values are taken as reference and, for calculate the definitive variable energy costs, the ex-post (definitive) fuel prices are used.

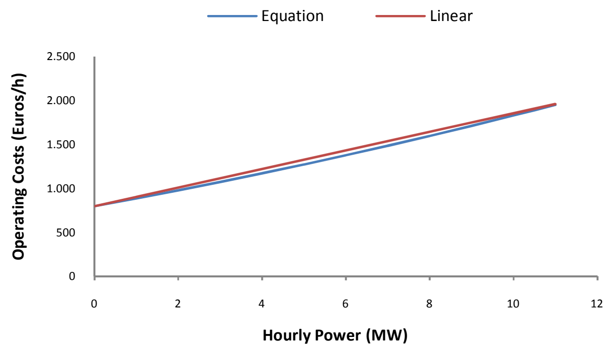

Fig. 4.1 - Curves comparison for variable operating costs

4.2.4. Variable Start up Costs

There is in (2.20) an exponential parameter, thus being necessary another simplification to use this cost component in the optimization algorithm. Fig.4 demonstrates some startup costs depending of the time since the last unit stop. It is linked with fuel units of Balearic Islands in the year 2006. Because we are interested in a daily generation dispatch (there is only the possibility of start-up and shut-down a unit in the beginning/end of each day) this value is set as constant for each unit and corresponds to the maximum value – very large time. As can be observed in Fig.4.2, the curves tend already to around their maximum when the time is 24 hours. Interestingly, this simplification leads to two very useful side effects – turn the equation linear (necessary for the GAMS model); and transform this cost component time-independent (the time since the last unit stop is an unknown input data).

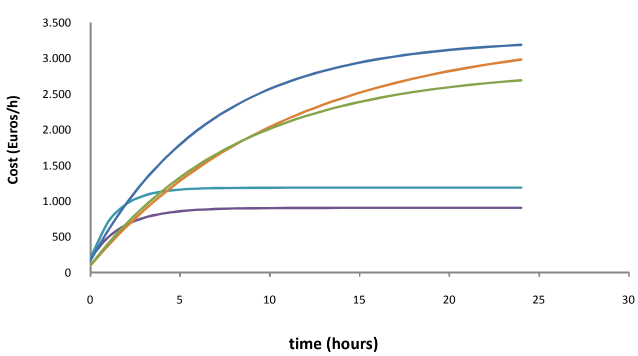

Fig. 4.2 - Start-up costs for fuel units

Therefore (2.20) is simplified to:

$$C_{st}(i,d) = y(i,d).\,[a'(i).\,pr(i,d) + ad] \tag{4.4}$$

The binary variable $y(i,d)$ refers to the start up decision of the unit i in the day d. The $pr(i,d)$ has the same magnitude as used in (4.3).

4.2.5. Variable Operation and Maintenance Costs

This expenditure is defined by (2.22). Since the interest is in a daily basis and the O&M functioning hour's parameter *a''* is hourly set, another final manipulation is needed:

$$C_{om}(i,d) = u(i,d).hr(i,d).a''(i) + \frac{b''(i)}{100}.C_{op}(i,d) \quad (4.5)$$

The *u(i,d)* is the binary variable indicating whether the unit *i* in the day *d* is connected {1} or disconnected {0}. In turn, *hr(i,d)* is defined as the number of functioning hours of a unit *i* in the day *d* (24 hours). Note that if the unit is disconnected (u equals to 0), the output energy is forced to zero, and therefore (4.3), and consequently (4.5), presents a null value.

4.2.6. Energy Constraints

In order to calculate the optimal solution taking into account the objective function, one necessary step is to stipulate boundaries for the variables in the system. In reality, for the SEIE, two main clusters of sub-sets of the generators set *i* had to be defined, one grouping units by technology and other by sub-systems. The first one was necessary because the most precise data gathered was the daily generation by technology – coal, fuel and gas, and CCGT generators. And the latter was additionally employed to take into account the restriction in transmission systems between islands.

Especially regarding the daily energy generated by each unit, the following case-condition is relevant:

$$energy(i,d) \leq u(i,d).24.Pnet(i) \quad (4.6)$$
$$energy(i,d) \geq u(i,d).24.MT(i,d).Pnet(i) \quad (4.7)$$

The upper bound represents that a given unit, if connected (u equals to 1), can generate in a day d a maximum energy equal to its maximum daily output – $24.Pnet(i)$. In (4.7), $MT(i,d)$ corresponds to a variable daily minimum technical. This was derived from the fact that it was not always possible to take into account a standard and fixed minimal technical for generation units when considering their operation. Some technologies (particularly CCGT) present from time to time a very low daily output, because they can operate just few minutes in a day, if necessary. Therefore, it could appear an incongruence of having a daily output lower than the daily minimum technical of the smallest unit in the system. In order to solve this constraint, a new condition was established:

$$MT(t,d) = MTn(t) \qquad \forall \qquad \frac{Gen(t,d)}{24.minPnet(t)} \geq MTn(t) \quad (4.8)$$
$$MT(t,d) = \frac{Gen(t,d)}{24.minPnet(t)} \qquad \forall \qquad \frac{Gen(t,d)}{24.minPnet(t)} < MTn(t) \quad (4.9)$$

The dynamic set *t(i)* refers to the technology cluster of generators *i*. Therefore, (4.8) says that, if the maximum allowed output energy of the smallest unit of a given technology – $24.minPnet(t)$- can supply the virtual established generation - $Gen(t,d)$ – the nominal minimal technical - $MTn(t)$- can be normally implemented (0,55 coal, 0,31 fuel and gas, 0,50 CCGT). But in the other cases (4.9), a new maximum feasible minimal technical, lower than the nominal, is calculated.

In this context, it is also necessary to meet the given daily technology and sub-system generation:

$$\sum_{t(i)} energy(i,d) = Gen(t,d) \tag{4.10}$$
$$\sum_{s(i)} energy(i,d) = Gen(s,d) \tag{4.11}$$

The index *s(i)* denotes the cluster of generators i by sub-systems. Especially concerning (4.10), the daily technology consumption by auxiliary services, necessary to obtain the net generation in a given day, was estimated proportionally to the technology contribution in the total gross energy. Regarding (4.11), normalization in the data provided by REE was necessary, because it is included in the present value by sub-systems a statistical forecast of special regime generation (there is an expressive time lag to receive the measurements of approximately 10 months). In addition, once there is only information starting in March/2008 about this output, some estimation based on average proportional values of 2008 and 2009 by sub-systems was prepared for 2006 and 2007. Fig.4.3 exemplifies the net input data by technology for Balearic Islands (ordinary regime). While Fig.4.4 gives the net production by year for all the SEIE, excluding auxiliary generation. It is interesting to note the significant increase in generation (i.e. demand) during peaky months in Balearic Islands (June, July, August, September) due to the intense tourism. What basically does not occur in Canary Islands, where the demand is almost flat. This fact gives an indication why in the first system the transition between peak, shallow and valley months is more significant (superior variation in the seasonality factor). Also, it is important to observe that the hydro unit of Canary Islands (*El Mulato*) has not been generating any megawatt-hour since 2006. The complete data can be assessed in Appendix 10.

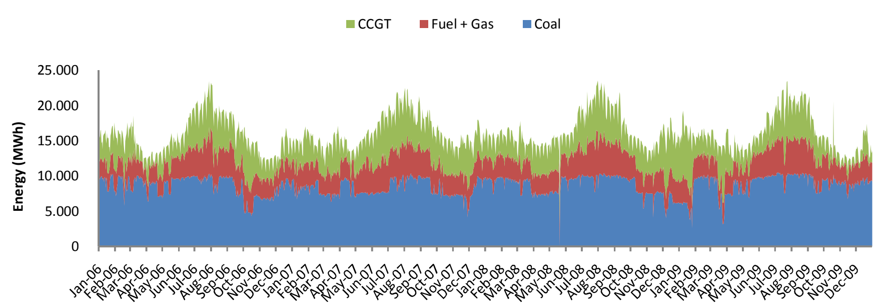

Fig. 4.3 - Daily net production by technology for Balearic Islands

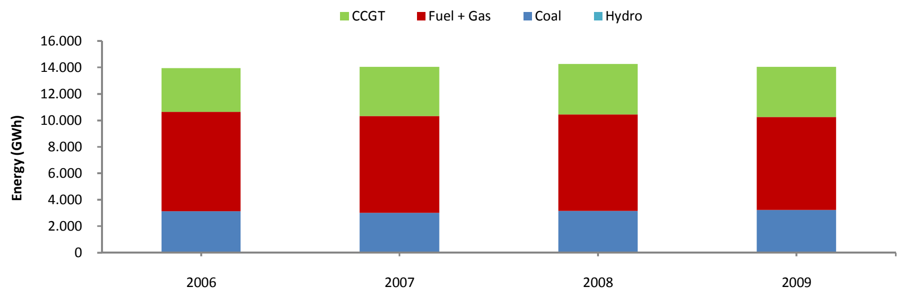

Fig. 4.4 - Total yearly net production by technology for the SEIE

4.2.7. Operating Logic

Finally, it is necessary to respect some binary operating logic for the units:

$$u(i,d) = uo(i) \qquad \forall \quad d = 1 \tag{4.12}$$

$$u(i,d) = u(i,d-1) + y(i,d) - z(i,d) \qquad \forall \quad d > 1 \tag{4.13}$$

$$y(i,d) + z(i,d) \leq 1 \tag{4.14}$$

$$u(i,d) = 0 \qquad \forall \quad Gen(t,d) = 0 \tag{4.15}$$

$$\sum_n u(ccgt_n, d) \leq 1 \tag{4.16}$$

The first two relations (4.12) and (4.13) above imply that, if the simulation period is the first day, the decision to connect or not to connect a generation unit (*u)* is equal to the first definition of operation (*uo*) - for the transition between years, the state of generation units in the 31 of December was maintained for the first day of the subsequent year. Also, it connects the decisions between days (i.e. memory feature). The (4.14) is set to force the units to be started-up (*y*) or shut down (*z*) in the day *d*, but never both[7]. In addition, (4.15) obliges the units to not be connected if the total generation of the technology is zero. To end with, (4.16) establishes that an individual CCGT unit just and only can operate in one of the *n* possible operations modes – 1/2/3 GT, 1 GT + 1 ST, 2 GT + 1 ST, or 3 GT + 1 ST.

[7] Formally, this relation would not be necessary in the model. The start-up (*y*) and shut-down (*z*) decisions are taken always simultaneously. The (4.14) was therefore implemented to speed the model convergence.

Chapter 5. SEIE: Simulations, Validations and further Discussions

After having defined the code to be entered in the optimization model and having clearly stipulated all the internal parameters of the generation units, the next step in to calculate the fixed generation costs and to run the economic dispatch of units for variable prices computation. With the output daily energy, is therefore possible to calculate the system total generation costs and, consequently, the final energy generation price in the SEIE.

5.1. Results Obtained

In the Appendix 11 is possible to find a complete view of the outcomes for fixed costs. Fig.6 shows the data for Balearic Islands applied to shallow months. Because the system must be run in daily basis, and there is a flexibility of transposing the hourly calculated data (by multiplying it by a factor of 24), the results are expressed in Euros per day. It is important to highlight that, even with the annual depreciation of investment values, the total amount remains almost constant between 2006 and 2009 (e.g. coal and fuel technologies in Fig.5.1). This is derived by the fact that the indices used to retribute financially and to readjust standard parameters generally increased in this time frame. In this way, the updates seem to compensate any depreciation in the net value of generation units. Exceptions occur when new units start operating (e.g. CCGT and gas units in Balearic Islands). In addition, the Canary Islands system appeared to be more costly in terms of fixed retributions than the Balearic Islands one, once there are more units functioning.

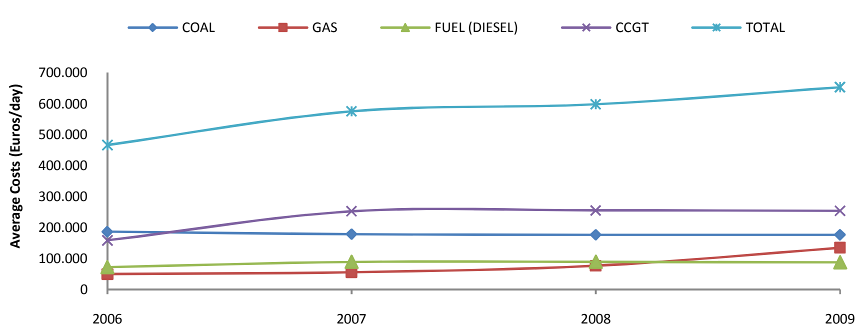

Fig. 5.1 - Balearic Islands total daily fixed average generation costs by technology

With relation to the optimization GAMS model run, Fig.5.2 exemplifies the unit commitment of fuel (oil) units in Canary Islands year 2007. Appendix 12 gives more examples of outputs for each technology, system and year. The results seem to be coherent, once the most economical generators produce in the base (e.g. *Tirajana 3* and *Tirajana 4*) of a given technology demand/generation, attending in this way the criterion of minimize the systems costs.

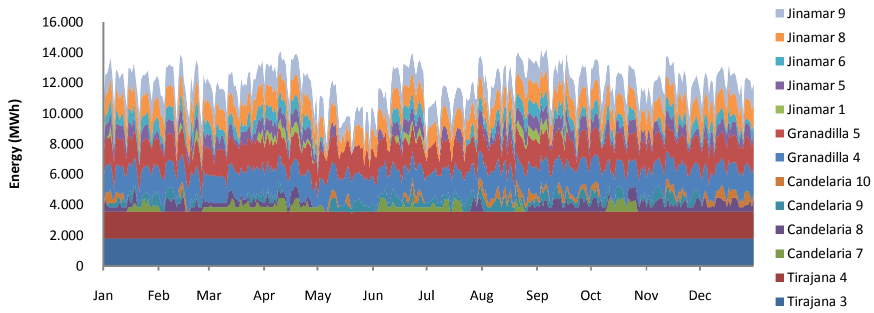

Fig. 5.2 - Fuel (oil) dispatch, Canary Islands 2007

Adding up the previous calculated fixed and variable costs by (2.1) and with the gathered daily generation by technology, it is possible to obtain the daily energy prices for all the horizon of simulation using (2.2). Fig.5.3, Fig.5.4 and Table.5.1 best illustrate this concept.

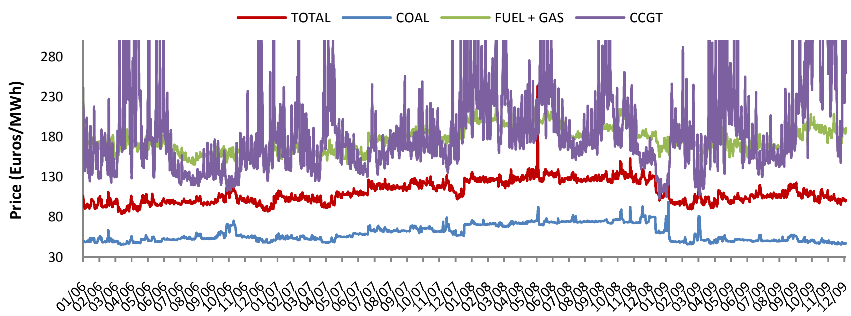

Fig. 5.3 - Daily generation cost (Balearic Islands)

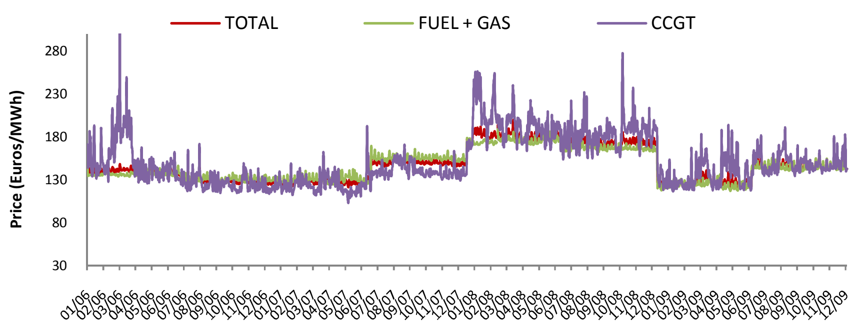

Fig. 5.4 - Daily generation cost (Canary Islands)

Table 5.1 - SEIE generation costs by system and year

	2006		2007		2008		2009	
	Fixed (MEuros)	Variable (MEuros)	Fixed (MEuros)	Variable (MEuros)	Fixed (MEuros)	Variable (MEuros)	Fixed (MEuros)	Variable (MEuros)
Balearic Islands	170,50	384,59	210,63	441,41	215,15	549,19	238,35	364,78
Canary Islands	264,32	838,91	280,55	903,71	325,53	1.182,11	322,72	807,77
Total	*434,82*	*1.223,50*	*491,18*	*1.345,12*	*540,68*	*1.731,30*	*561,07*	*1172,55*
TOTAL	**1.658,32**		**1.836,30**		**2.271,98**		**1.733,62**	

Source: own elaboration.

Some primary conclusions can be draw. Combined cycles are, as expected, marginal units with the highest energy prices. The soaring values obtained for some days in Balearic Islands are derived by the fact of really low daily energies for this technology. What points out to just only a quantity of hours, or probably minutes, of functioning. Truly, in Canary Islands CCGTs operate with the average of almost twice the load factor of Balearic Islands ones, mainly because its system characteristics: more isolated and with dispersed small generation. Another comment is that the 2008 increase in fuel prices appeared to impact more Canary Islands than Balearic Islands, once in the latter coal is base, with small variation of fuel product prices in the period and therefore less volatile to liquid fossil fuels commodities. Additionally, the Canary Islands power generation is in average almost 50% more costly. There are numerous small fuel, gas and CCGTs suppliers, representing in this way more capacity payments and more dependency to expensive petroleum derivatives. It is crucial to observe that, even not showed in the Fig.5.4, hydro units still characterize a cost of capacity. Because *El Mulato* has not been generating during the simulation period, there is no mathematical meaning of cost per energy.

5.2. Validation

In essence, this item supports a straightforward view about the usefulness of the model built to find real energy prices in the SEIE. For this purpose, it is taken the available real historical published data to compare statistically the outputs. What is usually called "historical data comparison". Practically, there are two main sources of validation, one in the context of fixed costs calculations and the other related with energy prices.

5.2.1. Statistical Testing of Bivariate Relations

Firstly, it is important to justify and describe the methodology used to prove the accuracy of the model's outputs, once it is the main way to corroborate quantitatively the several suppositions made along the work.

Because there are always two independent samples – one of real published values and other from the simulated data – the most appropriated and powerful way of analyzing these two data is thought to be by a statistical test. This is usually called "historical data comparison". This method of comparing samples is generally used to prove that a statistically significant relation between two variables exists. Therefore, the statistical tool SPSS[8] to compare two independent sample data was used along the validation process. Always, a zero (null) and alternative hypothesis were formulated as follows:

- H_o: The two sample data averages *can* be considered the same;
- H_1: The two sample data averages *cannot* be considered the same.

Note that the assumption was always formulated as two-tailed, without positive or negative directions. Also a distinction must be made between parametric and non-parametric tests. If the samples could be considered following a normal distribution (null hypothesis accepted), the *Student t-Test* for difference in averages was executed for both equal and not equal variances. If the distributions were not normal, a non parametric test, with less power and called Man-Whitney U was run. The confidence level was considered in the comparison as 5%. This means that if it is performed the test at this level and it is decided to reject the null hypothesis (Asymp. Sig. lower than 5%), it is similar to say that "there is significant evidence at the 5% level to suggest the hypothesis is false", and H_0 is rejected.

5.2.2. Annual Investment Costs

It is officially stated in [MITC91406] that the DGPEM establishes the annual capacity payment value before January 1th of each year". In practice, what is published, in the same document, is the recognized cost of investments (CIT_{in}) of each unit and the standards annual fixed operation and maintenance costs ($COMT_{in_{max}}$) and investment values ($VI_{in_{max}}$) by technology for a given year. There are documents from 2006, not always annually available [DGPEM08, DGPEM09, DGPEM10]. Thus, the first part of the validation process is to compare the calculated annual investment costs (2006 to 2009) and to contrast them statistically with real existing figures. Fig.5.5 represents graphically the comparison between modeled values (Calculated) and published ones (Real) for Balearic Islands in the year 2007. As can be easily noted, they appeared to converge to almost the same amount.

To ratify that these costs can be considered the same a statistical test was implemented. The complete set of results can be checked in Appendix 13. As product, for all simulated years and both for Balearic and Canary Islands, the tests always indicated a high degree of similarity between the calculated and real values, proving in this way the reliability of the model built and assumptions made for fixed costs representation. Any minor difference found can be derived basically by three factors:

- Readjustment of values accorded unilaterally between investors and regulator and not published on official documents (like recognized cost of investments);
- Assumptions about the precise day of starting operating (there is only indication about the month units start functioning);
- And errors when rounding values (available data are integer, but the regulator can possess more precise figures for the calculus).

[8] www.spss.com

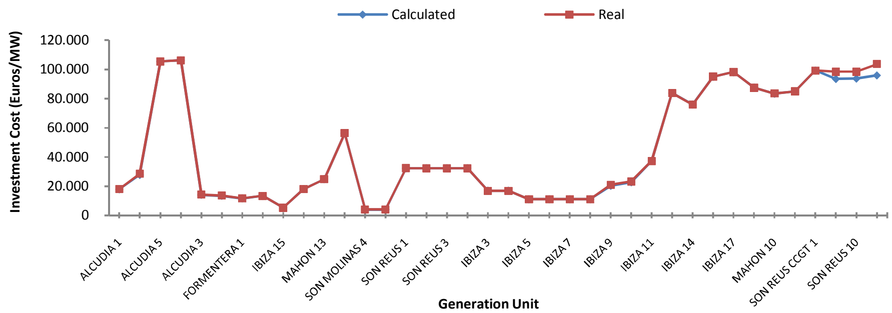

Fig. 5.5 - Investment costs comparison (Balearic Islands, 2007)

Based on exposed, it could be proved that the first part of the model for capacity payments calculus was successfully validated and therefore can be trustworthily utilized for this study.

5.2.3. Generation Prices

Another, and final, option to analyze the output simulated by the models is to compare final generation prices statistically with the existent available standards. In the context of the new electrical regulatory framework in the SEIE, REE calculates hourly the generation prices and publishes them in its internet platform on monthly settlements[9].

According to REE methodology, by month is published, at the end, five settlement files accounting different cost and aggregating diverse information concepts. There is also a distinction between *closures* (C1 to C5) and *advances* (A1 to A5) folders. Therefore, it was always taken the prices of the last advance or closure available – particularly in the year 2009 the settlements still have not been completed till the fifth closure. In addition, because the data available is in hourly basis, averages of these prices were implemented to obtain the necessary daily reference for comparison. Actually, the daily averages based in the 24 hourly prices are normally very close from the real daily averages (total daily generation costs divided by total daily energy generated). Therefore, the error margin is expected to be in a minimum level with this simplification. Fig.5.6 and Fig.5.7 demonstrate the graphical evaluation between calculated prices given by our model and the ones present in the settlements, both for Balearic and Canary Islands.

For both cases the curves showed the same basic tendency and inflexibility points. Especially in Balearic Islands, for the months of February and July (2009) there are discrete jumps in the settlement prices, and are where the differences are more expressive. One possible explanation is that, once the simulated model uses already ex-post fuel prices, its outputs would reflect the last settlement closure (the fifth one – C5). And precisely in the months of February and July the accounting was still not complete till the publication of this report (fifth advance – A5 - and fourth closure – C4 - respectively). For Canary Islands, the same seem to occur, but during all the second semester of 2009. Probably in this case the prices in the system are still not regularized by the ex-post fuel values.

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[9] www.esios.ree.es

A statistical verification was run in SPSS to prove the numbers are similar (Appendix 13). As a result, the daily obtained prices for Canary Islands *seem to be accurate enough* (Asymp. Sig. 20%), and for Balearic Islands the model *was not* validated (Asymp. Sig. 0%). Actually, the more precise figures for Canary Islands than Balearic Islands are most likely consequence of having to the first extra information about clusters of generators per sub-system and more precise data about fuels utilized. In reality, it would be very difficult, given the uncertainty level and the number of assumptions made, to obtain a statistical convergence in daily basis for the energy prices in both arrangements. Thus, another comparison was implemented with monthly averages of daily values. Fig.5.8 and Fig.5.9 illustrate this new assumption.

With average values of 30 independent samples (1 month) within two years, now both configurations of energy simulated prices are corroborated (see Appendix 13). Thus, the average results in a monthly foundation can be taken as precise enough to the objective of the model. Within this line of thought, the already built representation (both for variable and fixed costs) appeared to be robust and precise enough, successfully replicating, with public information and realistic assumptions, the new regulatory framework of generation costs in the SEIE.

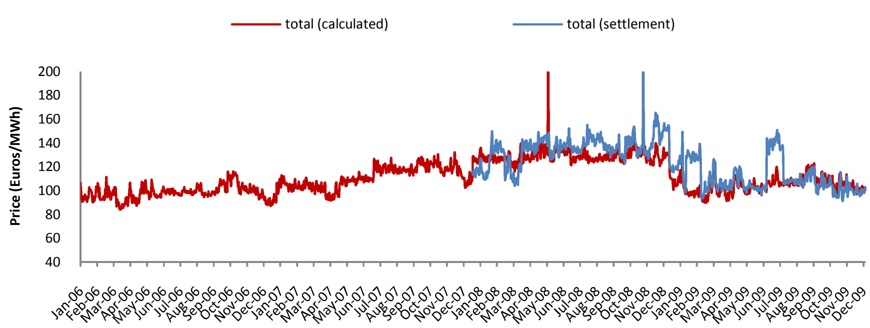

Fig. 5.6 - Balearic Islands daily generation price

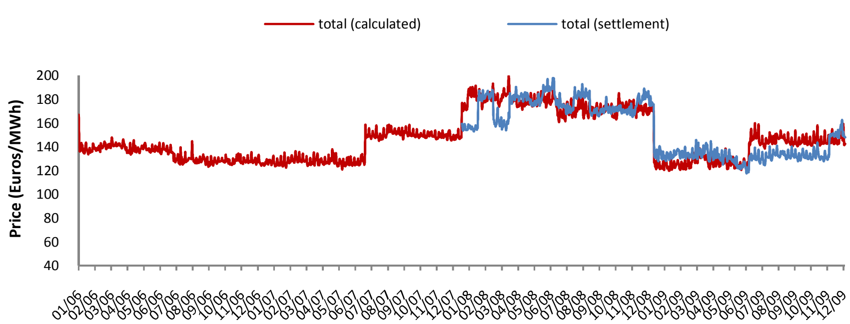

Fig. 5.7 - Canary Islands daily generation price

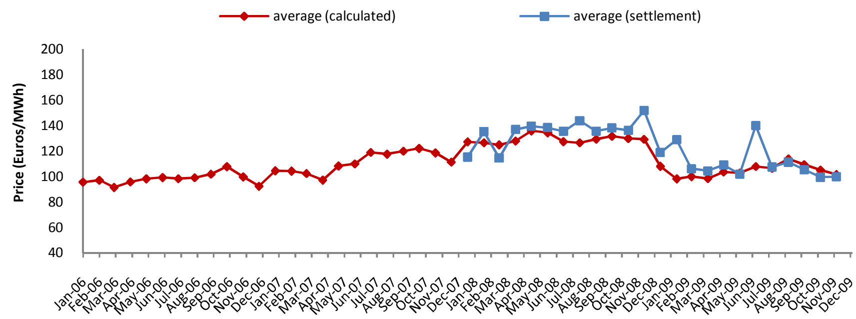

Fig. 5.8 - Balearic Islands average monthly generation price

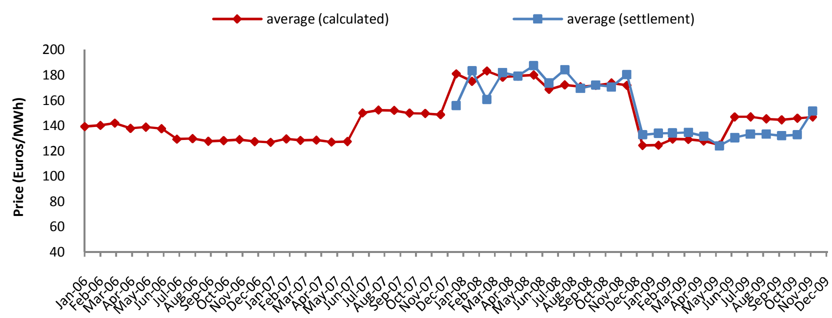

Fig. 5.9 - Canary Islands average monthly generation price

Chapter 6. Generation Costs Design applied to the Iberian System

Once the general conceptual structure, simplifications and modeling were successfully validated for the SEIE in the previous chapter, the last and most relevant step is to transpose it to the Iberian system. At some point, due to the logical complexity of the Iberian power structure, some changes and further considerations and mathematical manipulations in the model were necessary. These changes were implemented just when strictly necessary, realistically purposing to adequate the structure for simulations. Thus, the purity of the SEIE design was always taken as a priority during the process

The major conceptual changes in the fixed (2.3) and variable (2.14) costs retribution implemented for the SEIE can be generally defined with (6.1) and (6.2):

$$gc_f(i,h) = Gpow(i,h).Pavailable(i,h) + log_f(i,h) \tag{6.1}$$

$$gc_{var}(i,h) = C_{op}(i,h) + C_{om}(i,h) + C_{CO2}(i,h) + C_H(i,h) + C_{pum}(i,h) + log_v(i,h) \tag{6.2}$$

Where:

$log_f(i,h)$:	fixed LNG logistic cost of unit *i* (capacity reserve and conduction) [Euros/h]
$log_v(i,h)$:	variable LNG logistic cost of unit *i* (component of conduction) [Euros/h]
$C_{CO2}(i,h)$:	variable emissions costs of the unit *i* in the hour *h* [Euros/h]
$C_H(i,h)$:	variable hydroelectric costs of the unit *i* in the hour *h* [Euros/h]
$C_{pum}(i,h)$:	variable pumping costs of the unit *i* in the hour *h* [Euros/h]

There was aggregated another fixed cost: *the fixed logistic cost*. It is related to the fixed liquefied natural gas (LNG) logistic cost due to the capacity reserve and the gas conduction. Also, note that, differently from the SEIE modeling, the start-up costs here were not considered. And there are four another variable expenditures: the *variable emissions costs;* the *variable hydroelectric costs*; the *variable pumping costs*; and the *variable LNG logistic costs*. The first is due to the CO_2 emissions scheme present in the Spanish system. The second is related with the operation and maintenance hydro variable costs for generating electricity by both normal and pumping units. The third represents the extra costs to pump water by pure and mixed pumping units. While the latter stands for the variable logistic costs due to the LNG conduction. In addition, the hourly capacity payment was calculated taking into account investments with different amortization periods (like boilers investment and desulphurization processes for coal units). Furthermore, the fuel therm prices (product plus logistic) were calculated differently for each fuel taking into account the fuels specificity and the data available. Finally, it was stipulated a distinct methodology for the operation and maintenance variable costs indicated in the SEIE. Before going into the conceptual part and data gathering details, two aspects are convenient to be introduced firstly: specificity of gasified coal units (*Elcogás*); and characteristics of pumping units.

A) *Elcogás***:** This generation unit utilizes the technology GICC to gasify coal and then to run a CCGT unit. In practice, it utilizes a mix in weight of 50% coal and 50% oil coke. Also, it can burn natural gas, applied to auxiliary services for starting-up and shutting-down. Due to its particularity, specific references were consulted to address the calculus of its capacity payments and the fuel energy costs (it uses a mix between coal, oil coke and natural gas characteristics). Given that features, the unit was treated as a CCGT plant for its technical functioning, but inserted in the coal technology group to reference its output for the economic dispatch. Furthermore, no CO_2 emissions were accounted for the plant, and some degree of compulsory generation in the year was implemented in accordance with literature indication.

B) *Pumping Units*: In the generation structure of the Spanish power system, pumping units are largely utilized to generate and consume power. They can be divided into: mixed pumping for consumption (6 units, 2009); and pure pumping for generation and consumption (8 units, 2009)[10]. As it will be extensively discussed in the next chapter, for the mixed consumption plants there is no capacity payments retributions, there is no merit order to develop an economic dispatch, and they receive just a variable payment connected with the total daily amount of energy pumped to compensate their variable costs (reflected as a variable O&M cost to pay the pumps operation). Differently, the pure pumping plants could be virtually separated in two types for modeling purposes: generation and consumption. The methodology for the latter was similar to the mixed consumption pumping. While to the first case (pure generation) it was considered these units as a normal hydro, with the same data for fixed costs calculations and again with just a variable payment for their turbines operation[11].

All that has been mentioned in the previous lines is going to be deeply developed in the items below. Bearing in mind that just the main structural changes in the model of the SEIE for the Spanish power system are mentioned, the theory and data provided to the SEIE must be reflected for any aspect that is not explicitly elaborated.

6.1. Net Power of Generation Units and Operating Dates

In the case of net generation for each generation unit operating between 2006 and 2009 in Spain, it was taken as reference in the public web of *e-sios* (http://www.esios.ree.es/web-publica) the scheduled units for the day 05/04/2010. Filtering by offer (type 1) it was possible to get all the net power of the units in the ordinary regime used by REE for the economic dispatch this day. As it was necessary also a list of the units that have been operating but already have ended their lifetime between 31/12/05 and 31/12/09, another source based on internal database of **Iberdrola** (provided by OMEL), was used. And the same orientation was taken to obtain the start operation and end operation dates of generation units within the horizon we are interested in. The Appendix 14 shows these values.

