UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

Retail Prices Design in a Context of Flexible Consumers, Impacts on the Bulk Power System: a Spanish Case Application

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Abstract

The design of prices and charges may significantly impact the dispatch of flexible distributed resources and furthermore the operational costs of the bulk-power system. The analysis carried out in this thesis entitle a series of case studies where different prices and charges designs are modeled for allocating three cost components of retail prices: energy prices, network charges and other regulated costs (e.g. policy costs). The Spanish system operation is a reference case, where a group of flexible customers are assumed to be located at a single node of low voltage networks. The flexible resources are representative for the Spanish system for near future. Flexible customers can lower their electricity bills by dispatching their DERs according to the economic signals (prices and charges) that they receive.

The research is performed by using a unit commitment and dispatch modeling tool that allows to include an equivalent representation of an actual distribution network. The equivalent network representation is configured at different nodes split in distinct voltage levels. The network is built based on public data published by the Spanish regulator. Flexible demand is grouped in a single node with the flexibility given by demand response mechanisms, battery electric vehicles, back-up generation, and photo-voltaic generation. In addition, these flexible resources are managed by an aggregator which optimizes their dispatch according to the price signals.

Results show that different retail prices designs have distinct impacts on system thermal costs and generation dispatch of flexible consumers. A scheme with volumetric charges was found to promote the dispatch of expensive local generation that distort the economic dispatch, increasing in turn total generation costs. It was also found that flat energy prices do not incentivize the efficient operation of flexible resources such as demand response and electric vehicles vehicle-to-grid strategies, increasing total generation costs. In addition, flexible consumers were found to obtain savings in charges from modifying their net demand profile. However, savings in regulated charges of flexible customers are in turn paid by inflexible ones. Finally, the increase in local generation netting loads reduces network losses and locational marginal prices and, as a consequence, demand market payments.

Resumen

El diseño de precios y cargos puede impactar significativamente el despacho económico de recursos flexibles distribuidos, así como los costos de operación del sistema eléctrico. El análisis realizado en esta tesis incluye una serie de casos de estudio en los cuales se modelan distintos diseños de precios y cargos para los tres componentes del precio minorista de electricidad: el precio de la energía, el costo de las redes de distribución y otros cargos regulados. El sistema eléctrico español se utiliza como caso de referencia, en el que un grupo de consumidores flexibles son localizados en un nodo de baja tensión. Estos recursos flexibles son representativos del sistema español. Los consumidores flexibles pueden disminuir sus facturas eléctricas despachando sus recursos locales dsitribuidos de acuerdo con las señales económicas que reciben (precios y cargos).

La investigación se desarrolla utilizando un modelo de programación diaria y despacho de recursos de generación que permite incluir una representación equivalente de la red de distribución. La representación equivalente de la red se encuentra configurada en nodos distribuidos en distintos niveles de tensión. Esta red se construyó con base en información publicada por el ente regulador de España. Por otro lado, la flexibilidad de los consumidores flexibles es definida al proporcionarles mecanismos de respuesta de la demanda, vehículos eléctricos, generación térmica local y generación fotovoltaica. Por último, estos recursos flexibles son manejados por un agregador, el cual optimiza su despacho de acuerdo con señales de precio y cargos.

Los resultados muestran que los distintos diseños de precios finales puede tener diferentes impactos en el costo total de generación del sistema, así como en el despacho de los recursos de los consumidores flexibles. Se identificó que los esquemas de precios con cargos volumétricos promueven el despacho de generación local más costosa, incrementando asimismo el costo total térmico del sistema. Por otro lado, un esquema con precio fijo no incentiva la operación eficiente de los recursos felxibles, tales como la respuesta de la demanda y estrategias de inyección de energía en la red por parte de vehículos eléctricos, lo cual encarece el costo total del sistema. Asimismo, se identificó que los consumidores flexibles obtienen ahorros en cargos como resultado de modificar su perfil de demanda. Sin embargo, los ahorros en cargos que disfrutan los consumidores flexibles son pagados por los consumidores inflexibles. Por último, el aumento en generación local reduce las pérdidas de red así como los precios de la energía, y por lo tanto los pagos del componente de enrgía que deben realizar los consumidores.

Chapter 1

Introduction

The Spanish power network have suffered significant changes in the last years. These changes have responded both to political initiatives in a European context, and to technological advances. On one side, European targets for lower greenhouse gasses' emissions have foster the penetration of Renewable Energy Sources (RES) in the generation mix of the Spanish Electric System. Due to their intermittency, RES management as part of the generation mix represents an important challenge for the network operators. On the other hand, the deployment of new technologies in the power sector, like Electric Vehicles (EV), batteries, smart meters, and distributed energy generation, embodies an additional challenge, as networks' management needs to evolve to account for bidirectional flows in the grid instead of unidirectional ones. (i.e. electricity produced in lower voltage levels and flowing to higher voltage levels). These challenges have undeniable consequences on the operation of the networks that need to be accounted for.

Pricing schemes has also important effects on power systems. In a nodal pricing scheme it is considered that energy prices at low voltage nodes may impact significantly the operation of flexible Distributed Energy Resources (DER) on those nodes. In addition, the operation of DER would be also affected by other economic signals different to energy prices like network charges, the allocation of regulated costs, and support mechanisms for renewable sources such as net metering.

In order to measure the effect on the power system of different prices and charges it is necessary to account for the response from end-users, either by allowing them to change their demand or by managing the production of their distributed flexible resources. However, it is unlikely that end-users would dedicate time to monitor prices in a daily or hourly basis, as it entitle to them an important opportunity cost for them. In this line, aggregators have emerge as agents that groups the management and operation of several distributed flexible resources for a group of consumers. Aggregators are assumed to take optimal decisions in the management of its consumers resources, which is expected to produce benefits for both aggregator and its clients. Therefore, this research considers the existence of an aggregator that groups flexible consumer's resources. The aggregator is able to react to market prices by managing load flexibility and eventually changing the load profile or operation of flexible resources in representation of end-users.

1.1 Motivation

This research main motivation lies in the potential impacts that flexible costumers' behavior can cause on electric power systems, when responding to different prices. Some of the questions that are intended to be answered in this research are:

- How different pricing and tariff designs affect consumer reactions?
- How aggregated consumers reactions affect the bulk power system operation, i.e. system operational costs, resources dispatch, and locational marginal prices?
- Which retail prices design has a lower distorting effect on short term prices?

1.2 Objectives

The main objective of the thesis is to show how different end-users retail price designs can distort the efficiency of short term marginal prices that agents receive, affect agent's private benefits, and impact the overall operation of the system.

In particular, specific objectives include assessing the impact of different pricing and tariff design on:

- System operational cost
- Locational marginal prices
- Consumer payments, which includes both energy and charges payments
- Income redistribution effects among different groups of consumers, flexible and inflexible ones

The study case considers the Spanish system for the year 2020, with input demand data obtained from the Spanish Regulator Comisión Nacional de Mercados y Competencia (CNMC), flexible consumers resources managed by an aggregator, and the modeling of distinct tariff designs, which aims to exemplify current and alternative future regulatory frameworks.

1.3 Proposed Method

The methodology applied for achieving the thesis' objectives consists in assessing different retail prices design while using an economic dispatch tool and accounting for economic rational flexible consumers. In short, the methodology steps are:

i Define a reference case, which corresponds to the optimal economic dispatch of the system ii Define case studies based on the distinct ways regulated costs can be charged to flexible consumers

iii Compare case studies' results with the reference case

1.4 Thesis Structure

The thesis is structured as follows. The first chapter introduces the topic and presents the main objective, along with the research questions.

Chapter 2 includes the literature review, where the state of the art for two main topics is described. First, a general review of retail prices and its breakdown in energy prices, network costs, and other regulated costs is assessed. Then, a modeling framework is provided for key concepts used through the thesis, being those Distribution Locational Marginal Prices (DLMP), Demand Response (DR) alternatives, and a small review about aggregators figure.

Chapter 3 develops an extend description of the method used in the research. First, the characterization of the underlying optimization model along with its main features is assessed. Then, the inclusion of flexible consumers, their resources, and how those resources are managed is considered. Finally the distinct ways in which retail prices can be modeled is introduced.

Finally, Chapter 4 presents the main results of the thesis regarding the most important impacted variables for various case studies, whereas Chapter 5 presents the findings and policy recommendations.

Chapter 2

State of the Art

This chapter develops the main theoretical aspects regarding retail prices and its decomposition in energy, network costs, and other regulated cots; retail prices components and their characteristics, Demand Response (DR) modeling alternatives, and a reference to aggregators along with its advantages, disadvantages, and ways of operation.

2.1 Retail Prices

Retail prices referred to the final prices paid by end-users. In electricity bills, consumers do not only face the price paid by each unit of energy consumed (in €/Mwh), but also a series of charges related to the cost of the transmission and distribution networks, institutional costs, subsidies, taxes, and others. All these charges not specifically referred to the price of the energy consumed are known as regulated charges, and its classification can differ between countries.

In general, most power systems include in their retail prices every single cost associated with the production, transportation, selling, and provision of the electricity service. Nevertheless, the way in which the costs of the different components is charged to consumers can differ a lot between power systems. And one reason for this difference is the model in place, as it is known the power system regulation can have different structures between a centralized model and a full liberalized one.

In this research, the classification for the components of retail prices that categorize them in three main groups is used. These components are the following:

- **Energy prices:** in liberalized markets, correspond to the price that is set at wholesale markets resulting from the match of supply and demand bids
- **Network charges:** part of the tariff that consumers pay and is dedicated to pay the costs of the network infrastructure, both for the transmission and the distribution grids
- **Other regulated charges:** include charges for financing other costs related to the functioning of the power system like institutional cost (regulator, market operator, system operator), renewable subsidies, tariff deficit, and others.

2.1.1 Energy Prices

The energy price reflects de cost of producing a unit of electricity for supplying the demand. In liberalized markets, the energy prices entitles the hourly price that retailers pay for energy from generators at the electricity wholesale market. In addition, this component might include the commercialization margin of retailers.

