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Master´s thesis

SIMULATION OF THE OPTIMAL PROGRAMING STRATEGY BETWEEN DIFFERENT MARKETS OF A PURE PUMPING STORAGE PLANT

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Abstract

The increasing incorporation of renewable energies in the electrical system needs more and more energy storage systems due to their intermittent associated production. Currently, the industry's state of the art technology is pumping hydropower, that can be seen as giant batteries, being able to store the excess of energy in the system when there is not enough demand and act as regulators balancing the system when needed. For this reason, it is essential to manage this type of facilities in an optimal way.

This project seeks to obtain, through the formulation of optimization models, the optimum scheduling of a pumping plant not only for a single market, but for several electricity markets. The models developed try to replicate the behavior of these markets as detailed as possible and, as a result, obtain a tool that maximizes the usage of the plant.

Due to the wide options of market participation that this kind of plant offers, only the daily and intraday markets have been studied considering all possible options for the management of the energy reserves that are stored through pumping and turbining.

The results obtained by the developed models have been satisfactory, fulfilling the proposed objectives. These results show that the optimal management of the plant depends on several factors, such as taxes, initial and final level of the upper reservoir, time horizon, market prices, competition in the market, and pump storage plant characteristics.

Acknowledgment

To Ignacio Zumalave for giving me the opportunity to be part of a great team and teach me aspects of energy markets that are not learned in classrooms.

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Finally, as it could not be otherwise, my parents, my brother and family who have always been there to support me in all the decisions along my way and more now in this new stage.

To all, thank you very much.

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Chapter 1: Introduction

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1.1 Motivation

Pumped storage units have been increasingly important in recent years due to the continuous integration of renewable energies in the electrical system. This trend is likely to continue as the Winter Package (European Commission, 2016) presented by the European Union states that half of the energy generated in Europe should be renewable by 2030 . Pumped storage assets enable the system to absorb the short term variations introduced by these renewables. This thesis proposes a model to optimize the management of these particular generation assets. The presented study will focus on pumping hydro assets in the Spanish electricity market context.

1.2 Problem description

The flexibility of pump-storage assets offers opportunities across the time horizon and the market sequence. The market agent operating the asset faces a vast amount of parameters to be taken into account when determining an optimal exploitation. Optimisation models are therefore required to be able to determine the best possible generation and pumping schedule while accounting for the complete costs and returns within the limitations imposed by the asset and the markets.

1.2.1 Hydro energy

Hydroelectric power is very present in Europe and around the world. This energy source takes advantage of the natural water flow to generate electrical energy. By harnessing the energy of the water, this source does not release any type of greenhouse gases and therefore reduces a country's dependence on fossil fuels. Next, we will explain the different types of generation assets that exist to take advantage of this resource.

1.2.1.1 Hydro plants

There is a vast amount of hydropower capacity installed throughout Europe, as shown in figure 1, which shows a high percentage of renewable energy. This type of energy is extremely flexible and features a very fast response, which makes it suitable to optimize the production of electricity through the network in response to sudden fluctuations of the demand.

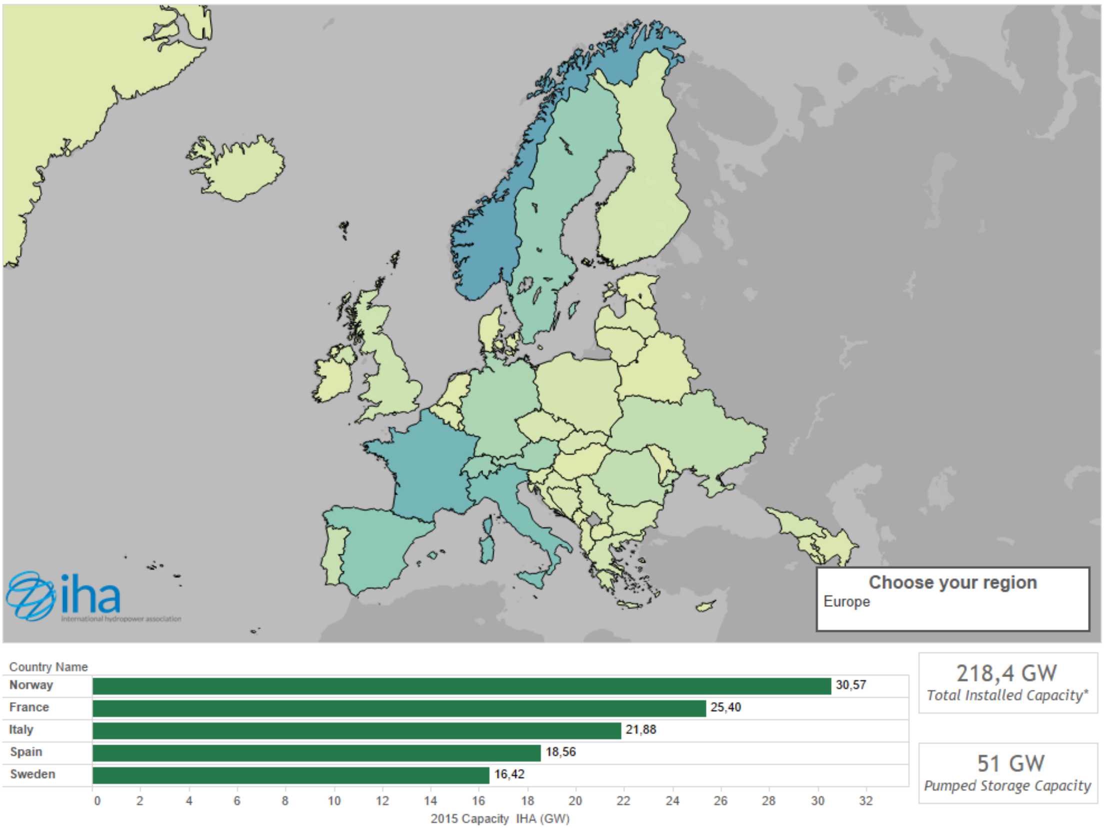

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Figure 1. Total hydroelectric power capacity in Europe. *Source: International hydropower association*

There are mainly three types of hydraulic production technology:

1- Run-of-river hydropower plant: This technology takes advantage of the continuous flow of the river for the electrical production. The production of the plant is conditioned mainly by the conditions of the fluvial flow which can be conditioned by the hydraulic installations upstream.

2- Reservoir hydropower plant: This type of facility is based on the storage of water resulting from the creation of an artificial reservoir in the basin of a river. Water is released through turbines that generate electrical energy.

3- Pumped storage plants: This special hydro power plants pump the water from a lower reservoir to an upper reservoir in order to turbine it afterwards to generate electric power. This type of facility is considered the primary way to store electricity. This type of hydraulic installation has several advantages, such as high efficiency, low operating cost and long service life. If the upper reservoir doesn't have inflows, these facilities are often referred to as "pure pumped storage plants".

This project focuses on pumped storage plants. For this type of facilities to be profitable, it is of uttermost importance to operate them optimally, pumping water at low price hours and generating electricity during peak hours. These types of power plants can also help the system operator by participating in ancillary services' markets.

1.2.1.2 Pump Storage Plants

The main characteristic of this type of hydraulic installations is that they have the capacity to pump water to an upper reservoir at a higher level and generate electricity by turbining water to the low reservoir, at the moment the asset manager decides is convenient.

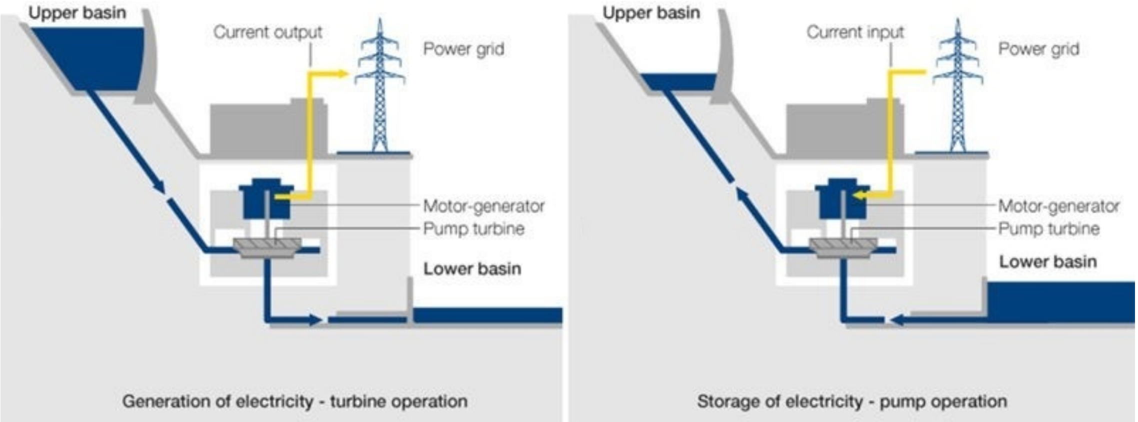

Figure 2. Hydroelectric pump storage working scheme. *Source: thehea.org*

This type of facilities are an efficient option for storing energy from non-flexible sources when the demand is low. For this reason, pumping power plants are profitable if valley hours are used to allocate pumping program, and consequently, electricity production is scheduled during peak hours.

One of the biggest barriers that we can find in this type of installation is the initial investment that must be made in the construction of the lower and upper reservoirs, in addition to the turbines.

Through optimization models it is possible to take advantage from the information available to the asset managers in order to achieve the maximum profit by making use of the above principle.

1.2.2 Electricity markets

Traditionally, the majority of the consumed electricity is traded in the day-ahead market, which is coupled with the rest of Europe. After the day-ahead market, Spain has its own set of auxiliary and balancing markets in which physical constrains and changing fundamentals are resolved. The flexibility of pump storage assets has an important added value in these electricity markets, which will be discussed in depth in the next chapter.

The proposed model in this thesis intends to look beyond the traditional day-ahead market optimization of pump storage assets. It will work out a framework to evaluate bidding strategies which include the main subsequent adjustment markets

1.2.3 Basic revenue mechanism

Given the basic logic of pumping in valley hours and depleting the upper reservoir during peak hours, the actual problem that asset managers face is to decide how to allocate the pumping and turbining program on a given time horizon. Previously, the decisions of when to carry out the pumping and generation operations were based on load duration curve and the experience of the operator in charge of making the offers to the electricity market.

Nowadays, different optimisation models (Braun & Hoffmann, 2016) have been developed to optimise these decisions, i.e. obtaining the maximum benefit from the asset.

1.3 Objective

Maximizing the profit of pump storage units in the context of various sequential markets requires adequate tools to support the elaboration of robust bidding strategies. Normally, pure pump storage plants have been optimised in a weekly cycle, filling the reservoir mainly during weekends and taking advantage of high prices during peak hours of week days to produce electricity by depleting the water stored in the upper reservoir.

The optimum weekly program of type of facilities can be carried out by means of the approach and subsequent resolution of an optimization problem, where a weekly forecast of daily market prices is required as inputs, taking into account forecasts of demand and eolicity and market behavior in recent weeks.

Finally, the objective of the present project is to go beyond the optimal programming of the daily markets and to develop one model that integrate different markets (ancillary services, Intraday Markets...) in the optimization program to obtain the best pumping and generation programs in all of them as well as evaluating different strategies for the future.

1.4 Document structure

The first chapter serves as an introduction to the problem that we are going to try to solve by carrying out the present project. It also includes the description of the objectives, motivations and background that justify the project.

A brief review of the state-of-the-art of pumped storage hydropower plants will be presented in chapter 2.

The Spanish electricity market will be described in Chapter 3 in a general context, focusing on the Day-ahead market and the differents sessions of intraday market, paying particular attention to the first intraday market. All this with the intention that the reader of the present project understands the market structure and has an overall view of it, since it is essential for the correct interpretation of the study and the conclusions drawn from it.

The methodology and the differents steps followed to develop the simple optimizaction model for the day-ahead market will be described and analysed in chapter 4. The main goal of this chapter is to understand step by step how the optimisation model has been developed and the different parameters and asumptions proposed.

In the next chapter 5 we will describe an optimisation model that takes into account both the day-ahead market and the first intraday market. The results of the model developed in this chapter will also be presented using the same scenarios considered in the previous model to be able to compare both results. Finally, a brief analysis and comparison will be made.

Finally, in chapter 6 will present a series of conclusions that can be drawn from the results obtained during the previous chapter while suggesting new directions to follow and future work to do.

Chapter 2: State-of-the-art review

Chapter 2 – Index

2.1 Introduction

The available information about optimization modeling problems of pump storage facilities or any other generation facility is not always easy to find because it is part of the definition of the strategy of the energy management of each one of the electric companies that Operate in different electric markets. However, it is easier to locate more purely academic information, but it can be perfectly applied when performing any model of optimization for a generation station.

2.2 State-of-the-art of optimization model of a hydropower storage plant.

The management of a pumping hydroelectric plant is especially particular because aside of being a power generation plant, it consumes large amounts of energy to supply water to the upper reservoir from the lower reservoir. These energy movements require additional management that other facilities do not require.