[10] Pumping units have two reservoirs connected by pumps to raise the water and turbines to produce electricity. When there is a significant natural contribution in the upper reservoir, this is known in the literature as mixed pumping.

[11] In reality, the variable compensation per output energy was set equal for both the pumps and turbines operation.

6.2. Recognized Investment Values and Amortizations

Ideally, it would be necessary to know the recognized investment value of the operating generation units in 31/12/05 and those values of units start operating from 01/01/06. In fact, values to reference these investments are scarce. In this context, some difficulties appeared while trying to bring back and actualize the old standards of investments sketched by the MLE. In practice, the recognized investment of generation units till 1997 in Spain was valued by their recognized investment in 31/12/87 in the document [MINER87], in pesetas, and actualized each year by a standard value (depending of technology, functioning years, etc) plus approved extraordinary investments. This methodology contrasts deeply with the one currently used in the SEIE. In the latter, just a recognized value for the units was published in [MITC91406]. There is no explicit mention to standard annual additional investment values. And, for extraordinary needs, values are discussed and approved unilaterally with REE. Therefore, to take and to try bringing forwards these recognized values from 1988 to 2006 would be a difficult and imprecise task. Even if it was possible, it would still have the latent problem of units start operating from 1988. So, an easier approach was defined.

Two different scenarios were formulated. One for units that start operating before the end of the MLE (1997), and other for those functioning in a market model (from 1998). For the first case, it is considered that they were already completely amortized in 2006 by the use of CTC[12]. In fact, precisely in 2006 this compensation has finished. Also, the units that have been operating before the new law of the electricity sector are mainly dated from the 60's, 70's and 80's. So, probably they would only represent a residual value to be amortized in 2006.

In this context, it is considered for the first scenario (units operating before 1998), that they were already completely amortized in 31/12/05 - $\mathrm{VNI}_{\mathrm{in}} \sim 0$ in (2.9). So, the investment costs for these units are equal to 50% of their recognized investment values in 31/12/05 (calculated for the year 2006) divided by their standard lifetime. And for the second case (units that start operating under the new regulatory framework) the normal methodology listed in Chapter 2 (with standard lifetime of 25 years and 65 years for thermal and hydraulic units, respectively) normally takes place. Note that after the restructuration of the sector (from 1998) just CCGT units were built. And that establishing a recognized investment value for old units already amortized based on the newest technology available is actually "helping" the system, decreasing its capacity payments (generation costs).

Under this logic, it is necessary just to define a standard and trustworthy value for investment values by technology dated recently and moved it upwards and forwards by the same index implemented in the methodology of SEIE to actualize investment values - the annual variation of the industrial price index (moved average of the last 12 months available when it is implemented the average tariff – Table 3.4). Mostly, those

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[12] Stranded competition costs refer to the companies' costs due to the regulatory change derived from the liberalization of the electricity sector. Also, it is utilized with the meaning of compensation for companies due to this regulatory change. Thus, it is related with values companies receive linked to: lost in the active values; or restructuring costs that need to be compensated. In Spain, within an always changing regulatory structure, the CTCs appeared from the difference between the values companies would receive in the MLE and those estimated in the new competitive framework. Officially, the period of compensation started in 01/01/1998 and would end in 01/07/2006. In reality, the last provisional settlement occurred in 31/12/2005. Due to the strong increase in generation prices from 2006, it is possible to implicitly defer that in 01/07/2006 the CTCs have already been paid completely (with exception of the gasified coal plant of *Elcogás*).

investment values were determined based on **Iberdrola** professional expertise in a 2010 basis and are presented on the Table 6.1. For units starting operating between 1998 and 2005, the recognized investment value is the one set for the year 2006. For the following years, the recognized value becomes the one fixed in the year the units initiate to generate.

Table 6.1 - Investment values by technology for Spain

Technology	Unit	Investment Value				
		2006	**2007**	**2008**	**2009**	**2010**
Hydraulic (normal & pumping)	Euros/MW	1.384.617	1.418.665	1.465.563	1.497.000	*1.500.000*
Nuclear	Euros/MW	2.538.465	2.600.886	2.686.866	2.744.500	*2.750.000*
Coal (normal)	Euros/MW	1.523.079	1.560.531	1.612.119	1.646.700	*1.650.000*
Desulphurization process	Euros	60.000.000	60.000.000	60.000.000	60.000.000	60.000.000
Boiler installation	Euros	30.000.000	30.000.000	30.000.000	30.000.000	30.000.000
Coal (gasification)	Euros/MW	*745.702*	763.599	788.035	804.583	806.192
Fuel & Gas	Euros/MW	581.539	595.839	615.536	628.740	*630.000*
Combined cycle	Euros/MW	646.155	662.044	683.929	698.600	*700.000*

Source: [SITC07], Iberdrola, own elaboration.

[UNESA09] provides a useful reference to contrast the costs present in the Table 6.1. In the report it calculates the investment opportunity cost for the year 2007 of distinct generation technologies. The values calculated by the Association and the ones defined by **Iberdrola** experience are in almost all cases of the same magnitude. Exceptions occur for coal (969.434 Euros/MW) and fuel & gas (315.000 Euros/MW) units. This difference is derived mainly due to the fact of considering for our study additional environmental restrictions on the year 2010, like the obligation of installing desulphurization and to capture and storage CO_2 gas, what increases the investment costs of these types of thermal units.

Within the Elcogás context, being currently an expensive way of generation, the consortium responsible for the active required from the regulator an extraordinary financial support for its activities. That leaded to [SITC07], which establishes a viability plan for the company. Whereas the methodology given in this document to fixed cost retribution of *Elcogás* differs significantly from one implemented in the SEIE (especially concerning the fixed operation and maintenance calculus), being very case-specific, it was decided to take just the recognized values available in the Resolution as indication to the fixed costs computation for this kind of generation. Therefore, the data used for investment costs and amortizations are: 745.702 Euros/MW (221.026.217 Euros), 2006 basis (amortization starting in 31/12/2005), within a time period of ten years and six months.

At this point, two major conditions regarding investment costs and amortization horizons must also be commented:

- Boiler installation for normal coal units;
- Desulphurization process for normal coal units.

6.2.1. Boiler Installation and Desulphurization Process of Normal Coal Units

According to the text about investment costs in [MITC279407], which revises the electrical tariffs from October 1st 2007, in some special cases generation units are allowed to receive investment incentives from the regulator. In special, units with installed capacity superior to 50 MW that promote significant increases in new installations or investments in technologies seemed as priority for the objectives of energetic policy and security of supply. Within this context, some coal units in Spain have invested on new technologies. Also, due to the lack of national fuel and the pressure of emissions rights, others units have changed their boiler to burn coal with a low content of sulfur. Regarding indicative numbers, [MITC386007] establishes a right for the investor to receive a fixed amount of 8.750 Euros/MW/year, during 10 years, due to desulphurization investments. As can be checked on Table 6.1, for the simulations it was defined a fixed amount of recognized investments for desulphurization processes and boiler installation that are independent of the year which they take place and the generators power installed. For both, the horizon for amortization of 10 years was utilized. In the Table 6.2 is possible to find the units that are affected, as well the investment dates considered.

Table 6.2 - Coal units' investments in new technologies

Generation Unit	Date
Boiler Installation	
Puentes de García Rodríguez 1	01/05/2009
Puentes de García Rodríguez 2	01/05/2006
Puentes de García Rodríguez 3	01/05/2007
Puentes de García Rodríguez 4	01/05/2008
Meirama	01/05/2009
Desulphurization Process	
Guardo 2	01/12/2008
Lada 4	01/06/2009
Compostilla 4	01/01/2009
Compostilla 5	01/01/2009
Puente Nuevo 3	01/10/2008
Narcea 3	01/01/2009
La Robla 2	01/01/2009
Soto de Ribera 3	01/01/2009
Aboño 2	01/01/2009
Litoral 1	01/10/2009
Los Barrios	01/08/2008

Source: Iberdrola, own elaboration.

6.3. Operation and Maintenance fixed Values

It is related with standard operation and maintenance fixed costs of the generation units in ordinary regime, stipulated annually from 2006, readjusted each year by the IPC minus 100 basis points. In practice, for the Spanish case, all the data was stipulated for the year 2010 (exception for Elcogás) and then readjust backwards by the moving index till 2006. Some standards were determinated by **Iberdrola** experience, while others (i.e. coal technologies) were referred using specific published documents.

For the fixed O&M coal values it was taken [MITC13410], of February 12th, as guide. It gives the remuneration procedures and a new technical framework in the context of the current regulatory structure for the indigenous coal[13], both in normal standards and with desulphurization process. Regarding the *Elcogás* unit [SITC07],

[13] The generation units can burn indigenous coal till a maximum limit of 15% of the total quantity of primary energy needed to produce the energy demanded annually in Spain.

which establishes a viability plan for the company, was consulted. Though the methodology given in this document to fixed cost retribution differ significantly from one implemented in the SEIE, it was taken just the standard value set in 2006 of 100.772 Euros/MW (29.854.000 Euros) for its fixed operation and maintenance costs, and then readjusted each year forwards by the applied index. Table 6.3 illustrates what has been explained in the previous lines.

Table 6.3 - Unitary operation and maintenance costs by technology in Spain

Technology	Unitary O&M Value (Euros/MW)				
	2006	2007	2008	2009	2010
Hydraulic (normal & pumping)	10.454	10.613	10.896	11.187	*11.000*
Nuclear	118.791	120.600	123.820	127.125	*125.000*
Coal (normal)	31.361	31.839	32.688	33.561	*33.000*
Desulphurization process	4.752	4.824	4.953	5.085	*5.000*
Coal (gasification)	100.722	104.247	109.043	114.059	114.401
Fuel & Gas	27.560	27.979	28.726	29.493	*29.000*
Combined cycle	11.404	11.578	11.887	12.204	*12.000*

Source: [MITC13410], [SITC07], Iberdrola, own elaboration.

6.4. Seasonality Factors

In the same way as to the SEIE, it was thought convenient to incorporate in the model for Spain the impact of different seasons in the demand and, as consequence, in the generation fixed retribution. Table 6.4 resumes the values used and the months considered. For the factors, the data provided to Balearic Islands was replicated.

Table 6.4 - Seasonality factors for Spain

PERIOD	Applied Months	Seasonality factors
Peak	January, February, July, December	1,15
Shallow	March, June, September, November	1
Valley	April, May, August, October	0,85

Source:.[MITC91406], own elaboration.

6.5. Hourly Available Power

The public web of *e-sios* provides detailed information about hourly technology and yearly units power availability. But as the methodology and simplifications developed to the SEIE proved to be robust enough for the intention of this work, and aiming to ease computational efforts, less specific information was taken (without prejudice the correctness of the simulations). There are available monthly reports in the official website of REE for the Spanish power system. On these documents is possible to find, among others, the average monthly generation availability by technology (nuclear, coal, fuel and gas, CCGT). And there are published reports from January 2007. Thus, it was defined a standard and fixed hourly availability, by technology, taking the monthly averages. Because there is no data for the year 2006, the same values of 2007 were utilized for that year. For hydroelectric generation, it was considered as 100% available. Appendix 15 resumes what was justified on the previous lines.

6.6. Variable Secondary Regulation Costs

The assigned secondary regulation is going to be neglected for the Iberian study. Indeed, there is a market and available information about secondary regulation of generation units in Spain. But is immersed in a market mechanism, where the regulation bids should not interfere in the bids inside the daily market (there is enough reserve margin in the system). In this way, *a'''(i,h)* does not need to be considered when adapting the theory to centralized mechanisms. In fact, previous validation on the SEIE demonstrated the accuracy of energy prices even without this expenditure.

6.7. Variable Operating Costs

For this expenditure, nuclear and GICC technologies had to be treated differently. For them, the most common procedure is to connect their variable operating costs with their generated energy. Note that in this case the relation for calculating the variable operating (fuel) costs (2.16) is changed to:

$$C_{op}(i,h) = P_{ff}(i).\, e_{pow}(i,h) \tag{6.3}$$

With:

$P_{ff}(i)$: fuel average price factor of the generator *i* [Euros/MWh]

It was assessed for the *nuclear fuel price factor* a value of 12 Euros/MWh, 2010 basis (4 Euros/MWh for the uranium product and 8 Euros/MWh for the fuel management[14]). For the power plant of *Elcogás*, it was taken the value of 11,16 Euros/MW, 2002 basis in [COCA]. And in this price is included, besides the coal, also the coke and natural gas expenditures. Backward and forward actualizations were implemented using the IPC foreseen in the tariff minus one-hundred basis points.

Table 6.5 - Fuel price factors (gasified coal and uranium)

Fuel	Fuel Price Factor (Euros/MWh)					
	2002	2006	2007	2008	2009	2010
Gasified Coal	*11,16*	11,61	11,73	11,85	11,97	N/A
Uranium	N/A	11,64	11,76	11,88	12,00	*12,00*

Source: [COCA], Iberdrola, own elaboration.

For the other plants operating with the remaining fuels, (2.16) normally takes place. Regarding the quadratic adjust parameters *a*, *b* and *c* in the SEIE methodology, they are measured for each generation unit and statistically adapted to be implemented in the quadratic relation by the regulator. Transposing the operating variable costs for the Spanish power system reality, a major adaptation is necessary. The **Iberdrola** estimation and the last data provided for the MLE about these parameters are related and mathematically molded to the linear equation employed in the MLE. Therefore,

[14] The extra-cost is due to the obligation of a correct and safe management of the radioactive residues produced in Spain. The company in charge of this work is ENRESA.

without prejudice the accuracy of the study, the parameter *c* is considered zero. Note that in this way the equation for calculating the fuel costs in the SEIE, in the presence of these new available parameters, becomes exactly the same as the linear one used in the old MLE. Thus, as already said, there are two distinct available information for the quadratic parameters: the one estimated by **Iberdrola**, and the other obtained with MINER, within the MLE context, available in [FERN10]. The Fig.6.1 exemplifies the graphical contrast between the two sources. It is related with the generator group *Puentes de García Rodriguez 2*. IBE refers to the curve calculated with **Iberdrola** parameters, while MLE is the curve using the Legal and Stable Framework data.

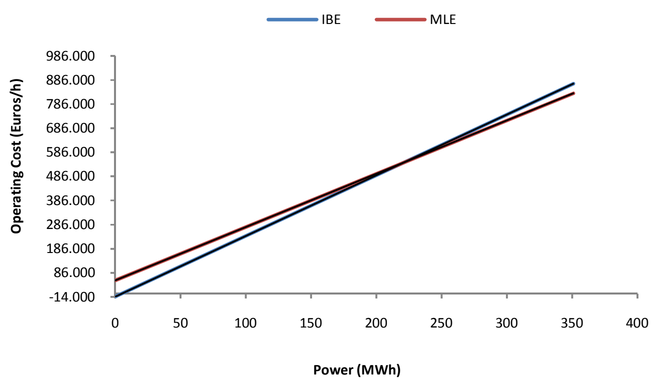

Fig. 6.1 - *Puentes 2* operating costs contrast

As can be observed, within the operating range of units (e.g. minimum technical of 55% for coal), the figures seem to converge. In this way, just the **Iberdrola** data was taken, mainly because it encloses the entire generation portfolio[15] and is estimated with more actualized data (see Appendix 14).

6.8. Start-up Costs

The exponential adjust parameters and additional operation and maintenance are necessary to compute start-up costs. Unfortunately, for the generation units in Spain, there is no actualized source for any. And because extrapolate published standards of the SEIE would not be reliable, due to this system singularity, an easier approach was formulated. In fact, because of this uncertainty, it was decided not to consider start-up costs in the model for Iberia. To ratify the accuracy of this new assumption, a sensitive analysis was run. The already built optimization model for Balearic Islands, year 2006, was implemented considering no start-up costs (*ad* & *a'* = 0). The output variable energy prices are demonstrated in Fig.6.2. The curve *real* is the one obtained with the complete model for the SEIE. Therefore, as graphically proved, start-up costs seem not to influence significantly energy prices. Thus the reliability of the building conceptual structure for the Spanish generation variable costs probably would not be affected with this now compulsory simplification.

[15] Because the centralized structure in Spain have finished in 1997, moving towards a competitive model, there is no published data of generation technical parameters for new capacity installed after this year (especially CCGTs units).

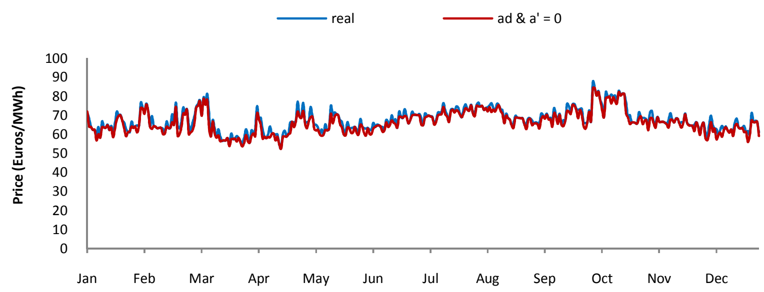

Fig. 6.2 - Variable energy prices contrast, Balearic Islands 2006

6.9. Variable Operation and Maintenance Costs

According to the methodology implemented in the Canary an Balearic Islands, to be able to consider variable operation and maintenance costs of generation units, *a''* and *b''* must be known. Again, like the exponential adjust parameters and additional operation and maintenance cost, there is no reference available for these values for the Spanish case. In the other hand, what is relatively easy to obtain in the literature is the operation and maintenance cost per generated energy – Euros per megawatt-hour. Therefore, in our approach to the SEP, the relation (2.22) is changed to:

$$C_{om}(i,h) = f(i).e_{pow}(i,h) \tag{6.4}$$

Where:

$f(i)$: O&M factor of the generation unit *i* [Euros/MWh]

Similarly to the O&M functioning hour's parameter, the *O&M factor* is here actualized annually with the forecast tariff IPC minus one hundred basis points. The values for 2010 (and then readjusted backwards till 2006) are based on **Iberdrola** study and given in the Appendix 14.

6.10. Variable Emissions Costs

An additional and crucial aspect must be incorporated in the variable costs inside the Spanish power system. It is the costs due to carbon emissions. According to the SEIE methodology, these costs are not explicitly taken into consideration when managing the economic dispatch and calculating energy prices. In reality, theoretically, the fuel costs are revised in the end of each year to take into account the internalization of emissions price rights by the generation groups. And this compensation is consequence of the difference between rights assigned for free and those really needed by the generation units. But due to the size and complexity of the SEE, those CO_2 costs are relevant to the generators dispatch strategies.

In the actual liberalized Spanish power system, in accordance with the European Union Directive and Kyoto Protocol targets, it has been operating a "Cap and Trade" mechanism for CO_2 emissions. The [EC8703] determines that each Member-State must elaborate a PNA[16]. It must enclose the maximum "cap" for the Members-State for several years, and the structure to divide the emissions between each country installation, according to individual national policies. This "cap" is connected to emissions rights (both for free[17] or acquired by auctions). Also, emissions can be traded between agents. In this way, the extra-cost of emitting for generation units reflects in their unitary payments, being a well-known and desirable effect. Actually, as a legitimate economic sign in marginal theory, generators have been already internalizing on their bids the emission's costs of opportunity[18].

In a centralized system philosophy, the commerce of emission would have a different treatment. Instead an individual management of the rights position, it would probably be applied a pooling system to all installations (aiming to minimize the system costs). Thus, it is thought to be valid the same political decisions of assigning for free the emissions rights and the same quantities of rights by thermal unit would have been taken. And still, a market would exist to set emissions prices. In this way the relations (6.5) and (6.6) guide the variable emissions costs for Spain. Hydro and nuclear plants are naturally excluded from this scheme. Furthermore, these expenditures are going to be neglected for the *Elcogás* unit, due to its specificity and innovative pilot project purpose. Thus the variable costs to be considered are:

$$C_{CO2}^{ea}(i,h) = Qe(i).\, e_{pow}(i,h).\, P_e^{ea}(i,h) \tag{6.5}$$

$$C_{CO2}^{ep}(i,h) = \left[Qe(i).\, e_{pow}(i,h) - \frac{A_f(i)}{H_d}\right].\, P_e^{ep}(i,h) \tag{6.6}$$

With:

$Qe(i)$:	emissions quantity factor of the generation unit i [tCO_2/MWh]
$P_e(i,h)$:	average price of emissions of the generator i in the hour h [Euros/tCO_2]
$A_f(i)$	annual free assigned certificates of generation unit i [tCO_2]
H_d	average equivalent hours per year [h]

At this point, there must be a clear distinction between the role of the equations above for the economic dispatch (6.5) and energy price calculations (6.6). The first relation suggests that the emissions cost of opportunity of individual units are fully internalized in their recognized costs. Thus, as in a marginal energy bids market, the merit order is changed, given incentives to low-polluting and more efficient generation. As an efficient and necessary economic sign, the system cost naturally increases by internalizing this new expenditure. The power plants are "pooled" in a way that the accountability is centralized and implemented each six-month to take into account the

[16] Two periods until today have been established – PNA I (2005 – 2007) and PNA II (2008 – 2012). The accountability for penalizations is established in the end of each natural year, based on audited emissions. The methodology for allocating individually these rights differs slightly from the PNA I and PNA II. In Spain, for the second phase of the program, the amount of free rights was decreased 36% for the electricity sector.

[17] In Spain it was politically decided to first assign for free these certificates to permit a gradual transition to the lost of competitiveness of the power plants more pollutant. From 2013, the majority of emission rights are planned to be obtained by normal auctions (*Energía y Sociedad* - www.energiaysociedad.es)

[18] The use of emission rights (CO_2) assigned to the installations of electricity generation implies to choose between two alternatives: utilizing them to generate electricity and avoid penalizations; or selling them in the market of emission rights. The cost of avoiding the payment that would be received selling the rights in the market of emission rights is called "opportunity cost", and it is equal to the price of emission rights in the market.

difference of emissions assigned for free and those really used to generate. A positive net value of a generation unit would represent a surplus of rights that are therefore required back by the central system operator and used to compensate some other eventual deficit, at current averaged CO_2 prices. The free rights in a centralized system work therefore to ease the transition towards a mechanism where all the generation costs are internalized to generation prices. So, the (6.6) is indispensable to estimate a real hourly costs sign for energy price computations. Also, the prices of emissions are likely to the averaged in order to decrease the dependency of decisions to volatility in the CO_2 market. For this purpose, the same methodology of the SEIE to compute product prices was taken as reference.

The individual *annual assigned certificates* for the year 2006 and 2007 were estimated from the PNA I and obtained in [PRE05]. For the year 2008 and 2009 (PNA II), the [PRE342007] was used. For those units without an administrative registration, a value was set based on the most similar technology. In addition, it is considered that the certificates are only individual. It is not allowed a pooling of generators as in the actual Spanish scheme. Thus, some group[19] values (in particular for the PNA II) were normalized to individual generators units taking into account their relative weight inside the group in the PNA I. In reality, according to the proposed methodology, there is no a real difference in assigning certificates individually or to group all the generators together. In the end of the day, the net system emissions costs just depend of the total emissions verified and the total of free rights given. The decomposition in values by unit was only implemented to be able to compute individual recognized emission costs. The *number of hours in a year* is standardized in 8.760 hours. In addition, the *emissions quantity factor* is calculated yearly from 2006 to 2008 based on the public information of thermal units' emissions [MARM07, MARM08, MARM09] divided by the energy generated by power plant available on REE website (Annual Report of the Spanish Power System - *Informe Anual del Sistema Electrico Español*). Because there is no information until this date about CO_2 quantities for the year 2009, the same data from the previous year were taken. Appendix 16 presents all the emissions parameters by individual unit and year.

The *price of emissions*[20] for the economic dispatch is calculated ex-ante each January and July with the moving average of the previous six months index. Also, the six-months calculated CO_2 prices used to the variable dispatch of generation costs are regularized each January and July by the real average values (from the last six months). Fig 6.3 demonstrates the European prices from January 2005 (EUA PointCarbon). It is interesting to observe the low liquidity of the market, particularly in the year 2007. The transition expectations of new allocation of certificates to the second phase of the PNA (2008-2012), with all its regulatory uncertainty, together with an excess of allowances supply, made the price drop to close to zero. And, at some moments, no trade was registered.

[19] The [L105], that regulates the trading of emissions rights, permits the "pooling" of generation power plants to manage their certificates and emissions quantities as a central entity.

[20] The price of emissions (emission rights) in a liberalized market like the currently implemented in Spain depends on the equilibrium between the European supply and demand. The main driver to set this price is the shortage in the market, once the supply and demand of rights depends mostly of the emissions cap fixed.

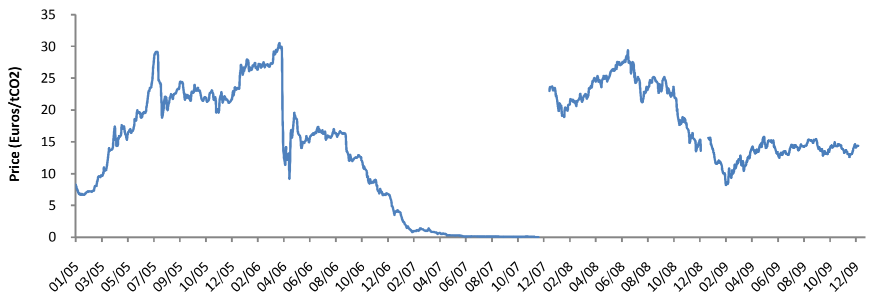

Fig. 6.3 - Price of emissions

6.11. Fuel Features

When calculating the variable generation costs of over a traditional system for Spain, a crucial step is to determine some fuels characteristics, like which fuel is relevant to be considered and how to obtain and calculate their prices and logistic costs. The next items work on these ideas.

6.11.1. Fuels to be Considered

The generation structure to Spain in the ordinary regime fuelled by any kind of non-renewable fuel is basically divided into: coal energy (fuelled by imported and national coal), nuclear plants (with uranium), gas turbines in open cycle (burning oil derivatives, natural gas and LNG), and CCGT units (using natural gas and LNG). For the present study, for the sake of simplicity and because their relevance, just the *imported coal*, *uranium*, and *LNG* have been considered as fuels.

Coal units in Spain typically are divided in: brown lignite, dark lignite, dark coal, and imported coal. The mix of generation changes from time to time, but basically nowadays they contribute to the total coal generation in Spain, respectively in: 20%, 10%, 50%, and 20% (Annual Report of the Spanish Power System - *Informe Anual del Sistema Electrico Español*). On these numbers, the gasified plant of *Elcogás* is also included. It is important to mention that, even some boilers have being projected for a specific type of fuel, several are actually using another kind of coal different of that designed[21]. Or still a mixture of different types. In this way, as already mentioned, it was decided just to consider the imported coal. It is understood that the decisions of generating are rational, with the purpose of minimizing the total system costs. In other words, there were taken always the most efficient decisions based on perfect information. So, being the external fuel cheaper and with a better quality (higher LHV and fewer emissions) compared with the other options, the centralized dispatch mechanism is going always to choose the imported fuel for generating.

There are still in the SEE some gas units in open cycle projected to burn gasified fuels instead natural gas. But, due to their old-fashion, costly, and inefficient technology, they are actually being gradually deactivated (till the end of 2009 just four

[21] Another classification for coal units in Spain could consider the real type of fuel burned: imported coal (*Aboño 1*, *Aboño 2*, *Litoral 1*, *Litoral 2*, *Los Barrios*, *Pasajes*, *Lada 3*, *Lada 4*, *Puentes 1*, *Puentes 2*, *Puentes 3*, *Puentes 4*, *Meirama*, and *Cercs*) and a mix of indigenous and imported coal (the remaining units).

units continue to operate – *Escombreras 4*, *Escombreras 5*, *Sabón 1*, and *Sabón 2*. Therefore, as a valid simplification, it was considered that all gas turbines in open cycle, and logically CCGT units, which have being operating from 2006 and 2009 in Spain, are burning just natural gas (in reality, liquefied natural gas – LNG).

In Spain, the natural gas in gasified state enters the country in pipelines from Norway (7% of consumption) and Algeria (28%). The rest of gas (65%) is imported in liquefied state (LNG). For this reason, Spain has a huge capacity of re-gasification (it has 6 of the 13 re-gasification plants of Europe). Due to the LNG flexibility of supply, national energy security (it decreases the dependency of just a few suppliers), and Spain isolation (lack of interconnection pipelines), it was decided to focus on the gas in liquefied state (what seems to compensate its elevated costs). In this way, because its relevance to the Spanish power system, it was decided just to consider the LNG along this study.

6.11.2. Fuel Average Prices (Coal)

One important step for variable energy calculation is the determination of the fuel therm average price. It is necessary to compute the variable operating (fuel) costs and is composed of two components: one related with product prices and other with logistic costs. For coal units, exactly the same references for product prices of the SEIE and LHV were employed. On the other hand, to take the SEIE indication for logistic costs for this technology would not be appropriate. In the Spanish power system, coal units are highly dispersed, with very different costs for logistic services (unload, port services, intermediate storage, transmission to the central cistern, ships and trucks, quality control and adequacy, commercialization tariffs and costs). In this way, based on the **Iberdrola** estimation, different values depending on the unit location and fuel were utilized (see Appendix 17). They are in a 2010 basis. Therefore, a backward actualization was implemented from 2010 to 2006 using the Consumption Price Index (IPC) foreseen in the tariff minus one-hundred basis points.

6.11.3. Fuel Average Prices – LNG Methodology

The proposed methodology for calculating the gas prices in a regulated system for Spain is consequence of several assumptions and already distinct published and tender schemes. The target is to estimate a realistic figure based on available information for gas prices and dispatch mechanisms under a current centralized regime.

The main reference used is the [MITC10][22]. This Order regulates different aspects of the SEIE. In special, it suggests the calculus of a new framework for gas prices in the islands due to the start of operation of a submarine pipeline to Balearic Islands. In this way, CCGT units and gas turbines in open cycles are going to be allowed to burn the new fuel. In this context, it represents an interesting indication about how can be calculated the cost of regulated payments to gas power plants. Thus, it basically

[22] Until the publication of this work, a definitive methodology for gas prices computations in the SEIE was published with the [MITC155910]. It takes as start point the [MITC10], adapting it to the context of the [MITC91306]. Also, it includes some changes suggested by the CNE in the [CNE810]. Inside this always changing regulatory structure, is our belief the Proposal [MITC10] still represents a valid and coherent approximation of how the mechanism would work inside the SEE. In addition, it was the most accurate methodology available when implementing the simulations structure.

suggests that the monthly natural gas prices result from the sum of three components multiplied by the monthly gas consumed plus one additional element of transmission:

- Product price (considering losses);
- Logistic until commercial operation: unloading, re-gasification, and canon of storage;
- Underground storage;
- Transmission and distribution toll: with a fixed component for the capacity reserve and a variable one for the gas conduction.

The steps for calculating the transmission and distribution toll comes from [MITC94901], which regulates the third party access to the gas facilities in Spain (ATR). Because the combined cycle units are connected to high pressure pipelines, the methodology elaborated below is focused on consumers connected between 4 and 60 bars. Also, it elaborates on thermal plants consuming more than 500.000.MWh_t/year (the CCGTs in the Peninsula are included in this range[23]). In addition, the distribution of gas is in a model not-interruptible. Also, all energy units are now associated with thermal megawatt-hour (instead electrical MWh). As last consideration, only the LNG is taken into account by the methodology. Therefore, it comes:

$$P_{NG}(i) = p_{NG}.(1 + l_r + l_t) + A_n + C_{us} \qquad (6.7)$$
$$T_{TD}(i) = C_{cr}(i) + C_c(i) \qquad (6.8)$$

With:

P_{NG}:	LNG average price utilized by the unit *i* [Euros/MWh_t]
p_{NG}:	LNG product price [Euros/MWh_t]
l_r:	re-gasification losses
$\mathrm{l_t}$:	transmission and distribution losses
A_n:	average toll cost for logistic until the "storage to commercial operation" (AOC) of unit *i* [Euros/MWh_t]
C_{us}:	underground storage cost [Euros/MWh_t]
$T_{TD}(i)$:	transmission and distribution toll of unit *i* [Euros/month]
$C_{cr}(i)$:	component of capacity reserve of unit *i* [Euros/month]
$C_c(i)$:	component of conduction of unit *i* [Euros/month]

The *transmission and distribution toll* is separated into two components: one referring to capacity reserve and other to gas conduction.

$$C_{cr}(i) = 10.C_{fc}.Q_e(i) \qquad (6.9)$$
$$C_c(i) = C_f.Q_{mc}(i) + C_v.Q_r(i) \qquad (6.10)$$

Where:

C_{fc}:	fixed component of capacity reserve [(cts/kWh_t/day)/month]
$Q_e(i)$:	equivalent invoice volume of natural gas of unit *i* [MWh_t/day]
$Q_{mc}(i)$:	maximum daily contracted volume of the user *i* in the month [MWh_t/day]
$Q_r(i)$:	real gas consumed by the unit *i* [MWh_t/month]

[23] For example, a CCGT unit of 300 MW, with an efficiency of 50%, and a load factor of 30%, would consume an average of 1.576.800 MWh_t/year.