In general, liberalized electric systems use two approaches to compute energy prices: nodal pricing and zonal pricing. Both approaches have its advantages and disadvantages, and have been adopted by several liberalized power systems worldwide. Their operation is described in the following lines.

2.1.1.1 Zonal Pricing

The zonal pricing scheme consists in defining a single market price for a certain zone, area or country, except when significant network congestions arises between well-defined zones (Pérez-Arriaga, 2013). The method consists in replicating the operation and dispatch of the system, in order to identify the main grid congestion areas. Once substantial congestions are identified, the grid affected by those congestions is divided into zones. Then a single price is defined for each zone, rather than for each single network node.

The zonal pricing approach is summarized by (Bjørndal & Jørnsten, 2001) as follows:

i The wholesale market is cleared considering supply and demand bids. In this step, the grid limitations are ignored.

ii If resulting flows from step *i* produce capacity problems in certain lines, the grid nodes are split into zones.

iii In a two zone case, the one with *net supply* is determined as the *low price are*, while the zone with *net demand* is defined as the *high price area*.

iv Net transmission over the zone-boundary is fixed when curtailed to meet the violated capacity limit.

v The zonal markets are cleared providing one price for each zone. If the flow resulting from this equilibrium still violates the capacity limit, the process is repeated from step *iv*. If any new limits are violated the process would be repeated from step *ii*, possibly generating additional zones.

Zonal pricing has been the cornerstone of the European Price Coupling (EPC) model, which defines prices and volumes for every relevant zones of Europe, based on the marginal pricing principle (Agency for the Cooperation of Energy Regulators [ACER], 2011).

2.1.1.2 Nodal Pricing

The nodal pricing scheme considers both ohmic losses and possible congestions, resulting from the existence of the network, in the computation of final marginal prices. These characteristics of the grid cause that, in nodal scheme, the price of one node may differ from the price of another node.

According to (Pérez-Arriaga, 2013), *the nodal price at system node k is defined as the system's short-term marginal operating cost of meeting an increment in demand at node k as economically as possible and within the constraints imposed by the system.*

The main characteristic of nodal prices is their ability to provide efficient short term signals (prices) to agents participating in the electricity market, as it internalizes in a single value (€/MWh) the network characteristics that cause differences in prices among nodes: ohmic losses and congestion. Authors in (Pérez-Arriaga, 2013) demonstrate with simplified network example, the efficiency of a nodal pricing scheme.

An additional feature of a nodal pricing scheme is that it allows the creation of an economic surplus. As prices in this scheme can differ among nodes, demand payments will also be different from generation revenues. This difference between demand payment and generation revenues is known as *economic surplus*. The usage of the economic surplus to pay part of the network costs is deeply explored in (Pérez-Arriaga, Rubio, Puerta, Arceluz, & Marin, 1995). The authors demonstrate that, if certain ideal conditions are meet, the surplus can recover 100% of network. However, they assesses that, in practice, such a large recovery is not possible. They have found that such application of nodal prices result in a recovery of no more than 30% of the network costs. According to the authors, some conditions that cause this shortfall in cost recovery include:

- Discrepancies between static and dynamic expansion plans
- Discrete decisions rather than continuous ones regarding network investments
- Economics of scale in network expansion investments
- Reliability requirements that cause the an expansion plan not to be the optimal one
- Financial, environmental, or technical factors that may cause deviations in network investments when compared to the optimal plan

Finally, these shortage of recovery cost in a nodal pricing scheme results in the necessity of implementing an additional charge to recover the remaining network costs, usually known as *complementary charge*.

Due to its advantages, nodal pricing schemes are nowadays used in several power systems around the globe, like most part of the Independent System Operator (ISO) working in the United States, several South American systems, and New Zealand as well.

2.1.2 Network Charges

Traditionally, generation and demand has been located far from each other, especially due to the location of the fuel sources necessary to produce electricity. Therefore, huge infrastructures like, towers, stations ans substations, have been build in order to transport the electricity from generation sites to demand sites. The cost of building this infrastructure is what is known as network costs. These costs usually entitle the larger part of the tariff.

Network charges can be charged as a volumetric charge (€/MWh) or as a capacity charge. The capacity charge method states that an increase of demand on peak hours will make necessary to expand the network on those hours. This network expansion implies an increase on the cost of the network, which in short should be charged to those agents responsible of the increase on demand.

An alternative method called Advance Demand Charge (ADC) is proposed by (Abdelmotteleb, Gómez, Chaves-Ávila, & Reneses, 2016), and explained below:

i Define a threshold based on the peak network usage

ii Notify *ex-ante* an approximate charge along with the expectation of which will the peak hours be. This hours are subjected to change according to consumers' reaction.

iii Announce the actual ADC and peak hours, and allocate ADC *ex-post*

Authors describe the two main objectives of the ADC method as:

- Sending awareness economic signals to consumers regarding their potential impact on the network
- Sending potential preventive economic signals guiding the consumers towards Distributed Energy Resources (DER) investment decisions, if the utilization level is expected to increase requiring network reinforcements

Finally, the key characteristic of the ADC method, is that it considers the investment opportunities available for consumers. The ADC is set below the DER investment opportunities when awareness economic signals are required, in order for consumers to avoid investing in DER. The ADC is set above them when preventive economic signals are required, encouraging consumers to invest in DER. Thus, the ADC method is closely linked to the long- term elasticity of consumers.

2.1.3 Other Regulated Charges

Other regulated charges include every other cost resulted from the provision of the electricity service, different from the costs of the energy and network. Its composition can differ between systems, but in general it includes the following components (Pérez-Arriaga, 2013):

- Funding of the regulatory body, which should guarantee the well operation of the power system and related markets
- Operators' retribution. These includes the funding for the correct functioning of the main operators, being these the system operator, the market operator, or a single entity in charge of both functions.
- Stranded costs. These costs appear in power systems under an important regulatory change, which can include moving from a centralized system to a liberalized one. Some agents might suffer losses in benefits during the process of migration, therefore the regulatory authority might consider to compensate them for those losses.
- Associated costs to environmental policies. Renewable Energy Sources (RES) are usually less competitive than traditional ones, therefore governments and/or regulators tends to incentivize their usage through subsidies, which are included in end-user tariffs.
- Deviations from previous year estimated revenues.

In addition, other regulated charges can include charges like capacity payments, in order to ensure the necessary investment in installed capacity so to guarantee future's demand; transmission and distribution losses, in cases where nodal prices are not implemented.

2.2 Modeling

The model used in this thesis implements several current technology breakthroughs in the modeling like DR mechanisms, aggregators for DER, Electric Vehicles (EV), among others. The following lines include some considerations regarding these aspects.

2.2.1 Demand Response (DR)

Due to electricity characteristic of bring an essential commodity, demand side have historically been very inelastic: despite variations in electricity prices demand side has not been known for responding with the corresponding changes in the quantity of energy bought. However, in the last years, technology breakthroughs have provided consumers with additional and new ways to respond to electricity prices through appliances with programmed functioning, real time metering of energy consumption, on site local generation, exemplify all ways in which DR can be activated.

DR can be defined as *"the changes in electric usage by end-use costumers from their normal consumption patterns in response to changes in the price of electricity over time"* (Albadi & El-Saadany, 2007). This is, electricity demand becomes elastic, as it can be able to modify its consumption patterns in response to hourly electricity prices.

There are two main DR mechanisms[1], demand shifting and peak shaving, which are explained as follows:

- **Demand Shifting** This mechanism entitles moving demand from certain hours to others. Generally, this movement is done from peak hours, when prices are the highest, to valley hours, when prices are the lowest.
- **Peak Shaving** The peak shaving mechanism implies consumers to reduce their demand during peak hours. The usage of this mechanism might be triggered when total demand surpasses total generation for a certain hour, in which case non-served energy can be possible. Therefore, through the reduction of demand on that hour, the existence of non-serve energy is avoided, considering that the price for non-served energy is usually very high.

DR provides benefits both for consumers and for the system as a whole. The main advantage for consumers is the savings they can get on electricity bills, as a consequence of consuming less electricity on peak hours. In addition, consumers can receive earnings from participating in DR programs that may benefit the whole system.

On the other hand, the power system as a whole may benefit from the implementation of DR programs. By lowering the peak demand, lower prices can be achieved on those peak hours which can result in lower peak prices for the whole system, benefiting even those consumers that do not participate in DR programs. In addition the net capacity of the system increases, as peak demand is lower in comparison to the system peak capacity, which can result in savings in short term capacity investments. Additional material regarding DR benefits can be consulted in (Albadi & El-Saadany, 2007), where benefits are extended to reliability and market performance matters.

It must also be considered that DR programs can entail some costs. On one hand, household consumers shifting or shaving their peak hours' demand can experience a discomfort from doing so, as a result of managing and using their appliances in different schedules from those they are used to. Theses costs related to discomfort might be even higher when the consumer is a commercial or industry agent, which require higher amounts of energy.

In addition, there is a cost associated to the installation of smart meters that allow to measure hourly energy consumed by end-users. In this matter, the European Union Third Energy Package requires Member States to *ensure the implementation of intelligent measuring systems that shall assist the active participation of consumers in the electricity supply market* (European Commission [EC], 2009), with a target of at least 80% of consumers equipped by 2020. In addition, an European Commission (EC) Report (EC, 2014) that assessed the progress of smart meters installation, found that on average an intelligent measuring point has a cost between €200 and €250 per customer, and ranges from a minimum of €77 in Malta to a maximum of €766 in Czech Republic.

[1] Notice that demand can also respond through investments on electric storage, distributed generation, and others. However, only short-term response of demand side is modeled here.

Finally, an important cost is the opportunity cost for consumers of monitoring hour by hour electricity prices in order to try to take advantage of hour differentials via DR. This series of costs have motivated the creation of the aggregator, in its function of managing consumers resources.