The operations in this type of facilities in the available electricity markets are double, i.e. it requires executing offers for the purchase and sale of energy for all hours of the day. In order to make these offers in the market, it is essential to make a good forecast of prices by analyzing the information available from competitors in the market and that normally provides in the long term, as far as possible, the market operator.

The management to determine and perform all the operations of purchase and sale of energy for each hour of the day after, plus determining the appropriate price at which to make the offer in the markets is not trivial. It is essential to apply an optimization problem of the production of the pump storage plant. This optimization problem does not have to be limited to calculating the production and optimum price of the offer for the daily market, but also to capturing opportunities beyond the daily market, which, in the case here developed, refer to the diferent intraday markets.

Looking at (Braun & Hoffmann, 2016), they develop an optimization model for pumping plants that takes into account not only the daily market but also the intraday market, which in the case of Germany is a continuous market with intervals of 15 minutes. The article provides enough information about how to carry out an optimization model on two consecutive markets, however, the idea behind the optimization model that develops is based on a multistage model due to the nature of the intraday market for which it was modeled, this is, continuous. The model is designed to run in real time, i.e. loop feeding data from time to time and thus obtaining optimal scheduling and prices to bid in the German continuous intraday market.

However, Sebastian Braun (Braun, 2016) develops a multi-stage optimization model considering the Spot and Intraday Auction markets for Germany, reason why it resembles more to the Iberian market. The main differences between the model developed by Braun and the one that is wanted by the present work is that it is a multistage model that first obtains an optimization for the daily market and uses the results extracted from it to execute a second optimization for the intraday market.

However, the methodology used by Braun does not take into account the liquidity of the daily market and the approach of that two separate optimization problems for each market can be computationally slow in the case of working with a high volume of data.

It is interesting to have information about the different strategies to follow when bidding in different electricity markets. For example, (A.Ugedo, et al., 2006) present a methodology to optimize the generation portfolio of a company by the usage of a stochastic optimization model. Applying the methodology developed in the article and clustering techniques, the optimal supply curves can be obtained for an agent that wants to sell its energy in each of the markets studied, daily, secondary-reserve and intraday markets. This article is especially relevant when determining a strategy to bid in different markets.

Chapter 3: Market context

Chapter 3 – Index

3.1 Introduction

It is fundamental to understand the Spanish electricity market well because it is the main topic on which is based the development of the optimization models that will be seen in the following chapters. During this chapter, a review will be made of the regulatory framework that governs this market followed by the description of the different markets that exist, focusing on the short term markets, those that are analyzes of this thesis.

3.2 European market context

Since its creation, the European Union has followed a firm path towards the creation of an internal energy market among member countries through policy and regulatory packages. The work done by the European Union will then be reviewed in order to better understand the rules and functioning of the electricity markets in Spain.

3.2.1 Regulatory Framework Overview

The supply of electricity constitutes a primary service, since economic and human activity can not be understood today without its existence. The management of this service distinguishes activities carried out under a natural monopoly regime and others under a market regime.

The approval of Law (Law 54/1997, 1997), of 27 November, on the Electricity Sector, marked the beginning of the process of the progressive liberalization of the sector through the opening of networks to third parties, the establishment of an organized market for the negotiation of energy and reduction of public intervention in the management of the system.

Thus, the vertical disintegration of the various activities was carried out, segregating activities under a natural monopoly, transportation and distribution, of those that are developed under free competition, generation and commercialization. The remuneration of the production activity was based on the organization of a wholesale market, abandoning the principle of recognition of costs. In the case of networks, the principle of third-party access to networks was established and their remuneration system would continue to be administratively fixed, depending on the costs of the activity. With this law also appeared the activity of commercialization of electric energy as an activity independent of the rest of activities for the supply, activity that was endowed with a normative framework to allow the freedom of contracting and election by the consumers. Finally, the management of the system was entrusted to both mercantile and private companies, respectively responsible for the economic and technical management of the system.

In this sense, this law (Law 54/1997, 1997), has contributed significantly to the fulfillment of the commitments derived from the Energy and Climate Change package (European commission, 2011), which set as targets, for 2020, the 20 percent reduction of greenhouse gases in the European Union compared to 1990, achieve a 20 percent share of renewable energy in primary energy and achieve a 20 percent improvement in energy efficiency.

In the following years, Directives 2003/54/EC (European Parliament, 2003) and 2009/72/EC (European Parliament, 2009), corresponding to the years 2003 and 2009 respectively, were introduced in the Spanish legislation as amendments to the previous law of 1997. Thus, we finally reached the main and more current regulatory law that exists in Spain, corresponding to the Electricity Sector Law that was approved in 2013, (Law 24/2013, 2013), which adopts urgent measures to ensure the financial stability of the electricity system, which among other things, Establishes a new remuneration regime for renewable energy generation, cogeneration and waste facilities and a series of additional remuneration principles for the transportation and distribution of electricity.

Therefore, thanks to this evolution in the regulatory framework, since the liberalization of the sector in 1997, have been strengthened characteristics such as: greater competition and liquidity in short-term markets through the increasing the interconnection electricity systems whitin Europe, transmission and distribution as regulated activities and generation and retailing completely liberalized, all consumers have free choice to choose their supplier, among others.

3.2.2 Historical Overview

Due to the adoption of the 1997 Directive, Spain began its process of liberalizing the electricity market in order to increase the competitiveness of electricity companies and to create a more efficient and fair system for all market participants. In 2007, it integrates the Portuguese and Spanish market under the management of MIBEL.

The following key points can be highlighted in the development of the liberalization of the electric system, which is still in constant development:

Unbundling of activities: The main idea is to create a complete separation of the regulated activities (transmission and distribution) from the competitive ones (generation and retailing). Specifically in Spain, most of the companies that existed prior to the implementation of the 1997 Directive (Law 54/1997, 1997) were vertically integrated, so a transmission company (REE) was created to separate the generation part of the transmission. REE (*Red Electica de España*) was the first company in the world in charge of the transmission and operation of the electrical system.

The exploitation of electricity networks (transport and distribution) is subject to significant economies of scale, which makes them a natural monopoly, making the introduction of competition in these activities inefficient. Directive 2003/54 / EC and its subsequent transposition into Spanish law (Law 17/2007) went deeper into this aspect and imposed on the vertically integrated groups the functional separation of their activities, which aims to guarantee the autonomy of management and decision of those responsible for the transmission and distribution networks.

Regarding retailing activities, the most significant event took place in 2010 when was the legal separation of Distribution System Operators (DSOs) from retailing activities, so DSOs no longer had the ability to offer electrical services to the clients. The new situation favored the proliferation of new companies that offered directly to consumers the services previously provided by the distributors, increasing the competitiveness in the sector, because before this new situation, the customer was able to choose the desired company. However, the latest packages (European Parliament, 2009) and (European Commission, 2016) and European directives are aimed at further enhancing competitiveness and transparency vis-à-vis the customer, highlighting figures such as aggregators and RES (Renewable Energy Sources).

<u>Privatization</u>: Prior to liberation, in most countries in Europe, state power companies (public national companies) governed the electricity sector, so the assets belonging to the system were placed under private management (generation and distribution) or to new companies (REE - Transmission) created for the management of regulated assets.

<u>Deregulation</u>: The deregulation of the activities associated with the generation and commercialization businesses were deregulated in order to increase efficiency by subjecting them to participate in a more competitive context in open markets. In the case of generation, a wholesale electricity market was created, where buyers and sellers can conduct transactions according to the rules of free trading. Due to the nature of the product, these markets are always under strict supervision by public bodies responsible for ensuring that transactions are carried out in accordance with the principles of objectivity, transparency and free competition. For all this, an integrated wholesale market was established between Spain and Portugal, with MIBEL, that started to operate in July 2007.

Due to the above, an electricity market operator (OMEL) was created to manage the wholesale market economic operations. This ensures that the market is transparent and competitive. To ensure that the market is in right way and there is not presence of market power carry out by agents, a regulatory and independent body, National Commission of Markets and Competition (CNMC), was created.

However, retailing activities have been deregulated more gradually. Firstly, with (Law 54/1997, 1997), it was possible to choose suppliers only for large consumers. Subsequently, in 2013, this possibility was opened to all customers including domestic customers.

With regard to transmission and distribution activities, they were maintained as regulated sectors, due to the fact that they are considered natural monopolies. Regarding the remuneration of these sectors, there was a change in remuneration based on the cost of service and the remuneration based on the incentive, in order to promote greater efficiency in the management of these sectors. The responsibility for calculating and formulating energy policy lies with the Ministry of Industry, Energy and Tourism, which approves the tariffs for access to the electricity grid, regulated components of electricity prices and the level of access charges.

<u>Third Party Acces (TPA)</u>: Third Party Access (TPA), was born to guarantee access to the distribution and transmission networks to any agent of the electricity market under

any type of discrimination. This measure aims to increase competitiveness in the electricity sector by providing access to the different participants.

In order to remunerate the network service, each participant has to pay a connection fee that is determined by the National Market Commission and Competition (CNMC) and finally approved by the Ministry of Industry, Energy and Tourism

3.3 Spanish market

The Spanish electricity generation market is structured in a daily market, six intraday markets (both managed by the OMIE market operator), organized markets (future markets), managed by OMIP, and markets for system adjustment services (Managed by REE). The latter are defined as those markets managed by the System Operator whose purpose is to adapt the programs of the production units, resulting from the participation of the subjects in the different energy contracting platforms, to ensure compliance with the conditions of safety and quality requirements for the supply of electricity. There is also an unorganized market constituted by bilateral physical contracts, whose terms and economic conditions are agreed between the parties.

This section will focus mainly on the short-term markets managed by OMIE, as futures markets are outside the thesis topic. In the following figure we can see how different organized and unorganized markets organize in time.

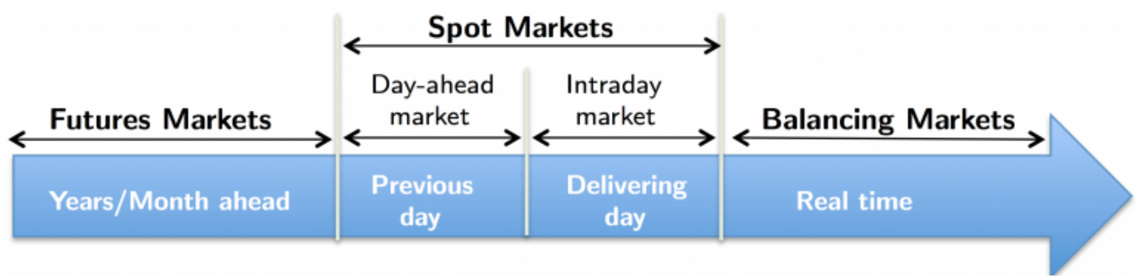

Figure 3. Type of electricity markets as a function of the time when enery is purchased

As mentioned above, the ancillary markets are managed by the System Operator, *Red Eléctrica de España* (REE), which is also responsible for the security and integrity of the system. The purpose of the system balancing service is to solve the technical constraints of the system by limiting and modifying, where appropriate, the production programs of the generation and pumping units that solve the technical constraints identified with the minor cost for the system, and the subsequent rebalancing of generation and demand to compensate for the program modifications incorporated to solve the identified technical constraints. All this is managed through market mechanisms where generators offer their available energy.

The spanish market operator (OMIE), in 2016, managed transactions with an economic volume of around 11 billion euros in the markets of Spain and Portugal (OMIE, 2016).

In other words, the Iberian market has sufficient liquidity to ensure broad competition without taking into account the market share in generation and demand of each company.

In most of the time during the year, the Spanish and Portuguese market is coupled in price, this is due to the wide interconnection that exists between the countries that make that it works like a unique system. In certain cases, there is a separation of markets due mainly to congestion in the transmission network where these congestions are remunerated with the difference of prices between both countries by 50% to each system operator.

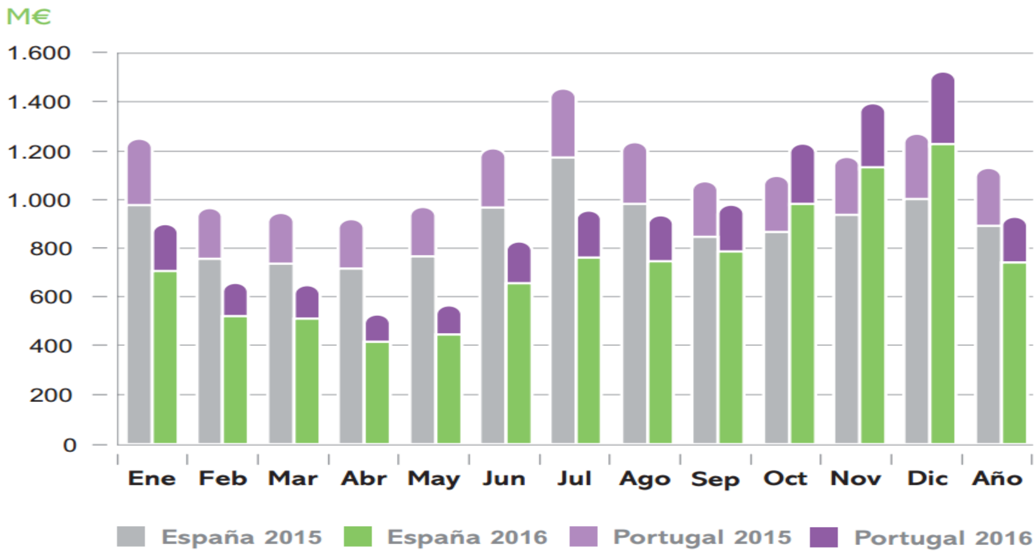

Figure 4. Economic volume of the purchases traded in the daily market and in the intraday market. *Source: OMIE, Annual report 2016*

3.3.1 Spanish electricity market

The markets described below are organized in a consecutive way as we will see below and are where a large part of the volume of energy produced and consumed is traded.