C_f:	fixed component of conduction toll [(Euros/MWh$_t$/day)/month]
C_v:	variable component of conduction toll [Euros/MWh$_t$]

In this way, the price of fuel can be rearranged as a sum of product prices and logistic costs. The singularity is that an element of the latter is actually fixed costs, and not just variable, as implemented in the SEIE. The relations above can therefore be modified:

$$pr(i) = \left(\frac{1}{860}\right).[p_{NG}.(1 + l_r + l_t) + A_n + C_{us}] \quad (6.11)$$

$$log_v(i,h) = \frac{e_{pow}(i,h)}{\eta(i)}.C_v \quad (6.12)$$

$$log_f(i) = \left(\frac{1}{720}\right).\left[10.C_{fc}.Q_e(i) + C_f.Q_{mc}(i)\right] \quad (6.13)$$

Where:

$pr(i)$:	LNG therm average price utilized by unit *i* [Euros/th]
$log_v(i)$:	variable LNG logistic cost of unit *i* (transmission and underground storage) [Euros/h]
$\eta(i)$:	efficiency of unit *i*

The (6.11) is normally implemented for the calculation of variable operating (fuel) costs of generation units. The logistic cost (6.12) is added up in the methodology as an extra parameter for economic schedule and variable generation costs computations. While (6.13) is summed up to the capacity payment retribution as an extra fixed cost related to LNG logistics. The average *efficiency* is set to 33% for gas units operating in open cycle and 50% for CCGT units.

The *product prices* for the LNG are published by the CNE in its Supervision Monthly Report of the Gas Wholesale Market (*Informe Mensual de Supervision del Mercado Mayorista de Gas*). Similarly to the fuels used in the SEIE, it is considered that they are fixed each six months, in January and July, and are calculated by the average of monthly prices, corresponding to the previous six months. Fig.18 illustrates these prices. Also, the six-months calculated fuel prices used to the variable dispatch of generation costs are regularized each January and July by the real average values (from the last six months). The *fixed capacity reserve* and the *fixed and variable conduction tolls* components are yearly set by an Order ITC in December of each year and are given in Appendix 18 [MITC410005, MITC399606, MITC386307, MITC380208].

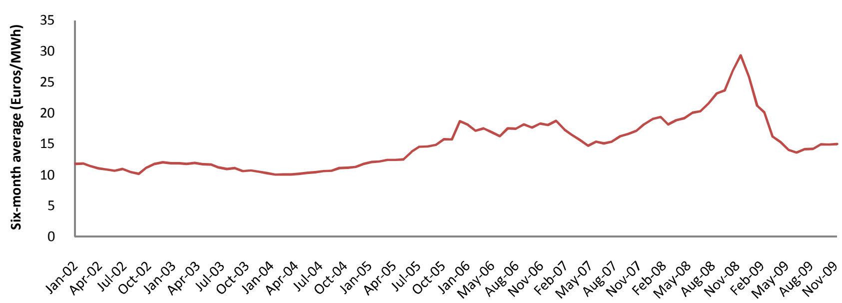

Fig. 6.4 - Six-month average of LNG product prices

The *re-gasification losses* are standardized in the [MITC380208] to 0,05%, while the *transmission and distribution losses* are 0,39% for units connected to pipelines working with pressure between 4 and 60 bars [MITC399306]. The *average toll cost* is determined by an equation established in the [SEE09] utilizing the absolute value of the distinct toll terms instead their variation, as it follows:

$$A_n = 10.\left[12.\frac{C_{fc}+C_{fr}}{360} + C_{vr} + \frac{C_{fu}}{7500000} + C_{vu} + \frac{C_{vs}}{1000}.5\right] \quad (6.14)$$

Being:

C_{fr}:	fixed component of re-gasification [(cts/kWh$_t$/day)/month]
C_{vr}:	variable component of re-gasification [cts/kWh$_t$]
C_{fu}:	fixed component of unloading [Euros/ship]
C_{vu}:	variable component of unloading [cts/kWh$_t$]
C_{vs}:	variable LNG storage canon component [cts/MWh$_t$/day]

For the *underground storage cost*, the relation below is adapted:

$$C_{us} = 10.\left\{\left[\left(\frac{12}{365}\right).12 + \frac{8}{365}\right].C_{fus} + \left(\frac{8}{365}\right).C_{vus}\right\} \quad (6.15)$$

Where:

C_{fus}:	fixed component of underground storage [cts/kWh$_t$]
C_{vus}:	variable component of underground storage (injection and extraction) [cts/kWh$_t$]

The *capacity reserve*, *fixed and variable re-gasification*, *fixed and variable unloading* and *variable LNG storage canon* components are also yearly published by an Order ITC in every December and specified in the Appendix 18.

The invoice volume of natural gas depends on the quantity nominated and the contracted one. So, it comes:

$$Q_e(i) = Q_{mn}(i) \quad \forall \quad 0{,}85.Q_{mc}(i) \leq Q_{mn}(i) < 1{,}05.Q_{mc}(i) \quad (6.16)$$
$$Q_e(i) = 0{,}85.Q_{mc}(i) \quad \forall \quad Q_{mn}(i) < 0{,}85.Q_{mc}(\mathrm{i}) \quad (6.17)$$
$$Q_e(i) = Q_{mn}(i) + 2.[Q_{mn}(i) - 1{,}05.Q_{mc}(i)] \quad \forall \quad Q_{mn}(i) \geq 1{,}05.Q_{mc}(i) \quad (6.18)$$

With:

$Q_{mn}(i)$:	maximum daily nominated (measured) volume of the user *i* in the month [MWh$_t$/day]

In practice, the *maximum volume contracted* by the user in the month can be estimated taking into account a forecast maximum need of gas. Broadly defining:

$$Q_{mc}(i) = \frac{24.P_n(i).UF(i)}{\eta(i)} \quad (6.19)$$

Being:

$P_n(i)$:	net power of unit *i* [MW]
$UF(i)$:	gas utility factor in the month of unit *i*

The *gas utility factor* in the month is constant for all units and estimated in 90%. So, under this line of thought, the units are always contracting gas for a monthly peak of 90% of its full capacity. Another comment is that the *maximum daily nominated volume by the user* is actually obtained by the economic dispatch. In this way, as it will be further elaborated in the next Chapter, the variable generation costs must be calculated before the fixed ones.

Chapter 7. Modeling Structure - Spanish Generation Costs

The very final step to get the expected cost in a centralized generation dispatch framework in Spain (say Iberia), is to develop the model based on the described methodology. The same structure and assumptions used to the SEIE model were maintained with some changes to adapt it. The capacity payment together with fixed logistic costs were calculated using spreadsheets models, while the variable generation costs were obtained based on optimization runs to the economic system dispatch.

Nevertheless, one important aspect that must be stressed is that several input statements were now taken as externally given from the current liberalized Spanish generation system. And they were considered unchangeable if a theoretical centralized structure had been operating – especially variables concerning investment and operational decisions. In short, it is supposed that some inputs would not be significantly different in the context of traditional and competitive liberalized schemes. *In fact, the economic theory shows that, ideally, individual decisions purposing to maximize profits in the short and long run lead to the very same results compared to a model trying to maximize social welfare (decrease system costs). And there is no clear indication decisions would have been taken differently by both models in Spain*. Therefore, along this Chapter, several assumptions are going to be just explicitly placed and no further considerations are going to be detailed. The last part of the work, focusing on the conclusions and discussions, is then reserved to openly comment and defend the validity of those assumptions specifically concerning the Spanish reality.

Here, is convenient to reflect the first assumption for generation prices computation.

> <u>Postulate 1</u> – *Investment decisions on generation expansion, as well operational or political conclusions on units' end of operation, would concur in both the actual liberalized market and in a hypothetical traditional centralized structure for Spain from the year 1998.*

7.1. Variable Costs Representation

The general code and tools implemented for the Spanish reality follows basically the same idea of the ones employed in the SEIE to calculate variable generation costs, with all the necessary structural changes explained in the previous Chapter. These conceptual variations enclosed, between others: variable emissions costs, variable logistic costs, and different equations to guide operation and maintenance expenditures. The first dilemma faced when adapting the already built design is about units energy output. In fact, the optimization model was choose as a reference instrument when modeling variable costs of the Insular and Extra-Peninsular Spanish system for two main reasons, one structural and other operational The latter reflects the way of ease computational efforts. While the first concerns the latent need of estimating a realistic figure for individual units energy output, once this information is unavailable for the SEIE reality. Turning back to the Iberian system, actually there is available more precise public data. It is possible to access, for example, the hourly energy dispatched by generator in the system. In the other hand, to maintain the already validated structure implemented for the islands, objectifying to find the best dispatch strategy minimizing the yearly system costs, it was taken similarly the daily generation by technology as a residual demand for a group of units. Thus, the GAMS tool takes place.

Regarding the project set-up, it was decided a daily aggregation for simulations – start-ups and shut downs decisions only occur in the end/beginning of each day. Also, the runs were executed from 2006 until the end of the year 2009, years where the new regulatory structure in the SEIE has been operating. And the CPLEX solver was again used to work the MIP (Mixed Integer Problem). Finally, the system is modeled as a single bus. Below is explained the most relevant topics for simulations. Appendix 19 gives a complete view of the GAMS code related with Spain for the year 2006.

7.1.1. Objective Function

The main purpose of centralized systems is to maximize social welfare. And this is translated to minimize the total system generation costs. Therefore, the objective function becomes:

$$min \sum_i \sum_d C_{op}(i,d) + C_{om}(i,d) + C^{ea}_{CO2}(i,d) + C_H(d) + C_{pum}(d) + log_v(i,d) \tag{7.1}$$

The variables $C_{op}(i,d)$, $C_{om}(i,d)$, $C_{CO2}(i,d)$, and $log_v(i,d)$, are related to, respectively: variable fuel, operation and maintenance, emissions, and logistic costs of the generation unit *i* in the day *d*. The pumping and hydro units are "*pooled*", once there is no need of a merit mechanism for them - they just receive a variable payment directly connected with their energy generated and pumped. Thus, $C_H(d)$ represents the hydroelectric costs and $C_{pum}(d)$ the pumping expenditures in the day *d*.

7.1.2. Variable Operating Costs

For computing the variable fuel costs of generation units, there is a distinction between two groups guided by different conceptual methodologies. Coal, gas, and CCGT power plants expenditures are calculated with (2.16) setting the exponential adjust parameter *c* to zero. Differently, fuel costs of nuclear and gasified coal technologies are defined with (6.3) and directly connected with their energy generated. In this way:

$$C_{op}(i,d) = pr(i,d).hr(i,d).\left[u(i,d).a(i) + b(i).\frac{energy(i,d)}{hr(i,d)}\right] \quad \forall \quad i = coal, gas, ccgt \tag{7.2}$$

$$C_{op}(i,h) = P_{ff}(i).energy(i,d) \quad \forall \quad i = nuclear, gicc \tag{7.3}$$

The *u(i,d)* is the binary variable indicating whether the unit *i* in the day *d* is connected {1} or disconnected {0}. The *hr(i,d)* is the number of operating hours of a unit *i* in the day *d*. - 24 hours. And the price of fuel *pr(i,d)* is calculated ex-ante and ex-post for the economic dispatch and energy costs definition. Note that this price for the LNG fuel is established with a specific methodology. And it was actually obtained with spreadsheet models, easing in this way the efforts in the optimization model.

7.1.3. Variable Operation and Maintenance Costs

For all units operating in Spain, this expenditure is linked to the daily output power of each generation plant. Therefore, (6.4) is simply manipulated to daily basis with:

$$C_{om}(i,d) = f(i).energy(i,d) \tag{7.4}$$

7.1.4. Variable Emissions Costs

As previously indicated, two different equations were formulated to the emissions costs mechanism inside Spain. One influence into the decision process of output energy of each unit and the other calculate the final variable emissions costs taking into account the free certificates assigned.

$$C_{CO2}^{ea}(i,d) = Qe(i).energy(i,d).pr(i,d) \tag{7.5}$$

$$C_{CO2}^{ep}(i,d) = \left[Qe(i).energy(i,d) - \frac{A_f(i)}{H_d}\right].pr(i,d) \tag{7.6}$$

7.1.5. Variable LNG Logistic Costs

The conduction of natural gas until the generation power plant could be viewed also as a strategic variable for decisions. It represents a variable cost connected with the “take or pay” contract. It is associated with the thermal gas energy consumed and was only set for CCGT and gas units. In simple terms:

$$log_v(i,d) = \frac{energy(i,d)}{\eta(i)}.C_v \qquad \forall \qquad i = ccgt, gas \tag{7.7}$$

7.1.6. Variable Hydroelectric and Pumping Costs

Typically, turbines and pumps operation while generating energy and pumping water for an upstream reservoir represent, even sometimes neglected, an extra-cost for the system. And these costs are attached with the amount of energy generated and consumed by and for pumping. In this context, it was defined that the mixed units for consumption and the pure ones when consuming power are grouped together in an equivalent plant. In this way, it does not matter the pumping strategy (to generate afterwards or to purely consume). It is thought to be valid that water is always and only pumped to generate electricity. And this expenditure is totally coupled with the daily pumping profile. Similar idea is worked out to hydro plants and to pure pumping units operating as generators. While water is turbined, an extra generation cost emerges. And being this payment factor very constant, the technology was “pooled” in one equivalent hydro unit. Thus it comes:

$$C_H(d) = f(H).Gen(H,d) \tag{7.8}$$

$$C_{pum}(d) = f(pum).Gen(pum,d) \tag{7.9}$$

The O&M factor of hydro generation $f(H)$ and pumping consumption $f(pum)$ are of the same magnitude. And $Gen(H,d)$ together with $Gen(pum,d)$ symbolize the total daily energy generated by hydro units and pumped by pumping plants.

7.1.7. Energy Constraints

Here the second main assumption of the work is declared.

> Postulate 2 – *The daily operational results of units' economic dispatch* ***by technology*** *would be the same in both the actual liberalized market and in a theoretical traditional centralized structure for Spain from the year 2006.*

The units were grouped by technology and must meet a daily residual demand in a day:

$$\sum_{t(i)} energy(i,d) = Gen(t,d) \tag{7.10}$$

The $Gen(t,d)$ denotes the energy produced by a group of units of the technology *t* in the day *d*. REE provides also for Spain a daily power schedule published on its website. The technologies are divided into: nuclear, coal, CCGT, fuel and gas and hydro. The generation consumption was estimated based on the relative weight of each group inside the technology. And it is considered that the *Elcogás* unit is together with the coal data. Fig.7.1 shows the generation profile by technology for Spain in the ordinary regime from 2006. Fig.7.2 gives the yearly aggregated demand by technology. As expected, CCGT work as peaky units, while hydro, nuclear and coal are in the base of generation. Also, it is possible to observe the low contribution of fuel and gas units to the Spanish system.

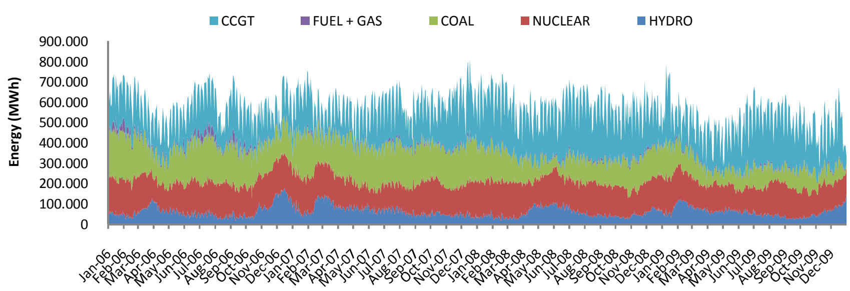

Fig. 7.1 - Daily net production by technology for the SEE

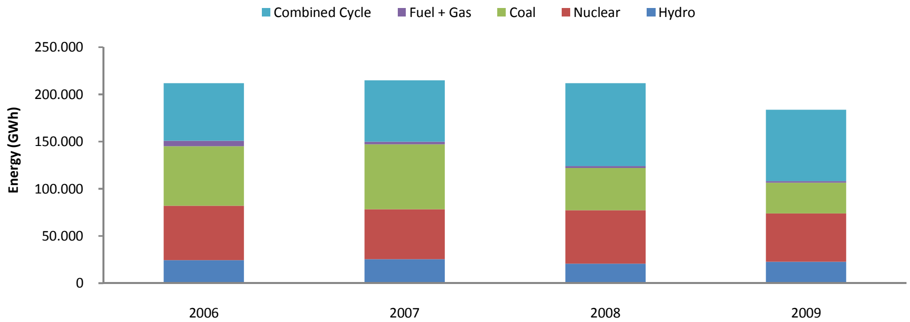

Fig. 7.2 - Total yearly net production by technology for the SEE

Specifically about the gasified power plant of *Elcogás*, because its singularity and innovative pilot project purposes, a compulsory objective production in the year was placed. It has the purpose of guaranteeing a minimal retribution for the unit and assuring it will operate a minimal number of hours to be able to access its technological development. In fact [SITC07], which sets up a viability plan for the company, already established indicative numbers for its yearly production, which also have been used for simulations. Table 7.1 shows these indicative figures.

Table 7.1 - *Elcogás* objective production

	Year			
	2006	**2007**	**2008**	**2009**
Energy (MWh)	1.098.694	1.548.464	1.588.771	1.377.606

Source: [SITC07], own elaboration.

The second condition to be met regarding technical boundaries of operation for the power plants was concerning the units' maximum and minimum possible power, limited respectively by their net capacity and minimum technical:

$$energy(i,d) \leq u(i,d).24.Pnet(i) \tag{7.11}$$
$$energy(i,d) \geq u(i,d).24.MT(i,d).Pnet(i) \tag{7.12}$$

If a given unit is connected (u equals to 1) its upper bound becomes equal to its maximum possible daily output power. And its lower bound is restricted by a given minimum technical $MT(i,d)$. For the Spanish power system, units from the same technology could have a very low daily output profile - especially fuel and gas plants operating for just some minutes in a day. Thus, it could appear an incongruence of having the daily technology demand lower than the minimum possible power of the smallest unit inside the group. To overcome this constraint, new conditions of minimum technical are defined as it follows:

$$MT(t,d) = MTn(t) \qquad \forall \qquad MTn(t) \leq \frac{Gen(t,d)}{24.maxPnet(t)} \tag{7.13}$$
$$MT(t,d) = \frac{Gen(t,d)}{24.maxPnet(t)} \qquad \forall \qquad \frac{Gen(t,d)}{24.maxPnet(t)} < MTn(t) < \frac{Gen(t,d)}{24.minPnet(t)} \tag{7.14}$$
$$MT(t,d) = \frac{Gen(t,d)}{24.minPnet(t)} \qquad \forall \qquad MTn(t) \geq \frac{Gen(t,d)}{24.minPnet(t)} \tag{7.15}$$

In this way, a given nominal minimum technical is applied (0,90 nuclear, 0,55 coal, 0,31 fuel and gas, 0,50 CCGT, 0,50 GICC) when the energy of the largest unit of the technology t - $24.maxPnet(t)$ - is able to meet alone a daily demand profile $Gen(t,d)$. If not, other values are set with (7.14) and (7.15) to cope with some singularities of the generators upper and lower bounds.

Note that nothing has been said until now about energy imports and exports to and from Spain in the context of MIBEL. In this context, the third and final consideration comes:

> *<u>Postulate 3</u> – The total daily net physical transactions of energy from and to Spain starting in 2006, as well as investment decisions on interconnection corridors from 1998, would be the same in both the current liberalized market and in a theoretical traditional centralized structure.*

7.2. Fixed Costs Representation

For modeling purposes, the configuration took a reverse order. To compute the fixed component of logistics in the ATR gas contracts, the monthly nominated volume of LNG by the generators must be known. It is used to reference the invoice volume of natural gas to the user. And this variable is actually obtained by the monthly maximum gas consumed. And the gas volume in reality is connected with the energy generated by combined cycle units and gas turbines in open cycle. Thus, there was the need of first estimating the output energy by the economic dispatch (and consequently to obtain the variable units generation costs) to then afterwards calculate the capacity payments together with the fixed logistic costs of natural gas.

With the entire theoretical framework already built and all information gathered, together with the monthly gas nominated by thermal unit from the economic dispatch, the representation of the fixed costs of individual units comes straightforward with spreadsheets models. In this way, it was possible to finally obtain a tendency for generation prices inside the Iberian market from 2006, what are going to be addressed in the item below.

7.3. Simulation Results and First Comments

In the Fig.7.3 below is possible to first observe some energy outputs by individual unit of the GAMS model. Appendix 20 shows some other results.

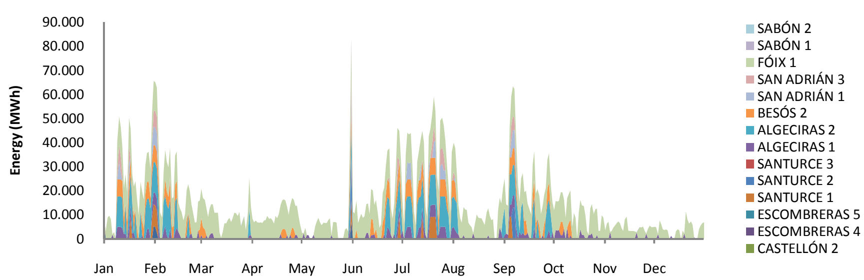

Fig. 7.3 - Daily generation of fuel & gas units, Spain 2006

Also, Fig.7.4 depicts the daily generation prices considering the whole simulation horizon (2006 to 2009). Those prices are already related with both the fixed and variable components. Fuel and gas units, due to its low outputs and high total costs, present several times soaring conceptual energy prices, becoming without doubt the marginal units of the system. This tendency probably would be overcome with the gradual deactivation of this kind of generation. What is already happened in the actual model in Spain.

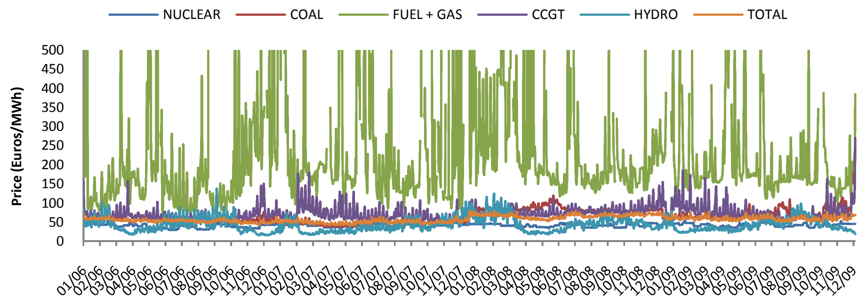

Fig. 7.4 - SEP centralized generation prices by technology

The validation process for the actual study is, in real terms, complicated. Analyses of the impact on generation prices of liberalizations in the electricity sector are scarce. And most of them use qualitative tools, statistical model or econometrics for estimating the welfare gain or loss due to the reforms. Particularly for the Spanish power sector, the only found reference in a sufficient aggregation and detailed level was the [FERN10]. It presents a global estimation of the yearly total system costs, included generation in the ordinary regime, over the old MLE in Spain from 1997 to 2010. Table 7.2 demonstrates the comparison on fixed and variable generation costs for both the present work – study 1 - and the published document – study 2.

Table 7.2 - SEP centralized generation costs comparison: model's output and published study

	2006		2007		2008		2009	
	1	2	1	2	1	2	1	2
Fixed Costs (MEuros)	5.261	4.324	5.653	4.547	6.026	4.668	6.146	4.742
Variable Costs (MEuros)	6.130	6.191	5.151	6.490	8.059	8.199	4.791	8.669
Total (MEuros)	11.390	10.515	10.803	11.037	14.085	12.867	10.937	13.411

Source: [FERN10], own elaboration.

More important than exact numbers, the relevant aspects are about general tendencies and overall magnitudes of values. Thus, both models seem to converge on recognized costs, principally for the years 2006 and 2007. Once the study 2 implements general ex-ante suppositions of future scenarios for estimating the two last years, and the present work is modeled in totality and detail by ex-post data, the figures are expected to diverge more significantly.

A more clear idea to contrast yearly and by technology obtained output generation prices is given on the Fig.7.5, representing the average costs in Euros/MWh. Average energy prices are peaky in 2008, reflecting the increase of fuel stock values (imported coal and LNG). Nuclear generation, less volatile to variations of the market, maintained its reference in around 40 Euros/MWh. Hydro plants is the cheapest way of suppling electricity in the system, with costs varying between 33 Euros/MWh and 41 Euros/MWh. Combined cycle and coal technologies appeared to represent almost the same average costs per generated energy (similar capacity payments retribution and variable costs compensation). And fuel and gas power plants prices are more than twice costly than the other options.

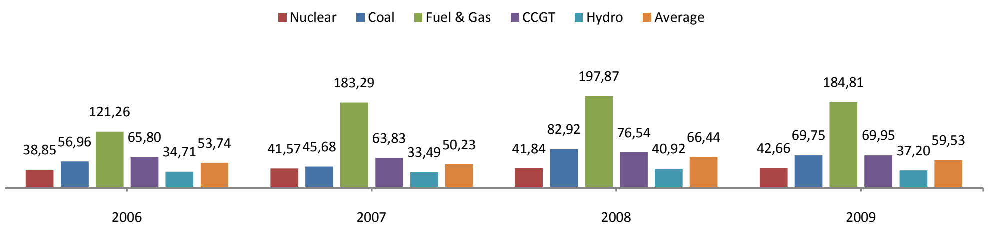

Fig. 7.5 - SEP yearly average centralized generation prices by technology

To a better understanding of the structure of these retributions, Table 7.3 and the Appendix 21 clearly illustrate the division between fixed and variable payments on the total prices by technology. In terms of capacity payments, it becomes evident the high cost of fuel and gas units. There is an excess of installed capacity compared with the dispatch of this kind of electricity. For the remaining technologies, there is not an expressive variation (especially in the year 2009 they seem to converge to around 30 Euros/MWh). Relating to variable costs, hydro units are, without surprise, the less costly, followed by the nuclear (13 Euros/MWh). Combined cycle and coal units again seem to compete in variable prices, changing from time to time their relative position on expenditures. To end the analysis, variable payments and fixed costs retributions have an average very similar weight on the generation prices composition – 47%/53% (2006), 48%/52% (2007), 57%/43% (2008), 44%/56% (2009).

Table 7.3 - SEP centralized generation costs by technology and year

	2006		**2007**		**2008**		**2009**	
	Fixed (MEuros)	**Variable (MEuros)**	**Fixed (MEuros)**	**Variable (MEuros)**	**Fixed (MEuros)**	**Variable (MEuros)**	**Fixed (MEuros)**	**Variable (MEuros)**
Nuclear	1.502,70	738,82	1.515,79	684,96	1.632,13	741,48	1.496,05	670,48
Coal	1.031,74	2.575,72	1.031,08	2.121,11	934,82	2.755,84	1.155,55	1.117,62
Fuel & Gas	348,52	338,41	315,48	106,68	277,72	174,92	255,52	114,89
CCGT	1.590,33	2.419,33	2.000,15	2.179,79	2.385,41	4.338,56	2.437,81	2.834,38
Hydro	787,25	57,43	790,24	58,19	795,90	48,23	801,04	53,41
Total	*5.260,54*	*6.129,71*	*5.652,75*	*5.150,73*	*6.025,98*	*8.059,03*	*6.145,97*	*4.790,78*
TOTAL	**11.390,25**		**10.803,48**		**14.085,01**		**10.936,75**	

Source: own elaboration.

7.4. Generation Price Assessment over Market Mechanisms – Preliminary Conclusions

With the extensive work put into practice along the previous pages, a comparison between the centralized modeled generation structure and the actual market prices of the MIBEL is now possible to be worked out. Firstly, a clear reference figure of market prices must be sketched. Then, graphical outcomes are possible to be built, statistical testing to ratify the visual conclusions can be applied, and economic discussions are able to be preliminary drawn.

In MIBEL, inside the current liberalized scheme, it is possible to find several different energy markets. Forward markets with bilateral contracts and short-term auctions. The day-ahead market for hourly energy schedules between load and supply. And the short-term markets: restrictions, secondary (MW) and tertiary (MWh) reserves, intra-daily markets, deviations management, and restrictions management. The day-ahead market occurs one day before the delivery of energy, and the sellers and buyers exchange energy for each one of the 24 hours of the next day. This type of structure is of the marginal type in Spain, where the generators bids represent the amount of energy they want to sell from a minimal price, say their cost of opportunity. On the other hand, due to real time unbalances and technical system restriction, several short-term markets also take place.

In this way, it was decided to use the day-ahead prices as a clear main reference of generation prices in ordinary regime over the market structure of MIBEL. In fact, these day-ahead values are expected to reflect the system generation variable costs and theoretically be able also in the long run to compensate their investment costs. Nevertheless, just and only marginal prices would not entirely reflect the generation prices. Forward markets[24], the compulsory tertiary reserve[25], and the intra-daily, deviations and restrictions management costs are legitimate expenditures and must also be included on ordinary regime generation prices. Note that here the secondary reserve (band regulation) was neglected, as well pumping prices. Due to the simplifications of modeling, this band regulation service was not included in both SEIE and Spanish simulations. And therefore to maintain the rationale for comparisons, in a market model this auxiliary service was also not considered. Concerning pumping prices, it was approached that they are already incorporated as a cost of opportunity for hydro units in the market. Thus there is no need to add it on the market reference line for evaluations.

As a final component, additional capacity payments over a marginal market models are central. The economic theory shows that generators do not incorporate on their day-ahead bids their fixed costs (investment amortization, fixed operation and maintenance costs, etc.) because they do not represent a cost of opportunity. In this way, units recover their fixed costs over a market structure by two complementary ways: market margin (difference between market prices and the incurred variable costs) and capacity payments (perceived by all generators and implemented in order to marginal units recover their fixed costs). The latter in Spain comes from the [L5497], with a compensation linked with output energy generated. Recently it was changed by the [L1707], with the new concept of medium term and long term capacity payments.

In resume, the generation costs for the ordinary Iberian market from 2006 were obtained by the daily sum of the following retributions: bilateral contracts; average prices in the day-ahead market; tertiary reserve costs; intra-daily energy prices; deviations management; restriction expenditures; and capacity payments. They are all publically available on monthly settlements in the REE website. The first record is from June of 2006. The Fig.7.6, Fig.7.7 and Fig.7.8 compare the simulated generation costs over a theoretical centralized structure and those obtained in a market model for the

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[24] All the bilateral contracts were valued in daily market prices. Assimilated contracts within the daily market, ruled by the [RDL 306], were also included.

[25] This service is compulsory for the generation units that are able to offer it. In this way, all the system units that can vary their production in a time lag not superior of 15 minutes and maintain the variation between 2 hours must offer all their capacity excess (not contract in other markets or services) to the system operator.

Iberian power system. Table 7.4 finally demonstrates the comparison on the total system costs between the model's output and the calculated market costs.

The results are consistent. Prices in market model seem to be on average lower. This indication points out, with just this single criterion, that competition has been bringing welfare reflected on low market prices. This conclusion can be quantitatively ratified by a statistical test for bivariate relations on SPSS. The tool proved with an two-tailed significance of 10,30%, 5% confidence level, that the two average monthly data sets *can* be considered the same within the simulated horizon.

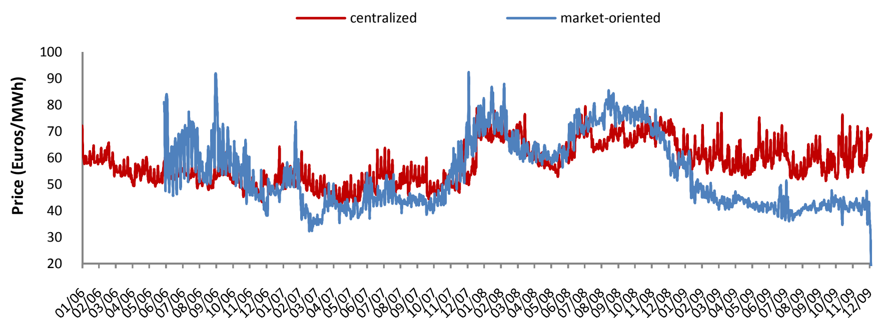

Fig. 7.6 - SEP daily contrast of generation prices: centralized *vs* market-oriented

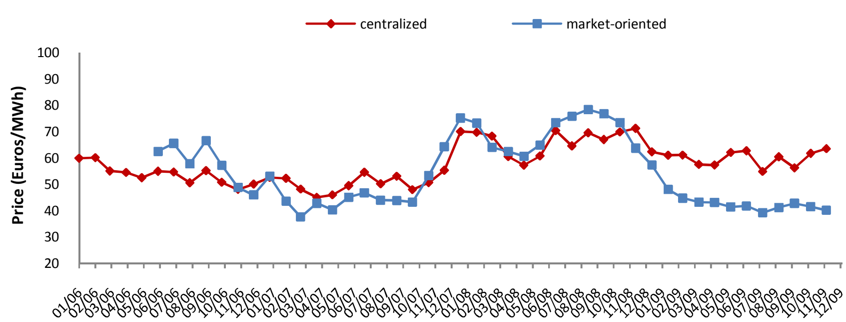

Fig. 7.7 - SEP monthly contrast of generation prices: centralized *vs* market-oriented

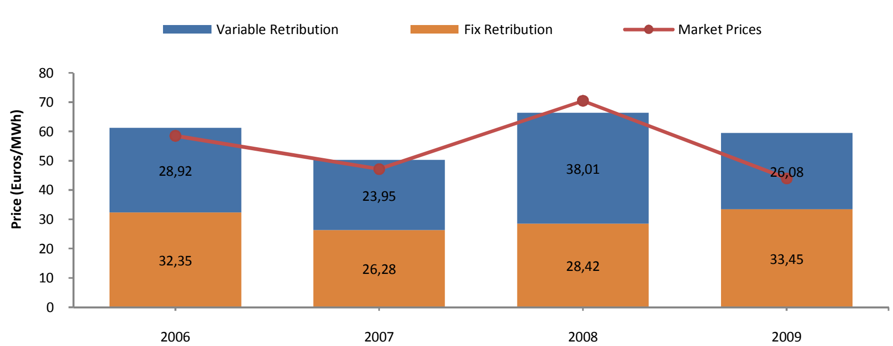

Fig. 7.8 - SEP fixed, variable and market-oriented average generation prices by year

Table 7.4 - SEP generation costs comparison: centralized *vs* market-oriented

	2006	2007	2008	2009
Market-oriented (MEuros)	7.366,47	10.150,20	15.093,14	8.117,20
Centralized (MEuros)	11.390,25	10.803,48	14.085,01	10.936,75

Source: own elaboration.