2.2.2 Aggregators

Even thought consumers have won alternatives to modify their demand profile, and due to the fact that electricity is produced every hour with different energy prices, rational consumers have an important opportunity cost for managing themselves their response to prices: change their daily activities schedule in order to have the time to monitor electricity hourly prices and change their demand accordingly. Therefore, a market opportunity has been created for managing consumers resources, and provide economic benefits to them, and the aggregator figure has emerged.

An aggregator is defined by (Ikäheimo, Evens, & Kärkkäinen, 2010) as *"a company who acts as intermediator between electricity end-users, who provide distributed energy resources, and those power system participants who wish to exploit these services."* In the context of this thesis, the aggregator is the agent that groups flexible consumers' distribute resources and put them to the service of the whole power system.

Aggregators can have different business models, from which (Ikäheimo et al., 2010) identifies four: retailer, Balancing Responsible Party (BRP), a retailer's service company, and independent aggregator. In the first case, retailers themselves act like aggregators, taking advantage og its connections to the electricity wholesale market and its portfolio of customers. On the other hand, aggregators as BRP provide balance supply to retailers when needed. Finally, independent aggregators do not have a electricity-related relationship with customers, however may have relationships in other domains.

An important feature of aggregators is their ability to provide value, either private to agents or to the power system if their actions increases economic efficiency. Authors in (Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2016) discuss the value aggregators can provide. In general, they argue that aggregators' value can be classified in fundamental, transitory, and opportunistic, depending of whether the beneficiary is the whole power system or private agents, the level of innovation in technology, and the regulatory context.

In general, the fundamental value created by aggregators comes from taking advantage of economies of scale and management of uncertainties. On the other hand, transitory value can be achieved during regulatory and technology transformations regarding the power system. Finally, opportunistic value usually comes from regulation gaps, and entails that agents may obtain private value without creating system value. This research assumes that aggregator is crating fundamental value, by capitalizing economies of scale on the management of its customers several resources. Figure 2.1 resumes the characteristics of each type of aggregator's value.

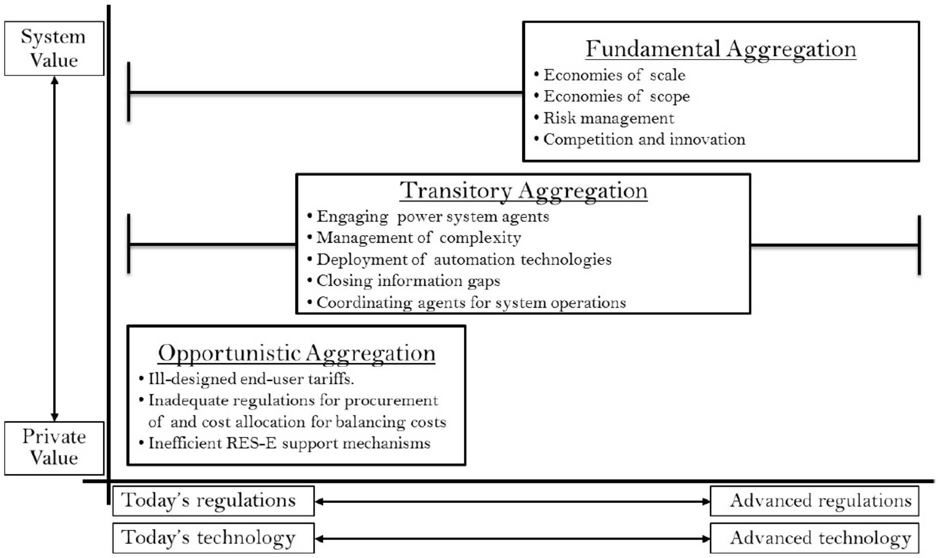

Figure 2.1: Types of aggregators' value

Source: (Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2016)

Finally, aggregator's customers can be diverse, as well as can be the transactions between an aggregator and them. Aggregators customers can range from households, commercial, and industry ones. Each of them differ on their knowledge of the power sector and in their needs. Therefore, the relationship between the aggregators and its customers can also take different forms. Figure 2.2 shows some of this transactions that can take place between both sides. The present thesis focuses on aggregators' abilities to reduce customer's load and selling on the market the generation provided by its customers' DER resources.

2.2.3 Electric Vehicles (EV)

The search for cleaner transportation technologies has resulted in the introduction of transport means different to petroleum-fueled Internal Combustion Engine (ICE) vehicles, being the most important EV.

As different EV technologies have appeared, different classification for EV have been made, mainly based on their main mean of propulsion. In this line, (Massachusetts Institute of Technology [MIT], 2010) provides one where EV are classified three groups:

i **Hybrid Electric Vehicles (HEV)** have both an ICE and an electric motor for propulsion, which can be configured in either series or parallel configuration. HEV are connected to the network to charge their batteries, which is recharged by conversion of braking energy.

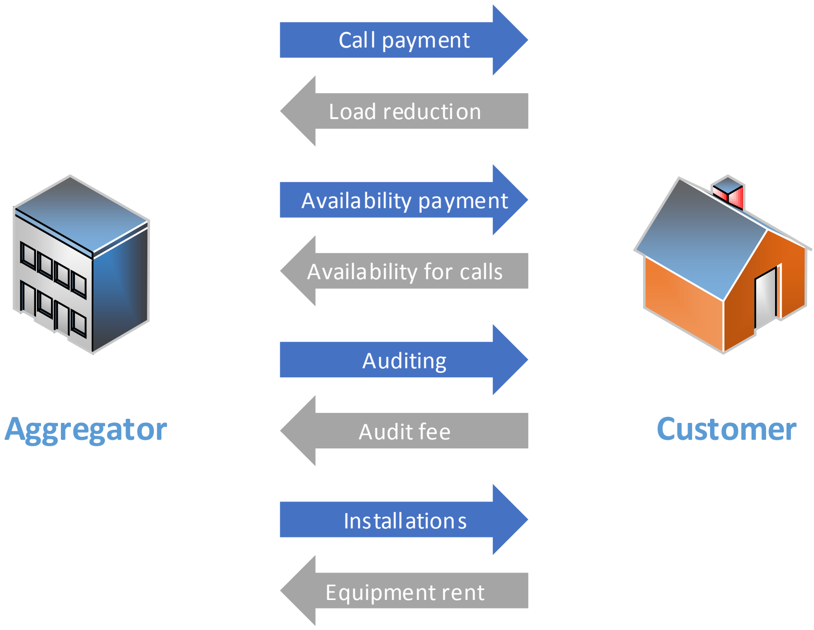

Figure 2.2: Aggregators's interactions with customers

Source: (Ikäheimo, Evens, & Kärkkäinen, 2010)

ii Plug-in Hybrid Electric Vehicles (PHEV) are HEV, as they include both an electric motor and a ICE motor, in which the battery is rechargeable by external power sources.

iii Battery Electric Vehicles (BEV) have only electric propulsion and a rechargeable battery pack.

According to data from (International Energy Agency [IEA], 2013), the EV global stock represented 0.02% of total passenger vehicles in 2012. However, and thanks in part to policies like the above mentioned, the Electric Vehicle Initiative, a multi-government policy forum dedicated to accelerating the introduction and adoption of electric vehicles worldwide, targets 20 million EV on the road by 2020, which would represent 2% of total passenger cars. Figure 2.3 shows the evolution of international EV stock from 2010 to 2015. It can be seen the constant growth of the EV quantities, and how 2015 stock almost doubled 2014 one, and tripled 2013 stock. It can also be seen that BEV in particular has seen their growth increased after 2013 when compared to the previous years.

In particular, (IEA, 2013) stated that Spain had stock of 787 EV in 2012. The same

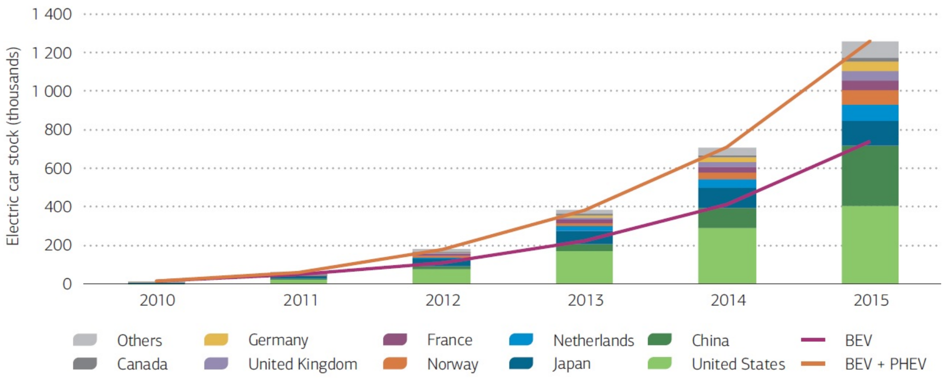

Figure 2.3: Evolution of the global electric car stock, 2010-2015

Source: (IEA, 2016)

publication targets for Spain sales in the order of 750 thousand EV in 2020 and a stock of around 2.5 million.

Therefore, it can be seen that countries' policies, global initiatives, and current data shows that the future (and present) importance of EV is undeniable. From them, BEV stand out due to their whole reliance on the electric network. Hence, it is highly valuable to consider BEV effects on the grid when modeling distinct future scenarios for electric systems. In this line, the present research considers only BEV in the modeling of the different case studies.

Chapter 3

Methodology

As stated before, the main objective of this thesis is to measure the impact of different retail prices designs on the operation of an electric system, by modeling consumers' flexibilities. This procedures entitles the usage of an adequate economic dispatch tool with certain characteristics, and the assumption that part of the demand correspond to economic rational consumers that has a flexible demand. Then, electricity charges are applied to consumers in distinct ways in order to assess the impact on the system operation of the different electricity charges alternatives.

In short, the procedure to be followed is shown in figure 3.1 and consists of using an economic dispatch tool and accounting for economic rational flexible consumers. The followed steps are:

i Define a reference case, which corresponds to the optimal economic dispatch of the system

ii Define case studies based on the distinct ways regulated costs can be charged

iii Compare case studies' results (impacts on the bulk power system) with the reference case

The methodology section goes as follows. First, the underlying model is introduced along with its main characteristics. Then, the way in which flexible consumers are represented is described. Finally, the modeling of the tariff design alternatives is included, and the impact on the power system is described.

