ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

MASTER IN THE ELECTRIC POWER INDUSTRY

ANALYSIS OF CAPACITY AUCTIONS PARAMETERS

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Madrid

July 2016

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SUMMARY

Security of electricity supply has an increasing importance in societies as they are becoming highly dependent on electricity. There are a many aspects that bring uncertainty to the availability of generation capacity. As a result, many countries are implementing different mechanism to address the security of supply problem.

An adequate definition of the capacity market's parameters is a key element to achieve the needed capacity and to guarantee that not only there will be enough capacity to comply with the reliability standards but also that this capacity will reflect the most efficient and optimal technology mix for the system.

The main objective is to analyse the influence of the capacity market's elements on the final investments and technology mix of the system.

This analysis is based on a simplified model of a power system with an long term scope (40 years) that will be able to assess energy and capacity costs for a given mix technology production, load curve and minimum energy margin reserve. This model will be the base to study different scenarios to expand capacity when necessary so it could be obtain the pseudo-optimal solution of the parameters considered.

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INTRODUCTION

1. Introduction

Security of electricity supply has an increasing importance in societies as they are becoming highly dependent on electricity. There are a many aspects that bring uncertainty to the availability of generation capacity. As a result, many countries are implementing different mechanism to address the security of supply problem.

Security of Supply can be defined as the "Ability of the electric power system to provide electricity to end users with a specified level of continuity and quality in a sustainable manner, relating to the existing standards and contractual agreements at the point of delivery" (EURELECTRIC).

This concept comprises different time scales and different activities (generation, transmission, distribution, retail and system operation). According to Pérez-Arriaga (2007) [PERE07] there are four dimensions of security of supply:

- Security (Short term dimension): According to the NERC is the "ability of the System to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements". So it can also be defined as the readiness of available generation and network capacity to meet demand in real time.

- Firmness (Short to Mid-term): Is the ability of the installed capacity to respond to actual requirements to meet existing demand. Depends on the generation and network facilities and their management in medium-term. It depends not only on the management of generator and network maintenance but also on other factors as fuel supply contracts and reservoir management.

- Adequacy (Long term dimension): refers to the existence of enough capacity (installed or expected to be installed) to be able to meet demand.

- Strategic expansion policy (Very Long term dimension): Is linked to the energy policy as it depends on the technology mix and the fuel supply diversification.

This thesis focuses on the adequacy dimension that aims to achieve the needed installed capacity to meet demand during the peak hours in order to guarantee that there will be enough capacity in the system.

2. Motivation

There is an increasing interest on Capacity Remuneration Mechanism (CRM) around the world as they provide an efficient solution to long term system adequacy.

This is becoming more important as in the energy mix is increasing penetration of Renewable Energy Sources that can lead to a higher volatility and uncertainty, not only in prices, but also in the frequency and duration of scarcity periods.

In order to provide stability for new investors and to ensure long term capacity availability, the capacity markets have been developed in many countries around the world.

The correct definition of the capacity market's elements is a key aspect to achieve the needed capacity and to guarantee that there will be not only enough capacity to solve the security of supply problem but also that this capacity will reflect the most efficient and optimal technology mix for the system.

Making an analysis of the capacity markets' elements has a huge importance when setting the main characteristics of any CRM as it will allow obtaining the optimal and needed capacity for the system.

3. Objectives

The main objective of this thesis is to provide an analysis of some of the core elements of the capacity markets and to reach a conclusion on how these elements should be defined in order to achieve the optimal results for the system. This has a great importance to achieve the expected security of supply of electricity.

The aim is to study how the elements of the capacity markets can influence the result of the capacity mechanism and because of that how it will affect the technology mix of the system.

This thesis also reviews some of the main capacity remuneration mechanisms that are set in different countries to provide a wide idea of how the security of supply problem is tackled nowadays.

4. State of the art: Different approaches to the Security of Supply problem.

Liberalization and decarbonisation with the increase of renewables share of generation is changing the electricity systems of many countries.

With liberalization the investment decisions that where centralised planned are nowadays taken by private investors. There are lower incentives to invest in new power plants, and there are increasing concerns about security of supply. This situation has result in some countries implementing different measures to provide enough signals to invest in the needed capacity in the medium and long term. These measures imply that there will be payments not only for the energy produce but also for the availability of this energy in the future.

Different approaches that can be classified in two big groups (Energy Only Markets and Security of Supply Mechanisms) are been applied around the world in order to prevent non-served energy to happen:

Energy Only Markets:

In an ideal Energy Only Market (EOM), the spike prices produced during scarcity periods should be enough to send the correct signals for new investments as these prices should provide the expected profit to allow recovering generator's fixed cost and to enhance the optimal portfolio of generation power plants.

In this scenario the regulator does not intervene as it is based on the idea that the demand will manage the long term risk.

But, as there is not an ideal market, in reality there are some barriers to achieve the proper level of installed capacity just by the energy only market. The investment signals created during the scarcity periods becomes too risky to really achieve the needed investment in new capacity.

There is a huge uncertainty about the scarcity periods not only in terms of frequency but also in terms of severity.

In some markets there is a price cap which prevents the prices to increase enough as to obtain the optimal level of investments. There should also be considered that there could be investors' risk aversion and that there are economies of scale and the effect of lumpy investments. It should also be taken into account that markets have not perfect information.

All of these possible situations, and the uncertainty linked to them, makes difficult for the Energy Only Markets to send the correct economic signals to enhance capacity investments. And this can lead to the missing money problem.

Security of supply mechanism:

In order to incentivize capacity investments and to tackle the security of supply problem, countries around the world have been implementing different Capacity Remuneration Mechanism (CRM).

The aim of this CRM is to give value to generating capacity in order to improve security of supply. These mechanisms are a tool to tackle the missing money problem that arises when the Energy Only Markets are not able to provide the real value of the capacity during scarcity.

These mechanisms can be classified as Figure 1 shows.

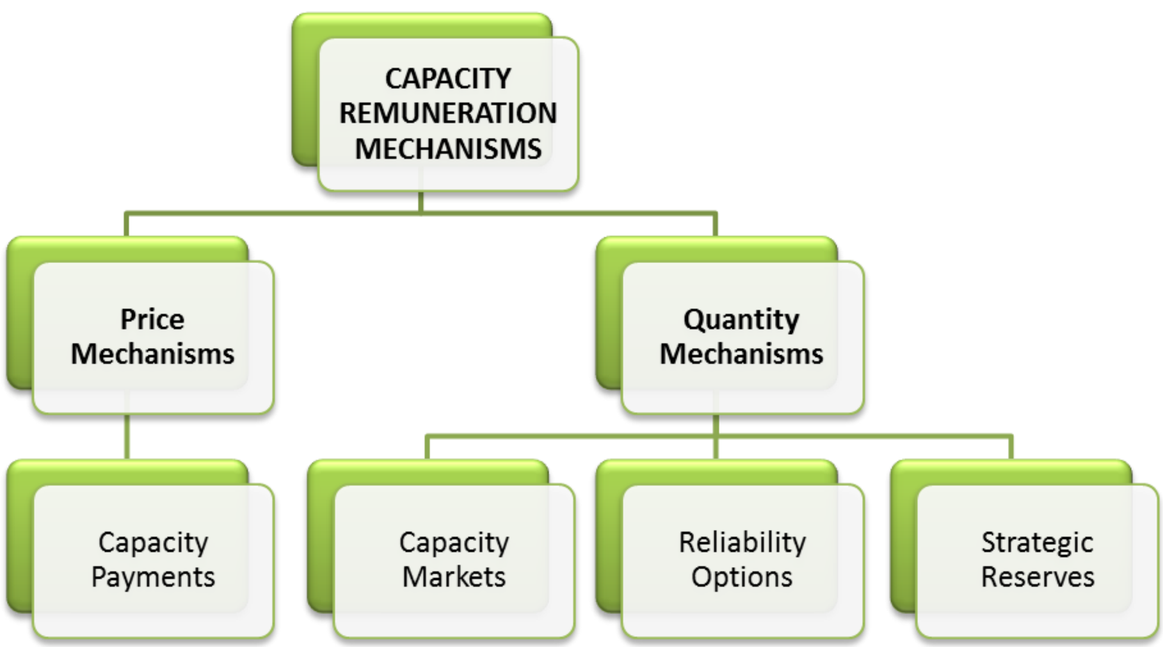

Figure 1. Capacity Remuneration Mechanisms' classification

- **<u>Price mechanism:</u>**

The regulator stablishes a payment to generators to remunerate the firm capacity they provide to the system. The price is set by the regulator and it aims to pay for the fixed cost of power plants (firm capacity).

Within this mechanism we can find the **Capacity Payments**.

The aim of the capacity payments is to ensure firm capacity (which is the reliability product of this mechanism) and to incentivize investments. There are two approaches:

- ✓ Based on the reliability of the system. The payment depends on the Loss of Load Probability (LOLP) and the Value of Lost Load (VOLL)
- ✓ Based on the cost of expansion. The payment is determined based on the fixed cost of a peak unit.

The definition of firm capacity can be based on the expected availability when it is most needed, but there could also be considered the unit's variable cost. The firm capacity of this mechanism can be determined *ex-ante* (based on historical records) or *ex-post* (based on generator performance).

The first capacity payment was introduced in 1982 in Chile. This capacity payment was determined according to each unit's firm supply and there was also the demand's obligation to contract firm generation capacity payment.

The main advantage of Capacity Payments is that it is easily implemented but it has some disadvantages as the way to distribute the payments and the effectiveness to enhance investments. Some authors [FINO08] also highlight that this mechanisms can be affected by agents manipulation as they can have incentives to increase the LOLP so the payments are higher.

There is no a specific obligation to the generator to provide capacity so it can also affect the reliability. All of these can lead to not sending correct signals to incentivize investments. So Capacity payments can result in not obtaining the expected firm capacity. If they are not well designed there could be underinvestment or overinvestments as not always reflect the needed payments for investments.

Some countries as Spain, Portugal, Peru, Argentina, Ireland, Italy and United Kingdom (1990-2001), have implemented Capacity Payments.

- **Quantity mechanisms:**

The volume or quantity mechanisms are market-based mechanisms where instead of setting the price, the regulator sets the needed capacity. The regulator (on behalf of the demand) or the demand itself purchases a specific quantity of the reliability product. The product can be long-term forward contract for energy or some capacity credit. This product can be traded bilaterally, through auctions or by organized markets.

The price of the product is set by the market-based mechanism.

Within this mechanism we can find:

- Capacity Markets:

Capacity Markets are mechanisms based on contracts between load serving entities and capacity suppliers. These markets decide *ex ante* the capacity that will be contracted. Within this mechanism we can have the Capacity Obligations and Capacity Auctions.

Capacity Auctions: The needed capacity is procured in a centrally auction run by an independent body. These Auctions are held some years in advance the delivery period. The price is set by the capacity demand curve and the bids offered by suppliers. The bids should consider the investment cost of the generators.

Capacity Auctions are been implemented in some countries as United Kingdom, United States of America, Colombia, Brazil and Panama.

Capacity Obligations: Within this mechanism the load serving entities have to purchase their own generation or enter into bilateral contracts for firm capacity. The level of capacity is related with their future consumption or supply requirements and has to include a reserve margin. This mechanism stablishes penalties in case of non-delivery.

This mechanism was adopted in Greece but it was not implemented, and it is expected to be implemented in France. Some regional pools in US also implemented capacity obligations.

- <u>Reliability Options</u>

  Within this quantity based mechanisms the regulator designed the SO or other entities to enter into option contracts with suppliers on behalf of demand. These contracts are settle in centralized auctions and they offer the option to procure power at a strike price; these contracts are call options with penalties for non-deliver. The strike price and amount of capacity that should be offered is set by the regulator.

  The aim of the reliability options is guarantee a price and protect the demand from the price spikes. Suppliers receive a premium as a compensation for guarantee the price.

  This mechanism has been introduced in Colombia and Italy.

- <u>Strategic Reserves:</u>

  Within this mechanism the System Operator or the Regulator stablishes the total amount of reserves that will be necessary in the future. This capacity is withdraw from the energy markets and only in periods of scarcity and under the pre-defined conditions stablished by the regulator or SO this capacity will be available for the system. So these reserves are only activated in periods of scarcity.

  This capacity is normally procured by a centralized public auction where the price, the type of generation and the conditions under which the reserve is activated are determined by the central body.

  This mechanism has been stablished to avoid the mothballing of old plants. Some countries that have implemented this mechanism are Sweden and Finland.

5. Capacity markets around the world.

Countries around the world have implemented different capacity mechanism to ensure the reliability levels of security of supply. This chapter review some of the mechanisms that have been introduced or are nowadays implemented. It does not try to be an exhaustive recompilation of all the existing CRM.

<u>EUROPE</u>

<u>United Kingdom (1990-2001):</u>

From 1990-2001 UK implemented the Capacity Payments.

Within this mechanism the electricity price was computed one day ahead and included the loss of load probability (LOLP) times the difference of the value of lost load (VOLL) and the plant's bid price or the marginal price (in case it was dispatched).

Capacity payment = LOLP x (LOLL – Marginal price)

As it was *ex-ante* calculated it provided higher prices than it should have done.

This mechanism had some problems as it allowed market manipulation (marginal units could increase the marginal price and so the capacity payment by reducing their availability).

Nowadays the mechanism that is implemented in UK is the Capacity Auctions. (See chapter 6.2)

<u>Spain (1998)</u>

Capacity payments are implemented since 1998. It was based on the average availability rate for thermal power plants and on average historical production for hydro units. The main disadvantages were the lack of effective incentives for generators and the instability of the payments. This methodology was modified by introducing in 2007 two services an availability service and an investment service.

Italy

Italy adopted Capacity Payments where payments were fixed by the regulator and depends on the availability during critical days (high-critical and mid-critical). The main drawback of this mechanism was that it did not ensure the recovery of investments costs.

Recently it was adopted a Reliability Option Mechanism to be procured in a centralized auction with a lead time of 4 years and a duration of 3 years. Auctions for the provision of capacity include the locational element to take into account the division of the country into different zones. This mechanism it has not been implemented yet.

Ireland:

The capacity remuneration is based on Capacity Payments. This mechanism is based on the system's capacity requirements to comply with security standards, the annual carrying cost of the best new entrant and the value of lost load (VOLL). This value depends on the declared availability at each hour and on the expected LOLP (calculated *ex-ante*) and the LOLP (calculated *ex-post*). As it was calculated every year it does not represent predictable incomes. Since 2013 the updating period was every 3 year.

LATIN AMERICA

Argentina

The CRM implemented since 1995 is the Capacity Payment that was based on a regulated price applied to the average annual power of the generation units dispatched in the non-valley hours and to the power of each unit dispatched each day for the amount that exceeds the unit's annual average. As this resulted in an inefficient operation the capacity payment was modified so currently it is based on the capacity available during the 90 hours of highest demand each week.

Colombia

The Capacity Payment was the first capacity mechanism that was implemented during the period 1996-2006. As this mechanism did not provided incentives for new investments it was implemented a quantity mechanism: The Reliability Charge since 2006. The reliability product was the reliability option and it was purchased in a centralized long-term auction in order to increase competition and improve transparency.

The auction has a descending clock format with a downward sloping curve. New and existing plants are subject to different rules. Existing plants are price takers.

Brazil:

In Brazil there are implemented different Auctions for new entrants and existing units.

The reliability product is a forward financial energy contract for hydro units and an energy call option for steam plants.

In 2004 a system based on mandatory reliability contracts was introduced as an incentive to the entrance of new generation. According to [MAUR11], its three main rules are:

1. First, all loads (captive consumers from distribution companies and free consumers) must prove to be 100 percent covered by energy contracts.
2. All contracts, which are financial instruments, should be covered by Firm Energy Certificates (FeC).
3. In order to promote the most efficient procurement mechanism for regulated (captive) consumers, the contract obligation scheme for distribution companies operates in tandem with the use of energy auctions of long-term contracts as the main mechanism for energy procurement.

USA

ICAP markets (Installed CAPaccity):

This markets were running in Eastern USA (PJM, NYISO and ISO-NE) the basis of them were that the demand or (the load serving entity) had to purchase capacity credits in order to back up their peak-demand capacity. Each generator received credit for their installed capacity.

As not all the capacity of the generators is available at any time the system operators stablished the Unforced Capacity (UCAP) by which the generators were only allowed to sell the credits according to their historical availability.

The main problems of these markets were that there was no investment recovery, the high price volatility and that there were no locational signals.

ISO New England:

The forward capacity market replaced the ICAP mechanism and the ISO New England. This mechanism includes locational signals as the capacity requirements and clearing prices are calculated separately for different areas.

The mechanism is very similar to the Colombian's one but one difference is that the demand can take part as a provider of reliability product.

PJM's reliability Pricing Model (RPM) and the new NYISO ICAP:

As the capacity payment described before have some drawbacks there was a new implementation of the security of supply mechanism: an auction. The reliability product was the variation of the UCAP taking into account the availability when during peak demand periods.

The main elements of the capacity market are:

1. procurement of capacity three years before it is needed through a competitive auction;
2. locational pricing for capacity that varies to reflect limitations on the transmission system and to account for the differing needs for capacity in various areas of PJM; and
3. a variable resource requirement curve, which is the energy demand formula used to set the price paid to market participants for capacity.

Capacity market participants offer or "bid" power supply resources into the market that either increase energy supply or reduce demand. These resources include new generators, upgrades for existing generators, demand response (consumers reducing electricity use in exchange for payment) energy efficiency and transmission upgrades. When a participant bids these resources into the market, that participant is committed to increase supply or reduce demand on the PJM system by the amount they offered, three years in the future.

AUSTRALIA

Western Australia (2004):

In Western Australia it is implemented the Reserve Capacity Mechanism to ensure enough generation capacity in the future. This reserve is set two years ahead. Capacity Credits are allocated through Bilateral Trade Declaration process and when it is needed a Reserve capacity Auction is held.

Since 1 June 2016 there are implemented changes to the WA's energy market that will impact Capacity Remuneration Mechanism.

The main reforms are:

- ✓ Introduction of an auction process for procuring capacity (it will start in 2021)
- ✓ Demand side management capacity will have a separate price arrangement. And there will be new requirements for demand side management.

6. Capacity markets in EU.

In EU we can find implemented a wide variety of Capacity Remuneration Mechanisms design. There are countries which have stablished price based mechanism as Capacity Payments (Spain, Portugal, Ireland…), and other countries that implement quantity based mechanism as Capacity Auctions (UK), and Strategic Reserves (Sweden, Finland…).

In figure 2 we can observe the current capacity mechanisms in EU countries.

The diversity of mechanisms and the different characteristics of each Electricity System have result in the definition of a Reference Model to implement Capacity mechanisms within Europe that stablish common rules at regional level.

Figure 2. Capacity Remuneration Mechanism in Europe. Source CEER.

6.1. Legislation

The UE concerns about security of supply were introduced in the EU **Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity**. This Directive states "Member States should ensure the possibility to contribute to security of supply through the launching of a tendering procedure or an equivalent procedure in the event that sufficient electricity generation capacity is not built on the basis of the authorization procedure".

It also stipulates the necessity of monitoring the supply/demand balance and the interconnection capacity between areas in regard security of supply.

In relation to security of supply, Member States may impose on undertakings operating in the electricity sector and may also introduce long-term planning.

