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ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

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Generation Costs Estimation in the Spanish Mainland Power System from 2011 to 2020

AUTHOR: Jesús David Crisóstomo Ramírez

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Abstract

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AUTHOR: J. DAVID CRISÓSTOMO R.

The electricity sector in Spain had been evolving steadily in an ascendant rate since the liberalization in late 90's. Demand was expected to keep growing but it suddenly dropped in 2009 creating and unbalance ion the system in term of demand and installed capacity. In addition the increasing share of renewable energy contribution has also imposed an additional pressure on the ordinary regime technology leaving less and less residual demand for such technologies. The current and expected scenario in the Spanish mainland power system seems to be harder for the ordinary regime technologies for the next years. It has just issued a Royal Decree to support the autochthonous coal mines, imposing quotas for coal units using such coal. This work has the purpose of gather all the regulatory and economical constraints and apply them to estimate the generation costs for the following ten years. The approach to do such extensive task is to apply a regulated cost structure based on fixed and variable costs already proved as a reference model of the system costs in the SEP. The generation dispatch is done using a traditional approach of unit commitment based on the least costly units and taking into consideration the different constraint to reflect the most plausible behavior of market players. The result are consistent with the costs associated to the different technologies. Nuclear units are base load during the whole year and CCGT is the technology that balances the system to keep equilibrium because of demand-generation variations. The most stable technology is the Nuclear while the technology with the lowest costs is hydro. Coal and CCGT technologies appear to be the most expensive and become the marginal technology. With respect to the evolution of the generation mix, there were thermal units decommissioned from the installed capacity according with its decommissioning schedule but there is also the assumption of what in reality would happen when the existing thermal capacity is not being dispatched and the owners decide closure. The implication of such hypothesis go straight to the Coverage index which will be affected and start dropping compromising the minimum safe level required by the system operator

Index Terms: regulated cost structure, optimization model, coverage index

List of definitions

Closed-cycle pumping generation. Production of electrical energy carried out by the hydroelectric power stations whose higher elevation reservoir does not receive any type of natural contributions of water, but uses water solely from the lower elevation reservoir.

Combined cycle Technology for the generation of electrical energy in which two thermodynamic cycles coexist in one system: one involves the use of steam, and the other one involves the use of gas. In a power station, the gas cycle generates electrical energy by means of a gas turbine and the steam cycle involves the use of one or more steam turbines. The heat generated by combustion in the gas turbine is passed to a conventional boiler or to a heat-recovery element which is then used to move a steam turbine, increasing the yield of the process. Electricity generators are coupled to both the gas and steam turbines.

Environmental impact. Environmental change, be it adverse or beneficial, derived wholly or partially from the activities, products or services of an organization.

Generation consumption. Energy used by the auxiliary elements of power stations, necessary for the everyday functioning of the production facilities.

International physical exchanges. The movements of energy which have taken place across lines of international interconnection during a certain period of time. It includes the flow of energy as a consequence of the network design.

Net national consumption. This is energy introduced into the electrical transmission grid from the ordinary regime power plants (conventional), special regime (cogeneration and renewables) and from the balance of the international exchanges. In order to transfer this energy to the point of consumption it would be necessary to deduct the losses originating from the transmission and distribution network.

Non-renewable energies. Those obtained from fossil fuels (liquid or solid) and their derivatives

Ordinary regime. The production of electrical energy from all those facilities which are not included under the special regime (see below Ordinary regime).

Outage Situation in which the transmission grid facility -line, transformer, busbar, etc.- is disconnected from the rest of the electricity system and, consequently, power cannot flow through it. The facilities that are put temporarily out-of-service for maintenance or other works, additionally are also grounded to earth in one or various points with the objective of ensuring that their voltage is zero. In this way, any type of works can be executed on the element without risk to the safety of the people that carry it out.

Pumped storage This is a type of hydroelectric power generation used by some power plants for load balancing. The method stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Low-cost off-peak electric power is used to run the pumps. During periods of high demand of electricity, the stored water is released through turbines.

Renewable energies Those obtained from natural resources and both industrial and urban waste. These different types of energy sources include the hydroelectric, solar, wind, solid industrial and urban residues, and biomass.

Special regime Production of electrical energy which falls under a unique economic regime, originating from facilities with installed power not exceeding 50 MW whose generation originates from cogeneration or other forms of production of electricity associated with non electrical activities, if and when, they entail a high energy yield, groups that use renewable non-consumable energies, biomass or any type of biofuel as a primary energy source, groups which use non-renewable or agricultural waste, livestock and service sector waste as primary energy sources, with an installed power lower than or equal to 25 MW, when they entail a high energy yield.

System operator A trading corporation whose main function is to guarantee the continuity and security of the electricity supply, as well as the correct coordination of the production and transmission system. It exerts its functions in coordination with the operators and agents of the Iberian Electricity Market and under the principles of transparency, objectivity and independence. In the current Spanish model, the operator of the system is also the manager of the transmission grid.

Transmission grid Set of lines, parks, transformers and other electrical elements with 220 kV or more, and those other facilities, regardless of their power, which fulfill transmission functions, international interconnections and the interconnections with the Spanish peninsular and extra-peninsular power systems

List of abbreviations

CCGT	Combined Cycle Gas Turbine
CI	Coverage Index (Indice de Cobertura)
CNE	National Commission for Energy (Comisión Nacional de Energía)
DGPEM	General Direction of Energy Policy and Mines (Dirección General de Política Energética y Minas)
EU	European Union
ELV	Emission Limit Values
GAMS	General Algebraic Modeling System
GHG	Green House Gases
IED	Industrial Emissions Directive
IGCC	Integrated Gasification in Combined Cycle (Gasificación Integrada en Ciclo Combinado)
INE	National Institute of Statistics (Instituto Nacional de Estadística)
IPC	Consumption Price Index (Índice de Precios del Consumo)
IPI	Industrial Price Index (Índice de Precios Industriales)
LNG	Liquefied Natural Gas
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 Stable Framework (Marco Legal Estable)
O&M	Operation and Maintenance
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)
PNA	National Assignation Plan (Plan Nacional de Asignación)
RD	Royal Decree

REE	Spanish National Grid Company (Red Eléctrica de España)
SCR	Selective Catalytic Reduction
SEIE	Insular and Extapeninsular Power System (Sistema Electrico Insular y Extrapeninuslar)
SEP	Mainland Spanish Power System (Sistema Eléctrico Español Peninsular)
VOC	Volatile Organic Compounds

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1. Introduction and Context

The electricity sector provides one of the most important drivers of the economy in a country and its supply is an essential input for the well functioning of the entire society. As a result, governments are always pursuing to achieve the so called *triple A* policy goals; *Availability* for a highly reliable system in terms of security of supply, *Affordability* in terms of lower prices for the end users and *Acceptability* by promoting sustainability in its development [VRIE10]; however a tradeoff is expected among these goals specially in liberalized markets. In order to overcome these challenges it is compulsory to implement large scope policies and collaborate worldwide to achieve agreements. To do so, it also desirable to have a broader vision and periodical studies about the current features, difficulties and trends in the energy sector specially for Europe who is highly dependent of gas supply and other commodities.

The case of Spain is particularly special in the world. It has become one of the countries with the largest installed capacity and energy produced by renewable energy sources and it has been already recognized by the EU as a successful case of designing policies to promote the use renewable energy sources. In fact, it was reported in 2009 that contribution of renewable energy was 25% of the total energy produced, a trend that is expected to keep growing in the coming years [PANER10]. The policy choices made by Spain are moving towards achieving the above mentioned goals and seem to go a step ahead from other European countries however this successful implementation of renewable energy policies along with other domestic constraints have brought uncertainty and are pushing players in the liberalized market to redesign their own strategies both to meet global and individual goals.

This work has been carried out in order to provide a plausible scenario of the generation costs expected in the Spanish mainland power systems taking into consideration the above mentioned constraints.

1.1 Background

This work has been developed as Master Thesis for the international Erasmus Mundus Program *Economics and Management of Network Industries* (EMIN). It is the result of a internship program between *Pontifical Univertity of Comillas* and *Iberdrola*. This particular work has an additional justification and it is linked to a previous work developed by a former EMIN student called "*Generation Cost Evaluation in Centralized Systems. A contrast over market mechanism*". In that work, the application of the regulated cost structure was applied first to the Insular and Extapeninsular systems namely SEIE, in order to validate what the regulator in Spain is doing to compensate generating companies in those systems and then, it was adapted to the Spanish mainland power system in order to be contrasted against historical market prices.

The results of such study were 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 that 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. Taking this into account, this work is intended to estimate the generation costs in the Spanish mainland power system for the period 2011 to 2020 based on the current and expected scenario in the sector. Assumption and hypothesis were made trying to reflect the most rational behavior of market players and using mostly public sources that provides the most plausible evolution of the electricity sector in Spain.

1.2 Overview of the Spanish Power System

The Spanish electricity sector currently works under a liberalized scheme as a result of the Law 54/1997 from November 27th that basically establishes the unbundling of regulated activities from those that can operated under a competitive market. The law considers transmission and distribution of electricity as natural monopolies due to scale of such sectors. On the other hand, it gives free competition to the generation and retailing sector leading to the freedom to contract and choice of the best provider for the end consumer. In addition, this law establishes that any market player is entitled to have network access for transmission and distribution purposes. To do so, it creates the so called system operator who is in charge of technical management of the system and another entity who is the market operator en charge of economical management in the market.

After liberalization in the generation sector two main figures were created. Ordinary regime generation and special regime generation. The first type of generation is mainly composed by the traditional thermal technologies which are the targer technologies in this work while the special regime technologies are mainly the renewable enrgy sources as well as cogeneration.

The transmission system in Spain is highly interconnected to provide reliability to the system. This sector as already said above is a natural monopoly and is not subject to competition. REE is the system operator and is in charge of the technical management of the network as well as to plan the network expansion for future needs. REE must give third party access to the network under the regulated cost defined by the regulator. On the other hand, the distribution sector is also regulated and distribution companies should provide all different services required for the well functioning of the distribution network. The access to the distribution network should be charged according with the regulated tariff defined by the regulator. Retailing sector is also subject to competition and there is a market for this purpose in which end user can choose the best retailing company in the market.

In Spain, there are different markets in which transaction are done. There is a market in which player buy-sell energy to be delivered I the future. This market uses period that can go from 24 to years. These kinds of contracts are bilateral contracts, contracts under the OMPI, and auctions. For shorter periods there is the so called spot market in which negotiations are done for the energy to be delivered either next day in the daily market or in the same day with the intra-day market. In the first type, the market operator receives bid from suppliers and consumers and the price is fixed on an hourly base according with the supply-demand curve. The second market is mainly to adjust any unbalance seen during the real time operation of the system.

According with the system operator, in respect to the generation mix in the SEP there are 97,447 MW installed capacity by the end of 2010. From this total, 26% are CCGT followed by 20% from wind farms. Figure below show the distribution of the total generation mix.

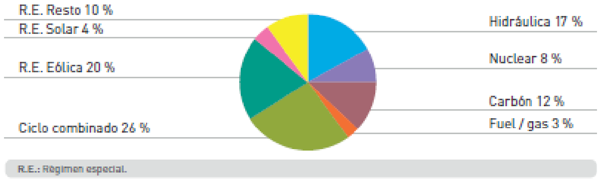

Figura 1.1 Share by technology of total installed cpactiy in Spain in 2010[1]

1.3 Motivation and Objectives

The market regime present in the electricity sector in Spain is constantly subject to unpredictable regulatory changes that not always are satisfactory for the participant players in the market and can lead to an inadequate equilibrium in the long run. Apart from the well known uncertainties in fuel prices evolution, under the current regulatory framework there are already some constraints that will impose volatility to the future electricity prices and might, as a consequence discourage investment in the sector compromising the triple A goals mentioned above. Besides, there are also communitarian regulations issued by the EU to achieve the 20-20-20 targets by 2020 related to cut in CO_2 emissions, renewable energy sources share and energy efficiency which ultimately define the path to follow in the coming years. This scenario makes challenging the coordination in all the links of the electricity supply chain.

This work has been developed to explore the trend in the generation costs in the Spanish mainland power system for the next 10 years based on two main foundations. First of all, as it has been explained above, the regulated cost structure used in the SEIEs has been proved to be consistent with the market price observed in the SEP from 2006 to 2009 in [WOTT2010]. The evolution of the market prices under the study period was slightly below the calculated with regulated cost structure which was an indication of the competition effect reflected in lower prices for end user as expected in a market mechanism. This methodology is now adapted to the current and expected evolution of the Spanish energy sector as a plausible approach to estimate the generation costs. Secondly, the regulatory pressure in the sector to meet EU targets as well as the local regulatory constraints, fuel and CO_2 prices are indeed constraints that will have a significant effect in the energy prices. It is expected that such constraints will be in the long run affecting decisions made by players in the market that can influence the functioning of the market.

[1] Taken from REE annual report 2010.

In this context, this study has been carried out with all the data needed for the formulation obtained only from public sources and trustworthy parties in the SEP in order to achieve the main goals below.

- To estimate the expected demand growth and share of renewable energy sources as a constraint for the ordinary regime technologies.
- To estimate the generation costs in the study period by using a regulated cost structure as a reference model and contrast them with the hypothetical market prices using the marginal generator of the economic dispatch.
- To assess the impact in the triple A goals as follows. Availability, by using the Coverage Index evolution according with the new and decommissioned unit during the study period. Affordability, by drawing conclusion about what the consequences are of evolution of generation costs and regulatory constraints imposed by the regulator, and Acceptability by assessing to what extent the renewable energy sources would contribute to meet targets.

1.4 Report Structure

This work starts in Chapter 2 by developing in detail the methodology applied to estimate the generations costs in the SEP. Its main purpose is to provide the conceptual structure cost used in the SEIEs for the generation costs retribution and use such methodology as a reference model for the SEP. Then, in Chapter 3 an introduction to the main technologies in which this work is most interested in will be given. This chapter will present firstly, a brief review of the technology in the SEP and the technical parameters required to calculate the generation costs, and secondly, the fixed and variable costs related and needed to be able to apply the methodology. Chapter 4 provides an extensive development of the data gathering and the assumptions made to forecast some important inputs in the study. Besides it provides insight about the key milestones that the current regulatory framework in Spain will impose in the evolution of the electricity sector. Chapter 5 is intended to provide the final mathematical formulation of the problem to be used in the language programming GAMS defining objective function to be optimized in the generation dispatch as well as the different constraint derived mainly from regulatory rules. In Chapter 6, an assessment of the results will be done paying special attention to the estimated costs compared with the hypothetical market price defined, the demand coverage with existing capacity installed and security of supply in the system. Finally, Chapter 7 is a compilation of the main conclusions drawn.

2. Methodology Applied

The methodology described in this Chapter provides the reference model of the approach used in this work to estimate the generation cost in the Spanish mainland power system. The actual methodology is usually applied in the SEIEs for the generation cost retribution based on a regulated scheme and will be adapted to be applied in the SEP. In this context, the Chapter is divided in two main parts. In the first part (Section 2.1), the methodology is explained as used in the SEIEs describing what the overall concept of the method is and its main components and then in the second part the methodology is used as a reference model and adapted to the SEP for the generation cost estimation, highlighting the main differences and changes needed with respect to the actual methodology. Finally, a short description of the Coverage Index (CI) will be given as an important index to measure the security of supply in the system.

2.1 The notion of regulated cost structure

In Spain, there are four SEIEs which are Canary Islands, Balearic Island, Ceuta and Melilla. Due to their size and isolation, these power systems do not fit into a market mechanism as the SEP does and had to be regulated under a different framework. The latter is supported by the Law 54/1997 in its article 12.2 that excludes the SEIEs from the market and also by the European Directive 96/92/CE which states that "it should be foreseen that some exception might apply to common norms for the electricity market especially for those small isolated systems"

[ME__03]. The Royal Decree RD1747/2003 provides a regulatory framework for the SEIEs focusing mainly on warranting security of electricity supply and quality at the lowest cost. The main regulations derived from this Royal decree are the establishment of a generation dispatch in which generating units in the ordinary regime are dispatched based on their variable costs and, consequently, on their economic merit taking into account the technical and environmental constraint. Besides, it states the main duties to be performed by the system operator and the market operator. The first one is mainly in charge of the generation dispatch in real time and management of any technical constraint that comes up in order to meet the demand while the second has to manage all the information related with final prices, payments and costs in the SEIEs. There are other regulations described in this Decree related with transmission, distribution and retailing, however, an important highlight is the generation cost methodology used for the retribution of ordinary regime generation units which is the foundation of this work.

As described in the Royal Decree, the cost structure for generating companies under the ordinary regime scheme has two main components; firstly, the so called variable costs which are the costs associated to fuel consumption and any other variable nature cost such as O&M expenses and secondly, the fixed costs or capacity payments which are given to generating companies to compensate investments and to maintain a required level of security in the system. The figure below shows the important factors considered in the components described above.

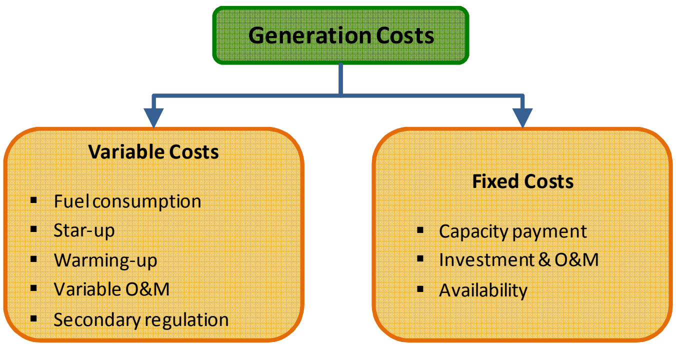

Figure 2.1 Regulated cost structure

The mathematical formulation for such cost structure is defined according with the RD1747 and it is extensively developed in [ITC91306] for variable costs and [ITC91406] for fixed costs considering the exiting generating units in the SEIE and their most important parameters in an hourly basis. However, before starting any mathematical formulation, it is important to point out that even though the actual methodology is formulated in a hourly basis, the aim of this work is not to estimate such detailed costs, therefore from now onwards, the formulas presented in this document will be expressed considering a daily basis analysis but keeping in mind that the actual calculations en each of the concepts can be done if hourly data is available.

Two concepts are the base to begin the analysis for the cost structure, first, the total daily cost of each generating unit in the system and second, the final generation system price per day which will actually be an average of the hourly price per day.

The first concept relates what was shown in Fig 1 and is an actual indicator of the retribution given to generating companies under a regulated scheme. Equation below represents the total generation costs in the SEIE.

$$gc(g, d) = gc_f(g, d) + gc_{var}(g, d) \quad (2.1)$$

Where:

$gc(g, d)$: Total cost of unit g in the day d [Euros]

$gc_f(g, d)$: Fixed cost of generation unit g in the day d [Euros]

$gc_{var}(g, d)$: Variable cost of generation unit g in the day d [Euros]

On the other hand, the final generation price gives an indication of how much end users are paying for the electricity supply in each SEIE and might be used to benchmark with a free market scheme. It is defined as follows.

$$FGP(d) = \frac{\sum_i gc(g,d)}{\sum_i e(g,d)} \quad (2.2)$$

With:

$FGP(d)$: Final generation price in the day d [Euros/MWh]

$e(g, d)$: Energy generated by the unit g in the day d [MWh].

The following sections will develop in detail the different components of the fixed costs term of equation 2.1 as well as the variable costs term.

2.1.1 Fixed costs formulation

Fixed costs are also known as capacity payments and are intended to provide an incentive to generating companies to assure security of electricity supply not only in the short term but also to meet the future needs in the SEIE´s power systems. These payments must mainly compensate the investment done by firms and the fixed operation and maintenance costs associated for maintaining a necessary reserve level in such systems. The order [ITC91406] develops extensively the methodology used for the fixed costs retribution to generating units in the ordinary regime. Its two main components are as follow.

$$gc_f(g,d) = G_{pow}(g,d).P_{Available}(g,d) \tag{2.3}$$

Being:

$G_{pow}(g,d)$:	Fixed cost retribution of the unit g in the day d [Euros/MW]
$P_{Available}(g,d)$:	Available power of the unit g in the day d [MW]

First of all, the second component of the equation refers to the actual net power available per unit and can be easily obtained by using a factor of hourly average power availability published by the system operator. The data needed is the net power of each unit, the aforesaid factor and the assumption that the unit works 24 hours per day.

On the other hand, the daily capacity payment requires a deeper analysis which has to start by defining its main components. First, the annual capacity payment, Gpow, is the retribution for the annual investment cost as well as for annual O&M fixed costs for each unit in the system. This component is published annually by the DGPEM before January 1st for each generating unit in the SEIE and applies for the whole year until it is updated for the following year. The next component is a normalized seasonality factor which is a relation between the representative demand in each season of the year (peak, shallow and shoulder) and the representative demand of the year. This value was originally defined in the [ITC91406] but can be updated according with the evolution of the system´s load curve and its reserve levels. Finally, there is a component related with the number of hours that each unit operates in the year considering a standard number of hours off because of unplanned outages and/or maintenance. This value is also published by [ITC91406] in general but it has been updated according with different technologies present in the SEIE. The formulation for the calculation of the daily capacity payment is as follows:

$$Gpow(g,d) = \frac{Gpow(g)_n}{Hi}.fsea_h \tag{2.4}$$

Where:

$Gpow(g)_n$:	Annual capacity payment of the unit g [Euros/MW]
$fsea_h$:	Seasonality factor
Hi:	Annual equivalent operating hours of the unit g [h]

As stated above, the term Gpow is obtained by adding up the annual investment cost (CITin) and the annual O&M fixed costs (COMTin) for each unit and there are values published annually for both terms. The formula below is the base for the calculation for each of the terms which will be done first for the CITin and then for the COMTin term.

$$\mathrm{Gpow}(\mathrm{g})_{\mathrm{n}} = \mathrm{CIT}_{\mathrm{in}} + \mathrm{COMT}_{\mathrm{in}} \quad [\text{Euros/MW}] \tag{2.5}$$

The [ITC91406] considers two possible cases for the calculation of the annual investment cost. The first case takes into account the retribution for amortization and the financial retribution of the investment (Eq. 2.6). This case applies when the total operation time of certain unit is less than a standardized maximum lifecycle time which will be defined later as 25 years for thermal units and 65 years for hydraulic units. The second case is used when the lifespan of the unit is over and it is still operating meaning that such time is greater than the standard lifecycle defined. In this case the retribution will be just 50% of the investment cost paid in its last year of the lifecycle (Eq. 2.7). See equations below.

$$\mathrm{CIT}_{\mathrm{in}} = \mathrm{A}_{\mathrm{i}} + \mathrm{R}_{\mathrm{in}} \tag{2.6}$$

$$\mathrm{CIT}_{\mathrm{in}} = 0{,}5.\,\mathrm{CIT}_{\mathrm{LC}_{\mathrm{i}}} \tag{2.7}$$

Being:

A_{i}: Retribution for investment´s annual amortization of unit g [Euros/MW]

R_{in}: Financial retribution of the investment for unit g [Euros/MW]

LC_{i}: Lifecycle of the unit g [yr]

$\mathrm{CIT}_{\mathrm{LC}_{\mathrm{i}}}$: Annual investment cost of unit g in last year of its lifecycle [Euros/MW]

The fist term of 2.6, the retribution for investment’s annual amortization, can be calculated from the recognized investment value and the lifecycle if the unit as shown in the equation 2.8. In this equation the term VIin can take two possible values. The first one does consider the real audited investment and the maximum investment value for each year according with equation 2.9 and the second is calculated according with equation 2.10 when the difference between the maximum investment value and the real one is negative.

$$\mathrm{A}_{\mathrm{i}} = \frac{\mathrm{VI}_{\mathrm{in}}}{\mathrm{LC}_{\mathrm{i}}} \tag{2.8}$$

With:

$\mathrm{VI}_{\mathrm{in}}$: Recognized investment value of unit g [Euros/MW]

$$\mathrm{VI_{in}} = \mathrm{VI_{in_{real}}} + 0{,}5.\left(\mathrm{VI_{in_{max}}} - \mathrm{VI_{in_{real}}}\right) \quad \forall \quad \left(\mathrm{VI_{in_{max}}} - \mathrm{VI_{in_{real}}}\right) \geq 0 \qquad (2.9)$$

$$\mathrm{VI_{in}} = \mathrm{VI_{i_{nmax}}} \quad \forall \quad \left(\mathrm{VI_{in_{max}}} - \mathrm{VI_{i_{nreal}}}\right) < 0 \qquad (2.10)$$

Where:

$\mathrm{VI_{in_{real}}}$: real audited investment value of unit g [Euros/MW]

$\mathrm{VI_{in_{max}}}$: maximum investment value of unit g [Euros/MW]

The real audited investment value is easily obtained from the records of each unit in which the actual investment done is available. On the other hand, the maximum investment values are defined by the DGPEM and are updated each year with the annual variation of Industrial Price Index (IPI). With the calculations done so far, the first term of equation 2.6 has already a value.