3.1 The Underlying Model

The simulation of the electric system is done by using the Reliability and Operation Model for Renewable Energy Sources (ROM). The ROM is a unit commitment and economic dispatch model that includes a series of inputs as generation units' characteristics, load profile, reliability parameters, and a series of parameters that represent the electric network characteristics. On the other hand, the main outputs of the model are the hourly operation of the generation units, Carbon dioxide (CO^2) emissions, prices, and grid related outputs like power flows.

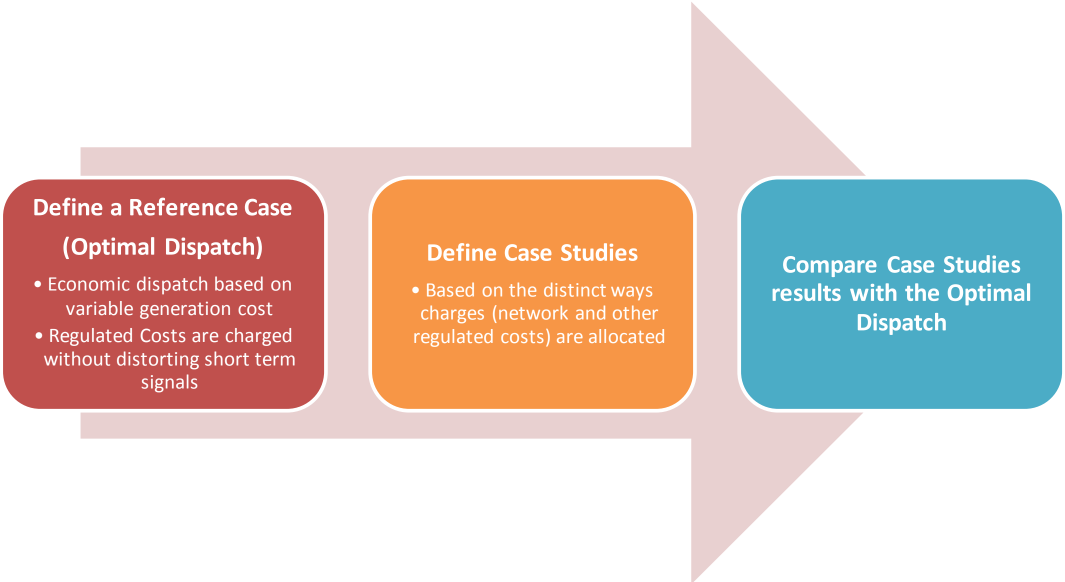

Figure 3.1: Methodology procedure

An additional important characteristic of the ROM is that it ables to produce Distribution Locational Marginal Prices (DLMP) rather than single price, which requires the existence of a network formed by several nodes. Marginal prices are a product of considering both line congestions and power flow losses during the dispatch process. Under this model, a different marginal price is obtained for each network node, and demand pays the marginal price corresponding to its node, while generation receives the marginal price of its node as well. Marginal prices implies obtaining an Economic Surplus (ES), resulting from extracting the total generation revenues from the total demand payments, which is usually used to pay a small part of the network costs.

The main inputs and outputs of the ROM can be seen in Figure 3.2, whereas additional detailed explanation of its features can be found in (Project MERGE [MERGE], 2011).

The ROM resolves a daily stochastic optimization for a whole year, and simulates the real time operation for each day. The present work considers only the daily unit commitment, which entitles minimizing the total cost of the generation dispatch subject to several restrictions and conditions. The forthcoming mathematical formulation is explained following (Dietrich, 2014). The main indexes considered by the model are p time periods, t thermal generation units, and h hydro generation units. The total variable cost (TC) is shown in equation 3.1.1.

$$TC = \sum_p \left[\sum_t (FC^t \cdot uc_p^t + VC^t \cdot g_p^t + StC^t \cdot on_p^t) + NSC \cdot nse_p \right] \tag{3.1.1}$$

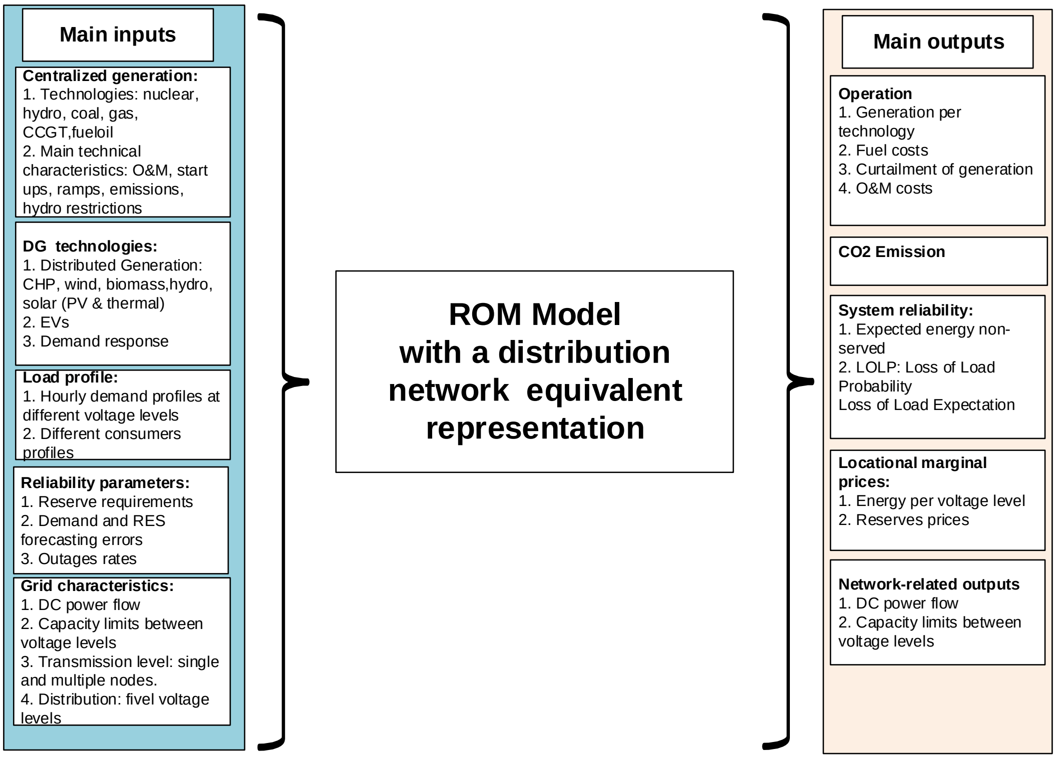

Figure 3.2: Reliability and Operational Model (ROM) inputs and outputs

where the unit commitment decision for each thermal unit uc_p^t is multiplied for the thermal fixed cost FC^t, the thermal output of each thermal generator g_p^t is multiplied for the variable thermal cost VC^t, the startup decision on_p^t is multiplied by the startup cost StC_t, and the non-served energy nse_p is multiplied by the cost of non-served energy NSC.

On the other hand, and as mentioned before, another key characteristic of the ROM is that it allows to model a representation of an actual network. In this line, the Spanish electric system is represented using an Electric Equivalent Network (EEN) representation, following (Chaves-Ávila, Gómez, Ramos, & Castro-Cerdas, 2015). A real network is composed of millions of nodes and lines, therefore the construction of an electric equivalent network comprises representing the distinct transmission and distribution voltage levels into a simplified representative network. The authors of (Chaves-Ávila et al., 2015) make this exercise for the Spanish power system. The resulting EEN is shown in figure 3.3.

The EEN considers a simplified network composed of two voltage levels for the transmission network, 400 Kilovolt (kV) and 220 kV, each of them composed of one node that represents the whole network at that voltage level. The distribution network is represented in four voltage levels , and four voltage levels for the distribution grid. For the former case, eleven nodes are depicted. The authors made the distribution of nodes among the different voltage levels in a way in which distinct real configurations are represented. As an example, an urban configuration which typically has a direct voltage transformation from high voltage to medium voltage is shown in the left side branch of the EEN, with the ending node N6.1; while a rural configuration which usually has several voltage drops from the highest to the lowest voltage level is shown in the right side of the EEN, with ending node the aggregator's node.

As part of the EEN computation, authors calculate the corresponding resistance of each line connecting two nodes based on the application of a quadratic approximation for the energy losses of the system. This inclusion allows for the consideration of quadratic losses for each line as an output of the model.

3.2 Accounting for Customer' Flexibility

A key assumption of the current study is the capacity of certain customer of being flexible, and therefore respond to different hourly prices and change part of their demand profile accordingly. Hence, some customers are assumed to be flexible and economically rational, this is, customers will modify their demand profile in order to minimize their cost of supplying their demand.

3.2.1 Aggregators

Flexible customers are grouped under an aggregator's figure. As already introduced, an aggregator is an agent that groups the management and operation of several distributed flexible resources for a group of customers. Aggregators are assumed to take optimal decisions in the management of its customers resources, which is expected to produce benefits for both aggregator and its clients.

The aggregator operation is modeled by including an additional node to the existing EEN shown in Figure 3.3, depicted as the aggregator's node. As this node is not a physical node per se, the equivalent resistance of the line connecting it to the system is considered to be close to zero, so that network effects on the node are neglected, and therefore network losses are considerably reduced for the rest of this document.