It also stablishes the obligation to ensure the monitoring of security of supply. Within this monitoring there should be information regarding supply/demand balance, expected future demand, foreseen additional capacity planned or under construction, measures to cover peak demand and to deal with shortfalls.

In the authorization procedure for new capacity Member States (MS) should take into account security of supply when stablishing the criteria for new generation capacity.

This Directive also contemplates the possibility for MS to provide new capacity or efficiency/demand side management measures to ensure security of supply through a tendering procedure or an equivalent procedure.

Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment.

This directive establishes the framework to define policies on security of electricity supply in accordance with a competitive market for electricity.

"Measures which may be used to ensure that appropriate levels of generation reserve capacity are maintained should be market-based and non-discriminatory and could include measures such as contractual guarantees and arrangements, capacity options or capacity obligations and could also be supplemented by other instruments as capacity payments".

Member States should stablish a framework to facilitate security of electricity supply.

The Scope of this directive is to establish measures to safeguard security of electricity supply to ensure the proper functioning of the internal market for electricity and to ensure an adequate level of generation capacity, an adequate balance between supply and demand

and an appropriate level of interconnection between Member States for the development of the internal market.

Member States shall ensure a high level of security of electricity supply, and in order to achieve this, they should take into account, among other things:

- the internal market and the possibilities for cross-border cooperation
- the need to ensure sufficient transmission and generation reserve capacity for stable operation
- the importance of stablishing liquid wholesale markets
- The degree of diversity in electricity generation
- The importance of reducing the long-term effects of the growth of electricity demand
- The importance of encouraging energy efficiency and adoption of new technologies as demand management, renewable and distributed generation.

This Directive also establishes the need to maintain the balance between supply and demand, so Member States should take measures as to:

- encourage the establishment of a wholesale market framework that provide price signals for generation and demand
- Ensure an appropriate level of generation reserve capacity is available for balancing purposes or adopt market based measures to ensure it.
- Facilitate new generation capacity and the entry of new generation companies to the market.

6.2.Example of UK Capacity Auction

The Capacity Market is one of cornerstone of the UK Electricity Market Reform (EMR). Its aim is to ensure adequate capacity within an electricity system.

The first Capacity Auction was held in 2014 for capacity to be available in 2018/2019.

The legislation frame that enables the Electricity Market Reform is the Energy Act 2013. This reform includes the implementation of the Capacity Market as a mechanism to encourage investments in generation in order to provide back-up generation and demand side response to ensure long-term energy supply. It provides a fixed income to the generators. The Capacity Market is part of the Electricity Market Reform (EMR) package.

The main goals of the Electricity Market Reform are:

- Incentivize investment in secure and low-carbon electricity
- Improve security of electricity supply
- Improve affordability for consumers.

The creation of a capacity market was created to ensure the goal of improving the security of electricity supply in Great Britain.

The Regulator is responsible for:

- Capacity Market rules
- Determining certain disputes
- Monitoring the Capacity Market
- Enforcing competition law and compliance with Rules
- Reporting on the effectiveness of the Capacity Market

Characteristics of the UK Capacity Auctions

- **The capacity needs:**

The Delivery Body (National Grid) carry out an Annual security of supply analysis on the amount of capacity required to meet a reliability standard. This analysis is studied by the Panel of Technical Experts.

The Government determined the capacity demand curved in advance and publishes it for each four-year ahead auction. This curve set a target level of capacity to be auctioned and set a cap on the maximum price to be set at auction.

The target capacity level depends on the capacity required to meet the reliability standard and takes into account the capacity expected to be available outside de Capacity Market.

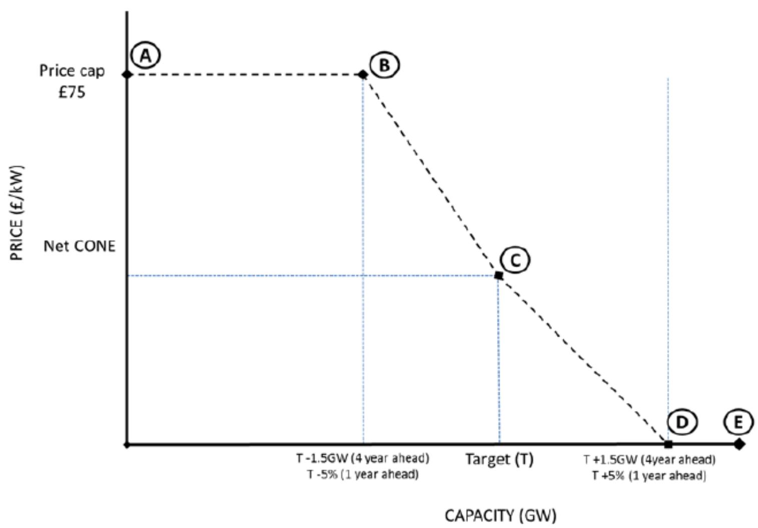

Figure 3. Illustrative capacity demand curve. Source: Implementing Electricity Market Reform.

The auction price cap is determined at a capacity of 0 GW and is set in a way that different projects and technologies have opportunities to set the price.

The net CONE (COst of New Entry) is determined as the cost of a new build combined cycle gas turbine plant minus expected electricity market and ancillary service revenue.

The slope of the demand curve is determined by setting D and B points. D represents the target level of capacity plus 1,5GW at a price of £0/kW and B is the point at which the demand is equal to the capacity minus 1,5 GW at the price cap. 1,5 GW is the de-rated capacity of two large CCGT plants.

In the year ahead auctions, the demand curve are calibrated differently (the demand is equal to the target level of capacity plus or minus 5% instead of 1,5 GW).

Payments for the 4 year ahead auction are indexed for inflation (consumer price index).

- **Pre-qualification:**

Within the definition of the capacity market it is essential to set which capacity can participate in the auction. So it is needed a pre-qualification process to determine the eligible Capacity.

The capacity that can participate in the auctions is:

- ✓ New and existing generation capacity
- ✓ Demand side response
- ✓ Electricity storage
- ✓ Interconnected non-GB capacity and the interconnectors themselves (not eligible at the 2014 auction but intended to be from 2015)

Not eligible capacity:

- ✓ Capacity with Renewables obligations, Contracts for Differences, small scale Feed in Tariffs, other incentivized or supported capacity…
- ✓ Capacity with long-term contracts to provide S-T Operation Reserve
- ✓ Capacity below 2 MW if not combined with other capacity.

Existing capacity can opt out of participating in the auction but it is mandatory to participate in the pre-qualification process.

- **Product:**

The products to be auctioned are capacity agreements.

Existing plants: the default is a one year capacity agreement but under specific circumstances can opt to up to 3 year capacity agreement

New entrants need long term agreement up to 15 years duration. (3 -15 year length)

- **Auction characteristics:**

The Auction takes place four years ahead of delivery for each delivery year. An additional auction takes place one year ahead of the delivery in order to adjust the level of capacity and allow the participation of the Demand Side Response. Some capacity is reserved for the year ahead auction.

The auctions have a descending clock format and will be pay-as-clear (the participants receive the clearing price which is set by the marginal bidder).

Within a descending clock auction (Dutch auction) participants offer capacity at a price which is lowered until the auction is cleared at the minimum price at which sufficient capacity is supplied.

- **Price takers and price makers**

<u>Price takers:</u>

Any existing generating capacity market unit is a price taker as a default and they can only bid up to a threshold (which is set to let most of the participants to bid as a price taker). The price taker threshold is an auction parameter.

Price takers are offered a one year price and capacity agreement at the auction clearing price

<u>Price maker:</u>

New plants and Demand Side Response (DSR) can participate as price maker without any justification. Any existing plant that want to participate as price maker and bid above the price taker threshold have to provide justification of their need to bid above that price.

- **Capacity agreements duration**

  The capacity agreement of an existing generation unit or a DSR or storage is one year duration at the clearing price.

  Refurbishing plants and new prospective generation can be awarded with long term agreements.

  The one-year ahead auction cannot have long-term agreements.

- **Rules for New build plant and Refurbishing plant**

  To ensure that a refurbishing plant has strong incentives to be ready on time of delivery, these plants have to provide evidences of:

  - ✓ Have incurred at least 10% of the total project capital expenditure within 8 months prior of wining the capacity agreement.
  - ✓ Have achieved 100% of the capacity stated in the capacity agreement by the start of the delivery year.

  In case of failing to achieve the 100% of capacity there are penalties.

  New build plant:

  - ✓ As well as the refurbishing plant, new plants have to demonstrate that they have incurred at least 10% of their total project capital expenditure within 18 months prior to be awarded with the capacity agreement.
  - ✓ If there is no evidence the penalty could result in the termination of the capacity agreement.

- **Secondary Market**

  Between the auction and the delivery year providers awarded with capacity agreements can physically trade their obligations. There are three forms of secondary trading:

  - ✓ Financial Trading
  - ✓ Volume Reallocation
  - ✓ Obligation Trading

- **Penalties**

  There are stablished a set of penalties rate for each obligation (1/24th of the relevant auction's clearing price). So providers that do not comply with their obligations at times of system stress are required to pay a penalty.

  On the other hand, those providers that deliver more than their obligation at times of system stress are paid for their over-delivery (with the total penalty payments received).

6.3. A reference Model for European Capacity Markets

The situation of the European energy mix that will increase the RES can result in Security of Supply problems as they need back-up energy for the periods when they are not available. The capacity market aim is to provide long-term system adequacy to back-up scarcity periods.

Eurelectric has developed a reference model for capacity markets that aims to send signals to increase investments in new capacity up to the necessary capacity. This reference model aims to attract the capacity needed and it provides a framework to stablish common rules at regional level.

It also pays special attention to the cross-border participation and emphasized the fact that all participants (including cross-border) should be subject to common rules in a non-discriminatory conditions.

Cross-border resources should be carefully taken into account when designing capacity remuneration mechanisms as, when the capacity remuneration mechanism are introduced prematurely, without proper problem identification or in an uncoordinated manner, the capacity mechanisms can distort cross-border electricity trade and competition.

The reference model stablishes some principles that the capacity markets should follow in order to be cost-efficient:

- Market-based
- Technology-neutral
- Open to new and existing plants

- Regional
- Open to generation ,demand response and storage.

Elements of the regional capacity markets:

- Capacity needs:

  It is important to define the total capacity that will be necessary. This should be based in a transparent and homogeneous methodology.

- Product Definition:

  It is also important to correctly define the "product" of this capacity markets. It should follow the same principles at regional level in order to not affect the European Internal Market and to enhance cross-border participation.

  The product of these markets is firm capacity availability. That mean that it should be defined the volume that is needed. It should be clearly differentiate from the product of the flexibility markets.

  In order to have a coherent regional market the product should be harmonized within the region.

  Another product details that have to be taken into account are:

  - ✓ Trigger price: There should also be defined a criteria that reflect the system tightness (the demand-supply gap). Eurelectric's reference model proposed the triggering price that is the price at which the capacity has to be available to the market.
  - ✓ To properly define the market it has to be decided the lead time (time between the certification and the start of the capacity contract) and the duration of the contracts. The lead time is important for new entrances because it should be long enough to led new entrances to build their infrastructures. A three or four years lead time period should be enough.
  - ✓ The duration of the contracts depends on the type of generation. It should not be less than 1 year duration but it can also be longer for new entrants.

- Penalty regimes:

  There should also be defined a penalty regime in case of not providing the capacity awarder in the market. It is necessary to stablish a harmonized penalty regime within the region in order to send the correct signals to the new capacity to be build where it is most needed. The penalty should be based on market prices.

- Certification:

  It is necessary that the providers that want to participate in the market have an *ex-ante* certification. This certification stablishes the amount of capacity that each provider can offer. In decentralized system there should be an *ex-post* verification process to ensure that the capacity that will be needed has been reached.

- TSO coordination:

  TSOs should cooperate and define the cross-border verification procedures. And they should also coordinate the definition of the elements of the regional market.

  When introduced prematurely, without proper problem identification or in an uncoordinated manner, and without taking into account the contribution of cross-border resources, there is a risk that capacity mechanisms distort cross-border electricity trade and competition.

Type of capacity market:

EURELECTRIC consider as the most cost-efficient to ensure long-term security of supply the capacity obligation certificates or capacity auctions:

- Capacity obligation:

  This mechanism is based on tradable capacity certificates. Capacity providers sell certificates in the capacity market to provide availability in periods of system scarcity. Suppliers and large customers have to buy capacity certificates to cover their demand (or to serve their customers). There should be defined the regulatory parameters as the lead time and the duration or delivery period which normally is 1 year.

  The capacity need of the suppliers has to be determined in order to guarantee that there has been contracted enough capacity to ensure the long-term adequacy. It is necessary an *ex-post* verification to certify that the suppliers have committed with their obligations and in case of not having committed there is a penalty regime to be applied.

- Capacity auctions:

  This mechanism is based on a centralized capacity market based on fixed payments. The providers who result cleared in the auction receive the marginal price of the auction (price for capacity in €/MW). The product of this mechanism is the firm capacity in scarcity periods.

  It should be determined a penalty regime in case of not fulfill the obligation of providers to have available capacity when it is required. These penalties should be market based.

Cross-border participation

In order to achieve the security of supply problem at regional level it is necessary to allow cross border participation in the same conditions (as the Directive 2003/54/EC specifies: Member States shall not discriminate between cross-border contracts and national contracts).

The cross-border participation can be modelled depending who is allowed to participate in cross-border transaction (capacity provider or interconnector) and which product is traded (availability or delivery). Eurelectric propose that the capacity provider is the one who sells the availability and the interconnector gets paid the congestion rent in order to minimize the energy market distortion.

The principles stablished by Eurelectric for cross border participation are:

- Common requirements and coherent market rules for all capacity market participants;

- Not allow participation with the same capacity in more than one capacity market for obligations ate the same timeframe;

- Non-discriminatory conditions;

- Not allow to neglect existing cross-border capacity contracts in situation of system stress;

- No reservation of cross-border capacity should be introduced in order not to interfere with the functioning of the different markets.

There are different approaches to set the socially optimum adequacy level:

- Reliability Margin
- Loss of Load Probability
- Expected Un served Energy

PROPOSED MODEL AND ANALYSIS OF CAPACITY AUCTION PARAMETERS:

The aim of the thesis is to assess how capacity remuneration mechanism parameters definition can affect the results of the capacity mechanism and as a consequence how this definition will have an effect on the system.

To study how the generation expansion model can be affected by the different scenarios and by the implementation of capacity remuneration mechanism this study is based on a simplified model of the system that represents a theoretical electricity system. The model has been developed in Microsoft Excel.

The Capacity Remuneration Mechanism studied is the Capacity Auctions, as many authors as well as the Reference Model considered that this is one of the most cost-efficient mechanisms to ensure long-term security of supply.

This simplified model is the base to study how capacity auctions can affect the long term signal to invest in new technologies. It is based on different investment scenarios and it stablishes the differences between a Centralized Planning and an Investor's point of view.

The main differences between these two points of view are that while in a Centralized Planning system the central operator is calling for capacity for the system, in a decentralized system the market agents are the ones who decide on the installed capacity based on the capacity mechanism stablished.

The period of study has been stablished for 40 years and it is divided into 5 years' blocks (T1-T8). During these periods we face different situation that will lead to a need of new capacity to meet demand.

This model represents a theoretical Electricity System to assess how the power system management can affect the future investments and as a result the social welfare of the system.

The model does not tries to make a quantitative analysis of the influence of the different parameters in the system, but it gives an qualitative overview of how they can affect the system and the main factors that have to be considered when defining the capacity remuneration mechanism.

The main inputs of this model are the technology mix, demand (load duration curve), the future evolution of the system, the needed capacity to ensure security of supply in the future, cost of each technology, electricity market and capacity auction parameters.

The model is analysed based on different investment scenarios, and the optimal solution will be the one that minimize the cost of the system (in case of a Centralised Planning) or maximize the investor profits (in case of an Investor's point of view).

For each of the scenarios the hypotheses are based on the same system. When analysing how a parameter can affect the system the rest of the inputs are supposed not to change in order to isolate the effect of this parameter so it could be compared in different situations.

The Electricity System that is represented in the model as well as the characteristics of the model that is used within the different Cases is explained with detail in the Base Case Scenario.

Within the other scenarios there will be a description of the main differences of model with respect to the base case.

1. Methodology

The methodology implemented is based on the simplified model. For each Case Scenario the methodology to obtain the results is the following:

1. Definition of the inputs of the studied Case. The inputs of the model are determined for each time scope period (T1-T8):
    a. Technology mix capacity and de-rated capacity
    b. Load duration curve
    c. Needed capacity (ICAP)
    d. Technologies' costs (CAPEX, OPEX, Variable Cost)
    e. Auction parameters
2. Energy Market. The model determines for each time period and each sub-block:
    a. Marginal cost of the Energy Market
    b. Revenues each generator receives from this market
    c. Energy produced by each generator.

3. Determination of the total cost of the system as the investment cost, O&M costs, and operation costs of the generators of the system
4. Determination of the Cash Flow for each generator
5. Auction simulation and determination of the bidding offers and clearing price.
6. Results for each investment scenario
7. Optimal investment scenario

Within each Case studied, it is defined the needed new capacity that should be built, so the model is run for each of the possible investments' scenarios (with the different hypothesis of investing in new CCGTs or new Peakers) in each time period where new capacity is needed.

The model's results are based on the total cost of the system as well the cash flow and the auction. These results are determined for each of the investment scenarios.

The optimal result (the optimal scenario) is determined as the scenario that minimize the total cost of the system for the centralized planning point of view or the one that maximize the profits for the investors for the decentralized point of view.

In the Base Case there is a description and definition of the inputs of the model as well as it is described in detail the methodology to obtain the total cost of the system, the energy market, the capacity auction structure and the different parameters that are considered within the model.

2. Base Case.

2.1. Objective

The aim of the Base Case is to determine which could be the optimal future investments in a hypothetical situation where it is necessary to increase the installed capacity to meet the peak demand and to ensure the reliability of supply level stablished by the regulator.

To assess the optimal investment decisions the model will evaluate the results from two different points of view:

- **<u>Centralised Planning System</u>**

  The centralized planning aims to maximize the total social well-being. In this case it has been defined that, as all the other variables are constant, the optimal investment is the one which minimized the total costs of the system. We suppose that all the plants recover their total cost (Fixed and Variable).

  This centralized planner stablishes a generation expansion plan based on the foreseen scenarios (demand growth and evolution of the system, available technologies, environmental constraints…).

  The centralized Planning System does not considered any capacity auctions, but it does consider the total investment cost of the system, that should be recovered by the generation units by the electricity market or by any other capacity remuneration mechanism. The aim is to minimize the total cost of the system as it will result in a system will lower cost for the consumers.

- **<u>Decentralised Market Based System with capacity auctions</u>**

  In a Market-Based Decentralised System, the expansion planning is based on maximizing the investor's profits. This scenario is based on the market revenues and the cost recovered with capacity mechanisms.

  Within the model the capacity mechanism that is consider are the capacity auctions.

  In order to be able to compare both points of view this scenario is based on the same theoretical system than the Centralised System.

  The aim of the market agents is to invest in the technology that allows them to recover all their cost and to maximize their incomes. So the objective is to invest in the most profitable technology according to the system.