The second term of 2.6, financial retribution of the investment is calculated yearly by applying the financial retribution rate to the net investment value for each unit as follows.

$$\mathrm{R_{in}} = \mathrm{VNI_{in}}.\mathrm{Rr_n} \qquad (2.11)$$

With:

$\mathrm{VNI_{in}}$: Investment´s net value of unit g in the year n [Euros/MW]

$\mathrm{Rr_n}$: Financial retribution rate to be applied in year n

The term VNIin is calculated considering the difference between the recognized investment value and the accumulated amortization in the year n-1 (Eq. 2.12). The latter is obtained by a linear depreciation of the recognized investment value of the unit within its lifecycle.

$$\mathrm{VNI_{in}} = \mathrm{VI_{in}} - \mathrm{Aai_{n-1}} \qquad (2.12)$$

With:

$\mathrm{Aai_{n-1}}$: accumulated amortization of unit g until the year n-1 [Euros/MW]

With the last equation, the calculation of the first term of 2.5 is completed and then it just misses the value of COMTin. These costs are computed as the sum of the maximum annual O&M fixed costs published by the DGPEM for each unit plus the recurrent nature's unitary expenses which are 1.5% of the recognized investment value for thermal units (Eq. 2.13).

$$\mathrm{COMT_{in}} = \mathrm{COMT_{in_{max}}} + \varphi.\mathrm{VI_{in}} \qquad (2.13)$$

Being:

$\mathrm{COMT}_{\mathrm{in}_{\mathrm{max}}}$: maximum annual operation and maintenance fixed costs of the unit g [Euros/MW]

φ: rate of unitary recurrent nature costs

So far, the calculation of the daily capacity payments can be done by using the results of 2.4 and the values of power available explained above. Next section will be dedicated to the methodology described in [ITC91306] regarding variable cost calculations.

2.1.2 Variable costs formulation

This section deals with the methodology to compute the second component of equation 2.1, the variable cost. These costs are defined in [ITC91306] and include 5 main concepts namely operating cost, start-up cost, warming-up cost, O&M costs and secondary regulation costs. All these cost are part of the premium given to generating units to compensate the cost associated to fuel consumption and are a complement to the average peninsular price. Equation below shows the general definition for the viable costs. The same criteria is used in this explanation as it was used in the fixed cost calculation, the [ITC91306] also considers an hourly calculation for the variable costs, however, due to constraints related with data availability and expected results in this work, the variable costs will be calculated considering a daily basis too.

$$\mathrm{gc}_{\mathrm{var}}(\mathrm{g},\mathrm{d}) = \mathrm{e}(\mathrm{g},\mathrm{d}).\left[\mathrm{APP} + \mathrm{PrF}(\mathrm{g},\mathrm{d})\right] \tag{2.14}$$

Where:

APP: Average peninsular price [Euros/MWh]

$\mathrm{PrF}(\mathrm{g},\mathrm{d})$: Premium for the generation unit g in the day d [Euros/MWh]

$\mathrm{e}(\mathrm{g},\mathrm{d})$: Energy generated by the unit g in the day d [MWh].

The average peninsular price works as a reference tariff which is published annually in the Royal Decree and it includes the charge for auxiliary services provided in the peninsular system without considering secondary reserve so its value can be easily found. The premium, which includes the variable costs aforesaid, requires an extensive explanation for each of its components. According with the [ITC91306], this premium is obtained as follows

$$\mathrm{PrF}(\mathrm{g},\mathrm{d}) = \frac{\mathrm{C}_{\mathrm{op}}(\mathrm{g},\mathrm{d}) + \mathrm{C}_{\mathrm{st}}(\mathrm{g},\mathrm{d}) + \mathrm{C}_{\mathrm{wu}}(\mathrm{g},\mathrm{d}) + \mathrm{C}_{\mathrm{om}}(\mathrm{g},\mathrm{d}) + \mathrm{C}_{\mathrm{reg}}(\mathrm{g},\mathrm{d})}{\mathrm{e}_{\mathrm{pow}}(\mathrm{g},\mathrm{d})} - \mathrm{APP} \tag{2.15}$$

With:

$C_{op}(g, d)$: Variable operating (fuel) costs of the unit g in the day d [Euros/d]

$C_{st}(g, d)$: Variable start-up costs of the unit g in the day d [Euros/d]

$C_{hs}(g, d)$: Variable hot standby costs of the unit g in the day d [Euros/d]

$C_{om}(g, d)$: Variable operation and maintenance costs of the unit g in the day d [Euros/d]

$C_{reg}(g, d)$: Variable secondary regulation costs of the unit g in the day d [Euros/d]

$e_{pow}(g, d)$: Average power of the unit g in the day d [MW]

a) <u>Variable operating costs</u>

These are the costs for each generating unit associated to the fuel consumption derived from the functioning of the unit.

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

Being:

$a(g)$: Quadratic adjustment parameter [th/h]

$b(g)$: Quadratic adjustment parameter [th/h.MW]

$c(g)$: Quadratic adjustment parameter [th/h.MW2]

$pr(g, d)$: Fuel therm average price utilized by unit g in the day d [Euros/th]

The term pr(i,d) gives the thermal average value of the fuel used by the unit an it is computed as follows. Its definition includes the low heating values of the fuels used and they are defined for each of the fuel authorized to be used in each SEIE.

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

Where:

$x(c, g, d)$: Fraction of the total therms of fuel c utilized by the unit g in the day d

$prf(c, g, d)$: Price of fuel c utilized by the unit g in the day d [Euros/t]

$lhv(c, g, d)$: Low heating value of fuel c utilized by the unit g in the day d [th/t]

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

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

With:

$Q(c, g, d)$: Consumption of fuel c by the unit g in the day d [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). The first is given according to the geographic zone and fuel package for each SEIE. They are defined 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 on the fuel type. 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) and they are regularly 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 updated annually with the IPC foreseen in the tariff minus one-hundred basis points. The DGPEM could revise these values each four years.

$$\mathrm{prf}(c, g, d) = \mathrm{prp}(c, g, d) + \log(c, g, d) \tag{2.19}$$

Where:

$\mathrm{prp}(c, g, d)$: Product price of fuel c by the unit g in the day d [Euros/t]

$\log(c, g, d)$: Logistic cost of fuel c by the unit g in the day d [Euros/t]

b) <u>Variable Start-up costs</u>

This term provides the costs associated to fuel consumption in starting-up the unit to be dispatched. The exponential adjustment parameters are also obtained from test approved by DGPEM. The formulations is as follows

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

Being:

t: time period since the last unit stop [h]

$a'(g)$: exponential adjustment parameter [th]

$b'(g)$: exponential adjustment parameter [h]

d: additional operation and maintenance costs [Euros]

c) <u>Variable Warming-up costs</u>

These cost pop up when the system operator has decided to avoid the stop and start-up of a generation unit and put it into a warming-up status which means that the unit keeps the thermal boiler conditions to be able to connect immediately to the network.

$$C_{wu}(g, d) = Q_{wu}(g, d). prf(g, d) \tag{2.21}$$

With:

$Q_{up}(g, d)$: fuel consumption of unit g in the day d during hot standby [t/h].

d) Variable O&M costs

These costs are associated to raw material and works related to scheduled inspections due to working hours of the units and maintenance schedule. This expenditure also includes other expenses related with the operation of the unit and the working capital costs. It is formulated as follows:

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

Where:

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

$b''(g)$: Raw material and working capital's parameter [%]

Both parameters are obtained following the same procedure as the parameters previously discussed.

e) Secondary regulation costs

These are the cost associated to the need of maintaining the equilibrium between demand and supply. There should be units ready to either increase or decrease production so the system is always in equilibrium. Besides, there is a cost associated to the reserve margin included in this term. The formulation is as follows.

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

Where:

$a'''(g, d)$: Secondary regulation price [Euros/MW]

$p_{reg}(g, d)$: Assigned secondary regulation of the unit g in the day d [MW]

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

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

2.2 The reference model applied to the SEP

The use of the methodology described above as a reference model has to be adapted in order to fit the particular features of the SEP. This process was carried out by making just the necessary changes and adaptations in order to keep the final cost structure as close as possible to the actual methodology. Based on this, the two main components of the cost structure (Equation2.1) turn into the following:

$$gc_f(g,d) = G_{pow}(g,d).\,P_{Available}(g,d) + \ log_f(g,d) \tag{2.25}$$

$$gc_v(g,d) = C_{op}(g,d) + C_{om}(g,d) + C_{CO2}(g,d) + \ log_f(g,d) + C_H(g,d) + C_{pum}(g,d) \tag{2.26}$$

Being:

$G_{pow}(g,d)$:	Fixed cost retribution of the unit g in the day d [Euros/MW]
$P_{Available}(g,d)$:	Available power of the unit g in the day d [MW]
$log_f(g,d)$:	Fix logistics costs of conduction toll [Euro]
$C_{op}(g,d)$:	Variable operating fuel cost of unit g in the day d [Euro]
$C_{om}(g,d)$:	Variable O&M cost of unit g in the day d [Euro]
$C_{CO2}(g,d)$:	Variable operating fuel cost of unit g in the day d [Euro]
$C_H(g,d)$:	Variable hydroelectric cost of unit g in the day d [Euro]
$C_{pum}(g,d)$:	Variable pumping cost of unit g in the day d [Euro]
$log_v(g,d)$:	Variable logistics costs of conduction toll [Euro]

There are new component in these formulation and they are part of the current markets structure in the SEP so it was necessary to include them in order to aggregate their effect when the reference model is used for generation cost estimation. There are two new components related to the use of natural gas as a fuel. These two components were not included initially but with the new interconnection of Balearic Islands to the Spanish mainland gas system a new methodology was issued and will be used as a reference for the costs associated to this fuel in the SEP. Besides, a variable component of CO_2 emissions was included due to the emission scheme present in the SEP. And finally, the two additional components C_H and C_{pum} are related to O&M costs of normal and pumping units and the second to the extra cost for pumping water by pure and mixed pumping units. All of them are further discussed in the next two sections.

2.2.1 Fixed cost retribution in the SEP

The fixed cost retribution will be applied to three main concepts in this work. First of all, a part from the CCGT units that were mostly built in the new market structure, most of the power plants in the SEP are older and started operations before the new markets structure came up. The impact of this goes the recognized investment value that is needed in the methodology and for the sake of simplicity, it was selected an approach in which units starting operation before the market model in Spain, were already amortized by 2006. This assumption is supported by stranded competition costs which were used as a compensation given to owner companies due to a regulatory change derived from the liberalization of the Spanish electricity sector. On the other hand, units built under the new market scheme were treated with the methodology described above.

Secondly, according with the energy policy present in the Spanish sector and the aim to increase energy efficiency and lowering GHG emissions some incentives are given by the regulator to promote such investments by those units above 50MW which may include enlargement or new facilities to increase efficiency as stated by the [ITC386007]. This led to some coal units to invest in both new boilers and desulphurization facilities. The first one was installed for those coal units aiming to burn coal with a lower content of sulfur while the desulfurization plant is a technology used to remove sulfur dioxide (SO2) from the exhaust flue gases of fossil fuel power plants. Both of these facilities will be given a fixed retribution based on the regulatory framework applicable.

Finally, late in 2010 it was issued a new European Directive [EUD7510] which is the Industrial Emissions Directive (IED) and sets objectives regarding environment protection. This new Directive aims to push the use of the best technologies available to tackle the emission for SO2, NOX and VOC (Volatile Organic Compounds). In order to achieve such aggressive goals, the Directive provides two main mechanisms that may be applied to the coal units in the SEP. The first one is an “opt-out’ of 17500 hours as maximum operating time in the period from 2016 to 2023 and the second is the investment by the coal units in a Selective Catalytic Reduction technology to tackle the NOX emissions. The latter supposes an investment by the owner companies and consequently a fixed cost retribution according with was it is stated in [ITC386007].

The three concepts explained above are the main sources used for the fixed costs calculations and will be explained step by step in Chapter 5.

2.2.2 Variable cost retribution in the SEP

The methodology described in the Section 2.1.2 is based on [ITC91306] for the SEIE which are special systems in the Spanish market. Its application to the SEP requires some adaptations and assumptions. It is important to mention at this point that the previous study done in [WOTT10] provides support for the validation of the results. The main goal in that study was to replicate the generation cost structure in the SEP for period from 2006 to 2009 in the Spanish market and make a comparison of the recorded prices under the market mechanism with the generation cost methodology used in the SEIE. It is not the goal of this work to prove again those assumptions and they will be taken as given and already validated. On the other hand, there will be an adaptation to the methodology used for the natural gas as a fuel in CCGT and Fuel-Gas units. With the new pipeline built in the Balearic system a new methodology for Natural Gas costs was published [ITC155910] this gives a clearer method to compute with more accuracy.

First, the methodology for the conventional thermal units will be explained highlighting important adaptation and assumptions made. Then, the new methodology explained in [ITC155910] will be extensively explained and finally a brief explanation of variable costs associated to hydro and pumping units.

2.2.2.1 Methodology for thermal units

As seen in the Section 2.1.2 there are 5 main components of the equation 2.15 to be calculated related to variable cost of the units. First, it will be explained briefly why some of those costs are not being considered in the SEP adaptation and then the specific calculation done for the different thermal technologies as well as other variable cost incurred by the generation units under the SEP context.

First of all, the cost associated to start-up require the exponential parameters and O&M costs associated to this action, however, there is not a public source with such information for the SEP's units. This cost won't be considered in this work and is supported by the fact that historical replication of this methodology done by [WOTT10] showed that such costs don't have a significant impact on final energy price. In addition to start-up costs, secondary regulation costs are not considered either. In the SEP, there is already a market for these services and the daily bids are not affected by this cost.

In regards to variable operating costs there are three conventional technologies to be calculated under this section. First, the variable operating costs associated to Coal units are done with equation 2.16, however as it can be seen, this equation has an exponential term which make the use of a solver more difficult so the equation was transformed into a linear equation. Besides equation 2.16 was still expressed in an hourly basis so and additional adaptation is needed to have it in a daily basis as follows.

$$C_{op}(g,d) = pr(g,d).\,hr(g,d).\left[a(g) + b(g).\frac{energy(g,d)}{hr(g,d)}\right] \tag{2.27}$$

Being

$energy(g,d)$	Energy produced by the unit g in the day d [MWh]
$hr(g,d)$	Number of operation hours of unit g in day d (24 h)

The other two technologies are Nuclear and the IGCC–Elcogas. In this case, equation 2.27 is not applied and a different approach is used to get operating cost of such technologies. Basically, the most common way to do it is by connecting their operating costs to the energy produced. To do that, an additional parameter is needed called fuel average price factor.

$$C_{op}(g,d) = P_{ff}(g) \cdot energy(g,d) \tag{2.28}$$

Being:

$P_{ff}(g)$	Fuel average price factor of unit g [Euros/MWh]

Regarding the O&M costs associated, a new adaptation was done. The parameters required in 2.22 are also unknown for the generation unit in the SEP. This makes difficult the calculation following the equation 2.22, instead, the approach to compute these costs was to use O&M cost associated to energy produced and by technology as follows.

$$C_{om}(g,d) = f(g) \cdot energy(g,d) \tag{2.29}$$

Being:

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

The latter is the expression that will be used later in Chapter 5 to compute O&M costs for all of the technologies.

Finally, the costs associated to CO_2 are also considered here. This component is not explicitly included in the SEIE methodology because the fuel costs are revised and emissions are internalized in it. In contrast, according with the EU there should be a "cap and trade" mechanism for CO_2 emission in liberalized markets in which countries have to allocate emissions rights by a PNA. This allocation can be done either by free emission rights or by auction and allowing market gents to trade them. For this methodology it has been taken the free emission rights allocated according with the [PNAII07][2] for the years 2011 and 2012 and the extra cost to be paid for exceeding the free rights as well. Afterwards this cost is fully considered as a criterion for minimizing the costs in the dispatch due to the end of the free rights mechanism allocated by the government.

$$C_{CO2}(g,d) = P_e(d) \cdot Q_e(g).\,\mathrm{energy}(g,d) \tag{2.30}$$

$$C_{CO2}(g,d) = P_e(d) \cdot \left[Q_e(g).\,\mathrm{energy}(g,d) - \frac{A_f(g)}{H_d}\right] \tag{2.31}$$

Being

$Q_e(g)$	Emission quantity factor of unit g [tCO_2/MWh]
$P_e(d)$	Average price of CO2 emissions [Euro/tCO_2]
$A_f(g)$	Annual free assigned certificates of unit g [tCO_2]
H_d	Average equivalent hours per year

One of the main features of the methodology is the focus on the economic dispatch of generators. The first equation aims to achieve this goal especially in the first two years of the simulation in which there are free allocated rights for thermal units. This means that on the one hand, the CO2 costs are fully internalized in the opportunity cost of units and on the other, that the merit order changes the dispatch of generators and sets a priority for the more efficient units. The second equation is used to compute the actual final energy price once the free rights have been used, however this equation will be used only in 2011 and 2012 as stated above.

2.2.2.2 Methodology for natural gas units

This methodology has been issued for the SEIEs as a result of the new pipeline connecting Spanish mainland gas system to the Balearic system. Before this pipeline was built, there were no power plants in any of the SEIE prepared to use natural gas as a fuel. The method is given to compute variable cost associated to natural gas use and it is described in

[2] The PNAII (Assignment National Plan - *Plan Nacional de Assignacion de Derecho de Emission* in Spanish) cover the period 2008-2012 and it allocate individual emission rights. It considers a decrease of 36% in total emission rights with respect to PNA I.

[ITC155910]. Ultimately, the operating costs associated to the units working with natural gas are actually calculated by using equation 2.27 however, the fuel therrmie average price is an unknown parameter. What the CNE publishes in a monthly basis is the product price of the natural gas in [€/MWh] which is an input for the following description.

First of all, the cost of natural gas is given by the next expression:

$$C = V \cdot [p_{LNG} \cdot (1 + l_r + l_t) + C_{VTPA}] + C_{FTPA} + T_{TD} \qquad (2.30)$$

p_{LNG}:	LNG product price [€/MWh]
l_r:	Re-gasification losses
l_t:	Transmission losses
C_{VTPA}:	Variable component of gas third party access [€/MWh]
C_{FTPA}:	Fix component of gas third party access [€/MWh]
T_{TD}:	Monthly invoicing of the conduction component of transmission and distribution toll [€]

This expression gives an indication not only of the variable costs associated to the use of natural gas for the product price and the variable component of costs such as re-gasification, unloading, storage and underground storage, it also gives the fixed component for the third party access to the gas network which includes fixed re-gasification toll as well as the fixed component for the capacity reserve. The first step is to calculate the different subcomponents of the variable third party access costs as follows;

$$C_{VTPA} = CR_v + CU + CS + CUS \qquad (2.31)$$

CR_V:	Variable cost of re-gasification toll [€/MWh]
CU:	Cost of unloading [€/MWh]
CS:	Cost of LNG storage [€/MWh]
CUS:	Cost of underground storage [€/MWh]

Then after defining the four components of the latter term the formulation for each of them is necessary. The variable cost of re-gasification toll includes the C_{VR} term which is annually published by the MITC and the transmission losses term which is consider as 0.39% considering these facilities are units connected to a pipeline with pressures between 4 and 60 bars [ITC399306]. Finally the percentage of LNG in Spain's gas income is published in the [ITC155910] with a value of 0.74.

$$\mathrm{CR_V} = \frac{10 \cdot \mathrm{C_{vr}} \cdot \%\mathrm{LNG}}{1 - \mathrm{l_t}} \tag{2.32}$$

C_{vr}: Variable component of re-gasification [cts/KWh]

%LNG: Share of LNG entering Spain out of total gas income

To compute the costs of unloading the values are set annually for the fixed and variable costs of unloading while ship's average size has been set initially in 650,343 MWh.

$$\mathrm{CU} = \left(\frac{\mathrm{C_{fu}}}{\mathrm{S_{ship}}} + 10 \cdot \mathrm{C_{vu}}\right) \cdot \left(\frac{\%\mathrm{LNG}}{(1-\mathrm{l_r}) \cdot (1-\mathrm{l_t})}\right) \tag{2.33}$$

C_{fu}: Fix component of unloading [€/ship]

S_{ship}: Ship average size [MWh]

C_{vu}: Variable component of unloading [cts/KWh]

Then the cost of LNG storage depends on the terms storage canon component which published also yearly in an order ITC. The storage average time has been set to 8.2 days.

$$\mathrm{CS} = \frac{\mathrm{C_{vs}} \cdot \mathrm{NA_{LNG}}}{100 \cdot (1-\mathrm{l_t})} \tag{2.34}$$

C_{vs}: LNG storage canon component [cts/MWh/day]

NA_{LNG}: Storage average time of LNG

Finally, the costs of underground storage are obtained as shown below.

$$\mathrm{CUS} = 10 \cdot \left(\frac{12 \cdot 20 \cdot \mathrm{C_{fus}}}{365} + \frac{8}{365} \cdot \mathrm{C_{vus}}\right) \tag{2.35}$$

C_{fus}: Fix component of underground storage [cts/KWh/month]

C_{vus}: Variable component of underground storage [cts/KWh]

Having defined equations 2.31 to 2.35 the LNG average price can be obtained as defined in the equation below with a final conversion of units given by the conversion factor of 860 [th/MWh].

$$\mathrm{pr(g)} = \left(\frac{1}{860}\right) [\mathrm{p_{LNG}} \cdot (1 + \mathrm{l_r} + \mathrm{l_t}) + \mathrm{C_{VTPA}}] \tag{2.36}$$

Then the formulation of the fixed cost associated to the use of LNG is also implicit in this methodology. From equation 2.30 the fix component of gas third party access is divided into two terms. The first is realted with fixed re-gasification costs (CR_f) and the second is the cost of capacity reserve (C_{CR}).

$$C_{FTPA} = CR_f + C_{CR} \tag{2.37}$$

$$CR_f = \left(\frac{C_{fr}}{100}\right) \cdot \left(\frac{Q_e \cdot \%LNG}{1-l_t}\right) \tag{2.38}$$

$$C_{CR} = \left(\frac{C_{fc}}{100}\right) \cdot \left(\frac{Q_e}{1-l_t}\right) \tag{2.39}$$

C_{fr}: Fix component of re-gasification [(cts/KWh/day)/month]

C_{fc}: Fix component of capacity reserve [(cts/KWh/day)/month]

Q_e: Daily volume contracted taken from the fix component of T & D conduction toll [MWh/day]

The term to be used as Q_e in the lasts two equations correspond to volume of flow applied in the fixed term of the transmission and distribution toll which is defined in [RD94901] and quantified as follows:

$$Q_e = Q_{mn} \quad \forall \quad 0{,}85.Q_{mc} \leq Q_{mn} < 1{,}05.Q_{mc} \tag{2.40}$$

$$Q_e = 0{,}85.Q_{mc} \quad \forall \quad Q_{mn} < 0{,}85.Q_{mc} \tag{2.41}$$

$$Q_e = Q_{mn} + 2.[Q_{mn} - 1{,}05.Q_{mc}] \ \forall \quad Q_{mn} \geq 1{,}05.Q_{mc} \tag{2.42}$$

With:

Q_{mn}: Maximum daily measured volume of the user g in the month [MWh/day]

Q_{mc}: Maximum daily contracted volume of the user g in the month [MWh/day]

The maximum volume contracted by the user in the month can be estimated taking into account a forecast maximum need of gas. This estimation is based on the assumption that units using gas will be contracting a having a peak demand of 90% of their full capacity per month. The contracted volume is estimated accordingly,

$$Q_{mc}(g) = \frac{24.P_n(g).UF(g)}{\eta(g)} \tag{2.43}$$

Being:

$P_n(g)$: Net power of unit g [MW]

$\mathrm{UF(g)}$: Gas utility factor in the month of unit g

$\eta(g)$: Efficiency of the unit

Finally just the term T_{TD} in 2.30 is missing which is the conduction component of the transmission and distribution toll and is defined as shown below

$$C_C = C_f \cdot Q_{mc} + C_V \cdot Q_e \qquad (2.44)$$

C_f: Fix component of conduction toll [(Euro/MWh/day)/month]

C_v: Variable component of conduction toll [Euro/MWh]

Q_r: Real amount of gas consumed by the unit g [MWh/day]

The fixed component of the last equation is combined with equation 2.37 and both together provide the formulation for the fixed cost associated to the use of natural gas. On the other hand, there is still the variable component of equation 2.44 which will be later used as a variable cost to be used in the model for those units working with natural gas.