3.2.2 Flexible Customers' Resources

Customers have different flexible resources upon which they can decide on their dispatch. These resources include technologies that nowadays are gaining penetration, and includes Demand Response (DR), flexible thermal generation, and Battery Electric Vehicles (BEV). Even thought Photovoltaic (PV) generation is not a flexible resource *per*

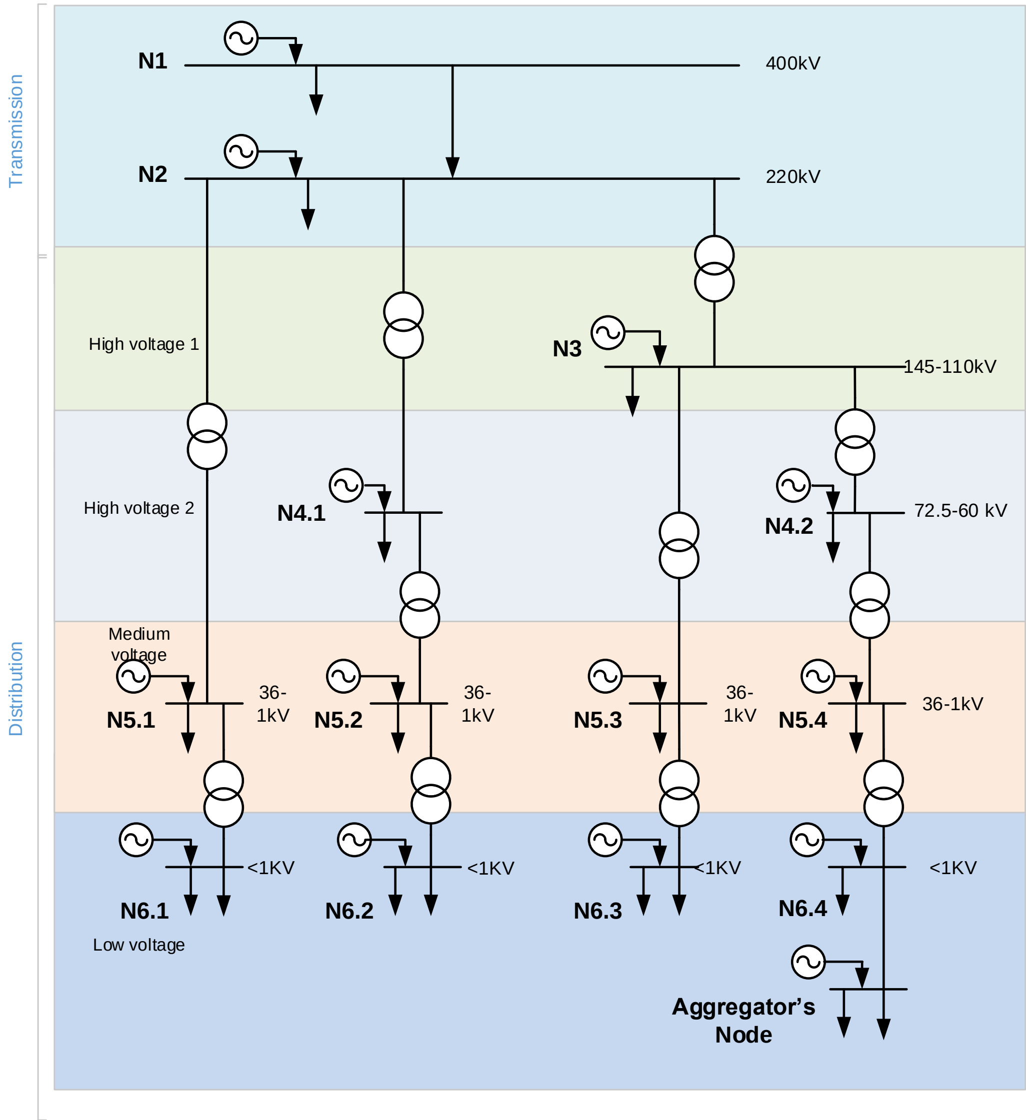

Figure 3.3: Electric Equivalent Network (EEN)

se, it is included here as flexible as it can be used as so when combined with other resources, like batteries.

3.2.2.1 Demand Response (DR)

DR is included as demand shifting rather than peak shaving. This means that customers can move their demand between hours, usually from peak hours with higher prices to non-peak hours with lower prices. In addition, demand flexibility upward and downward is set at 8% of the reference demand without DR. It is assumed that demand can only be moved within the same day, so that final daily energy remains the same. Regarding DR costs, the analysis will assume that DR movements have no costs for customers.

3.2.2.2 Back-up Generation

Flexible thermal generation units assigned to the aggregator's node represent the real back-up generation installations throughout Spain. As (Ramírez, Galán, & Martínez, 2014) explains, back-up units are classified according to the prime mover fuel of the engine, where the most common are natural gas, gasoline, and diesel. Each technology has its advantages and disadvantages, which (Ramírez et al., 2014) develops extensively. The present study considers only natural gas fueled back-up units and their respective costs.

Additionally, (Ramírez et al., 2014) estimates that the installed capacity of back-up generators from diverse technologies reached 6,808 Megawatt (MW) in Spain in 2015. For defining the installed capacity of back-up in the aggregator's node, the ratio of the node's demand over total system demand was taken as a reference, which yields 6.7%. This ratio applied to the estimation provided by (Ramírez et al., 2014), results in back-up generation installed at the aggregator's node is approximately 454 MW. The model considers that the aggregator's node has an installed capacity of natural gas fueled back-up generation of 300 MW. Table 3.1 depicts the characteristics of the considered back-up units.

Table 3.1: Back-up generation technology characteristics

Characteristic	Unit	Value
Maximum output	MW	10
Fuel cost	€/MWh	26.7
CO^2 cost	€/t CO^2	8
Specific emissions	t CO^2/MWh	0.245
O&M Variable Cost	€/MWh	6.48
Startup Consumption	Mcal/st	26667

3.2.2.3 Photovoltaic Generation (PV)

Different scenarios of PV generation penetration for the Spanish system are considered following (PricewaterhouseCoopers [PWC], 2015), and shown in table 3.2.

The first scenario was built considering the current Spanish regulation regarding self-consumption, covered by the Royal Decree 900/2015. According to this regulation, self-consumption users that inject energy into the grid pay network charges and are paid the wholesale price for each MW sold to the system. The second scenario considers a hypothetical situation where self-consumption users are not required to pay for system charges, therefore the higher expected PV penetration. Finally, the third scenarios accounts for a situation where users do not pay for system charges, investment costs in PV have decreased in 30%, and in addition every MWh they sell to the system is bought with a premium of 30% over the wholesale market price. Evidently, this last scenario is forecasted to have the largest PV penetration from the three analyzed situations.

Table 3.2: Forecasted photovoltaic generation in Spain with current and alternative self-consumption regulation

	Unit	Current Regulation (Royal Decree 900/2015)	Current Regulation with no system charges	Paying PV a 30% premium over energy price
Current generation	GWh	7,861	7,861	7,861
Expected increase	GWh	6,443	24,479	59,014
Total expected	GWh	14,304	32,340	66,875

3.2.2.4 Battery Electric Vehicles (BEV)

BEV are also modeled as part of the aggregator's node resources. BEV can be modeled in two ways, depending on their ability or not to inject electricity to the grid. The present study considers the evolution of BEV until year 2020, which are expected to be fully capable of storing energy and injecting it into the network. Table 3.3 shows the main usage and efficiency characteristics of the vehicles that are used.

The quantity of vehicles for 2020 modeled is defined based on existing literature regarding forecasts for Spain. In this line, documentation from specialized agencies like (IEA, 2013) and (Amsterdam Roundtable Foundation and McKinsey & Company, 2015) set targets of stock of Electric Vehicles (EV) for European countries for the year 2020, being the Spanish target 2.5 million EV. However, the same authors warn that those numbers should not be considered reliable forecasts, but targets to design country level electric-vehicle penetration strategies. Therefore, additional sources were reviewed and (Ministerio de Industria, Energía y Turismo [MINETUR], 2014) sets a much lower value of electric vehicles, with a forecast of 150,000 EV for 2020 in Spain.

Even thought both quantities are considerably different, a value in between might be a good approximation of EV for Spain in 2020. Therefore, 150,000 is the quantity of EV assigned to the flexible customers node, taken into account that the total amount of vehicles for whole Spain is pretty much larger.

Table 3.3: Battery electric vehicles characteristics

Characteristic	Unit	Value
Av. distance weekdays	km	60
Av. distance weekends	km	52
Initial load at midnight	kWh	4
Specific consumption	kWh/km	0.14
Energy storage	kWh	28
Minimum energy	p.u.	0.20
Maximum energy	p.u.	0.95
Grid to battery efficiency	p.u	0.95
Battery to wheel efficiency	p.u.	0.95
Battery to grid efficiency	p.u.	0.95
Charging ramp	kW/h	3.0
Discharging ramp	kW/h	3.0
Maximum output	kW	3.0

3.3 The Optimization Process

The optimization process entitles the cost minimization of the system, and includes an interaction between the system and the aggregator's node. As discussed in Chapter 2, aggregators can be modeled with two different strategies: self-consumption, where the aggregators tries to cover as much as possible of its own demand with own generation resources and then obtain the remaining energy from the market; and a benefit maximization scheme, where the aggregator manages its resources in a way to obtain the higher possible profitability given the wholesale market prices. The aggregator implemented on this thesis is assumed to behave with a benefit maximization strategy, and its inclusion is done following (Dietrich, 2014).

The optimization process used is composed by three steps, and shown below:

- **Step 1** The cost minimization problem is solved for the whole system, by minimizing equation 3.1.1. The following are considerations of this step:
  - Regulated charges are modeled in the energy exchanges between the system and aggregator's node
  - BEV and DR of the aggregator's node are not modeled in this step, as these are resources that required an initial reference price to be modeled
  - The rest of resources of the aggregator's node and from the rest of nodes are included in the dispatch

  The main outputs of this first step include the optimal scheduling of all system's resources (except BEV and DR), the reference locational marginal prices for each node, and the energy flows between nodes. Figure 3.4 shows the logic behind this step.