The optimal investment is the one which is more profitable so that the needed recovering cost is lower.

The needed recovering cost after the electricity market margin represents the bid that the new plant will offer in a capacity auction. This bid internalized the total cost that each generator has not recovered within the electricity market.

2.2.Description of the system

2.2.1. Time scope

The model represents a time scope of 40 years and it has been divided in 8 blocks of 5 years (T1- T8). Within each block there is a representation of a year (it is supposed that the 5 years of each block have the same conditions). Each year is divided in sub-blocks of hours (10 sub-block) that represents the different levels of the demand. The sub-block does not have constant time duration; they are aggregated taking into account the mean of the load demand.

The length of the time scope has been stablished in 40 years in order to be long enough to be able to represent a long term scenario and to take into account the useful-life of new installed capacity during the first periods.

2.2.2. Technology mix

The technology mix that represents the base of the studied system is based on a theoretical Electricity System and the most probable evolution of it according to the hypothesis of the future scenarios. This hypothesis tries to represent how an electricity system within Europe will probably evolve.

The technologies that are represented in the model are classified in the following main groups:

- Nuclear
- Coal
- Renewables
- Combined Cycle Gas Turbine

- Peaker

Each technology has its own characteristics but they complement each other to cover the total demand.

In terms of operation the technologies can be classified within two main groups:

- Base load technologies: they have high inversion costs and lower variable cost. This generation units will operated full load during most part of the year to cover the minimum demand of the system. Nuclear power plants are an example of base load units.

- Peak technologies: these technologies count with high variable costs and will only operate at peak demand when the prices are high enough to recover their production cost.

Brief description of the main technologies in the model:

- **Nuclear power plants:**

  This technology is based on fission of uranium atom. It has no atmospheric gas emissions what makes these plants a carbon free technology but on the other hand they have radioactive wasted that has to follow a specific treatment and final disposal.

  Nuclear power plants have high investment cost (fixed costs) and lower variable cost so its short-run low marginal cost makes this technology to be operated base load. Its lower production cost, allows this units to recover most of its fixed cost by the energy market revenues.

  As this is a base load technology, these plants plays a key role providing security of supply.

  In Europe 28 the Nuclear Installed Electricity Capacity accounts for around 12% of the total Technology mix and provides 50% of the European carbon-free electricity. It is expected a decrease of the total nuclear capacity in a future as only in three EU 28 countries are investing in new nuclear power plants.

  The Base Case stablishes a total of 20 GW of Nuclear Power Capacity in the system with a remaining useful-life of 20 years. So the nuclear power plants will be phased out after this period. It is supposed that the system will not invest again in this technology in the future. The main reason to do not invest in this technology is the social opposition and the environmental repercussion that makes difficult to get the permissions to invest as well as the higher investment cost that makes Nuclear Power plants a non-attractive technology to invest in.

The model stablishes a load factor of 90%. During the first 20 years this technology will be operating in the system and it will cover the base load of the system.

- **Coal-fired Power Plant:**

Coal power plants are based on burning fossil fuels to generate electricity. Coal-fired plants burn coal and capture the heat released to operate the steam turbine generator to produce energy.

The coal-fired power plants are the most world spread technology for electricity generation. Coal is a cheap fossil fuel for power plants (mostly to plants close to the mines as the transport price increases the total cost).

Coal technology is one of the most pollutant sources of power generation as it produces green-house gas emissions. There are different technologies, types of coal and emission-control systems that reduce the emissions but the adverse environmental impacts have result in worldwide commitments to reduce carbon emissions to mitigate global warming.

As a result, the share of this technology is decreasing in most of developed countries as in the European Union. On the other hand, developing countries are increasing their share coal-fired power plants as it represents the quickest and cheapest alternative to meet their energy needs.

This technology has high-medium investment costs and variable costs that depend on the type of plant and coal's origin and type. Historically coal-fired plants have operated full load but nowadays this technology is been replaced by other ones.

The European Union low-carbon economy roadmap suggest that by 2050 the EU should cut emissions to 80% below 1990 levels so the clean technologies plays an important role and that will lead to a reduction in coal-fired power plants.

The Base Case stablishes a total of 60 GW of installed capacity with a capacity load factor of 85% that will still have a useful-life of 5 years. These thermal plants are old coal power plants that during their useful-life have been making investments in order to meet the environmental standards.

As environmental policies are increasing the requirements that power plants have to meet, some of the installed coal power plants will have to close as they will not be able to keep investing in order to meet the environmental standards and other coal power plants will phase out as they reach the end of their useful-life. Within the model it is considered that coal power plants will not be replaced with new ones as the foreseen scenario stablishes that the most pollutant plants will disappeared in order to have a zero emissions portfolio to meet the environmental European commitments.

- **Renewables:**

Within this classification we can identify a wide range of technologies, as hydro, wind, solar, geothermal, tide, wave and ocean.

This study focuses on the wind and solar technologies that are growing around the world.

Wind and Solar power (PV and thermal) are clean sources of energy that does not have pollutant emissions.

These technologies have high investment costs but a very low operation and a maintenance costs. The huge development that these technologies have experience during the last years and the fact that both are an intermittent source of energy has made the technology mix in European Systems to evolve.

To cover the periods in which these plants are not operating it is needed back-up energy. So, conventional generators still have an important role to play at the present and future.

Renewables sources of energy in Europe have had an important growth during the last years. Wind installed capacity in EU 28 (2014) accounted for 13% and solar PV for 8%.

In 2014, 28 % of the gross electricity produced in EU 28 was due to renewables sources of energy. Wind power generation and solar are the renewables technologies which has increased their share in a greater percentage.

The Base Case stablishes 50 GW of wind installed capacity at the first period (T1) that will gradually increase its share up to 130 GW in the last years of the study.

Wind technology has a load capacity factor of 15% which gives an idea of the intermittency of this generation units.

As for the solar technology, it counts for 30 GW that, as the wind, will increase its share up to 65 GW after 35 years. The capacity factor considered for this technology is 10%.

Power generation from renewables is extremely dependant on weather conditions so the huge penetration of renewables with intermittent generation will have an impact on the future capacity share of other technologies.

- **Gas Turbines and Combined Cycle Gas Turbines (CCGT)**

The Gas Turbines Power Generation has two main configurations:

- Simple System with one gas turbine which drives the electrical power generator.
- Combined Cycle Gas Turbine: These plants combine both a gas and a steam turbine together in the same plant to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant.

CCGTs are a high efficiency power generation technology that has lower pollutant gas emissions compared to conventional thermal plants.

CCGT is a flexible technology as it can be operated based-load and during peaking hours. Some years ago there was a wide spread of this technology as it was expected to ensure a base load production, but nowadays in most EU countries this capacity is operating at the high demand periods.

To maintain stability due to the increase in renewables that has not a predictable power generation it is necessary to increase flexibility in power generation and this technology allows having a more flexible portfolio.

The Base Case scenario stablishes a 20 GW installed capacity with a capacity load factor of 85%. It is supposed that these turbines will have a remaining useful life of 20 years.

- **<u>Peaking power plants (Peakers)</u>**

  The technology considered in the model as "Peakers" is Open Cycle Gas Turbines.

  These are power plants with low efficiency. This technology (OCGT) present lower investment cost than CCGTs but an operation costs very expensive.

  They are a flexible technology so it can be operated in peak hours and can also contribute to the ancillary services requirements so it provides security of supply.

  The Base Case scenario stablishes a 5 GW installed capacity at the first period (T1) It is supposed that this generators will still have a remaining useful-life of 20 years.

New investment scenario:

The system has a long term scope of 40 years old. The Base Case stablishes that during these years some technologies will phase-out and will be replace with other generation plants.

This Base Case scenario shows the disappearance of nuclear and thermal plants and the increase of the renewables source of energy. It is also foreseen an increase in electricity demand that will result in a future need of capacity.

The increase of the intermittent generation will make necessary to invest in power generation to back up the demand during the periods in which the renewables sources of energy cannot operate.

The system needs to increase the share of capacity with flexible technologies that can switch from baseload to intermediate or peak load operation. This power plants need to be able to start-up and shut-down on a daily basis. This kind of technologies should also be able to respond to the ancillary services demand.

CCGTs and Peakers power plant are able to provide the needed flexible operation. As a result this study only focuses on these technologies (CCGTs and Peakers) to assess which one will be installed to optimize the system well-fare and the investor's benefits. The aim of these new investments is to ensure long term adequacy.

The hypothesis of these new investments stablishes that this technologies will have a useful life of 25 years and a load capacity factor of 85%.

This hypothesis remains constant during the time scope of the study.

2.2.3. Installed Capacity Scenario

The Base Case scenario's technology mix is based on Nuclear, Coal, CCGT, Peaker and Renewables generation. This scenario will evolve during the 40 years of study as it is represented in the table 1

Table 1. Total Installed Capacity in the Base Case

Capacity (GW)	T1 (Years 1-5)	T2 (Years 6-10)	T3 (Years 11-15)	T4 (Years 16-20)	T5 (Years 21-25)	T6 (Years 26-30)	T7 (Years 31-35)	T8 (Years 36-40)
Nuclear	20	20	20	20	0	0	0	0
Wind	50	60	70	80	90	100	120	130
Solar	30	35	40	45	50	55	60	65
Coal	60	0	0	0	0	0	0	0
CCGT	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	**185**	**140**	**155**	**170**	**140**	**155**	**180**	**195**

At the first period (T1) we can observe that the share of installed capacity comprises a wide range of technologies. It is a system with a great dependency on renewables but it counts with enough thermal and nuclear installed capacity to be operating base load and to back up the intermittent generation.

Figure 5 represents evolution of the share of the installed capacity that has been in operation since the first year of study. The chart represents the percentage of each technology at T1, T2 and T5 as this are the periods where we can observe the main differences in the technology mix.

These charts do not represent the needed installed capacity that will face the system, only the capacity that remains since the first period and the increase in renewables.

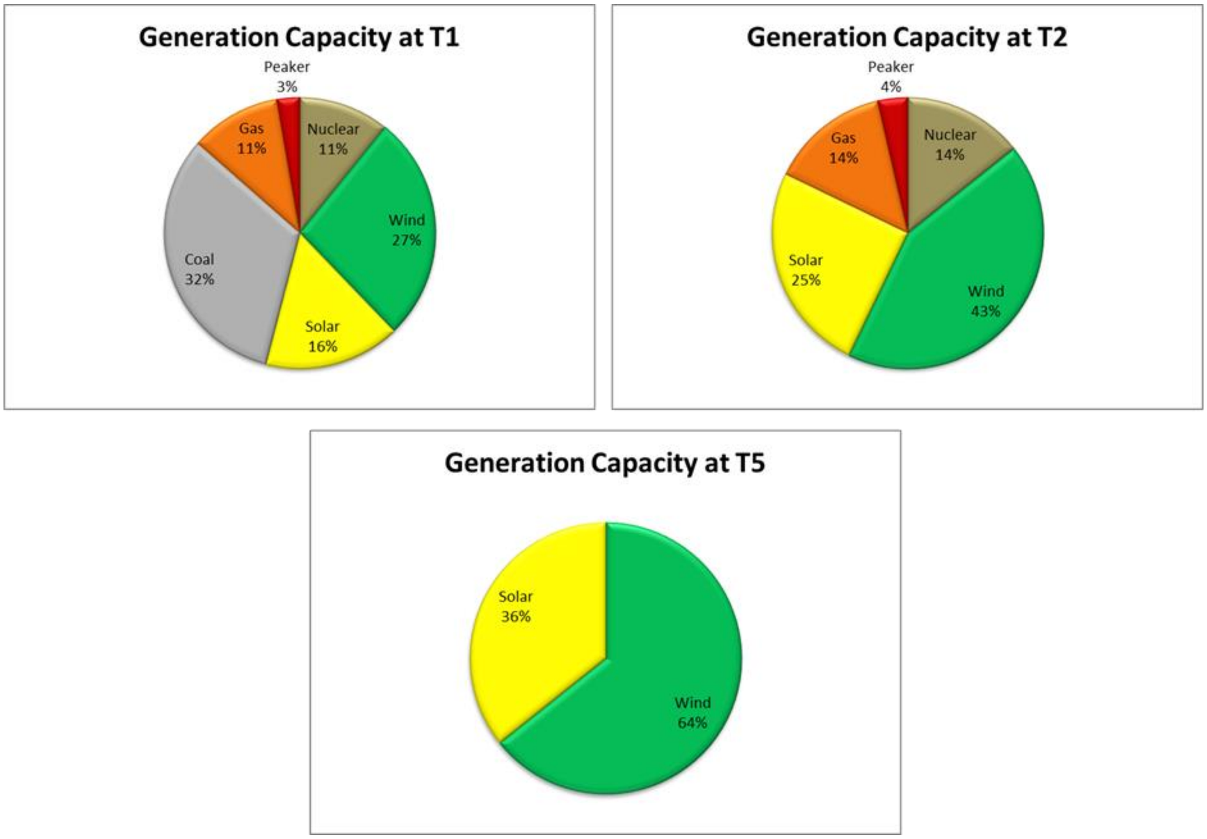

Figure 4. Evolution of the share of installed capacity. Base Case.

The Base Case's hypothesis stablishes that the system will face a need of investment in new capacity. The key points of the capacity generation future trends are:

- After the first 5 years of study, the fossil fuel plants (coal power plants in the Base Case) will not be in operation as the most pollutant power generation plant will phase out in order to meet the environmental commitments.

- At the end of the T4 (after 20 years of study) there will be a drop of nuclear generation as they will reach the end of its useful life and it is not foreseen new investments in this technology. During this period the CCGT and Peaker Plants that were in operation since the first year of the study will also reach the end of its useful life. The phase out of all this plants will increase the need of new investments.

- There will be an important increase in Renewable Capacity due to the growth of wind and solar plants to meet the EU energy policies.

2.2.4. Demand. Load Duration Curve.

Electricity demand is an indicator of development of a country so it is important to properly forecast the evolution of the consumption.

Although most countries will face an increase of the demand, the rate of growth varies from a developed to a developing country.

It can also be considered that there are some factors that can lead to a decrease in the demand. Investments in more efficient technologies, the efficient use of the energy and an economic crisis that can lead to a lower economic activity are some examples that can make the electricity demand to fall.

Electricity demand can be represented in different ways. The load duration curves are one of the most common representations and it can have different time scales. For the purpose of this study the demand is shown as an annual load duration curve.

This Load Duration Curve represents the number of hours that the demand exceeds a given load. This curve is represented in descending load values but it does not give information about the chronological demand. The annual peak demand is a characteristic of the chart that has a huge importance for the purpose of the model as it allows determining the needed capacity to meet the demand.

In order to ensure security of supply, it is vital to forecast the future demand and to make previsions of the needed capacity to cover this demand.

The Base Case Scenario hypothesis stablishes an annual demand of 300TWh with a peak load of 90 GW at the first period (T1). This hypothesis supposes a demand increase of 1% every 5 years.

The load duration curve is represented for the whole years in 10 blocks with different duration. Each block is defined by its level of load demand that remains constant within each block.

The Base Case's load duration curve for the first period (T1) is represented in Figure 6.

This Demand has to be covered with the existing de-rated capacity and new capacity. In Figure 7 we can see the technology mix that covers the peak demand during the first 5 years. The load is covered based on the merit order of the generation units. This merit order is the result of variable cost of the units and the energy market represented in the model.

Figure 7 and Figure 8 represent the situation where all the new installed capacity are CCGTs units although the model stablishes the possibilities to install both CCGT or Peakers. As the merit order depends on the variable cost, in the Annex is represented the load duration curves with the technologies for periods T1, T2 and T5 considering two investment scenarios where all the new capacity installed are CCGT or in case that all the new capacity are Peakers.

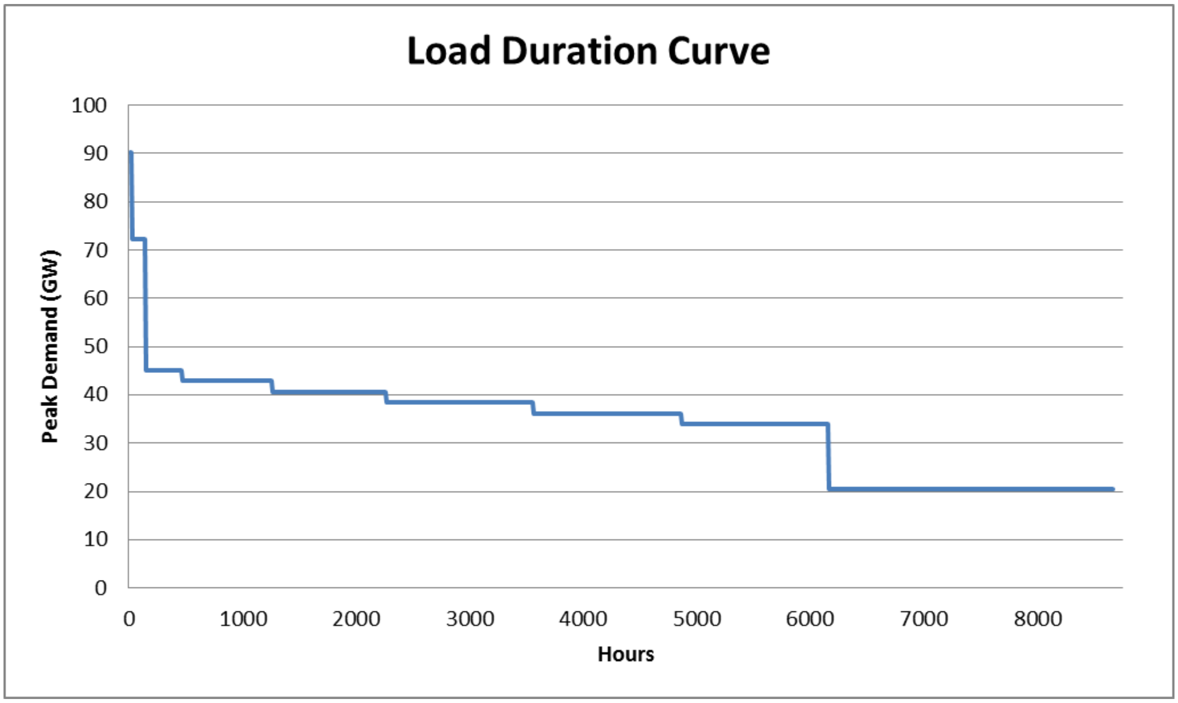

Figure 5. Load Duration Curve at T1

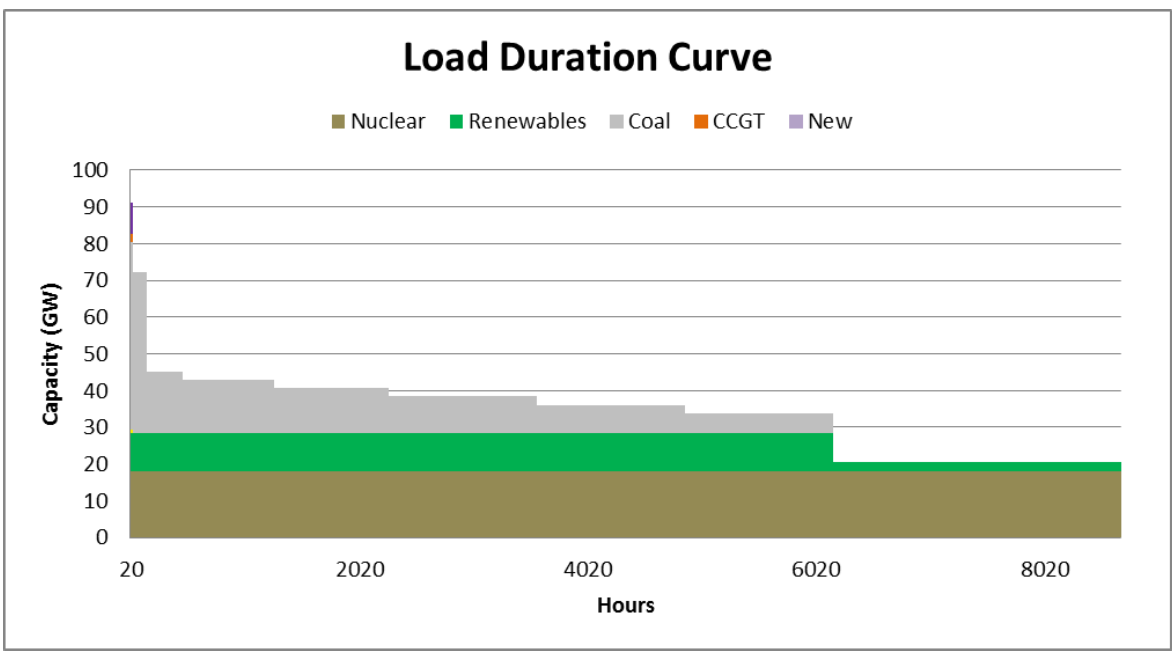

Figure 6. Load Duration Curve at T1 that is given with technologies.