First, energy is traded mainly in the day-ahead market because is mandatory to all agents to offer their power generation available, thus, this market has greater liquidity and volume traded. Subsequently, the intra-day markets (6 periods) are a platform where agents can adjust their offers before the real time delivery of the energy. These markets are organized and managed by OMIE.

Although it is not the object of this work, it is interesting to mention and to know briefly the markets and services that come into operation after the previous ones. The so-called ancillary services to resolve possible technical restrictions that may arise due to capacities in the transmissions lines are taken into account once the previous markets have been solved (day-ahead and intra-day markets). The markets for ancillary services are also opened to balance the active power, secondary reserve, tertiary reserve and diversion management. The balance of reactive power is also another ancillary service. All these markets are managed by the system operator REE.

Agents can also negotiate energy through contracts or bilateral agreements. The market operator does not need to know the volumes of energy traded through these contracts. In the following figure 5, the organization of the markets can be observed sequentially.

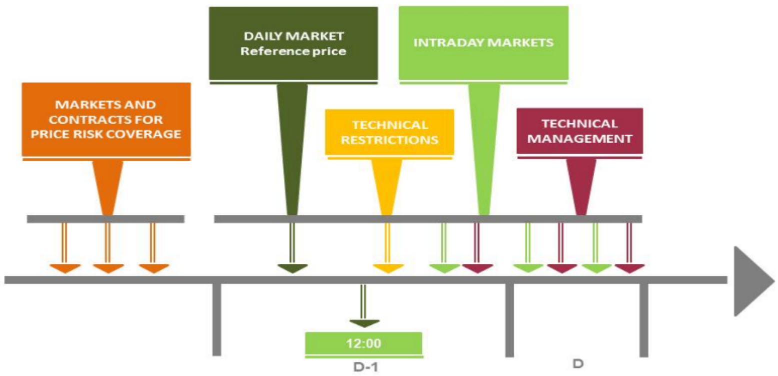

Figure 5. Time sequencie for markets and processes in MIBEL. *Source: OMIE*

3.3.1.1 Day-Ahead Market

The day-ahead spot market is the main market for the delivery of electricity and is used as a reference price for the ancillary services. In this market a greater volume of energy is traded and applies the principle of marginal price setting where price and volume in each hour is established according to the point where supply and demand intersect, as we can see in figure 6.

This market follows the following sequence: all market players must submit their offers for each hour of the following day until 12:00 pm. All bids that are made for each hour form two aggregate supply and demand curves and are solved using the European optimization algorithm called EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm). Once obtained the prices and volumes for each hour of the following day, OMIE publishes them like reference for the following markets that come next. In 2016, the day-ahead market traded approximately 88% of the total energy traded in all markets (OMIE, 2016), which confirms the greater liquidity.

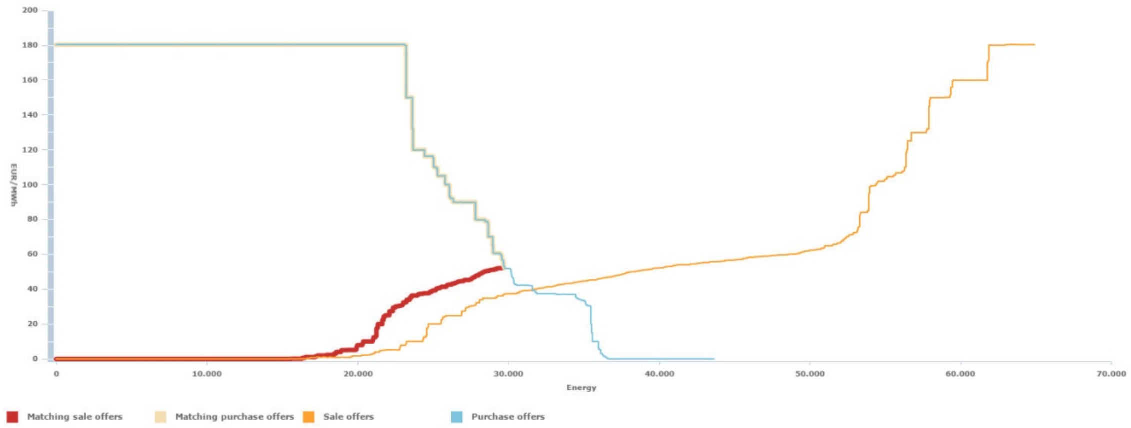

Figure 6. Aggregate supply and demand curves MIBEL, 29/05/2017. *Source: OMIE*

All generating agents must submit their available generation offers in the day-ahead market. Only generation capacity declared unavailable in advance may not be offered. Generating agents must offer their production by generation units, they are not allowed to offer their portfolio in aggregate form.

However, the agents of the demand are composed of retailers, re-sellers and medium / large consumers who acquire energy directly in the daily market. According to OMIE, we find the following agents on the demand side:

Reference retailers, established in the last electrical reform in 2014, come to the market to acquire the electricity they need to supply to consumers.

Resellers come to the market to buy energy for sale to direct consumers.

Direct consumers can purchase energy directly in the organized market, through a reseller by subscribing a bilateral physical contract with a producer.

In reference to the bid format presented, there are two possible ways to proceed to submit an offer by the generator agents, simple and complex offers (OMIE, 2017). The simple offers are economic offers of sale of the energy that the sellers present for each time period and unit of production with expression of a price and of an amount of energy. Offers that incorporate complex conditions of sale are those that, complying with the requirements required for simple offers, also incorporate all, some or any of the following technical or economic conditions:

- Condition of indivisibility.
- Load gradient.
- Minimum income.
- Scheduled stop.

This complex condition was incorporated as a measure so that the generating agents could secure risks that involve the simple offers due to the increase of the participation of RESs. As OMIE expalin (OMIE, 2017), the condition of minimum income enables bids to be presented in all hours, provided that the production unit does not participate in the daily matching result if the total production obtained by it in the day does not exceed an income level above an established amount, expressed euros, plus a variable remuneration established in euros for every matched MWh. The elimination of these offers that do not meet the conditions described, create a gap between the accepted offers and the offers presented, as shown in the following figure 7. Sumarizing, It was designed mainly to incorporate start-up cost (wich mainly apply to the thermal production).

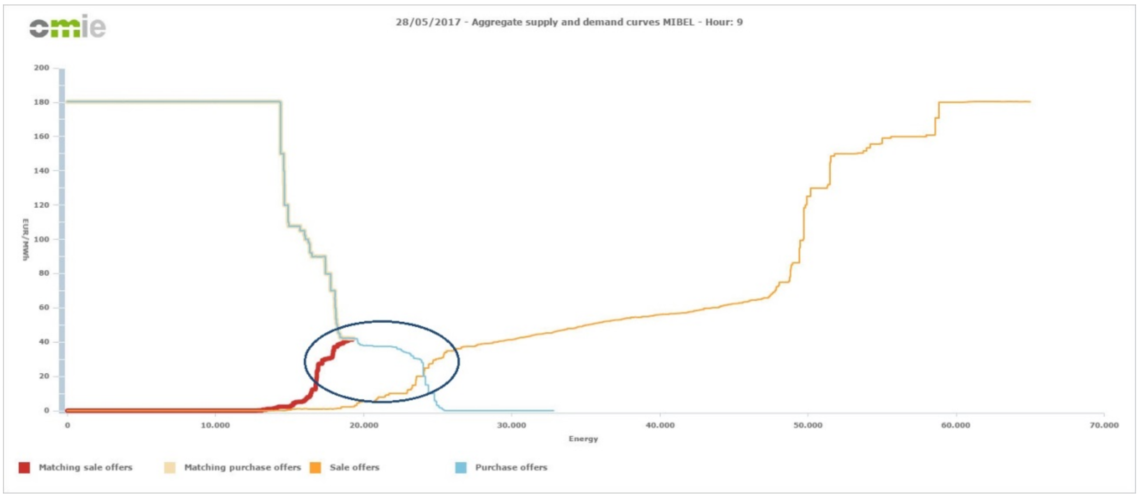

Figure 7. Gap due to complex bis between accepted offers and submitted offers.
Source: OMIE

3.3.1.2 Intra-day Market

Once the day-ahead market is closed and cleared, the different intraday markets (6 sessions) are opened and allow energy buyers and sellers to adjust their programs before entering real time and getting closer to their optimum. The different intraday sessions are organized sequentially in order as can be seen in the following figure 8.

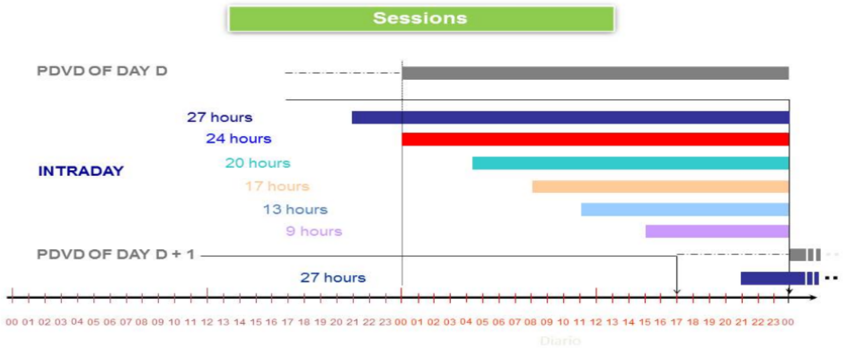

Figure 8. Intraday market in MIBEL. Time horizon for the six sessions. *Source: OMIE*

The way to make the offers in the different sessions of the intraday markets is the same as for the daily market. The main difference with the day-ahead market is that, this market does not have the constraint of forcing generators agents to bid all their available generation.

As we can see in Figure 8 above, the market with the longest horizon is the first intraday market and the first to open before the day-ahead market closes, therefore it is the market that has more liquidity and more energy trading after previous, as can be seen in figure 9. The present project focuses mainly on implementing a strategy for the optimization of a pumping station in different electric markets, so as we will see in the following chapters, apart from considering the day-ahead market to optimize the strategy, it will be interesting also incorporate this first intraday market session into the optimization process.

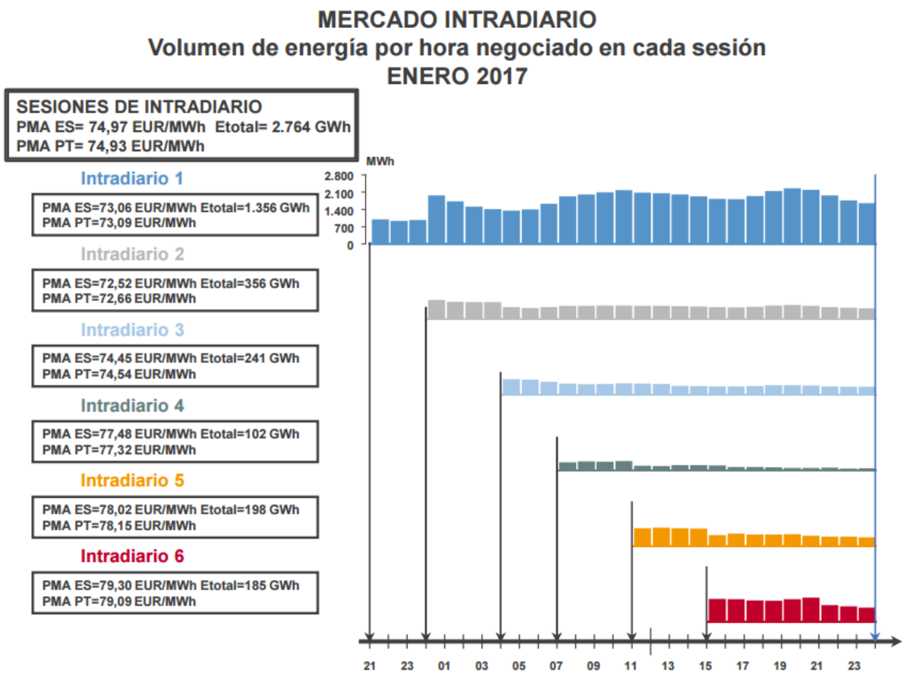

Figure 9. Energy volume traded in any intraday session. *Source: OMIE*

Chapter 4: Single market optimization

Chapter 4 – Index

4.1 Introduction

Once introduced in the previous chapter the different electrical markets existing in the Iberian system, we will see during the development of this chapter, the proposed optimization models seek to obtain the optimal programming of the installation taking into account the physical and energy limitations of the layout and nature of the plant, as well as the installed equipment. The models aim to determine an offer of purchase and sale energy for the installation for each hour of the following day so that the generation revenues less pumping costs are the best in order to make the operation cost-effective for the installation.