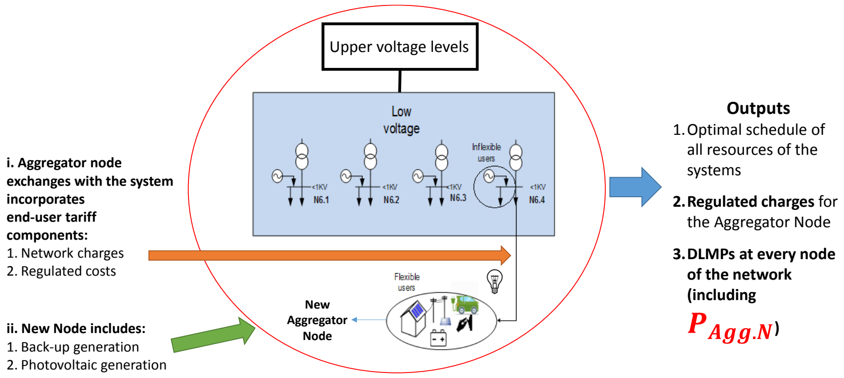

Figure 3.4: Optimization process step 1, optimization of the whole system

- **Step 2** The second step of the process consists of the optimization at the aggregator node. The aggregator incorporates the reference computed marginal prices from Step 1 as an input in its local optimization, and reacts to these prices by setting the necessary demand variations to maximize its benefit. This process is done through DR mechanisms and BEV dispatch, and the output is a new energy exchange (flow) between the aggregator node and the system. Figure 3.5 shows the main inputs and outputs of this step.

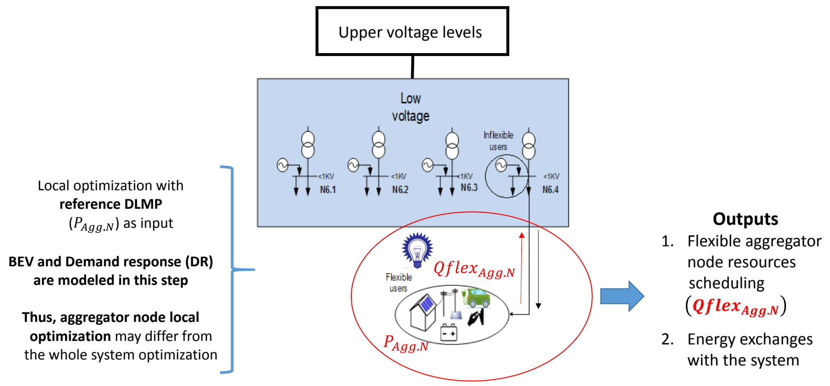

Figure 3.5: Optimization process step 2, aggregator reaction to price signals

- **Step 3** In the third step, an optimization of the whole system, similar to that of Step 1, is performed. The demand variations at the aggregator node are considered as fixed and incorporated as inputs in the optimization of the whole system. As a result, new marginal prices are obtained, and are expected to not differ a lot from the prices computed in Step 1. Then, an iteration process starts to ensure this convergence of prices and benefits from Step 3 to next iterations. The iterative process stops when the market prices obtained in both steps converge, or after a certain number of iterations is reached, which have been set in five iterations (Figure 3.6)

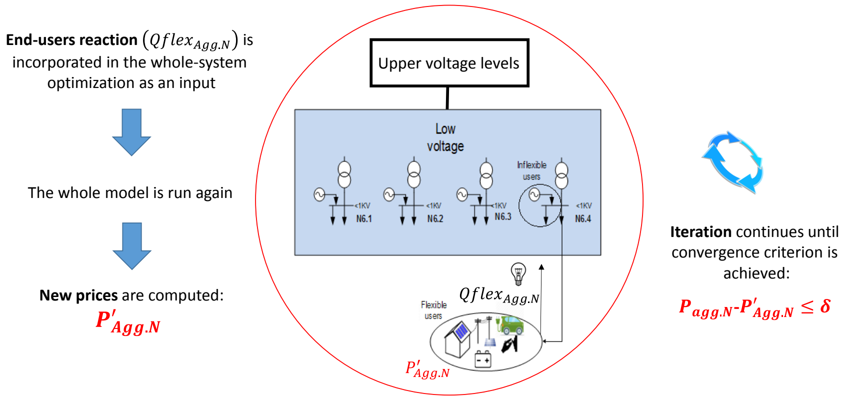

Figure 3.6: Optimization process step 3, optimization of the whole system resources with aggregator's node net demand fixed

3.3.1 Iteration Process from an Economic Perspective

An analogous way to understand this iterative process is the one explained by (Masiello & Aguero, 2016). The authors present an example of the interaction between responsive agents in a wholesale market. The case start assuming an imbalance between load and generation, being the former higher than the latter. In this case, the Independent System Operator (ISO) ask for more generation which in turn elevates the spot price for energy. The respond from the generator might not be immediate, and might take some minutes. In the meanwhile, when the new higher price is published, Distributed Energy Resources (DER) with immediate response, like BEV, might respond to the new price by stop charging. In consequence, the initial imbalance is restored prior the generation responds.

This process is called by economists the *cobweb theorem* and is shown in figure 3.7. Authors also mention that depending on the level of response from agents, the process can turn to be unstable.

For this thesis objectives, the aforementioned interaction between the ISO and the DER can be translated to be between the system and the aggregator node respectively. On one hand, the system defines a nodal price for the aggregator, and then the latter respond

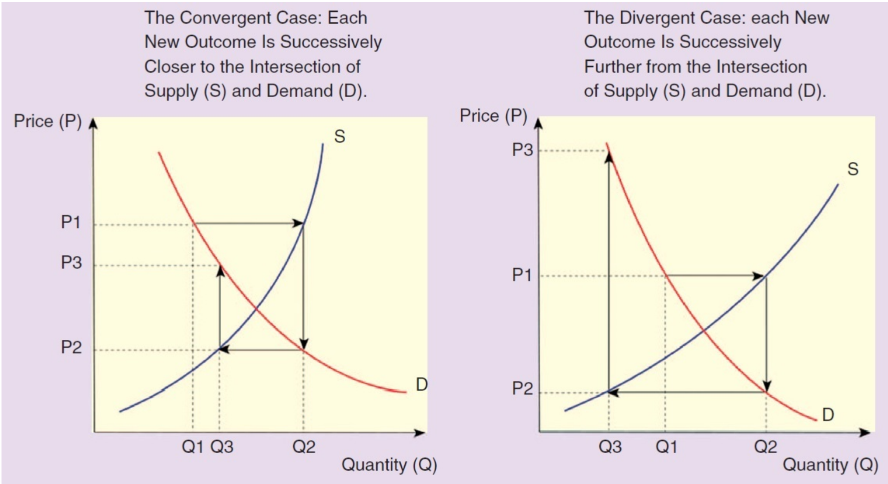

Figure 3.7: Convergence and divergence in the cobweb theorem

Source: (**mas**)

to that price by changing its fast response resources, like BEV and DR. The system will in turn respond to the aggregator change on its net demand profile, and will set a new price. The iteration process continues until convergence is reached.

3.4 Modeling

This section define how end-user tariffs will be modeled, as well as the definition and modeling of the selected case studies.

3.4.1 End-user Tariffs

The key aspect of this thesis is the implementation of end-user tariffs in the way of distinct charges, considering as reference the Spanish system. Regulated costs are implemented either to the energy exchanges between the system and the aggregator's node or to its consumption. The different ways in which charges are modeled will define the various study cases.

3.4.1.1 Network Costs

As explained in Chapter 2, network charges can be recovered in two ways, either as a volumetric charge or with the capacity charge plus a fixed charge. On the former method, an amount of money is charged to customers based on their energy consumption. On the latter the cost of expanding the network due to an hypothetic increase of the demand on peak hours is charged over that incremental demand, whereas the rest is charged using a fix charge.

In this research, when modeled as volumetric charge, the total network charges are distributed among the users' yearly consumption to obtain an amount per Megawatt hour (MWh). This per MWh charge is then implemented in the system total cost objective function, by multiplying it times the flows from the system to the aggregator's node. As explained in the previous section, the unitary charge for network costs accounts for 60.82 €/MWh.

On the other hand, the Advance Demand Charge (ADC) proposed by (Abdelmotteleb et al., 2016) provides a suitable benchmark for allocating network costs. However, as authors state, ADC is closely linked to long-term signals (investment on DER), whereas the present research focuses on short-term signals (prices). Therefore, *proxy* of the ADC method is used. The chosen method implements network costs as *peak demand charges*, and is described below:

- Obtain total network costs for aggregator's node based on the Optimal Dispatch Case results. According to table 3.7, this value totals 998 M€.
  - Define a percentage of the aggregator's node total reference cost to be recovered in the way of peak demand charge. This percentage was defined as a 20% of network costs to be recovered this way is reasonable amount, which therefore is the percentage used in this thesis.
- Define a threshold for the flows from the system to aggregator's node. This threshold, known from now on as *peak threshold* (θ), is defined as the 60$^{\text{th}}$ percentile of the flows for every hour of the year from the system to the aggregator's node.
- Based on the Optimal Dispatch Case, create a parameter for capacity charge in €/MWh by dividing the network charges amount to be recovered among the sum of flows which are above the defined threshold.
- Implement the parameter in the modeling, by increasing the hourly price for the hours where flows are above the threshold.
- DR may change flows from hours with flows over the threshold to hours with flows below the threshold. Therefore, an additional restriction is included to avoid that any of the resulting new flows is higher than previous maximum flow, and also to avoid convergence problems.

3.4.1.2 Other Regulated Costs

Other regulated costs are included either as a volumetric charge or as a fixed charge. When modeled as volumetric charge, the charges are incorporated over each MWh of energy exchanged between the system and the aggregator's node. The unitary charge for other regulated costs accounts for 61.77 €/MWh.

On the other side, as fixed charges the reference other regulated costs for each node are allocated in a way where short term signals are not distorted. For simplicity, this assignation is done ex-post based on nodal demand.

3.4.1.3 Support Policies

Support policies to distributed green technologies are also modeled to consider their impact on the system's operation. Currently, (MINETUR, 2015) defines for Spain two types of consumers for self-consumption:

- **Type 1:** include users that have self-consumption facilities but are not allowed to inject energy to the network.According to the regulation, these users require two meters: one to measure onsite generation and a second one to measure net consumption, which is installed in the connection point with the network.
- **Type 2:** this type of users are considered generators, as they have self-consumption facilities and are allowed to inject energy to the grid. Type 2 self-consumers are paid the wholesale market price for each MWh sold to the grid. These consumers also require two meters: the first one to measure generation and another to measure the total energy consumed.