One interesting consideration would be to use the simulated structure of costs for centralized generation as an economic reference model. Optimally, investment and operational decisions reached by this model concur with independent decisions made by agents in a perfect market model. Being the centralized decisions rational, always trying to minimize the overall costs based on optimal central decisions and perfect information, the model could thus be stated as a snapshot of the minimum necessary retribution to compensate generation activities in the ordinary regime for the Iberian system. There is no much restriction about variable payments. Generators most likely have been compensated a minimum for their fuel costs, variable operation and maintenance and other related expenditures. On the other hand, market prices seem to do not be sufficient to recover fixed costs, like investments amortizations. Surely, it is a long term equilibrium and the simulated horizon is quite short. But it gives a nice sign that generation prices are probably underestimated (especially due to the global crisis in the year 2009). And to let the market work efficiently, the low prices are likely to be compensated with higher values over the long view.

Therefore, as preliminary conclusions of the work, it could be stated:

- For the same ***operational*** and ***investment expansion*** decisions (in generation capacity and interconnectors) the theoretical centralized generation prices simulated and those from the current liberalized market in Spain seem to concur in the short term. The results for 2009 should be explained as a consequence of global economic crisis;
- Therefore, there is a ***strong indication*** the liberalized market has been working efficiently, setting prices in accordance with the most rational centralized decisions that would have been taken in a Reference Model;
- Also, short-term analysis points towards the necessity of future marginal prices at ***higher average levels***, to the long term correct economic equilibrium for generators fixed costs compensation;
- Market prices show higher volatility than cost-reflecting prices. Customers can hedge this risk in long term markets.

Chapter 8. Conclusions, Discussions and Recommendations

The present work would not be complete without further elaboration on several key points. The technical background behind centralized generation cost structure for the Iberian market was extensively elaborated and validated on the previous Chapters. In this general context, there is not "one best option" to be chosen when trying to put into practice such theoretical mechanism. The variables included in the problem are complex, inter-related and several times unknown. And, besides technical constraints, several assumptions lie on economics reasoning and deep regulatory issues.Even with all these natural difficulties, it is our conjecture the report encloses a realistic, actual and very aggregated figure about what would have been happening with the Iberian power system under a traditional regulatory scheme. All the main concepts and methodologies were formulated taking into account the most actual and public published data available, and also using our deep knowledge of the Spanish power sector along several years of experience.

All the possible generation costs were fully incorporated by the model, like the emissions costs and variable and fixed portions of gas contracts. Actually, many assumptions were under-estimated. To namely some: considering all the generation units built before the year 1998 already amortized by the use of CTCs; taking into account indigenous coal; defining standard values for investments based on the most efficient technology available; and indicating investment on interconnection corridors as unchangeable. All these rational simplifications likely led to obtain generation expenditures over traditional schemes lower than they would have been occurring in reality.

The partial conclusions when contrasting output trend prices between these two polar structures (centralized *vs* market-oriented) are coherent and in line with what could have been expected. Markets working efficiently, setting prices in accordance with the most rational decisions taken by centralized dispatch mechanisms.

In this Chapter, first some regulatory recommendations for the SEIE and SEP are indicated. Then, the three main economic postulations when translating the SEIE structure to the Iberian reality are going to be explicitly discussed. And finally prospects for future studies are elaborated.

8.1. Regulatory Recommendations for the SEIE

All the regulatory progress made on the SEIE system since the publication of the [ME174703], and especially from 2006 with [MITC91306] and [MITC91406], is noticeable. It helped to bring more transparency to a before cloudy system, stimulating efficiency and retributing accordingly generation activities based on minimal audited costs. The methodology implemented is simple without loss of preciseness, relatively stable, and coherent with the necessity of isolated systems. And the recent open discussion for gas prices and tolls methodology, culminating on the document [MITC155910], is expected to impact positively the SEP costs with the new connected pipeline to Balearic Islands.

One important aspect to be mention is the no addition of environmental criteria for dispatching units on the SEIE. Emissions are only considered ex-post for accounting the difference between rights assigned for free and those really needed by units. *Is our approach this new constraint should be explicitly incorporated*. It would give special incentives for investing in more efficient and low polluting technologies, possibly changing the merit order of some units. And it is aligned with the EU environmental policy. An interesting theoretical starting point for integrating these costs is elaborated on the item 6.10 of this report.

8.2. Regulatory Recommendations for the SEP

The SEP is immersed in a constantly changing regulatory framework, subject to an unpredictable and several times not satisfactory political interference that need to be compensated in the long run for adequate market equilibrium. Therefore, regulatory stability, together with appropriate interventions into the market, is indispensable for achieving all the benefits a liberalized market system can provide.

The regulator should take care with institutions to give the right signals to demand to reduce consumption and to generators for investing. The most relevant signal is the market price. And the regulator should guarantee that the price allows the generators to recover their long-term costs. Markets should be used as much as possible, with the prices of energy, emissions and green or white certificates sending the correct economic signals for investment in adequate technologies or consumption. These prices would be set by different measures, like incentives, quotas, or contracts. However, while the long-term and sustainability implications of the energy model are not duly internalized in these prices, market instruments will need to be supplemented by other measures, such as R&D support.

8.3. Postulate 1: Investment and Decommissioning Decisions

Generation expansion planning, or capacity expansion planning, is to decide which generation assets are going to be build (or to decommission, or to acquire, or to sell) and the most appropriate moments of these actions. It is a highly complex problem, where decisions are taken under a great uncertainty, taken into account, between others:

- economic activity and demand growing forecasting;
- available technologies and its costs;
- estimations of fuel prices and their availability;
- reliability criteria;
- environmental impact;
- policies about diversification and external dependency.

In this arena, there are two major approaches in the academic theory: *traditional planning* (reference model) and *liberalized management* (market model). The first case is typical from centralized structures, like the one working in the SEIE. There, a single and centralized agent makes all the rational decisions based on perfect information. Usually there is also a strong coordination with the transmission network expansion. In the other way, for the liberalized management, there is freedom for the markets agents for building new power plants (subject to permits). Therefore, each generator makes its own decisions. And these decisions can be controlled by just one variable: the price. The regulator in this case may control the market objectives by different levels, like with reference planning and capacity payments. In this way some governance framework must be found to facilitate efficient coordination of generation and transmission investments.

For both theoretical reference and market models approaches, economic theory shows that the long term investment decisions should concur. Turning to real life decisions, there are several imperfections that could have influence on perfect investment outputs. To cite just some: public goods, positive and negative externalities, information asymmetries, and irrational behavior. All these traditional and market imperfections, together with an uncertainty environment (demand growing, market behavior, availability of technologies, climate conditions, inflation rates, economic growing, etc) make it difficult to be conclusive in any comparison between these different models. As a valid statement, traditional planning and liberalized management in real markets are expect to converge to approximately the same point if, in the first case, decisions are made close to the most rational behavior with the available information (decrease system costs subject to technical constraints). While that for the latter the regulator should interfere as few as possible, being responsible to efficiently regulate market imperfections.

For the Spanish system, similarly to other industrialized countries, one of the main drives of the transition to market model was the excess of system capacity during the MLE. Many companies had expressive debts in foreign currencies due to expensive investments on coal, nuclear and hydro plants. Fig.8.1 (adapted from the REE 2008 System Report) shows that from 1990 coverage indexes (blue curve) were far above the minimum acceptable system level set to 1,1 (red curve). From 1998, generation expansion seems to fluctuate around an optimal, situation that has been gradually changing from 2008 to high values. The relative overcapacity of the recent times (close to what happened during the previous regulatory framework) is explained greatly because investors, foreseeing an upwards demand curve and market opportunities, have investment on new CCGT capacity. This technology typically requires around 2 years to start operating[26], being very adaptable. Thus, they were already prepared to operate in the beginning of the economic crises. The *relative* overcapacity of the system together with the retracted demand due to the crisis pushed down generation prices to improbable levels.

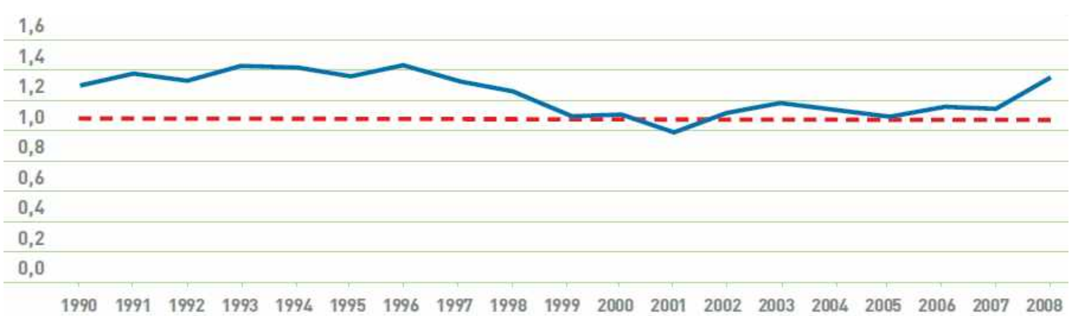

Fig. 8.1 - Evolution of the Spanish electricity coverage index (REE, 2008)

Based on exposed, *is our belief that there is not any indication generation investment decisions in Spain from 1998 would have been different if a centralized dispatch mechanism had been operating*. There are always strong imperfections and political interventions in both configurations. And decisions are always strongly related

[26] Up to 6 years, taking into account the time to get permits.

with futures scenarios about the evolution of demand. In this way, the strong demand growth from 1998 to 2007 would have influenced a centralized decision of investing in the same generation expansion as well. So, the conclusion *is not* that investment decisions on generation capacity would be equal. But that there is not *any clear indication* they would have been different.

8.4. Postulate 2: Operational Decisions on Units' Dispatch

Taken the investment decisions on generation capacity as externally given, the short-term operation of the market does not differ significantly between market-oriented and centralized dispatch mechanisms.

The individual aggregated decisions purposing to maximize profits from all the independent firms in the market should concur with centralized dispatch strategies to minimize the system costs. In well functioning and no-monopolistic liberalized markets like the regulated by OMEL/OMIP, firms bids taking into account their real marginal costs – their extra cost of producing one additional megawatt-hour of electricity. Therefore, the most efficient firms are scheduled to be dispatched in the day-ahead market and the system perceives the minimal generation costs. In reference models, similarly the decision of economic dispatch is centralized taken to achieve the minimal possible system expenditure. And with real-time operation, there is not a visible distinction. In both structures a central network operator decides the optimal power flow to cope with the electrical system restrictions and operation specificities.

Consequently, without loss of preciseness, *the study indicates that day-ahead operational results of Spanish units' economic dispatch by technology could be considered the same in both the actual liberalized market and in a theoretical traditional centralized structure.*

8.5. Postulate 3 - Energy Imports and Exports and Interconnection Corridors

The literature shows two extreme models for transmissions investments. The *centralized planning* (normally coordinated with generation capacity expansion). And the *market driven investments* (merchant lines), relying entirely on free entry of investors into the activity of constructing transmission lines and with no regulation of the prices that they can charge. The owners of these transmission lines are rewarded through the congestion rents associated with these lines. No restructured electric power industry has adopted a pure merchant transmission model. Transmission investment on interconnection corridors worldwide have been mainly made by centralized planning.

Spain is not an exception. It relies on centralized investment decisions to expand its interconnection capacity with neighbor countries (Portugal, France, and Morocco/Andorra). Specifically in relation to Portugal due to the MIBEL market, even decision are taken by a central body, they are strongly influenced by market forces. Therefore, there is an indication interconnection lines have been expanding in a more efficient and speedy way under the actual regulatory structure. As a consequence, due to the market splitting logic, it probably has been reflecting in decreasing market prices inside the SEP if compared with purely centralized investments. Nevertheless, once there is not more reliable information, it was considered to this work that *the same decisions on international interconnection corridors would have been taken over a traditional scheme*.

About net physical transactions, with the exception of the MIBEL market ruled by market splitting model, all the remained connections are based in explicit capacity auctions with an annual, monthly, day-ahead and intra-daily horizon. Therefore, *together with the previous postulations on the generation expansion and operation, the total daily net physical transactions from and to Spain are likely to converge to the same point with a theoretical centralized system and with the actual liberalized market mechanism*.

8.6. Perspectives for Future Studies

The study is not exhausted with this report. Several interesting lines for researching can be followed after this publication. The most preeminent is the model extension (both in the SEIE and SEP) in the next years, together with a regression and extrapolation of it based on past behavior and future economic and technical scenarios. Just four years of comparison represent only a snapshot for conclusions. There are cycles in the economy and generation investment compensations are measured by long-term equilibriums, limited addressed in few years of analysis.

Another topic is about investigating ex-ante regulatory measures in the SEIE. For instance, it could assess the impact on costs of interconnecting electrically the systems of islands. Or it can demonstrate the different behaviors when adding emissions criteria for the economic dispatch of units. The built structure can be run also to evaluate the possible impact on energy prices of the new interconnected gas pipeline to Baleares.

The third aspect for perspective studies is related with extensive sensitive analysis to prove the validity/impact of the several assumptions implemented, especially while translating the SEIE methodology to the SEP reality. Assumptions were rationally made based in our deep knowledge, literature review and public information available. But they are far away of not being contestable.

The final point encloses transparency. There are several periodical publications by REE about recognized costs in the SEIE. The built representation can therefore replicate generation expenditures in the islands, and in this way may be implemented to ratify these public values.

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[MITC94901] Ministry of Industry, Tourism and Commerce, ROYAL DECREE 949/2001 of August 3rd, which regulates the third party access to gas installations and establishes an integrated economic system to the natural gas sector (in Spanish).

[NEWB97] Newbery, Pollitt, Michael, "The Restructuring and Privatization of the U.K. Electric Supply – Was it Worth it?", Public Policy for the Private Sector, n. 124. 1997.

[PERE07] Perez, Y., Ramos, F.J., "*Desintegración vertical y regulación del subsistema canario*", Revista de Estudios Regionales n. 80, pp. 171-192. 2007 (in Spanish).

[PRE05] Sub-secretary of the Presidential Ministry, RESOLUTION of November 14th, which publishes the Ministers Council Agreement, of January 21st 2005, which approves the individual assignation of emission rights to the installations included in the application range of the Royal Decree – Law 5/2004, of August 27th, which regulates the regime of emission rights commerce of greenhouse gases.

[PRE342007] Sub-secretary of the Presidential Ministry, ORDER PRE 3420/2007 of January 26th, which publishes the Ministers Council Agreement, of November 2nd 2007, which approves the individual assignation of emission rights to the installations included in the Assignation National Plan of rights of greenhouse gases emission, 2008-2012.

[RDL206] ROYAL DECREE LAW 3/2006 of February 24th, which modifies the mechanism of the selling and acquisition of energy offered simultaneously to the day-ahead and intra-daily production markets by members the same power group (in Spanish).

[RDL609] ROYAL DECREE LAW 6/2009 of April 30th, which adopts some measures for the energy sector and approves the social bond (in Spanish).

[SEE09] Government Secretary of Energy, CORRECTION in mistakes of the RESOLUTION of May 19th, which establishes the operative rules to the auction development for the acquisition of natural gas to the fixation of the lost resort tariff in the period between 1 July 2009 and 30 June 2010 (in Spanish).

[SITC07] Sub-secretary of Industry, Tourism and Commerce, RESOLUTION of March 27th, which publishes the Agreement of the Ministers Council of March 16th 2007, for the establishment of a Viability Plan to the company *Elcogás Sociedad Anónima* (in Spanish).

[UNESA09] Asociación Española de la Industria Eléctrica (UNESA), "*La Situación Económico-Financiera de la Actividad Eléctrica: 1998 – 2008*", Informe M-16796-2009, Gráficas MARCAR SA, Madrid (in Spanish).

Appendix 1 – SEIE: Generators Input for Capacity Payment Estimation

Balearic Islands islands

Generation Unit	Net Power (MW)	Unitary Investment Value (Euros)	Start Operation	End-of-life
ALCUDIA 1	113,60	95.600.000	Dec-81	Dec-06
ALCUDIA 2	113,60	95.600.000	Aug-82	Aug-07
ALCUDIA 5	120,60	154.490.000	Aug-97	Aug-22
ALCUDIA 6	120,60	154.000.000	Dec-97	Dec-22
TOTAL COAL	**468,40**	**499.690.000**		
ALCUDIA 3	32,70	7.712.000	Feb-89	Feb-14
ALCUDIA 4	32,70	7.338.000	Feb-89	Feb-14
FORMENTERA 1	11,50	6.269.000	Mar-66	Mar-91
IBIZA 12	21,10	4.855.000	Jul-88	Jul-13
IBIZA 15	11,50	2.814.000	Jan-68	Jan-93
MAHON 12	32,70	8.126.000	Jan-94	Jan-19
MAHON 13	33,70	9.531.000	Jul-99	Jul-24
MAHON 14	39,40	21.981.000	Jun-04	Jun-29
SON MOLINAS 4 (IBIZA 19)	17,70	3.316.000	Nov-80	Nov-05
SON MOLINAS 5 (IBIZA 18)	17,70	3.316.000	Dec-80	Dec-05
SON REUS 1	33,70	12.067.000	Jul-00	Jul-25
SON REUS 2	33,70	12.039.000	Jul-00	Jul-25
SON REUS 3	33,70	12.039.000	Jul-00	Jul-25
SON REUS 4	33,70	12.034.000	Aug-00	Aug-25
IBIZA TG5 (IBIZA 22)	21,02	15.372.564	jun/08	Jun-33
MAHON TG4 (MAHON 15)	42,04	30.745.127	set/08	Sep-33
CAS TRESORER TG4	66,42	47.327.588	dez/08	Dec-33
CAS TRESORER TG5	66,42	47.327.588	dez/08	Dec-33
MAHON TG5	43,72	31.152.336	dez/08	Dec-33
IBIZA TG6	21,86	16.323.203	dez/08	Dec-33
TOTAL GAS	**646,99**	**311.685.406**		
IBIZA 3	1,90	1.493.000	May-71	May-96
IBIZA 4	1,90	1.493.000	Jul-71	Jul-96
IBIZA 5[1]	7,10	3.630.000	Apr-73	Apr-98
IBIZA 6	7,10	3.630.000	Nov-73	Nov-98
IBIZA 7	7,10	3.630.000	Oct-74	Oct-99
IBIZA 8[2]	7,10	3.630.000	Dec-74	Dec-99
IBIZA 9	14,20	9.253.000	Jul-82	Jul-07
IBIZA 10	14,20	9.253.000	Sep-82	Sep-07
IBIZA 11	14,20	10.178.000	Jun-86	Jun-11
IBIZA 13	14,50	16.894.000	Oct-93	Oct-18
IBIZA 14	14,50	15.208.000	Dec-93	Dec-18
IBIZA 16	17,40	17.784.000	Jul-01	Jul-26
IBIZA 17	17,40	18.332.000	Aug-01	Aug-26
MAHON 9	13,60	18.159.000	Jun-91	Jun-16
MAHON 10	13,60	17.425.000	Apr-91	Apr-16
MAHON 11	13,60	17.778.000	Mar-91	Mar-16
MAN 3 (IBIZA 20)	15,44	23.369.737	Dec-06	Dec-31
MAN 4 (IBIZA 21)	15,44	23.369.737	Dec-06	Dec-31
TOTAL FUEL (DIESEL)	**210,28**	**214.509.474**		
SON REUS CCGT 1	204,00	212.106.000	Jun-02	Jun-27
SON REUS 5	48,70	41.758.000	Jul-01	Jul-26
SON REUS 6	48,70	41.758.000	Jul-01	Jul-26
SON REUS 7	48,70	41.758.000	Aug-01	Aug-26
SON REUS 8	57,90	86.832.000	Jun-02	Jun-27
SON REUS CCGT 2	189,90	190.893.000		
SON REUS 9	63,30	63.631.000	Jun-03	Jun-28
SON REUS 10	63,30	63.631.000	Jun-03	Jun-28
SON REUS 11	63,30	63.631.000	Jun-05	Jun-30
CAS TRESORER TV3	194,22	206.900.416	Dec-06	Dec-31
TOTAL CCGT	**588,12**	**609.899.416**		
TOTAL ORDINARY REGIME	**1.913,78**	**1.635.784.297**		

[1] End operation in the year 2008

[2] End operation in the year 2009

Canary Islands

Generation Unit	Net Power (MW)	Unitary Investment Value (Euros)	Start Operation	End-of-life
ARONA 1	21,60	15.905.000	May-03	May-28
ARONA 2	21,60	16.472.000	Jun-03	Jun-28
BCO. TIRAJANA 1	32,34	9.198.000	Jul-92	Jul-17
BCO. TIRAJANA 2	32,34	11.181.000	May-95	May-20
CANDELARIA 5	14,70	3.512.000	Dec-72	Dec-97
CANDELARIA 11	32,34	7.906.000	Nov-88	Nov-13
CANDELARIA 12	32,34	8.664.000	Jul-89	Jul-14
GRANADILLA 1	32,34	10.519.000	Aug-90	Aug-15
GRANADILLA 6	39,20	30.208.000	Dec-01	Dec-26
GUINCHOS, LOS 15	21,00	20.190.000	Dec-04	Dec-29
JINAMAR 7	17,64	3.879.000	May-81	May-06
JINAMAR 10	32,34	8.502.000	Feb-89	Feb-14
JINAMAR 11	32,34	8.378.000	May-89	May-14
PUNTA GRANDE 9	19,60	5.964.000	Jun-88	Jun-13
PUNTA GRANDE 14	32,34	13.512.000	jan/98	Jan-23
SALINAS,LAS 7	21,85	8.486.000	Oct-92	Oct-17
SALINAS,LAS 8	29,40	15.965.000	Jul-00	Jul-25
SALINAS, LAS 9 (GUINCHOS, LOS 11)	11,74	4.997.000	Jan-88	Jan-13
TIRAJANA GAS 5	65,83	52.974.819	Dec-06	Dec-31
TIRAJANA GAS 6	65,83	52.974.819	Dec-06	Dec-31
TOTAL GAS	**608,71**	**309.387.639**		
BCO. TIRAJANA 3	74,24	143.557.000	Jan-96	Jan-21
BCO. TIRAJANA 4	74,24	125.821.000	Jun-96	Jun-21
CANDELARIA 7	37,28	14.080.000	May-75	May-00
CANDELARIA 8	37,28	14.295.000	Jan-76	Jan-01
CANDELARIA 9	37,28	14.161.000	Mar-79	Mar-04
CANDELARIA 10	37,28	42.992.000	Oct-85	Oct-10
GRANADILLA 4	74,24	144.155.000	Sep-95	Sep-20
GRANADILLA 5	74,24	127.711.000	Dec-95	Dec-20
JINAMAR 1	28,02	13.862.000	Dec-72	Dec-97
JINAMAR 5	37,28	11.745.000	Jun-75	Jun-00
JINAMAR 6	37,28	11.354.000	Dec-78	Dec-03
JINAMAR 8	55,56	41.875.000	Aug-82	Aug-07
JINAMAR 9	55,56	52.731.000	Nov-85	Nov-10
TOTAL FUEL (OIL)	**659,78**	**758.339.000**		
CANDELARIA 3	8,51	4.027.000	May-72	May-97
CANDELARIA 4	8,51	3.983.000	Feb-72	Feb-97
CANDELARIA 6	8,51	3.954.000	Nov-73	Nov-98
GRANADILLA 2	20,51	25.317	Jun-91	Jun-16
GRANADILLA 3	20,51	25.558.000	Aug-91	Aug-16
GUINCHOS, LOS 6	3,82	2.016.000	Feb-73	Feb-98
GUINCHOS, LOS 7	3,82	1.949.000	Dec-73	Dec-98
GUINCHOS, LOS 8	3,82	2.443.000	May-75	May-00
GUINCHOS, LOS 9	4,30	2.567.000	Jul-80	Jul-05
GUINCHOS, LOS 10	6,69	3.976.000	Mar-83	Mar-08
GUINCHOS, LOS 12	6,69	8.064.000	Mar-95	Mar-20
GUINCHOS, LOS 13	11,50	12.254.000	Feb-01	Feb-26
GUINCHOS, LOS 14	11,20	28.888.000	Nov-03	Nov-28
JINAMAR 2	8,51	4.781.000	Feb-73	Feb-98
JINAMAR 3	8,51	4.158.000	Sep-73	Sep-98
JINAMAR 4	8,51	4.870.000	Feb-74	Feb-99
JINAMAR 12	20,51	36.973.000	Jun-90	Jun-15
JINAMAR 13	20,51	39.198.000	Aug-90	Aug-15
LLANOS BLANCOS 1	1,07	470.000	Jun-87	Jun-12
LLANOS BLANCOS 9	0,67	374.000	Aug-79	Aug-04
LLANOS BLANCOS 11	0,88	716.000	Mar-86	Mar-11
LLANOS BLANCOS 12	1,07	711.000	Sep-91	Sep-16
LLANOS BLANCOS 13	1,07	972.000	Dec-91	Dec-16
LLANOS BLANCOS 14	1,26	1.028.000	Feb-95	Feb-20
LLANOS BLANCOS 15	1,36	1.160.000	Mar-00	Mar-25
LLANOS BLANCOS 16	1,90	4.121.353	Oct-05	Oct-30
LLANOS BLANCOS 17	1,90	4.121.353	Dec-05	Dec-30
PALMAR, EL 12	1,06	536.000	Oct-87	Oct-12
PALMAR, EL 13	1,40	1.255.000	May-88	May-13
PALMAR, EL 14	1,40	1.249.000	Jan-87	Jan-12
PALMAR, EL 15	1,84	2.492.000	Aug-87	Aug-12
PALMAR, EL 16	1,84	2.416.000	Jun-88	Jun-13
PALMAR, EL 17	2,51	2.786.000	Mar-96	Mar-21
PALMAR, EL 18	2,51	2.742.000	May-00	May-25
PALMAR, EL 19	3,10	6.966.000	Dec-04	Dec-29
PALMAR, EL 20	3,10	6.724.312	Jun-05	Jun-30

PUNTA GRANDE 2	6,49	7.912.000	Jun-86	Jun-11
PUNTA GRANDE 3	6,49	7.773.000	Dec-86	Dec-11
PUNTA GRANDE 7	6,49	5.392.000	Oct-87	Oct-12
PUNTA GRANDE 11	12,85	17.172.000	Jul-89	Jul-14
PUNTA GRANDE 12	12,85	16.959.000	May-89	May-14
PUNTA GRANDE 13	20,51	35.052.000	Sep-92	Sep-17
PUNTA GRANDE 15	17,20	24.811.000	Feb-02	Feb-27
PUNTA GRANDE 16	17,20	25.228.000	Jan-02	Jan-27
SALINAS, LAS 1	3,82	2.336.000	Oct-75	Oct-00
SALINAS, LAS 2	3,82	2.503.000	Feb-76	Feb-01
SALINAS, LAS 3	4,11	2.652.000	Feb-80	Feb-05
SALINAS, LAS 4	6,21	3.967.000	Nov-81	Nov-06
SALINAS, LAS 5	6,21	4.648.000	Oct-81	Oct-06
SALINAS, LAS 6	20,51	40.228.000	Jun-90	Jun-15
SALINAS, LAS 10	17,20	36.193.000	Jul-04	Jul-29
SALINAS, LAS 11	17,20	30.257.518	Jul-05	Jul-30
SALINAS, LAS 12	17,20	30.257.518	Sep-05	Sep-30
TOTAL FUEL (DIESEL)	**411,24**	**523.865.370**		
BCO. TIRAJANA CCGT 1	206,10	225.177.000		
BCO.TIRAJANA 5	68,70	75.059.000	Jul-03	Jul-28
BCO.TIRAJANA 6	68,70	75.059.000	Aug-03	Aug-28
BCO.TIRAJANA 7	68,70	75.059.000	Nov-04	Nov-29
GRANADILLA CCGT 1	206,10	214.596.000		
GRANADILLA 7	68,70	71.532.000	Sep-03	Sep-28
GRANADILLA 8	68,70	71.532.000	Apr-04	Apr-29
GRANADILLA 9	68,70	71.532.000	Jun-05	Jun-30
BCO. TIRAJANA CCGT 2	209,53	245.791.019	Dec-07	Dec-32
TOTAL CCGT	**621,73**	**685.564.019**		
EL MULATO	0,30	708.000	Jan-56	Jan-21
TOTAL HYDROELECTRIC	**0,30**	**708.000**		
TOTAL ORDINARY REGIME	**2.301,76**	**2.277.864.027**		

Appendix 2 – SEIE: Maximum Investment Values of Units

Technology	Power (MW)	Unitary Investment Value (Euros/MW)			
		2006 (base)	2007	2008	2009
Balearic Islands					
Diesel Units – 4T	< 5	*N/A*	N/A	N/A	N/A
Diesel Units – 4T	≥ 5 and < 14	*N/A*	N/A	N/A	N/A
Diesel Units – 4T	≥ 14 and < 24	*1.478.284*	1.513.763	1.562.203	1.595.009
Diesel Units – 2T	≥ 24	*1.747.161*	1.789.093	1.846.344	1.885.117
Gas turbines (aero-derivative)	< 50	*70.683*	72.379	74.696	76.264
Gas turbines (heavy duty)	≥ 20 and < 50	*692.054*	708.663	731.341	746.699
Gas turbines (heavy duty)	> 50	*660.382*	676.231	697.871	712.526
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	*1.040.310*	1.065.277	1.099.366	1.122.453
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	*1.111.153*	1.137.821	1.174.231	1.198.890
Canary Islands					
Diesel Units – 4T	< 5	*2.169.133*	2.221.192	2.292.270	2.340.408
Diesel Units – 4T	≥ 5 and < 14	*2.160.451*	2.212.302	2.283.095	2.331.040
Diesel Units – 4T	≥ 14 and < 24	*1.759.158*	1.801.378	1.859.022	1.898.061
Diesel Units – 2T	≥ 24	*2.079.121*	2.129.020	2.197.149	2.243.289
Gas turbines (aero-derivative)	< 50	*857.612*	878.195	906.297	925.329
Gas turbines (heavy duty)	≥ 20 and < 50	*823.544*	843.309	870.295	888.571
Gas turbines (heavy duty)	> 50	*785.855*	804.716	830.466	847.906
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	*1.110.054*	1.136.695	1.173.070	1.197.704
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	*1.322.272*	1.354.007	1.397.335	1.426.679

Appendix 3 – SEIE: O&M Maximum Values of Units

Technology	Power (MW)	Unitary O&M Value (Euros/MW)			
		2006 (base)	2007	2008	2009
Balearic Islands					
Diesel Units – 4T	< 5	*N/A*	N/A	N/A	N/A
Diesel Units – 4T	≥ 5 and < 14	*N/A*	N/A	N/A	N/A
Diesel Units – 4T	≥ 14 and < 24	*71.976*	73.056	74.955	76.904
Diesel Units – 2T	≥ 24	*55.691*	56.526	57.996	59.504
Gas turbines (aero-derivative)	< 50	*21.694*	22.019	22.592	23.179
Gas turbines (heavy duty)	≥ 20 and < 50	*19.208*	19.496	20.003	20.523
Gas turbines (heavy duty)	> 50	*13.110*	13.307	13.653	14.008
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	*32.949*	33.443	34.313	35.205
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	*32.949*	33.443	34.313	35.205
Diesel Units - 2T	< 5	*79.142*	80.329	82.418	84.561
Diesel Units - 2T	≥ 5 and < 14	*55.516*	56.349	57.814	59.317
Diesel Units - 2T	≥ 14 and < 24	*46.890*	47.593	48.831	50.100
Gas turbines (heavy duty)	< 20	*36.451*	36.998	37.960	38.947
Coal Steam		*46.392*	47.088	48.312	49.568
Fuel-oil Steam	≤ 40	*21.852*	22.180	22.756	23.348
Fuel-oil Steam	> 40 and ≤ 60	*N/A*	N/A	N/A	N/A
Fuel-oil Steam	> 60 and ≤ 80	*N/A*	N/A	N/A	N/A
Hydroelectric		*N/A*	N/A	N/A	N/A
Canary Islands					
Diesel Units – 4T	< 5	*145.681*	147.866	151.711	155.655
Diesel Units – 4T	≥ 5 and < 14	*119.570*	121.364	124.519	127.756
Diesel Units – 4T	≥ 14 and < 24	*78.640*	79.820	81.895	84.024
Diesel Units – 2T	≥ 24	*65.120*	66.097	67.815	69.579
Gas turbines (aero-derivative)	< 50	*25.367*	25.748	26.417	27.104
Gas turbines (heavy duty)	≥ 20 and < 50	*22.461*	22.798	23.391	23.999
Gas turbines (heavy duty)	> 50	*15.330*	15.560	15.965	16.380
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	*38.527*	39.105	40.122	41.165
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	*38.527*	39.105	40.122	41.165
Diesel Units - 2T	< 5	*N/A*	N/A	N/A	N/A
Diesel Units - 2T	≥ 5 and < 14	*64.916*	65.890	67.603	69.361
Diesel Units - 2T	≥ 14 and < 24	*54.829*	55.651	57.098	58.583
Gas turbines (heavy duty)	< 20	*42.624*	43.263	44.388	45.542
Coal Steam		*N/A*	N/A	N/A	N/A
Fuel-oil Steam	≤ 40	*25.552*	25.935	26.610	27.301
Fuel-oil Steam	> 40 and ≤ 60	*23.771*	24.128	24.755	25.399
Fuel-oil Steam	> 60 and ≤ 80	*22.540*	22.878	23.473	24.083
Hydroelectric		*133.403*	135.404	138.925	142.537