It should be kept in mind that important equation to be used in for the natural gas costs calculation are first equation 2.36 for the computation of the fuel operating costs for gas units. In addition, equation 2.45 shown below will be used as an additional variable cost to be used in the economic dispatch to be explained later in chapter 5. Finally, the formulation of the fixed cost calculation will be as shown below in equation 2.46.

$$\log_v(g, d) = \frac{\text{energy}}{\eta} \cdot C_v \qquad (2.45)$$

$$\log_f(g, d) = CR_f + C_{CR} + C_f \cdot Q_{mc} \qquad (2.46)$$

$\log_v$: Variable logistic costs of conduction toll [Euro/day]

$\log_f$: Fixed logistic costs of conduction toll [Euro/day]

2.2.3 Variable costs associated to hydro and pumping power plants

These costs are mainly attached to the energy produced by or for pumping. Mixed pumping units defined as those units with a significant natural contribution in the upper reservoir and pure pumping units were grouped together so the variable costs totally depend on the daily pumping profile [WOTT10]. The same assumption is done for normal hydro power plants in which the cost is considered as the total cost of generating certain energy in a daily basis. The latter assumptions are best understandable considering the following formulation.

$$C_H(d) = f(H) \cdot \text{energy}(H, d) \qquad (2.47)$$
$$C_{pum}(d) = f(pum) \cdot \text{energy}(pum, d)$$

Being:

$f(H) = f(pum)$	O&M factor of the generation and pumping consumption [Euros/MWh]

2.3 Coverage Index formulation

This One of the main issues related with meeting the electricity demand is the evolution of the installed capacity. The system operator has defined a coverage index equal 1.1 which means that there should be a 10% reserve margin with respect to the demand [CNE_11]. The way to compute this index is by taking the peak demand in the both summer and winter seasons of the year and compares it against the expected available installed capacity. Mathematically it is as follows

$$CI = \frac{AP_i}{PD_i} \qquad (2.46)$$

Being:

AP_i	Expected available power in period i[MW]
PD_i	Peak demand in period i [MW]

It will be explored in more detail in chapter 6 what the effects of the different constraints are related with the evolution of the installed capacity in the SEP and its consequences regarding new power plants needed to keep the system within a safe reserve margin.

3. Technology Overview

This chapter is intended to present an overview of the different technologies covered in this work. First, it will be given the most relevant technical parameters needed to achieve the goal of the model and secondly, the expected costs for the calculation of both variable and fixed costs will be presented as well. Many of these parameters have been taking as given by [WOTT2011] while some others have been estimated taking into account an stable scenario given the fact that future estimations are always subject to unpredictable and immeasurable changes.

3.1 Presentation of the power technologies and technical parameters

As it will be shown in more detail in next chapter, the increasing share of special regime generation in the SEP has left less energy to be produced by the traditional thermal generation technologies and this has imposed an additional constraint for them making difficult to have a significant contribution in the generation dispatch. In the Spanish case, there are four main technologies to compete for that residual demand left by the technologies that have priority in the dispatch such as wind energy. The main technologies are:

- Nuclear
- Coal
- CCGT

- Fuel-Gas
- Hydro generation

Indeed, hydro generation power plants are not thermal units but their contribution for meeting the demand and its impact in the variable const calculation for the economic dispatch are part of the constraints for the model which will be dealt with later.

3.1.1 Common technical parameter

There are some technical parameters that were common for all the units under study. The first parameter is the so called minimum stable load which is introduced as a production constraint. It is given as a percentage of the maximum energy that can be produced and will prevent thermal units not to operate below in day. In contrast, the maximum energy produced has been also set up taking into account unplanned outages and O&M works in the units. These values are shown in the table below. For the Elcogas IGCC plant these values were set different as the coal units.

Technology	Minimum stable load factor	Factor of maximum production
Nuclear	0.90	0.970
Coal	0.55	0.912
Fuel-Gas	0.35	0.877
CCGT	0.45	0.917
Elcogas	0.50	0.800

Table 3.1 Factors of minimum and maximum production

Finally, for the fixed capacity payment it is also needed the availability factor but in a monthly basis. For getting so, it was taken the historical availability of nuclear power plants published by the system operator. These figures can be found in Appendix 1.

3.1.2 Nuclear power plants

There are currently in the SEP eight nuclear generation units with total installed capacity of 7,515 MW. Its main primary fuel is the uranium. According with the system operator, this technology has provided the energy to meet 21% of the final electricity demand in year 2010 [REE2010]. For calculation of variable costs, there is not technical parameter associated because those cost are only related to the energy produced by the unit multiplied by factors for both operating fuel and O&M costs. There is a standard fuel recharge schedule for the nuclear power plants which have been defined from the experience observed in the past years and will be used in the economic dispatch. Table below shows an example of such schedule for 2011 and the extended version can be found in Appendix 2.

Nuclear Unit	2011	
	Month	**Days**
Almaraz 1	Abr	40
Almaraz 2	--	--
Cofrentes	Sep	60
Garoña	May	35
Trillo	Jun	35
Vandellós 2	--	--
Asco 2	Oct	40
Asco 1	May	40

Table 3.2 Nuclear units fuel recharge schedule for 2011

There is no expected growth of the installed capacity of nuclear power plants. In fact these technology is currently facing a stronger opposition due to the pressure of the current events and many decision made in the EU might drastically affect the future scenario of the electricity supply.

3.1.3 Coal units

The share of coal technology in the SEP is around 12% with 11,102 MW and a contribution of 8% in 2010 according with [REE_10]. For these units some other parameters are considered. An *emissions quantity factor* is defined for each of the coal units and was taken from an Iberdrola´s source for 2010 and kept constant for the whole period. The later was estimated taking the verified emissions and production estimated by unit.

Unit	CO2 emissions factor [tCO2/MWh]
Puentes 1	0.897
Puentes 2	0.897
Puentes 3	0.897
Puentes 4	0.897
Meirama	0.916

Table 3.3 Emission quantity factor for coal units

In regards to the quadratic adjustment parameters *a* and *b* needed to compute the operating fuel costs in 2.25, these were taken from [WOTT10] who compared the last public data available used when the MLE was the regime in Spain and the data provided by Iberdrola portfolio for all the existing units. These values were already validated and proved to be accurate enough in the energy-operating fuel cost curve (See Figure 3.1 below).

Finally, Elcogas, is an IGCC unit that uses as a fuel a mixture of coal and oil coke to be gasified and then run a CCGT unit so it was treated as such but its outputs were referenced to the coal to have its impact in the economic dispatch.

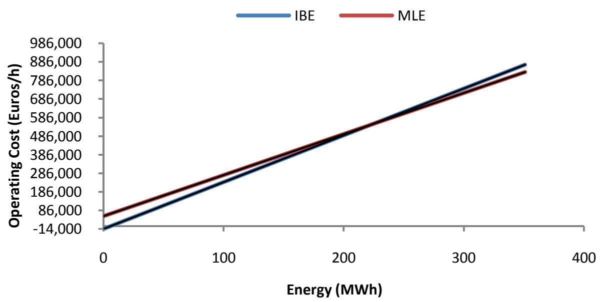

Figure 3.1 Energy vs. Operating costs curve for the coal unit Puentes 2[3]

Coal power plants play an important role in the Spanish electricity market due to the just approved [RD13410] which will impose quotas for some coal units, however this issues will be explored in more detail in the next chapter.

3.1.4 CCGT power plants

Combined cycle units are indeed the most popular technology of the investors in the Spanish sector and it has experienced the most remarkable growth from 8,280 MW in 2005 to 24,831 MW of installed capacity by the end of 2010 reaching a 26% of the total installed capacity and contributing with 23% of the total energy supplied in 2010. Its fuel is the natural gas. It is the technology with the highest availability index during the year and it is reflected in its fixed cost retribution. The emission quantity factor is lower than the values for coal units and fuel-gas units which gives them an advantage when the CO2 variable costs are calculated. The factor for every unit can be seen in Appendix 3 but broadly they are not larger than 0.4 [tCO_2/MWh] which is more than half the factors of coal units in some cases. The quadratic

[3] Graph taken from [WOT2010]

adjustment parameters *a* and *b* defined previously were also taken from Iberdrola portfolio. Finally, the nominal efficiency used for this technology is 52%.

This technology will be kept growing, however it is currently uncertain which the most likely scenario will be. According with the system operator's scenario there will be an additional installed capacity of 5130 MW by the end of 2014; however this figure contrasts with the number set by promoter's scenario which estimates a more conservative increase of 1945 MW for the same horizon.

3.1.5 Fuel – gas power plants

Even though these units have a small contribution to meet the demand, they are still present in the generation mix in Spain and are expected to be in it until 2015 as it will be shown in the analysis of mix generation evolution in next chapter. Currently there are just four power plants left. It has been recently approved by MITC in [RES919811] that San Adrian units 1 and 3 leaving just 806 MW of installed capacity however due to security of supply reason this groups will be still present.

These units use natural gas as their fuel because of the *Integrated Environmental Authorization* issued per unit in their local community which imposes environmental constrains that force them to use gas a fuel. Their technical parameter *a* and *b* were taken in the same way as the other technologies. The efficiency of fuel-gas power units used is 33%.

3.1.6 Hydro power plants

For such power plants no relevant technical parameter was needed. As it will be seen its variable costs depends on the energy produced and an O&M factor which will be exposed in the next section.

3.2 Data on generation costs by technology

A part from the technical parameters described above, other important inputs in this work are the costs needed for the complete calculation of both variable and fixed costs. The estimation of such cost has a slight difficulty mainly because it is the intention of this work to foresee a plausible evolution of such costs. However, it should be kept in mind that future is always uncertain and unexpected events might change even the most accurate forecast. Below it is first presented the most important cost by technology for the fixed cost retribution and then those costs used for the variable cost calculation.

3.2.1 Fixed costs by technology

According with methodology explained in section 2.1.1, there are two main concepts needed for the fixed cost retribution. The recognized investment value and the O&M fixed cost associated to each unit.

For the first, the assumption above mentioned in section 2.2 of considering already amortized all the power plant starting operation before the current market regime was taken due to the lack of accurate information[4]. As a result, the recognized investment values were defined based on Iberdrola professional experience for 2010 and updated yearly.

On the other hand, the capacity payment retribution also compensates the standard O&M fixed cost associated to each unit under the ordinary regime scheme. These costs were taken from Iberdrola experience. Table below shows these two costs for the year 2011.

Technology	Unitary Investment Value [Euros/MW]	O&M Fixed Costs [Euros/MW]
Nuclear	2,763,750	127,875
Coal	1,658,250	33,759
IGCC	810,223	117,032
CCGT	703,500	12,276
Fuel & Gas	633,150	29,667
Hydraulic	1,507,500	11,253

Table 3.4 Fixed costs by technology

Furthermore, due to the environmental constraints imposed by the EU and consequently by the Spanish government, additional investment were and are going to be done. From 2006 several coal units in the SEP invested in a new boiler so they can burn coal with a lower content of sulfur while other units installed desulphurization process both with the right to get a fixed cost retribution according with [MITC279407] which provides the regulatory framework to incentivize investment in new technologies. For the future scenario, it was said in section 202 that a new directive will push coal units to either invest in a new technology to reduce SO_2,

[4]The recognized investments values of generation units done until 1997 were valued by their recognized investment published in 1987 in [MINER87] and updated annually by a standard value which depended on the technology and functioning hours plus an extraordinary investment value. However, this contrasts to the reference model used in this work which does not consider any additional investment. Therefore, it was decided not to take such values.

NO_X, and VOC or decide a cap 17,500 hours connected to the network in a period no longer than 2023. This investment in the SCR can also receive a fixed retribution. For the latter, an additional investment in will be needed to enlarge the lifespan of the coal units but this investment given in Euro/MW will be taken from the recognized investment value for the corresponding year. Below are shown the investment costs and their corresponding O&M costs for the year 2011.

Technology	Unitary Investment Value [Euro]	O&M Fixed Costs [Euros]
Desulphurization process	60,000,000	5,695
Boiler Installation	30,000,000	--
SCR installation	120,000,000	52,570

Table 3.5 Fixed costs of new technologies in 2011

It is important to mention at this point how different costs were estimated for the future scenario. This indeed presents a source of uncertainty mainly because the forward estimation is done using the industrial price index (IPI) and the consumption price index for the (IPC) for the unitary investment and the O&M fixed costs respectively. Indeed the estimation of such indexes is strongly linked to the macroeconomic situation in Spain and so far it is still a challenge for the coming years to tackle the effects of the crisis so a conservative estimation was done to set them in 1.5% for the IPI and 2.5% for the IPC.

3.2.2 Variable costs by technology

There are different costs to be considered for the variable cost calculation. To begin with, O&M variable costs are standardized for the different technologies according with an Iberdrola´s study with a basis in 2010. Then, they are estimated forwards with the forecast IPC minus 100 points. This component is called the O&M cost factor and will be used in that way to obtain the O&M variable cost. For the case of hydro and pumping units, this factor is used to calculate their variable payment because there is no merit mechanism in the dispatch for them and they receive a payment directly linked to the energy the produce or pump. For coal units, logistic costs were also needed to reflect its impact in the fuel average price. The source used for such cost was estimated by Iberdrola in 2010 taking into consideration location of the coal units and all their costs associated such as unloading, storage and transport.

Regarding nuclear power plants and Elcogas, it was stated before that their operation fuel costs are linked with the energy produced and a fuel price factor. In the first case, this factor reflects not only the price of the primary fuel namely uranium but also the cost associated to the safe management of the residues produced. For Elcogas, this factor was taken from a study done for the IGCC technology in Spain [TREVINO] . In both the case the factor is estimated forwards in the same way as the O&M costs. Table below summarizes the aforesaid costs for the year 2011.

Technology	O&M Cost Factor (Euros/MWh)	Logistic Costs (Euros/th)	Fuel Cost Factor (Euros/MWh)
Nuclear	1.2262	N/A	12.240
Coal	1.2262	12.120	N/A
IGCC	1.2262	N/A	12.210
CCGT	2.1458	N/A	N/A
Fuel-Gas	3.5000	N/A	N/A
Hydraulic	2.0402	N/A	N/A

Table 3.6 Main variable costs by technology

Finally, all the LNG logistic components mentioned in the section 2.3.2 were taken from the last published source available by the MITC in [ITC335410] and then estimated forwards using the IPC as a measure of the inflation in Spain. These values and the previous costs can be further seen in Appendix 4.

4. Data collection, assumptions and key milestones

Once the methodology has been explained in Chapter 2 and the different technical and economical parameters were described in Chapter 3, it is time to go into the data gathering and development of the main assumptions and key milestones to be considered in this work. At this point it is important to emphasize once again that this study is done based on public information available relevant to the aim of the work. Several public sources were consulted and compared each other in order to come up with the most plausible scenario and apply the regulated cost structure. In particular cases Iberdrola's professional criterion was used to estimate some values mainly due to the lack of public information to do so.

One of the most important inputs for this work is the electricity demand growth. This sections starts by providing an estimated demand growth which was done based on the public information and the most plausible scenario given the current and expected situation in the electricity sector in Spain. The second important input is the expected special regime generation and its installed capacity growth for the period under study. Later in this work, it will be seen how special regime generation becomes a constraint for the model especially due to the targets imposed be the EU in terms of renewable energy sources. Afterwards, an overview of the evolution of installed capacity in general will be given taking into account the hydro unit currently under construction and also the ones to be decommissioned according with different regulatory constraints.

4.1 Electricity demand growth

The estimation done for the demand growth is the base for achieving the goal of this study. This estimation was done taking several assumptions made mainly by the system operator and CNE in [CNE_11]. It was observed that he electricity demand in Spain had been experienced a steady growth from the year 2000 with an annual average growth of 4.16% until 2009 in which it suddenly falls and register a negative growth of 4.7% leading demand levels observed in 2007. This situation represents a difficulty because the trend observed in the previous years was lost and a new forecasting is subject to uncertainty.

According with the CNE in [CNE_11] the electricity demand would evolve according with the expected economic scenario for the period 2010-2014 which shows a moderated growth in the first 3 three years and then a more pronounced spike in the last year. On the other hand, the document [DC__10] which was launched in December 2010 provides an annual demand growth of 2.3% for the period 2011-2020 with the latest information available. As it is not the intention of this work to develop a model to forecast exactly what the demand will be, it was considered that such estimation provides a plausible scenario to be considered because it reflects the most likely demand growth foreseen by different entities[5].

In order to estimate the annual demand for the whole period, it was taken the total electricity demand provided by REE in 2010 and then the estimated percentage growth was applied. Below it is shown the table with the annual values obtained in the scenario used in this work. These projected values are net demand and already exclude the energy used for auxiliary services in the power plants.

Besides, the estimated values were compared with two additional scenarios proposed by REE in order to validate the assumptions made here. These two scenarios reflect, on the one the hand the most likely demand growth according with current trends and constraints (*central scenario*) and on the other, it proposes the so called *design scenario* which supposes a larger demand growth which could have been done in order not to compromise demand meeting and justify additional investments. Unfortunately, the source consulted [REE_11] do not provide values for the whole period; however it still can be compared with the values in this work. An additional remark about the comparison is that these values are presented as demand after considering pumping consumption and international exchanges mainly because those were the values provided by REE. In order to obtain such values in the scenario presented here, first, it

[5] The annual demand growth estimation takes the economic growth as one of the most influencing factors. In order to calculate the effect of the economic activity on electricity demand, GDP´s annual growth is usually taken into account as well as the demand response to any changes in the economic activity.

was deducted the estimated pumping consumption which will be explained later in this chapter and for the international exchanges it was taken the same projections used by REE in its scenarios leading to the final values in the table below.

Year	Net demand
2011	279,124
2012	286,244
2013	292,333
2014	298,897
2015	305,831
2016	313,730
2017	319,639
2018	327,339
2019	334,966
2020	343,731

Table 4.1 Annual demand projection in GWh

Results show that the projected demand used in this work is in line with the scenarios given by REE who is certainly approaching the issue considering more variables that go beyond of the scope of this work.

Scenario	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Own	265,700	271,892	276,804	281,415	287,403	294,358	299,353	306,140	313,733	322,463
Central	265,000	-	-	-	-	295,000	-	-	-	325,000
Design	-	273,610	-	289,020	-	302,260	-	-	-	330,660

Source. REE, Own Elaboration

Table 4.2 Annual demand projection in GWh

4.1.1 Monthly and daily distribution of the demand

After having the expected annual demand in the SEP, the next step was to distribute it in the year according with the logical pattern observed in the actual demand. To do so, two main steps were done. First of all, the annual demand was distributed in the year according with peaks and valleys observed historically and then these monthly values were again distributed in each months in order to reflect tan actual pattern followed by the demand in a day, however it is important to say that no efficiency effect was included in order to tackle extreme demand values.

The approach used for the monthly distribution was based on the historical consumption patterns observed in the last 5 years. This approach is intended to reflect the different season observed in Spain and it is robust enough to be considered in a future projection and to achieve the goals of this study. Figure 6.1 shows the historical average monthly demand from 2006 to 2010 which were the values used for the whole period. The monthly demand obtained in GWh for each year can be seen in Appendix 5.

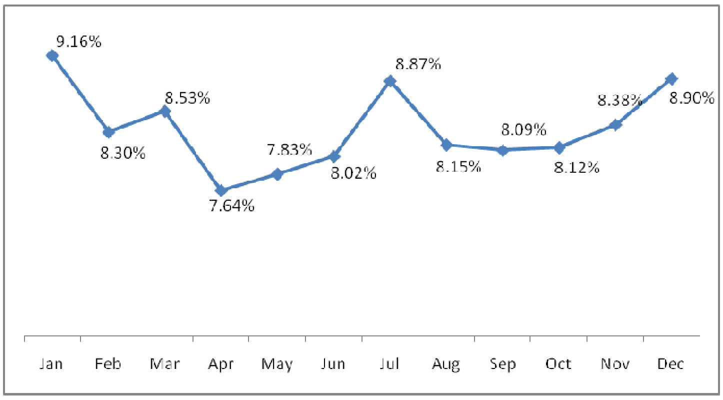

Figure 4.1 Monthly distribution of demand

In regards to the daily distribution, the month was divided in four types of days; type 0 for off days which mostly represent national holydays in Spain shown in table 4.3. Then day type 1 represents the working days and a final division was made between Saturdays with day type 2 and Sundays with day type 3.

Day	2011
New Year's Day	01/01/2011
12th Night	06/01/2011
Good Thursday	21/04/2011
Good Friday	22/04/2011
Labor day	01/05/2011
Asumption Day	15/08/2011
Columbus Day	12/10/2011
All saints	01/11/2011
Constitution Day	06/12/2011
Immaculate Con	08/12/2011
Christmas Day	25/12/2011

Table 4.3 National holidays in Spain

Afterwards, these days were classified in two reference years, 2008 and 2010. The first year was used for the leap years and the second for a normal year but in both the cases the procedure was as follows:

1. First, it was gathered the daily demand for the years 2008 and 2010 from the public information published by the system operator REE.

2. The second step was to obtain the daily percentage of such demand according with the day type and referred to the month that day belongs to. The results are that off and working days as well as Saturdays and Sundays have a different weight each month.

3. Then it is obtained an average of the four types of days for each month leading to have an accurate demand pattern for the whole year. The table below depicts the final result of these three steps for the leap and normal year.

Month	0 - Off		1 - Working		2 – Sat		3 - Sun	
	Leap	Normal	Leap	Normal	Leap	Normal	Leap	Normal
January	0.026	0.026	0.034	0.035	0.030	0.030	0.027	0.028
February	0.000	0.000	0.036	0.037	0.032	0.033	0.030	0.030
March	0.028	0.000	0.034	0.034	0.030	0.030	0.027	0.027
April	0.000	0.030	0.035	0.035	0.030	0.031	0.028	0.028
May	0.026	0.027	0.034	0.034	0.030	0.030	0.027	0.027
June	0.000	0.000	0.035	0.035	0.031	0.030	0.028	0.028
July	0.000	0.000	0.034	0.034	0.030	0.029	0.026	0.027
August	0.027	0.026	0.034	0.034	0.030	0.030	0.027	0.028
September	0.000	0.000	0.035	0.035	0.030	0.030	0.027	0.028
October	0.026	0.028	0.034	0.034	0.029	0.030	0.026	0.028
November	0.028	0.027	0.035	0.035	0.031	0.031	0.028	0.029
December	0.028	0.029	0.034	0.034	0.030	0.031	0.028	0.029

Table 4.4 Percentage of daily demand by day type and month

4. Finally, these percentages are combined with the monthly distribution percentages presented previously and with the projected annual demand in order to obtain the daily demand in MWh as shown in equation below.

$$D_d = D_y \cdot W_m \cdot W_{m,t}$$

With:

D_d: Demand of day d in year n [MWh]

D_y: Projected annual demand in the year n [MWh]

W_m: Demand weight of month m in the year n [%]

$W_{m,t}$: Demand weight of day type t in the month m of the year n [%]

It is important to say that two minor difficulties arose when the method was applied. First of all, the days related to the Easter vary from year to year and are not in the same month as the reference years used and second due to the natural movement of the calendar weekends and working days also vary, leading to unreal demand patterns. However, these inconvenient were adjusted and can be verified on the yearly demand graphs.