If we focus on the peak demand of the year that corresponds to a period of 20 hours where the level of demand has reach the 90 GW, we can see that there is a need of around 10 GW of new installed Capacity to cover all the demand. The demand levels that are not the peak demand can be supplied with the existing technologies.

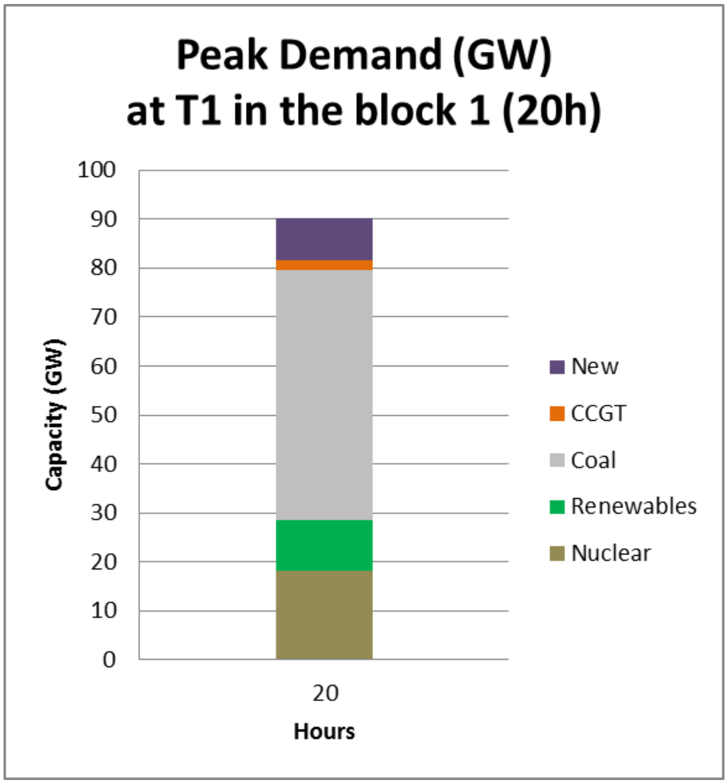

Figure 7. Peak Demand during 20h at T1.

2.2.5. ICAP

ICAP can refer to the first capacity markets designs that appeared in the world. But, for the purpose of this study, in the model, the ICAP or Installed Capacity Needed is the minimum peak load that has to be met in a period plus an additional capacity to cover the Installed Reserve Margin.

The ICAP level is the capacity that will be auctioned at the capacity auctions.

This capacity level should be based on the security of supply analysis carried out by the regulator. And it is determined as the amount of capacity needed to meet the reliability levels.

The needed installed capacity is normally determined by the delivery body, and is based on the experience of a panel of experts and on scenarios that provides the most probable energy needs that will be face the system.

This parameter of the capacity auctions is of great importance as if it is underestimated it can lead to security of supply problems as there will not be enough capacity to respond to the future electricity demand and fluctuations. But in case of been overestimated it can result in overinvestment and in an increase of the total cost of the system, what will have an impact on the consumers.

In the hypothesis of the Case Base it is considered that the margin (buffer between the peak demand and the foreseen capacity need) is 20% of the peak demand.

$$\boxed{ICAP = Peak\ Demand + 20\%}$$

This situation will lead to a need of investment in new capacity. As a result of the new investments there will be a different technology mix that will depend on the final technologies installed. (Figure 9).

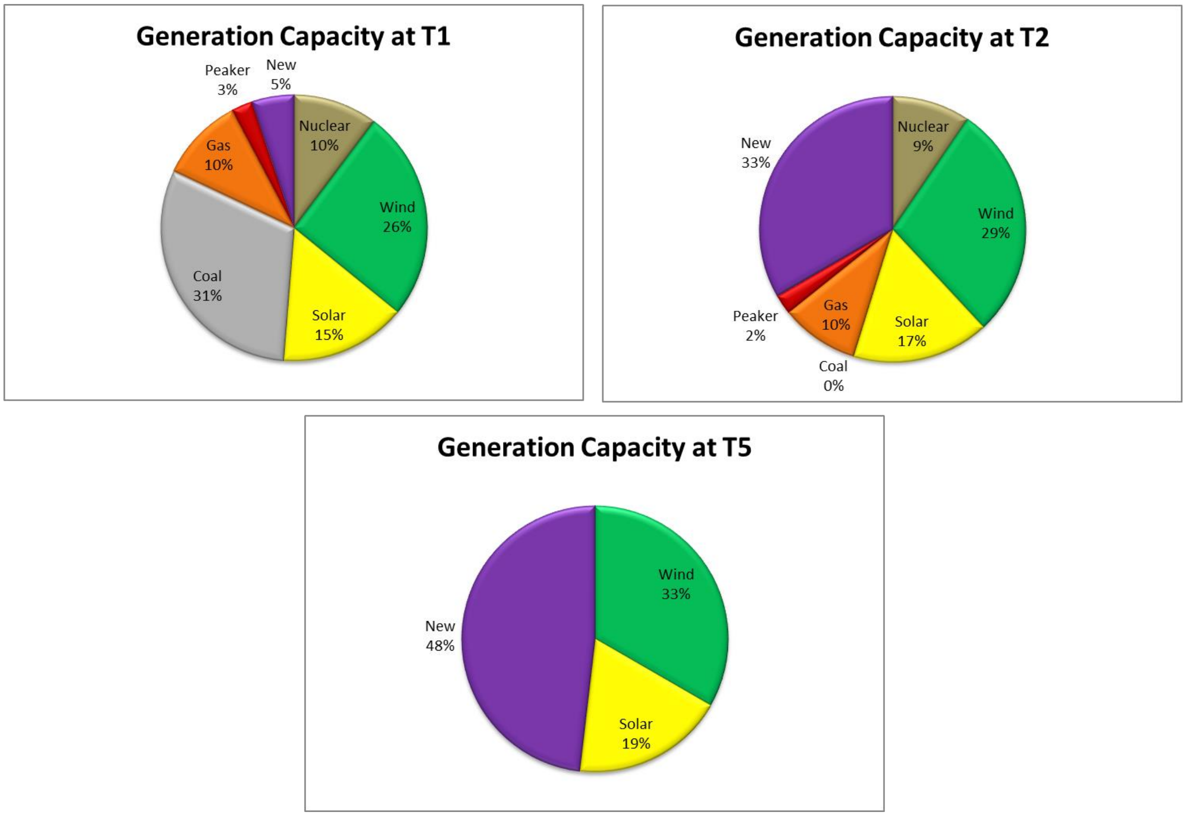

Figure 8. Technology mix taking into account the need of installed capacity

2.2.6. System Costs:

There are different costs associated to the generation of electricity within this costs it can be include the capital cost, operation and maintenance and fuel costs. In this model the total cost of the generating units have been divided into:

- CAPEX: Capital Expenditure: That is related with the investment and includes the cost of developing and constructing a plant and financing it. The units are in €/KW.

  In the model the CAPEX is represented in terms of remaining cost until the end of the useful life of each technology.

- OPEX: Operating Expenditures: That is the annual operating expenditure given in per unit of installed capacity. It covers the cost of the staff and the maintenance operations and repairs. OPEX can be divided into:

- Fixed OPEX: The fixed cost of operation and maintenance do not depend on the operating hours and include expenses for staff salaries, insurance, fees…)

- Variable OPEX: Operation and Maintenance costs that depends on the operating number of hours and produced electricity. Within variable O&M costs it is included the cost of activities related with the operation and maintenance of the generator that depends on the actual operation hours. These costs can include replacements, turbine maintenance, inspections, water treatment expenses…

- Variable Cost: Cost of producing in per unit of MWh produced. Within this classification we can define the fuel cost.

For the simplification of the model it is considered that the costs are an average total cost that remains constant during the study's scope.

Within the model, costs are divided into:

- Fixed costs :
  - CAPEX (investment cost) (€/KW): The study supposes an investment cost recovery during the useful-life of the generation unit.
  - OPEX (fixed operation and maintenance cost)) (€/KW-year)
- Production cost: cost of producing the energy (€/MWh)

In table 2 we can see the considered cost for the model.

For the Renewable Power Generation (Wind and Solar) it is not considered the investment costs as we suppose that these technologies has been subsidised and counts with different incomes to recover the capital cost.

Table 2. Generation Costs by technology

Technology	CAPEX Investment [€/kW] Remaining	OPEX (fixed Cost) €/KW-year	Variable Cost (€/MWh)
Nuclear	83.3	80.0	10.0
Wind	0.0	0.0	10.0
Solar	0.0	0.0	10.0
Coal	7.5	5.0	40.0
CCGT	16.0	5.0	60.0
Peaker	8.0	4.0	90.0
New CCGT	26.0	10.0	45.0
New Peaker	12.0	10.0	75.0

2.2.7. Pre-Tax Cash flow

The model determines the total cost for each technology and period of time and the incomes due to the electricity market.

The total cost of the System is the base of the optimal Centralized Planning Scenario while the cash flow is the base to define the optimal investment from the point of view of investors.

The cash flow for each unit is related with the auction bid that the generation unit has to summit in case of taking part in the capacity auction as it is based on the cost recovery that the unit need after the electricity market incomes.

The cash flow determined within the model is the Pre-Tax Cash Flow and it does not consider the taxes.

CASH FLOW = Electricity Market Revenues - Total Cost

Total Costs= CAPEX Investment Costs+ O&M Fixed Costs + Production costs

Within this cash flow simulation we can observe that only the generating units with lower fixed cost are able to recover their cost and make revenues from the Energy Only Markets.

So it is needed to implement a different cost recovery measures as the capacity auctions to incentivize new investments.

2.2.8. Electricity Market:

The wholesale electricity market represented in the model is the day-ahead market. Within this market the clearing price is determined based on the submitted bids by suppliers and demand. In the DA Markets the clearing price is calculated for each hour of the following day.

There are different options to define the supply offer:

- Cost based: the generator bids are based on their costs and define the maximum cost-based offer that may be submitted.
- Market based: within this scenario generators bids are based not only in their view of costs but also in other factors that can influence the market as operating risks and market forces.

There are also two kinds of markets depending on the pricing method:

- Pay-as-bid markets: where cleared generators are paid the bid they have submitted.
- Uniform price or System marginal price markets: Most of the European power markets have adopted this system. The clearing price is unique for each hour an each cleared generator are paid this marginal price.

The model is based on a System with Marginal Price Market and the supply offer is determined in a cost base analysis with the variable cost of the generation units.

Figure 10 shows an example of the aggregated supply and demand curves the cleared price as well as the quantity cleared in at the OMIE’s Day-Ahead Market for one session.

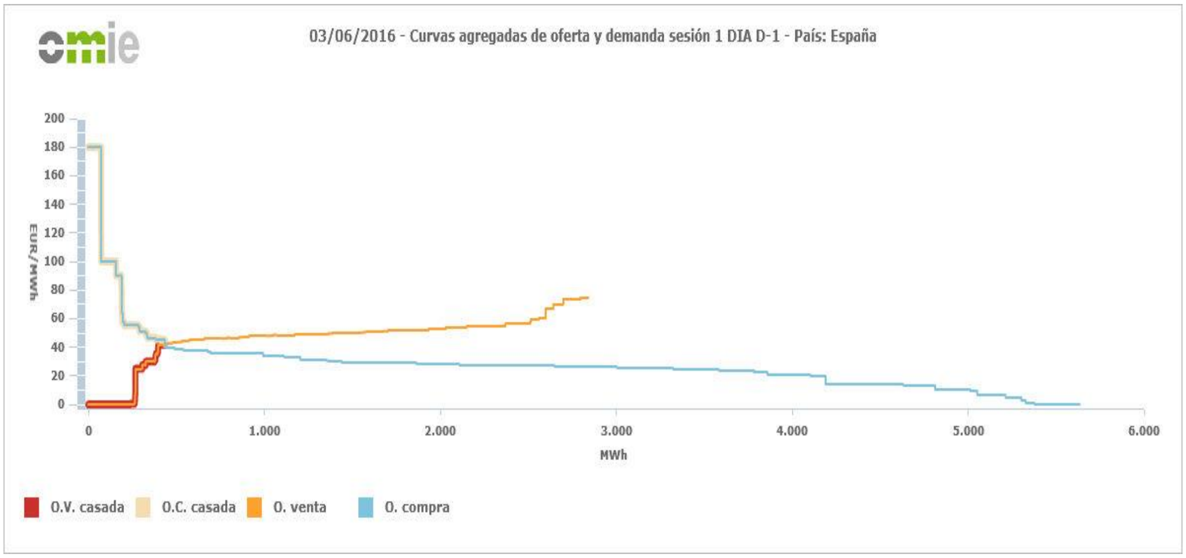

Figure 9. Clearing price in Day-Ahead Market. Source OMIE

2.2.9. Determining the wholesale electricity price:

In order to define the Market Revenues of each generating unit it has been modelled a cost-based supply offer. This model is based on de suppliers biding its marginal cost *i.e.* the cost of producing an additional unit of energy and it is based on their variable cost.

The clearing price for each hour is defined as the marginal cost of the marginal unit.

The clearing price at which the price of electricity is set is defined as the point where the supply and demand curves meet. The model sets the target demand as the peak demand for each sub-block and it is supposed an inelastic demand for each sub-block.

This model calculates a price for each of the sub-blocks in which the year has been divided according to the average demand level. So the model determines the clearing price as the minimum offer at which the demand is covered for each sub-block.

The clearing price is determined for each time period of 5 years (T1-T8) and within it for each of the 10 blocks in which the year is divided based on the average demand. So, for each sub-block we will have the same wholesale electricity price. And there will be 10 different prices within each year.

As for the electricity profit margin, it is defined as the difference between the bid submitted and the cleared price for each block with the same average load demand.

In Figure 11 we can observe the clearing price for the Base Case scenario at T1 supposing an inelastic demand equal to the peak demand and the supply offer established based on the variable cost of each technology. In this case it is supposed that the new technology installed is CCGT.

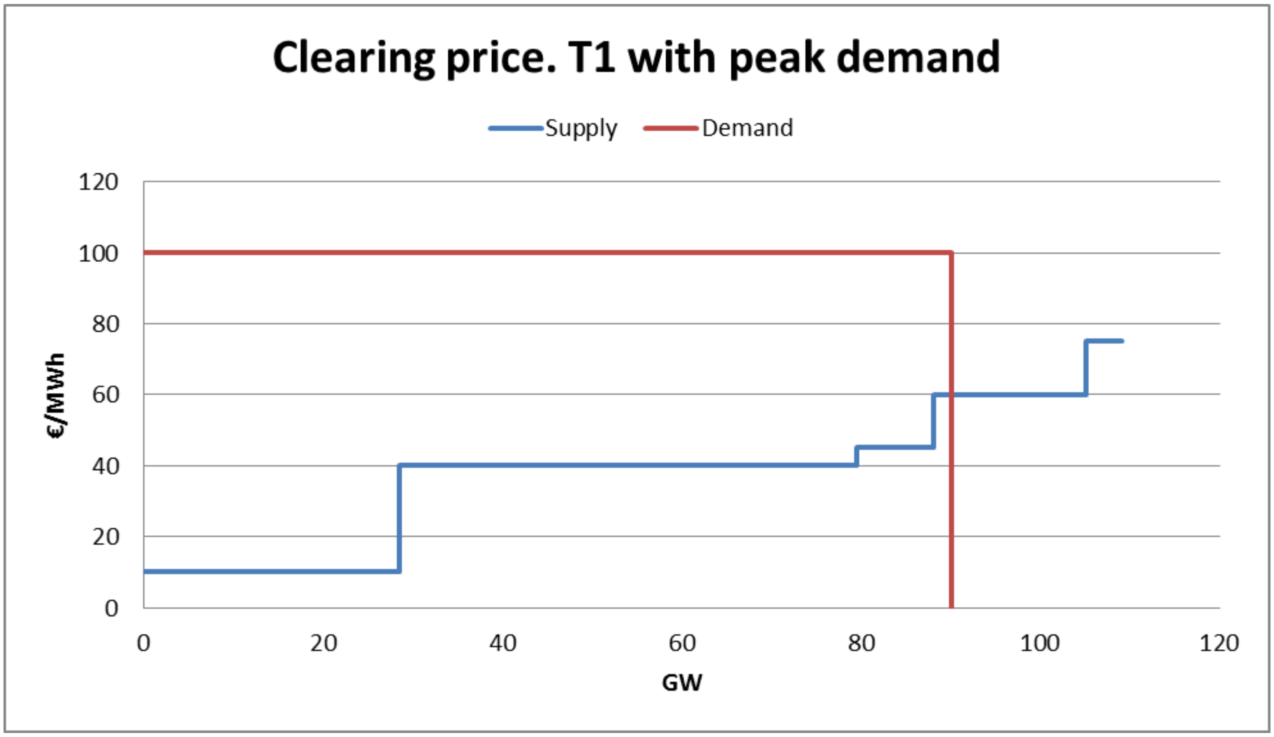

Figure 10. Clearing price for the T1 period with the peak demand.

2.2.10. Needed capacity

The Base Case scenario stablishes a hypothesis of installed capacity for each of the periods of the time scope.

Taking into account the de-rated installed capacity and the future needs of the system (ICAP) there will be a need of investments in new capacity in the future. The future needs are defined as the difference between the total de-rated capacity and the ICAP.

Table 3. Installed capacity and ICAP.

Capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
Nuclear	20	20	20	20	0	0	0	0
Wind	50	60	70	80	90	100	120	130
Solar	30	35	40	45	50	55	60	65
Coal	60	0	0	0	0	0	0	0
Gas	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	185	140	155	170	140	155	180	195
TOTAL de-rated capacity	101	52	54	56	19	21	24	26
ICAP	108	109	110	112	113	114	115	116

As it can be observed from the table, there is a need of investment in new capacity. The periods of time in which it will be necessary to make new investments are T1, T2, T5 and T7.