In this chapter, the optimization model will be developed only taking into account the day-ahead market.

4.2 Objective function

To begin to develop the model, the first thing to be defined is the objective function. When defining this function, two hypotheses will be taken into account for the day-ahead market. Firstly, we have to take into account that the supply and demand curves are composed by multiple steeped and discontinues offers from many agents parcipating in the electricity market, for this reasons, the first hypothesis that we have considered is the simplification of the curves making the demand totally inelastic. Then, secondly, taking into consideration the first hypothesis, it is going to be implemented in the model that the agents are not totally elastic and the prices at which the energy is sold and bought can be altered depending on the amount of energy bought or sold by each agent.

4.2.1 Price taker model

As discussed previously, the objective function that seeks to obtain the optimal programming of a pure pump storage plant in the day-ahead market will be developed.

The objective function of the problem posed for a pump storage generation facility from which one wants to obtain profit is considered as a maximization of the difference between the revenues and costs of the plant for each hour of the day:

$$Max \quad Benefit = \sum_i Income_i - Costs_i \tag{1}$$

The income that the facility obtains is the product of the energy produced and the price paid by the market at each hour of the day. However, the costs involved in the production or consumption of energy by this type of installation are a sum of several factors corresponding to the characteristics of the plant:

- Amount of energy pumped (consumed) by market price in each hour
- Network access tarif
- Taxes applied to electricity generation

The taxes applied depend on the type of installation and the income obtained from the generation of electric energy.

Therefore, by introducing these concepts into equation (1), taking into account only the day-ahead market, we have:

$$Max \quad Benefit = \sum_i [P_i * e_{i,t} - (P_i * e_{i,p} + T_t * e_{i,t} + T_p * e_{i,p} + t * (P_i * e_{i,t}))] \tag{2}$$

Where:

- $T_t = \ Access\ tariff\ for\ generation$
- $T_p = Access\ tariff\ for\ consumption$
- $t = taxes\ per\ income$

As a result of applying the above concepts, the objective function remains a linear equation that can be solved by using a Linear Programming (LP) solver.

4.2.2 Price elasticity

As the market does not always work under the price taker hypothesis, it is considered opportune to take into account that the offer made by any agent could modify the market prices. To model this hypothesis, this assumption will be included within the objective function considering the market for which the pumped storage plant is being modeled.

Depending on the market liquidity (amount of energy traded in the market) in which we are negotiating the energy generated or absorbed by the pump storage plant, the price of the offer to be made will be more or less affected. Therefore, the appropriate way to introduce this assumption into the optimization model, is to generate a new price variable based on the amount of energy generated or consumed by the facility.

When modeling this new price variable, you have to take into account how energy can affect the market price. When an offer for sale energy (generation) is made, it must be below the marginal price to be accepted by the market, therefore, assuming that the offer is divided into small tranches, each time a tranche is offered, this offer will be lower than the previous one, therefore, the energy produced by a liquidity factor of the market offer should reduce the price of our offer. With respect to the energy purchase offer (pumping), this is totally the opposite case, this means, whenever the facility is desired to pump an amount of energy, the offers will be higher than the marginal price in order to be accepted by the market, so the amount of energy purchased multiplied by a liquidity ratio of market demand should raise the price of our offer.

For all the above mentioned, the new price variable to be introduced in the objective function will be the marginal price of one hour of the daily market less the quantity generated by a liquidity coefficient of the supply curve and more the quantity bought by a coefficient of liquidity corresponding to the demand, all for the same hour. Thus the following equation is constructed:

$$P_i^* = P_i - (q_t * e_{i,t}) + (q_p * e_{i,p}) \tag{3}$$

Estimate these elasticity coefficients for the demand and supply curves for each hour and section is complicated and requires a larger work that can significantly complicate the problem that is being addressed in the present work. In the model developed, we will consider the simplification that these coefficients are constant and estimated values, based in the studies of the supply and demand curves for all hours.

Therefore, incorporating the new price in the previous objective function, we have to:

$$Max \quad Benefit = \sum_i [P_i{}^* * e_{i,t} - (P_i{}^* * e_{i,p} + T_t * e_{i,t} + T_b * e_{i,p} + t * (P_i{}^* * e_{i,t}))] \tag{4}$$

$$Max \quad Benefit = \sum_i \left[(1-t) * \left(P_i * e_{i,t} - q_t * e_{i,t}{}^2 + q_p * e_{i,p} * e_{i,t}\right) - \left(P_i * e_{i,p} - q_t * e_{i,t} * e_{i,p} + q_p * e_{i,p}{}^2\right) - T_t * e_{i,t} + T_b * e_{i,p}\right] \tag{5}$$

Under the hypothesis that the plant won't turbine and pump during the same hour, the objective function (5) can be simplified:

$$Max \quad Benefit = \sum_i \left[-q_t * e_{i,t}{}^2 - q_p * e_{i,p}{}^2 - (P_i - T_b) * e_{i,p} + \left((1-t) * P_i - T_t\right) * e_{i,t}\right] \tag{6}$$

Note that the introduction of price elasticity transforms the objective function from a Liner into a Quadratic problem. The variables corresponding to the produced or consumed energies by the turbining and pumping groups are now quadratic variables and a different solver is required to solve the new objective function but that does not imply any restriction when solving the problem.

4.3 Constraints

Once the equation for the objective function to be maximized is defined, it is also necessary to develop the equations that define the physical and energy constraints imposed by the characteristics of a hydraulic pump generation plant.

We can distinguish between two groups of constraints that will be developed more in depth later, capacity and energy constraints. The capacity restrictions are those that impose the limitations of the equipment and the capacities of the reservoirs. The plant has a limited turbining and pumping capacity. Likewise, with the capacities of the upper and lower reservoirs, they can not hold more than the maximum capacity for those that were constructed or designed. However, the energy constraints correspond to the energy balance that takes place in the reservoirs of hourly form and that define the amount of energy transferred between the upper and lower reservoirs by turbining and pumping.

It should also be taken into account that it is a pure pumping storage plant, so it does not receive any water supply in the upper reservoir, this simplifies the development of the restriction equations.

4.3.1 Capacity constraints

Next, the equations that define the capacity constraints of the installation will be developed, taking into account the previous considerations.

- Lower limits:

$$e_{i,t} \geq 0 \tag{7}$$

$$e_{i,p} \geq 0 \tag{8}$$

$$e_{reserv_i} \geq 0 \tag{9}$$

- Upper limits:

$$e_{i,t} \leq e_{gen\_max} \tag{10}$$

$$e_{i,p} \leq e_{pump\_max} \tag{11}$$

$$e_{reserv_i} \leq e_{reserv\_max} \tag{12}$$

As mentioned above, the developed equations describe the limitations of generating or pumping energy from the machines available in the installation. It also limits the maximum power storage capacity of the upper reserve.

4.3.2 Energy balance

In theory, according to the energy conservation equation, the energy currently stored in the upper tank is a function of the energy stored in the previous hour and the current programmed generation and pumping programs. Thus, the equations can be developed as expressed below.

$$e_{reserv_1} = e_{reserv_0} + \mu * e_{1,p} - e_{1,t} \tag{13}$$

$$e_{reserv_i} = e_{reserv_{i-1}} + \mu * e_{i,p} - e_{i,t} \tag{14}$$

$$e_{reserv_f} = e_{reserv_{f-1}} + \mu * e_{f,p} - e_{f,t} \tag{15}$$

4.4 Optimization model inputs

Once the functions that define the objective of maximizing the profit for a pure pumping storage plant have been developed, it is necessary to define the values that the model needs to know in advance in order to obtain the optimal solution of the problem taking into account the constraints imposed. It will also be necessary to define for which time horizon is more interesting to run the models, a priori, the short term seems the most advisable, as will be seen below. The main inputs to be introduced in the models are:

- Time horizon
- Availability
- Pump storage plant characteristics
- Day-Ahead Prices
- Elasticity coefficients
- Taxes and network charges

4.4.1 Time horizon

The management of a pumping storage plant is usually weekly because during the weekend with low prices the facility is used to pump and fill as much as possible the upper reservoir and take advantage of the higher prices during the week to release water from the upper reservoir towards the lower reserve and generate electricity, attempting to reach the lowest level of the upper reservoir before starting the weekend, and repeat the process, as explained in section 1.2.3.

Therefore, the minimum time horizon to be taken into account when executing the optimization model is one week. However, it is more interesting to extend this horizon to two weeks, because analyzing a larger horizon can take advantage of additional generation or pumping opportunities. As will be seen below, prices during weekends are not always lower than the days of the week, and this may be due to multiple factors such as scarcity of renewable energy resources such as water and wind or high demand due to meteorological factors.

A two-week time horizon allows the model to better adapt the optimum production schedule to possible extraordinary situations. Therefore, when executing the optimization model developed, it will be done with a time horizon of two weeks.

4.4.2 Availability

Typically, pumping plants are composed of groups of turbinating/pumping machines with the same or different power to exchange water between the upper and lower reservoirs. The optimization model developed only takes into account one variable for the pumping energy and another for the generation energy of the entire pumping plant, that is, the sum of the power of all the installed groups.

Due to what was commented in the previous paragraph, it is important to emphasize that it is necessary to take into account the availability of the different groups of pumping and turbining in the execution of the model. Groups may be unavailable because of causes of maintenance or unexpected breakdowns that reduce the maximum energy the plant can turbine or pump. This mainly affects in the model the values of maximum energy represented in the constraint equations (16) and (17):

$$e_{i,t} \leq e_{gen\_max} \tag{16}$$

$$e_{i,p} \leq e_{pump\_max} \tag{17}$$

$$e_{reserv_i} \leq e_{reserv\_max} \tag{18}$$

Regarding the maximum capacity of the upper reservoir, it should remain constant and equal to the design capacity.

4.4.3 Market Prices

In order to obtain optimum scheduling during the time horizon established above and to generate offers to sell or buy energy in the day-ahead market, one has to have marginal price values for each hour of each day of the week. The prices for each week can be estimated by analyzing the historical information of the electricity markets, metheorological data, system operator information, etc. Therefore, for the model developed, market prices are an input value to obtain the optimal programming schedule.

However, when executing the optimization model, different historical periods of day-ahead market prices will be used to observe and analyze the results obtained. The analysis of the results obtained using historical prices will allow to understand how the model manages the production of the pumping plant considering the restrictions imposed.

4.4.3.1 Price elasticity

Elasticity is introduced in the optimization model through coefficients that relate the amount of energy produced or absorbed by the pumping plant to the prices. As mentioned above, the offer curves are elastic and the model developed should reproduce as much as posible the real market behaviour, for it has been determined constant coefficients for all hours of the day through the analysis of supply curves and demand.

The coefficients have been obtained obtaining the slopes of the aggregate curves at the points near the point where both curves are crossed and the marginal price of the determined hour is established.

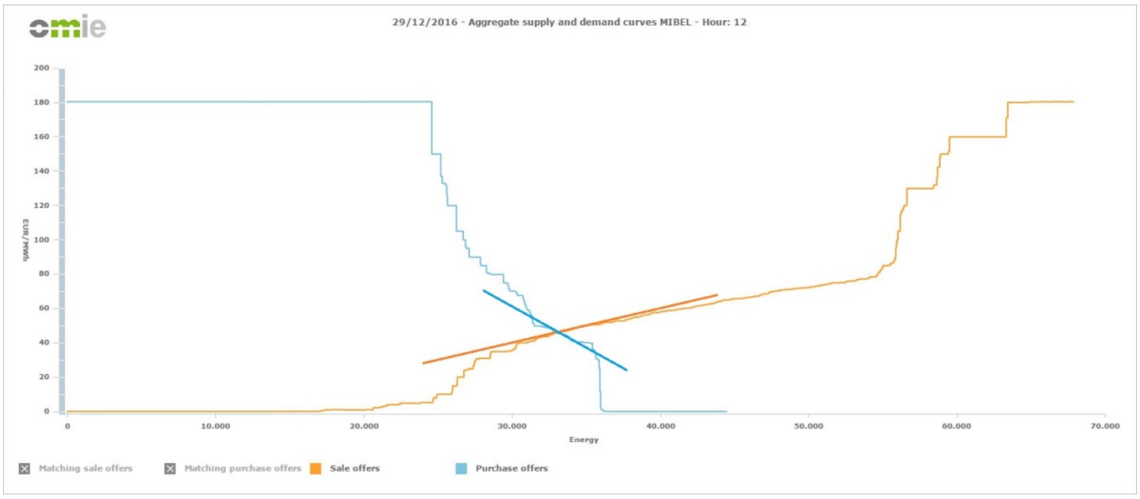

Figure 10. Slopes of the aggregate supply and demand curves. *Source: OMIE and own elaboration*

As can be seen in the previous figure, the slope corresponding to the line drawn for the supply curve (orange) is smaller than the slope plotted for the demand curve (blue), therefore, varying the same amount of energy for both, the price of the demand curve shows a wider variation than the price associated with the supply curve.