4.1.2 Peak demand

Peak demand represents the highest demand in a year and it is usually given for winter and summer. These two values were taken from the estimation done in [CNE_10] for the period 2011-2014 and for the next years of the period it was decided to apply the same growth rate as applied for the annual demand.

Year	Winter		Summer	
	CNE	REE	CNE	REE
2011	46,400	-	42,500	42,200
2012	47,200	47,300	43,200	-
2013	48,400	-	44,300	-
2014	49,650	49,700	45,450	-
2015	50,792	-	46,495	-
2016	51,960	52,200	47,565	47,600
2017	53,155	-	48,659	-
2018	54,378	-	49,778	-
2019	55,629	-	50,923	-
2020	56,908	58,000	52,094	53,000

Table 4.5 Peak demand for winter and summer

The values are compared in the table above with the latest values provided by REE; however, they are not given for the whole period but they still can provide a reference point. Peak demand values are important for the coverage index analysis that will be done later in this work.

4.2 Generation constraints

Once the total expected demand has been estimated, the next step is to find out what the impact of the exiting generation technologies will be in the system and what their share in production will be for the period under study. Two main generation constraint were taken into consideration to estimate the residual demand left for the thermal technologies which the main focus of this work. First, it should be considered the impact of the special regime generation and its contribution to meet the demand and second, the yearly hydro production. These generation constraints will reduce the so called residual demand for the thermal technologies which are the target technologies for the goal of this work.

4.2.1 Expected hydroelectric contribution and pumping

Historically, the hydro generation has represented around 9% of the total energy in the SEP with a particular case in 2010 in which its production was close to 15% because of the rain patter in that year. This production is one of the two important generation constraints for thermal technologies and has to be estimated of the period under study. The first step is to define the hydro production and pumping for the year 2011. Then, the yearly hydro production and pumping will be estimated based on the total installed capacity for each and will be updated according with new hydro and pumping units and afterwards an approach will be defined to distribute monthly both the energy production and pumping.

To begin with, the total hydro production for 2011 has been estimated according with the historical series from 2006 to 2010 and will be assumed to be constant until new capacity is added to the system. This value was set in 27,120 GWh annual. The same criterion was used for pumping and its consumption was fixed in 4,424 GWh annual. Pumping consumption is needed to variable costs and will be further explained in Chapter 5. Afterwards, the distribution of hydro production was made based on Iberdrola experience in hydro forecasting considering an average year and applying a similar approach described below using 2012 as the reference year.

1. The method considers two type of day, working and off days and then it takes three different periods in a day namely peak, shallow and valley and their corresponding hours per day. Finally, the equivalent hours for the month are computed for each period. Table 4.6 depicts this information for January.

Jan 2012						
Day type	Work		22	Off		9
Level within the day	Peak	Shallow	Valley	Peak	Shallow	Valley
Hours per level and day [hr/day]	4	14	6	4	14	6
Hours per level per month [hr]	88	308	132	88	308	132

Table 4.6 Classification of day level and hours in hydro production and pumping

2. Then it is estimated the total capacity in MW producing and pumping in the three different periods and by combining this information with last row of table 4.6 it is possible to obtain the energy produced and pumped in each period and ultimately in the whole month by type of day. Table 4.7 summarizes the main results for January 2012.

Jan-12						
Day type	Work			Off		
Level within the day	Peak	Shallow	Valley	Peak	Shallow	Valley
Pumping consumption [MW]	28	328	1,594	75	569	1,582
Generation [MW]	6,682	4,773	2,114	5,735	3,650	2,023
Total pumping by level and day [MWh]	2,429	100,906	210,375	2,693	71,719	85,440
Production by level and day [MWh]	587,976	1,470,026	279,040	206,478	459,869	109,261
Total pumping by month and day [MWh]	313,711			159,851		
Production by month and day [MWh]	2,337,041			775,608		

Table 4.7 Total energy produced and pumped by month and type of day

3. With this information it is now possible to estimate what will be called intra-month weight by type of day and month weight for both generation and pumping. The first one is calculated just by finding the percentage over the total generation and pumping in each month which will give a percentage for working and off days in the month. The second one is also a percentage of the generation and pumping in the month with respect to the total in the whole year. Table below summarizes this intra-month and monthly weight for the reference year considering that type of day 0 is off day and 1 working day.

Month	Monthly pumping weight	Monthly generation weight	Intra-month pumping weight	Intra-month generation weight	Day type
January	0.1032	0.1073	0.63 0.37	0.72 0.28	1 0
February	0.0737	0.0926	0.66 0.34	0.77 0.23	1 0
March	0.0714	0.1029	0.66 0.34	0.76 0.24	1 0
April	0.0647	0.0897	0.58 0.42	0.68 0.32	1 0
May	0.0670	0.0939	0.66 0.34	0.76 0.24	1 0
June	0.0819	0.0817	0.61 0.39	0.76 0.24	1 0
July	0.0880	0.0698	0.68 0.32	0.77 0.23	1 0
August	0.0800	0.0597	0.69 0.31	0.77 0.23	1 0
September	0.0810	0.0548	0.63 0.37	0.75 0.25	1 0
October	0.0846	0.0583	0.67 0.33	0.77 0.23	1 0

November	0.0859	0.0770	0.63 0.37	0.75 0.25	1 0
December	0.1188	0.1123	0.56 0.44	0.66 0.34	1 0

Table 4.8 Monthly and intra-month weights of hydro generation and pumping

The results obtained above are the departing point to estimate the hydro generation and pumping in a monthly basis and for the whole period. To do so, the monthly weights were taken for both generation and pumping and applied to the annual values set previously of 27,120 GWh and 4,424 GWh respectively. As already said before, annual production is considered constant unless new units are connected to the network. Table below shows the expected hydro production and pumping. It already includes the additional generation and pumping considering the expected installed capacity in the coming years.

Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro production	27,120	27,120	28,502	29,314	29,314	29,314	29,973	30,631	30,631	30,631
Pumping	4,300	4,300	5,793	6,877	6,877	6,877	7,755	8,633	8,633	8,633

Table 4.9 Expected annual hydro production and pumping in GWh

The additional hydro generation and pumping was estimated taking an average operating time of 1,500 hours for the hydro power plants and for the pumping units it was first estimated the average energy pumped according with an utilization factor of 20% out of the total capacity of the plant and then it was considered an efficiency of 75% for the energy produced by such units.

4.2.2 Impact of special regime generation

The EU Directive 2009/28/CE was launched to boost the use of renewable energy source and increase their share by 2020 up to 20% out of the total gross energy consumption [PANER10]. In Spain the goal is that renewable energy sources will have a share of 20% in the final energy consumption as the directive establishes for the EU countries along with a contribution of 10% in the transportation sector. These targets imply a 35% production in the electricity sector coming from renewable energy sources, a target that seems achievable taking into consideration that few years ago the share of such sources was limited to the hydro production and nowadays their production has achieved values above 20% in the Spanish sector.

The above mentioned targets depend on the evolution of the special regime technologies in the SEP and especially on the evolution of renewable energy sources. In 2010 the total installed capacity of especial regime technologies was 36,636 MW and their energy contribution was slightly above 33% according with REE. Out of this amount of energy renewable sources contributed with nearly 20% on the total energy produced without considering the big hydro production. According with this figures and supported by the new PANER 2011-2020, Spain seems to be on the way to achieve the EU target, however this trend has an important impact on the goal of this study because the more energy produced by renewable energy sources, the less residual demand for thermal technologies.

The scenario presented here for the special regime mostly considers the assumptions made in [PANER10] and [CNE_10] as well as other rational assumptions based on the historical evolution of the renewable and non-renewable sources in the special regime. The estimated evolution of the installed capacity is shown below in table 4.6 and it reflects the most rational evolution of the different technologies. PANER is mostly focused on renewable energy sources and as such, it considers than apart from the more mature technologies such as wind and solar, there will be also new capacity from technologies such as geothermal, waves and wind offshore, however given the cost and technological constraints to boost the development of such technologies it was assumed a more conservative growth for such technologies. On the other hand, it was considered that most of the new installed capacity will be in the renewable sources side which will be reflected in their final contribution. The full scenario provided can be found in Appendix 6.

Technology	2011	2013	2015	2017	2019	2020
Wind Onshore	19,956	24,560	27,310	30,098	32,913	34,320
Solar PV	3,990	4,585	5,065	5,688	6,403	6,760
Solar Thermal	1,330	2,375	3,010	3,675	4,425	4,800
Others Renewable	2,870	3,135	3,380	3,800	4,340	4,610
Cogeneration	7,410	8,415	9,210	9,685	10,155	10,390
Others Non Renewable	80	80	90	115	145	160
Total	**35,636**	**43,150**	**48,065**	**53,060**	**58,380**	**61,040**

Table 4.10 Evolution of special regime installed capacity in MW

Given the total installed capacity estimated, the next step is to define energy contributions. It is not the aim of this work to estimate the individual contribution of each technology; instead, it will be presented the total contribution according with its observed trend and the data available in [PANER10] and [CNE_10]. As a result of, and in order to meet the EU target in 2020 it has been defined the following percentages of special regime production and it equivalent energy contribution. In Appendix 6 it can be found the complete set of tables for special regime generation.

Year	%	GWh
2011	34.2	95,462
2012	35.4	101,084
2013	36.6	106,915
2014	37.8	112,960
2015	39.0	119,226
2016	40.2	125,721
2017	41.4	132,452
2018	42.6	139,426
2019	43.8	146,651
2020	45.0	154,134

Tale 4.11 Expected annual contribution of special regime generation

The values above are given in yearly basis, however as this work aims at simulating the SEP in a daily basis, it was necessary to make assumptions on how the total energy would be distributed. To do so, the same approach used for the total demand was adapted here with some differences. It should be kept in mind that special regime generation involves a high production of renewable energy sources and their daily production considering their randomness would be a huge an extensive task to do and would not lead to a more accurate result. Therefore, a simpler way to estimate daily production was by finding the historical monthly distribution of special regime generation and their equivalent in energy produced monthly and then it was equally distributed in each month. This approach is valid enough considering that historical monthly production followed a similar path from 2006 to 2010.

4.2.3 Residual demand for thermal units

The two previous sections represent constraints due to the fact that both of them have special treatment in the generation dispatch. This situation directly affects the aim of this work that is more focused on estimating costs for the thermal units. In terms of economic theory the residual demand is defined as the market demand minus the supply if other firms in the market. This concept is taken here to define what the residual demand, or also known as thermal gap, will be in the period under analysis. In simple terms, the market demand will be equal to the total expected demand by year and the supply to be deducted will be the special regime contribution and hydro generation.

Table below shows the annual residual demand that at first glance seems no to increase in the whole period mainly because of the trend in the contribution of special regime and renewable energy sources.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total demand	279,124	286,244	292,333	298,897	305,831	313,730	319,639	327,339	334,966	343,731
Total Special Regime	(95,462)	(101,084)	(106,915)	(112,960)	(119,226)	(125,721)	(132,452)	(139,426)	(146,651)	(154,134)
Hydro	(27,120)	(27,120)	(28,502)	(29,314)	(29,314)	(29,314)	(29,973)	(30,631)	(30,631)	(30,631)
Total Residual Demand	**156,542**	**158,040**	**156,917**	**156,623**	**157,290**	**158,695**	**157,214**	**157,281**	**157,684**	**158,966**

Table 4.12 Total expected residual demand in GWh[6]

4.3 Evolution of the generation mix

In Section 4.2.2 it was explained the main assumptions for the evolution of the special regime installed capacity and its contribution for meeting the demand. This section deals with the evolution of the technologies in the ordinary regime namely hydro and thermal power plants. It has been said above that the residual demand depends on the production of hydro and especial regime therefore, this will determine to some extent the evolution of the generation mix of thermal technologies.

4.3.1 Hydro, nuclear and fuel-gas power plans evolution

First of all, there are not hydro power plants expected to be decommissioned, instead, there are some new units under construction for the study period. According with the promoters and CNE scenario in [CNE_10], there will be 1,025 MW additional to the exiting hydro capacity in 2013. This new capacity will be pure pumping and mix pumping. Then the next year, there will be 400 MW more of pure pumping. In addition, EON has announced on 09/03/2011 that they will repower the hydro power plant Aguayo adding 1,000 MW in two stages, the first 500 MW are expected to start production in 2017 and the remaining in 2018. Now, this installed capacity growth justifies the hydro contribution calculated in section in the same years as just explained.

In respect to nuclear units, there is only one unit scheduled to be decommissioned namely *Santa Maria de Garona*. This nuclear power plant has been renewing its license to produce

[6] Numbers in brackets have negative sign connotation in order to show them as the energy already supplied

energy since 1971 and almost every year since then, however in 1999 it got a 10 years license even thought the power plant was already close to the 30 years old. Its final allowance to extend its license was given in [ITC178509] and allowed the owner until July 2013 to decommission the facilities considering that it will achieve 40 years old which was the maximum design criterion. Apart from this, there is no plant to either build new nuclear power plants or decommissioning the existing.

Finally, in the beginning of 2011 there was 1,402 MW installed of fuel-gas units, however due to their technical characteristics this power units have not been supplying continuously energy to the system but they were kept in order to warranty security of supply. However on may 26 of this year, it was published the [RES919811] that allows the closure of units San Adrian 1 and 3 without compromising the security of supply of the system and they were already considered decommissioned since the beginning of 2011 taking into consideration that their production was too little. Aceca 1 and Foix 1 are expected to be decommissioned in by the end of 2015. Table below summarizes the evolution for the aforesaid technologies.

Unit	Technology	New [MW]	Decommission [MW]	Date
C.H.B. La Muela II	Hydraulic	850.00	-	01/01/13
UGH. San Esteban		175.00	-	01/01/13
C.H.B. Moralets		400.00	-	01/01/14
C.H.B. Aguayo		500.00	-	01/01/17
C.H.B. Aguayo		500.00	-	01/01/18
Santa Maria de Garona	Nuclear	-	455.20	01/07/13
Aceca 1	Fuel-Gas	-	301.00	12/31/15
San Adrian 1		-	313.00	01/01/11
San Adrian 2		-	283.30	01/01/11
Foix 1		-	505.50	12/31/15

Table 4.13 Evolution of Hydro, nuclear and fuel-gas units

The case of CCGT evolution is actually constrained by the current overcapacity context in the SEP. There is a extensive CCGT portfolio either in planned phase or in the approval process however, the assumption made in regards to its evolution was that new CCGT unit won't be added until the Coverage Index drops below the value set by the system operator.

4.3.2 Regulatory constraints

There are four main regulatory constraints that have an important effect especially on the coal units. The first one is a derived from the EU Directive 2001/80/CE related with environmental issues, the second is the already approved RD134 which is intended to support autochthonous coal mines in Spain. The third one is the Mining Help Plan that is intended to help the lest efficient minis in the country to keep operating until 2018 and finally the future situation for the ELV which is developed ion the Directive 2010/75/EU which was launched on December 17 in 2010. Below it is explained what are the main arguments of such constraints and what the implications are for the goal of this study.

a) Directive 2001/80/CE

In the EU, one of the most important environmental regulations with effects on the electricity sector is the Directive 2001/80/CE. This directive sets emission limitations for some pollutants agents coming from big combustion facilities. Spain has designed its own plan [MITC07] in order to meet the ELV imposes by the EU. This has plan has the goal to reduce NOX, SO2 and VOC and proposes two options to achieve such a goal. The first one consists in grouping firms in bubbles with fixed annual limits in tons of NOX, SO2 and VOC so its use should be rational because it imposes an extra variable cost. The second alternative is that units should be connected to the network more than 20,000 hours as the latest on the 31 of December in 2015. The facilities affected by this regulation are mainly the coal units Lada 3, Cercs 1 and Escucha 1 and the fuel-gas Aceca 1. Therefore its decommissioning is assumed to be imminent in 2015 if they do not reach the maximum hours allowed.

b) RD 134/2010 – SGR and the Mining Help Plan

According with the article 25 of the Law 54/1997, the government can come up with different mechanisms respecting the fundamental of the free market in order to make work those power plants using any kind of autochthonous primary energy up to 15% of the total demand. The RD134 takes this rule from the law and it establishes the so called Supply Guarantee Restriction which is defined as the necessary energy production from units using autochthonous coal and force owner for these kinds of units to buy an annual quota. In addition, the RD134 also establishes the maximum volumes of production per years. The latter is the special interest for the aim of this work, first because by having an annual quota to fulfill with coal units, the residual demand will be even less that it was estimated in the previous section, letting to a excess of installed capacity and second because the application of the RD is currently estimated to be done until 2014. So it will condition the evolution of the thermal units in the SEP. Besides, after the RD134 finished in 2014 these units were assumed to follow the mining help plan in which coal mines are candidates to receive support from the state. These helps are decreasing with the years and they were estimated in terms of energy quotas for the coal units. Table 4.14 shows quotas for both RD134 and then according with the mining plan.

c) Directive 2010/75/EU

Finally, this directive tries in essence to achieve the same goals as the first one. This new directive harmonizes criteria and achieve the best values for the NOX, SO2 and VOC. The two options available for the coal units are first the so called opt-out similar to the previous directive in which units cannot be connected to the network for more than 17,500 hours from the period 2016-2023. And the second option, is with same kind of bubble, however this option implies a huge investment first in a NOx-SCR to reduce anthracite from NOx and also an additional investment to extend the lifespan of the unit.

Unit	RD134	Mining Plan			
	2011-2015	2015	2016	2017	2018
ELCOGAS	1,400,000	1,120,000	840,000	700,000	420,000
Compostilla (2-5)	5,444,250	3,266,550	2,722,125	2,177,700	1,633,275
Teruel (1-3)	6,183,800	4,328,660	3,710,280	3,091,900	1,855,140
Soto de Ribera 3	1,311,940	918,358	787,164	655,970	393,582
Puente Nuevo 3	1,482,090	1,037,463	889,254	741,045	444,627
Escucha	371,860	260,302	223,116	185,930	111,558
Anllares	1,968,150	1,377,705	1,180,890	984,075	590,445
Narcea 3	1,205,880	844,116	723,528	602,940	361,764
La Robla 2	2,035,200	1,424,640	1,221,120	1,017,600	610,560
Guardo 2	1,943,140	1,360,198	1,165,884	971,570	582,942

Table 4.14 Coal units' quotas

These regulatory constraints will determine to some extent the evolution of the coal capacity in the system and will have a huge impact first on the total generation cost and then in the coverage index required. Appendix 7 shows the complete scenario proposed for this work.

5. Model Construction

This Chapter describes the model set up for the calculation of both fixed and variable costs. For the calculation of the fixed cost it was already said that an excel sheet was used following the steps described in the methodology in Chapter 2. The main input data for doing such calculation was also explained in Chapter 3 for the different technologies under study, then it will be explained how this information was processed and what the main result were for the fixed costs calculation. On the other hand, for the variable cost calculation it was built a model in GAMS, which is considered as a reliable language for linear programming problems. In fact, the main goal of the model is to find the cheapest solution for the generation dispatch and as a result, to compute the variable costs associated to such dispatch.

In this context, this chapter will first provide a step-by-step description of the fixed costs calculation in order to understand the excel sheet model, what the main outcomes are and how they are used for the final energy price. Then, Section 5.2 is dealing with the optimization model and its main equations, parameter and constraints.

5.1 Computation of fixed costs

The calculation of fixed costs follows the methodology described in Chapter 2. There were no further adaptations and the method was applied according with the criterion established in [ITC91406]. As already mentioned in Section 2.2.1 fixed retribution are given in three main cases. First, they are given to existing and new power plants in order to guarantee the security of supply and to incentivize investments in new capacity. Second, to new facilities used to improve efficiency, especially to coal units that have invested in new facilities to burn other coal type. And finally, they are given for the expected future investment in new technologies to reduce the GHG emissions.

The relations in the methodology for the fixed costs calculations are given by simple linear equations and its computation has been made using an Excel spreadsheet. The main input data in fixed costs calculations are the unitary investment value of facilities and the maximum O&M costs given in Chapter 3 for the different technologies. The following are steps are intended to provide a description of how the daily fixed costs is obtained.

1. The spreadsheet is organized by the technology and each one has its individual calculation. The values to be introduced are the *unitary investment value* and the *maximum O&M* costs. The first will allow to obtain the annual investment cost and the second will be used to obtain the fixed O&M costs.

2. By adding up the two terms above it is found the annual capacity payment. The latter explains the simplest case in which units are only paid by the power plant itself like the case of nuclear units; however some coal units made investments in new boilers and desulfurization processes which are candidates to get fixed payments. For the case of boilers, the only cost considered was the unitary investment value and for the second both the investment and O&M expenses are taken into account. The latter case also applies for the future investments in SCR. The final annual capacity payment will be the sum of those individual payments where it applies. Finally, this payment is decomposed in seasons according with the table below which indicates a seasonality factor and the months considered in each season. By doing so, there are three different capacity payments namely peak, shallow and valley.

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

Table 5.1 Seasonality factors

3. Finally, these three values obtained in the step before are distributed according with the months they apply and multiplied by a monthly availability factor (See Appendix 1) which will give the daily individual capacity payments.

5.2 Optimization model for variable cost calculation

This section describes the main features of the model used for the variable costs calculations. The main goal of the model is to represent the current and expected composition of the SEP in terms of power installed capacity in order to find the less costly generation dispatch in a ten years period, taking into account the different constrains, assumptions and evolution of the generation mix.

The model will run in a daily base and will match the expected residua demand for each day according with the estimation done in Chapter 4. Because of the huge number of variables managed in the model, simulations were done in separate years starting in 2011. It was assumed for the first year of the simulations that units connected to the network in the first day were the usual base power plants namely nuclear units plus the coal units with a quota to be met. Then the model is run and fixes the economic dispatch in the whole year. These units dispatched in the last days of the year are used for the first day in the following year and so on. The main output of the model is the generation dispatch as well as the daily variable costs; however it will also provide the natural gas consumed by gas units and the CO_2 costs associated to energy produced.

The optimization tool chosen for building the model was GAMS (General Algebraic Modeling System) using the solver CPLEX. GAMS imports data from a input excel sheet and the operates this data in a GDX file and then the results are again exported to the excel sheet automatically. The complete GAMS code can be found in Appendix 8.

5.2.1 Model Indexes and sets

The following are the model indexes used for the formulation of the model.

d	It takes values of 1 to 365 for normal year and 366 for leap years
g	Thermal units in the SEP. The thermal units number varies
t	Technology type. It is used for defining some technical parameters
$nuclear(g)$	Subset of thermal units belonging to nuclear technology
$coal(g)$	Subset of thermal units belonging to coal technology
$gicc(g)$	Subset of ELCOGAS unit
$fuel\_gas(g)$	Subset of thermal units belonging to fuel-gas technology
$ccgt(g)$	Subset of thermal units belonging to combined cycle technology

Input data for indexes and set are mainly the thermal units in the SEP and then they are rearranged internally by GAMS to differentiate them according with the different technologies.

5.2.2 Parameter and variables

These are the second group of important data to achieve the goal of the model. It is first shown the parameters of the system and units, which usually are constant values, and then the main equations.

a) System Parameters

$dem\_te(d)$	Residual demand to be met by thermal technologies [GWh]
$Cp(d)$	Variable O&M costs of hydro generation by day [MEuro]
$Cp(d)$	Variable pumping cost by day [MEuro]
dem_gi	Elcogas target production [GWh]
Tp	Target production of coal units in the RD 134 [GWh]

b) Units' parameters

$Emax(g)$	Maximum energy produced by the unit g in a day [GWh]
$Emin(g)$	Minimum energy produced by the unit g in a day [GWh]
$quadA(g)$	Quadratic adjustment parameter A of generator g [th/h]
$quadB(g)$	Quadratic adjustment parameter B of generator g [th/h.GW]
$f(g)$	O&M cost factor of generator g [MEuro/GWh]
$Qe(g)$	Emissions quantity factor of generator g [MEuro/GWh]
$Af(g)$	Annual free emissions rigths of generator g [tCO_2]
$Prc(g)$	Coal fuel thermie price [MEuro/th]
Prg	Gas fuel thermie price [MEuro/th]
$Effn(t)$	Nominal efficiency of unit g (only for CCGT and fuel-gas units)
$Pf(t)$	Fuel cost price factor [MEuro/GWh]
Pre	CO_2 emission price [MEuro/tCO_2]
Cv	Variable component of LNG conduction toll [MEuro/GWh]

The following list gives the most important variables that are needed to model the system. It includes variables that are part of the outcomes and also variables to represent particular characteristics of the units such as state, star-up and shutdown decisions.