The need at T1 is the result of the difference between the current installed capacity and the foreseen needs of capacity for this period (ICAP for T1).

For T2 and T5, as there will be a phased out of some plants (coal fired power plants and nuclear power plants) there will be a higher need of new investments.

During the period T7 period the need of new investments is due to the end of the useful life of the new investments that have taken place during the first years as all the new capacity is supposed to have a useful life of 25 years.

The investment scenarios are taking into account that the same investor will build all the capacity needed within each block.

Table 4. Need of new investments for the Base Case

	T1	T2	T5	T7
Needed Capacity (GW)	10	60	60	50

2.2.11. Capacity Auction

The model defines the electricity system, and the electricity market for the time scope considered, this model also includes a simplified Capacity Auction as an example of a capacity remuneration mechanism, the aim of the capacity auction is to be able to assess how market agents will be able to recover their fixed costs. The capacity auction considered has the following characteristics:

- **The capacity needs. Amount of capacity to be auctioned.**

  The capacity needs have been stablished as the amount of capacity that will be required in the future to meet the reliability standards. For the purpose of the model, we have defined a needed capacity for each of the time periods T1-T8 and the value has been defined as the ICAP.

Table 5. Base Case ICAP

	T1	T2	T3	T4	T5	T6	T7	T8
ICAP (GW)	108	109	110	112	113	114	115	116

The needed capacity, as it has been explained before, is determined based on futures scenarios of demand and it includes a margin to cover the foreseen need of security of supply.

The capacity to be auctioned is based on the need of installed capacity but it does not take into account the capacity that will be available during the period of delivery. This capacity is considered to be available as it has other sources of incomes or is supported by other mechanisms to be able to pay for their investment costs.

In the model, de-rated capacity from renewables is not considered when determining the capacity to be auctioned.

- **Pre-qualification:**

The model supposed that each of the power generation plants that are considered have been eligible to offer capacity and to participate in the capacity auction with the exception of renewables sources of energy.

As it has been considered that renewables (Wind and Solar) have been incentivized and are awarder with subsidies, this technologies will not participate in the auction and its de-rated capacity is considered to be operating in the future so as it was explained the capacity to auction will be reduced in this amount.

- **Product:**

The product to be auctioned is firm capacity availability.

The capacity auction stablishes the amount of firm capacity that need to be available and the generators which has been considered eligible to participate offer their de-rated capacity to be available for the time scope of the auction.

- **Auction characteristics:**

For each delivery year the auction is held four years in advance. The objective is to have a lead time long enough to allow new participants to enter into the auction.

The aim is that there will be enough incentives for investors to build new plants with more efficient characteristics that will ensure future capacity needs.

If it was considered a shorter lead time investors could not take into consideration the capacity auctions to decide whether to invest or not, as only new plants which were already in construction could take part into the capacity auction.

- **Price takers and price makers**

The auction in the Base Case Scenario considerer that only the new investments are the price makers, so old plants are price takers. In case of not having any new plant for the auction the model considers that old plants can also be a price maker.

It is supposed that the new investment which bid a lower price will set the clearing price.

- ### Capacity agreements duration

The model considers for the Base Case scenario, a one year capacity agreement for all the participants that results cleared, both new and old plants. The auctions are held every year for capacity to be delivered four years later.

- ### Auction Format

The auction is “pay as clear” what means that all the participants that have been awarded with a capacity agreement will be paid the cleared price.

The cleared price is set by the price maker’s marginal bidder.

The auction format has a descending clock format. For the simplification of the model it is considered that the first round sets the clearing price.

- ### Bids

For the Base Case Scenario the bids that the generators offer in the auction are determined by its needed cost recovery. It is suppose that they bid with the knowledge that there will be capacity auctions during its useful-life, so each plant will be able to adjust their biding taking into account this hypothesis.

The bids are calculated within the cash flow analysis, so each generator’s bid (€/KW) is the cost per unit of capacity KW that the generator has not recover by the electricity margin taking into account all their fixed cost (CAPEX and OPEX).

- ### Penalties

As the analysis suppose that all the plants that results awarder with a capacity agreement will be available for the period of delivery, the model does not consider a penalty regimen, but when defining a capacity auction it is necessary to stablish penalties in case of non-delivery.

2.3.Results:

The Base Case aims to make a first analysis of the system from two different approaches and to determine which will be optimal investment scenario from each point of view:

- **Centralized Planning**:

  The aim of this analysis is to minimize the total costs of the system. It takes into account the total cost for each generation plant.

  This approach does not take into consideration the capacity auction to recover the generator's fixed costs. It assumes that the cost will be recovered by any mechanisms in the future.

  The model stablishes which is the optimal investment scenario that minimizes the total cost.

  After analysing the different investment scenarios that consider if in each of the time period where new capacity is needed it is installed CCGTs or Peakers plants. The scenario which reduces the total cost of the system so that represents the optimal solution of the ones analysed for the Centralized Planning is:

  - 10 GW of Peaker in T1
  - 60 GW of CCGT in T2
  - 60 GW of Peaker in T5
  - 50 GW of CCGT in T7

  We can observe in Figure 12 the share of installed capacity in this optimal scenario during the whole time scope.

  At table 8 there is the total cost of the system for this scenario comparing to the optimal scenario from the investor's point of view.

  With this scenario, the electricity market clearing price for each year can be seen at table 6. With this electricity revenues, the plants will be able to recover part of their total costs.

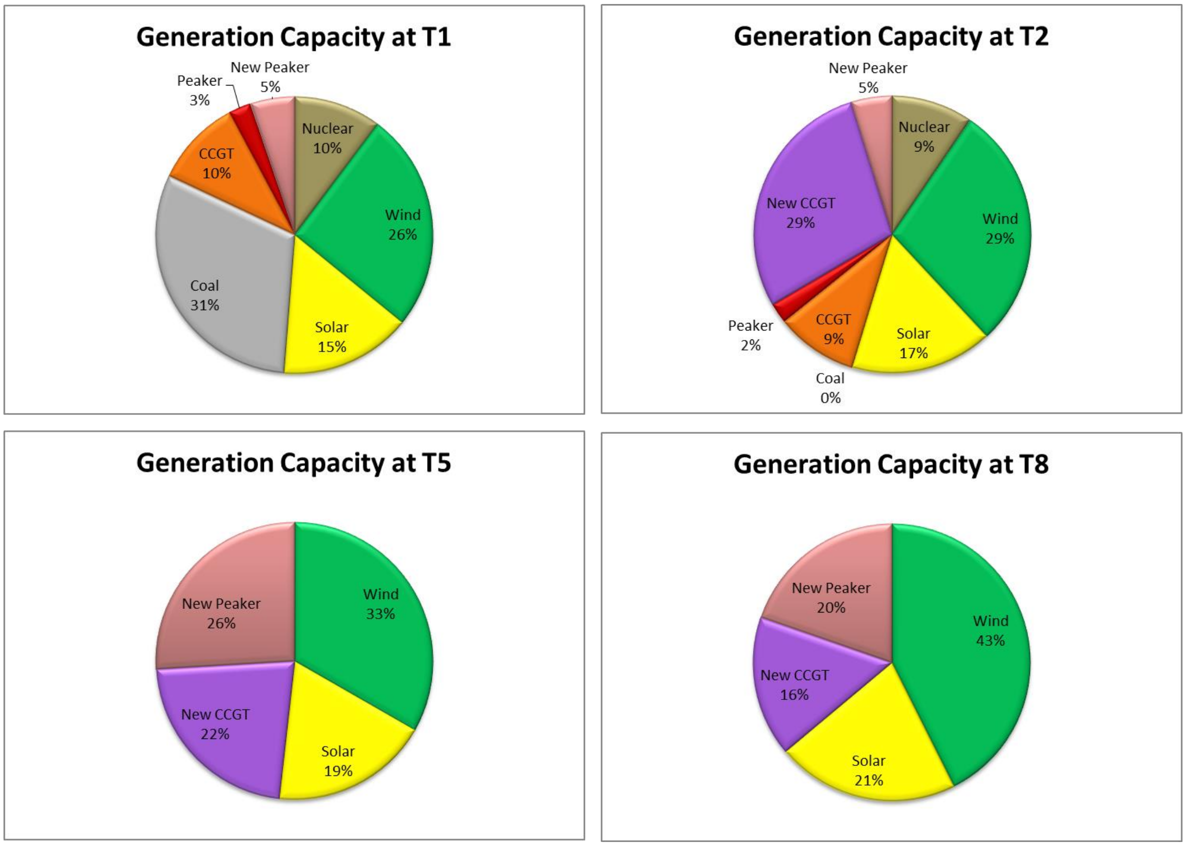

Figure 11. Share of installed capacity at T1, T2, T5 and T8 for the Case Base from the Centralized Planning approach

Table 6. Clearing price at electricity market (€/MWh) for Optimal Scenario in Centralized Planning approach for each period in the Base Case

Sub-block	T1	T2	T3	T4	T5	T6	T7	T8
1	60	60	60	60	75	75	75	75
2	40	45	45	45	75	75	75	75
3	40	45	45	45	45	45	45	45
4	40	45	45	45	45	45	45	45
5	40	45	45	45	45	45	45	45
6	40	45	45	45	45	45	45	45
7	40	45	45	45	45	45	45	45
8	40	45	45	45	45	45	45	45
9	10	10	10	10	45	45	10	10
10	10	10	10	10	45	45	10	10
Annual Mean (€/MWh)	31.14	34.65	34.65	34.65	45.48	45.48	35.09	35.09

- **Investors:**

The investor's approach aims to stablish which is the optimal investment scenario that will allow new plants to recover their fixed costs.

This approach is based on the capacity auction that has been described before.

For each of the scenarios the model stablishes the most probable investment that an investor will do.

The objective is to minimize the total cost that has to recover, so this will be the most probable scenario as the investor will look for a more stable cost recovery from the capacity auctions. The needed cost recovery takes into account the total cost of each plant (production costs and fixed costs) and the electricity market revenues.

It is considered that the investor will have the incentives to invest in the technology that minimized the bid that has to summit in the auction so this situation will make more probable that the new generator will be cleared in the auction and will receive the capacity payment to cover its cost.

The optimal solution for this approach is:

- 10 GW of CCGT in T1
- 60 GW of Peaker in T2
- 60 GW of CCGT in T5
- 50 GW of Peaker in T7

We can observe in the following figure and table the share of installed capacity and the market prices that will allow the plants to recover part of their costs.

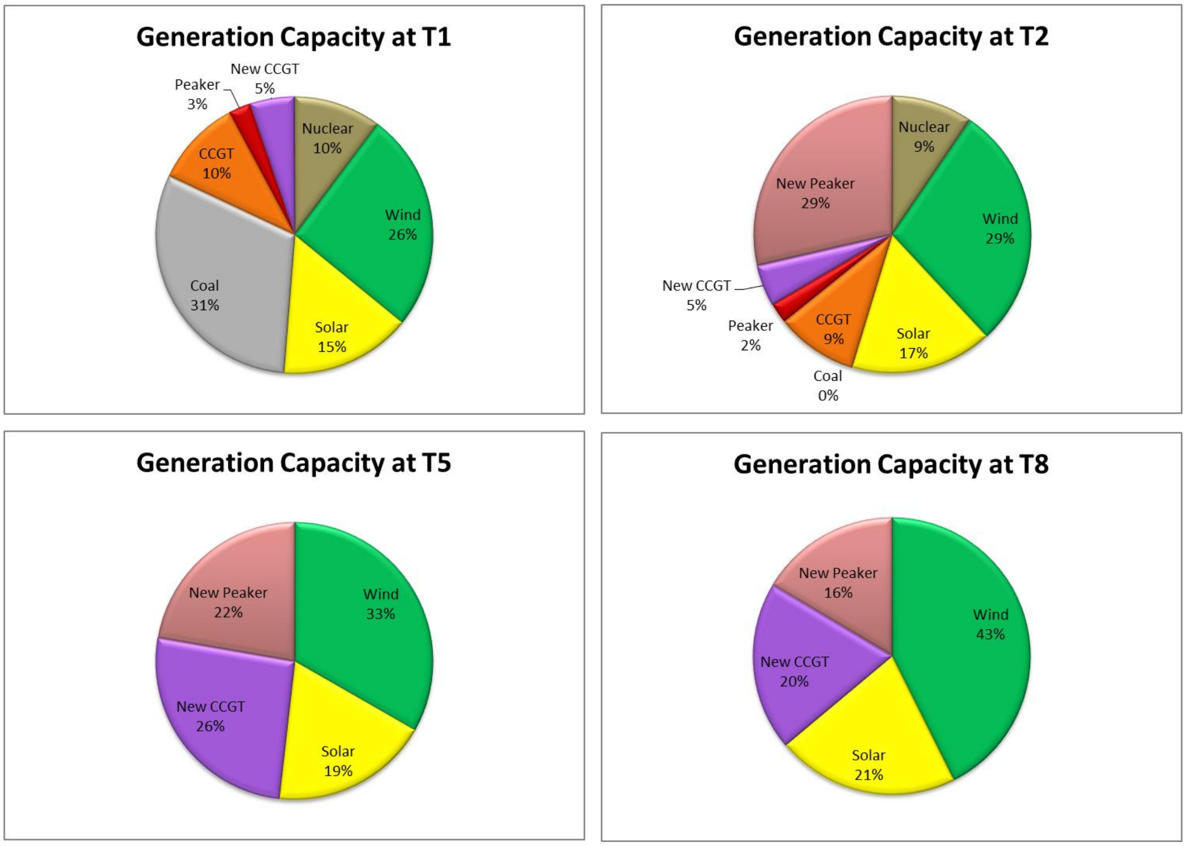

Figure 12. Share of installed capacity at T1, T2, T5 and T8 for the Case Base from the Market Agent's approach

Table 7. Clearing price at electricity market (€/MWh) for Optimal Scenario in Market Agent's approach for each period in the Base Case

Sub-block	T1	T2	T3	T4	T5	T6	T7	T8
1	60	75	75	75	75	75	75	75
2	40	75	75	75	45	75	75	75
3	40	60	60	60	45	45	45	45
4	40	60	60	60	45	45	45	45
5	40	60	60	45	45	45	45	45
6	40	45	45	45	45	45	45	45
7	40	45	45	45	45	45	45	45
8	40	45	45	45	45	45	45	45
9	10	10	10	10	45	45	10	10
10	10	10	10	10	45	45	10	10
Annual Mean (€/MWh)	31.14	38.72	38.72	37.01	45.07	45.48	35.09	35.09

The optimal investment scenario for each approaches are the represented in the table 8. The total cost consider the costs of production and fixed cost for each generation unit during the time scope of the study (40 years) with the exception of the new investments at T7 as for this investments is it not considered its useful life but only the first 10 years.

The results for each investment scenario are in the Annex III.

Table 8. Optimal investments in the Base Case

	T1	T2	T5	T7	Total Cost (M€)
Optimal for Centralized planning	Peaker	CCGT	Peaker	CCGT	**303 750**
Optimal for Investor	CCGT	Peaker	CCGT	Peaker	**349 562**

2.4.Conclusions:

The main conclusions from the Base Case's Analysis are:

- The first conclusion that we can extract from this scenario is that Energy Only Markets (EOM) are not able to recover all the system's fixed costs. The model analysed the total cost of each power plant and the incomes from the electricity market.

  Only old plants which have almost recovered all its fixed costs, and that have lower variable cost are able to recover all their costs and even to make market revenues within EOM.

  New plants that only count with the spike prices in electricity market during the peak demand are not able to recover all their fixed costs.

  This means that there will not be long-term signals to invest in new capacity with Energy Only Markets. So it is necessary to take additional measures and mechanisms to ensure the future capacity needs to guarantee the reliability standards.

- This model stablishes a simplified capacity auction to ensure that there will be enough capacity to cover the future demand.

  Capacity remuneration mechanisms send the correct signals to market agents to invest in new technology. This model is based on having a capacity auction every year for the time scope of study. So this scenario is the optimal taking into account that the market agents will be able to participate in the capacity auction during the useful life of new plants.

- The two approaches that have been taken into consideration reveal a total cost for the system that has not a huge difference.

- The main difference from the two approaches is that:

  - The Centralized Planning sees the system as a whole and so it has a long-term vision of the best investments for the system in terms of minimizing the costs.

  - The investor has a shorter term vision as it takes the decision on investments depending on the current signals given by the market. According to the decisions on investments, the market sooner or later will provide actual signals of the necessities of the System, so both solutions will tend to similar result, but the pathway could be different.

3. Case 2: Without Renewable Capacity

3.1. Introduction. Objective

There is an increasing interest in promotion of Renewable energy around the world; developed countries are undergoing an important change in their Electricity Systems as the penetration of renewables is becoming more significant.

Within the European Union the Renewable Energy Directive has as its main purpose the establishment of a European Energy Policy that has as a cornerstone the promotion of energy from renewable source. The specific target that the Directive stablishes is to achieve the 20% of energy production with renewables by 2020. This target needs to be accomplished through national measures.

Renewables are intermittent generators of energy that cannot be dispatched to respond to the demand when needed. This situation leads to a new scenario where other sources of energy need to back-up this technology when there is not electricity produced by renewables generation.

A small share of renewables can be absorbed by the system, as there should be enough capacity to respond not only to the fluctuation of demand but also there are some reserves that can respond to the variation of the renewables output. But, in the scenario that many countries are facing, with a huge penetration of renewables, Systems needs to adapt their existing portfolio to a new one with enough capacity to respond to the quick fluctuation of renewables generation.

This will call for new investments in flexible generation that can back-up the periods when renewables are not in operation.

In the Base Case it has been studied a scenario where the share of renewables was significantly growing. This Second Case Scenario is focus on the opposite situation.

The aim of this scenario is to see how investments would change in case of not having a renewable portfolio so there will be less need of capacity to back-up. The capacity needs will respond to the lack of installed generation from renewable sources so new capacity will be needed for power and for energy.

3.2. Differences with Base Case Scenario description of the system

The model that is the base to study this case is the same that has been used in the Base Case Scenario, but there are some inputs that have change.

3.2.1. Installed Capacity and Needed Capacity

The hypothesis for this scenario considers that there are not renewables sources of energy. This situation results in a need to invest in more capacity than in the first scenario.

Table 9 represents the installed capacity if we do not take into account the future new investments. After the first 20 years there will not be any capacity to meet the demand so the system will face a need of new generation power plants.

This scenario assumes that the demand and needed capacity (ICAP) of the Base Case do not change. Table 10 shows the need of capacity investments to cover the demand that was covered by renewables in the Case Base.

Table 9. Installed Capacity before new investments and future need of capacity (ICAP)

Capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
Nuclear	20	20	20	20	0	0	0	0
Wind								
Solar								
Coal	60	0	0	0	0	0	0	0
Gas	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	105	45	45	45	0	0	0	0
TOTAL de-rated capacity	90.25	39.25	39.25	39.25	0	0	0	0
ICAP	108	109	110	112	113	114	115	116

Table 10. New capacity needed

	T1	T2	T5	T7
Needed Capacity (GW)	30	60	80	60

3.3. Results

If we compare the different investments scenarios, where the market agents can just invest in one technology, we can observe that the Centralized Planning System will face an increase of total costs as the investment has suffered a significant growth comparing with the Base Case Scenario.