4.4.4 Taxes and network charges

As described briefly in previous sections, taxes and tariffs for network access directly affect the costs that are taken into account in the objective function to be optimized, therefore, any change in these values directly impacts on the result of the optimization and the profit obtained.

Taxes are determined directly by the government of the country where the pumping plant is installed and are based purely on political-economic decisions. In this case, the taxes correspond to those set by the government of Spain and are basically two:

- General tax on the generation of electrical energy for any type of installation implemented in the last energy reform carried out in 2013
- Tax on the net income obtained by hydroelectric plants

The last tax described has a reduction of 90% in installations with an installed capacity of less than 50 MW and pump storages installations with a capacity exceeding 50 MW (Royal Decree, 2012). The second condition applies to the installation for which the present project is being carried out, that is to say, when taking into account the second type of tax defined above, a reduction of 90% has to be applied.

Network access fees correspond to the amount to be paid for an energy installation because it is connected to the transmission or distribution network in order to be able to sell the energy generated or to buy the energy consumed. In the case of a pure pumping plant, both tariffs (generation and consumption) apply because the plant consumes mains energy to pump water to the upper tank and generates electricity which flows into the network by releasing the water from the upper tank to the bottom.

Determining the amount of the fees is the responsibility of the General Administration of the state according to (Law 24/2013, 2013) and to the methodology established by the National Commission of Markets and Competition (CNMC). These tariffs are different depending on the use you make of the grid (generate or consume) and as mentioned, both apply in the case of a pure pump storage plant, therefore, both tariffs should be reflected as costs within the objective function.

4.5 Results and observations

In this section, the results obtained from the execution of the optimization model developed for each of the suppositions introduced (price taker and price elasticity) for the day-ahead market will be presented. Before presenting the results, we will introduce the values of the inputs considered in the model, as well as the different scenarios of prices of the day-ahead market considered.

4.5.1 Input data

At this point we will introduce and present the values of the inputs of the developed optimization model that are needed to be able to determine the optimal production of the pumping station.

- **Temporal horizon**

The time horizon to be applied when executing the optimization model, is two weeks as explained in section 3.5.1.

- **Pump storage plant characteristics**

The characteristics of the pumping plant correspond to determining the maximum capacity of energy able to pump and turbine of each installed machine. As the model has been defined, it is taken into account that all the machines will be available and the maximum capacity is determined as the sum of all. In this case, we will consider:

- $e_{gen\_max} = 500\ MWh$
- $e_{pump\_max} = 500\ MWh$

The maximum capacity of the upper reservoir of the pumping plant remains to be defined. This capacity will also be expressed in energy values (MWh) and is of particular importance, since it greatly conditions the management of the reserve. In this case, this maximum capacity is:

- $e_{reserv\_max} = 10000\ MWh$

- **Day - Ahead prices**

For the developed model, the market prices of day-ahead for the defined time horizon, ie two weeks, have to be taken into account. For this purpose, it has been considered appropriate to extract two periods with different price curve evolutions.

It is interesting to verify and analyze that the model presented provides adequate results in different scenarios with different price curves for the Day-Ahead market. For this reason, two different periods have been chosen at different times in 2016 with a time horizon of two weeks (336 hours) as discussed above and in point 3.5.1, in order to capture additional opportunities (as in case of weekends with high prices or in periods with little modulation of prices). Then, in figures 11 and 12, the evolution of prices per hour can be observed in the selected weeks.

- Period 1: 09/01/2016 to 22/01/2016

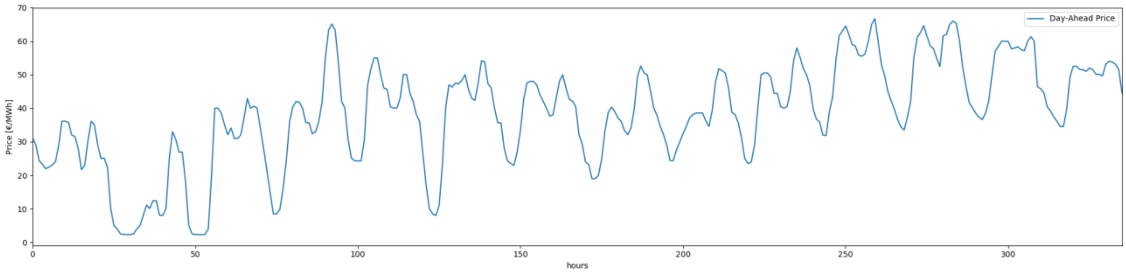

Figure 11. Day-Ahead prices of period 1

- Period 2: 16/04/2016 to 29/04/2016

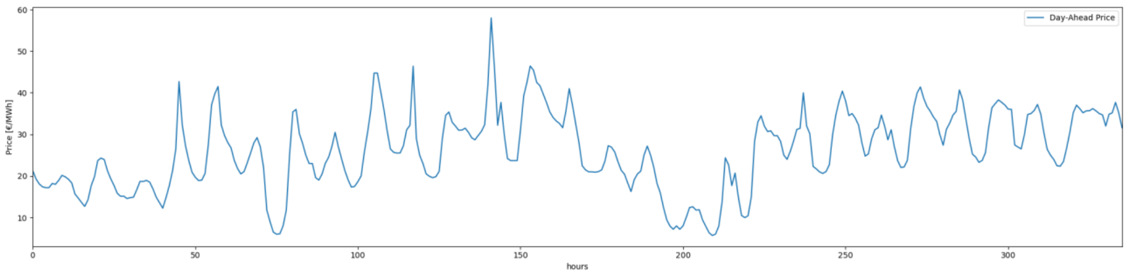

Figure 12. Day-Ahead prices of period 2

Emphasize that the periods begin on the 1st hour of a Saturday and ends on the 24th of a Friday, completing two weekly cycles for the pumping plant.

In the first period, the first weekend can be clearly distinguished due to the fall in prices that is produced, but it is almost impossible to locate the second weekend in a priori, since prices are kept in line with those seen during the week before. Therefore it will be interesting to analyze the results obtained by the optimization models for this unique price period.

In the second price period for which the results of the models are intended to be analyzed, they are better distinguished on weekends because both correspond to lower prices than those seen during the week. Higher price spikes can also be found during the week, so it is interesting to analyze how the model optimizes the scheduling of pumping and turbining in the face of these peculiarities in the evolution of prices during this period.

- **Elasticity coefficients**

Determining the elasticity coefficients to be applied in the model when we assume that the offer curves are elastic is not easy, therefore, as explained above the values for these coefficients have been determined based on slopes estimations for the aggregate curves of supply and demand. The results presented below, take into account the following values for these coefficients:

- $q_t = \frac{1}{1000}€/MWh$
- $q_p = \frac{1}{300}€/MWh$

- **Intial and final upper reservoir energy**

For the defined optimization model, it has been considered appropriate to leave as input the amounts of energy that the upper reservoir must have at the beginning and end of the period. These quantities are determined when defining the strategy to be followed with the operation of the pump storage plant influenced by the energy sector conditions within the period. In this case, as the model is based on historical data, it is not necessary to determine specific values for these inputs, but following the logic presented in the previous points of the weekly operation to obtain benefit of the operation of the installation (pump water to the upper tank during weekends and turbine during the week), these values will be close to the minimum capacity of the upper reserve, ie zero. Therefore, the following values will be considered:

- $e_0 = 50\ MWh$
- $e_f = 50MWh$

- **Taxes and network charges**

The value of the taxes to be taken into account, at the time of the realization of this project, in the costs of the pumping plant are as follows:

- 25.5% of the annual net income generated by a hydroelectric plant with a discount of 90% because it is a pumping plant with an installed capacity greater than 50 MW (Royal Decree, 2017).
- 7% of annual net revenues applicable to any power generation plant (Royal Decree, 2012).

Therefore, the term that is introduced in the objective function of the model, taken into account the discount described in the section 4.4.4, has a value of:

$$t\ (taxes\ per\ incomes) = 0{,}255 * 0.1 + 0.07 = 0.0955$$

Regarding the access tariffs to the transmission network to sell and purchase energy by the pump storage plant, it corresponds to the following values set by the public administration under the CNMC methodology , are:

- $T_t(Access\ tariff\ for\ generation) = 0{,}5$ €/MWh (Royal Decree, 2011)
- $T_b(Access\ tariff\ for\ consumption) = 0{,}15$ €/MWh (Order, 2016)

4.5.2 Results

Taking into account the inputs presented in the previous point, the results obtained from the execution of the optimization model are presented below, taking into account only the price curves corresponding to the day-ahead market. Two cases will be presented, one considering a price taker hypothesis and the other taking into account the supposition of a more realistic market of electricity where the existing liquidity is considered through price elasticity asumption.

For both cases, the model will be considered considering the two periods presented of 2 weeks each.

4.5.2.1 Price taker hypothesis

Taking into account the fact that the market is completely elastic and there are enough buyers and sellers of energy participating in the market, the results obtained by the model, considering the previous inputs, can be observed below for the two scenarios proposed for the function objective (2).

- Period 1: 09/01/2016 to 22/01/2016

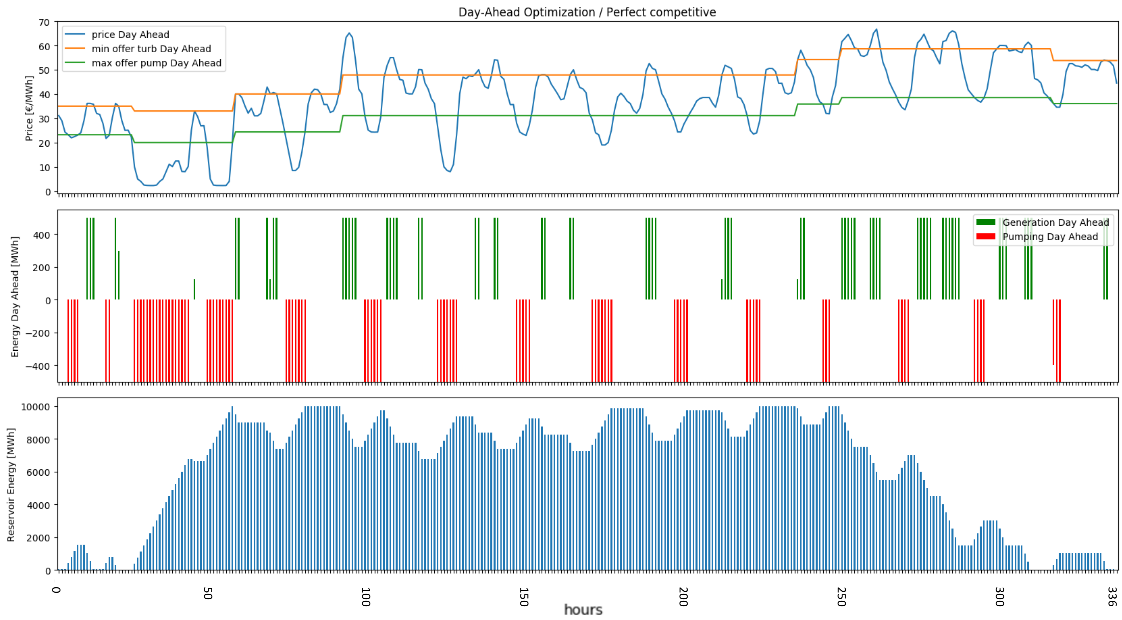

Figure 13. Optimization model result considerind price taker hypothesis for the Day-Ahead for period 1.

- Period 2: 16/04/2016 to 29/04/2016

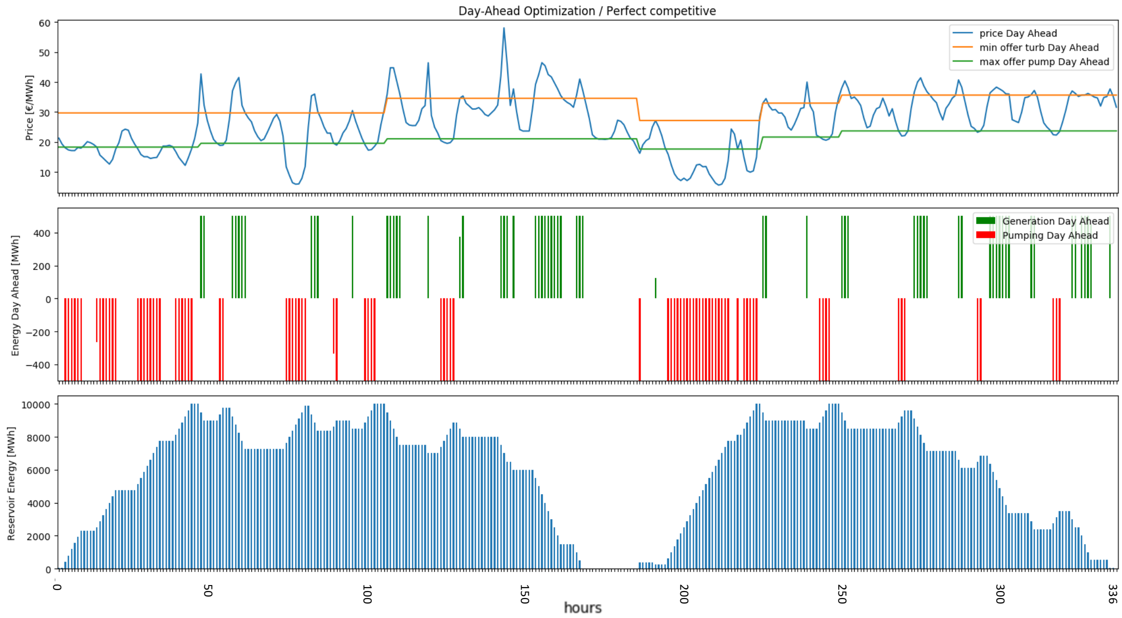

Figure 14. Optimization model result considerind price taker hypothesis for the Day-Ahead for period 2.