$energy(d, g)$	Energy dispatched by unit g in a day [GWh]
$Cg(d, g)$	Total generation costs of unit g in a day [MEuro]
$Cop(d, g)$	Variable operating costs of unit g in a day [MEuro]
$Com(d, g)$	Variable O&M costs of unit g in a day [MEuro]
$Cco2\_ea(d, g)$	Variable ex-ante emissions costs of unit g in a day [MEuro][7]
$logv(d, g)$	Variable LNG logistic costs of unit g in a day [MEuro]
$Qmn(d, g)$	LNG consumed by unit g in a day [GWh]
$Cco2\_ep(d, g)$	Variable ex-post emissions costs of unit g in a day [MEuro][8]
$u(d, g)$	Binary variable indicating the state of unit g in a day [1,0]
$y(d, g)$	Start-up decision of unit g in a day [1,0]
$z(d, g)$	Shut down decision of unit g in a day [1,0]

5.2.3 Objective function

The objective function represents the target equation in the model. It is either minimized or maximized depending of the formulation or the aim of the model. As already said several times, the aim of the model is to minimize the variable cost in the SEP.

$$min \sum_d \sum_g C_{op}(d,g) + C_{om}(d,g) + C_{CO2\_ea}(d,g) + log_v(d,g) + C_H(d) + C_{pum}(d)$$

Equation 1 Objective function of the model

The first four terms are related with thermal units variable costs already explained. For C_H and C_{pum} it was also said that there is not merit mechanism for them and they are just receiving a variable payment linked to the energy produced and pumped.

5.2.4 Constraints

This set of equation fixes the boundaries for the model. Minimizing the objective function is controlled by a set of constraints that will help to assure that the solution is accurate and meets all the technical and any other limitation.

[7] This variable is used of the economic dispatch and suggests that emissions costs of opportunity of individual units are fully internalized in their recognized costs. Thus, in a market where bids are submitted and compete with each others, the merit order changes and gives incentives to low polluting and more efficient units.

[8] These variable includes the free emission rights assigned by the PNA I and II. In a centralized system this rights ease the transition towards a mechanism where all the generation costs are internalized in the generation prices so this variable is intended to estimate the actual daily cost needed to final energy price.

$$dem\_te(d) = \sum_{g} energy(d,g)$$

Equation 2 Meet thermal demand in day d

$$\mathrm{C_{op}(d,g) = 24 \cdot Pr(g)\left[u(d,g) \cdot a(g) + b(g). \frac{energy(d,g)}{hr(d,g)}\right] \ \forall \ g = coal, gas, CCGT}$$

Equation 3 Operating variable cost for coal, gas and CCGT units

$$\mathrm{C_{op}(d,g) = P_{ff}} \cdot energy(d,g) \ \forall \ g = nuclear, Elcogas$$

Equation 4 Operating variable cost for nuclear and Elcogas

$$\mathrm{C_{om}(d,g) = f(g) \cdot energy(d,g)}$$

Equation 5 Operation and maintenance variable costs

$$\mathrm{C_{CO2\_}ea(d,g) = Qe(g) \cdot energy(d,g) \cdot Pre}$$

Equation 6 Ex-ante CO2 emissions costs

$$\mathrm{logv(d,g) = \frac{energy(d,g)}{\eta(g)} \cdot Cv \ \ \forall \ g = CCGT, gas}$$

Equation 7 Variable LNG logistic costs

The economical constraints are given in equations 2 to 7 and they depict the main terms of the methodology used in this work. The following set represents the main technical constraints considered in this model.

$$energy(d,g) \leq u(d,g) \cdot Emax(g)$$

Equation 8 Upper bound for the energy produced by a unit g in one day

$$\mathrm{energy(d,g) \geq u(d,g) \cdot Emin(g)}$$

Equation 9 Lower bound for the energy produced by a unit g in one day

$$\mathrm{u(d,g) = u(d-1,g) + y(d,g) - z(d,g)}$$

Equation 10 Logic of start up and shut down

$$y(d,g) + z(d,g) \ \leq 1$$

Equation 11 Respect logic of start up and shut down

5.2.5 Singularities

The equations explained above represent the base case for the model. However there are also other particular constraints imposed by either coal quotas or scheduled maintenance for nuclear units. This equations vary from year to year and won´t be put in this section, instead, it will be shown in a table two of the most relevant constraints that change every years.

First of all, the already mentioned coal quotas are part first of the RD 134 which has a scope until 2014, and then a decreasing quota as a result of the Mining Plan until 2018 with a decreasing quota. Table below shows these quotas and the coal units involved.

Unit	RD134	Mining Plan			
	2011-2015	2015	2016	2017	2018
ELCOGAS	1,400	1,120	840	700	420
Compostilla (2-5)	5,444	3,267	2,722	2,178	1,633
Teruel (1-3)	6,184	4,329	3,710	3,092	1,855
Soto de Ribera 3	1,312	918	787	656	394
Puente Nuevo 3	1,482	1,037	889	741	445
Escucha	372	260	223	186	112
Anllares	1,968	1,378	1,181	984	590
Narcea 3	1,206	844	724	603	362
La Robla 2	2,035	1,425	1,221	1,018	611
Guardo 2	1,943	1,360	1,166	972	583
Total	**23,346**	**15,938**	**13,463**	**11,129**	**7,004**

Table 5.2 Quotas for coal units [GWh]

Secondly, the nuclear units have a fuel recharge schedule which can vary according with the season of the year. This schedule has been set according with the table below from 2011 to 2015 trying to represent the actual impact of this power plants being unavailable. The complete schedule can be found Appendix 2.

Nuclear Unit	2011		2012		2013		2014		2015	
	Month	Days	Month	Days	Month	Days	Month	Days	Month	Days
Almaraz 1	Abr	40	Nov	40	-	-	Abr	40	Nov	40
Almaraz 2	-	-	Abr	40	Nov	40	-	-	Abr	40
Cofrentes	Sep	60	-	-	Sep	60	-	-	Sep	60
Garoña	May	35	-	-						
Trillo	Jun	35	Jun	35	Jun	35	Jun	35	Jun	35
Vandellós 2	-	-	May	40	Oct	40	-	-	May	40
Asco 2	Oct	40	-	-	May	40	Oct	40	-	-
Asco 1	May	40	Oct	40	-	-	May	40	Oct	40

Table 5.2 Fuel recharge schedule for nuclear units from 2011-2015

A final remark about the optimization model is related with the units used. It is usually found in the literature that prices or costs are given in Euro/MWh but this would imply to work in such units the whole set of input and outputs in the model. However, because of the huge number of variables and equations generated when the model was run, the order of the objective function was too high and the stability of the model was compromised, leading to long solving times and inaccurate solutions so in order to cope with such issues it was necessary to scale variable to the order GWh and MEuro so the solution found was more reliable and the solving times.

5.3 Calculation of the final generation price

For the calculation of the final energy price, equation 2.2 is used. Then, both results fixed costs calculation and variable costs calculations from the optimization model are combined according with equation 2.1. The following steps describe the way the final energy price is obtained.

1. Fixed costs are exported from the Excel book called FC to a new book usually called GC2011[9]. These costs are placed in a daily basis and for each of the units in the year under study.

2. Variable costs obtained with the optimization model are taken from the input-output Excel book and exported to the same *GC2011* book. In this step, costs are brought back to the order of Euros.

3. The production for each of the units is also exported from the input-output Excel book and placed in a separate sheet in the *GC2011* file. In this step, costs are brought back to the order of MWh.

4. The total generation costs of each unit are computed on a daily basis by adding up fixed costs and variable costs according with equation 2.1 in Chapter 2. This information can be used to know what total costs of the units are in a year and also the total daily costs.

5. Finally, the final generation price is equal the total costs in the day divided by the total generation in that day. This price represents the total average price for the day but in addition to this, it was obtained the final generation price by technology with the same information in order to have an overview of the evolution of prices.

6. A final step was done to have the monthly average prices by taking the average of the prices per month. This result was compared with the hypothetical marginal prices fixed in

[9] The last four digits correspond to the year being simulated

a market mechanism. This price was considered as the price of the marginal generator, excluding the coal units subject to quotas in order to exclude the effect of such imposition.

Next chapter will deal with the analysis and further explanations of the results obtained with the model and Excel sheet.

6. Simulation and Result Analysis

This Chapter will present the most noticeable results achieved with the model. Key aspects to be studied are the expected generation costs based on the assumptions and simplifications made, the evolution of the demand coverage by technology and the impact of special regime generation as well as the expected consequences of the implementation of current regulatory constraints.

6.1 Simulation and Assessment of the model results

This section is intended to assess some of the most interesting result found with the model regarding demand coverage and generation cost for the different technologies It should be kept in mind that most of the results presented are associated to the ordinary regime technologies described in Chapter 3 and any reference done to any other technology will be explicitly pointed out.

6.1.1 Ordinary regime demand coverage and generation costs

The Figure 6.1 below shows the dispatch in 2011. The daily dispatch during the years is consistent with the costs associated to the different technologies. Nuclear units are mostly running a maximum capacity and just stop production during scheduled fuel recharging. Hydro generation is only an input and its dispatch does not depend on the variable cost. Indeed it influences the economic dispatch by imposing an additional variable cost component to the objective function but its daily production has been estimated beforehand which ultimately reduces the thermal gap to be filled. Fuel-gas units are not part of the dispatch and won't appear in the following years either; however they are kept by the system operator due to security of supply issues. The generation dispatch for the whole period is presented in Appendix 9.

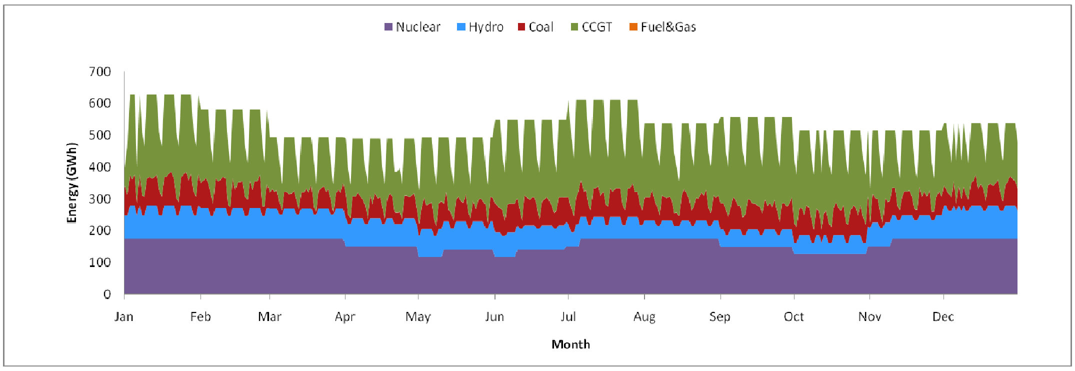

Figure 6.1 Generation dispatch in the year 2011

In regards to coal production, the units being dispatched are the ones subject to the SGC and they normally meet the maximum production required per year in the [RD13410]. CCGT becomes the technology that balances the system in order to keep equilibrium in demand-generation variations. This behavior is observed during the whole simulation period and Figure 6.2 shows how CCGT production is growing through the years, first, because of the slight variations in the residual demand for thermal units second, as a result of unavailability of nuclear power plants and finally it is also absorbing the production of those units being decommissioned, however in the years 2014, 2017 and 2018 this growth is minimized due to new hydro units which can supply at a lower cost than CCGTs.

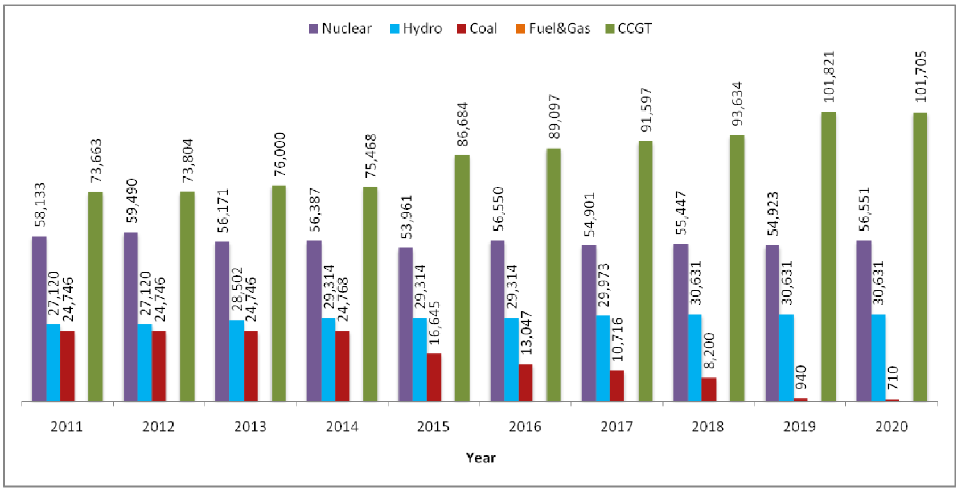

Figure 6.2 Evolution of generation by technology in GWh

The average yearly generation costs under the regulated scheme which includes fixed plus variable costs rises steadily from 65.71 Euro/MWh in 2011 until reaching 78.6 Euro/MWh in 2020 mainly because the assumptions made in all the cost involved follow the same behavior and any unexpected event was considered apart from the already known constraints. However, it should be pointed out that this cost structure is subject to mandatory production of coal units which are increasing considerably the price per MWh. The most stable technology in term of price is the Nuclear which has an average cost of 43.2 Euro/MWh (± 2 Euro/MWh). The cheapest energy is still coming from hydro power plants with an average cost of 40.8 Euro/MWh however it experiences a considerably increases in cost due to new units in 2013, 2017 and 2018. Coal and CCGT technologies appear to be the most expensive however in the economic dispatch, coal production is limited to quota required by the RD134 and this increases its generation costs becoming the most expensive with costs around 105.9 Euro/MWh from 2011 to 2014 and rising exponentially from 2015 onwards. This leaves the remaining energy to CCGT with more stable costs around 88.6 Euro/MWh during the simulation period. The latter is supported by the fact that the generation dispatch is done based on variable costs and the general expectation is that CCGT units will have cheaper variable costs as compared with coal units. This trend can be clearly observed after the end of the RD134 where the coal productions does remain at same level because its competitiveness in terms of variable costs is not enough to compete with CCGT units. Appendiz 10 show generation costs by technology.

The information given above is supported by the total costs computed. Tables 6.1 (a) and (b) show a division between variable and fixed cost for the different technologies in the ordinary regime during the whole simulation period which also gives a clearer idea of what the regulated scheme is about. First, the fuel-gas units are just receiving the fixed cost associated for being available in the system because they are not being dispatched which causes this cost to be present until 2015 when they are decommissioned. It is important to mention that at a first glance these costs are excessive, however the [ITC91410] considers a fixed payment of 50% its last fixed payment after the unit has been completely amortized which applies to all units in the system. Secondly, nuclear units cost confirm that such units usually have a larger fix component than other base load units while their variable cost are the second cheapest in the system just below hydro power plants which have the lowest variable costs. CCGT units represent the largest expense for the system on the one hand, for the large amount of units installed in the system and on the other for the energy supplied. Finally, the coal units show high fixed cost as compared with the energy dispatched for the system. This trend remains in the whole period and is more evident from 2015 onwards where the energy dispatched is even less and the costs reached level above 200 Euro/MWh.

Technology	2011		2012		2013		2014		2015	
	Fix	Variable	Fix	Variable	Fix	Variable	Fix	Variable	Fix	Variable
Nuclear	1,595	739	1,632	809	1,587	772	1,574	782	1,598	756
Coal	1,149	1,356	1,160	1,425	1,160	1,505	1,165	1,569	1,174	1,081
Fuel & Gas	58	0	61	0	61	0	63	0	64	0
CCGT	2,638	3,548	2,644	3,725	2,607	4,007	2,579	4,160	2,552	4,997
Hydro	831	64	841	65	1,036	71	1,113	76	1,112	77
Total	6,270	5,708	6,338	6,024	6,452	6,355	6,493	6,587	6,500	6,911
TOTAL [MEuro]	**11,978**		**12,362**		**12,807**		**13,080**		**13,412**	

Table 6.1(a) Generation cost from 2011 to 2015

Technology	2016		2017		2018		2019		2020	
	Fix	Variable	Fix	Variable	Fix	Variable	Fix	Variable	Fix	Variable
Nuclear	1,629	801	1,648	785	1,674	800	1,700	801	1,734	833
Coal	1,195	886	1,193	755	1,194	607	940	76	991	57
Fuel & Gas	-	-	-	-	-	-	-	-	-	-
CCGT	2,533	5,287	2,498	5,613	2,472	5,911	2,831	6,610	2,994	6,799
Hydro	1,115	77	1,212	82	1,203	86	1,293	87	1,356	87
Total	6,472	7,051	6,552	7,234	6,543	7,405	6,764	7,573	7,075	7,776
TOTAL [MEuro]	**13,523**		**13,786**		**13,948**		**14,337**		**14,851**	

Table 6.1(b) Generation cost from 2016 to 2020

6.1.2 Thermal generation evolution

The evolution of the thermal technologies is linked mainly to regulatory constraints, especially for the coal units which first, according with the RD134 starting in 2011, some units have to meet and annual quota as a compulsory requirement for helping the mining sector in Spain and secondly, are subject to an EU Directive which pushes to close the most pollutant units or invest in the newest technology available to decrease emissions. However, it is important to emphasize that this regulatory constraints were introduced as a variable for the model in order to assess their possible consequences in the system but they cannot be taken as simulation of the actual behavior of the players involved because in reality there are other factors out of the scope of this work that influence their decisions.

First of all, there is a restriction to some units (Cercs, Escucha, Lada 3, & fuel-gas units) not to be connected to the network for more than 20,000 hours before 2015. Apart from Escucha none of these units has a quota to be met during the year, however not even Escucha goes further than 20,000 hours being connected. As a result of this, none of the units was decommissioned for reaching the limit.

The second important regulatory constraint is the so called SGC imposed by RD134. This RD gives annual constant quota to some coal units from 2011 to 2014 (See Table 6.2). The application of this RD is initially set to be finished by the end of 2014. Their production has been constant and every year the goal is reached. It is expected that after finishing SGC the more inefficient unit will be decommissioned. In this context it was considered that from the group of units in the SGC, Compostilla 2, Escucha y Anllares are going to be closed in 2015.

Finally, after completing the SGC there is a new IED Directive issued by the EU in which the existing installations should meet the ELV accordingly either by a limited number of operating hours (17,500) from 2016 to maximum 2023 or by installing the best available technology (SCR) to reduce emissions. The coal units subject to these mechanisms were monitored in order to keep track of both number of hours connected to the network and energy production for those units investing in the new technology.

Coal Unit	2011
	Quota
Escucha	372
Teruel (1-3)	6,184
Guardo 2	1,943
Compostilla (2-5)	5,444
Puente Nuevo 3	1,482
Anallares	1,968
Narcea 3	1,206
Robla 2	2,035
Soto de R. 3	1,312
ELCOGAS	1,400
Total RSG	**23,346**

Table 6.2 Coal units' quotas subject to SGC in GWh

Based on the previous information, some decisions were made in order to meet the regulatory constraint as well as to reflect what in reality could happen with the current information known. First, there were thermal units decommissioned from the installed capacity according with its decommissioning schedule such as Garona in 2013 and the two of fuel-gas units in 2015. Regarding coal units, Compostilla 2, Anllares 1 and Escucha 1 were dismantled in 2015 and 7 more coal units accounting to 1,257.20 MW were decommissioned in 2016. This effect in the coal units is expected to show up as a result of the SGC´s end in 2015 and the more rigorous environmental constraints imposed by the EU-IED. It was observed that after completing the SGC the production rate of coal units falls as a result of a disadvantage in variable costs with CCGT plants. Besides, EU requires that such units should invest in best available technologies to cope with the high rate of emissions from these units, however the investment required is not only for the new technology but also to extend the lifespan of the already aged power plant therefore given the low production rate expected from coal units it is not justified to make such a huge investment. Afterwards it was considered that units in Table

6.3 below are taking the 17,500 hours of maximum production to avoid investment in new technology which might not be profitable for them if they are not being dispatched. From these group, a decision was made to decommission Teruel 1, 2 and 3 and Compostilla 4 in 2018 due to the fact that by that year their operating hours are close to the limit and the residual time cannot be reached in the following year because the mining plan has also finished and in 2019 and 2020 the generation dispatch do not include any minimum production for coal units. On the other hand, just three groups are assumed to make investment in SCR in 2015 which are Litoral 1 and 2 and Barrios mainly because they are the groups being dispatched during the simulation period along with those groups in the SGC.

Coal Unit	2016	2017	2018	2019	2020	Total Hours
	Production [hr]	Production [hr]	Production [hr]	Production [hr]	Production [hr]	
Puentes GR 1	0	0	1,680	240	120	2,040
Puentes GR2	0	0	3,336	48	0	3,384
Puentes GR 3	0	0	0	216	0	216
Puentes GR 4	0	0	0	144	2616	2,760
Meirama	0	0	0	72	0	72
Teruel 1	6,192	5,640	3,240	-	-	15,072
Teruel 2	6,600	5,400	3,672	-	-	15,672
Teruel 3	6,408	5,112	4,080	-	-	15,600
Guardo 2	3,912	3,456	1,992	528	0	9,888
Lada 4	0	0	0	144	0	144
Compostilla 4	8,016	7,032	1,104	-	-	1,6152
Compostilla 5	1,248	24	4,176	0	0	5,448
Pte nuevo 3	3,432	2,760	1,680	48	0	7,920
Narcea 2	0	0	0	528	312	840
Narcea 3	2,472	1,944	1,152	96	0	5,664
Robla 1	0	0	0	624	168	792
Robla 2	4,104	3,336	2,448	696	0	10,584
Soto 3	2,760	2,328	1,248	72	0	6,408
Abono 1	0	0	0	984	0	984
Pasajes	0	0	0	192	0	192

Table 6.3 Coal units subject to 17,500 hours production

In summary, the change in thermal installed capacity is driven by scheduled decommissioning of old power plants as well as assumptions of what in reality would happen when the existing thermal capacity is not being dispatched. This massive *take away* of thermal units during the period represents a total 4,833 MW decommissioned which will bring the need of installing new capacity to keep the system in safe reserve margins. For doing so, additional hydro capacity already schedule in 2013, 2017 and 2018 was taken for coverage index calculation. In addition, a decision was made based on the desirable IC to install an additional 4,000 MW of CCGT in the years 2019 and 2020. Figure 6.3 below summarizes the units to be decommissioned in solid color while the additions are depicted in gradient color bars. In addition to CCGT unit installed in 2019 and 2020, it is included the new hydro power plants.

Unit	Technology	New [MW]	Decommission [MW]	Year
San Adrian 1	Fuel-Gas	-	313	2011
San Adrian 2	Fuel-Gas	-	283	2011
C.H.B. La Muela II	Hydraulic	850	-	2013
UGH. San Esteban	Hydraulic	175	-	2013
Santa Maria de Garona	Nuclear	-	455	2013
C.H.B. Moralets	Hydraulic	400	-	2014
Escucha	Coal	-	142	2014
Compostilla 2	Coal	-	138	2014
Anllares	Coal	-	347	2014
Aceca 1	Fuel-Gas	-	301	2015
Foix 1	Fuel-Gas	-	506	2015
Cercs	Coal	-	146	2015
Guardo 1	Coal	-	143	2015
Lada 3	Coal	-	148	2015
Compostilla 3	Coal	-	323	2015
Puertollano	Coal	-	206	2015
Narcea 1	Coal	-	52	2015
Soto de Ribera 2	Coal	-	239	2015
C.H.B. Aguayo	Hydraulic	500	-	2017
C.H.B. Aguayo	Hydraulic	500	-	2018
Compostilla 4	Coal	-	341	2018
Compostilla 5	Coal	-	341	2018
Elcogas	Coal	-	296	2018
CCGT 1-7	CCGT	2,800	-	2019
CCGT 8-10	CCGT	1,200	-	2020
Total [MW]		**6,425**	**4,721**	

Table 6.4 Scenario of thermal units decommissioned and new additions

It should be emphasized that the table above only depicts the power plants to be decommissioned from the system as well as the additions. There is a base installed capacity of 56,573 MW which is not expected to change in the simulation period.