This increase in total cost is due to the new technologies that substitute the renewables. As wind and solar were not taking into account the fixed costs for the system (because of recovering their fixed cost by other incomes) the CCGTs or Peaker installed to cover the gap of energy makes the total cost increase in an important proportion.

The system optimal investment is to invest in new CCGT technology, as the total cost (591.359 M€) are significant lower than investing in Peaker (1.077.348 M€)

The main reason is that, although Peaker's investment costs are lower than CCGT's investment cost, the Variable Cost is greater in the Peaker technology than in CCGT.

If all the needed capacity is replace by Peakers the marginal price of the Electricity Market will be set by this technology, and that will result in an increase in the total cost of production with respect to a CCGT investment scenario.

3.4.Conclusions

The hypothesis of increasing the need of new capacity by decreasing the share of renewables shows an optimal investment scenario with the CCGT technology as it will lead to a more reasonable cost because this new investments will be necessary not only for back-up capacity to cover peak demand and ancillary services but also in the daily basis to meet the valley hours demand.

The CCGT generation will provide more stable prices in the future as it has a lower production cost comparing to Peakers.

The investor, in case of not having other competitors would try to exercise market power by investing in Peakers in order to increase the Electricity Price, but if there are other investors that introduce cheaper production generation this will result in Peakers not been cleared in electricity market and not recovering their investment cost if there is no capacity payments.

In the first scenario, where there was a need just for capacity, and the new investments where producing few hours, the optimal solution was to increase the capacity with more Peaker units than in the case of having a higher need of installed capacity that has to respond to the demand not only at peaking hours.

4. Case 3. ICAP

4.1. Introduction. Objective

This scenario aims to assess the importance to properly define the needed installed capacity (ICAP) for the capacity auction and for the system.

An adequate definition of the future needs of capacity will result in an optimal investment scenario, but, in case of overestimating the need of future capacity although there will not be risks of security of supply in the future, it will result in overinvestments and over costs for the system.

For this scenario the model will assess two situations where there will be a huge need of capacity for the future years. The objective is to evaluate how the optimal investments could change depending on the system and the technology mix in the moment in which there is a need of capacity.

4.2. Hypothesis A

Within the first scenario there is an increase of the margin that is applied to determine the ICAP (the installed capacity that will need the system).

In this case the margin that is applied over the peak demand is 55%. This margin is considered as a very extreme situation that does not try to be a likely situation. The aim is to study a risky situation in order to see how this can affect the system.

Table 11 shows the technology mix and the future needs of capacity for this scenario. As a result we can see in table 12 the period of time where there will be an increasing need of new investments.

As it can be observed, there is a growing need of capacity at periods T1 and T5, the higher increase is in T1 as the stablished ICAP has been defined with a margin of 55% over the peak demand for this time period. At T5 all the investments that have been in operation since T1 will be phased-out, that will result in another increase in capacity needs.

The system will be the same as in the base case scenario and so will be the rest of the hypothesis.

Table 11. Technology mix and need of installed capacity for the future.

Capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
Nuclear	20	20	20	20	0	0	0	0
Wind	50	60	70	80	90	100	120	130
Solar	30	35	40	45	50	55	60	65
Coal	60	0	0	0	0	0	0	0
Gas	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	185	140	155	170	140	155	180	195
TOTAL de-rated capacity	101	52	54	56	19	21	24	26
ICAP	140	141	143	144	146	147	149	150

Table 12. Need of installed capacity

	T1	T2	T5	T7
Needed Capacity (GW)	50	60	100	50

4.3.Results hypothesis A.

After modelling the different possible investment scenario, which total cost for the system are represented in table 14, this situation leads to the result that the optimal investment scenario is to install a Peaker at T1, CCGT at T2, Peaker at T5 and CCGT at T7.

Table 13. Optimal investment for hypothesis A

	T1	T2	T5	T7
Scenario 6	Peaker	CCGT	Peaker	CCGT

Table 14. Total cost for the different investments scenarios

	T1	T2	T5	T7	Total Cost (M€)
Scenario 1	Peaker	Peaker	Peaker	Peaker	**564 536**
Scenario 2	Peaker	Peaker	Peaker	CCGT	**526 909**
Scenario 3	Peaker	Peaker	CCGT	Peaker	**405 605**
Scenario 4	Peaker	Peaker	CCGT	CCGT	**390 245**
Scenario 5	Peaker	CCGT	Peaker	Peaker	**380 977**
Scenario 6	Peaker	CCGT	Peaker	CCGT	**343 350**
Scenario 7	Peaker	CCGT	CCGT	Peaker	**415 220**
Scenario 8	Peaker	CCGT	CCGT	CCGT	**399 860**
Scenario 9	CCGT	Peaker	Peaker	Peaker	**441 661**
Scenario 10	CCGT	Peaker	Peaker	CCGT	**404 034**
Scenario 11	CCGT	Peaker	CCGT	Peaker	**408 158**
Scenario 12	CCGT	Peaker	CCGT	CCGT	**392 798**
Scenario 13	CCGT	CCGT	Peaker	Peaker	**397 361**
Scenario 14	CCGT	CCGT	Peaker	CCGT	**359 734**
Scenario 15	CCGT	CCGT	CCGT	Peaker	**432 631**
Scenario 16	CCGT	CCGT	CCGT	CCGT	**417 271**

The main reason for this situation is that at T1 there is just need to install capacity but not to provide energy for the system. The installed capacity does not result cleared in the electricity market, as a result the optimal investment is to install a Peaker that have lower fixed costs and higher variable costs.

The situation changes at T2 and during the following years, where, as some of the load-based power plants have phased out (coal power plants) there is a need of plants to produce energy. So the optimal situation will be the one that minimize the clearing price of electricity markets, as they have lower variable costs.

4.4.Hypothesis B.

This hypothesis is based on the same situation than in hypothesis A but in this case it is focused on increasing the need of installed capacity when there is need not only for capacity but also for electricity.

The aim of this scenario is to assess if there is any change when the need of capacity is placed on a different system scenario.

It is suppose that the higher need of capacity that the system will face is at time period T2 where base load power plants will disappear from the system. As this scenario aims to do the greater increase in capacity at T2, it is also suppose that there are new entrants to the system with no fixed costs (as these costs have different incomes) at T6. So at T5 the need of installed capacity will remain similar to the Case Base scenario and there will be more need of capacity at T7 when the installed capacity at T2 will phase out. Total need of new capacity is described in table 16.

Table 15 shows the electricity system evolution for this scenario.

This scenario to determine the ICAP supposes a 20% of margin over the peak demand at T1 and a 55% of margin from the period T2. It is an hypothetical situation that do not try to be a real case.

Table 15. Technology mix and need of installed capacity for the future. Case 3 Hypothesis B.

Capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
Nuclear	20	20	20	20	0	0	0	0
Wind	50	60	70	80	90	200	200	200
Solar	30	35	40	45	50	55	60	65
Coal	60	0	0	0	0	0	0	0
Gas	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	185	140	155	170	140	255	260	265
TOTAL de-rated capacity	101	52	54	56	19	36	36	37
ICAP	108	141	143	144	146	147	149	150

Table 16. Need of installed capacity. Case 3 Hypothesis B.

	T1	T2	T5	T7
Needed Capacity (GW)	10	100	50	90

4.5. Results hypothesis B

The simulation of the different investment scenarios and the total cost for the system that each scenario will produce is show in table 18. As a result in table 17 it can be observed the optimal investment scenario. This hypothesis stablishes as the optimal scenario a higher need to install CCGT comparing to the hypothesis A.

Table 17. Optimal investment. Case 3 hypothesis B

	T1	T2	T5	T7
Scenario 12	CCGT	Peaker	CCGT	CCGT

Table 18. Total cost for the different investments scenarios. Case 3 hypothesis B

	T1	T2	T5	T7	Total Cost (M€)
Scenario 1	Peaker	Peaker	Peaker	Peaker	443 112
Scenario 2	Peaker	Peaker	Peaker	CCGT	430 656
Scenario 3	Peaker	Peaker	CCGT	Peaker	316 936
Scenario 4	Peaker	Peaker	CCGT	CCGT	307 274
Scenario 5	Peaker	CCGT	Peaker	Peaker	324 080
Scenario 6	Peaker	CCGT	Peaker	CCGT	311 624
Scenario 7	Peaker	CCGT	CCGT	Peaker	340 639
Scenario 8	Peaker	CCGT	CCGT	CCGT	330 978
Scenario 9	CCGT	Peaker	Peaker	Peaker	384 337
Scenario 10	CCGT	Peaker	Peaker	CCGT	371 881
Scenario 11	CCGT	Peaker	CCGT	Peaker	309 901
Scenario 12	CCGT	Peaker	CCGT	CCGT	300 240
Scenario 13	CCGT	CCGT	Peaker	Peaker	327 532
Scenario 14	CCGT	CCGT	Peaker	CCGT	315 076
Scenario 15	CCGT	CCGT	CCGT	Peaker	344 091
Scenario 16	CCGT	CCGT	CCGT	CCGT	334 430

It could have been expected that the capacity at T2 will be covered by new CCGTs, as there is an increasing need of electricity for the system. The result shows that in this situation the optimal investment is to install at T2 a Peaker.

This is as a consequence of the huge investment that has been stablished. That makes that although installing the Peaker will increase the electricity market prices and as a result the production costs of the system. There will be a higher increase on fixed costs (and capacity revenues) if it is installed CCGTs than if investing in Peakers as their capital costs are lower.

4.6.Conclusion

The main conclusion of this Case is that it has a great importance to properly define the amount of capacity that will need the system as an inadequate definition of the ICAP can have huge impact on the system costs. If ICAP is overestimated there will be higher costs for the system but in case of an underestimation the system will probably face security of supply problems.

When defining the ICAP, it is also important to take into account not only the structure of the electricity system and the capacity remuneration parameters, but it has also a huge influence the electricity market definition and forecast. If electricity markets are not properly simulated there could be an inaccurate estimation of the remuneration that a power plant could have and that will lead to suboptimal investments in the system.

It is important to properly define all the parameters so the optimal signals for investors could be sent.

5. Case 4: Bidding offers in capacity auction

5.1. Introduction. Objective

The aim of Case 4 is to study how the definition of capacity remuneration parameters can affect the total cost of the system and the optimal signals send to the investors.

This Case assesses the total cost of the system from two different points of view:

- Centralized Planning approach which takes into account the total cost that all the generators will face.

- A system with capacity remuneration mechanism. In this case it will be studied two capacity auctions with different definitions of their parameters.

The characteristics of the capacity auction that are considered to change are the duration and the frequency of the capacity agreements. It is important for market agents to have the most accurate information about the system and the evolution of it. Depending on the information that market agents have about the future, they will decide on the investments they can make.

It is also important to take into consideration market agents' risk aversion as when participating in the capacity auctions they will have an important role to play. The new entrants' bidding offer will be different depending on the information they have about the characteristics of the auctions and how the system will evolve.

5.2.Hypothesis

This case is based on the Base Case's Electricity System.

It is supposed that the system will foresee the same capacity needs, and as a consequence the system will face new investments at periods T1, T2, T5 and T7.

As the goal of the study is to focus on how the parameters of the capacity auctions affect the system it is considered that all the new generation power plants that are needed will be CCGTs. The objective is to have a static hypothesis of the technology mix of the electricity system so the different simulations of capacity auction parameters are not influence by the different investments technologies.

Table 19. Capacity installed and future need of capacity.

Capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
Nuclear	20	20	20	20	0	0	0	0
Wind	50	60	70	80	90	100	120	130
Solar	30	35	40	45	50	55	60	65
Coal	60	0	0	0	0	0	0	0
CCGT	20	20	20	20	0	0	0	0
Peaker	5	5	5	5	0	0	0	0
TOTAL	185	140	155	170	140	155	180	195
TOTAL de-rated capacity	101	52	54	56	19	21	24	26
ICAP	108	109	110	112	113	114	115	116

Table 20. New installed capacity in Case 4

New installed capacity (GW)	T1	T2	T3	T4	T5	T6	T7	T8
New CCGTs	10	60			60		50	

As for the other inputs of the model, as the load duration curve, the peak demand and cost of the generation units, this Case 4 also establishes the same hypothesis than the Base Case scenario.

Regarding the electricity market simulation, it has the same characteristics as the Base Case, and it is supposed not to change during this simulation.

As it has been explained the objective is to isolate the effect of the capacity auction parameters assess from other effects that can affect the result of the system.

The analysis of the different scenarios is realized from different points of view so it could be compared total costs depending on the structure of the capacity payments.

- Total cost of the system from a Centralized point of view

  This scenario only takes into consideration the total cost of the system but it does not contemplate the electricity market revenues.

  The total cost of the system is determined as:

  - Total production cost (the variable cost of each unit times the energy produced during this period). This cost takes into consideration the capacity that will result cleared in the electricity market *i.e*. the produced energy, but it calculates the real the cost with the variable cost of the units.

  - Total Fixed cost (CAPEX + OPEX per KW). This cost depends on the installed capacity of each technology.

- Total cost of the system with capacity markets.

  This scenario contemplates two Auction's hypotheses. These auctions have some common characteristics.

  In both of the capacity auction the amount of capacity to be auctioned is the same. The product for both auctions is firm capacity to be available at the period of delivery. All the generation units with the exception of the renewables plants can participate in the auction.

  - Auction 1:

    This scenario contemplates an auction with a descending clock format that is paid as cleared. The clearing price will be the lower bidding price to cover all the needed capacity. And all the units that are awarder with capacity agreement will receive the same price cleared.

    As for the frequency of the capacity auctions, this scenario establishes that the auctions will be held each of the time periods (from T1 to T8).

    All the market agents that are eligible can participate in each of the capacity auctions, so new investors and old plants can assume that in case of been cleared they will be able to recover their fixed cost during the useful-life of its plants.

As it is foreseen that there will be capacity auctions in each period, the hypothesis establishes that the capacity agreements have a duration of 5 years for all the generation units (new and old plants). That means that every year the cleared units will receive the capacity remuneration.

The bidding offer of each unit is calculated as the needed recovery cost of each unit during its useful-life taking into account that there will be capacity auctions every period.

The total cost determined in this scenario is the sum of the production cost and the capacity payments for all the installed capacity that has participate into the auction.

- Auction 2:

As in Auction 1, this scenario contemplates an auction with a descending clock format that is paid as cleared. The clearing price will be the lower bidding price to cover all the needed capacity. And all the units that are awarder with capacity agreement will receive same the price cleared.

As for the frequency of the capacity auctions, this scenario establishes that the auctions will be held only at the periods where there is a need of capacity, *i.e.* there will only be capacity auctions at T1, T2, T5 and T7.

The duration of the capacity agreements is 15 years for new investments and 5 years for old plants.

This scenario contemplates a higher uncertainty comparing with auction 1, as market agents do not know in advance if there will be new capacity mechanism in the future. That result in new entrants bidding in order to recover their fixed cost within the 15 years that they will receive the payments of the capacity agreement.

New investments are price makers, and old investments are price takers.

The total cost of this scenario is the sum of production cost and capacity payments but taking into consideration that for old plants there will only be 5 years of capacity payments in each auction held.

5.3.Results

The simulation of the different scenarios within the model shows the total costs for each of the periods from the three points of view as well as the total cost for the whole time scope (40 years).

Table 21.Total cost of the system for the three approaches.

COSTS (M€)	T1	T2	T3	T4	T5	T6	T7	T8	Total
Production Cost	20 906	20 295	18 068	15 848	32 384	29 131	24 208	22 010	
Auction Cost1	20 421	20 843	20 804	20 854	23 389	21 590	19 800	19 800	
Auction Cost2	34 627	34 853	21 000	18 000	38 982	17 992	32 985	14 993	
Total Fixed Costs	24 294	31 344	31 344	31 344	23 422	21 611	19 811	19 811	
TOTAL COST with Auction 1	41 327	41 138	38 873	36 702	55 774	50 721	44 008	41 810	350 708
TOTAL COST with Auction 2	54 941	55 148	39 068	33 848	71 366	47 123	57 192	37 003	396 283
TOTAL COST without Auction	45 200	51 639	49 413	47 193	55 806	50 742	44 019	41 821	385 834

Table 22. Capacity auctions Clearing price.

Clearing price (€/MWh)	T1	T2	T3	T4	T5	T6	T7	T8
Auction 1	42.1	42.2	42.1	42.2	42.3	42.3	42.4	42.4
Auction 2	70.1	70.6			70.6		70.6	

As for the clearing price of capacity auctions, table 22 shows the price at each of the auctions that are held.

In Auction 1 the bidding offer of new and old investments is based on recovering the total costs of the generation power plants during the useful-life of each unit (25 years for new investments). The cost that has to be recovered through capacity auctions is determining taking into account the electricity markets revenues.

Regarding Auction 2, the bidding offer for new investments is determined by the hypothesis that new power plants have to recover their total needed cost during 15 years as this is the capacity payments duration. This situation leads to higher clearing prices in Auction 2 comparing with Auction 1. It has to be considered that this hypothesis does not take into account a price cap.

The results can be analysed in three time scope:

- <u>Costs in periods with new investments</u>

  During the periods T1 and T2 both capacity auctions are held.

  As it can be observed in the results at T1 the auction costs in Auction 1 is lower than in Auction 2 the main reason is that as both of the capacity auctions are paid as cleared, *i.e.* all the plants that are cleared in the auction will receive the same price and the clearing price in auction 1 is higher than at auction 2.

  With regard to the total costs of the system, Auction 2 has higher costs than the total cost of the system. The uncertainty of future capacity auctions makes the system to try to recover the cost in a shorter time and this leads to an increase in payments to all the generation units.

  If we compare Auction 1 with total cost of the system, we can see how the cost is lower in Auction 1, the main reason is that Auction bidding price internalize the electricity market revenues of each power plant while the Centralised Planning cost shows the total cost of production and fixed costs but does not takes into account the electricity market revenues.

  At T2 there is more fixed cost, as in the previous period instead of new CCGT there was coal generators that have almost recovered its investment cost.

- <u>Costs in periods where there is no need of new investments</u>

  During periods where there are no new investments (T3, T4, T6 and T8) there is a different situation in Auction 1 and Auction 2.

  Auction 1, has the same structure costs than in T1 and T2, as these auctions will be held and the participants will receive the clearing price for each period.

  Auction 2 will not be held, so the cost that this auction has is the result of the capacity payments that the new investments still receive (as the duration of the contracts is 15 years). At T3 the cost includes the payments of capacity contracts for new entrants in T1 and T2 while during the T4 period the costs are only from capacity contracts of new investments that where cleared at T2.

  For this reason total cost of Auction 2 in this period is lower than total cost of the system.

➢ Total cost during the time scope of the study (40 years).

If it is considered the cost during the whole time scope of the study (T1-T8) it can be seen that the higher costs are represented in Auction 2.

Auction 1 represents a more adjusted cost of the system as the market agents can bid with the knowledge that there will be capacity auctions during their useful-life so they will be able to recover their costs and even get a margin.

Auction 2 hypothesis represents greater uncertainty of the system, so the bidding offers are higher and that increases the total cost of this scenario.