4.5.2.2 Price elasticity hypothesis

Under the assumption that the aggregated supply and demand curves are elastic, the following results are obtained when maximizing the profit for the objective function (6) and using the elasticity coefficients defined in section 3.6.1.

- Period 1: 09/01/2016 to 22/01/2016

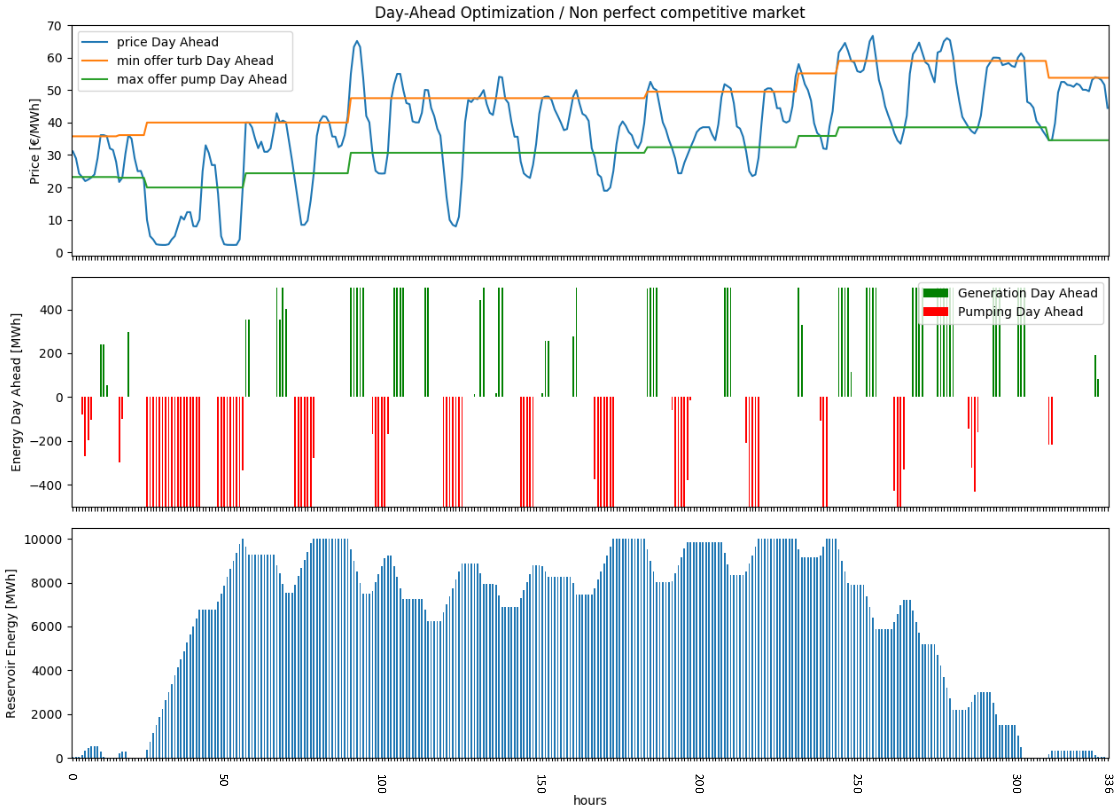

Figure 15. Optimization model result considerind price elasticity hypothesis for the Day-Ahead for period 1.

- Period 2: 16/04/2016 to 29/04/2016

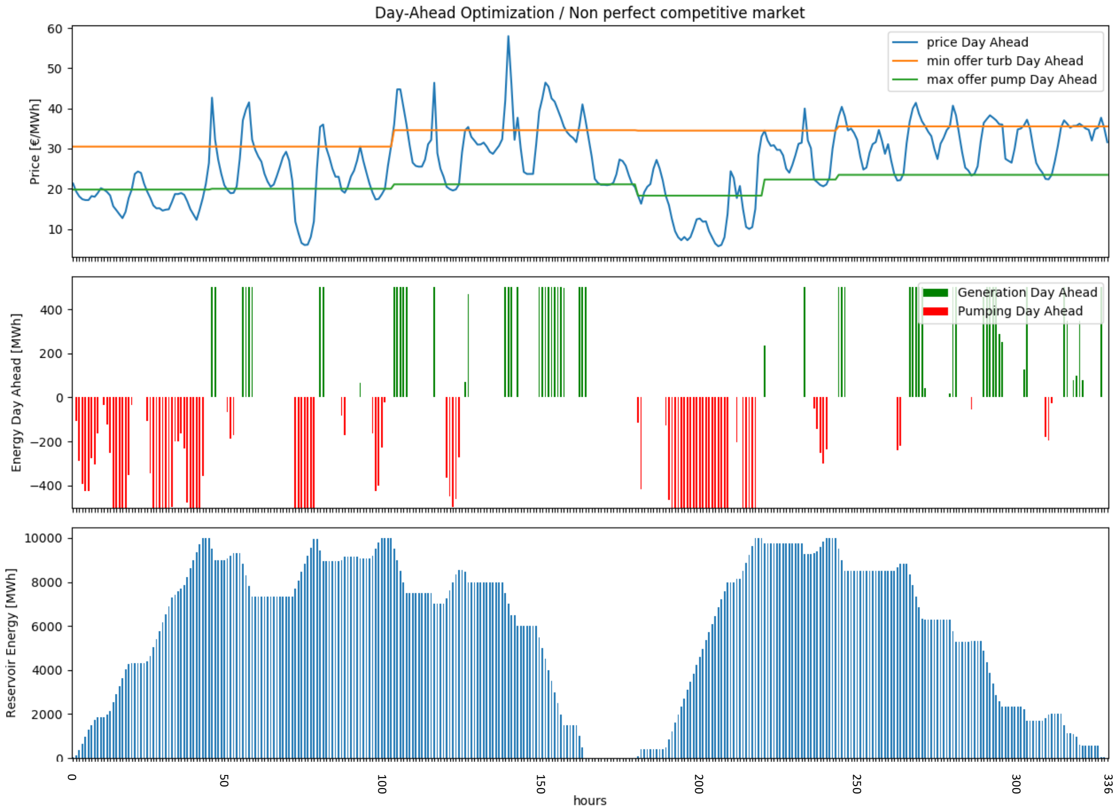

Figure 16. Optimization model result considerind price elasticity hypothesis for the Day-Ahead for period 2

4.5.2.3 Results comparison

In all the figures the first price curve can be identified, corresponding to the period determined along with the lines that fix the prices of the offers of purchase and sale of energy. The offers of purchase and sale correspond to the price of the first hour at which the model decides that it is optimal to turbine or pump for each cycle, ie in each cycle the water has a different value than the one to be offered in the market. The cycles change every time the top reserve reaches its maximum capacity or is practically emptied.

Second, the bar graph represents the amount of energy pumped or turbinated by the facility at each hour of the associated period. Finally, the graph corresponding to the variation of the amount of energy in the upper reservoir can be seen.

When comparing the results obtained between the two different time periods, it can be verify that for both hypothesis (Price taker and price elasticity) there is a clear difference with respect to the management of the production of the installation that the model perfoms. During period one, the model identifies that the prices in the second weekend remain constant to those seen during the previous week and therefore do not perform two filling cycles - emptying the upper reserve as one would expect. However, in period two, the model identifies that during the second weekend prices are lower and it manages the energy of the upper tank so that 2 fill-empty cycles occur. The management of the installation for period two is that which is performed under the idea explained in point 1.2.3, but this is not always the case as shown by the results for period one.

With respect to the difference between the results obtained for the two hypotheses made of price taker and price elasticity, we can verify the effect of including in the objective function (2) the elasticity consideration in prices as described in point 3.3.2. In the case of the price taker idea, the energy produced or pumped during periods 1 and 2 are practically an "all or nothing" (figures 13 and 14), that is, in the hours in which the model decides that It is optimal to start the installation, it is done with the machines practically always at the limit of maximum energy capacity. The model considers to offer to the market all the available energy of the installation to a single offer price.

This is not the case, however, under the assumption of a price elasticity hypothesis and assuming coefficients of elasticity in prices. The figures 15 and 16 show how, unlike the price taker hypothesis, the production or pumping produced by the installation for the hours in which the model decides that it is optimal to raise or lower water from the upper reservoir, is more modular, which would adjust more to the reality of market behaviour.

To conclude, it is also interesting to make a comparison between the benefits obtained for each of the assumed assumptions as well as for the two scenarios of price curves.

Benefit (€)			
Price taker hypothesis		Price elasticity hypothesis	
Period 1	**Period 2**	**Period 1**	**Period 2**
754671	451897	674068	379012

Table 1. Pumped storage plant benefit under different daily market hypothesis

It can be seen from the table that the profit under the hypothesis of price elasticity is lower for both periods. This is due in practice to two reasons discussed earlier:

- Offers prices to sell or buy power in the day-ahead market vary due to the consideration of market elasticity
- The amounts of energy that the model determines are optimal to maximize the profit during the periods considered taking into account the elasticity of the market are more modular, ie, as explained above, they are not "all or nothing" as in price taker hypothesis market.

4.6 Conclusions

An optimization model has been developed under the hypothesis of a price taker where the demand curve is considered to be inelastic and another model that takes into account the hypothesis of the market elasticity through the application of elasticity coefficients in the objective function. The models provide in each case the optimum pumping and turbining schedule for each hour over a two-week time horizon. With this schedule for the chosen price periods, the revenues performed by the model are the maximum that can be generated due to the pumping and generating optimal programming obtained.

In general, several conclusions can be drawn from the results obtained and the analyses carried out:

1. A two-week horizon allows capturing additional opportunities such as weekends with high prices or periods with low price modulation.
2. The hypothesis of price elasticity in the aggregated curves of the market is closer to reality, including the market elasticity to adapt the distribution of real energy in markets versus the purely theoretical model. This results in a staggering of energy as a function of the elasticity of the market, ensuring that the opportunities of the different hours are captured together.

Along with the above conclusions, the model can be designed to operate automatically so that it can repeat the optimization of the installation schedule on a recurrent basis (once every hour) including the new forecast of prices and information available for each time period within the scheduling horizon.

Chapter 5: Cross-market optimization

Chapter 5 – Index

5.1 Introduction

As explained in the chapter 3, the intraday market consists of 6 sessions that open consecutively after the day-ahead market. Within the 6 sessions available, without a doubt, the one that has the most negotiated volume is the first session. The first session of the intraday is the first opportunity for agents to correct and adjust to their optimal program after the allocation of their production or consumption in the day-ahead market, which is why it is the period of the intraday market that has more liquidity and therefore the best to consider optimizing the production of the installation.

Therefore, in the present chapter, a model of optimization will be developed following the hypothesis of a price elasticity market as seen in the previous chapter, including and modeling the behavior of the intraday market. Next, the differences between day-ahead and intraday markets will be identified to include, in the model developed in the previous chapter, the variations due to these described differences.

5.2 Differences with single market model

The modeling of the intraday market has many similarities with the day-ahead market previously seen but also differences. Next, the differences between both are highlighted because it is what interests to know more to understand the concepts to consider in the formulation of the new optimization model. The following points highlight the main differences that must be taken into account when performing the optimization model including both markets within the same optimization problem.

5.2.1 Variables

The first is to define the variables that have to be taken into account when correctly defining the model, since in this market you have the possibility of not only turbining and pumping, but of buying-back and selling-back the allocated energy in the Day-ahead market. Thus, if in the previous model, three variables were defined (pumped energy - $e_{i,p}$, turbined energy - $e_{i,t}$ and reservoir energy available - e_{reserv_i}), the new four variables corresponding to the intraday market will now be added to the new definition of the optimization model. Below are the new variables and then the variables corresponding to the model previously developed for the day-ahead market:

- Intraday model variables:

- $E_{i,t}$: energy generated in intraday market
- $E_{i,p}$: energy pumped in intraday market
- ES_i: day-ahead energy sell-back in intraday market

- EB_i: day-ahead energy buy-back in intraday market

Therefore, the optimization model now has seven variables, all corresponding to the amount of energy to be optimized for each hour of the defined period, except the variable corresponding to the evolution of the amount of energy stored in the upper reservoir of the installation.