6.1.3 CO_2 Emissions scenario

It is important to assess how the CO_2 emission is evolving in this study. Initially, with a larger contribution of coal units in the daily dispatch, the CO_2 emission are close to the 50 million tons and even on 2013 and 2014 they go up a little. Afterwards in the following years the total emissions start decreasing as well as the average emissions in term of MWh produced. The latter is initially around 0.27 tCO_2/MWh because the emission factor of coal units is far larger than the one of CCGT and its contribution increases the overall emission in the systems, however, as soon as the SGC finishes in 2014 the CCGT technology takes the energy previously produced by coal units and this factor starts decreasing until reaching 0.20 tCO_2/MWh in 2020 as can be seen in the figure below.

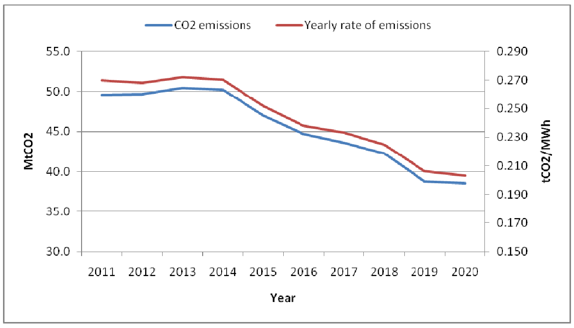

Figure 6.4 Total CO_2 emissions and rate of emissions

6.2 Assessment on the impact of the special regime and regulatory constraints

The imposed targets by the EU to its member countries related to renewable energy use imply a new challenge for markets. For the period under study, the assumption of special regime generation has consequences for the ordinary regime technologies. According with the estimation done in Chapter 4, the evolution of the special regime technologies in terms of installed capacity will be reflected in its production especially from renewable energy sources. In the Table 6.4 below it can be seen the limited demand growth for the ordinary regime technologies mainly because renewable energy sources are expected to meet slightly more than 30% of the total demand by 2020. The consequence of such problem goes straight to the thermal technologies namely CCGT and coal which are the most expensive technologies in the system and have to compete for the residual demand after nuclear production. Under a regulated cost structure this would be a problem for those units with the highest costs because they won´t be dispatched, on the other hand, in a market mechanism this will force companies to redesign strategies mainly because there will be a new supply - demand balance and the energy production expectations decrease for those technologies putting an additional risk in the long term fuel contracts usually signed by power plants using gas which typically have a take or pay clause.

Along with the above mentioned constraint, the imposition of minimum generation for coal units in the SGC has impact on the generation costs and even though the SGC´s quota represents around 12% of the remaining energy, the overall generation costs tend to rise considerably. These costs in the SEP were compared to marginal cost of the last unit dispatched in the day but without taking into account the coal units forced to produce because this wouldn´t reflect the actual price under a market mechanism. Figure 6.5 below shows the trend in generation cost during the simulation period and the marginal cost which is lower than the average costs under the regulated scheme. In regards with the average generation cost in the system it can be observed that the regulated costs rise in the whole period, especially from 2011 to 2014 when the SGC is applied. Afterwards, the costs seem to be more stable from 2015 to 2017 most likely because the model finds less production constraints and is able to dispatch more uniformly with the increases in costs just reflected by the increase in variable costs. Regarding the marginal costs used in the study, it is clear that they are far below the overall generation costs mainly because these prices belong to the cheapest CCGT units and, in some cases, to coal units.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Ordinary Regime	**183,662**	**185,159**	**185,418**	**185,938**	**186,604**	**188,009**	**187,187**	**187,913**	**188,315**	**189,597**
SR-Renewable	56,619	61,718	65,625	70,297	75,985	81,882	87,336	93,012	99,576	106,377
SR- Non Renewable	38,843	39,366	41,290	42,662	43,241	43,839	45,116	46,414	47,075	47,757
Special Regime	**95,462**	**101,084**	**106,915**	**112,960**	**119,226**	**125,721**	**132,452**	**139,426**	**146,651**	**154,134**
Total	**279,124**	**286,244**	**292,333**	**298,897**	**305,831**	**313,730**	**319,639**	**327,339**	**334,966**	**343,731**

Table 6.4 Expected contribution of special and ordinary regime in GWh

It can be observed too in the figure that from 2011 to 2017 there is a huge difference between the regulated cost and the marginal costs. This effect has mainly a twofold explanation. On the one hand, as a result of the economical crisis in 2009 the electricity demand felt dramatically as was mentioned in Chapter 4 leading to a four years lag in the demand growth therefore the regulated costs are absorbing this lag and the marginal costs reflects an overcapacity in the system. On the other hand, it also reflects the imposed production by the RD134 for the coal units which are considerably more expensive according with the scenario in this work. These extra costs can be seen in Table 6.5.

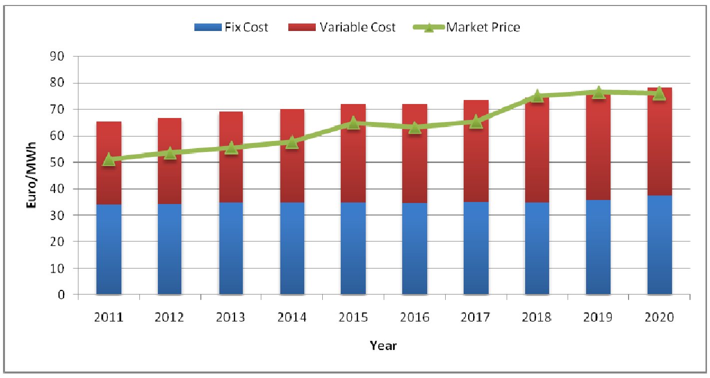

Figure 6.5 Average generation cost compared with marginal costs

In terms of total cost for the system, it can be computed in a simple way what the total cost for establishing coal quotas in the SGC. For the sake of simplicity the estimation is done taking the marginal cost and the average generation costs of the units in the SGC considering that each of them has its own cost. Then the total costs were computed taking the annual production for the annual SGC´s quota of 23,346 GWh.

	2011	**2012**	**2013**	**2014**
Maginal Cost [Euro/MWh]	51.07	53.58	55.49	57.72
SGC costs [Euro/MWh]	80.29	83.39	86.03	88.56
Δ Price [Euro/MWh]	29.22	29.81	30.54	30.83
Total [MEuro]	**682**	**696**	**713**	**720**

Table 6.5 Summary of additional costs due to SGC

The total extra costs incurred for dispatching the units in the SGC is considerably high and accounts to slightly more than 50% of the total fixed costs paid to the whole coal units. This is indeed a burden not only for the end user but also for the system and generation companies which are expected to be affected in their production and ultimately in loss of profit. By giving incentives to some technologies and reducing the residual demand even more, the system prices drops affecting ultimately to both hydro and nuclear unit who could have obtained a better price if this constraint is not present.

6.3 Impact on Coverage Index (IC)

Once the previous analysis is done, it is possible to use such results to evaluate the expected availability of the installed capacity. In section 2.4 it was said that a safe parameter established by the system operator is the so called Coverage Index which is just a relation between the available capacity and the peak demand.

The first step is to formulate a medium scenario in order to compute the coverage index. The scenario has been based on [CNE_10] and is valid based on the fact that it is an average of the two opposite scenarios proposed by the system operator, the design scenario which includes measures to increase efficiency and the trend scenario which do not include measures at all. This scenario considers the peak demand in winter which has been historically larger than peak in summer therefore the coverage in summer is assumed to be guaranteed when the CI in winter is within safe values. On the other hand, the available installed capacity has been calculated yearly based on the availability factor by technology and evolution of the power plants in the next years given in Chapter 4.

Table 6.6 summarizes the different assumption made in regards to net available capacity and evolution of the installed capacity as well as the rational decisions made with respect to decommissioning of coal power plants not being dispatched in the last years of the simulation

Year	Net Installed Capacity Available	Base Scenario [MW]	CI	Additional MW required	CI corrected
2011	58108	46,400	1.25	0	--
2012	58178	47,200	1.23	0	--
2013	59543	48,400	1.23	0	--
2014	60246	49,650	1.21	0	--
2015	60056	50,792	1.18	0	--
2016	58517	51,960	1.13	0	--
2017	59318	53,155	1.12	0	--
2018	60120	54,378	1.11	0	--
2019	**58616**	**55,629**	**1.05**	**2,800**	**1.10**
2020	**58968**	**56,908**	**1.04**	**4,000**	**1.10**

Table 6.6 Coverage Index evolution in the SEP

It can be seen how CI drops considerably in 2015 and 2016 when there is a massive decommission of coal units and by 2018 the index is close the minimum required. REE, show it its prevision an According with the assumption made regarding coal units being decommissioned, in 2019 the index is already below 1.1 and it is necessary to install new capacity in the system. To do so it was considered the installation of CCGT units which have been proved to be efficient in the last years; however, this assumption depends on the willingness to invest by market players. Another scenario might be that no investment is expected for those years and the system operator wouldn't allow those coal units to be dismantled.

On the other hand, it can be said that the CI clearly reflect the lack of investment in backup technologies. It was said in Chapter 4 that special regime technologies are expected to grow considerably in the coming years, however most these technologies do not provide security to the systems for peak hours, in fact, it is in the other way around, they are expected to have back up technologies.

Finally, in order to validate the results above, they were contrasted with the scenarios provided by the system operation, REE. Unfortunately, it doesn't provide information about the units being decommissioned in the study period but still its results are comparables with the ones obtained in this work. REE does consider two different scenarios so called trend scenario and design scenario and in both the cases in only provides values for 2012, 2014, 2016 and 2020. For the design scenario it gives a CI of 1.18, 1.15, 1.11 and 1.07 respectively which would imply and additional power capacity of 1,800 MW in 2020 and for the trend scenario it provides a CI of 1.15, 1.11, 1.08 and 1.02 with additional firm capacity in 2019 and 2020 of 1,300 MW and 4,500 MW respectively. Even thought the assumptions made by REE are not explicitly shown, these values can be contrasted with the ones obtained in this work which shows similar trends.

7. Final Conclusions

During the whole simulation period it was observed that the daily dispatch during the years is consistent with the costs associated to the different technologies. Nuclear units are base load during the whole year and CCGT is the technology that balances the system to keep equilibrium because of demand-generation variations. In terms of costs, the most stable technology is the Nuclear while the technology with the lowest costs is hydro. Coal and CCGT technologies appear to be the most expensive however in the economic dispatch, coal production is limited to quota required by the RD134 and this increases its generation costs becoming the most expensive from 2011 to 2014 and rising exponentially from 2015 onwards. Fuel-gas units are just receiving the fixed cost associated for being available in the system because they are not being dispatched which causes this fixed cost to be present until 2015 when they are decommissioned. With respect to the evolution of the generation mix, there were thermal units decommissioned from the installed capacity according with its decommissioning schedule such as Garoña in 2013 and assumption of what in reality would happen when the existing thermal capacity is not being dispatched and the owners decide closure which represented a total 4,833 MW decommissioned. The implication of such hypothesis go straight o the Coverage index which will be affected and start dropping compromising the minimum safe level required by the system operator.

Whit the above mentioned results it is possible to draw interesting conclusions. Available, affordable and acceptable are the three important goals for EU in the following years. It was said before that availability can be measured in terms of security of supply meaning reliability in the system and capacity available to meet the demand. The first point relates more to quality of electricity however the most important aspect in this work is related with capacity available. On the other hand, affordability is seen from the point of view of lower prices for end users and even though this work is not intended to predict prices, the generation costs estimated can be used as a reference. Finally, acceptability has become important for achieving EU target by 2020 and the role of the electricity sector in achieving such goal is very important. This final Chapter is developed to draw conclusion about the results obtained in this work and how they can either boost or constraint the achievement of such triple A goals in Spain.

7.1 Assessment of security of supply

Ensuring security of supply requires opportune, diverse correctly sized and placed investments in all segments of the value chain specially in the generation and transmission sectors. The reality is that there are major barriers for investment, including policy and market uncertainties. In the currently weak economic environment, with low and uncertain energy demand growth, generating technologies with high fixed generation costs and long lead times such as nuclear facilities may struggle.

As aforesaid, an important factor in the choice of the technologies for meeting electricity demand is certainly the generation costs associated to it; however investment decisions in new capacity not only consider such costs but also take into account other risks and uncertainties such as regulatory risks. Firms usually use the best information available and are always trying to gain additional information through the time in order to reduce uncertainty and risk. By having the expected generation costs, investors have an additional tool to assess whether their projects have good values and can go ahead in new investments. In the end, investments decisions in specific technologies depend on a number of different factors such as generation costs however policy uncertainties might act as a barrier specially when there are not long term commitments and the policy framework is more focus on fulfilling short term needs.

In Spain, the current scenario puts market players with different risk and uncertainties. According with [CNE_10] there are currently in the portfolio for new capacity in Spain around 14,000 MW of CCGT technology without starting operation date mainly because investors do not find profitable to build new facilities under the current scenario in the SEP. Table below provides a qualitative assessment of the different technologies reviewed in this work from of the point of view of risk and uncertainties in the process of investment decision making. Nuclear technology will be facing a huge pressure in the coming years due to, one the recent nuclear disaster in Japan and two the announcement made by Germany about closing its nuclear power plants by 2022 which certainly puts some pressure in other EU countries. Coal and fuel-gas units are not only under pressure for CO_2 emission prices but also are subject to fuel prices and to some extend to regulatory pressures specially coal technology. Finally, even though CCGT technology is subject to a high risk in fuel prices it is still the preferred technology by investors.

Technology	Unit size	Fixed costs	Variable costs	Fuel costs	CO2 Emissions	Regulatory framework
Nuclear	Very large	High	Medium	Low	Nil	Very high
Coal	Larga	High	Low	High	Very high	High
Fuel-Gas	Large	High	Low	High	Very high	High
CCGT	Medium	Low	Low	High	Medium	Low
Hydro	Very large	Very high	Very Low	Nil	Nil	Medium

Table 7.1 Qualitative assessment of generating technologies risks

From table above it is important to highlight that regulatory framework risk includes also a social factor which can be considered to inside the regulatory framework. Nuclear technology is always under pressure due to safety issues while coal and fuel-gas have to face environmental rejection. Finally, even though hydro power plants can bring other benefits a part from electricity, they also face rejection due to the flooding needed which can affect local communities.

Nowadays the electricity Spanish sector is experiencing an over capacity due to the drop in demand in 2009. It is expected according with this analysis that for the next 5 years the Coverage Index will be still far above the minimum required by the system operator but the increasing share of renewable energy sources will affect this trend because of the fact that these technologies do not provide security to the system.

On the other hand, after 2015 the massive decommissioning of thermal power units specially coal and fuel-gas units will challenge the system in order to incentivize investment and maintain the capacity available in safe levels. Both coal and fuel-gas units are subject to two main constraints, firstly, there are environmental pressure on pollutant technologies and many of these power plants will have to close because of that and secondly, these technologies could invest in cleaner solutions to cope with emissions and also to extend the lifespan of the unit, however their low load factor observed in the simulations do not provide incentive to recover investments. So far, the signals needed from investors are weak and need to be strengthened especially considering that coal units are expected to experience an intensive program of decommission after 2014.

Finally, it should be said that investment in new capacity is just one of the options to assure electricity supply however there are also other options that have to be exploited such as improvements in interconnection with neighboring countries and improvements in efficiency in the end-use or the so called demand response effect which certainly is hard to measure and boost.

7.2 Social impact of generation costs

Under current market mechanism in Spain prices are set by the marginal cost of the last dispatched technology and any forecast under this mechanism is not an easy task to do for a 10 years future period. This mechanism is the so called day-ahead market in which market players send bids with the amount of energy they want to sell and the price which reflects the cost of opportunity for the firm. This means that average costs thus cannot be automatically recovered from consumers, and therefore companies and operators must accept the risk associated with the energy produced that can be either limited or for some units even without production at all which ultimately affects the companies' revenue. On the other hand, in the traditional context the regulated electricity prices charged to consumers reflected the long term average cost of producing electricity. The methodology used in this work to estimate the generation costs does consider a final generation price which meets all the cost associated for producing an MWh by a power unit.

Using the estimated generation costs in this work it is possible to make assumptions about the expected electricity prices under a market mechanism considering these results as a reference model. First, it can be said that if under the current market mechanism the decisions are made taking into account the different constraints in a rational way, prices should reflect those conditions. Secondly, it was assumed that under a market mechanism, marginal costs of the last unit dispatched should be similar and reflect the market prices of electricity therefore the marginal cost of the last unit dispatched in the model was used in order to have a reference to compare. Saying that, the marginal costs observed and the average generation cost differ in the first years of the period due to the fall in demand in 2009 which causes a disequilibrium in the capacity available and the demand and there should be a time to balance supply-demand. Another cause for this effect is the quota imposed for coal units which displaces more efficient and cheaper technologies. The latter two reasons might explain why the investments plans in the SEP are stopped and might compromise the well functioning of the market.

Another important issue which can affect the future prices is the decisions made by the owners. Assumption of decommissions were made just considering regulatory constraints such as the end of RD134 or the European Directive IED which forces certain units to close, however, there are several units in the system that are not producing energy in the whole year and there is no certainty whether owners will close the power plants because no incentive is given to them. The consequences of such a problem are that in an *only energy market* these units can affect considerably the price because as they are not producing and when required they can set a extremely high price in order to recover investments. This is problem that the regulator should take into account by assuming the risk of such situation considering the evolution of the coverage index or copping with the problem by implementing an capacity payment mechanism to avoid closure of units without production. On the other hand, the assumptions made regarding investments decisions were mainly focus on new CCGT units; however it can also be argued that due to the low production of several units in the system, a feasible solution could be gas turbines for those periods where peak demand requires more capacity.

7.3 Meeting the EU-2020 targets

There are various and complementary reason to boost the growth of renewable energy sources in Spain and all over Europe. Firsts, an important incentive to issue new policies has been to reduce the environmental impact of energy usage at both levels local and global. There is also an additional incentive for replacing fossil fuels sources related with the Europe´s dependency on foreign sources which it is expected to grow in the following decade. Further arguments in favor of renewable energy sources are the economic and social benefits they bring along such as job creation, industry development and ultimately the positive structural effects in on regional economics. In addition, the growing integration of Europe continues to highlight the importance of the future development of these sources.

For Spain, the development of renewable energy sources has brought several positive effects. In addition to the aforesaid mentioned, emissions reduction, a technological change and distribution generation are other benefits of renewable energy sources. Although deployment of such technologies has implied a greater economic effort in Spain, this has been tackled with the time not only considering that more experience is gained in the learning curve but also thanks to the considerable improvements made in the technical management of the system integrating storage techniques such as pumping power plants. Besides, in Spain the goal is also focus in the long term considering that initial investments in renewable sources were high, however these costs have been going down lately and it is expected that in the long term the benefits surpass the current costs.

The bet of Spain for renewable energy sources has already been recognized by the EU as an example of proper design for renewable energy promotion which is reflected with the volume of electricity achieved in 2009 when their contribution was around 25% out of the total electricity generated and around 12.2% out of the total energy consumed in the country [PANER10]. The most noticeable share in Europe is the one from wind energy in which Spain reported 19,149 MW in 2009 and became the second country with the largest installed capacity only below Germany which had 25,777 MW in the same year.

In regards to back up needs, the large scale deployment of generation from renewable resources implies challenges in security of supply issues. An expected generation system with an increasing share of intermittent renewable energy sources will require the development of a market for the provision of ancillary services, with significantly larger volume and variety than present systems. Thermal power plants will have to manage these burdens and will have a additional market where they can recover part of their costs. Flexible thermal generation and the expansion of energy storage will be integral to this market.

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Appendixes

Appendix 1 – Factors of availability

Month	Power Availability (%)				
	Nuclear	Coal	Fuel & Gas	CCGT	Hydro
January	94.8	89.3	81.4	95.5	100.0
February	95.0	87.6	85.4	95.2	100.0
March	87.8	87.1	86.7	91.8	100.0
April	82.6	82.9	85.8	90.4	100.0
May	75.4	84.0	85.0	88.2	100.0
June	76.3	86.6	84.0	94.9	100.0
July	83.1	88.0	85.3	97.5	100.0
August	92.1	88.3	82.2	95.0	100.0
September	90.7	88.3	80.3	91.4	100.0
October	86.5	84.8	83.9	87.5	100.0
November	81.4	84.8	75.9	88.2	100.0
December	86.4	89.8	76.4	94.6	100.0

Appendix 2 – Standard nuclear fuel recharge schedule

Nuclear Unit	2011		2012		2013		2014		2015	
	Month	Days	Month	Days	Month	Days	Month	Days	Month	Days
Almaraz 1	Abr	40	Nov	40	-	-	Abr	40	Nov	40
Almaraz 2	-	-	Abr	40	Nov	40	-	-	Abr	40
Cofrentes	Sep	60	-	-	Sep	60	-	-	Sep	60
Garoña	May	35	-	-	End	End				
Trillo	Jun	35	Jun	35	Jun	35	Jun	35	Jun	35
Vandellós 2	-	-	May	40	Oct	40	-	-	May	40
Asco 2	Oct	40	-	-	May	40	Oct	40	-	-
Asco 1	May	40	Oct	40	-	-	May	40	Oct	40

Nuclear Unit	2016		2017		2018		2019		2020	
	Month	Days	Month	Days	Month	Days	Month	Days	Month	Days
Almaraz 1	-	-	Abr	40	Nov	40	-	-	Abr	40
Almaraz 2	Nov	40	-	-	Abr	40	Nov	40	-	-
Cofrentes	-	-	Sep	60	-	-	Sep	60	-	-
Garoña										
Trillo	Jun	35	Jun	35	Jun	35	Jun	35	Jun	35
Vandellós 2	Oct	40	-	-	May	40	Oct	40	-	-
Asco 2	May	40	Oct	40	-	-	May	40	Oct	40
Asco 1	-	-	May	40	Oct	40	-	-	May	40

Appendix 3 – Emissions Quantity factors

Coal Technology

Generation Unit	Emission Quantity Factor [tCO2/MWh]										Free Certificates [tCO2]	
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011	2012
PUENTES_GR_1	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	1,054,994	1,054,994
PUENTES_GR_2	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	1,055,595	1,055,595
PUENTES_GR_3	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	1,052,889	1,052,889
PUENTES_GR_4	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	0.8969	1,054,693	1,054,693
MEIRAMA	0.9156	0.9156	0.9156	0.9156	0.9156	0.9156	0.9156	0.9156	0.9156	0.9156	1,618,787	1,618,787
CERCS	1.0055	1.0055	1.0055	1.0055	1.0055	--	--	--	--	--	0	0
ESCUCHA	0.958	0.958	0.958	0.958	--	--	--	--	--	--	301,196	292,426
TERUEL_1	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	1,332,872	1,332,872
TERUEL_2	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	1,332,494	1,332,494
TERUEL_3	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	0.9602	1,329,845	1,329,845
GUARDO_1	0.9558	0.9558	0.9558	0.9558	0.9558	--	--	--	--	--	282,823	274,587
GUARDO_2	0.9466	0.9466	0.9466	0.9466	0.9466						1,036,730	1,036,730
LADA_3	0.9410	0.9410	0.9410	0.9410	0.9410	--	--	--	--	--	306,977	306,977
LADA_4	0.9410	0.9410	0.9410	0.9410	0.9410						723,142	723,142
COMPOSTILLA_2	0.9377	0.9377	0.9377	0.9377	--	--	--	--	--	--	404,887	403,745
COMPOSTILLA_3	0.9377	0.9377	0.9377	0.9377	0.9377	--	--	--	--	--	946,493	943,823
COMPOSTILLA_4	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	998,604	995,787
COMPOSTILLA_5	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	0.9377	997,141	994,327
PTE_NUEVO_3	0.8815	0.8815	0.8815	0.8815	0.8815	0.8815	0.8815	0.8815	0.8815	0.8815	929,809	929,809
PUERTOLLANO	0.9174	0.9174	0.9174	0.9174	0.9174	--	--	--	--	--	527,272	511,919
ANLLARES	1.0451	1.0451	1.0451	1.0451	--	--	--	--	--	--	1,042,306	1,011,956
NARCEA_1	0.9350	0.9350	0.9350	0.9350	0.9350	--	--	--	--	--	120,620	119,958
NARCEA_2	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	359,297	357,328
NARCEA_3	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	0.9733	809,176	804,741