As for the total cost of the system, as it has been explained these costs include the total fixed cost of all the generation units, but it does not take into account the electricity market that is internalized in the auctions' bidding offers. So Auction 1 has lower cost.

Cost recovery for old units assessment

If we compare the situation where there are capacity auctions every period (Auction 1) we can observe that all the old units not only recover their cost but also gain a margin with the auctions as these units get payments during all their useful life.

In auction 2 (where old units only get paid during 5 years (T1)) old units receive a higher price for 5 years but they don't receive more capacity payments. It is enough to get a margin for all but the old gas units that as they still have a 20 years of useful life so this units do not recover all their costs within T1. In case of having a second Auction at T2, we can observe how all the units increases in an important quantity the capacity revenues as the higher bidding price will allow the units to receive higher margins.

Table 23. Cost recovery for old units

	Auction 1 at T1	Auction 2 at T1	Auction 2 at T1 and T2
Nuclear	24 749	15 912	22 265
Coal	7 082	14 236	14 236
CCGT	5 907	-2 439	3 561
Peaker	2 377	290	1 790

5.4.Conclusions

From the results of the model we can see how total cost of the system can change depending on the duration of capacity agreements and frequency of the auctions.

It is also essential to properly define the electricity market of the system and the system itself.

It has also a huge importance to know how the system will evolve in the future, so market agents can take the best decisions when investing in new technology.

In case that the investor knows that there will be capacity auctions during the useful life of a new plant, and that there will not be more need of capacity the new investor can bid at the auction a price that represents its need of capacity investment for each year.

Uncertainty about the future capacity market revenues can make the system to increase its total cost, as a risk aversion investor will try to ensure its fixed cost by bidding higher prices. As we have seen, bids are closer to the real necessity of the inversion in capacity auctions when there is enough information about the future.

The length of the contracts should be long enough to recover the fixed cost of new investments so there system could send the optimal signals to market agents in order to recover their total costs and to invest in the most profitable technology.

If the duration of contracts is shorter, the bidding price in order to recover all the fixed cost would be higher than a hypothetical price cap. And if they bid lower, they may not recover all their cost so only investors with no risk aversion will invest in new capacity.

It is necessary to properly define the parameters of capacity auctions as an inadequate definition will result in suboptimal situation. This can lead to overinvestments (and increasing the total cost of the system) or underinvestment and a system with future security of supply problems.

So, if the centralized planning body ensure a system that allow new market agents to recover their investment cost, this will lead to a more adjusted cost and also to minimize the total cost of the system.

CONCLUSIONS

Capacity remuneration mechanism plays an important role to ensure long term adequacy in Electricity Systems. There are different approaches to tackle the reliability problems that a system can face.

This thesis analyse the different measures that have been implemented around the world to mitigate the security of supply problem. The aim of the thesis is to assess how capacity remuneration mechanisms can affect the system. The study makes a qualitative analysis of some of the capacity auction parameters in order to assess the influence that they can have in the system.

The main conclusions are:

- Energy Only Markets depends on scarcity periods where the spike electricity prices show an important increase to allow market agents to recover their investment cost. Under this scenario, market agents have to assume higher risks to invest in new technologies. This will result in not sending the optimal signals to investors in order to obtain the optimal Electricity System structure.

- Capacity Remuneration Mechanisms are an interesting option to ensure reliability of supply to the system as this mechanism can send long-term signals to market agents to invest in new capacity for the system.

- The uncertainty about the system evolution as the electricity demand, the future investments and the technology mix (as the increase of penetration of intermittent sources of energy) can lead to underinvestment and to problems to guarantee the security of supply.

- It is necessary for risk averse market agents to count with different mechanisms to ensure that they will be able to recover their investment costs. So the Centralized Planner body should guarantee a future scenario where market agents could have a more stable cost recovery situation.

- The different Cases studies with the capacity auctions scenarios shows that an adequate definition of the capacity auction parameters has a huge importance as an inadequate definition of them will result in suboptimal situation. This can lead to overinvestments (and increasing the total cost of the system) or underinvestment and a system with future security of supply problems.

- The capacity to be auctioned has to be properly defined. As this capacity is related with the future needs of capacity it has been determined that when defining a very high capacity need, the signals send to investors will end in an overinvestment scenario with huge impact on the costs for the system that will be result in increasing the costs for consumers and in an sub-optimal scenario.

  In case of underestimating the needed capacity the system will probably face security of supply problems.

- The duration of the Auction contract Agreements and the frequency of the Auctions should also be adequately defined as it will play an important role when sending the optimal signals to investors.

  The length of the contracts should be long enough to allow new investments to recover the fixed cost so there system could send the optimal signals to market agents and they could invest in the most profitable technology.

  If the market agent have enough information about the future capacity auctions and there is enough competition in the system the bidding offers and so the cleared auction price will be more adjusted to the real cost of the needed new investments. And this will lead to an optimal system.

  In case of having uncertainty about the characteristics of capacity auction, the more risk averse investors will not invest in new capacity and this can lead to lower competition and that the market agents that participate into the auction exercise market power. It is also important to set price caps in order to avoid this to happen.

- It is essential to properly define the lead time, it should be long enough to allow new entrants to build the needed capacity.

- Electricity market definition and forecast has a huge influence on the system. If electricity markets are not properly simulated there could be an inaccurate estimation of the remuneration that a power plant could have and that will lead to suboptimal investments in the system.

- It has also a huge importance to know how the system will evolve in the future, so market agents can take the best decisions when investing in new technology.

- Capacity mechanism should be properly designed in order to complement electricity market instead of distortion the results of them and to ensure that only the needed capacity is remunerated. So it should guarantee that there will not be non-competitive investments.

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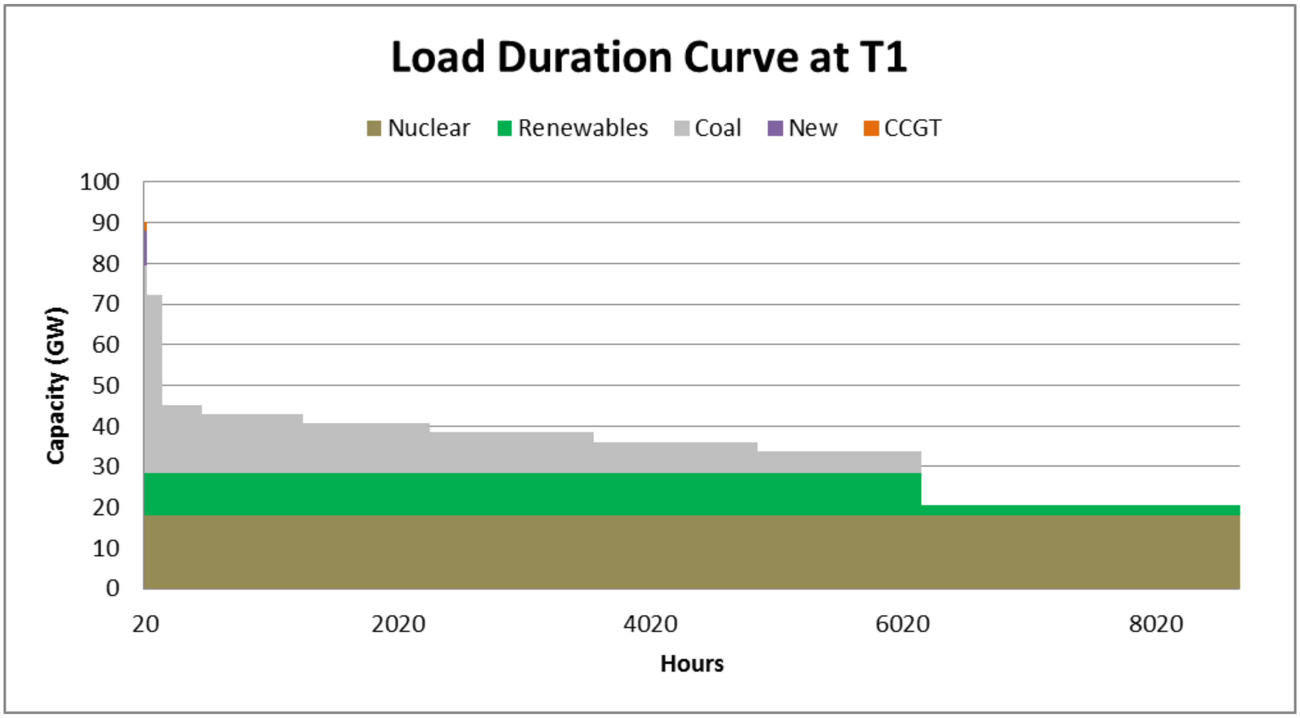
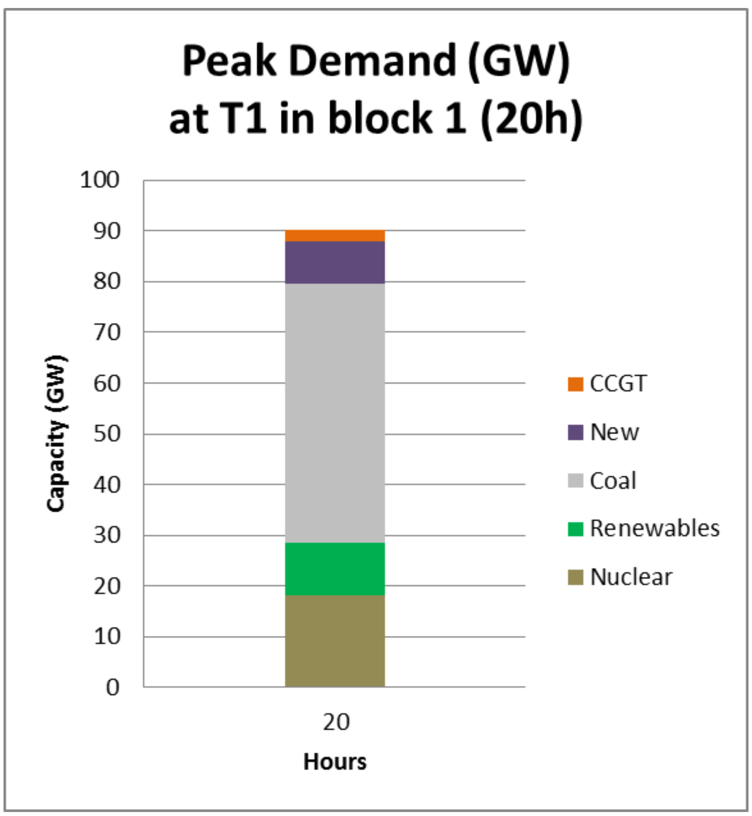
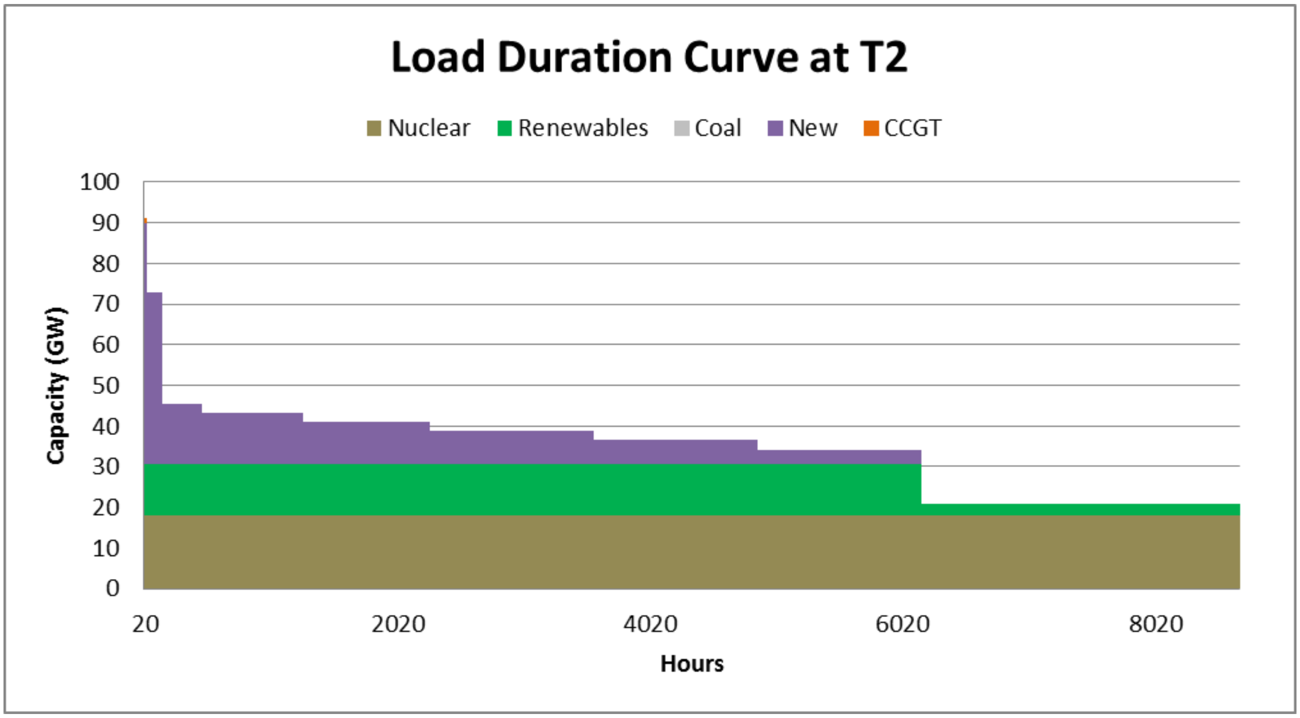
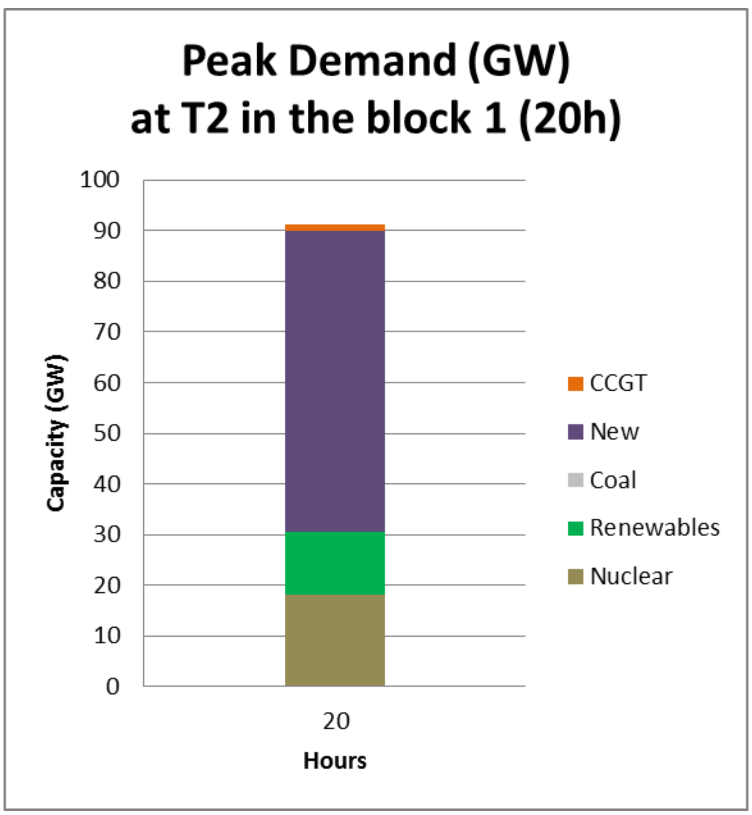
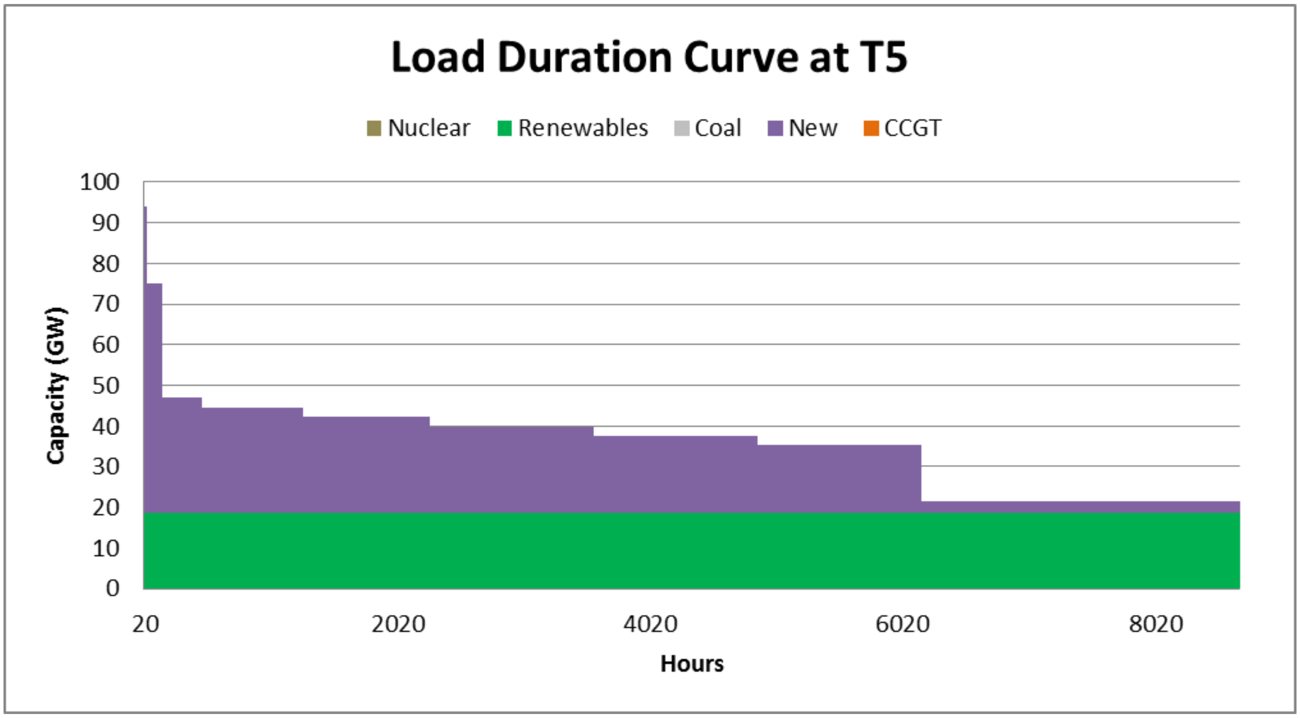
ANNEX I. Load Duration Curves. CCGTs' investment's Scenario.