Appendix 4 – SEIE: Quadratic Adjustment Parameters

Technology	Power (MW)	Consumption Curve Parameters		
		***a* (th/h)**	***b* (th/h.MW)**	***c* (th/h.MW^2)**
Diesel Units – 4T	< 5	865,969	1.678,83	81,52
Diesel Units – 4T	≥ 5 and < 14	1.286,06	2.511,43	6,13
Diesel Units – 4T	≥ 14 and < 24	9.556,47	1.039,20	36,41
Diesel Units – 2T	≥ 24	7.613,79	1.381,90	15,25
Gas turbines (aero-derivative)	< 50	9.167,14	2.154,04	1,59
Gas turbines (heavy duty)	≥ 20 and < 50	31.391,05	1.773,42	11,58
Gas turbines (heavy duty)	> 50	60.436,76	1.925,54	0,53
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250			
Functioning 1 GT + 1 ST		118.213,53	-390,57	11,18
Functioning 2 GT + 1 ST		239.683,59	-440,63	5,76
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250			
Functioning 1 GT + 1 ST		43.062,18	1.188,46	3,97
Functioning 2 GT+ 1 ST		87.203,24	1.193,07	1,98
Functioning 3 GT + 1 ST		131.932,88	1.188,19	1,34

Appendix 5 – SEIE: Fuel Parameters

Low heating values

Fuel	Low Heating Value (th/t)
Imported coal	6.000
Fuel Oil BIA	9.000
Fuel Oil nº 1	9.750
Fuel Oil 1250''	9.750
Gas Oil	10.150
Diesel Oil	10.000

Methodology for computation of product prices

Fuel	Product Price
Imported coal	Index API#2 published by the Coal Daily of Energy Argus
Fuel Oil BIA	Arithmetic average of the Fuel Oil one percent values of CIF Mediterranean market (Génova/Lavera) published by the Platts European Marketscan
Fuel Oil 1250'' Redwood and Fuel Oil nº 1	Arithmetic average of the composition of Gas Oil 0,2 percent (14 percent) and Fuel Oil 3,5 percent (86 percent) values of CIF Mediterranean market (Génova/Lavera) published by the Platts European Marketscan
Diesel Oil	Arithmetic average of the composition of Gas Oil 0,2 percent (83 percent) and Fuel Oil 3,5 percent (17 percent) values of CIF Mediterranean market (Génova/Lavera) published by the Platts European Marketscan
Gas Oil	Arithmetic average of the Gas Oil 0,2 percent values of CIF Mediterranean market (Génova/Lavera) published by the Platts European Marketscan

Logistic costs

Fuel	Logistic Costs (Euros/t)			
	2006 (base)	2007	2008	2009
Balearic Islands				
Imported Coal	*12,00*	12,12	12,24	12,36
Fuel Oil BIA 1%	*44,77*	45,22	45,67	46,13
Fuel Oil BIA 0,3%	*N/A*	N/A	N/A	N/A
Fuel Oil N.1	*44,77*	45,22	45,67	46,13
Fuel Oil 1250"	*N/A*	N/A	N/A	N/A
Diesel Oil	*N/A*	N/A	N/A	N/A
Gas Oil	*60,66*	61,27	61,88	62,50
Canary Islands				
Imported Coal	*N/A*	N/A	N/A	N/A
Fuel Oil BIA 1%	*22,89*	23,12	23,35	23,58
Fuel Oil BIA 0,3%	*57,89*	58,47	59,05	59,64
Fuel Oil N.1	*N/A*	N/A	N/A	N/A
Fuel Oil 1250"	*N/A*	N/A	N/A	N/A
Diesel Oil	*53,53*	54,07	54,61	55,15
Gas Oil	*35,01*	35,36	35,71	36,07

Product prices

Year	Applied Months	Fuel					
		Imported Coal	Fuel Oil BIA	Fuel Oil 1250"	Fuel Oil N.1	Diesel Oil	Gas Oil
Provisional Product Price (Euros/t)[1]							
2006	January - June	46,52	254,38	252,58	252,58	425,80	468,48
	July - December	49,53	271,46	280,35	280,35	446,96	488,00
2007	January - June	52,24	230,82	254,91	254,91	422,75	464,10
	July - December	54,00	230,11	251,92	251,92	401,18	437,95
2008	January - June	74,21	309,75	324,00	324,00	486,40	526,41
	July - December	97,57	369,29	375,98	375,98	610,99	677,09
2009	January - June	101,35	344,17	342,52	342,52	527,10	593,12
	July - December	51,31	225,65	228,13	228,14	315,71	346,61
2010	January - June	50,16	302,48	307,70	307,71	384,47	406,03
Definitive Product Price (Euros/t)[2]							
2006	January - June	49,53	271,46	280,35	280,35	446,96	488,00
	July - December	52,24	230,82	254,91	254,91	422,75	464,10
2007	January - June	54,00	230,11	251,92	251,92	401,18	437,95
	July - December	74,21	309,75	324,00	324,00	486,40	526,41
2008	January - June	97,57	369,29	375,98	375,98	610,99	677,09
	July - December	101,35	344,17	342,52	342,52	527,10	593,12
2009	January - June	51,31	225,65	228,13	228,14	315,71	346,61
	July - December	50,16	302,48	307,70	307,71	384,47	406,03

[1]For economic dispatch

[2]For generation variable costs calculation

Appendix 6 – SEIE: Start-up Parameters

Technology	Power (MW)	Start-up Parameters						
		a' (th)	*b'* (h)	*ad* (Euros)				
				2002 (base)	2006	2007	2008	2009
Balearic Islands								
Diesel Units – 4T	< 5	N/A	N/A	*N/A*	N/A	N/A	N/A	N/A
Diesel Units – 4T	≥ 5 and < 14	N/A	N/A	*N/A*	N/A	N/A	N/A	N/A
Diesel Units – 4T	≥ 14 and < 24	57.689,14	6,74387	*170,37*	177,29	179,06	180,85	182,66
Diesel Units – 2T	≥ 24	79.576,42	5,53611	*169,23*	176,10	177,86	179,64	181,44
Gas turbines (aero-derivative)	< 50	8.120,00	0,21715	*700,51*	728,95	736,24	743,61	751,04
Gas turbines (heavy duty)	≥ 20 and < 50	10.094,78	0,21715	*3.524,38*	3.667,48	3.704,16	3.741,20	3.778,61
Gas turbines (heavy duty)	> 50	49.877,10	0,72135	*10.368,81*	10.789,83	10.897,72	11.006,70	11.116,77
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250							
Functioning 1 GT + 1 ST		281.985,03	0,55379	*25.922,03*	26.974,57	27.244,31	27.516,76	27.791,92
Functioning 2 GT + 1 ST		410.809,81	0,60483	*25.922,03*	26.974,57	27.244,31	27.516,76	27.791,92
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250							
Functioning 1 GT + 1 ST		176.511,00	0,54568	*30.204,30*	31.430,72	31.745,02	32.062,47	32.383,10
Functioning 2 GT+ 1 ST		298.551,00	0,56189	*30.204,30*	31.430,72	31.745,02	32.062,47	32.383,10
Functioning 3 GT + 1 ST		420.591,00	0,60483	*30.204,30*	31.430,72	31.745,02	32.062,47	32.383,10
Canary Islands								
Diesel Units – 4T	< 5	5.075,00	1,44290	*67,82*	70,57	71,28	71,99	72,71
Diesel Units – 4T	≥ 5 and < 14	15.172,71	2,88669	*150,70*	156,82	158,39	159,97	161,57
Diesel Units – 4T	≥ 14 and < 24	57.689,14	6,74387	*192,80*	200,63	202,63	204,66	206,71
Diesel Units – 2T	≥ 24	79.576,42	5,53611	*195,89*	203,84	205,88	207,94	210,02
Gas turbines (aero-derivative)	< 50	8.120,00	0,21715	*763,42*	794,42	802,36	810,39	818,49
Gas turbines (heavy duty)	≥ 20 and < 50	10.094,78	0,21715	*3.720,04*	3.871,09	3.909,80	3.948,90	3.988,39
Gas turbines (heavy duty)	> 50	49.877,10	0,72135	*12.296,86*	12.796,16	12.924,12	13.053,36	13.183,90
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250							
Functioning 1 GT + 1 ST		281.985,03	0,55379	*30.847,22*	32.099,74	32.420,74	32.744,95	33.072,40
Functioning 2 GT + 1 ST		410.809,81	0,60483	*30.847,22*	32.099,74	32.420,74	32.744,95	33.072,40
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250							
Functioning 1 GT + 1 ST		176.511,00	0,54568	*35.943,11*	37.402,54	37.776,57	38.154,34	38.535,88
Functioning 2 GT+ 1 ST		298.551,00	0,56189	*35.943,11*	37.402,54	37.776,57	38.154,34	38.535,88
Functioning 3 GT + 1 ST		420.591,00	0,60483	*35.943,11*	37.402,54	37.776,57	38.154,34	38.535,88

Appendix 7 – SEIE: O&M Cost Parameters

Technology	Power (MW)	O&M Cost Parameters					
		b'' (%)	a'' (Euros/h)				
			2002 (base)	**2006**	**2007**	**2008**	**2009**
Balearic Islands							
Diesel Units – 4T	< 5	N/A	N/A	N/A	N/A	N/A	N/A
Diesel Units – 4T	≥ 5 and < 14	N/A	N/A	N/A	N/A	N/A	N/A
Diesel Units – 4T	≥ 14 and < 24	11,18	85,186	88,645	89,531	90,427	91,331
Diesel Units – 2T	≥ 24	5,35	84,615	88,051	88,931	89,821	90,719
Gas turbines (aero-derivative)	< 50	1,50	143,194	149,008	150,498	152,003	153,523
Gas turbines (heavy duty)	≥ 20 and < 50	1,50	224,063	233,161	235,492	237,847	240,226
Gas turbines (heavy duty)	> 50	1,50	698,944	727,324	734,597	741,943	749,363
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	2,52	1.747,360	1.818,310	1.836,493	1.854,858	1.873,406
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	2,52	1.510,215	1.571,536	1.587,251	1.603,124	1.619,155
Canary Islands							
Diesel Units – 4T	< 5	10,18	33,910	35,287	35,640	35,996	36,356
Diesel Units – 4T	≥ 5 and < 14	10,18	75,349	78,408	79,193	79,984	80,784
Diesel Units – 4T	≥ 14 and < 24	10,18	96,400	100,314	101,317	102,331	103,354
Diesel Units – 2T	≥ 24	4,90	97,944	101,921	102,940	103,970	105,009
Gas turbines (aero-derivative)	< 50	1,50	156,032	162,368	163,991	165,631	167,287
Gas turbines (heavy duty)	≥ 20 and < 50	1,50	239,372	249,091	251,582	254,098	256,639
Gas turbines (heavy duty)	> 50	1,50	828,910	862,567	871,193	879,905	888,704
Combined cycle (configuration 2x1)	≥ 200 and ≤ 250	2,37	2.079,358	2.163,788	2.185,426	2.207,280	2.229,353
Combined cycle (configuration 3x1)	≥ 200 and ≤ 250	2,37	1.797,156	1.870,128	1.888,829	1.907,717	1.926,794

Appendix 8 – SEIE: Generators Parameters for Variable Costs Estimation

Balearic Islands islands

Generation Unit	Net Power (MW)	*a* (th/h)	*b* (th/h.MW)	*c* (th/h.MW^2)	*a'* (th)	*b'* (h)	*ad* (Euros)*	*a''* (Euros/h)*	*b''* (%)
ALCUDIA 1	113,60	36.092,337	1.964,270	2,770	1.105.780,00	3,21123	14.850,000	172,800	6,63
ALCUDIA 2	113,60	36.092,337	1.964,270	2,770	1.105.780,00	3,21123	14.850,000	172,800	6,63
ALCUDIA 5	120,60	39.925,725	1.964,270	1,620	1.256.007,40	8,67612	14.850,000	172,800	6,63
ALCUDIA 6	120,60	39.925,725	1.964,270	1,620	1.256.007,40	8,67612	14.850,000	172,800	6,63
TOTAL COAL	**468,40**								
ALCUDIA 3	32,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
ALCUDIA 4	32,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
FORMENTERA 1	11,50	19.938,331	202,480	29,240	13.850,36	0,21715	3.388,822	215,445	1,50
IBIZA 12	21,10	24.050,692	2.242,580	14,510	12.293,68	0,21715	3.388,822	215,445	1,50
IBIZA 15	11,50	19.923,222	2.172,400	40,810	13.850,36	0,21715	3.388,822	215,445	1,50
MAHON 12	32,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
MAHON 13	33,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
MAHON 14	39,40	31.391,054	1.773,420	11,580	10.094,78	0,21715	[1]	[1]	1,50
SON MOLINAS 4 (IBIZA 19)	17,70	24.128,890	2.271,470	11,620	12.293,68	0,21715	3.388,822	215,445	1,50
SON MOLINAS 5 (IBIZA 18)	17,70	24.128,890	2.271,470	11,620	12.293,68	0,21715	3.388,822	215,445	1,50
SON REUS 1	33,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
SON REUS 2	33,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
SON REUS 3	33,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
SON REUS 4	33,70	31.391,054	1.773,420	11,580	10.094,78	0,21715	3.388,822	215,445	1,50
IBIZA TG5 (IBIZA 22)	21,02	31.391,054	1.773,420	11,580	10.094,78	0,21715	[1]	[1]	1,50
MAHON TG4 (MAHON 15)	42,04	31.391,054	1.773,420	11,580	10.094,78	0,21715	[1]	[1]	1,50
CAS TRESORER TG4	66,42	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
CAS TRESORER TG5	66,42	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
MAHON TG5	43,72	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
IBIZA TG6	21,86	31.391,054	1.773,420	11,580	10.094,78	0,21715	[1]	[1]	1,50
TOTAL GAS	**646,99**								
IBIZA 3	1,90	3.899,915	-865,710	826,350	12.968,45	1,85009	198,592	99,296	5,35
IBIZA 4	1,90	3.899,915	-865,710	826,350	12.968,45	1,85009	198,592	99,296	5,35
IBIZA 5	7,10	3.465,000	1.597,280	42,000	18.239,15	1,37324	198,592	99,296	5,35
IBIZA 6	7,10	3.465,000	1.597,280	42,000	18.239,15	1,37324	198,592	99,296	5,35
IBIZA 7	7,10	3.465,000	1.597,280	42,000	18.239,15	1,37324	198,592	99,296	5,35
IBIZA 8	7,10	3.465,000	1.597,280	42,000	18.239,15	1,37324	198,592	99,296	5,35
IBIZA 9	14,20	5.647,584	1.425,340	29,240	60.251,10	10,99709	99,296	49,648	5,35
IBIZA 10	14,20	5.647,584	1.425,340	29,240	60.251,10	10,99709	99,296	49,648	5,35
IBIZA 11	14,20	5.647,584	1.425,340	29,240	60.251,10	10,99709	99,296	49,648	5,35
IBIZA 13	14,50	6.463,500	1.305,980	21,390	50.988,67	8,38551	99,296	49,648	5,35
IBIZA 14	14,50	6.463,500	1.305,980	21,390	50.988,67	8,38551	99,296	49,648	5,35
IBIZA 16	17,40	9.556,467	1.039,200	36,410	57.689,14	6,74387	163,820	81,910	11,18
IBIZA 17	17,40	9.556,467	1.039,200	36,410	57.689,14	6,74387	163,820	81,910	11,18

MAHON 9	13,60	6.319,165	1.329,850	22,880	50.988,67	8,38551	99,296	49,648	5,35
MAHON 10	13,60	6.319,165	1.329,850	22,880	50.988,67	8,38551	99,296	49,648	5,35
MAHON 11	13,60	6.319,165	1.329,850	22,880	50.988,67	8,38551	99,296	49,648	5,35
MAN 3 (IBIZA 20)	15,44	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	11,18
MAN 4 (IBIZA 21)	15,44	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	11,18
TOTAL FUEL (DIESEL)	**210,28**								
SON REUS CCGT 1	204,00								
Operating 1 GT [2]	48,70	47.785,860	1.684,020	7,740	18.306,00	0,21715	9.970,012	672,061	1,50
Operating 2 GT [2]	97,40	47.785,860	1.684,020	7,740	18.306,00	0,21715	9.970,012	672,061	1,50
Operating 3 GT [2]	146,10	47.785,860	1.684,020	7,740	18.306,00	0,21715	9.970,012	672,061	1,50
Operating 1 GT + 1 ST	68,00	43.062,180	1.188,460	3,970	176.511,00	0,54568	[1]	[1]	2,52
Operating 2 GT + 1 ST	136,00	87.203,239	1.193,070	1,980	298.551,00	0,56189	[1]	[1]	2,52
Operating 3 GT + 1 ST	204,00	131.932,884	1.188,190	1,340	420.591,00	0,60483	[1]	[1]	2,52
SON REUS CCGT 2	189,90								
Operating 1 GT [2]	63,30	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 2 GT [2]	126,60	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 1 GT + 1 ST	94,95	118.213,531	-390,570	11,180	281.985,03	0,55379	[1]	[1]	2,52
Operating 2 GT + 1 ST	189,90	239.683,594	-440,630	5,760	410.809,81	0,60483	[1]	[1]	2,52
CAS TRESORER TV3	194,22								
Operating 1 GT [2]	64,74	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 2 GT [2]	129,48	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 1 GT + 1 ST	97,11	118.213,531	-390,570	11,180	281.985,03	0,55379	[1]	[1]	2,52
Operating 2 GT + 1 ST	194,22	239.683,594	-440,630	5,760	410.809,81	0,60483	[1]	[1]	2,52
TOTAL CCGT	**588,12**								
TOTAL ORDINARY REGIME	**1.913,78**								

* Values fixed for December 31st , 2001; readjusted each year using IPC foreseen in the tariff minus 100 basis points

[1] Values calculated taking into account published standards for 2002; readjusted each year using IPC foreseen in the tariff minus 100 basis points

[2] Parameters defined by individual turbine

Canary Islands

Generation Unit	Net Power (MW)	*a* (th/h)	*b* (th/h.MW)	*c* (th/h.MW^2)	*a'* (th)	*b'* (h)	*ad* (Euros)*	*a''* (Euros/h)*	*b''* (%)
ARONA 1	21,60	9.167,142	2.154,040	1,590	8.120,00	0,21715	[1]	[1]	1,50
ARONA 2	21,60	9.167,142	2.154,040	1,590	8.120,00	0,21715	[1]	[1]	1,50
BCO. TIRAJANA 1	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
BCO. TIRAJANA 2	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
CANDELARIA 5	14,70	23.254,276	2.742,840	6,130	14.210,00	0,21715	3.576,957	230,166	1,50
CANDELARIA 11	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
CANDELARIA 12	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
GRANADILLA 1	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
GRANADILLA 6	39,20	31.391,054	1.773,420	11,580	10.094,78	0,21715	[1]	[1]	1,50
GUINCHOS, LOS 15	21,00	9.167,142	2.154,040	1,590	8.120,00	0,21715	[1]	[1]	1,50
JINAMAR 7	17,64	23.287,862	2.737,040	6,370	12.180,00	0,21715	3.576,957	230,166	1,50
JINAMAR 10	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
JINAMAR 11	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
PUNTA GRANDE 9	19,60	23.411,648	2.530,000	3,240	14.210,00	0,21715	3.576,957	230,166	1,50
PUNTA GRANDE 14	32,34	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
SALINAS,LAS 7	21,85	23.439,541	2.526,180	3,360	14.210,00	0,21715	3.576,957	230,166	1,50
SALINAS,LAS 8	29,40	29.363,266	2.225,920	1,360	10.150,00	0,21715	3.576,957	230,166	1,50
SALINAS, LAS 9 (GUINCHOS, LOS 11)	11,74	25.849,662	2.113,220	12,270	10.150,00	0,21715	3.576,957	230,166	1,50
TIRAJANA GAS 5	65,83	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
TIRAJANA GAS 6	65,83	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
TOTAL GAS	**608,71**								
BCO. TIRAJANA 3	74,24	21.254,082	2.159,800	0,230	357.255,00	7,21595	11.117,000	135,000	1,72
BCO. TIRAJANA 4	74,24	21.254,082	2.159,800	0,230	357.255,00	7,21595	11.117,000	135,000	1,72
CANDELARIA 7	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
CANDELARIA 8	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
CANDELARIA 9	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
CANDELARIA 10	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
GRANADILLA 4	74,24	21.254,082	2.159,800	0,230	357.255,00	7,21595	11.117,000	135,000	1,72
GRANADILLA 5	74,24	21.254,082	2.159,800	0,230	357.255,00	7,21595	11.117,000	135,000	1,72
JINAMAR 1	28,02	8.673,483	2.942,310	0,470	99.000,28	15,66098	5.676,000	76,000	1,72
JINAMAR 5	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
JINAMAR 6	37,28	8.388,391	2.859,920	0,460	199.254,56	18,71790	8.356,000	101,000	1,72
JINAMAR 8	55,56	12.991,345	2.677,030	0,190	269.052,81	17,43684	10.264,000	115,000	1,72
JINAMAR 9	55,56	12.991,345	2.677,030	0,190	269.052,81	17,43684	10.264,000	115,000	1,72
TOTAL FUEL (OIL)	**659,78**								
CANDELARIA 3	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90
CANDELARIA 4	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90
CANDELARIA 6	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90

GRANADILLA 2	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	188,353	94,177	4,90
GRANADILLA 3	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	188,353	94,177	4,90
GUINCHOS, LOS 6	3,82	504,221	2.248,310	23,650	9.675,39	6,04355	65,211	32,606	10,18
GUINCHOS, LOS 7	3,82	504,221	2.248,310	23,650	9.675,39	6,04355	65,211	32,606	10,18
GUINCHOS, LOS 8	3,82	504,221	2.248,310	23,650	9.675,39	6,04355	65,211	32,606	10,18
GUINCHOS, LOS 9	4,30	346,039	2.406,120	17,630	11.287,89	6,04425	144,902	72,451	10,18
GUINCHOS, LOS 10	6,69	1.599,883	2.243,210	10,660	16.842,61	6,04405	144,902	72,451	10,18
GUINCHOS, LOS 12	6,69	1.599,883	2.243,210	10,660	16.842,61	6,04405	144,902	72,451	10,18
GUINCHOS, LOS 13	11,50	1.203,375	2.038,810	9,450	58.446,37	5,52231	144,902	72,451	10,18
GUINCHOS, LOS 14	11,20	1.286,063	2.511,430	6,130	15.172,71	2,88669	[1]	[1]	10,18
JINAMAR 2	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90
JINAMAR 3	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90
JINAMAR 4	8,51	1.286,063	2.511,430	6,130	15.142,71	2,88669	118,162	59,081	4,90
JINAMAR 12	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	188,353	94,177	4,90
JINAMAR 13	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	188,353	94,177	4,90
LLANOS BLANCOS 1	1,07	347,817	2.189,280	57,430	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 9	0,67	104,773	2.697,390	194,850	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 11	0,88	413,312	1.778,650	174,990	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 12	1,07	693,677	1.762,030	127,380	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 13	1,07	693,677	1.762,030	127,380	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 14	1,26	622,562	1.765,840	72,600	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 15	1,36	622,562	1.765,840	72,600	2.791,00	1,44307	65,211	32,606	10,18
LLANOS BLANCOS 16	1,90	865,969	1.678,830	81,520	5.075,00	1,44290	[1]	[1]	10,18
LLANOS BLANCOS 17	1,90	865,969	1.678,830	81,520	5.075,00	1,44290	[1]	[1]	10,18
PALMAR, EL 12	1,06	373,116	1.991,540	240,660	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 13	1,40	399,908	1.895,460	186,520	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 14	1,40	399,908	1.895,460	186,520	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 15	1,84	630,189	1.780,000	88,060	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 16	1,84	630,189	1.780,000	88,060	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 17	2,51	865,969	1.678,830	81,520	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 18	2,51	865,969	1.678,830	81,520	5.075,00	1,44290	65,211	32,606	10,18
PALMAR, EL 19	3,10	865,969	1.678,830	81,520	5.075,00	1,44290	[1]	[1]	10,18
PALMAR, EL 20	3,10	865,969	1.678,830	81,520	5.075,00	1,44290	[1]	[1]	10,18
PUNTA GRANDE 2	6,49	1.599,883	2.243,210	10,660	16.842,61	6,04405	144,902	72,451	10,18
PUNTA GRANDE 3	6,49	1.599,883	2.243,210	10,660	16.842,61	6,04405	144,902	72,451	10,18
PUNTA GRANDE 7	6,49	1.599,883	2.243,210	10,660	16.842,61	6,04405	144,902	72,451	10,18
PUNTA GRANDE 11	12,85	3.418,403	1.606,250	14,550	51.392,07	5,53583	118,162	59,081	4,90
PUNTA GRANDE 12	12,85	3.418,403	1.606,250	14,550	51.392,07	5,53583	118,162	59,081	4,90
PUNTA GRANDE 13	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	118,162	94,177	4,90
PUNTA GRANDE 15	17,20	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	10,18
PUNTA GRANDE 16	17,20	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	10,18
SALINAS, LAS 1	3,82	504,221	2.248,310	23,650	9.675,39	6,04355	65,211	32,606	10,18

SALINAS, LAS 2	3,82	504,221	2.248,310	23,650	9.675,39	6,04355	65,211	32,606	10,18
SALINAS, LAS 3	4,11	346,039	2.406,120	17,630	11.287,89	6,04355	144,902	72,451	10,18
SALINAS, LAS 4	6,21	1.588,738	2.247,640	10,230	16.842,61	6,04355	144,902	72,451	10,18
SALINAS, LAS 5	6,21	1.588,738	2.247,640	10,230	16.842,61	6,04355	144,902	72,451	10,18
SALINAS, LAS 6	20,51	7.613,794	1.381,900	15,250	79.576,42	5,53611	188,353	94,177	4,90
SALINAS, LAS 10	17,20	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	10,18
SALINAS, LAS 11	17,20	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	10,18
SALINAS, LAS 12	17,20	9.556,467	1.039,200	36,410	57.689,14	6,74387	[1]	[1]	10,18
TOTAL FUEL (DIESEL)	**411,24**								
BCO. TIRAJANA CCGT 1	206,10								
Operating 1 GT [2]	68,70	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 2 GT [2]	137,40	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 1 GT + 1 ST	103,05	118.213,531	-390,570	11,180	281.985,03	0,55379	[1]	[1]	2,37
Operating 2 GT + 1 ST	206,10	239.683,594	-440,630	5,760	410.809,81	0,60483	[1]	[1]	2,37
GRANADILLA CCGT 1	206,10								
Operating 1 GT [2]	68,70	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 2 GT [2]	137,40	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 1 GT + 1 ST	103,05	118.213,531	-390,570	11,180	281.985,03	0,55379	[1]	[1]	2,37
Operating 2 GT + 1 ST	206,10	239.683,594	-440,630	5,760	410.809,81	0,60483	[1]	[1]	2,37
BCO. TIRAJANA CCGT 2	209,53								
Operating 1 GT [2]	69,84	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 2 GT [2]	139,69	60.436,761	1.925,540	0,530	49.877,10	0,72135	[1]	[1]	1,50
Operating 1 GT + 1 ST	104,76	118.213,531	-390,570	11,180	281.985,03	0,55379	[1]	[1]	2,37
Operating 2 GT + 1 ST	209,53	239.683,594	-440,630	5,760	410.809,81	0,60483	[1]	[1]	2,37
TOTAL CCGT	**621,73**								
TOTAL ORDINARY REGIME	**2.301,76**								

* Values fixed for December 31st, 2001; readjusted each year using IPC foreseen in the tariff minus 100 basis points

[1] Values calculated taking into account published standards for 2002; readjusted each year using IPC foreseen in the tariff minus 100 basis points

[2] Parameters defined by individual turbine

Appendix 9 – GAMS Code Overview: Balearic Islands, 2008

SETS

d	Time periods (days)	/ d1*d366 /
g	Generators	
t	Technology type {c=coal - fg=fuel&gas - cc=ccgt}	/ c, fg, cc /

**** Cluster by technology*

coal(g)	Coal generators
fuel_gas(g)	Fuel & Gas generators
ccgt(g)	CCGT generators

**** Cluster by islands' systems*

g_mm(g)	Majorca-Menorca generators
g_if(g)	Ibiza-Formentera generators

PARAMETER

MTn(t)	Nominal minimum technical of technology t	/ c 0.55, fg 0.31, cc 0.50 /;
minP(t)	Minimum power of technology t	/ c 113.6, fg 1.9, cc 48.7 /
Lsem	Last day of the first semester	/ 182 /
hr	Number of hours in a day	/ 24 /

TABLE X1(g,*) Parameters by generation unit

** uo - Initial status of generator g at the beginning of the first day {1 0}*
** pr1_ea - First semester fuel thermie ex-ante average price used by unit g in the day d [Euros per th]*
** pr2_ea - Second semester fuel thermie ex-ante average price used by unit g in the day d [Euros per th]*
** pr1_ep - First semester fuel thermie ex-post average price used by unit g in the day d [Euros per th]*
** pr2_ep - Second semester fuel thermie ex-post average price used by unit g in the day d [Euros per th]*
** Pnet - Net power of generator g [MW]*
** quadA - Quadratic adjustment parameter of generator g [th per h]*
** quadB - Quadratic adjustment parameter of generator g [th per h.MW]*
** quadC - Quadratic adjustment parameter of generator g [th per h.MW2]*
** expA - Exponential adjustment paramater of generator g [th]*
** adOM - Additional operation and maintenance costs of generator g [Euros]*
** opOM - Operation and maintenance operating hours parameter of generator g [Euros per h]*
** fun - Fungible material and working capital parameter of generator g [%]*

TABLE X2(d,*) Daily demand by technology and system

** dem_c - Coal demand in day d [MWh]*
** dem_fg - Fuel and Gas demand in day d [MWh]*
** dem_cc - CCGT demand in day d [MWh]*

** dem_mm - Majorca-Menorca demand in day d [MWh]*
** dem_if - Ibiza-Formentera demand in day d [MWh]*

VARIABLES

Fobj Value of objective function;;

POSITIVE VARIABLES

energy(d,g)	Energy dispatched by generator g in the day d [MWh]
Cop_ea(d,g)	Variable ex-ante operating (fuel) costs of the unit g in the day d [Euros]
Cst_ea(d,g)	Variable ex-ante start up costs of the unitg in the day d [Euros]
Com_ea(d,g)	Variable ex-ante O&M costs of the unit g in the day d [Euros]
Cop_ep(d,g)	Variable ex-post operating (fuel) costs of the unit g in the day d [Euros]
Cst_ep(d,g)	Variable ex-post start up costs of the unit g in the day d [Euros]
Com_ep(d,g)	Variable ex-post O&M costs of the unit g in the day d [Euros]
GCc_ep(d)	Total variable ex-post generation cost of Coal in the day d [Euros]
GCfg_ep(d)	Total variable ex-post generation cost of Fuel & Gas in the day d [Euros]
GCcc_ep(d)	Total variable ex-post generation cost of CCGT in the day d [Euros];

BINARY VARIABLES

u(d,g)	Variable indicating whether unit g is connected (1) or disconnected (0) in the day d
y(d,g)	Start-up decision for unit g in the day d
z(d,g)	Shut Down decision for unit g in the day d;