Based on the previous definitions, three cases of support policies are defined, depending on the treatment the regulation at issue gives to the exports to the system:

- Exports not paid, corresponds to the Spanish definition of consumers Type 1.
- Exports paid at wholesale market price, which represents the Spanish Type 2.
- Exports paid at retail prices. In this cases, distributed generation is paid a premium over the wholesale market price. In some regulations it might even be specifically at the retail price.

3.4.2 Definition of Case Studies

The case studies are defined by considering the different combinations for implementing the distinct retail prices components explained in the previous section, being those energy prices, network charges, and other regulated charges. The first group of possible cases are categorized as *nodal prices*, as they entitle the usage of a nodal pricing scheme. Figure 3.8 shows the possible combinations for case studies to be analyzed for nodal prices cases.

The purpose of this study is to analyze those that result to be more significant due to their representativeness current international electricity regulatory frameworks. The following are the selected cases to be modeled from figure 3.8:

- **Case C: Volumetric** This case exemplifies the regulatory framework of most United States' states and Australian states. Henceforth it is called "Volumetric

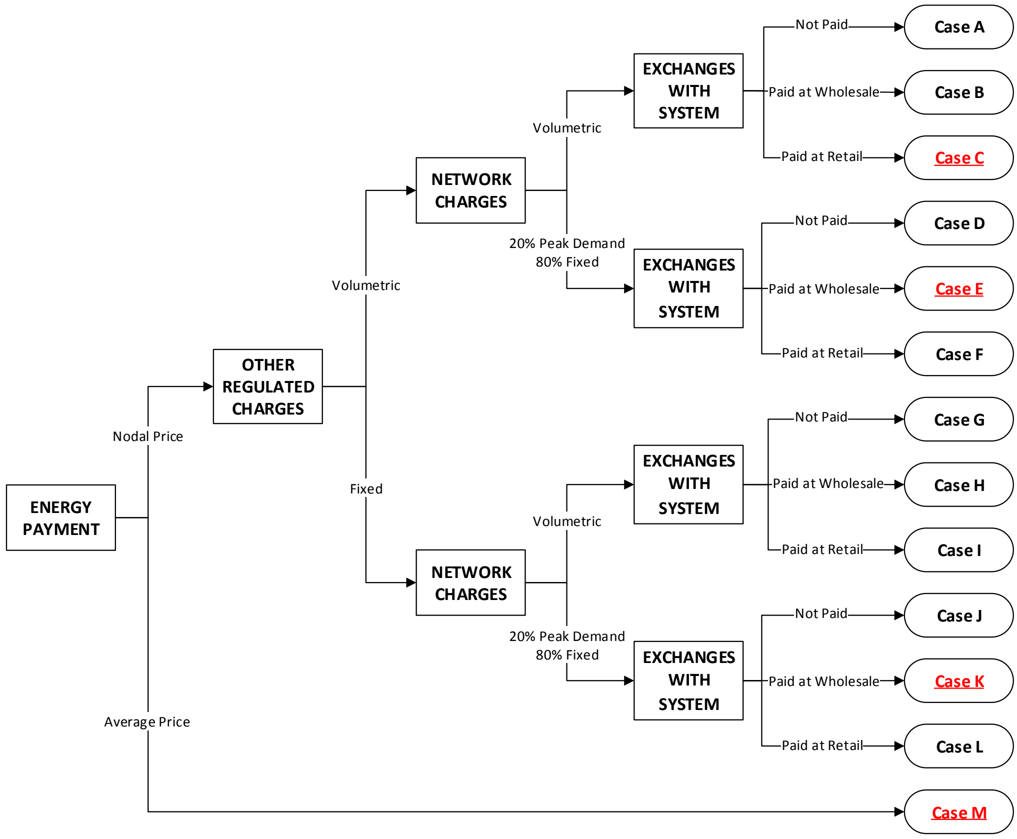

Figure 3.8: Nodal prices case studies possibilities' tree

Case", as both network costs and other regulated costs are charged to customers based on their final demand, i.e. based on their volumetric demand.

- **Case E: Intermediate** Exemplifies the Spanish regulation with Type 2 self-consumption users. This case assumes that network costs are charged as a proxy of incremental charges, while other regulated costs are charged based on the volumetric demand.
- **Case K: First Base** This case represents the First Best alternative, the most efficient case.It is expected to recover part of the network costs by charging customers with the proxy of incremental charges, and recovering the remaining network charges as a fixed charge. This case is expected to introduce the less distortion on short term signals.
- **Case M: Flat Energy Price** In this case, customers at the aggregator's node do not perceive a hourly changing marginal price, but rather a flat price during every hour of the year. This alternative is in place in several countries where smart

meters have not been deployed yet.

In addition, two alternative case studies are included, as described below:

- **Case N: Single Node Case** The single node case exemplifies the traditional market approach in Europe, where the same price is computed for the whole system and DLMP are not considered.
- **Case O: Aggregator Connected to a Different Node** In this case the aggregator's node is connected to a different node than the node 6.4, specifically node 6.1 from figure 3.3. Node 6.1 represents an urban node whereas node 6.4 represents a rural one due to the different characteristics of each one. Node 6.1 upstream configuration has only two voltage changes, from 220 kV to 36 kV and from 36 kV to low voltage, whereas node 6.4 upstream configuration has every possible voltage change the EEN offers: from 220 kV to 145 kV, from 145 kV to 72.5 kV, from 72.5 kV to 36 kV, and from 36 kV to low voltage. Both differences, demand and upstream configuration, results in differences as well in the losses each node must pay.

3.4.3 Modeling of Case Studies

The following subsections include the modeling of each selected case study, as well as the methodology of how payments, revenues, and charges are assessed for each case.

In general, the procedure used for each case study that implement end-user tariff in the model is similar and goes as follows:

i **Modeling of Charges:** in this step the different tariff designs are implemented in the ROM in accordance to each case study. As mentioned before, the implementation for charges can be in the way of a volumetric or as a peak demand charge. The objective function of the model is therefore changed to reflect the implemented charges.

ii **First Run of the Model:** a first run of the model is performed by minimizing the objective function of the system, which at this point includes the corresponding modeling of charges. The main outputs of this step are the system's resources dispatch (except for BEV and DR) and DLMP. In addition, charges are obtained in this step for the aggregator's node.

iii **Second Run of the Model:** By considering prices from the previous step, a second run of the model is performed. Its main outputs include the system total cost, the final dispatch of resources (including BEV and DR), demand payments, generation revenues, ES, and final DLMP.

Equations 3.4.1 and 3.4.2 show, for each node i the expressions for demand energy payment DP_i and generation revenues GR_i respectively. DP_i for node i is defined as the sum for every period p of the final demand $d_{p,i}$ of node i times the marginal price $MP_{p,i}$. Similarly, generation revenue GR_i for node i is the sum for every time period p of the node's i generation $g^t_{p,i}$ times the node's marginal price $MP_{p,i}$.

$$DP_i = \sum_p (d_{p,i} \cdot MP_{p,i}) \tag{3.4.1}$$

$$GR_i = \sum_p (g^t_{p,i} \cdot MP_{p,i}) \tag{3.4.2}$$

Demand energy payment for the whole system DP_S is defined as the sum of every node's demand payment DP_i (equation 3.4.3), whereas system generation revenue GR_S is given by the sum of every node's generation revenue GR_i (equation 3.4.4).

$$DP_S = \sum_i DP_i \tag{3.4.3}$$

$$GR_S = \sum_i GR_i \tag{3.4.4}$$

System demand payments DP_S are used to pay the system generation revenues GR_S, and the remaining money corresponds to the system economic surplus ES_S (equation 3.4.5).

$$DP_S = GR_S + ES_S \tag{3.4.5}$$

iv Distribution of the Economic Surplus: the ES obtained in the previous step is distributed among all the nodes of the system. The distribution is done based on each node's demand ratio over the system demand, as shown in equation 3.4.6:

$$ES_i = ES_S \cdot \frac{\sum_p d_{p,i}}{\sum_i \sum_p d_{p,i}} \tag{3.4.6}$$

where ES_S represents the economic surplus of the whole system, ES_i represents the ES corresponding to node i and $d_{p,i}$ represents the final demand of period p for node i. The ES is assumed to be used for paying a small part of the network costs, and not of other regulated costs.

v Allocation of Regulated Costs Shortfall: the reference regulated costs for the aggregator node are obtained from the Optimal Dispatch Case. These costs are implemented as a *per MWh charge* in the model, in order to obtain them through end-users consumption. As flexible customers respond to these charges, it is expected that the charges recovered from this implementation differ from the reference ones, causing a shortfall in charges. This shortfall is then assigned to the remaining nodes other than the aggregator, so their charges payment are increased. This distribution is done based on the ratio of each node's demand over the sum of every node's demand except the aggregator's node. Equations 3.4.7 and 3.4.8 describe this procedure:

$$NCh_{i'}^{inc} = NCh_S^{sho} \cdot \frac{\sum_p d_{p,i'}}{(\sum_{i'} \sum_p d_{p,i'})} \tag{3.4.7}$$

$$ORCh_{i'}^{inc} = ORCh_S^{sho} \cdot \frac{\sum_p d_{p,i'}}{(\sum_{i'} \sum_p d_{p,i'})} \tag{3.4.8}$$

where i' represents a node other than the aggregator's node, $NCh_{i'}^{inc}$ represents the increment in network costs allocation for node i', NCh_S^{sho} the network costs shortfall, $ORCh_{i'}^{inc}$ stands for the increment in other regulated costs assignation for node i', $ORCh_S^{sho}$ represents the other regulated costs shortfall, and $d_{p,i'}$ the final demand of node i'.

vi Remaining Regulated Charges: are obtained as the final step of the process, after the surplus has been distributed and the shortfall in charges assigned.