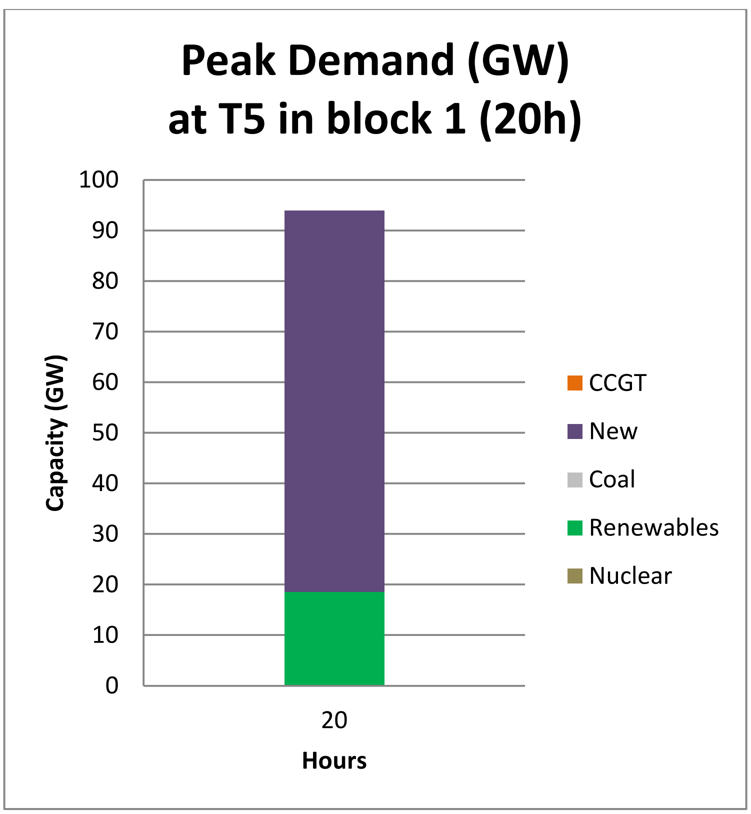




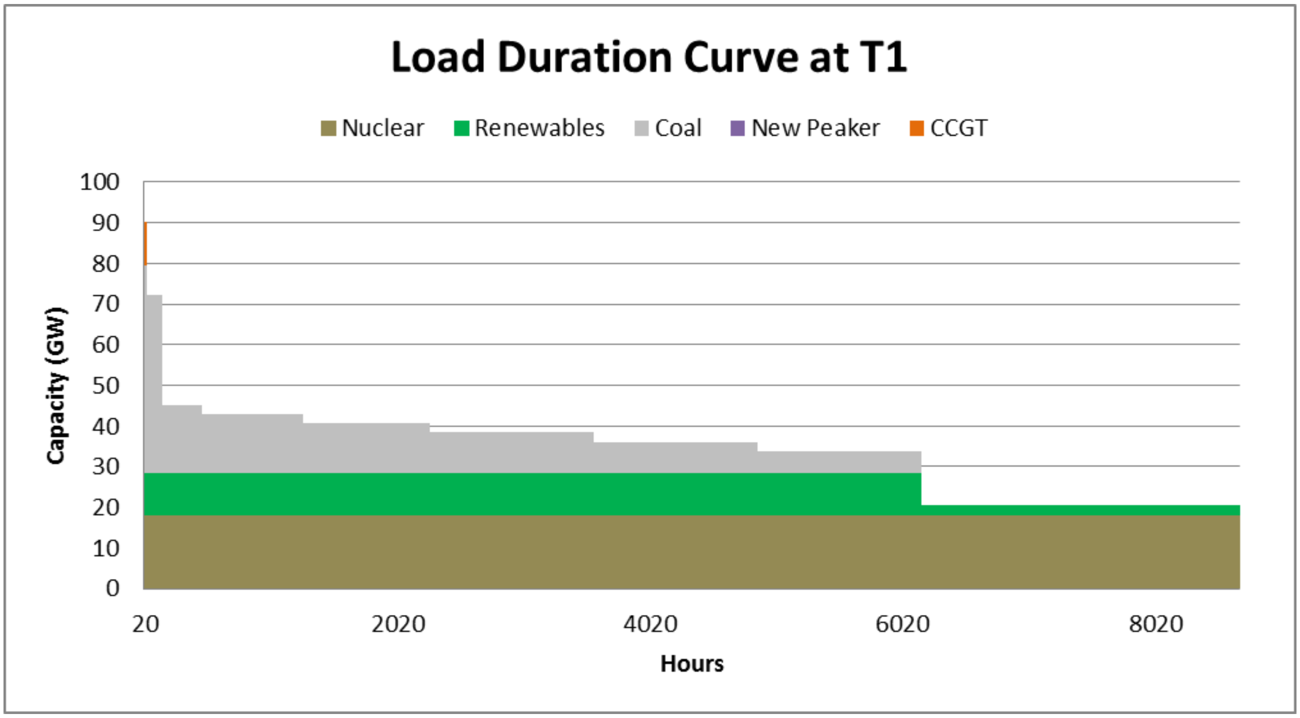

Load Duration Curve at T2
Nuclear
Renewables
Coal
New
CCGT
Capacity (GW)
100
90
80
70
60
50
40
30
20
10
0
20
2020
4020
6020
8020
Hours

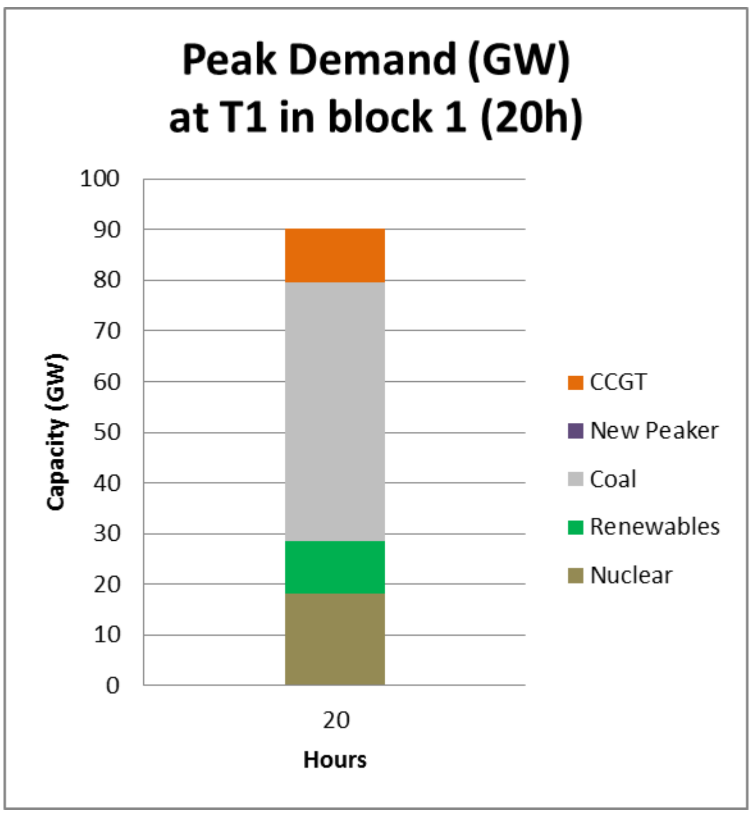

Peak Demand (GW)
at T2 in the block 1 (20h)
Capacity (GW)
100
90
80
70
60
50
40
30
20
10
0
20
Hours
CCGT
New
Coal
Renewables
Nuclear

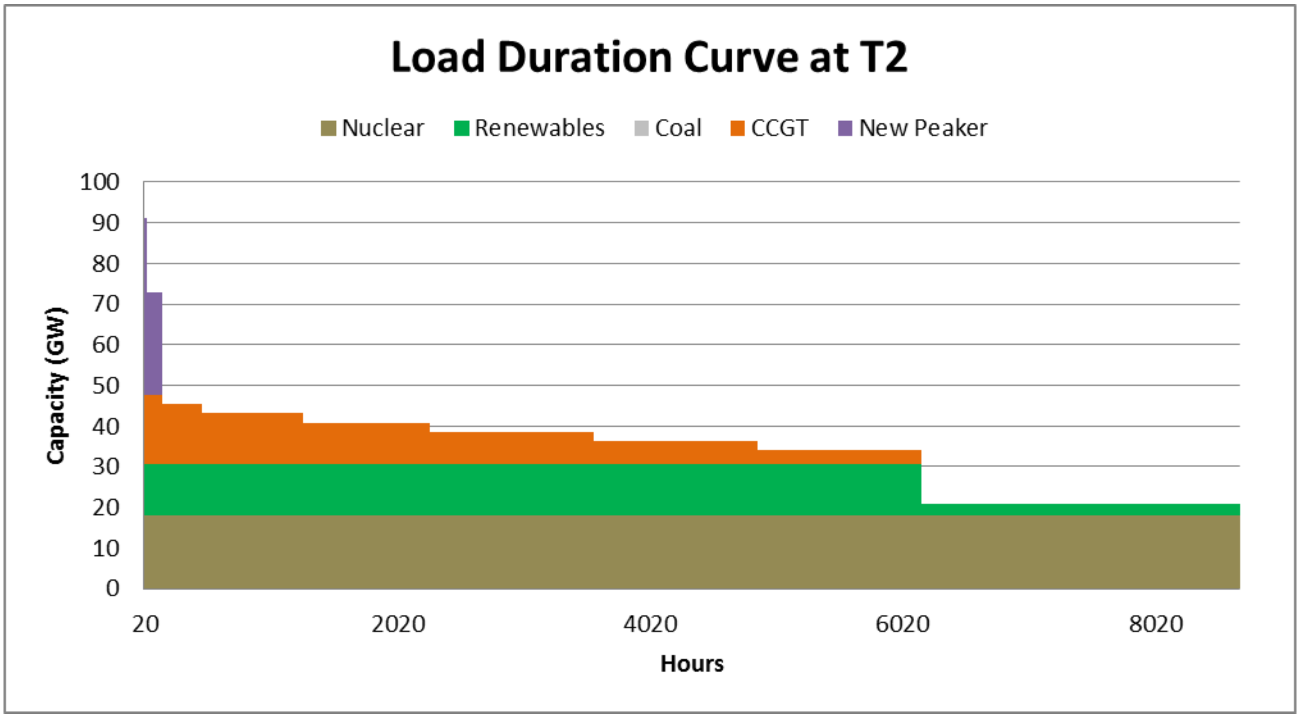

Load Duration Curve at T5
Nuclear
Renewables
Coal
New
CCGT
Capacity (GW)
100
90
80
70
60
50
40
30
20
10
0
20
2020
4020
6020
8020
Hours

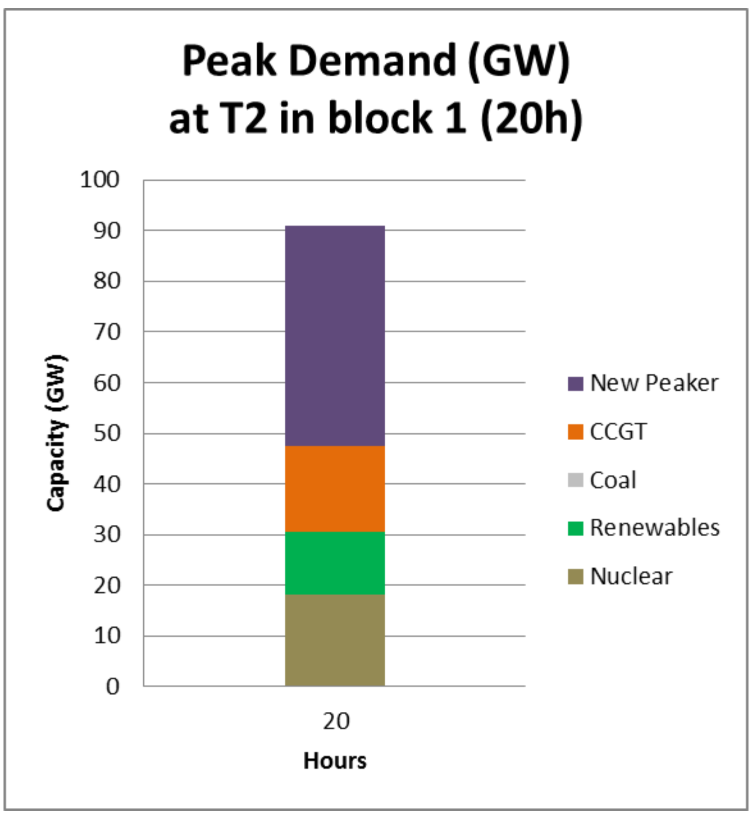

Peak Demand (GW)
at T5 in block 1 (20h)
Capacity (GW)
100
90
80
70
60
50
40
30
20
10
0
20
Hours
CCGT
New
Coal
Renewables
Nuclear

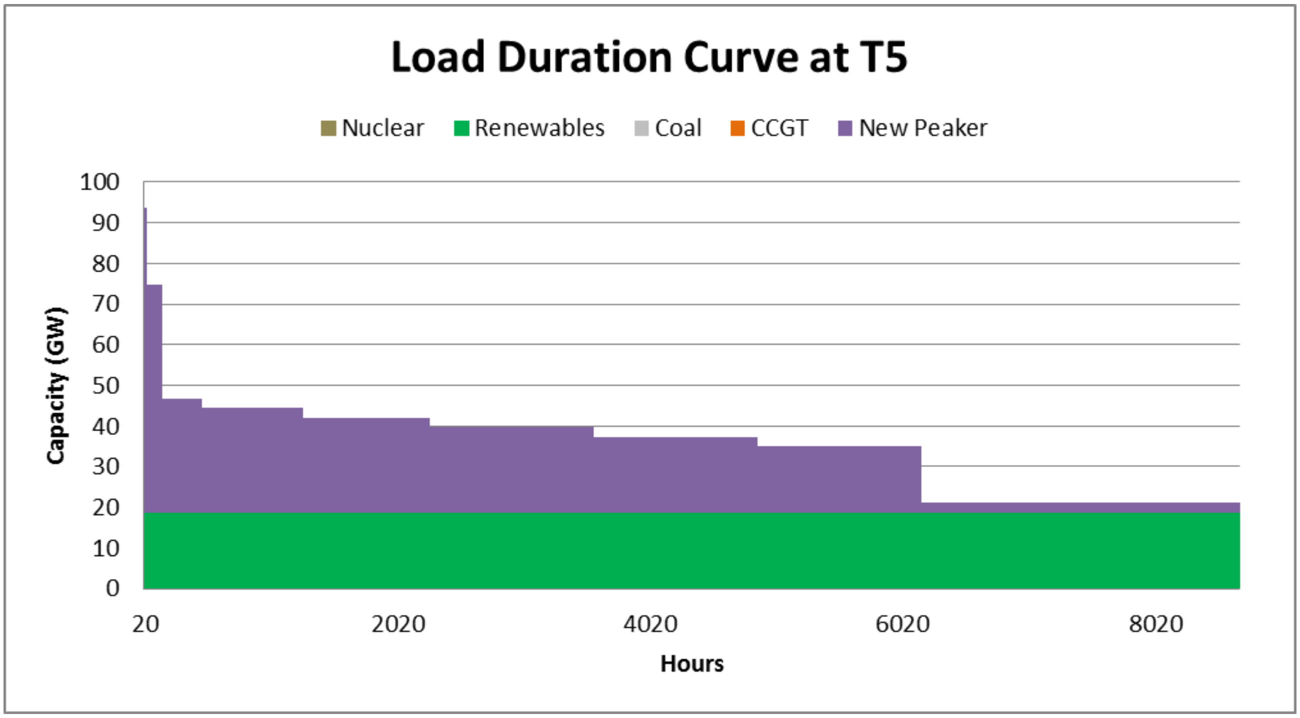
ANNEX II. Load Duration Curves. Peaker investment's Scenario.

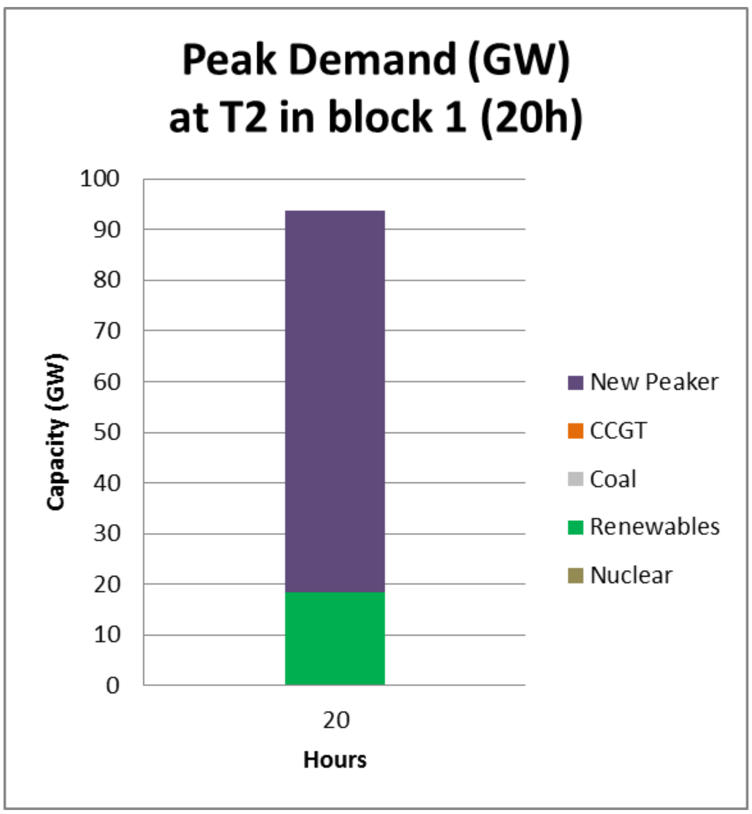





Load Duration Curve at T2
Nuclear
Renewables
Coal
CCGT
New Peaker
100
90
80
70
60
50
40
30
20
10
0
Capacity (GW)
20
2020
4020
6020
8020
Hours


Peak Demand (GW)
at T2 in block 1 (20h)
100
90
80
70
60
50
40
30
20
10
0
Capacity (GW)
New Peaker
CCGT
Coal
Renewables
Nuclear
20
Hours


Load Duration Curve at T5
Nuclear
Renewables
Coal
CCGT
New Peaker
100
90
80
70
60
50
40
30
20
10
0
Capacity (GW)
20
2020
4020
6020
8020
Hours


Peak Demand (GW)
at T2 in block 1 (20h)
100
90
80
70
60
50
40
30
20
10
0
Capacity (GW)
20
Hours
New Peaker
CCGT
Coal
Renewables
Nuclear

ANNEX III: Base Case Total Cost's Results

	T1	T2	T5	T7	Total Cost (M€)
Scenario 1	Peaker	Peaker	Peaker	Peaker	**524 936**
Scenario 2	Peaker	Peaker	Peaker	CCGT	**487 309**
Scenario 3	Peaker	Peaker	CCGT	Peaker	**356 278**
Scenario 4	Peaker	Peaker	CCGT	CCGT	**335 385**
Scenario 5	Peaker	CCGT	Peaker	Peaker	**341 377**
Scenario 6	Peaker	CCGT	Peaker	CCGT	**303 750**
Scenario 7	Peaker	CCGT	CCGT	Peaker	**364 351**
Scenario 8	Peaker	CCGT	CCGT	CCGT	**343 458**
Scenario 9	CCGT	Peaker	Peaker	Peaker	**466 161**
Scenario 10	CCGT	Peaker	Peaker	CCGT	**428 534**
Scenario 11	CCGT	Peaker	CCGT	Peaker	**349 562**
Scenario 12	CCGT	Peaker	CCGT	CCGT	**328 669**
Scenario 13	CCGT	CCGT	Peaker	Peaker	**344 051**
Scenario 14	CCGT	CCGT	Peaker	CCGT	**306 424**
Scenario 15	CCGT	CCGT	CCGT	Peaker	**367 767**
Scenario 16	CCGT	CCGT	CCGT	CCGT	**346 874**