EQUATIONS

E_fobj	Objective Function
E_Cop_ea(d,g)	Ex-ante operating (fuel) costs
E_Cst_ea(d,g)	Ex-ante start-up costs
E_Com_ea(d,g)	Ex-ante operation and maintenance costs
E_Cop_ep(d,g)	Ex-post operating (fuel) costs
E_Cst_ep(d,g)	Ex-post start-up costs
E_Com_ep(d,g)	Ex-post operation and maintenance costs
E_coal(d)	Meet the daily Coal demand
E_fg(d)	Meet the daily Fuel & Gas demand
E_ccgt(d)	Meet the daily CCGT demand
E_mm(d)	Meet the daily Majorca-Menorca demand
E_if(d)	Meet the daily Ibiza-Formentera demand
E_Emax(d,g)	Respect maximum generator power
E_Emin(d,g)	Respect minimum generator power
E_Acop(d,g)	Logic of startups and shut downs
E_rAcop(d,g)	Respect logic of startups and shut downs
E_fsd(d,g)	Force shut-down of generator g in the day d when output is zero
E_ccgt(d,g)	Respect CCGT operating logic
EE_ist(d,g)	Respect initial start up conditions
E_isd(d,g)	Respect initial shut down conditions
E_ibiza5(d,g)	Respect IBIZA 5 end of operation
E_ibizatg5(d,g)	Respect IBIZA TG5 start operation

```
E_mahontg4(d,g)         Respect MAHON TG4 start operation
E_GCc_ep(d)             Total Coal ex-post variable generation cost
E_GCfg_ep(d)            Total Fuel & Gas ex-post variable generation cost
E_GCcc_ep(d)            Total CCGT ex-post variable generation cost;


* Formulation of equations:

** Objetive function

E_fobj ..
       fobj =e= SUM[(d,g), Cop_ea(d,g) + Cst_ea(d,g) + Com_ea(d,g)];

** Variable ex-ante daily generation costs (for economic dispatch)

E_Cop_ea(d,g)..
      Cop_ea(d,g) =e= hr * (X1(g,'pr1_ea')$[ORD(d) <= Lsem] + X1(g,'pr2_ea')$[ORD(d) > Lsem] ) *
      (u(d,g) * X1(g,'quadA') + [X1(g,'quadB') + X1(g,'quadC') * X1(g,'Pnet')] *
       (energy(d,g) / hr));

E_Cst_ea(d,g)..
            Cst_ea(d,g) =e= y(d,g) * [X1(g,'expA') *
              (X1(g,'pr1_ea')$[ORD(d) <= Lsem] + X1(g,'pr2_ea')$[ORD(d) > Lsem]) +
               X1(g,'adOM')];
E_Com_ea(d,g)..
       Com_ea(d,g) =e= u(d,g) * hr * X1(g,'opOM') + [X1(g,'fun') / 100] * Cop_ea(d,g);

** Respect units' energy boundaries

E_Emax(d,g)..
      energy(d,g) =l= u(d,g) * hr * X1(g,'Pnet');

E_Emin(d,g)..
      energy(d,g) =g= u(d,g) *
              {(MTn('c')$
               [( X2(d,'dem_c') / (hr * minP('c'))) >= MTn('c')] +
               ( X2(d,'dem_c') / (hr * minP('c')))$
               [( X2(d,'dem_c') / (hr * minP('c'))) < MTn('c')])$
               [coal(g)] +
               (MTn('fg')$
               [( X2(d,'dem_fg') / (hr * minP('fg'))) >= MTn('fg')] +
               ( X2(d,'dem_fg') / (hr * minP('fg')))$
               [( X2(d,'dem_fg') / (hr * minP('fg'))) < MTn('fg')])$
               [fuel_gas(g)] +
               (MTn('cc')$
               [( X2(d,'dem_cc') / (hr * minP('cc'))) >= MTn('cc')] +
               ( X2(d,'dem_cc') / (hr * minP('cc')))$
               [( X2(d,'dem_cc') / (hr * minP('cc'))) < MTn('cc')])$
               [ccgt(g)]
              } * (24 * X1(g,'Pnet'));
```

*** Meet daily islands' system generation*

```
E_mm(d)..
      SUM[g_mm, energy(d,g_mm)] =g= X2(d,'dem_mm');

E_if(d)..
      SUM[g_if, energy(d,g_if)] =g= X2(d,'dem_if');
```

*** Meet daily technology generation*

```
E_coal(d)..
              SUM[coal, energy(d,coal)] =e= X2(d,'dem_c');

E_fg(d)..
           SUM[fuel_gas, energy(d,fuel_gas)] =g= X2(d,'dem_fg');

E_ccgt(d)..
             SUM[ccgt, energy(d,ccgt)] =e= X2(d,'dem_cc');
```

*** Respect units operating logic: shut-down and start-up*

```
E_Acop(d,g)..
                 u(d,g) =e= u(d-1,g)$[ORD(d) > 1] + X1(g,'uo')$[ORD(d) = 1] + y(d,g) - z(d,g);

E_rAcop(d,g)..
                  y(d,g) + z(d,g) =l= 1;

E_fsd(d,g)..
               u(d,g)$[(X2(d,'dem_c')$[coal(g)] +
                X2(d,'dem_fg')$[fuel_gas(g)] +
                X2(d,'dem_cc')$[ccgt(g)]) = 0]
                =e= 0;

E_ist(d,g)..
              y('d1',g) =e= 0;
E_isd(d,g)..
              z('d1',g) =e= 0;
```

*** Respect CCGT one-mode operation*

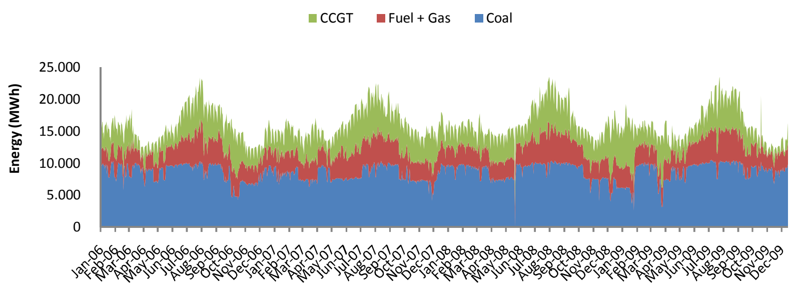
```
E_ccgt(d,g)..
            u(d,'CCGT_1') + u(d,'CCGT_2') + u(d,'CCGT_3') +
            u(d,'CCGT_1x1') + u(d,'CCGT_2x1') + u(d,'CCGT_3x1') =l= 1;
```

*** Respect units operating logic: start operation and end operation*

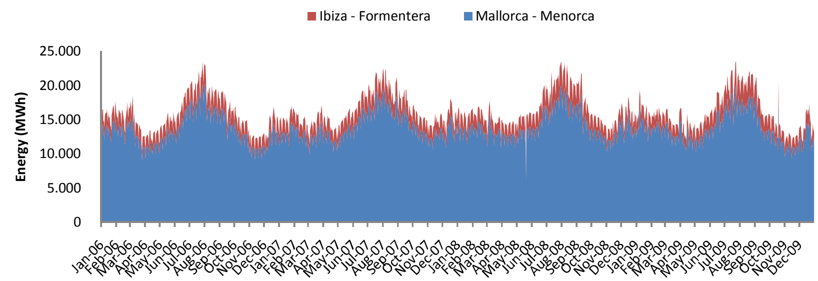
```
E_ibiza5(d,g)..
           u(d,'IBIZA_5')$[ORD(d) > 335] =e= 0;

E_ibizatg5(d,g)..
```

```
            u(d,'IBIZA_TG5')$[ORD(d) < 153] =e= 0;

E_mahontg4(d,g)..
            u(d,'MAHON_TG4')$[ORD(d) < 245] =e= 0;

** Variable ex-post daily generation costs (for energy price computation)

E_Cop_ep(d,g)..
          Cop_ep(d,g) =e= hr * (X1(g,'pr1_ep')$[ORD(d) <= Lsem] + X1(g,'pr2_ep')$[ORD(d) > Lsem]) *
                          (u(d,g) * X1(g,'quadA') + [X1(g,'quadB') + X1(g,'quadC') * X1(g,'Pnet')] *
                          (energy(d,g) / hr));
E_Cst_ep(d,g)..
           Cst_ep(d,g) =e= y(d,g) * [X1(g,'expA') *
                          (X1(g,'pr1_ep')$[ORD(d) <= Lsem] + X1(g,'pr2_ep')$[ORD(d) > Lsem]) +
                           X1(g,'adOM')];

E_Com_ep(d,g)..
           Com_ep(d,g) =e= u(d,g) * hr * X1(g,'opOM') + [X1(g,'fun') / 100] * Cop_ep(d,g);

* Options for execution:

** Selection of the optimizer for solving binary variables

OPTION MIP = cplex;

** Tolerance for optimization convergence with binary variables

OPTION OPTCR = 0.001;

OPTION iterlim=1e+6 ;

MODEL UCSEIE /all/;

SOLVE UCSEIE USING MIP MINIMIZING fobj;

* Open data in gdxviewer

EXECUTE_UNLOAD 'results.gdx', energy, Cop_ep, Cst_ep, Com_ep;
EXECUTE '=gdxviewer results.gdx';
```

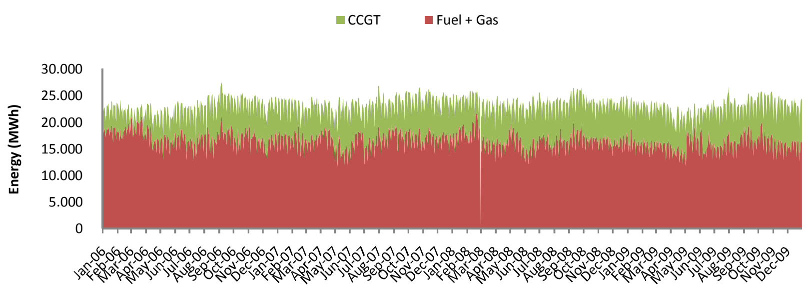
Appendix 10 – SEIE: Daily Net Generation by Technology and Sub-Systems



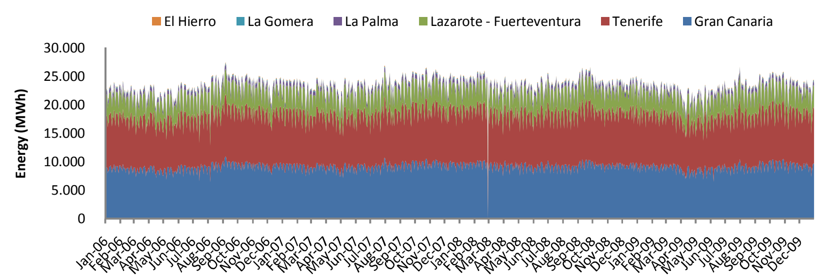
Balearic Islands net generation by technology



Balearic Islands net generation by sub-system



Canary Islands net generation by technology



Canary Islands net generation by sub-system

Appendix 11 – SEIE: Expected Fixed Costs Values by Generation Unit

Balearic Islands islands

Generation Unit	Generators Fixed Cost Average Payment (Euros/day)											
	2006			2007			2008			2009		
	Peak	Shallow	Valley	Peak	Shallow	Valley	Peak	Shallow	Valley	Peak	Shallow	Valley
ALCUDIA 1	36.100,33	31.391,59	26.682,85	30.041,29	26.122,86	22.204,43	30.432,30	26.462,87	22.493,44	31.002,41	26.958,62	22.914,82
ALCUDIA 2	37.230,19	32.374,08	27.517,97	33.872,31	29.454,19	25.036,06	30.308,65	26.355,35	22.402,05	30.878,42	26.850,80	22.823,18
ALCUDIA 5	70.403,55	61.220,48	52.037,41	70.657,75	61.441,52	52.225,30	71.134,83	61.856,37	52.577,92	70.617,33	61.406,38	52.195,42
ALCUDIA 6	70.689,26	61.468,92	52.248,58	70.971,64	61.714,47	52.457,30	71.483,72	62.159,75	52.835,79	70.978,79	61.720,69	52.462,59
TOTAL COAL	**214.423,33**	**186.455,07**	**158.486,81**	**205.542,99**	**178.733,03**	**151.923,08**	**203.359,50**	**176.834,35**	**150.309,19**	**203.476,95**	**176.936,48**	**150.396,01**
ALCUDIA 3	4.008,96	3.486,05	2.963,15	4.003,90	3.481,65	2.959,40	4.010,81	3.487,66	2.964,51	4.009,02	3.486,10	2.963,19
ALCUDIA 4	3.915,33	3.404,63	2.893,94	3.912,02	3.401,75	2.891,49	3.920,97	3.409,54	2.898,11	3.922,28	3.410,68	2.899,07
FORMENTERA 1	2.138,07	1.859,19	1.580,31	2.158,87	1.877,28	1.595,69	2.189,47	1.903,89	1.618,30	2.233,02	1.941,76	1.650,49
IBIZA 12	2.532,30	2.202,00	1.871,70	2.528,09	2.198,34	1.868,59	2.531,32	2.201,15	1.870,97	2.530,67	2.200,59	1.870,50
IBIZA 15	1.725,07	1.500,06	1.275,05	1.745,87	1.518,15	1.290,43	1.777,60	1.545,74	1.313,88	1.820,02	1.582,63	1.345,23
MAHON 12	4.450,34	3.869,86	3.289,38	4.464,47	3.882,15	3.299,83	4.495,56	3.909,18	3.322,81	4.497,20	3.910,61	3.324,02
MAHON 13	5.367,02	4.666,97	3.966,92	5.406,89	4.701,64	3.996,40	5.471,06	4.757,45	4.043,83	5.473,16	4.759,27	4.045,38
MAHON 14	10.856,85	9.440,74	8.024,63	10.969,50	9.538,70	8.107,89	11.131,69	9.679,73	8.227,77	11.082,22	9.636,72	8.191,21
SON MOLINAS 4 (IBIZA 19)	1.521,04	1.322,64	1.124,24	1.537,91	1.337,31	1.136,72	1.563,31	1.359,40	1.155,49	1.598,05	1.389,61	1.181,17
SON MOLINAS 5 (IBIZA 18)	1.521,04	1.322,64	1.124,24	1.537,91	1.337,31	1.136,72	1.563,31	1.359,40	1.155,49	1.598,05	1.389,61	1.181,17
SON REUS 1	6.327,40	5.502,09	4.676,77	6.375,72	5.544,11	4.712,49	6.451,53	5.610,03	4.768,52	6.439,20	5.599,30	4.759,41
SON REUS 2	6.317,69	5.493,64	4.669,59	6.365,97	5.535,63	4.705,28	6.441,72	5.601,50	4.761,27	6.429,57	5.590,93	4.752,29
SON REUS 3	6.317,69	5.493,64	4.669,59	6.365,97	5.535,63	4.705,28	6.441,72	5.601,50	4.761,27	6.429,57	5.590,93	4.752,29
SON REUS 4	--	--	--	6.373,41	5.542,09	4.710,78	6.449,83	5.608,54	4.767,26	6.437,88	5.598,15	4.758,43
IBIZA TG5 (IBIZA 22)	--	--	--	--	--	--	7.884,85	6.856,39	5.827,93	7.910,53	6.878,72	5.846,92
MAHON TG4 (MAHON 15)	--	--	--	--	--	--	15.769,70	13.712,78	11.655,86	15.897,11	13.823,58	11.750,04
CAS TRESORER TG4	--	--	--	--	--	--	--	--	--	24.279,67	21.112,76	17.945,85
CAS TRESORER TG5	--	--	--	--	--	--	--	--	--	24.279,67	21.112,76	17.945,85
MAHON TG5	--	--	--	--	--	--	--	--	--	15.981,56	13.897,01	11.812,46
IBIZA TG6	--	--	--	--	--	--	--	--	--	2.197,04	1.910,47	1.623,90
TOTAL GAS	**56.998,77**	**49.564,14**	**42.129,52**	**63.746,50**	**55.431,74**	**47.116,98**	**88.094,46**	**76.603,88**	**65.113,30**	**155.045,49**	**134.822,16**	**114.598,84**
IBIZA 3	6.324,59	5.499,64	4.674,70	684,94	595,60	506,26	696,16	605,36	514,56	711,54	618,73	525,92
IBIZA 4	677,48	589,11	500,75	684,94	595,60	506,26	696,16	605,36	514,56	711,54	618,73	525,92
IBIZA 5	677,48	589,11	500,75	1.761,91	1.532,09	1.302,28	1.791,41	1.557,75	1.324,09	--	--	--
IBIZA 6	1.742,34	1.515,08	1.287,82	1.761,91	1.532,09	1.302,28	1.791,41	1.557,75	1.324,09	1.831,63	1.592,72	1.353,81
IBIZA 7	1.742,34	1.515,08	1.287,82	1.761,91	1.532,09	1.302,28	1.791,41	1.557,75	1.324,09	1.831,63	1.592,72	1.353,81
IBIZA 8	1.742,34	1.515,08	1.287,82	1.761,91	1.532,09	1.302,28	1.791,41	1.557,75	1.324,09	3.446,02	2.996,54	2.547,06

IBIZA 9	1.742,34	1.515,08	1.287,82	3.644,74	3.169,34	2.693,94	3.377,12	2.936,63	2.496,13	3.453,08	3.002,68	2.552,28
IBIZA 10	4.003,95	3.481,70	2.959,44	3.762,00	3.271,30	2.780,61	3.384,16	2.942,75	2.501,33	4.447,27	3.867,19	3.287,11
IBIZA 11	4.017,23	3.493,25	2.969,26	4.492,04	3.906,13	3.320,21	4.470,47	3.887,36	3.304,26	7.095,22	6.169,75	5.244,29
IBIZA 13	4.521,22	3.931,50	3.341,77	7.141,45	6.209,96	5.278,46	7.154,51	6.221,31	5.288,11	6.651,93	5.784,29	4.916,65
IBIZA 14	7.145,39	6.213,38	5.281,37	6.679,43	5.808,20	4.936,97	6.698,15	5.824,48	4.950,81	10.719,29	9.321,12	7.922,95
IBIZA 16	6.678,27	5.807,19	4.936,11	10.558,13	9.180,99	7.803,84	10.704,87	9.308,58	7.912,30	10.928,45	9.503,00	8.077,55
IBIZA 17	10.462,70	9.098,00	7.733,30	10.767,86	9.363,36	7.958,85	10.917,14	9.493,17	8.069,19	6.881,23	5.983,68	5.086,12
MAHON 9	10.670,58	9.278,76	7.886,95	6.982,69	6.071,90	5.161,12	6.961,44	6.053,43	5.145,41	6.665,63	5.796,20	4.926,77
MAHON 10	7.013,96	6.099,10	5.184,23	6.760,86	5.879,01	4.997,16	6.740,55	5.861,35	4.982,15	6.740,18	5.861,03	4.981,87
MAHON 11	6.791,13	5.905,33	5.019,53	6.840,88	5.948,59	5.056,30	6.818,16	5.928,83	5.039,51	13.458,65	11.703,17	9.947,70
MAN 3 (IBIZA 20)	6.873,20	5.976,70	5.080,19	13.234,26	11.508,06	9.781,85	13.470,51	11.713,49	9.956,46	13.458,65	11.703,17	9.947,70
MAN 4 (IBIZA 21)	6.324,59	5.499,64	4.674,70	13.234,26	11.508,06	9.781,85	13.470,51	11.713,49	9.956,46	1.831,63	1.592,72	1.353,81
TOTAL FUEL (DIESEL)	**82.826,55**	**72.023,09**	**61.219,62**	**102.516,12**	**89.144,45**	**75.772,79**	**102.725,57**	**89.326,58**	**75.927,59**	**100.863,57**	**87.707,45**	**74.551,33**
SON REUS CCGT 1	103.460,84	89.965,95	76.471,06	104.329,69	90.721,47	77.113,25	105.621,09	91.844,43	78.067,76	104.987,43	91.293,42	77.599,40
SON REUS CCGT 2	103.460,84	89.965,95	76.471,06	76.579,86	66.591,18	56.602,50	77.485,05	67.378,30	57.271,56	77.020,83	66.974,64	56.928,44
CAS TRESORER TV3	--	--	--	109.196,31	94.953,31	80.710,31	110.896,29	96.431,56	81.966,82	110.321,39	95.931,64	81.541,89
TOTAL CCGT	**182.651,50**	**158.827,39**	**135.003,29**	**290.105,85**	**252.265,96**	**214.426,07**	**294.002,43**	**255.654,29**	**217.306,14**	**292.329,65**	**254.199,69**	**216.069,74**
TOTAL ORDINARY REGIME	**536.900,15**	**466.869,69**	**396.839,24**	**661.911,46**	**575.575,18**	**489.238,91**	**688.181,96**	**598.419,09**	**508.656,23**	**751.715,65**	**653.665,79**	**555.615,92**

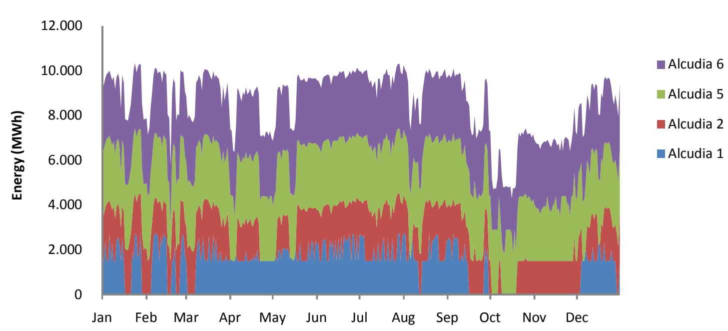
Canary Islands

Generation Unit	Generators Fixed Cost Average Payment (Euros/day)											
	2006			2007			2008			2009		
	Peak	Shallow	Valley	Peak	Shallow	Valley	Peak	Shallow	Valley	Peak	Shallow	Valley
ARONA 1	7.069,14	6.732,51	6.395,89	7.135,83	6.796,03	6.456,23	7.233,37	6.888,93	6.544,48	7.198,03	6.855,27	6.512,50
ARONA 2	7.267,19	6.921,13	6.575,08	7.335,70	6.986,38	6.637,06	7.435,73	7.081,65	6.727,57	7.397,47	7.045,21	6.692,95
BCO. TIRAJANA 1	4.553,99	4.337,13	4.120,27	4.562,64	4.345,37	4.128,10	4.587,59	4.369,13	4.150,68	4.588,51	4.370,01	4.151,51
BCO. TIRAJANA 2	5.306,47	5.053,79	4.801,10	5.325,23	5.071,65	4.818,07	5.363,60	5.108,19	4.852,78	5.355,52	5.100,49	4.845,47
CANDELARIA 5	2.282,87	2.174,16	2.065,45	2.311,35	2.201,29	2.091,22	2.355,01	2.242,87	2.130,73	2.412,88	2.297,98	2.183,08
CANDELARIA 11	3.999,18	3.808,75	3.618,31	3.997,21	3.806,87	3.616,52	4.008,38	3.817,51	3.626,63	4.013,86	3.822,73	3.631,59
CANDELARIA 12	4.216,01	4.015,25	3.814,49	4.213,47	4.012,83	3.812,19	4.224,22	4.023,07	3.821,92	4.224,82	4.023,63	3.822,45
GRANADILLA 1	4.735,68	4.510,18	4.284,67	4.731,06	4.505,77	4.280,48	4.739,93	4.514,22	4.288,51	4.728,34	4.503,18	4.278,03
GRANADILLA 6	12.604,33	12.004,12	11.403,91	12.702,63	12.097,74	11.492,86	12.850,09	12.238,18	11.626,28	12.761,57	12.153,88	11.546,18
GUINCHOS, LOS 15	8.725,03	8.309,55	7.894,08	8.817,60	8.397,72	7.977,83	8.948,94	8.522,80	8.096,66	8.894,27	8.470,74	8.047,20
JINAMAR 7	1.697,26	1.616,44	1.535,62	1.635,24	1.557,37	1.479,51	1.662,38	1.583,22	1.504,06	1.699,44	1.618,52	1.537,59
JINAMAR 10	4.151,30	3.953,61	3.755,93	4.147,72	3.950,21	3.752,70	4.157,13	3.959,17	3.761,21	4.158,39	3.960,38	3.762,36
JINAMAR 11	4.138,67	3.941,59	3.744,51	4.136,62	3.939,64	3.742,66	4.147,89	3.950,37	3.752,85	4.150,41	3.952,78	3.755,14
PUNTA GRANDE 9	2.671,00	2.543,81	2.416,62	2.663,41	2.536,58	2.409,75	2.662,63	2.535,84	2.409,05	2.656,60	2.530,10	2.403,59
PUNTA GRANDE 14	6.233,38	5.936,55	5.639,73	6.266,66	5.968,25	5.669,83	6.324,08	6.022,93	5.721,78	6.306,25	6.005,95	5.705,66
SALINAS,LAS 7	3.674,36	3.499,39	3.324,42	3.675,22	3.500,21	3.325,20	3.686,74	3.511,18	3.335,62	3.671,66	3.496,82	3.321,98
SALINAS,LAS 8	7.074,02	6.737,16	6.400,31	7.123,67	6.784,45	6.445,23	7.201,56	6.858,63	6.515,70	7.168,83	6.827,46	6.486,09
SALINAS, LAS 9 (GUINCHOS, LOS 11)	2.620,58	2.495,79	2.371,00	2.619,20	2.494,47	2.369,75	2.626,69	2.501,61	2.376,53	2.633,24	2.507,85	2.382,46
TIRAJANA GAS 5	--	--	--	22.835,96	21.748,53	20.661,11	23.218,78	22.113,12	21.007,47	23.057,25	21.959,28	20.861,32
TIRAJANA GAS 6	--	--	--	22.835,96	21.748,53	20.661,11	23.218,78	22.113,12	21.007,47	23.057,25	21.959,28	20.861,32
TOTAL GAS	**93.020,48**	**88.590,93**	**84.161,39**	**139.072,40**	**132.449,91**	**125.827,41**	**140.653,52**	**133.955,74**	**127.257,95**	**140.134,61**	**133.461,53**	**126.788,46**
BCO. TIRAJANA 3	45.683,84	43.508,42	41.333,00	45.623,49	43.450,94	41.278,39	45.628,34	43.455,56	41.282,78	44.845,75	42.710,23	40.574,72
BCO. TIRAJANA 4	41.070,87	39.115,11	37.159,36	41.052,58	39.097,69	37.142,81	41.103,11	39.145,82	37.188,52	40.444,05	38.518,14	36.592,24
CANDELARIA 7	4.436,22	4.224,97	4.013,73	4.479,53	4.266,22	4.052,91	4.543,27	4.326,92	4.110,58	4.633,88	4.413,22	4.192,56
CANDELARIA 8	4.458,20	4.245,90	4.033,61	4.501,50	4.287,15	4.072,79	4.565,18	4.347,79	4.130,40	4.655,86	4.434,15	4.212,44
CANDELARIA 9	4.442,96	4.231,39	4.019,82	4.486,26	4.272,63	4.059,00	4.549,98	4.333,32	4.116,65	4.640,62	4.419,63	4.198,65
CANDELARIA 10	11.635,20	11.081,15	10.527,09	11.423,89	10.879,90	10.335,90	11.190,34	10.657,47	10.124,60	10.927,42	10.407,07	9.886,72
GRANADILLA 4	45.480,05	43.314,34	41.148,62	45.395,79	43.234,08	41.072,38	45.370,97	43.210,45	41.049,93	44.576,90	42.454,19	40.331,48
GRANADILLA 5	41.117,04	39.159,08	37.201,13	41.066,49	39.110,94	37.155,39	41.077,41	39.121,34	37.165,28	40.396,24	38.472,61	36.548,98
JINAMAR 1	3.694,07	3.518,16	3.342,26	3.726,62	3.549,16	3.371,70	3.773,54	3.593,85	3.414,16	3.842,64	3.659,65	3.476,67
JINAMAR 5	4.178,56	3.979,58	3.780,60	4.221,87	4.020,83	3.819,78	4.286,31	4.082,20	3.878,09	4.376,22	4.167,83	3.959,44
JINAMAR 6	4.136,50	3.939,52	3.742,54	4.179,80	3.980,76	3.781,72	4.244,36	4.042,25	3.840,13	4.334,16	4.127,77	3.921,38
JINAMAR 8	11.288,77	10.751,21	10.213,65	9.933,92	9.460,87	8.987,83	8.471,62	8.068,21	7.664,80	8.597,60	8.188,19	7.778,78
JINAMAR 9	14.560,05	13.866,71	13.173,37	14.306,85	13.625,57	12.944,29	14.029,10	13.361,05	12.693,00	13.714,94	13.061,85	12.408,76
TOTAL FUEL (OIL)	**236.182,33**	**224.935,55**	**213.688,77**	**234.398,57**	**223.236,74**	**212.074,90**	**232.833,54**	**221.746,22**	**210.658,91**	**229.986,27**	**219.034,54**	**208.082,82**
CANDELARIA 3	2.117,97	2.017,11	1.916,26	2.143,08	2.041,03	1.938,98	2.181,29	2.077,42	1.973,55	2.232,60	2.126,28	2.019,97
CANDELARIA 4	2.112,92	2.012,31	1.911,69	2.138,04	2.036,23	1.934,42	2.176,26	2.072,63	1.969,00	2.227,55	2.121,48	2.015,41
CANDELARIA 6	2.108,59	2.008,18	1.907,77	2.133,70	2.032,10	1.930,49	2.171,94	2.068,51	1.965,08	2.223,22	2.117,35	2.011,48