5.2.2 Elasticity coefficients

Similarly to previous chapter, where coefficients had been defined to account for the effect of the market elasticity in the day-ahead market, in the intraday market we will use the same approach. As explained above, the way to determine the values for these coefficients follows the same method. However instead of defining the slopes of the aggregate curves of the day-ahead market, this time it is necessary to define these slopes for the curves corresponding to the intraday market. Therefore two coefficients that correspond to the intraday market must be defined:

- $q_{im,t}$: elasticity coefficient for intraday supply curve
- $q_{im,p}$: elasticity coefficient for intraday demand curve

As explained in Chapter 3, the intraday market has much less liquidity than the day-ahead market and therefore these coefficients of elasticity will be higher, ie the price will be more sensitive to the quantities of energy traded in this intraday market.

As in the model previously developed for a market under the price elasticity hypothesis, a new price will have to be defined in the objective function as a function of the amount of energy produced or pumped in the pumping plant in each day-ahead and intraday market.

5.2.3 Objective function

Just as for the objective function defined for the hypothesis of price elasticity corresponding only to the day-ahead market, a new price is defined for the variables that involve negotiating the energy for the intraday market, because, as mentioned, this market has less liquidity than the main market or day-ahead.

Because this additional market will be included in the same model, the elasticity of demand and supply prices for this market should also be considered. Therefore, the price included in the objective function for the energy traded within the intraday market will be:

$$P_{im,i}^{*} = P_{im,i} - \left(q_{\,im,t} * E_{i,t}\right) + \left(q_{im,p} * E_{\,i,p}\right) - \left(q_{im,p} * ES_{\,i}\right) + \left(q_{im,t} * EB_{i}\right) \tag{19}$$

The price that has been defined in the equation is only linked to the variables corresponding to the energy traded in the intraday market. For energy traded in the day-ahead market, the price is the same as that defined in section 4.3.2:

$$P_{i}^{*} = P_{i} - (q_{\,t} * e_{i,t}) + (q_{p} * e_{i,p}) \tag{20}$$

Therefore, once the prices are defined according to the energy generated or absorbed by the installation for each market and the corresponding variables, the objective function can be defined following the same principle of maximizing the benefits of the installation through the definition of costs and revenues:

$$Max \quad Benefit = \sum_{i} Income_{i} - Costs_{i} \tag{21}$$

Where:

$$Income_{i} = e_{i,t} * P_{i}^{*} + E_{i,t} * P_{im,i}^{*} + ES_{\,i} * P_{im,i}^{*} \tag{22}$$

$$Costs_{i} = e_{i,b} * P_{i}^{*} + E_{\,i,p} * P_{im,i}^{*} + EB_{i} * P_{im,i}^{*} + T_{t} * \left(e_{i,t} + E_{i,t} - EB_{i}\right) + T_{b} * \left(e_{i,b} + E_{\,i,p} - ES_{\,i}\right) + t * Income_{i} \tag{23}$$

The objective function can be expressed:

$$Max \quad Benefit = \textstyle\sum_{i} e_{i,t} * P_{i}^{*} + E_{i,t} * P_{im,i}^{*} + ES_{\,i} * P_{im,i}^{*} - (e_{i,b} * P_{i}^{*} + E_{\,i,p} * P_{im,i}^{*} + EB_{i} * P_{im,i}^{*} + T_{t} * \left(e_{i,t} + E_{i,t} - EB_{i}\right) + T_{b} * \left(e_{i,b} + E_{\,i,p} - ES_{\,i}\right) + t * (e_{i,t} * P_{i}^{*} + E_{i,t} * P_{im,i}^{*})) \tag{24}$$

As in the previous chapter, the simplification in the development of the objective function that the installation can not be generating and pumping water between the lower and upper reservoirs for a same hour of the considered period is considered. However, pumping and generation in different markets for the same hour is possible, and it is indeed what happens if optimality is reached by doing so.

Therefore, the new objective function has been developed to maximize the benefit of the installation taking into account the existence of two successive markets. This allows the optimization model to identify possible opportunities in the intraday market to improve the benefit of the facility than just considering the daily market.

5.2.4 Constraints

Once the objective function of the optimization model for the day-ahead and intraday market is defined, only the constraints limiting the problem are left to be defined. As defined for previous models, this time we also have to consider the physical limits of machines and reserves, in addition to defining the limits of energy between both markets.

5.2.4.1 Capacity constraints

As for the model developed in the previous chapter, the energy that can be pumped or turbine between the two upper and lower reservoirs for the same one is limited by the characteristics of the machines, so that the limits of the variables of the problem between zero and the maximum capacity of the installation to move that amount of energy in the same hour. Also defined is the minimum and maximum capacity of the upper tank to store energy in the form of water.

- Lower limits

$$e_{i,t} \geq 0 \tag{25}$$

$$e_{i,p} \geq 0 \tag{26}$$

$$E_{i,t} \geq 0 \tag{27}$$

$$E_{i,p} \geq 0 \tag{28}$$

$$ES_i \geq 0 \tag{29}$$

$$EB_i \geq 0 \tag{30}$$

$$e_{reserv_i} \geq 0 \tag{31}$$

- Upper limits

$$e_{i,t} \leq e_{gen\_max} \tag{32}$$

$$e_{i,p} \leq e_{pump\_max} \tag{33}$$

$$E_{i,t} \leq e_{gen\_max} \tag{34}$$

$$E_{i,p} \leq e_{pump\_max} \tag{35}$$

$$ES_i \leq e_{pump\_max} \tag{36}$$

$$EB_i \leq e_{gen\_max} \tag{37}$$

$$e_{reserv_i} \leq e_{reserv\_max} \tag{38}$$

5.2.4.2 Energy balance

Keeping in mind the energy conservation equation, the current energy contained in the upper reservoir at a given time must be equal to the energy stored in the previous hour plus the current energy supplied by means of pumping from the lower reserve less the current energy that is released through generation for each of the hours included in the given period and for each different market. Therefore, the energy conservation equations between the lower and upper reservoirs of the pumping plant can be expressed as:

$$e_{reserv_1} = e_{reserv_0} + \mu * e_{1,p} - e_{1,t} + \mu * E_{1,p} - E_{1,t} + EB_1 - \mu * ES_1 \tag{39}$$

$$e_{reserv_i} = e_{reserv_{i-1}} + \mu * e_{i,p} - e_{i,t} + \mu * E_{i,p} - E_{i,t} + EB_i - \mu * ES_i \tag{40}$$

$$e_{reserv_f} = e_{reserv_{f-1}} + \mu * e_{f,p} - e_{f,t} + \mu * E_{f,p} - E_{f,t} + EB_f - \mu * ES_f \tag{41}$$

It should be mentioned that the energy used to raise the water through pumping is not exactly the same as the one stored in the upper reservoir. The machines responsible for the pumping have a coefficient of performance that affects this energy, therefore, the variables corresponding to the pumped energy are multiplied by this coefficient determined by the characteristics of the machines themselves.

As the energy resale variable has a meaning of letting turbine down at a given time, the corresponding performance is also applied.

Unlike the balance equations developed in the previous chapter for a model based only for the daily market, these equations define the balance of energy between two markets where they increase the possibilities of performing operations with the available energy.

5.2.4.3 Cross-market constraints

The amount of energy turbined and pumped for each hour of the considered time period between the upper and lower reservoirs for the intraday market is limited by the amount of energy traded in the daily market.

It should also be noted that the sums of the quantities of energy traded in each market can not exceed the limits of maximum energy turbined or pumped by the machines. For that, equations 42 and 43 represent that the energy generated or pumped in the daily market plus the intraday energy minus the energy bought-back or sold-back can not be greater than the maximum load imposed by the physical limitation of the machine. However, equations 44 and 45 limit the energy that can be sold-back or brought-back in the intraday market to the amount of energy sold or purchased in the day-ahead market. Therefore, all these restrictions are defined, and only the constraints that limit the variation of energy between the upper and lower reservoirs remain to be reshaped.

$$e_{i,t} + E_{i,t} - EB_i \leq e_{gen\_max} \tag{42}$$

$$e_{i,p} + E_{i,p} - ES_i \leq e_{pump\_max} \tag{43}$$

$$EB_i \leq e_{i,t} \tag{44}$$

$$ES_i \leq e_{i,p} \tag{45}$$

5.3 Results

The results of the optimization model that has been developed in this chapter have been obtained using the same amount of inputs than in the previous model where only the daily market was considered. This has been done with the aim of obtaining results comparable to those obtained by the previous model in order to analyze the main differences between both.

Due to the incorporation of a new market to the model, additional inputs corresponding to the intraday market are needed when executing the model.

5.3.1 Cross-market input data

The additional inputs that need to be incorporated into the model in order to obtain the optimal programming are the price curves corresponding to the intraday market for the same hours of the day-ahead market, plusthe elasticity coefficients that define the liquidity of the first intraday market.

- **Intraday Price curves**

As for the model of the previous chapter, the price curves for both markets will be considered for the same periods of time selected. Thus, in this case the same periods are again:

- Period 1: 09/01/2016 to 22/01/2016

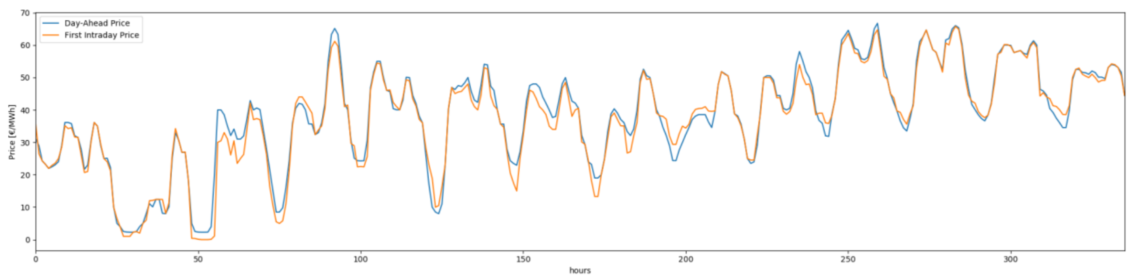

Figure 17. Day-Ahead and intraday prices of period 1

- Period 2: 16/04/2016 to 29/04/2016

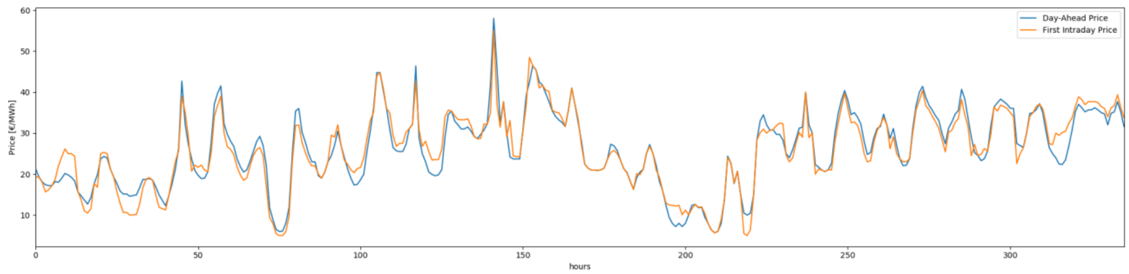

Figure 18. Day-Ahead and intraday prices of period 2

On this occasion, the figures 17 and 18 corresponding to periods 1 and 2 respectively represent the price curves for the daily market (blue line) and for the intraday market (orange line). As portrayed in these figures, the price curves for both markets follow a very steady evolution, except at certain times when the prices of one market differ significantly from the prices of the other market. These differences are those that the model uses to identify an extra benefit in obtaining the optimal program of pumping and turbining.

The model identifies hours in which it is more beneficial to turbine or pump in the intraday market than doing so in the day-ahead market or vice versa. The model even has the option of being able to sell the energy bought in the day-ahead market if there is a real opportunity to obtain an extra profit and to match the energy sold in the daily market, the model can see a better opportunity and buy it again from the daily market because the price difference is wide enough to make a profit from the operation.

- **Elasticity coefficients**

Just as for the day-ahead market, where coefficients of elasticity were defined for the model to take into account the liquidity of the market, i.e. the amount of energy traded, for the first intraday market these coefficients are also defined. They are calculated similarly to those corresponding to the day-ahead market, through the slope of the aggregate supply and demand curves. The values of the coefficients must be greater than the coefficients corresponding to the daily market because, as discussed in Chapter 2, the intraday market has much less liquidity than the daily. Therefore, the values for the estimated intraday market elasticity coefficients are:

- $q_{im,t} = 1/100$
- $q_{im,p} = 1/30$

In the intraday market, because liquidity is lower, the price is more susceptible to greater variations for the same amount of traded energy, so the value of the coefficients is higher.

5.3.2 Results

Taking into account the inputs presented for the first intraday market and keeping the values of the inputs for the day-ahead market, the results obtained from the execution of the optimization model are presented below, taking into account the price curves corresponding to both markets. The model has accounted for the liquidity of each market through the definition of the elasticity coefficients.

For both cases, the model will consider the two periods presented with a time horizon of two weeks each.