ROBLA_1	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	687,876	681,077
ROBLA_2	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	0.9498	925,246	916,101
SOTO_R_2	0.9310	0.9310	0.9310	0.9310	0.9310	--	--	--	--	--	580,028	575,487
SOTO_R_3	0.9310	0.9310	0.9310	0.9310	0.9310	0.9310	0.9310	0.9310	0.9310	0.9310	839,381	832,810
ABONO_1	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1,069,899	1,069,899
ABONO_2	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1.1729	1,677,469	1,677,469
ELCOGAS	--	--	--	--	--	--	--	--	--	--	--	--
PASAJES	0.9447	0.9447	0.9447	0.9447	0.9447	0.9447	0.9447	0.9447	0.9447	0.9447	0	0
LITORAL_1	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	1,658,622	1,658,622
LITORAL_2	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	0.8762	1,672,307	1,672,307
BARRIOS	0.8487	0.8487	0.8487	0.8487	0.8487	0.8487	0.8487	0.8487	0.8487	0.8487	1,631,146	1,631,146

CCGT Technology

Generation Unit	Emissions Quantity Factor [tCO2/MWh]										Free certificates [tCO2]	
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011	2012
ACECA_IB_3	0.3891	0.3891	0.3891	0.3891	0.3891	0.3891	0.3891	0.3891	0.3891	0.3891	297,645	297,645
ARCOS_IB_1	0.3952	0.3952	0.3952	0.3952	0.3952	0.3952	0.3952	0.3952	0.3952	0.3952	300,739	300,739
ARCOS_IB_2	0.3914	0.3914	0.3914	0.3914	0.3914	0.3914	0.3914	0.3914	0.3914	0.3914	288,393	288,393
ARCOS_IB_3	0.3940	0.3940	0.3940	0.3940	0.3940	0.3940	0.3940	0.3940	0.3940	0.3940	636,903	636,903
CASTELLON_IB_3	0.3815	0.3815	0.3815	0.3815	0.3815	0.3815	0.3815	0.3815	0.3815	0.3815	602,990	602,990
CASTELLON_IB_4	0.3805	0.3805	0.3805	0.3805	0.3805	0.3805	0.3805	0.3805	0.3805	0.3805	649,044	649,044
CASTEJON_IB_2	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	292,384	292,384
ESCOMBRERAS_IB_6	0.3955	0.3955	0.3955	0.3955	0.3955	0.3955	0.3955	0.3955	0.3955	0.3955	618,818	618,818
SANTURCE_IB_4	0.3866	0.3866	0.3866	0.3866	0.3866	0.3866	0.3866	0.3866	0.3866	0.3866	306,091	306,091
BAHIA_VIZCAYA	0.3703	0.3703	0.3703	0.3703	0.3703	0.3703	0.3703	0.3703	0.3703	0.3703	604,017	604,017
TARRAGONA_POWER	0.4396	0.4396	0.4396	0.4396	0.4396	0.4396	0.4396	0.4396	0.4396	0.4396	550,795	550,795
SANROQUE_END_2	0.3710	0.3710	0.3710	0.3710	0.3710	0.3710	0.3710	0.3710	0.3710	0.3710	310,363	310,363
BESOS_END_3	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	318,771	318,771
TARRAGONA_END	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	307,844	307,844
COLON_END_4	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	302,518	302,518
PUENTES_END_5	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	635,307	635,307

CC_ESCATRON_2	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	146,720	146,720
ACECA_UF_4	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	0.3725	284,197	284,197
C_GIBRALTAR_UF_1	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	300,739	300,739
C_GIBRALTAR_UF_2	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	300,739	300,739
PALOS_UF_1	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	300,926	300,926
PALOS_UF_2	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	300,926	300,926
PALOS_UF_3	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	300,926	300,926
SABON_UF_3	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	304,084	304,084
SAGUNTO_UF_1	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	358,426	358,426
SAGUNTO_UF_2	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	328,558	328,558
SAGUNTO_UF_3	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	0.3836	238,951	238,951
CASTEJON_HC_1	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	303,514	303,514
CASTEJON_HC_3	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	300,000	300,000
SOTO_DE_RIBERA_4	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	328,304	328,304
SANROQUE_GN_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	300,412	300,412
BESOS_GN_4	0.3720	0.3720	0.3720	0.3720	0.3720	0.3720	0.3720	0.3720	0.3720	0.3720	309,086	309,086
ARRUBAL_GN_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	300,340	300,340
ARRUBAL_GN_2	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	300,340	300,340
CARTAGENA_GN_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	321,657	321,657
CARTAGENA_GN_2	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	321,657	321,657
CARTAGENA_GN_3	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	321,657	321,657
PLANA_DE_VENT_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	348,682	348,682
PLANA_DE_VENT_2	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	305,098	305,098
MALAGA_GN_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	251,439	251,439
AMOREBIETA_ESB	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	604,693	604,693
CASTELLNOU_ELB_1	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	606,518	606,518
ESCOMBRERAS_AES_1	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	298,527	298,527
ESCOMBRERAS_AES_2	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	298,527	298,527
ESCOMBRERAS_AES_3	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	298,527	298,527
ESCATRON_EON_3	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	596,962	596,962
BESOS_END_5	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	0.3675	163,339	163,339
PUERTO_BCN_GN_1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	250,000	250,000
PUERTO_BCN_GN_2	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	250,000	250,000
SOTO_DE_RIBERA_HC_5	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	0.3580	250,000	250,000
ALGECIRAS_EON_3	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	0.3756	250,000	250,000
CCGT_1	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_2	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_3	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--

CCGT_4	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_5	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_6	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_7	--	--	--	--	--	--	--	--	0.3580	0.3580	--	--
CCGT_8	--	--	--	--	--	--	--	--	--	0.3580	--	--
CCGT_9	--	--	--	--	--	--	--	--	--	0.3580	--	--
CCGT_10	--	--	--	--	--	--	--	--	--	0.3580	--	--

Fuel-Gas Technology

Generation Unit	Emissions Quantity Factor [tCO2/MWh]					Free Certificates [tCO2]	
	2011	2012	2013	2014	2015	2011	2012
ACECA_1	0.6274	0.6274	0.6274	0.6274	0.6274	0	0
FOIX_1	0.6274	0.6274	0.6274	0.6274	0.6274	0	0

Appendix 4 – Components of LNG costs

LNG Component	Unit	2011	2012	2013	2014	2015
Cfr	(cts/kWht/day)/month	1.7323	1.9055	1.9532	2.0020	2.0520
Cvr	cts/kWht	0.0103	0.0113	0.0116	0.0119	0.0122
Cfu	Euros/ship	30,013	33014	33,840	34,686	35,553
Cvu	cts/kWht	0.0060	0.0066	0.0068	0.0069	0.0071
Cvs	cts/MWht/day	2.8907	3.1798	3.2593	3.3407	3.4243
Cfus	cts/kWht	0.0411	0.0452	0.0463	0.0475	0.0487
Cvus	cts/kWht	0.0375	0.0413	0.0423	0.0433	0.0444
Cfc	(cts/kWht/day)/month	0.9582	1.0540	1.0804	1.1074	1.1351
Cf	(Euros/MWht/day)/month	30.783	33.8613	34.7078	35.5755	36.4649
Cv	Euros/MWht	0.753	0.8283	0.8490	0.8702	0.8920

LNG Component	Unit	2016	2017	2018	2019	2020
Cfr	(cts/kWht/day)/month	2.1033	2.1559	2.2098	2.2651	2.3217
Cvr	cts/kWht	0.0125	0.0128	0.0131	0.0135	0.0138
Cfu	Euros/ship	36,442	37,353	38,286	39,244	40,225
Cvu	cts/kWht	0.0073	0.0075	0.0077	0.0078	0.0080
Cvs	cts/MWht/day	3.5099	3.5976	3.6876	3.7797	3.8742
Cfus	cts/kWht	0.0499	0.0512	0.0524	0.0537	0.0551
Cvus	cts/kWht	0.0455	0.0467	0.0478	0.0490	0.0503
Cfc	(cts/kWht/day)/month	1.1634	1.1925	1.2223	1.2529	1.2842
Cf	(Euros/MWht/day)/month	37.3765	38.3110	39.2687	40.2504	41.2567
Cv	Euros/MWht	0.9143	0.9371	0.9606	0.9846	1.0092

LNG Constants		
%GNL	%	0.74
Cmship	MWht	650343
AD	day	8.2

Appendix 5 – Historical and project demand per month

Historical generation per month (MWh & %)												
	2006		2007		2008		2009		2010		Average	
Month	**Monthly demand [MWh]**	**Percentage**	**Monthly demand [MWh]**	**Percentage**	**Monthly demand [MWh]**	**Percentage**	**Monthly demand [MWh]**	**Percentage**	**Monthly demand [MWh]**	**Percentage**	**Historical Average Consumption [MWh]**	**Historical Average Percentage**
January	24,241,657	9.25%	24,347,178	8.97%	25,212,660	9.07%	24,987,172	9.49%	24,626,920	9.03%	**24,683,117**	**9.16%**
February	22,201,661	8.47%	21,720,528	8.00%	23,536,184	8.46%	21,498,385	8.17%	22,842,897	8.37%	**22,359,931**	**8.30%**
March	22,953,733	8.76%	23,103,718	8.51%	23,813,798	8.56%	21,310,992	8.10%	23,840,104	8.74%	**23,004,469**	**8.53%**
April	18,787,062	7.17%	20,701,400	7.63%	22,888,179	8.23%	19,642,443	7.46%	21,022,549	7.70%	**20,608,327**	**7.64%**
May	20,541,051	7.84%	21,640,564	7.97%	21,811,218	7.84%	20,166,906	7.66%	21,319,778	7.81%	**21,095,903**	**7.83%**
June	21,391,409	8.17%	21,551,833	7.94%	22,313,066	8.02%	21,370,340	8.12%	21,475,840	7.87%	**21,620,498**	**8.02%**
July	23,819,436	9.09%	23,395,179	8.62%	24,188,325	8.70%	23,708,811	9.01%	24,420,297	8.95%	**23,906,410**	**8.87%**
August	20,850,518	7.96%	21,696,247	7.99%	22,534,962	8.10%	22,336,586	8.48%	22,442,786	8.23%	**21,972,220**	**8.15%**
September	21,543,346	8.22%	22,009,233	8.11%	22,070,458	7.94%	21,582,179	8.20%	21,811,676	7.99%	**21,803,378**	**8.09%**
October	21,075,075	8.04%	22,589,272	8.32%	22,285,803	8.01%	21,526,658	8.18%	21,998,908	8.06%	**21,895,143**	**8.12%**
November	21,272,425	8.12%	23,873,988	8.80%	23,149,509	8.32%	21,784,115	8.27%	22,892,032	8.39%	**22,594,414**	**8.38%**
December	23,308,510	8.90%	24,812,477	9.14%	24,302,718	8.74%	23,343,169	8.87%	24,159,608	8.85%	**23,985,296**	**8.90%**
Total Annual	261,985,883	100.00%	271,441,617	100.00%	278,106,880	100.00%	263,257,756	100.00%	272,853,395	100.00%	269,529,106	100.00%

Projected Generation per month [MWh]										
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**
Month	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**	**Monthly projected demand [MWh]**
January	25,571,377	26,159,519	26,761,188	27,376,695	28,006,359	28,650,505	29,309,467	29,983,585	30,673,207	31,378,691
February	23,155,110	23,687,678	24,232,495	24,789,842	25,360,008	25,943,289	26,539,984	27,150,404	27,774,863	28,413,685
March	23,819,857	24,367,714	24,928,171	25,501,519	26,088,054	26,688,079	27,301,905	27,929,849	28,572,236	29,229,397
April	21,321,818	21,812,220	22,313,901	22,827,121	23,352,145	23,889,244	24,438,697	25,000,787	25,575,805	26,164,048
May	21,844,569	22,346,994	22,860,975	23,386,777	23,924,673	24,474,940	25,037,864	25,613,735	26,202,851	26,805,516
June	22,395,386	22,910,480	23,437,421	23,976,482	24,527,941	25,092,084	25,669,202	26,259,593	26,863,564	27,481,426
July	24,766,634	25,336,267	25,919,001	26,515,138	27,124,986	27,748,861	28,387,085	29,039,988	29,707,907	30,391,189
August	22,757,109	23,280,523	23,815,975	24,363,742	24,924,108	25,497,363	26,083,802	26,683,730	27,297,456	27,925,297
September	22,586,767	23,106,263	23,637,707	24,181,374	24,737,546	25,306,509	25,888,559	26,483,996	27,093,128	27,716,269
October	22,676,039	23,197,588	23,731,132	24,276,949	24,835,318	25,406,531	25,990,881	26,588,671	27,200,211	27,825,815
November	23,393,017	23,931,056	24,481,470	25,044,544	25,620,569	26,209,842	26,812,668	27,429,360	28,060,235	28,705,620
December	24,841,338	25,412,689	25,997,181	26,595,116	27,206,804	27,832,560	28,472,709	29,127,582	29,797,516	30,482,859
Total Annual	**279,129,023**	**285,548,991**	**292,116,617**	**298,835,300**	**305,708,511**	**312,739,807**	**319,932,823**	**327,291,278**	**334,818,977**	**342,519,814**

Appendix 6 – Evolution of special regime technologies

Expected evolution of Special Regime [MW]										
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Wind Onshore	19956	23190	24560	25930	27310	28690	30097.5	31505	32912.5	34320
Solar PV	3990	4370	4585	4800	5065	5330	5687.5	6045	6402.5	6760
Solar Thermal	1330	2030	2375	2720	3010	3300	3675	4050	4425	4800
Others Renewable	2870	3040	3135	3230	3380	3530	3800	4070	4340	4610
Cogeneration	7410	7860	8415	8970	9210	9450	9685	9920	10155	10390
Others Non Renewable	80	80	80	80	90	100	115	130	145	160
Total	**35,636**	**40,570**	**43,150**	**45,730**	**48,065**	**50,400**	**53,060**	**55,720**	**58,380**	**61,040**

Expected SR-Renewable contribution			
Year	**%**	**MWh**	**GWh**
2011	20.3%	56,619,153	56,619
2012	21.6%	61,717,907	61,718
2013	22.5%	65,624,936	65,625
2014	23.5%	70,297,367	70,297
2015	24.9%	75,985,195	75,985
2016	26.2%	81,881,969	81,882
2017	27.3%	87,335,779	87,336
2018	28.4%	93,011,934	93,012
2019	29.7%	99,575,938	99,576
2020	31.1%	106,376,513	106,377

Expected SR-Non Renewable contrubution			
Year	**%**	**MWh**	**GWh**
2011	13.9%	38,842,973	38,843
2012	13.8%	39,366,436	39,366
2013	14.1%	41,289,746	41,290
2014	14.3%	42,662,376	42,662
2015	14.1%	43,241,124	43,241
2016	14.0%	43,839,434	43,839
2017	14.1%	45,116,409	45,116
2018	14.2%	46,414,151	46,414
2019	14.1%	47,074,774	47,075
2020	13.9%	47,757,403	47,757

Appendix 7 – Evolution of thermal technologies

1 – Units operating

2 – Units operating and subject to maximum production of 17,500 hours

3 – Units operating and subject to investment in SCR

0 – Units decommissioned in the beginning of the year

Unit	Age in 2010	GSR	20.000 hours	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Cofrentes				1	1	1	1	1	1	1	1	1	1	1	1	1
Almaraz 1				1	1	1	1	1	1	1	1	1	1	1	1	1
Almaraz 2				1	1	1	1	1	1	1	1	1	1	1	1	1
Garona 1				1	1	1	0	0	0	0	0	0	0	0	0	0
Trillo				1	1	1	1	1	1	1	1	1	1	1	1	1
Vandellos 1				1	1	1	1	1	1	1	1	1	1	1	1	1
Asco 1				1	1	1	1	1	1	1	1	1	1	1	1	1
Asco 2				1	1	1	1	1	1	1	1	1	1	1	1	1
Puentes 1	40			1	1	1	1	1	2	2	2	2	2	2	2	2
Puentes 2	40			1	1	1	1	1	2	2	2	2	2	2	2	2
Puentes 3	40			1	1	1	1	1	2	2	2	2	2	2	2	2
Puentes 4	40			1	1	1	1	1	2	2	2	2	2	2	2	2
Compoestilla 2	51	1	-	1	1	1	1	0	0	0	0	0	0	0	0	0
Compostilla 3	44	1	-	1	1	1	1	1	0	0	0	0	0	0	0	0
Compostilla 4	35	1	-	1	1	1	1	1	2	2	2	2	2	2	2	2
Compostilla 5	35	1	-	1	1	1	1	1	2	2	2	2	2	2	2	2
Litoral 1	31			1	1	1	1	1	3	3	3	3	3	3	3	3
Litoral 2	19			1	1	1	1	1	3	3	3	3	3	3	3	3

Teruel 1	37	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Teruel 2	37	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Teruel 3	37	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Soto 2				1	1	1	1	1	0	0	0	0	0	0	0	0
Soto 3	32	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Abono 1	42			1	1	1	1	1	2	2	2	2	2	2	2	2
Abono2	31			1	1	1	1	1	3	3	3	3	3	3	3	3
Barrios1	31			1	1	1	1	1	3	3	3	3	3	3	3	3
Puente Nuevo 3	35	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Puertollano 1	44			1	1	1	1	1	0	0	0	0	0	0	0	0
Cercs 1			1	1	1	1	1	1	0	0	0	0	0	0	0	0
Escucha 1		1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Meilla 1	36			1	1	1	1	1	2	2	2	2	2	2	2	2
Anllares 1	34	1	_	1	1	1	1	0	0	0	0	0	0	0	0	0
Narcea 1	51			1	1	1	1	1	0	0	0	0	0	0	0	0
Narcea 2	47			1	1	1	1	1	2	2	2	2	2	2	2	2
Narcea 3	31	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Robla 1	45			1	1	1	1	1	2	2	2	2	2	2	2	2
Robla 2	31	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Pasajes 1	49			1	1	1	1	1	2	2	2	2	2	2	2	2
Guardo 1	52			1	1	1	1	1	0	0	0	0	0	0	0	0
Guardo 2	32	1	_	1	1	1	1	1	2	2	2	2	2	2	2	2
Lada 3			1	1	1	1	1	1	0	0	0	0	0	0	0	0
Lada 4	35			1	1	1	1	1	2	2	2	2	2	2	2	2
Elcogas 1		1	_	1	1	1	1	1	1	1	1	0	0	0	0	0
Aceca 1			1	1	1	1	1	1	0	0	0	0	0	0	0	0
Sand Adria 1			1	1	1	1	1	1	0	0	0	0	0	0	0	0
Sand Adrian 3			1	1	1	1	1	1	0	0	0	0	0	0	0	0
Fox 1				1	1	1	1	1	0	0	0	0	0	0	0	0
CICLOS				1	1	1	1	1	1	1	1	1	1	1	1	1

Appendix 8 – GAMS Code

```
$Title Unit Commitment: Spain 2011
$onecho > UC2011in.txt
dset=g        rng=GeneratorsTable_X1!A2:A97    rdim=1
par=uo        rng=GeneratorsTable_X1!A2        rdim=1
par=Emax      rng=GeneratorsTable_X1!C2        rdim=1
par=Emin      rng=GeneratorsTable_X1!E2        rdim=1
par=quadA     rng=GeneratorsTable_X1!G2        rdim=1
par=quadB     rng=GeneratorsTable_X1!I2        rdim=1
par=f         rng=GeneratorsTable_X1!K2        rdim=1
par=Qe        rng=GeneratorsTable_X1!M2        rdim=1
par=Af        rng=GeneratorsTable_X1!O2        rdim=1
par=Prc       rng=GeneratorsTable_X1!Q2        rdim=1
par=dem_te    rng=DailyTable_X2!J2             rdim=1
par=Ch        rng=DailyTable_X2!N2             rdim=1
par=Cp        rng=DailyTable_X2!P2             rdim=1
$offecho

$call gdxxrw.exe SEP_UC.xlsx @UC2011in.txt
$gdxin SEP_UC.gdx

SETS

d             Time periods (days)
/ d1*d365 /
g(*)          Generators
$load g
t             Technology type
/ n, c, fg, cc, gi /
r             Coal Units in the RD134 2010
/ Sri3, Nrc3, All1, Robl2, Comp, Ter, Guad2, Pnn3, Ech1/

** Statement of dynamic sets

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

PARAMETERS

uo(g)         Initial status of generator g at the beginning of the first day {1 0}
Emax(g)       Maximum energy of generator g [GWh]
Emin(g)       Nominal minimum technical energy [GWh]
quadA(g)      Quadratic adjust parameter of generator g [th per h]
quadB(g)      Quadratic adjust parameter of generator g [th per h.GW]
f(g)          O&M costs factor of generator g [Euros per GWh]
Qe(g)         Emissions quantity factor of generator g [tCO2 per GWh]
Af(g)         Annual free assigned certificates of generator g [tCO2]
Prc(g)        Coal ex-ante fuel thermie price 1 semester [MEuros\th]
dem_te(d)     Thermal generation in day d [GWh]
```

```
Ch(d)          Variable hydro generation operation and maintenence costs in the day d [MEuros]
Cp(d)          Variable pumping costs in the day d [MEuros]
$load uo Emax Emin quadA quadB f Qe Af Prc dem_te Ch, Cp
$gdxin

EFFn(t)                 Nominal efficiency [%]
/ fg 0.33, cc 0.53 /
dem_gi                  GICC production objective [GWh]
/ 1400.000 /
Pf(t)                   Fuel cost average price factor [MEuros per GWh]
/ n 0.01224, gi 0.01221 /
Cv                      Variable component of LNG conduction toll [MEuros\GWht]
/ 0.0007530 /
Prg                     Gas fuel thermie price [MEuro\th]
/0.00000002650/
Pre                     CO2 emission price [MEuro\tCO2]
/0.00001410/
Tp                      Target Production of Coal Units in the RD134 [GWh]
/Sri3 1311.940, Nrc3 1205.880, Robl2 2035.200,
 Comp 5444.250, Ter 6183.800, Guad2 1943.140,
 Pnn3 1482.090, All1 1968.150, Ech1 371.860/

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

POSITIVE VARIABLES
energy(d,g)     Energy dispatched by generator g in the day d [GWh]
Cop(d,g)        Variable operating (fuel) costs of the unit g in the day d [MEuro]
Com(d,g)        Variable operation and maintenance costs of the unit g in the day d [MEuro]
Cco2_ea(d,g)    Variable ex-ante emissions costs of the unit g in the day d [MEuro]
logv(d,g)       Variable LNG logistic costs of the unit g in the day d [MEuro]
Qmn(d,g)        LNG consumed by generator g in the day d [GWht]
Sri3(g)         Soto de Ribera 2 annual production [GWh]
Nrc3(g)         Narcea 3 annual production [GWh]
Robl2(g)        Robla 2 annual production [GWh]
Guad2(g)        Guardo 2 annual production [GWh]
Pnn3(g)         Puente Nuevo 3 annual production [GWh]
Comp(g)         Compostilla annual production [GWh]
Ter(g)          Teruel annual production [GWh]
All1(g)         Anllares annual production [GWh]
Ech1(g)         Escucha annual production [GWh]
;

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(d,g)          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_Cg(d,g)           Total generation costs
E_TeDem(d)          Meet thermal demand in day d
E_gicc              Meet the annual GICC demand
E_coal              Meet the annual coal 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_Qmn(d,g)          LNG consumed
E_Sri3(g)           Soto de Ribera 2 annual production
E_Nrc3(g)           Narcea 3 annual production
E_Robl2(g)          Robla 2 annual production
E_Guad2(g)          Guardo 2 annual production
E_Pnn3(g)           Puente Nuevo 3 annual production
E_Comp(g)           Compostilla annual production
E_Ter(g)            Teruel annual production
E_All1(g)           Anllares annual production
E_Ech1(g)           Escucha annual production
;


* Formulation of equations:

** Objetive function


E_fobj..
    fobj =e= SUM[(d,g), (Cop(d,g) + Com(d,g) + Cco2_ea(d,g) + logv(d,g) + Ch(d) +
Cp(d))/100000];

E_TeDem(d)..
    dem_te(d) =e= SUM(g,energy(d,g));

*=====================================================================
** Variable costs computation (for economic dispatch). There is an ex-ante computation for
CO2 emissions cost
*=====================================================================

E_Cop(d,g)..
        Cop(d,g) =e= 24  * (Prg $[fuel_gas(g) OR ccgt(g)] + Prc(g) $[coal(g)])
                   * (u(d,g) * quadA(g) + quadB(g) * (energy(d,g) / 24)) +
                   [(Pf('n')$[nuclear(g)] + Pf('gi')$[gicc(g)]) * energy(d,g)];

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

E_Cco2_ea(d,g)..
         Cco2_ea(d,g) =e= Qe(g) * energy(d,g) * Pre;
```