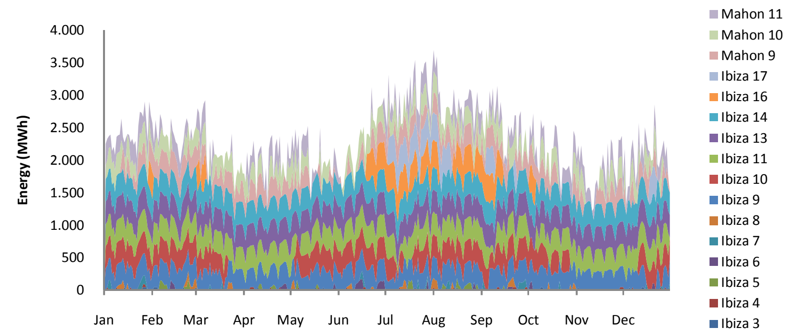
GRANADILLA 2	10.310,72	9.819,73	9.328,74	10.291,08	9.801,03	9.310,98	10.295,81	9.805,53	9.315,26	10.233,86	9.746,53	9.259,21
GRANADILLA 3	10.403,40	9.908,00	9.412,60	10.385,07	9.890,54	9.396,01	10.391,52	9.896,69	9.401,85	10.328,50	9.836,67	9.344,83
GUINCHOS, LOS 6	1.911,57	1.820,55	1.729,52	1.936,87	1.844,64	1.752,41	1.975,97	1.881,87	1.787,78	2.027,05	1.930,52	1.833,99
GUINCHOS, LOS 7	1.932,78	1.840,74	1.748,71	1.924,74	1.833,08	1.741,43	1.963,87	1.870,35	1.776,83	2.014,91	1.918,96	1.823,02
GUINCHOS, LOS 8	1.955,24	1.862,13	1.769,03	1.980,54	1.886,23	1.791,91	2.019,51	1.923,35	1.827,18	2.070,71	1.972,11	1.873,50
GUINCHOS, LOS 9	1.838,97	1.751,40	1.663,83	1.862,34	1.773,66	1.684,98	1.898,26	1.807,87	1.717,48	1.945,66	1.853,01	1.760,36
GUINCHOS, LOS 10	3.153,76	3.003,58	2.853,40	3.161,60	3.011,04	2.860,49	2.981,83	2.839,84	2.697,85	2.974,33	2.832,70	2.691,06
GUINCHOS, LOS 12	4.653,30	4.431,71	4.210,12	4.678,72	4.455,92	4.233,13	4.725,27	4.500,26	4.275,25	4.744,26	4.518,34	4.292,43
GUINCHOS, LOS 13	8.116,80	7.730,29	7.343,78	8.197,88	7.807,50	7.417,13	8.323,99	7.927,61	7.531,23	8.378,73	7.979,74	7.580,76
GUINCHOS, LOS 14	13.989,30	13.323,15	12.656,99	14.132,79	13.459,80	12.786,81	14.342,88	13.659,89	12.976,89	14.312,07	13.630,54	12.949,02
JINAMAR 2	2.200,73	2.095,94	1.991,14	2.225,85	2.119,85	2.013,86	2.263,83	2.156,03	2.048,23	2.315,36	2.205,11	2.094,85
JINAMAR 3	2.129,98	2.028,56	1.927,13	2.155,10	2.052,47	1.949,85	2.193,27	2.088,83	1.984,39	2.244,61	2.137,73	2.030,84
JINAMAR 4	2.207,80	2.102,66	1.997,53	2.232,91	2.126,58	2.020,25	2.270,87	2.162,74	2.054,60	2.322,43	2.211,83	2.101,24
JINAMAR 12	12.907,49	12.292,85	11.678,21	12.832,88	12.221,79	11.610,70	12.773,44	12.165,18	11.556,92	12.621,34	12.020,32	11.419,31
JINAMAR 13	13.491,37	12.848,93	12.206,48	13.411,79	12.773,14	12.134,48	13.347,01	12.711,44	12.075,87	13.179,50	12.551,90	11.924,31
LLANOS BLANCOS 1	574,12	546,79	519,45	578,81	551,25	523,68	587,11	559,15	531,19	597,55	569,10	540,64
LLANOS BLANCOS 9	334,03	318,12	302,22	338,47	322,35	306,23	345,33	328,88	312,44	354,28	337,41	320,54
LLANOS BLANCOS 11	536,52	510,97	485,42	538,25	512,62	486,99	542,56	516,72	490,88	548,41	522,30	496,18
LLANOS BLANCOS 12	649,69	618,75	587,82	654,61	623,44	592,27	663,30	631,71	600,13	672,32	640,30	608,29
LLANOS BLANCOS 13	716,64	682,52	648,39	720,88	686,55	652,23	728,82	694,12	659,41	736,01	700,96	665,91
LLANOS BLANCOS 14	839,84	799,84	759,85	846,75	806,43	766,10	858,45	817,57	776,70	868,26	826,91	785,57
LLANOS BLANCOS 15	966,03	920,03	874,03	976,28	929,79	883,30	992,42	945,16	897,90	1.003,59	955,80	908,01
LLANOS BLANCOS 16	2.317,79	2.207,42	2.097,05	2.346,04	2.234,33	2.122,61	2.386,99	2.273,33	2.159,66	2.391,63	2.277,74	2.163,86
LLANOS BLANCOS 17	2.321,37	2.210,83	2.100,29	2.349,85	2.237,95	2.126,06	2.391,08	2.277,22	2.163,36	2.395,79	2.281,71	2.167,62
PALMAR, EL 12	585,38	557,50	529,63	589,74	561,66	533,58	597,66	569,20	540,74	607,47	578,55	549,62
PALMAR, EL 13	898,59	855,80	813,01	902,00	859,05	816,10	909,72	866,40	823,08	918,53	874,79	831,05
PALMAR, EL 14	884,38	842,26	800,15	887,01	844,77	802,53	893,75	851,19	808,63	902,34	859,38	816,41
PALMAR, EL 15	1.354,87	1.290,35	1.225,83	1.354,51	1.290,01	1.225,51	1.358,93	1.294,22	1.229,51	1.363,72	1.298,78	1.233,84
PALMAR, EL 16	1.353,91	1.289,44	1.224,97	1.354,91	1.290,39	1.225,87	1.361,00	1.296,19	1.231,38	1.366,70	1.301,62	1.236,53
PALMAR, EL 17	1.899,88	1.809,41	1.718,94	1.914,07	1.822,93	1.731,78	1.938,22	1.845,92	1.753,62	1.953,31	1.860,30	1.767,28
PALMAR, EL 18	1.975,89	1.881,80	1.787,71	1.995,66	1.900,63	1.805,60	2.026,76	1.930,25	1.833,74	2.043,94	1.946,61	1.849,28
PALMAR, EL 19	3.820,96	3.639,01	3.457,06	3.865,01	3.680,96	3.496,91	3.929,35	3.742,24	3.555,13	3.934,76	3.747,39	3.560,02
PALMAR, EL 20	3.761,69	3.582,56	3.403,43	3.806,54	3.625,28	3.444,01	3.871,79	3.687,42	3.503,05	3.878,95	3.694,24	3.509,53
PUNTA GRANDE 2	4.002,59	3.811,99	3.621,39	3.993,56	3.803,39	3.613,22	3.996,64	3.806,32	3.616,00	4.003,55	3.812,91	3.622,26
PUNTA GRANDE 3	4.003,76	3.813,10	3.622,45	3.997,40	3.807,04	3.616,69	4.003,75	3.813,10	3.622,44	4.012,40	3.821,33	3.630,26
PUNTA GRANDE 7	3.532,60	3.364,38	3.196,16	3.541,18	3.372,55	3.203,92	3.565,28	3.395,50	3.225,73	3.593,54	3.422,42	3.251,30
PUNTA GRANDE 11	6.128,12	5.836,30	5.544,49	6.089,66	5.799,68	5.509,69	6.058,51	5.770,01	5.481,51	5.993,03	5.707,65	5.422,26
PUNTA GRANDE 12	6.056,65	5.768,24	5.479,83	6.017,69	5.731,14	5.444,58	5.985,84	5.700,80	5.415,76	5.921,51	5.639,54	5.357,56
PUNTA GRANDE 13	13.059,01	12.437,15	11.815,29	13.029,73	12.409,27	11.788,80	13.026,21	12.405,91	11.785,62	12.900,74	12.286,42	11.672,10
PUNTA GRANDE 15	12.298,48	11.712,84	11.127,19	12.410,24	11.819,27	11.228,31	12.579,27	11.980,26	11.381,25	12.564,43	11.966,12	11.367,82
PUNTA GRANDE 16	12.419,69	11.828,28	11.236,87	12.531,26	11.934,53	11.337,81	12.700,22	12.095,45	11.490,67	12.682,72	12.078,79	11.474,85
SALINAS, LAS 1	1.944,31	1.851,72	1.759,14	1.969,61	1.875,82	1.782,02	2.008,61	1.912,96	1.817,32	2.059,78	1.961,70	1.863,61
SALINAS, LAS 2	1.960,99	1.867,61	1.774,23	1.986,29	1.891,70	1.797,12	2.025,25	1.928,81	1.832,37	2.076,46	1.977,58	1.878,70

SALINAS, LAS 3	1.779,65	1.694,91	1.610,16	1.801,99	1.716,18	1.630,37	1.836,27	1.748,82	1.661,38	1.881,62	1.792,02	1.702,42
SALINAS, LAS 4	2.895,07	2.757,21	2.619,35	2.717,75	2.588,34	2.458,92	2.769,55	2.637,67	2.505,79	2.838,07	2.702,93	2.567,78
SALINAS, LAS 5	2.978,34	2.836,51	2.694,69	2.790,66	2.657,77	2.524,89	2.842,26	2.706,92	2.571,57	2.910,98	2.772,36	2.633,75
SALINAS, LAS 6	13.687,48	13.035,69	12.383,91	13.600,95	12.953,29	12.305,62	13.527,89	12.883,70	12.239,52	13.351,73	12.715,93	12.080,14
SALINAS, LAS 10	16.732,26	15.935,49	15.138,71	16.909,18	16.103,98	15.298,78	17.164,10	16.346,76	15.529,42	17.099,85	16.285,57	15.471,29
SALINAS, LAS 11	14.900,53	14.190,98	13.481,43	15.073,54	14.355,75	13.637,96	15.321,26	14.591,68	13.862,10	15.292,55	14.564,33	13.836,12
SALINAS, LAS 12	14.942,24	14.230,70	13.519,17	15.117,86	14.397,96	13.678,06	15.368,85	14.637,00	13.905,15	15.340,99	14.610,46	13.879,94
TOTAL FUEL (DIESEL)	**256.656,04**	**244.434,33**	**232.212,61**	**257.422,93**	**245.164,70**	**232.906,46**	**259.459,83**	**247.104,60**	**234.749,37**	**259.458,23**	**247.103,07**	**234.747,92**
BCO. TIRAJANA CCGT 1	88.620,69	84.400,65	80.180,62	89.438,82	85.179,83	80.920,84	90.597,34	86.283,18	81.969,02	89.689,10	85.418,19	81.147,28
GRANADILLA CCGT 1	85.663,40	81.584,19	77.504,98	86.496,83	82.377,94	78.259,04	87.670,29	83.495,51	79.320,74	86.833,58	82.698,65	78.563,72
BCO. TIRAJANA CCGT 2	--	--	--	--	--	--	122.430,70	116.600,66	110.770,63	122.021,37	116.210,83	110.400,29
TOTAL CCGT	**174.284,08**	**165.984,84**	**157.685,60**	**175.935,66**	**167.557,77**	**159.179,88**	**300.698,32**	**286.379,35**	**272.060,38**	**298.544,06**	**284.327,68**	**270.111,29**
TOTAL HYDRO (EL MULATO)	**235,29**	**224,08**	**212,88**	**236,97**	**225,69**	**214,40**	**239,76**	**228,34**	**216,92**	**241,82**	**230,30**	**218,79**
TOTAL ORDINARY REGIME	**760.378,22**	**724.169,73**	**687.961,25**	**807.066,53**	**768.634,79**	**730.203,05**	**933.884,97**	**889.414,26**	**844.943,54**	**928.364,99**	**884.157,13**	**839.949,28**

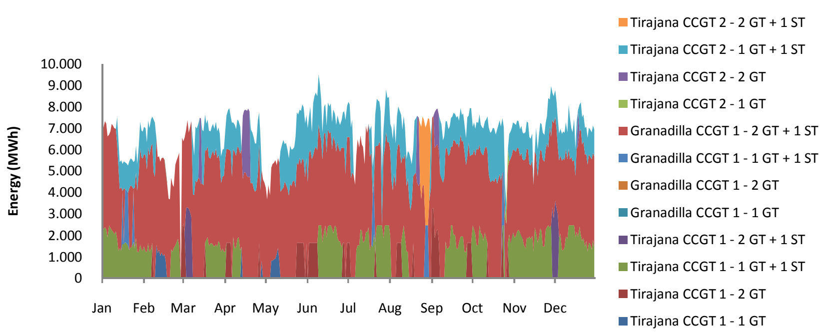
Appendix 12 – SEIE: Graphical Outcomes of Units' Dispatch



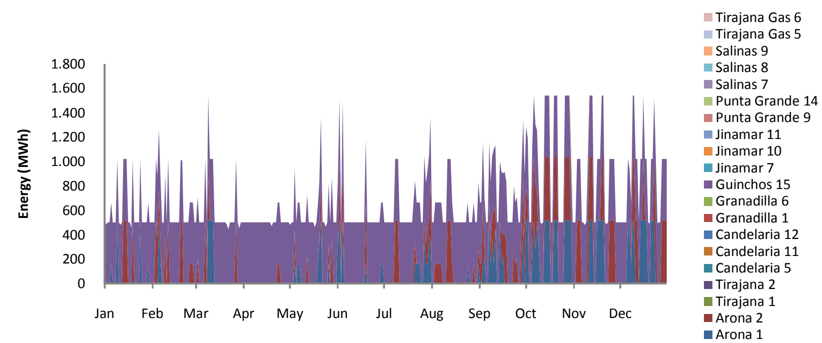
Coal units, Balearic Islands 2006



Fuel units, Balearic Islands 2006



CCGT units, Canary Islands 2008



Gas units, Canary Islands 2009

Appendix 13 – SEIE: Statistical Tests

Annual Investment Costs

Here is presented the SPSS statistical test results for checking if the calculated investment values and the published ones can be considered the same. Depending on the conditions, the *Student t-Test* or the non-parametric *Mann-Whitney U* test was used. As can be observed, in all cases they can be viewed as similar – (Asymp. Sig)/2 > 5%

	Balearic Islands				Canary Islands			
	2006	2007	2008	2009	2006	2007	2008	2009
Test	Man-Withney U	Man-Withney U	Man-Withney U	Man-Withney U	Man-Withney U	Man-Withney U	Man-Withney U	Man-Withney U
Asymp. Sig. (2-tailed)	0,963	0,852	0,852	0,818	0,987	0,965	0,914	0,908

Generation Prices

Here is presented the SPSS statistical test results for checking if the calculated generation prices values and the published ones can be considered the same. Depending on the conditions, the *Student t-Test* or the non-parametric *Mann-Whitney U* test was used. As can be observed, Balearic Islands figures *cannot* be validated when taking a daily basis of prices. But both are validated when considering average monthly values (Asymp. Sig)/2 > 5%.

	Balearic Islands		Canary Islands	
	Daily Basis	**Average Monthly Basis**	**Daily Basis**	**Average Monthly Basis**
Test	Man-Withney U	Student t-Test	Man-Withney U	Man-Withney U
Asymp. Sig. (2-tailed)	0,000	0,165	0,409	0,926

Appendix 14 – Spanish Generators Individual Parameters

Nuclear technology

Generation Unit	Code	Net Power (MW)	Start Operation	End Operation	*a* (th/h)	*b* (th/h.MW)	*f* (Euros/MWh)				
							2006	2007	2008	2009	*2010 (base)*
COFRENTES	COF1	1.063,90	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
ALMARAZ 1	ALZ1	944,40	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
ALMARAZ 2	ALZ2	955,70	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
SANTA MARÍA DE GAROÑA	GAR1	455,20	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
TRILLO	TRL1	1.003,40	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
VANDELLÓS II-1	VAN2	1.045,30	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
ASCÓ 2	ASC2	991,70	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
ASCÓ 1	ASC1	995,80	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
JOSÉ CABRERA	JCB1	141,70	--	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020

Fuel and gas technology

Generation Unit	Code	Net Power (MW)	Start Operation	End Operation	*a* (th/h)	*b* (th/h.MW)	*f* (Euros/MWh)				
							2006	2007	2008	2009	*2010 (base)*
ACECA 1	ACE1	301,00	--	--	28.853,000	2.183,000	1,1663	1,1781	1,1900	1,2020	1,2020
ACECA 2	ACE2	314,00	--	17/09/2009	26.375,000	2.210,000	1,1663	1,1781	1,1900	1,2020	1,2020
CASTELLÓN 2	CTN2	542,00	--	29/02/2008	75.271,000	2.113,000	1,1663	1,1781	1,1900	1,2020	1,2020
ESCOMBRERAS 4	ESC4	289,00	--	--	40.899,000	2.214,000	1,1663	1,1781	1,1900	1,2020	1,2020
ESCOMBRERAS 5	ESC5	289,00	--	--	40.899,000	2.214,000	1,1663	1,1781	1,1900	1,2020	1,2020
SANTURCE 1	STC1	378,00	--	10/12/2009	76.500,000	2.033,000	1,1663	1,1781	1,1900	1,2020	1,2020
SANTURCE 2	STC2	542,00	--	10/12/2009	88.602,000	2.100,000	1,1663	1,1781	1,1900	1,2020	1,2020
SANTURCE 3	STC3	17,00	--	23/12/2008	15.645,000	2.523,000	1,9406	1,9602	1,9800	2,0000	2,0000
ALGECIRAS 1	ALG1	211,00	--	06/09/2007	5.868,000	2.035,000	1,1663	1,1781	1,1900	1,2020	1,2020
ALGECIRAS 2	ALG2	524,00	--	11/09/2007	54.205,000	1.911,000	1,1663	1,1781	1,1900	1,2020	1,2020
BESÓS 2	BES2	294,00	--	31/12/2006	13.401,000	2.133,000	1,1663	1,1781	1,1900	1,2020	1,2020
SAN ADRIÁN 1	ADR1	313,00	--	--	23.605,000	2.228,000	1,1663	1,1781	1,1900	1,2020	1,2020
SAN ADRIÁN 3	ADR3	283,30	--	--	23.605,000	2.228,000	1,1663	1,1781	1,1900	1,2020	1,2020
FÓIX 1	FOI1	505,50	--	--	36.370,000	2.103,000	1,1663	1,1781	1,1900	1,2020	1,2020
SABÓN 1	SBO1	115,50	--	--	24.081,000	2.115,000	1,1663	1,1781	1,1900	1,2020	1,2020
SABÓN 2	SBO2	330,00	--	--	12.332,000	2.283,000	1,1663	1,1781	1,1900	1,2020	1,2020

Coal technology

Generation Unit	Code	Net Power (MW)	Start Operation	End Operation	*a* (th/h)	*b* (th/h.MW)	*f* (Euros/MWh)				
							2006	2007	2008	2009	*2010 (base)*
Brown Lignite											
PUENTES DE GARCÍA RODRÍGUEZ 1	PGR1	350,90	--	--	-10.104,000	2.394,000	1,1663	1,1781	1,1900	1,2020	1,2020
PUENTES DE GARCÍA RODRÍGUEZ 2	PGR2	351,10	--	--	-13.391,000	2.519,000	1,1663	1,1781	1,1900	1,2020	1,2020
PUENTES DE GARCÍA RODRÍGUEZ 3	PGR3	350,20	--	--	-10.104,000	2.394,000	1,1663	1,1781	1,1900	1,2020	1,2020
PUENTES DE GARCÍA RODRÍGUEZ 4	PGR4	350,80	--	--	-10.104,000	2.394,000	1,1663	1,1781	1,1900	1,2020	1,2020
MEIRAMA	MEI1	542,30	--	--	70.069,000	2.325,000	1,1663	1,1781	1,1900	1,2020	1,2020
Dark Lignite											
CERCS	CRC1	145,70	--	--	23.005,000	2.460,000	1,1663	1,1781	1,1900	1,2020	1,2020
ESCATRÓN 5	ECT1	67,00	--	--	18.612,000	2.133,000	1,1663	1,1781	1,1900	1,2020	1,2020
ESCUCHA	ECH1	142,30	--	--	32.950,000	2.412,000	1,1663	1,1781	1,1900	1,2020	1,2020
TERUEL 1	TER1	352,20	--	--	-1.883,000	2.424,000	1,1663	1,1781	1,1900	1,2020	1,2020
TERUEL 2	TER2	352,10	--	--	-1.883,000	2.424,000	1,1663	1,1781	1,1900	1,2020	1,2020
TERUEL 3	TER3	351,40	--	--	-1.883,000	2.424,000	1,1663	1,1781	1,1900	1,2020	1,2020
Dark Coal											
GUARDO 1	GUA1	143,40	--	--	31.000,000	2.390,000	1,1663	1,1781	1,1900	1,2020	1,2020
GUARDO 2	GUA2	342,40	--	--	55.000,000	2.210,000	1,1663	1,1781	1,1900	1,2020	1,2020
LADA 3	LAD3	147,60	--	--	37.021,000	2.278,000	1,1663	1,1781	1,1900	1,2020	1,2020
LADA 4	LAD4	347,70	--	--	67.634,000	2.203,000	1,1663	1,1781	1,1900	1,2020	1,2020
COMPOSTILLA 1	CCO1	133,00	--	31/12/2006	34.156,000	2.296,000	1,1663	1,1781	1,1900	1,2020	1,2020
COMPOSTILLA 2	CCO2	138,30	--	--	41.539,000	2.263,000	1,1663	1,1781	1,1900	1,2020	1,2020
COMPOSTILLA 3	CCO3	323,30	--	--	67.606,000	2.204,000	1,1663	1,1781	1,1900	1,2020	1,2020
COMPOSTILLA 4	COM4	341,10	--	--	14.765,000	2.298,000	1,1663	1,1781	1,1900	1,2020	1,2020
COMPOSTILLA 5	COM5	340,60	--	--	43.453,000	2.251,000	1,1663	1,1781	1,1900	1,2020	1,2020
PUENTE NUEVO 3	PNN3	299,80	--	--	27.190,000	2.316,000	1,1663	1,1781	1,1900	1,2020	1,2020
PUERTOLLANO	PLL1	206,10	--	--	68.295,000	2.116,000	1,1663	1,1781	1,1900	1,2020	1,2020
ANLLARES	ALL1	346,80	--	--	33.348,000	2.268,000	1,1663	1,1781	1,1900	1,2020	1,2020
NARCEA 1	NRC1	51,80	--	--	26.944,000	1.990,000	1,1663	1,1781	1,1900	1,2020	1,2020
NARCEA 2	NRC2	154,30	--	--	15.221,000	2.229,000	1,1663	1,1781	1,1900	1,2020	1,2020
NARCEA 3	NRC3	347,50	--	--	25.251,000	2.241,000	1,1663	1,1781	1,1900	1,2020	1,2020
LA ROBLA 1	ROB1	264,00	--	--	19.640,000	2.390,000	1,1663	1,1781	1,1900	1,2020	1,2020
LA ROBLA 2	ROB2	355,10	--	--	20.524,000	2.371,000	1,1663	1,1781	1,1900	1,2020	1,2020
SOTO DE RIBERA 1	SRI1	65,00	--	17/12/2007	-2.983,000	3.073,000	1,1663	1,1781	1,1900	1,2020	1,2020
SOTO DE RIBERA 2	SRI2	239,30	--	--	-2.980,000	2.505,000	1,1663	1,1781	1,1900	1,2020	1,2020
SOTO DE RIBERA 3	SRI3	346,30	--	--	31.084,000	2.254,000	1,1663	1,1781	1,1900	1,2020	1,2020
ABOÑO 1	ABO1	341,80	--	--	27.706,000	2.356,000	1,1663	1,1781	1,1900	1,2020	1,2020
ABOÑO 2	ABO2	535,90	--	--	31.258,000	2.258,000	1,1663	1,1781	1,1900	1,2020	1,2020
Gasified Coal											
ELCOGÁS	ELC1	296,40	31/12/2005	--	--	--	1,1663	1,1781	1,1900	1,2020	1,2020
Imported Coal											
PASAJES	PAS1	214,50	--	--	37.038,000	2.183,000	1,1663	1,1781	1,1900	1,2020	1,2020
LITORAL 1	LIT1	557,50	--	--	34.146,000	2.147,000	1,1663	1,1781	1,1900	1,2020	1,2020
LITORAL 2	LIT2	562,10	--	--	36.845,000	2.139,000	1,1663	1,1781	1,1900	1,2020	1,2020
LOS BARRIOS	BRR1	552,50	--	--	97.597,000	2.092,000	1,1663	1,1781	1,1900	1,2020	1,2020

CCGT technology

Generation Unit	Code	Net Power (MW)	Start Operation	End Operation	*a* (th/h)	*b* (th/h.MW)	*f* (Euros/MWh)				
							2006	2007	2008	2009	*2010 (base)*
ACECA IB 3	ACE3	386,00	01/04/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ARCOS IB 1	ARCOS1	389,20	28/10/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ARCOS IB 2	ARCOS2	373,20	22/07/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ARCOS IB 3	ARCOS3	822,80	06/09/2005	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTELLÓN IB 3	CTN3	782,00	25/04/2002	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTELLÓN IB 4	CTN4	839,30	20/11/2007	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTEJÓN IB 2	CTJON2	378,90	10/04/2003	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ESCOMBRERAS IB 6	ESC6	815,60	29/06/2006	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
SANTURCE IB 4	STC4	396,40	23/06/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
BAHIA DE VIZCAYA	BAHIAB	785,30	06/02/2003	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
TARRAGONA POWER	TAPOWER	416,90	15/12/2003	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SANROQUE END 2	SROQ2	401,80	09/05/2002	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
BESÓS END 3	BES3	411,90	09/05/2002	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
TARRAGONA END	TARRAG	385,80	07/06/2003	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
COLÓN END 4	COL4	390,90	19/03/2006	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PUENTES END 5	PGR5	834,70	13/08/2007	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
CC ESCATRON 2	ECT2	274,60	15/06/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ACECA UF 4	ACE4	372,60	26/11/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CAMPO DE GIBRALTAR UF 1	CAMGI10	392,60	02/04/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CAMPO DE GIBRALTAR UF 2	CAMGI20	387,90	07/05/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PALOS UF 1	PALOS1	386,70	11/08/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PALOS UF 2	PALOS2	389,10	26/11/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PALOS UF 3	PALOS3	391,00	08/03/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SABÓN UF 3	SBO3	391,30	15/08/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SAGUNTO UF 1	SAGU1	409,70	24/03/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SAGUNTO UF 2	SAGU2	411,80	22/05/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SAGUNTO UF 3	SAGU3	410,60	17/07/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTEJÓN HC 1	CTJON1	392,60	21/06/2002	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTEJÓN HC 3	CTJON3	418,40	19/09/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SOTO DE RIBERA HC 4	SRI4	426,00	19/04/2008	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
SANROQUE GN 1	SROQ1	389,80	01/03/2002	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
BESÓS GN 4	BES4	399,70	16/07/2002	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ARRUBAL GN 1	ARRU1	394,60	30/07/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ARRUBAL GN 2	ARRU2	390,00	09/08/2004	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CARTAGENA GN 1	CTGN1	418,20	28/09/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CARTAGENA GN 2	CTGN2	417,80	08/10/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CARTAGENA GN 3	CTGN3	412,70	22/10/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PLANA DE VENT GN 1	PVENT1	405,00	20/03/2007	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
PLANA DE VENT GN 2	PVENT2	414,00	25/04/2007	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
MÁLAGA GN 1	MALA1	433,00	18/05/2009	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
AMOREBIETA ESB	AMBIETA	786,40	16/03/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
CASTELLNOU ELB 1	CTNU	790,60	13/03/2006	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
ESCOMBRERAS AES 1	ESCCC1	402,60	04/11/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ESCOMBRERAS AES 2	ESCCC2	401,30	04/11/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ESCOMBRERAS AES 3	ESCCC3	395,20	04/11/2005	--	101.186,000	1.234,000	2,0410	2,0616	2,0825	2,1035	2,1035
ESCATRÓN NV 2	ECT3	804,30	09/10/2007	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035
ALGECIRAS NV 3	ALG3	806,20	01/03/2010	--	182.918,000	1.252,000	2,0410	2,0616	2,0825	2,1035	2,1035

Hydro technology

Generation Unit	Code	Net Power (MW)	Start Operation	End Operation	*f* (Euros/MWh)				
					2006	2007	2008	2009	*2010 (base)*
Mixed Pumping (Consumption)									
UGH.B. DUERO BOMBEO	DUEB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
ENDESA GENERACION BOMBEO MONTA	ENDPRB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. GUADALQUIVIR BOMBEO	GDLQB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH.B. SIL BOMBEO	SILB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH.B. TAJO BOMBEO	TAJB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B. TANES BOMBEO	TANB	--	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
Pure Pumping (Generation/Consumption)									
C.H.B. AGUAYO BOMBEO	AGUG/AGUB	360,40	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B. GUILLENA BOMBEO	AGUIG/GUIB	206,70	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B.IP BOMBEO	IPG/IPB	88,70	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B. MORALETS BOMBEO	MLTG/MLTB	217,80	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B. LA MUELA BOMBEO	MUEG/MUEB	633,90	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH.B. ESTANG. SALLENTE BOMB.	SLTG/SLTB	439,20	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H. B. TAJO ENCANTADA BOMBEO	TJEG/TJEB	358,00	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
C.H.B. BOLARQUE BOMBEO	UFBG/UFBB	214,80	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
Hydro									
UGH. DUERO GENERACION	DUER	3.551,50	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. EBRO ALTO	EBRA	219,70	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. EBRO ERZ	EBRERZ	17,60	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH EBRO FECSA ENHER GARONA	EBRFEN	1.878,30	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. GUADALQUIVIR	GDLQ	441,40	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. GUADIANA	GDNA	221,50	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. HIDROCANT. HIDRAULICA	HCHI	425,20	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. JUCAR	JUCA	847,00	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. SIL-BIBEY-EUME	SBEU	622,20	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. SIL GENERACION	SIL	1.345,60	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. TAJO GENERACION	TAJO	2.233,30	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. TERA-ESLA	TEES	113,80	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. TER	TERE	150,80	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. UF-GALICIA COSTA	UFGC	389,30	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. UF-MIÑO	UFMI	885,40	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. UF-TAJO	UFTA	360,80	--	--	1,9406	1,9602	1,9800	2,0000	2,0000
UGH. VIESGO	VIES	335,20	--	--	1,9406	1,9602	1,9800	2,0000	2,0000

Appendix 15 – Spanish Monthly Average Power Availability

Month	Power Availability (%)											
	2007				2008				2009			
	Nuclear	Coal	Fuel & Gas	CCGT	Nuclear	Coal	Fuel & Gas	CCGT	Nuclear	Coal	Fuel & Gas	CCGT
January	98,2	97,2	82,2	96,9	98,4	84,3	87,4	94,8	99,9	82,4	82,2	94,3
February	96,7	96,5	82,6	93,9	100,0	79,9	89,9	95,4	88,9	82,6	76,8	95,8
March	91,8	96,8	80,7	95,2	98,0	80,8	94,6	91,7	72,2	82,6	81,0	90,5
April	84,2	92,4	76,0	89,8	77,3	82,5	95,6	92,4	76,9	72,5	78,1	88,7
May	66,3	91,4	78,2	92,8	86,5	78,4	89,5	92,4	68,3	78,6	78,0	88,3
June	60,8	89,3	85,8	98,8	88,0	75,5	76,2	93,0	68,0	87,6	79,8	97,3
July	72,3	90,9	87,9	98,8	85,5	76,7	76,7	94,9	76,9	90,6	83,2	99,0
August	75,1	90,5	87,4	95,8	93,4	77,4	70,7	96,5	100,0	91,7	88,6	94,0
September	95,4	88,0	79,2	92,3	85,4	81,6	71,2	93,3	85,1	91,8	88,8	86,7
October	90,5	78,0	86,9	91,9	80,3	81,6	76,9	87,7	75,7	90,5	87,1	83,1
November	74,8	80,1	68,2	88,5	77,8	77,3	78,0	89,8	77,3	90,0	67,1	86,9
December	94,6	88,4	81,3	92,3	91,0	80,7	83,2	92,5	72,4	94,9	59,2	96,7

Appendix 16 – Spanish Emissions Parameters

Coal technology

Generation Unit	Code	Qe (tCO_2/MWh)				A_f (tCO_2)			
		2006	2007	2008	2009	2006	2007	2008	2009
Brown Lignite									
PUENTES DE GARCÍA RODRÍGUEZ 1	PGR1	0,9568	0,9253	0,8894	0,8894	1.871.492	1.631.629	1.354.103	1.183.358
PUENTES DE GARCÍA RODRÍGUEZ 2	PGR2	0,9568	0,9253	0,8894	0,8894	1.804.434	1.573.165	1.305.583	1.140.956
PUENTES DE GARCÍA RODRÍGUEZ 3	PGR3	0,9568	0,9253	0,8894	0,8894	1.800.535	1.569.766	1.302.762	1.138.491
PUENTES DE GARCÍA RODRÍGUEZ 4	PGR4	0,9568	0,9253	0,8894	0,8894	1.758.406	1.533.037	1.272.281	1.111.853
MEIRAMA	MEI1	1,1688	1,2824	1,0820	1,0820	2.553.409	2.280.522	2.008.907	1.755.594
Dark Lignite									
CERCS	CRC1	0,9275	0,9414	0,9143	0,9143	390.506	340.456	310.317	108.822
ESCATRÓN 5	ECT1	1,8520	1,8520	1,8520	1,8520	270.088	0	0	0
ESCUCHA	ECH1	0,9532	0,9795	0,9501	0,9501	524.230	457.041	568.050	404.052
TERUEL 1	TER1	0,9705	0,9527	0,9719	0,9719	1.534.486	1.337.816	1.453.690	1.367.205
TERUEL 2	TER2	0,9705	0,9527	0,9719	0,9719	1.552.196	1.353.256	1.470.467	1.382.984
TERUEL 3	TER3	0,9705	0,9527	0,9719	0,9719	1.555.960	1.356.538	1.474.034	1.386.338
Dark Coal									
GUARDO 1	GUA1	0,9527	0,9572	0,9741	0,9741	548.894	478.544	475.485	359.779
GUARDO 2	GUA2	0,9086	0,9300	0,9417	0,9417	1.493.063	1.301.702	1.286.577	1.124.346
LADA 3	LAD3	1,0003	0,9826	0,9611	0,9611	502.949	438.488	267.342	327.698
LADA 4	LAD4	1,0003	0,9826	0,9611	0,9611	1.374.763	1.198.564	730.754	895.729
COMPOSTILLA 1	CCO1	0,9325	--	--	--	0	--	--	--
COMPOSTILLA 2	CCO2	0,9325	0,9356	0,9204	0,9204	441.782	385.161	377.989	333.491
COMPOSTILLA 3	CCO3	0,9325	0,9356	0,9204	0,9204	1.435.883	1.251.850	1.228.541	1.083.912
COMPOSTILLA 4	COM4	0,9325	0,9356	0,9204	0,9204	1.431.078	1.247.661	1.224.430	1.080.285
COMPOSTILLA 5	COM5	0,9325	0,9356	0,9204	0,9204	1.489.844	1.298.895	1.274.710	1.124.646
PUENTE NUEVO 3	PNN3	0,8860	0,9078	1,7220	1,7220	1.386.012	1.208.371	1.153.888	1.008.389

PUERTOLLANO	PLL1	0,8473	0,8946	0,9584	0,9584	736.580	642.175	754.691	624.536
ANLLARES	ALL1	0,9323	0,9503	0,9363	0,9363	1.191.913	1.039.149	1.353.170	1.185.940
NARCEA 1	NRC1	0,9533	0,9574	0,9350	0,9350	171.950	150.230	131.387	105.167
NARCEA 2	NRC2	0,9533	0,9574	0,9350	0,9350	571.919	498.618	436.079	349.052
NARCEA 3	NRC3	0,9533	0,9574	0,9350	0,9350	1.720.099	1.499.640	1.311.548	1.049.808
LA ROBLA 1	ROB1	0,9123	0,9169	0,9441	0,9441	1.250.906	1.090.582	930.366	774.409
LA ROBLA 2	ROB2	0,9123	0,9169	0,9441	0,9441	1.723.534	1.502.635	1.281.885	1.067.002
SOTO DE RIBERA 1	SRI1	0,9129	0,9158	--	--	176.932	154.449	--	--
SOTO DE RIBERA 2	SRI2	0,9129	0,9158	0,9279	0,9279	1.151.237	1.003.686	806.589	655.704
SOTO DE RIBERA 3	SRI3	0,9129	0,9158	0,9279	0,9279	1.729.172	1.507.550	1.211.508	984.876
ABOÑO 1	ABO1	1,0975	1,1148	1,1826	1,1826	1.959.729	1.708.558	1.233.874	1.135.342
ABOÑO 2	ABO2	1,0975	1,1148	1,1826	1,1826	3.015.746	2.629.228	1.898.758	1.747.130
Gasified Coal									
ELCOGÁS	ELC1	--	--	--	--	--	--	--	--
Imported Coal									
PASAJES	PAS1	0,8946	0,9192	0,9472	0,9472	1.021.733	890.781	432.679	151.732
LITORAL 1	LIT1	0,8811	0,8752	0,8704	0,8704	2.878.303	2.509.400	1.626.440	1.839.044
LITORAL 2	LIT2	0,8811	0,8752	0,8704	0,8704	2.775.546	2.419.813	1.568.375	1.773.389
LOS BARRIOS	BRR1	0,9051	0,8794	0,9013	0,9013	3.012.048	2.626.004	2.024.245	1.768.998