- Period 1: 09/01/2016 to 22/01/2016

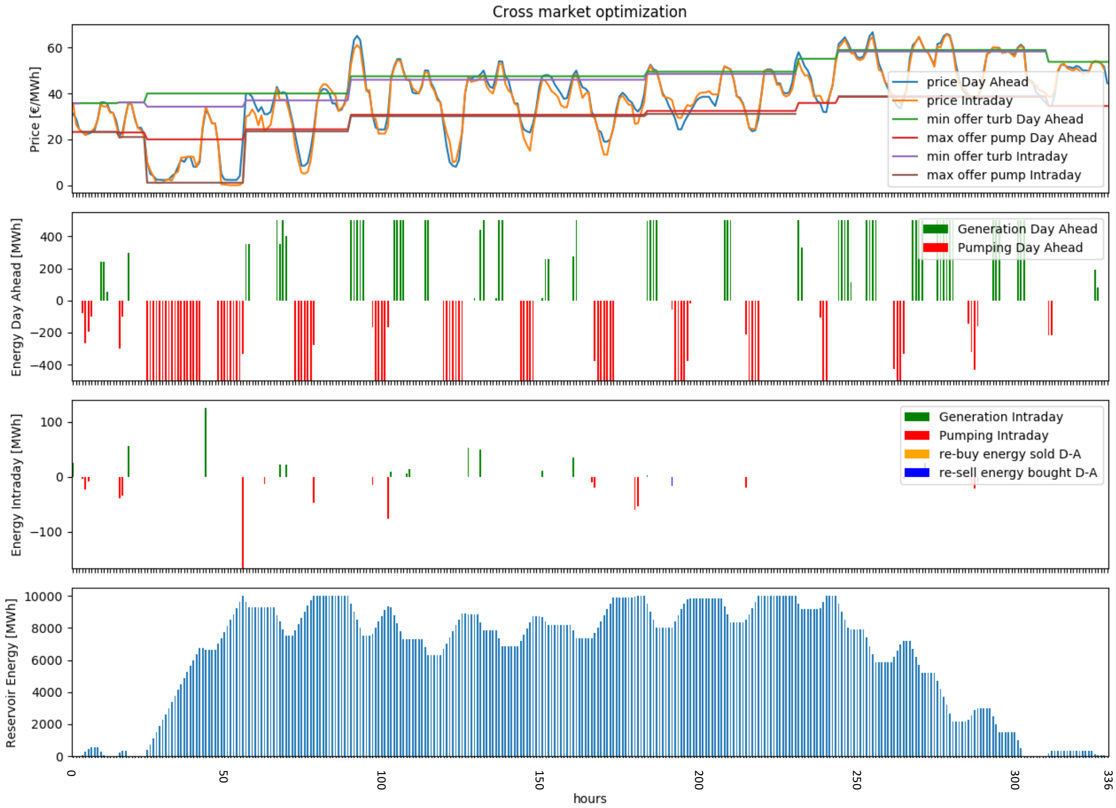

Figure 19. Optimization model result considerind day-ahead and first intraday markets for period 1

- Period 2: 16/04/2016 to 29/04/2016

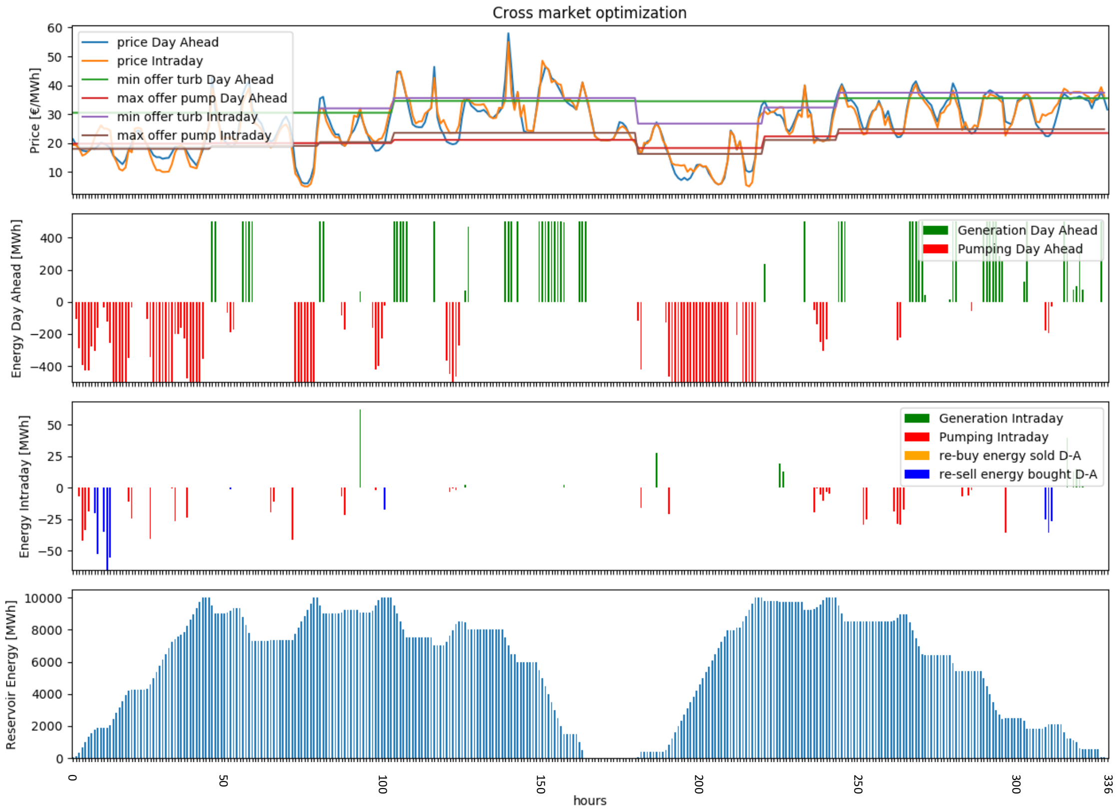

Figure 20. Optimization model result considerind day-ahead and first intraday markets for period 2

5.3.3 Analysis and comparison with single market model

In figures 19 and 20 we can see several graphs that represent the optimum program calculated by the optimization model developed in this chapter.

As in the results presented in section 4.6.2.1, the first graph shows the corresponding price curves for the periods selected for each of the markets, daily and intraday, together with the lines representing the optimal bidding prices obtained to sell or buy energy in each market.

The second graph represents the pumping and turbining program for each hour of the associated period in the day-ahead market. The bars with green, positive values correspond to the amount of energy turbinated in each hour, however, bars with red, negative values are the amount of energy pumped in each hour.

The turbining and pumping program for the intraday market is represented in the third graph of figures 19 and 20. These bar graphs represent the results of the hours in which it is optimal to turbine and pump in view of intraday market prices. It also represents the amount of energy bought-back or sold-back from the daily market, ie the model identifies opportunities to undo positions of energy set in the daily market and obtaining an additional benefit.

Finally the evolution of the energy stored in the upper reservoir is represented in the last bar graph. As it is shown in the figure, the maximum level of energy in the reservoir reaches the level set in the restrictions.

The optimal programs determined by the optimization model closely resemble the ones obtained through the model developed in the previous chapter where only the day-ahead market is integrated. This is because the model has in consideration the liquidity defined for each market and assigned the great majority of the energy to turbine and pump in the market with the most liquidity, i.e. the day-ahead. It can be observed that the energy allocated in the intraday market is much lower than in the daily market, so the energy profile stored in the upper reservoir does not vary much.

5.3.4 Benefit comparison

The following table shows the optimum benefit obtained by the model for the pumping plant. The table also shows that the benefit obtained by the model that only considers the day-ahead market is not perfectly competitive, this conclusion arising when comparing it with the results obtained by the model that considers two markets.

Benefit (€)			
Day-Ahead and intraday model		Day-ahead model (Price elasticity)	
Period 1	**Period 2**	**Period 1**	**Period 2**
677 463	380 289	674 068	379 012

Table 2. Pumped storage plan benefit under diferents models

As can be seen in the table above, the benefit obtained by the new optimization model which integrates both markets is slightly higher than the one obtained by the model that only considers the day-ahead market. Unsurprisingly, benefit have increased due mainly to opportunities found in the intraday market. The difference between both benefits corresponds to the energy traded in the first intraday market.

5.4 Conclusions

The optimization model developed takes into account both the day-ahead market and the first intraday market. The model returns the optimum of pumping and turbining schedule for each hour of the considered period differentiating between the energy to be traded in the day-ahead market and in the first intraday. The results obtained are in line with what is expected because they comply perfectly with the restrictions imposed. In addition, the results regarding the economic benefit of the facility for the whole period considered was greater than those obtained by the model developed in the previous chapter that only considers the day-ahead market under the price elasticity hypothesis.

Therefore, this model offers the possibility of backtesting, performing the analysis of the past including the movements of the price of complementary markets to evaluate strategies and allow processes of improvement and continuous adaptation.

Chapter 6: Conclusions and future work

Chapter 6 – Index

6.1 Future work

There are still multiple options to increase the opportunities captured by the plant by optimizing the pumping plant beyond what was done in this project. Therefore, the study of the incorporation of more opportunities in consecutive markets, such as the rest of intraday markets, remains pending. It is also interesting to consider taking into account balancing markets for future optimizations of the plant.

There is still work to be done on the models developed if we want to reflect the real behaviour of electricity markets. You can not completely model the behavior of markets because of the uncertainty and environmental factors that surround them, but you can try to get as close as possible. Therefore, the development of tools that capture and estimate the elasticity coefficients for each hour in each day-ahead or intraday market is still pending or would interesting to have in order to obtain results closer to the real market behaviour.

Last, it is pending to develop price prediction models for the different sessions of the intraday markets in order to apply in real time the optimization of an integrated market session.

6.2 Overall project conclusions

An important explanation and analysis has been carried out in relation to the existing electricity markets in the Spanish system, placing a handicap in day-ahead and intraday markets, because they are the main object of this project.

The optimization models have been developed in function of the complexity that each carried and adding variables and hypotheses in order to adjust as much as possible the models developed to the reality associated to the behavior of the electricity markets and obtain results that are the closest to reality.

The results obtained by the optimization model under the hypothesis of operating under a price taker hypothesis market were adjusted to the considered price curves, i.e. the model actually adjusts the pumping schedule to hours where the price is low (valley hours) and turbining in hours with high prices (peak hours), so that it would respond to the basic remuneration of a pump storage plant described in point 1.2.3. However, the model does not resemble to what it is actually happening in the market.

The marginal prices for each hour of the different electricity markets depend to a large extent on the volume traded in each session of the intraday market, i.e. liquidity. This factor has been taken into account in the previous model incorporating a new price in the objective function dependent on the energy traded in the market through elasticity coefficients. The results obtained considering that the market behaves according to the volume of energy traded in the market respond more to the reality. The energy programmed by the pumping and turbining model is more staggered over the hours corresponding to the optimal prices marked by the model. Therefore, the model more closely resembles the reality of what happens in the markets and calculates offers prices of purchase and sale of energy to bid on the day-ahead market.

In order to take full advantage of the pumping plant, it is necessary to look beyond the day-ahead market and consider other markets as the first intraday where additional opportunities can be found to generate an extra profit to the one obtained in the daily market. It has been taken into account that the intraday market is less liquid than the day-ahead market through the calculation of the elasticity coefficients for this market. The results show an increase in the benefit of optimum programming of the pumped and turbine energy associated with both markets, so that the model improves with respect to the previous one in the profit obtained.

It also takes uses two variables for the intraday market of energy buying-back and sellin-back fixed in the daily market. Through these variables, the model looks for opportunities to generate an extra benefit when prices between both markets are large enough. Therefore, an alternative route has been incorporated into the model to simply perform an optimum pumping and turbining schedule in each of the markets.

Finally, the optimization models developed and the obtained results comply with the objectives established in chapter 1. A tool has been developed that allows to obtain the optimal programming of a pumping storage plant taking into account the liquidity of each market, going from a totally theoretical model to one that better represents the market behavior in reality.

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Annex A: Nomenclature and Abbrevations

NOMENCLATURE USED IN THE MODELS

Sets

i: hours of the day (1,2,3,…)

Parameters

P_i: price for day-ahead market [€]

$P_i{}^*$: price for day-ahead market considering elasticity [€]

$P^*_{im,i}$: price for intraday market considering elasticity [€]

e_{reserv_i}: energy capacity of reservoir [MWh]

e_{gen_max}: maximum turbine power [MWh]

e_{pump_max}: maximum pump power [MWh]

q_t: elasticity coefficient for day-ahead supply curve [-]

q_p: elasticity coefficient for day-ahead demand curve [-]

$q_{im,t}$: elasticity coefficient for intraday supply curve [-]

$q_{im,p}$: elasticity coefficient for intraday demand curve [-]

T_t: network access tax for energy generation [€/MWh]

T_p: network access tax for energy consumption [€/MWh]

t: taxes appling for conventional generation installation [-]

μ: performance of pumping machines [-]

Variables

$e_{i,t}$: energy generated in day-ahead market [MWh]

$e_{i,p}$: energy pumped in day-ahead market [MWh]

e_{reserv_i}: energy available in the upper reserve [MWh]

$E_{i,t}$: energy generated in intraday market [MWh]

$E_{i,p}$: energy pumped in intraday market [MWh]

ES_i: energy re-selled in intraday market [MWh]

EB_i: energy re-buyed in intraday market [MWh]