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

E_coal..
    SUM[(d,coal), energy(d,coal)] =g= 23346.320;


*** Respect units energy boundaries
E_Emax(d,g)..
        energy(d,g) =l= u(d,g)*Emax(g);

E_Emin(d,g)..
        energy(d,g) =g= u(d,g)*Emin(g);


*** Respect units operating logic: shut-down and start-up
E_Acop(d,g)..
        u(d,g) =e= u(d-1,g)$[ORD(d) > 1] + uo(g)$[ORD(d) = 1] + y(d,g) - z(d,g);

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


*** Respect coal target production of units in RD134

E_Sri3(g)..
    Sri3(g) =e= SUM[d, energy(d,'SOTO_R_3')];

E_Nrc3(g)..
    Nrc3(g) =e= SUM[d, energy(d,'NARCEA_3')];
E_Robl2(g)..
    Robl2(g) =e= SUM[d, energy(d,'ROBLA_2')];
E_Guad2(g)..
    Guad2(g) =e= SUM[d, energy(d,'GUARDO_2')];
E_Pnn3(g)..
    Pnn3(g) =e= SUM[d, energy(d,'PTE_NUEVO_3')];
E_Comp(g)..
    Comp(g) =e= SUM[d, energy(d,'COMPOSTILLA_2')] +
               SUM[d, energy(d,'COMPOSTILLA_3')] +
               SUM[d, energy(d,'COMPOSTILLA_4')] +
               SUM[d, energy(d,'COMPOSTILLA_5')];
E_Ter(g)..
    Ter(g) =e= SUM[d, energy(d,'TERUEL_1')] +
                SUM[d, energy(d,'TERUEL_2')] +
                SUM[d, energy(d,'TERUEL_3')];
E_All1(g)..
    All1(g) =e= SUM[d, energy(d,'ANLLARES')];
E_Ech1(g)..
    Ech1(g) =e= SUM[d, energy(d,'ESCUCHA')];
```

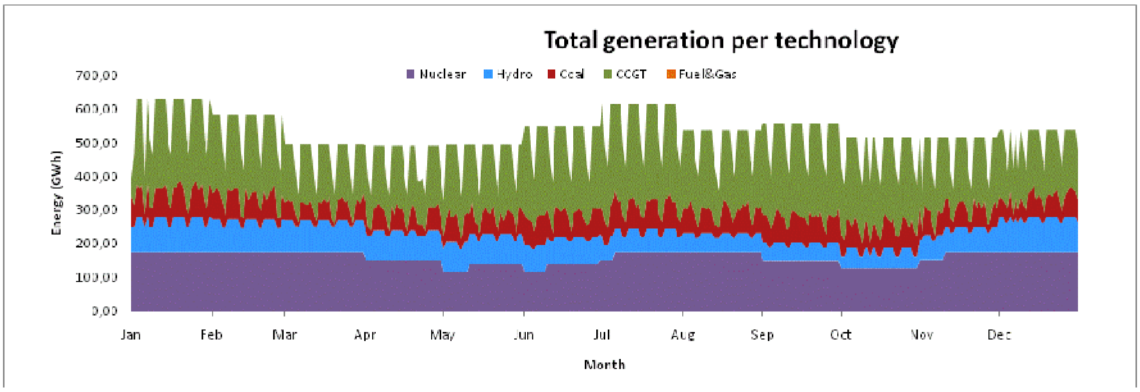
```
*=======================================================================
** Variable costs computation (for energy prices computation)
*=======================================================================

E_Cco2_ep(d,g)..
          Cco2_ep(d,g) =e= [Qe(g) * energy(d,g) - Af(g) / 8760] * Pre;

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

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)];

*=======================================================================
***Initial dynamic sets
y.fx('d1',g) = 0;
z.fx('d1',g) = 0;


***Respect unavilability for fuel recharge in nuclear units
u.fx(d,'COFRENTES')$[(ORD(d)>=244) AND (ORD(d)<=303)] = 0;
u.fx(d,'ALMARAZ_1')$[(ORD(d)>=91) AND (ORD(d)<=130)] = 0;
u.fx(d,'GARONA')$[(ORD(d)>=121) AND (ORD(d)<=180)] = 0;
u.fx(d,'TRILLO')$[(ORD(d)>=152) AND (ORD(d)<=186)] = 0;
u.fx(d,'ASCO_2')$[(ORD(d)>=274) AND (ORD(d)<=313)] = 0;
u.fx(d,'ASCO_1')$[(ORD(d)>=121) AND (ORD(d)<=160)] = 0;

***Respect coil units production
Sri3.fx(g) = Tp('Sri3');
Nrc3.fx(g) = Tp('Nrc3');
Robl2.fx(g) = Tp('Robl2');
Guad2.fx(g) = Tp('Guad2');
Pnn3.fx(g) = Tp('Pnn3');
Comp.fx(g) = Tp('Comp');
Ter.fx(g) = Tp('Ter');
All1.fx(g) = Tp('All1');
Ech1.fx(g) = Tp('Ech1');


* Options for execution:

** Selection of the optimizer for solving binary variables
OPTION MIP = cplex;

** Tolerance for optimization convergence with binary variables
OPTION OPTCR = 0.01;

OPTION iterlim=1e+6 ;

OPTION ResLim = 18000 ;

MODEL SUC2011 /all/;
```

```
** Option to include zero values in excel sheet
energy.scale(d,g)=0.1;
Cop.scale(d,g)=0.1;
Com.scale(d,g)=0.1;
Cco2_ep.scale(d,g)=0.1;
logv.scale(d,g)=0.1;
Cg.scale(d,g)=0.1;
Qmn.scale(d,g)=0.1;


SOLVE SUC2011 USING MIP MINIMIZING fobj;

* Open data in gdxviewer
EXECUTE_UNLOAD 'SEP_UC.gdx', energy, Cop, Com, Cco2_ep, logv, Cg, Qmn, u;
EXECUTE 'gdxxrw.exe SEP_UC.gdx o=SEP_UC.xlsx Squeeze=N var=energy.l
rng=UnitCommitment!B2';
EXECUTE 'gdxxrw.exe SEP_UC.gdx o=SEP_UC.xlsx Squeeze=N var=Cco2_ep.l
rng=CO2!B2';
EXECUTE 'gdxxrw.exe SEP_UC.gdx o=SEP_UC.xlsx Squeeze=N var=Cg.l
rng=GenCosts!B2';
EXECUTE 'gdxxrw.exe SEP_UC.gdx o=SEP_UC.xlsx Squeeze=N var=Qmn.l    rng=LNG!B2';
```

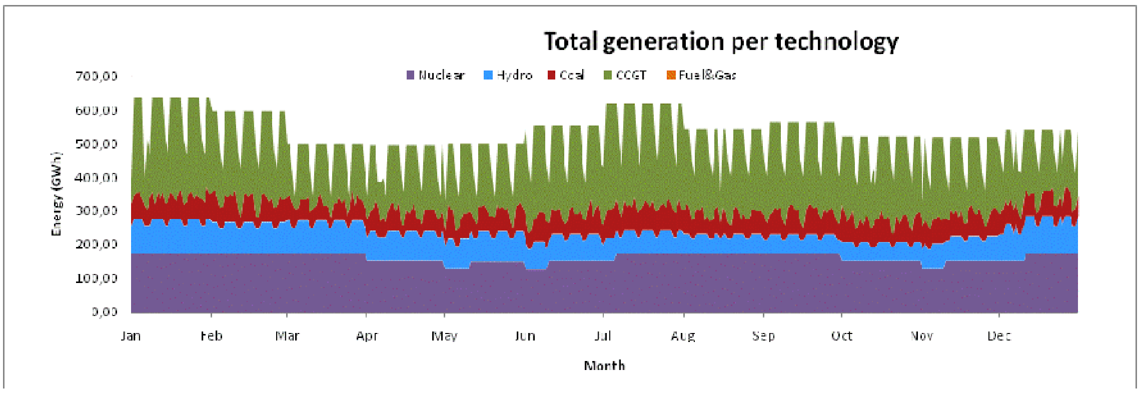
Appendix 9 – Generation Dispatch in period 2011-2020

Yearly Contribution by Technology [GWh]										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nuclear	58,133	59,490	56,171	56,387	53,961	56,550	54,901	55,447	54,923	56,551
Coal	24,746	24,746	24,746	24,768	16,645	13,047	10,716	8,200	940	710
Fuel&Gas	0	0	0	0	0	0	0	0	0	0
CCGT	73,663	73,804	76,000	75,468	86,684	89,097	91,597	93,634	101,821	101,705
Hydro	27,120	27,120	28,502	29,314	29,314	29,314	29,973	30,631	30,631	30,631
Total Ordinary Regime	183,662	185,159	185,418	185,938	186,604	188,009	187,187	187,913	188,315	189,597
SR- Renewable	56,619	61,718	65,625	70,297	75,985	81,882	87,336	93,012	99,576	106,377
SR- Non Renewable	38,843	39,366	41,290	42,662	43,241	43,839	45,116	46,414	47,075	47,757
Total Special Regime	95,462	101,084	106,915	112,960	119,226	125,721	132,452	139,426	146,651	154,134
Total	279,124	286,244	292,333	298,897	305,831	313,730	319,639	327,339	334,966	343,731

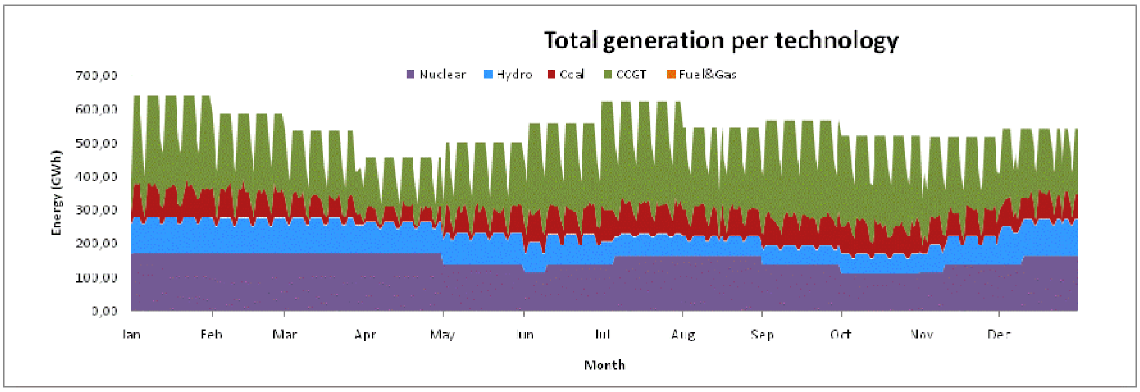
2011



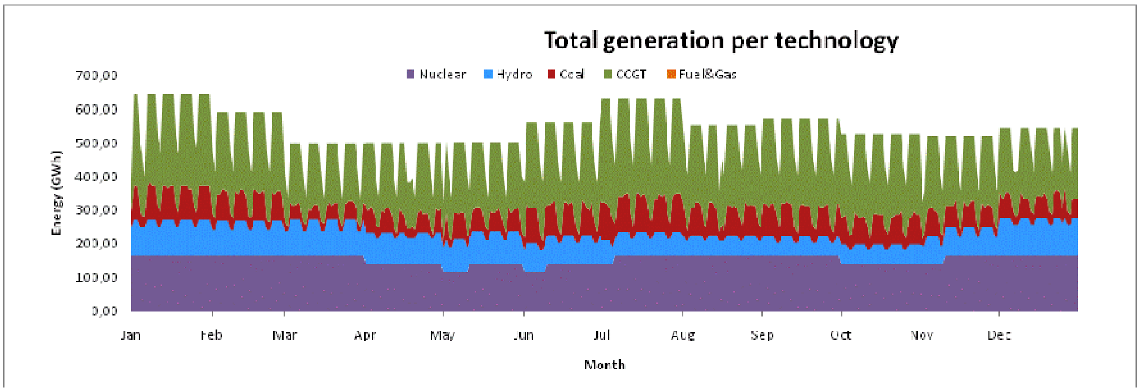
2012



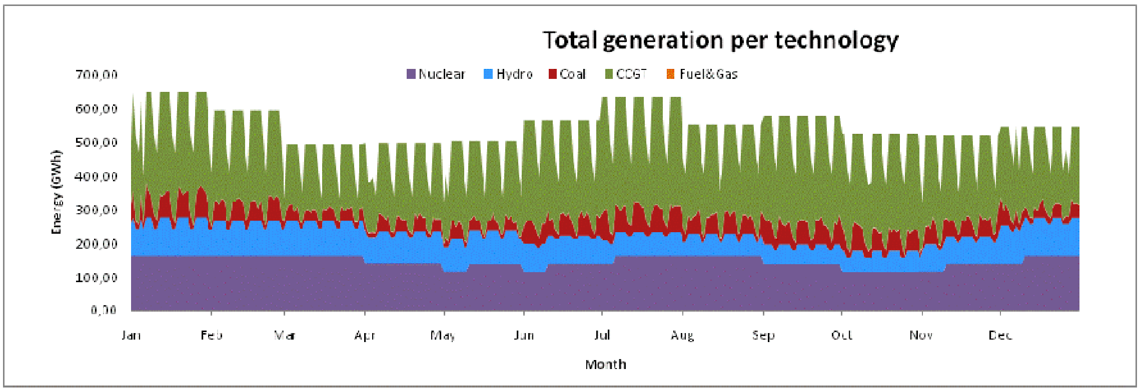
2013



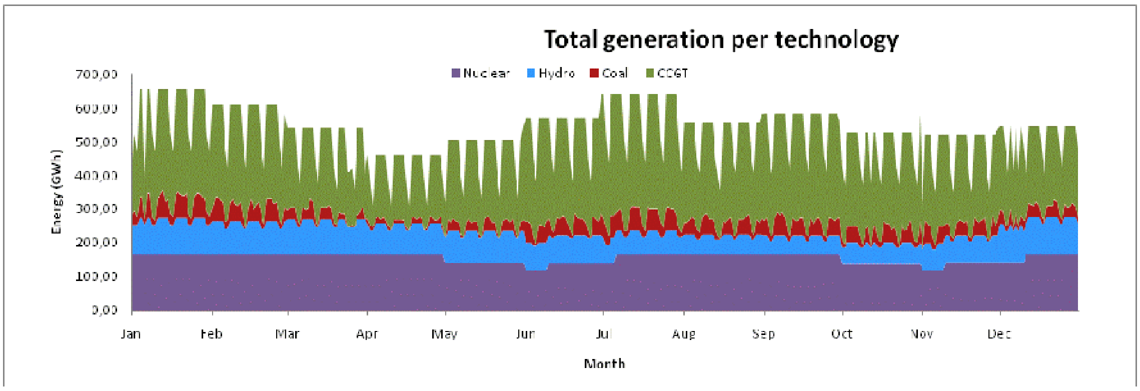
2014



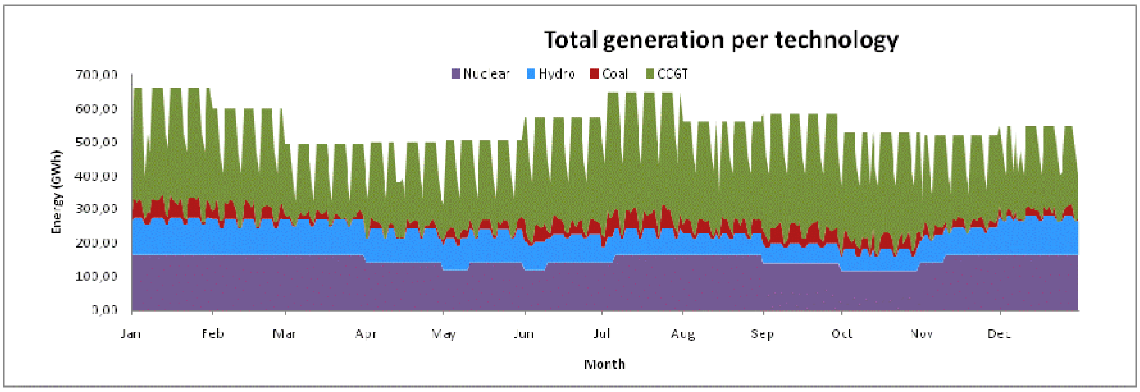
2015



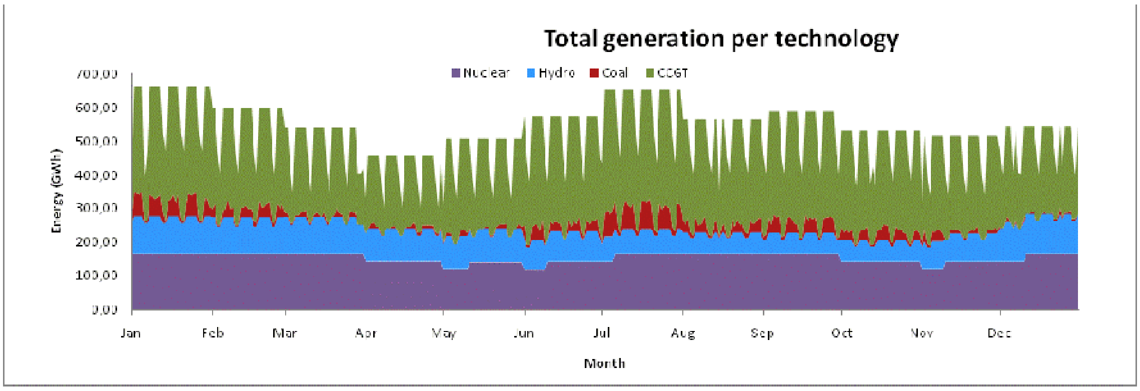
2016



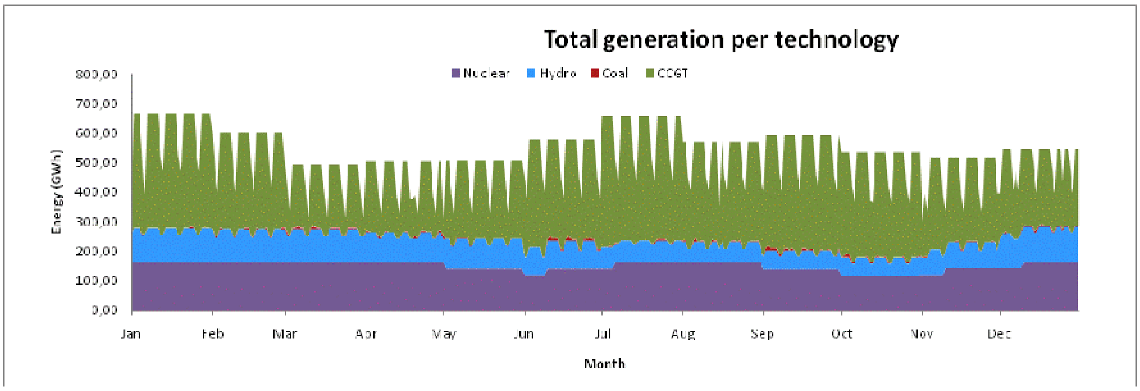
2017



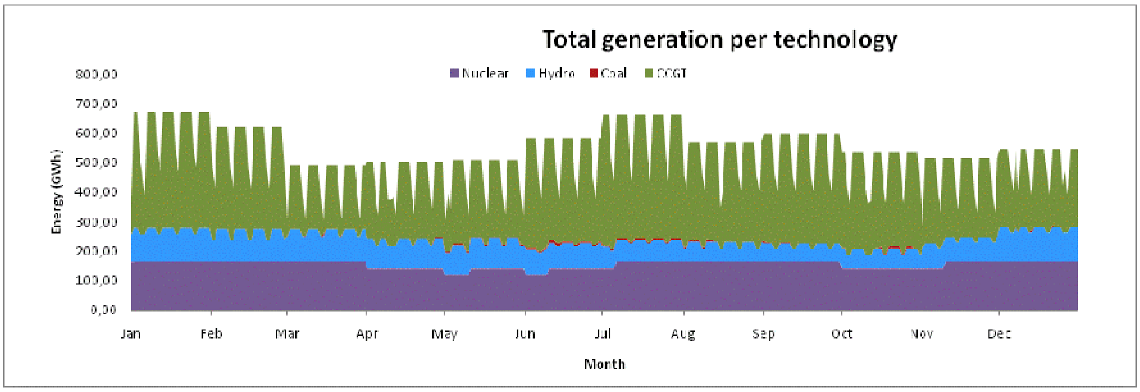
2018



2019


Total generation per technology
Nuclear
Hydro
Coal
CCGT
Energy (GWh)
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

2020


Total generation per technology
Nuclear
Hydro
Coal
CCGT
Energy (GWh)
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

Appendix 9 – Generation costs by technology

	2011			2012			2013			2014			2015		
	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]
Nuclear	27.43	13.47	40.90	27.44	13.60	41.04	28.25	13.74	41.99	27.92	13.87	41.79	29.62	14.02	43.64
Coal	46.43	54.81	101.24	46.88	57.59	104.47	46.89	60.80	107.69	47.02	63.36	110.38	70.53	64.96	135.48
Fuel & Gas	--	--	--	--	--	--	--	0.00	--	--	--	--	--	--	--
CCGT	35.81	48.17	83.98	35.83	50.47	86.30	34.31	52.72	87.02	34.17	55.12	89.29	29.44	57.64	87.09
Hydro	30.64	2.36	33.01	31.02	2.38	33.39	36.35	2.50	38.86	37.95	2.60	40.55	37.94	2.62	40.56
Total	34.14	31.32	**65.46**	34.23	32.53	**66.76**	34.80	34.27	**69.07**	34.74	35.43	**70.35**	34.84	37.04	**71.87**

	2016			2017			2018			2019			2020		
	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]	Fix [Euros/ MWh]	Variable [Euros/ MWh]	Total [Euros/ MWh]
Nuclear	28.80	14.16	42.96	30.02	14.29	44.31	30.19	14.43	44.63	30.96	14.59	45.55	30.66	14.73	45.39
Coal	91.59	67.89	159.48	111.36	70.43	181.79	145.63	74.06	219.68	1,000.11	80.37	1,080.49	1,396.31	80.23	1,476.54
Fuel & Gas	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
CCGT	28.43	59.34	87.77	27.28	61.28	88.55	26.40	63.13	89.54	27.80	64.92	92.72	29.44	66.85	94.08
Hydro	38.05	2.64	40.69	40.45	2.73	43.18	39.27	2.80	45.40	42.20	2.83	45.03	44.26	2.85	47.12
Total	34.42	37.50	**71.92**	35.00	38.65	**73.65**	34.82	39.41	**74.77**	35.92	40.22	**76.13**	37.32	41.01	**78.33**