CCGT technology

Generation Unit	Code	Qe (tCO_2/MWh)				A_f (tCO_2)			
		2006	2007	2008	2009	2006	2007	2008	2009
ACECA IB 3	ACE3	0,3649	0,3763	0,3733	0,3733	692.497	709.386	303.411	297.645
ARCOS IB 1	ARCOS1	0,3747	0,3840	0,3821	0,3821	617.656	709.386	306.565	300.739
ARCOS IB 2	ARCOS2	0,3734	0,3840	0,3821	0,3821	617.656	709.386	293.980	288.393
ARCOS IB 3	ARCOS3	0,3289	0,3840	0,3821	0,3821	1.154.160	1.418.772	649.242	636.903
CASTELLÓN IB 3	CTN3	0,3657	0,3750	0,3325	0,3325	692.497	709.386	248.107	324.522
CASTELLÓN IB 4	CTN4	--	0,3750	0,3325	0,3325	--	709.386	248.107	324.522
CASTEJÓN IB 2	CTJON2	0,3686	0,3719	0,3722	0,3722	692.497	709.386	298.049	292.384
ESCOMBRERAS IB 6	ESC6	0,1103	0,3703	0,3633	0,3633	115.416	709.386	630.806	618.818
SANTURCE IB 4	STC4	0,3700	0,3736	0,3744	0,3744	692.497	709.386	312.021	306.091
BAHIA DE VIZCAYA	BAHIAB	0,3678	0,3683	0,3693	0,3693	1.384.994	1.418.772	615.718	604.017
TARRAGONA POWER	TAPOWER	0,4831	0,3950	0,6061	0,6061	792.316	803.591	557.206	550.795
SANROQUE END 2	SROQ2	0,3638	0,3753	0,3676	0,3676	692.497	709.386	316.376	310.363
BESÓS END 3	BES3	0,3660	0,3733	0,3624	0,3624	692.497	709.386	324.947	318.771
TARRAGONA END	TARRAG	0,3678	0,3701	0,3691	0,3691	790.580	801.953	313.808	307.844
COLÓN END 4	COL4	0,0697	0,3650	0,3569	0,3569	0	709.386	308.378	302.518
PUENTES END 5	PGR5	--	0,2602	0,2602	0,2602	--	354.693	647.615	635.307
CC ESCATRON 2	ECT2	--	0,0625	0,5517	0,5517	--	368.437	149.563	146.720
ACECA UF 4	ACE4	0,2574	0,3609	0,3634	0,3634	634.789	709.386	289.702	284.197
CAMPO DE GIBRALTAR UF 1	CAMGI10	0,3917	0,3917	0,3917	0,3917	617.656	709.386	306.565	300.739
CAMPO DE GIBRALTAR UF 2	CAMGI20	0,3917	0,3917	0,3917	0,3917	617.656	709.386	306.565	300.739
PALOS UF 1	PALOS1	0,3533	0,3528	0,3524	0,3524	692.497	709.386	306.756	300.926
PALOS UF 2	PALOS2	0,3533	0,3528	0,3524	0,3524	692.497	709.386	306.756	300.926
PALOS UF 3	PALOS3	0,3533	0,3528	0,3524	0,3524	692.497	709.386	306.756	300.926
SABÓN UF 3	SBO3	--	0,2795	0,2795	0,2795	--	295.578	309.975	304.084
SAGUNTO UF 1	SAGU1	--	0,2673	0,3526	0,3526	--	709.386	365.370	358.426
SAGUNTO UF 2	SAGU2	--	0,2673	0,3526	0,3526	--	650.271	334.923	328.558
SAGUNTO UF 3	SAGU3	--	0,2673	0,3526	0,3526	--	472.924	243.580	238.951
CASTEJÓN HC 1	CTJON1	0,3685	0,3653	0,6323	0,6323	692.497	709.386	309.394	303.514
CASTEJÓN HC 3	CTJON3	--	0,3773	0,3773	0,3773	--	0	300.000	300.000
SOTO DE RIBERA HC 4	SRI4	--	--	0,0313	0,0313	--	--	300.000	300.000
SANROQUE GN 1	SROQ1	0,3593	0,3624	0,3675	0,3675	692.497	709.386	306.232	300.412
BESÓS GN 4	BES4	0,3547	0,3581	0,3623	0,3623	692.497	709.386	315.074	309.086

ARRUBAL GN 1	ARRU1	0,3517	0,3570	0,3570	0,3570	692.497	709.386	306.158	300.340
ARRUBAL GN 2	ARRU2	0,3517	0,3570	0,3570	0,3570	692.497	709.386	306.158	300.340
CARTAGENA GN 1	CTGN1	0,2931	0,3546	0,3524	0,3524	692.497	709.386	327.889	321.657
CARTAGENA GN 2	CTGN2	0,2931	0,3546	0,3524	0,3524	634.789	709.386	327.889	321.657
CARTAGENA GN 3	CTGN3	0,2931	0,3546	0,3524	0,3524	577.081	709.386	327.889	321.657
PLANA DE VENT GN 1	PVENT1	--	0,3069	0,3644	0,3644	--	472.924	355.438	348.682
PLANA DE VENT GN 2	PVENT2	--	0,3069	0,3644	0,3644	--	413.809	311.008	305.098
MÁLAGA GN 1	MALA1	--	--	--	0,3644	--	--	--	600.000
AMOREBIETA ESB	AMBIETA	0,3664	0,3787	0,3535	0,3535	1.384.994	1418772	616.408	604.693
CASTELLNOU ELB 1	CTNU	0,3411	0,3799	0,3670	0,3670	807.914	709.386	618.268	606.518
ESCOMBRERAS AES 1	ESCCC1	0,0705	0,3600	0,3471	0,3471	692.497	709.386	304.310	298.527
ESCOMBRERAS AES 2	ESCCC2	0,0705	0,3600	0,3471	0,3471	692.497	709.386	304.310	298.527
ESCOMBRERAS AES 3	ESCCC3	0,0705	0,3600	0,3471	0,3471	692.497	709.386	304.310	298.527
ESCATRÓN NV 2	ECT3	--	0,2223	0,2223	0,2223	--	118.231	405.685	596.962
ALGECIRAS NV 3	ALG3	0,3649	0,3763	0,3733	0,3733	692.497	709.386	303.411	297.645

Fuel and gas technology

Generation Unit	Code	*Qe* (tCO_2/MWh)				A_f (tCO_2)			
		2006	2007	2008	2009	2006	2007	2008	2009
ACECA 1	ACE1	0,7039	0,7913	0,7823	0,7823	41.798	0	0	0
ACECA 2	ACE2	0,8079	0,8158	0,8218	0,8218	33.492	0	0	0
CASTELLÓN 2	CTN2	0,7982	0,8128	0,8128	--	89.544	0	0	--
ESCOMBRERAS 4	ESC4	0,8206	0,8281	0,8281	0,8281	44.072	0	0	0
ESCOMBRERAS 5	ESC5	0,8206	0,8281	0,8281	0,8281	40.574	0	0	0
SANTURCE 1	STC1	0,7003	0,7715	0,7207	0,7207	30.781	0	0	0
SANTURCE 2	STC2	0,7003	0,7715	0,7207	0,7207	57.014	0	0	0
SANTURCE 3	STC3	0,7003	0,7715	0,7207	--	0	0	0	--
ALGECIRAS 1	ALG1	0,7618	0,6917	--	--	17.489	0	--	--
ALGECIRAS 2	ALG2	0,7618	0,6917	--	--	71.442	0	--	--
BESÓS 2	BES2	0,6386	--	--	--	0	--	--	--
SAN ADRIÁN 1	ADR1	0,6386	0,6602	0,6682	0,6682	18.072	0	0	0
SAN ADRIÁN 3	ADR3	0,6386	0,6602	0,6682	0,6682	20.229	0	0	0
FÓIX 1	FOI1	0,4566	0,5798	0,5895	0,5895	47.891	0	0	0
SABÓN 1	SBO1	0,8131	0,8738	0,8642	0,8642	13.379	0	0	0
SABÓN 2	SBO2	0,8131	0,8738	0,8642	0,8642	41.682	0	0	0

Appendix 17 – Logistic Costs of Coal Units

Generation Unit	Logistic Costs (Euros/t)				
	2006	2007	2008	2009	*2010 (base)*
Brown Lignite					
PUENTES DE GARCÍA RODRÍGUEZ 1	11,64	11,76	11,88	12,00	12,00
PUENTES DE GARCÍA RODRÍGUEZ 2	11,64	11,76	11,88	12,00	12,00
PUENTES DE GARCÍA RODRÍGUEZ 3	11,64	11,76	11,88	12,00	12,00
PUENTES DE GARCÍA RODRÍGUEZ 4	11,64	11,76	11,88	12,00	12,00
MEIRAMA	11,64	11,76	11,88	12,00	12,00
Dark Lignite					
CERCS	11,64	11,76	11,88	12,00	12,00
ESCATRÓN 5	15,52	15,68	15,84	16,00	16,00
ESCUCHA	15,52	15,68	15,84	16,00	16,00
TERUEL 1	15,52	15,68	15,84	16,00	16,00
TERUEL 2	15,52	15,68	15,84	16,00	16,00
TERUEL 3	15,52	15,68	15,84	16,00	16,00
Dark Coal					
GUARDO 1	15,52	15,68	15,84	16,00	16,00
GUARDO 2	15,52	15,68	15,84	16,00	16,00
LADA 3	11,64	11,76	11,88	12,00	12,00
LADA 4	11,64	11,76	11,88	12,00	12,00
COMPOSTILLA 1	15,52	15,68	15,84	16,00	16,00
COMPOSTILLA 2	15,52	15,68	15,84	16,00	16,00
COMPOSTILLA 3	15,52	15,68	15,84	16,00	16,00
COMPOSTILLA 4	15,52	15,68	15,84	16,00	16,00
COMPOSTILLA 5	15,52	15,68	15,84	16,00	16,00
PUENTE NUEVO 3	15,52	15,68	15,84	16,00	16,00
PUERTOLLANO	15,52	15,68	15,84	16,00	16,00
ANLLARES	15,52	15,68	15,84	16,00	16,00
NARCEA 1	15,52	15,68	15,84	16,00	16,00
NARCEA 2	15,52	15,68	15,84	16,00	16,00
NARCEA 3	15,52	15,68	15,84	16,00	16,00
LA ROBLA 1	15,52	15,68	15,84	16,00	16,00
LA ROBLA 2	15,52	15,68	15,84	16,00	16,00
SOTO DE RIBERA 1	15,52	15,68	15,84	16,00	16,00
SOTO DE RIBERA 2	15,52	15,68	15,84	16,00	16,00
SOTO DE RIBERA 3	15,52	15,68	15,84	16,00	16,00
ABOÑO 1	3,88	3,92	3,96	4,00	4,00
ABOÑO 2	3,88	3,92	3,96	4,00	4,00
Gasified Coal					
ELCOGÁS	15,52	15,68	15,84	16,00	16,00
Imported Coal					
PASAJES	5,82	5,88	5,94	6,00	6,00
LITORAL 1	3,88	3,92	3,96	4,00	4,00
LITORAL 2	3,88	3,92	3,96	4,00	4,00
LOS BARRIOS	3,88	3,92	3,96	4,00	4,00

Appendix 18 – Components of LNG Logistic Costs

Component \ Year	2006	2007	2008	2009
C_{fr} [(cts/kWh$_t$/day)/month]	1,4662	1,3536	1,4348	1,4348
C_{vr} (cts/kWh$_t$)	0,0087	0,0080	0,0085	0,0085
C_{fu} (Euros/ship)	20.000	20.000	21.200	22.600
C_{vu} (cts/kWh$_t$)	0,0040	0,0040	0,0042	0,0045
C_{vs} (cts/MWh$_t$/day)	1,2236[*1]	1,9073	2,0980	2,576
C_{fus} (cts/kWh$_t$)	0,0189	0,0227	0,0241	0,04030
C_{vus} (cts/kWh$_t$)	0,0174	0,0174	0,0184	0,0368[*2]
C_{fc} [(cts/kWh$_t$/day)/month]	0,6625	0,6625	0,7023	0,7936
C_f (Euros/MWh$_t$/day)/month	21,288	21,288	22,565	25,498
C_v (Euros/MWh$_t$)	0,520	0,521	0,552	0,624

[*1] 8,6873 cts/m^3/day (1 m^3 - 7,09977 MWh$_t$)
[*2] injection + extraction (0,02392 cts/kWh$_t$ + 0,01288 cts/kWh$_t$)

Appendix 19 – GAMS Code Overview – Spain, 2006

SETS

d	Time periods (days)	/ d1*d365 /
g	Generators	
t	Technology type	/ n, c, fg, cc, gi /
p	Price periods	/ ea1, ea2, ep1, ep2 /

nuclear(g)	Nuclear generators
coal(g)	Coal generators
gicc(g)	GICC generators
fuel_gas(g)	Fuel & Gas generators
ccgt(g)	CCGT generators

PARAMETERS

MTn(t)	Nominal minimum technical [%]	/ n 0.90, c 0.55, fg 0.31, cc 0.50, gi 0.50 /
EFFn(t)	Nominal efficiency [%]	/ fg 0.33, cc 0.50 /
minP(t)	Minimum technology net power [MW]	/ n 141.70, c 51.80, fg 17.00, cc 372.60 /
maxP(t)	Maximum technology net power [MW]	/ n 1063.90, c 552.50, fg 542.00, cc 822.80 /
dem_gi	GICC production objective [MWh]	/ 1098694 /
Pf(t)	Fuel cost average price factor [Euros per MWh]	/ n 11.64, gi 11.27 /
Fh	O&M cost factor of hydro and pumping units [Euros per MWh]	/ 1.9406 /
Cv	Variable component of LNG conduction toll [Euros per MWht]	/ 0.52 /
Lsem	Last day of the first semester	/ 181 /

TABLE X1(g,*) Parameters by generation group

** uo - Initial status of generator g at the beginning of the first day {1 0}*
** Pnet - Net power of generator g [MW]*
** quadA - Quadratic adjust parameter of generator g [th per h]*
** quadB - Quadratic adjust parameter of generator g [th per h.MW]*
** f - O&M costs factor of generator g [Euros per MWh];*
** Qe - Emissions quantity factor of generator g [tCO2 per MWh]*
** Af - Annual free assigned certificates of generator g [tCO2]*
** Prc1_ea - Coal ex-ante fuel thermie price (1 semester) [Euros/th]*
** Prc2_ea - Coal ex-ante fuel thermie price (2 semester) [Euros/th]*
** Prc1_ep - Coal ex-post fuel thermie price (1 semester) [Euros/th]*
** Prc2_ep - Coal ex-post fuel thermie price (2 semester) [Euros/th]*

TABLE X2(d,*) Daily demand by technology

** dem_h - Hydro generation demand in day d [MWh]*
** dem_n - Nuclear demand oin day d [MWh]*
** dem_c - Coal demand in day d [MWf]*
** dem_fg - Fuel and Gas demand in day d [MWh]*
** dem_cc - CCGT demand in day d [MWh]*
** dem_p - Pumping consumption in day d [MWh]*

TABLE X3(p,*) Prices

** prg - Gas fuel thermie price [Euros per th]*
** pre - Emission price [Euros per tCO2]*

VARIABLES

Fobj	Value of objective function
Cco2_ep(d,g)	Variable ex-post emissions costs of the unit g in the day d [Euros]
Cg(d,g)	Total ex-post variable generation costs of generator g in the day d [Euros];

POSITIVE VARIABLES

energy(d,g)	Energy dispatched by generator g in the day d [MWh]
Cop_ea(d,g)	Variable ex-ante operating (fuel) costs of the unit g in the day d [Euros]
Cop_ep(d,g)	Variable ex-post operating (fuel) costs of the unit g in the day d [Euros]
Com(d,g)	Variable operation and maintenance costs of the unit g in the day d [Euros]
Cco2_ea(d,g)	Variable ex-ante emissions costs of the unit g in the day d [Euros]
Ch(d)	Variable hydro generation operation and maintenence costs in the day d [Euros]
Cp(d)	Variable pumping costs in the day d [Euros]
logv(d,g)	Variable LNG logistic costs of the unit g in the day d [Euros]
Ep(d)	Variable energy price in the day d [Euros per MWh]
Qmn(d,g)	LNG consumed by generator g in the day d [MWht];

BINARY VARIABLES

u(d,g)	Binary variable indicating whether unit g is connected (1) or disconnected (0) in the day d
y(d,g)	Start-up decision for unit g in the day d
z(d,g)	Shut Down decision for unit g in the day d;

EQUATIONS

E_fobj	Objective Function
E_Cop_ea(d,g)	Ex-ante operating (fuel) costs
E_Cop_ep(d,g)	Ex-post operating (fuel) costs
E_Com(d,g)	Operation and maintenance costs
E_Cco2_ea(d,g)	Ex-ante emissions costs
E_Cco2_ep(d,g)	Ex-post emissions costs
E_logv(d,g)	Variable LNG logistic costs
E_Ch(d)	Hydro operation and maintenance generation costs
E_Cp(d)	Pumping operation and maintenance costs
E_Cg(d,g)	Total ex-post generation costs
E_n(d)	Meet the daily Nuclear demand
E_c(d)	Meet the daily Coal and GICC demand
E_fg(d)	Meet the daily Fuel & Gas demand
E_ccgt(d)	Meet the daily CCGT demand
E_gicc	Meet the annual GICC demand
E_Emax(d,g)	Respect maximum generator power
E_Emin(d,g)	Respect minimum generator power
E_Acop(d,g)	Logic of start ups and shut downs
E_rAcop(d,g)	Respect logic of start ups and shut downs
E_fsd(d,g)	Force shut-down of generator g in the day d when output is zero
E_ist(d,g)	Respect initial start up conditions

```
E_isd(d,g)            Respect initial shut down conditions
E_esc6(d,g)           Respect Escombreras IB 6 start operation
E_cast1(d,g)          Respect Castellnou ELB 1 start operation
E_colon4(d,g)         Respect Colon END 4 start operation
E_Ep(d)               Energy price
E_Qmn(d,g)             LNG consumed;

* Formulation of equations:

** Objetive function

E_fobj..
      fobj =e= SUM[(d,g), Cop_ea(d,g) + Com(d,g) + Cco2_ea(d,g) + logv(d,g) + Ch(d) + Cp(d)];

*** Ex- ante variable costs computation (for economic dispatch)
E_Cop_ea(d,g)..
       Cop_ea(d,g) =e= 24  * ((X3('ea1','Prg')$[ORD(d) <= Lsem] + X3('ea2','Prg')$[ORD(d) > Lsem])
                            $[fuel_gas(g) OR ccgt(g)] +
                            (X1(g,'Prc1_ea')$[ORD(d) <= Lsem] + X1(g,'Prc2_ea')$[ORD(d) > Lsem])
                            $[coal(g)]
                              ) * (u(d,g) * X1(g,'quadA') + X1(g,'quadB') * (energy(d,g) / 24)) +
                           [(Pf('n')$[nuclear(g)] + Pf('gi')$[gicc(g)]) * energy(d,g)];

E_Com(d,g)..
           Com(d,g) =e= X1(g,'f') * energy(d,g);

E_Cco2_ea(d,g)..
              Cco2_ea(d,g) =e= [X1(g,'Qe') * energy(d,g)] *
                             (X3('ea1','Pre')$[ORD(d) <= Lsem] + X3('ea2','Pre')$[ORD(d) > Lsem]);

E_logv(d,g)..
          logv(d,g) =e= [(energy(d,g) / (EFFn('fg')$[fuel_gas(g)] + EFFn('cc')$[ccgt(g)]) ) * Cv]
                       $[ccgt(g) OR fuel_gas(g)];

E_Ch(d)..
        Ch(d) =e= fh * X2(d,'dem_h');

E_Cp(d)..
       Cp(d) =e= fh * X2(d,'dem_p');

*** Respect unts energy boundaries

E_Emax(d,g)..
           energy(d,g) =l= u(d,g) * 24 * X1(g,'Pnet');

E_Emin(d,g)..
           energy(d,g) =g= u(d,g) * {(MTn('n')
                                $[(X2(d,'dem_n') / (24 * maxP('n'))) >= MTn('n')] +
                               (X2(d,'dem_n') / (24 * minP('n')))
                                $[(X2(d,'dem_n') / (24 * minP('n'))) <= MTn('n')] +
                               (X2(d,'dem_n') / (24 * maxP('n')))
                                $[(X2(d,'dem_n') / (24 * maxP('n'))) < MTn('n') AND
                                  (X2(d,'dem_n') / (24 * minP('n'))) > MTn('n')])
```

```
$[nuclear(g)] +
(MTn('c')
  $[(X2(d,'dem_c') / (24 * maxP('c'))) >= MTn('c')] +
(X2(d,'dem_c') / (24 * minP('c')))
 $[(X2(d,'dem_c') / (24 * minP('c'))) < =MTn('c')] +
(X2(d,'dem_c') / (24 * maxP('c')))
 $[(X2(d,'dem_c') / (24 * maxP('c'))) < MTn('c') AND
     (X2(d,'dem_c') / (24 * minP('c'))) > MTn('c')])
$[coal(g)] +
(MTn('fg')
  $[(X2(d,'dem_fg') / (24 * maxP('fg'))) >= MTn('fg')] +
(X2(d,'dem_fg') / (24 * minP('fg')))
 $[(X2(d,'dem_fg') / (24 * minP('fg'))) <= MTn('fg')] +
(X2(d,'dem_fg') / (24 * maxP('fg')))
 $[(X2(d,'dem_fg') / (24 * maxP('fg'))) < MTn('fg') AND
     (X2(d,'dem_fg') / (24 * minP('fg'))) > MTn('fg')])
$[fuel_gas(g)] +
(MTn('cc')
 $[(X2(d,'dem_cc') / (24 * maxP('cc'))) >= MTn('cc')] +
(X2(d,'dem_cc') / (24 * minP('cc')))
 $[(X2(d,'dem_cc') / (24 * minP('cc'))) <= MTn('cc')] +
(X2(d,'dem_cc') / (24 * maxP('cc')))
 $[(X2(d,'dem_cc') / (24 * maxP('cc'))) < MTn('cc') AND
     (X2(d,'dem_cc') / (24 * minP('cc'))) > MTn('cc')])
$[ccgt(g)] +
MTn('gi')$[gicc(g)]
} * (24 * X1(g,'Pnet'));

*** Meet daily technology generation

E_n(d)..
        SUM[nuclear, energy(d,nuclear)] =e= X2(d,'dem_n');
E_c(d)..
        SUM[coal, energy(d,coal)] + SUM[gicc, energy(d,gicc)] =e= X2(d,'dem_c');

E_fg(d)..
        SUM[fuel_gas, energy(d,fuel_gas)] =e= X2(d,'dem_fg');

E_ccgt(d)..
          SUM[ccgt, energy(d,ccgt)] =e= X2(d,'dem_cc');

E_gicc..
        SUM[(d,gicc), energy(d,gicc)] =e= dem_gi;

*** Respect units operating logic: shut-down and start-up

E_Acop(d,g)..
            u(d,g) =e= u(d-1,g)$[ORD(d) > 1] + X1(g,'uo')$[ORD(d) = 1] + y(d,g) - z(d,g);

E_rAcop(d,g)..
            y(d,g) + z(d,g) =l= 1;
```

```
E_fsd(d,g)..
          u(d,g)$[(X2(d,'dem_n')$[nuclear(g)] +
                   X2(d,'dem_c')$[coal(g) OR gicc(g)] +
                   X2(d,'dem_fg')$[fuel_gas(g)] +
                   X2(d,'dem_cc')$[ccgt(g)]) = 0]
               =e= 0;

E_ist(d,g)..
         y('d1',g) =e= 0;

E_isd(d,g)..
          z('d1',g) =e= 0;

*** Respect units operating logic: start operation and end operation

E_esc6(d,g)..
            u(d,'ESCOMBRERAS_IB_6')$[ORD(d) < 180] =e= 0;

E_cast1(d,g)..
            u(d,'CASTELLNOU_ELB_1')$[ORD(d) < 153] =e= 0;

E_colon4(d,g)..
             u(d,'COLON_END_4')$[ORD(d) < 72] =e= 0;

** Ex- post variable costs computation (for energy prices computation)

E_Cop_ep(d,g)..
       Cop_ep(d,g) =e= 24  * ((X3('ep1','Prg')$[ORD(d) <= Lsem] + X3('ep2','Prg')$[ORD(d) > Lsem])
                                $[fuel_gas(g) OR ccgt(g)] +
                             (X1(g,'Prc1_ep')$[ORD(d) <= Lsem] + X1(g,'Prc2_ep')$[ORD(d) > Lsem])
                                $[coal(g)]
                              ) * (u(d,g) * X1(g,'quadA') + X1(g,'quadB') * (energy(d,g) / 24)) +
                          [(Pf('n')$[nuclear(g)] + Pf('gi')$[gicc(g)]) * energy(d,g)];

E_Cco2_ep(d,g)..
              Cco2_ep(d,g) =e= [X1(g,'Qe') * energy(d,g) - X1(g,'Af') / 8760] *
                              (X3('ep1','Pre')$[ORD(d) <= Lsem] + X3('ep2','Pre')$[ORD(d) > Lsem]);

E_Cg(d,g)..
          Cg(d,g) =e= Cop_ep(d,g) + Com(d,g) + Cco2_ep(d,g) + logv(d,g);

E_Ep(d)..
        Ep(d) =e= (SUM[g, Cg(d,g)] + Cp(d) + Ch(d)) /
                  (X2(d,'dem_h') + X2(d,'dem_n') + X2(d,'dem_c')+ X2(d,'dem_fg') + X2(d,'dem_cc'));


E_Qmn(d,g)..
            Qmn(d,g) =e= [energy(d,g) / (EFFn('fg')$[fuel_gas(g)] + EFFn('cc')$[ccgt(g)])]
                         $[ccgt(g) OR fuel_gas(g)];

* Options for execution:

** Selection of the optimizer for solving binary variables
```

OPTION MIP = cplex;

*** Tolerance for optimization convergence with binary variables*

OPTION OPTCR = 0.001;

OPTION iterlim=1e+6 ;

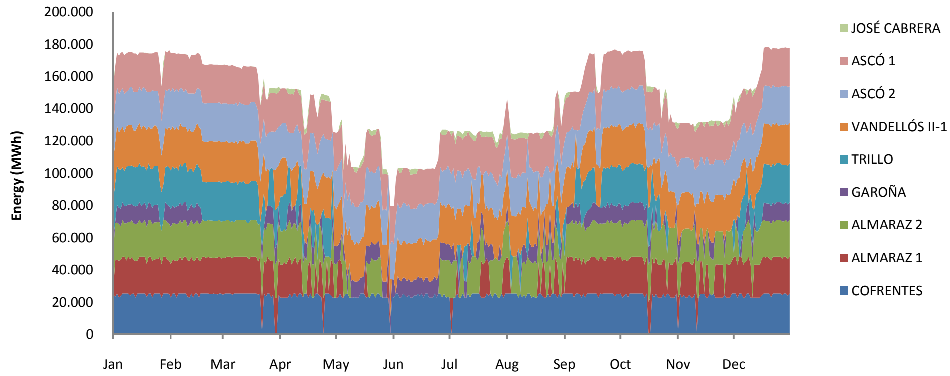
MODEL UCSPA_G /all/;

SOLVE UCSPA_G USING MIP MINIMIZING fobj;

** Open data in gdxviewer*

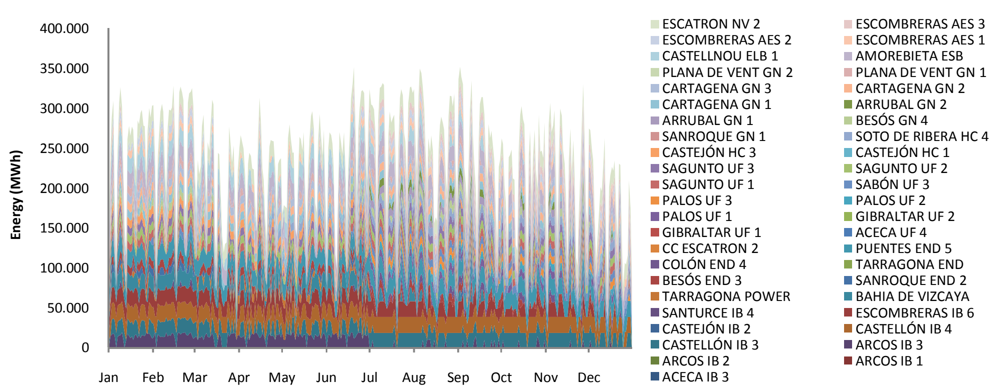
EXECUTE_UNLOAD 'results.gdx', energy, Cop_ep, Com, Cco2_ep, logv, Ch, Cp, Ep, Cg, Qmn;
EXECUTE '=gdxviewer results.gdx';

Appendix 20 – Spanish Graphical Outcomes of Units' Dispatch



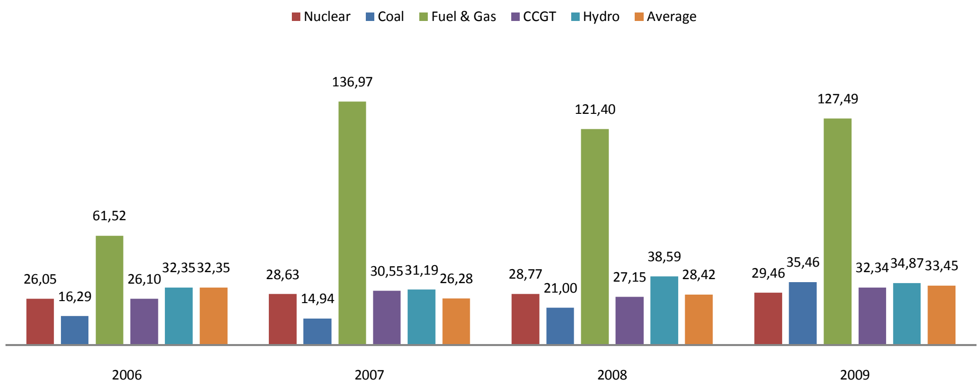
Nuclear units, 2007

Coal units, 2007

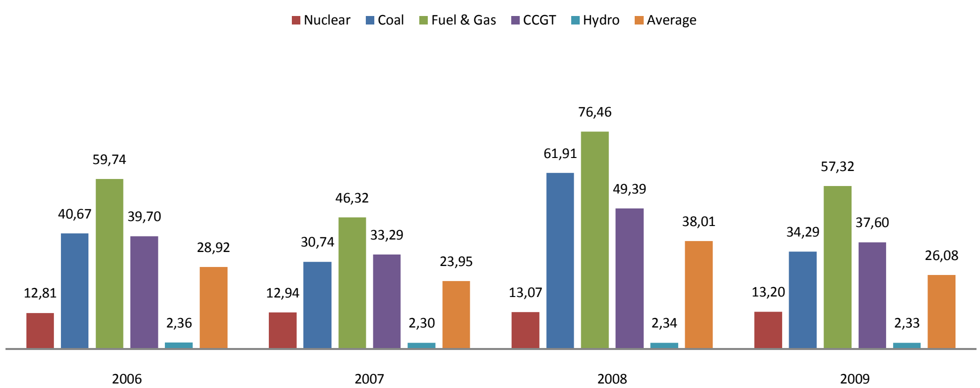


CCGT units, 2008

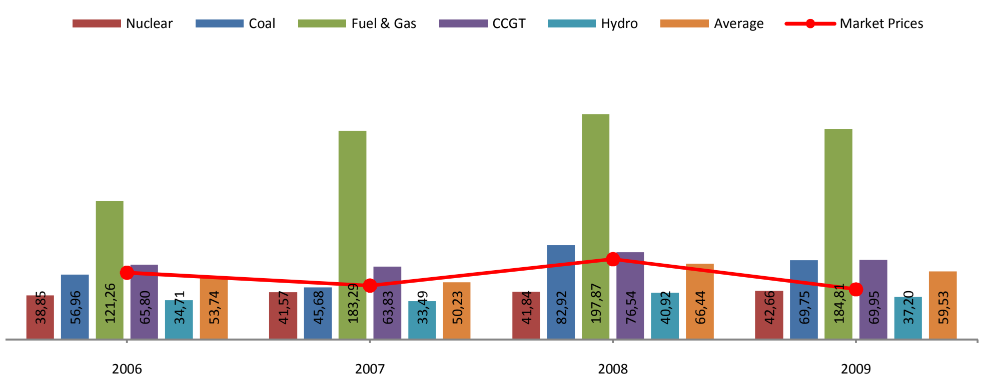
Appendix 21 – SEP Centralized and Market-oriented Generation Prices



Fixed centralized generation prices by technology and year (Euros/MWh)



Variable centralized generation prices by technology and year (Euros/MWh)



Centralized and market-oriented generation prices by technology and year (Euros/MWh)