The reference case study implies a slightly different set of steps, as it entitles the definition of the reference regulated charges that expect to be recovered in the rest of case studies.

3.4.3.1 Reference Case: The Optimal Dispatch

The definition of a reference case is the first step of the method. The reference case exemplifies the optimal economic dispatch of the model resources, with a cost minimization objective function. Results from further case studies will be analyzed to those of the Optimal Dispatch Case. The reference case for the present research is built upon the following steps:

i Modeling of Charges

The Optimal Dispatch Case includes charges in a way in which they do not distort short-term signals. In other words, charges are not implemented in the model, but assign *ex-post* to each node.

ii First Run of the Model

As previously mentioned, the objective function of the Optimal Dispatch Case corresponds to equation 3.1.1, which is minimized in this step. Here, the existence of the aggregator's node resources is included in the whole optimization, except for BEV and DR.

The Optimal Dispatch Case representation and operation is shown in Figure 3.9.

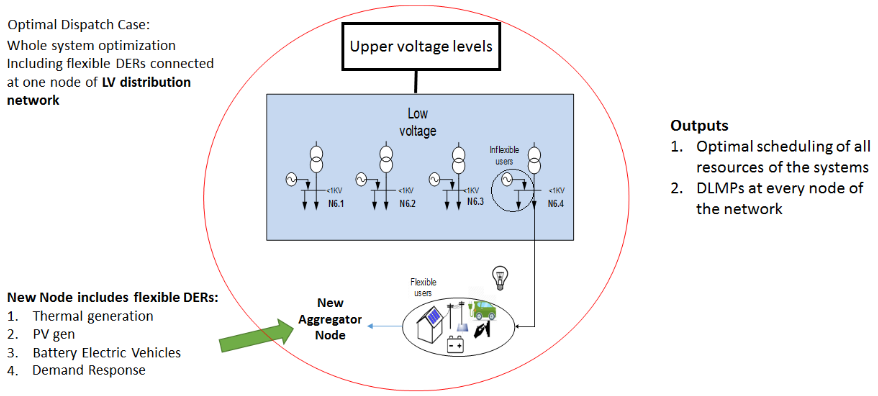

Figure 3.9: Reference Case operation: Optimal Dispatch

iii Second Run of the Model

An optimal schedule of all system resources and nodal marginal prices is obtained as outputs after the second run of the model. Table 3.4 shows this results for this case. For each node, final demand including losses, generation, demand energy payments, and generation energy revenues are shown.

Table 3.4: Model results for the Optimal Dispatch Case

Node	Marginal Price (€/MWh)	Final Demand (MWh)	Demand Energy Payment (M€)	Generation (MWh)	Generation Energy Revenues (M€)
Node 1	45.4	12,076,746	468	149,579,170	7,312
Node 2	45.8	28,960,930	1,379	34,028,635	1,448
Node 3	45.9	13,198,848	630	20,364,371	874
Node 4.1	46.8	9,193,263	450	8,805,232	403
Node 4.2	46.9	9,546,949	463	8,744,290	404
Node 5.1	46.4	12,281,698	595	2,908,514	135
Node 5.2	47.9	20,358,972	1,020	4,497,456	216
Node 5.3	46.8	18,178,382	882	3,917,780	185
Node 5.4	48.0	21,077,112	1,050	4,453,233	217
Node 6.1	48.3	18,857,345	947	4,182,749	193
Node 6.2	51.3	30,658,995	1,648	4,270,603	214
Node 6.3	49.7	27,512,390	1,409	4,191,008	214
Node 6.4	51.0	15,834,868	823	2,304,532	123
Agg. Node	51.0	16,409,210	850	1,898,134	101
Total		254,145,707	12,614	254,145,707	12,038

Two important remarks shall be done from the previous data. First, it is shown in table 3.4 that total final demand and total generation account for the same amount, which confirms the absence of Non-Served Energy (NSE) in the Optimal Dispatch Case. This result confirms the correct execution of the model.

In addition, the total Energy Payment made by the demand (12,614 M€) is higher than the total Energy Revenues received by the generation side (12,038 M€). This amount of money corresponds to the ES, and its existence is a direct consequence of the usage of DLMP. For the Optimal Dispatch Case, the ES is as high as 577 M€ (Table 3.5). How this ES is used will be assessed in further sections.

Table 3.5: Demand energy payment, generation energy revenue, and surplus for the Optimal Dispatch Case

	Demand Energy Payment (M€)	Generation Energy Revenue (M€)	Surplus (M€)
Total	12,614	12,038	577

The total amount of network costs and other regulated costs must be defined for the Reference Case, and then assigned in the way of charges to customers in such a way that they do not distort short term signals. For simplicity, charges are allocated ex-post based on the total demand of each node, and a unitary charge per consumed MWh. The following lines explain this procedure, both for network and other regulated charges

Reference Network Costs

With respect to network costs, official data from Comisión Nacional de Mercados y Competencia (CNMC) of Spain is used for this objective (Comisión Nacional de los Mercados y la Competencia [CNMC], 2015). Table 3.6 shows 2014 demand consumption, contracted capacity charge, energy billing, and access tariff billing by voltage level, provided by (CNMC, 2015). Based on this information, an additional column is added that shows the network charges by MWh, which is a result of dividing the contracted capacity billing over the consumption for each voltage level.

Consequently, an amount of 8.77 €/MWh is the quantity to be multiplied for each MWh of demand at the high voltage nodes of this reference base case, 31.48 €/MWh for the medium voltage demand, and 60.82 €/MWh for the low voltage demand, in order to obtain the reference network costs for each node i (NC_i^{ref}).

Reference Other Regulated Costs

On the other hand, a reference amount for other regulated costs is defined. For this purpose, the *Precio Voluntario para el Pequeño Consumidor (PVPC)* provided by the Spanish System Operator, *Red Eléctrica de España (REE)*, was used.

Table 3.6: Settlement components for Spanish electric sector, 2014

Voltage Level	Consumption (GWh)	Contracted Capacity Billing (M€)	Energy Billing (M€)	Access Tariff Billing (M€)	Network Charge per MWh (€)
HV	50’848	446	157	603	8.77
MV	71’663	2’256	589	2’845	31.48
LV	108’805	6’618	3’631	10’249	60.82
TOTAL	231’316	9’320	4’377	13’697	

First, the PVPC was extracted for the 8760 hours of 2015 on a per MWh basis, and breakdown in the distinct components that REE provided. Then, from these components, those different to energy price are considered as Other Regulated Charges. Therefore, these charges where extracted from the PVPC for every hour of 2015, and then an average was calculated. The resulting average value is of 61.77 €/MWh. This value is multiplied by each node’s demand, so to obtain the Other Regulated Costs for each node i (ORC_i^{ref}).

Reference Total Regulated Costs

Total reference regulated costs (TRC_S^{ref}) for the whole system are given by summing the reference network costs (NC_i^{ref}) and reference other regulated costs (ORC_i^{ref}) for every node i (equation 3.4.9).

$$TRC_S^{ref} = \sum_i NC_i^{ref} + \sum_i ORC_i^{ref} \tag{3.4.9}$$

iv Reference Regulated Costs

Hereafter, the amount of charges to be assigned to customers from the total reference costs (TRC_S^{ref}) must be defined. For this purpose, the ES is taken into account. First, the ES is distributed among every node based on the ratio of its final demand over the final total demand as described in equation 3.4.6, and then subtracted from the network costs.

Therefore, the final amount of network charges assigned to each node is given by total network costs of node i (NC_i) less the surplus corresponding to node i (ES_i), as shown in equation 3.4.10. Other regulated charges accounts for the same amount of other regulated costs for each node i (equation 3.4.11).

$$NCh_i^{ref} = NC_i^{ref} - ES_i \tag{3.4.10}$$

$$ORCh_i^{ref} = ORC_i^{ref} \tag{3.4.11}$$

Total reference regulated costs are shown in table 3.7.

Table 3.7: Reference total regulated costs for Optimal Dispatch Case

Node	(1) Reference Network Costs (M€)	(2) Network Charges after DLMP surplus (M€)	(3) Reference Other Regulated Costs (M€)	(4=1+3) Reference Total Regulated Costs (M€)
Node 1	106	79	746	852
Node 2	254	188	1,789	2,043
Node 3	116	86	815	931
Node 4.1	81	60	568	649
Node 4.2	84	62	590	673
Node 5.1	387	359	759	1,145
Node 5.2	641	595	1,258	1,898
Node 5.3	572	531	1,123	1,695
Node 5.4	664	616	1,302	1,965
Node 6.1	1,147	1,104	1,165	2,312
Node 6.2	1,865	1,795	1,894	3,758
Node 6.3	1,673	1,611	1,699	3,373
Node 6.4	963	927	978	1,941
Agg. Node	998	961	1,014	2,012
Total	9,549	8,972	15,699	25,248

It is important to mention that even though there are reference regulated costs for each node, the intention is not to charge the same amount for each node in the different case studies. The objective is to recover the total amount of reference regulated costs of 25,248 M€ for the system as a whole, even thought nodes might end paying more or less than their reference value.

In short, it can be seen from table 3.7 that total network costs (NC^{ref}) for the system amounts 9,549 M€, from which 8,972 M€ are finally billed to customers in the way of remaining network charges (NCh). Similarly, other regulated costs amount 15,699 M €, from which the whole quantity is billed to customers as other regulated charges ($ORCh$).

3.4.3.2 The Volumetric Case

The Volumetric Case implies the implementation of network costs and other regulated cost as a volumetric charge to the aggregator's node's imports from the system, as shown in figure 3.8. The results for the Volumetric Case is to obtain final energy and charges payments for every node and then compare them with the energy and charges payment of the Optimal Dispatch Case. Hereafter the steps followed:

i Modeling of Volumetric Charges

Next, the modeling for the volumetric charges is explained. This case means an increase in prices in the amount of the volumetric charge times the aggregator's node imports. Therefore, a component must be added to the system total cost objective function shown in equation 3.1.1 in order to represent the increase in cost per MWh of flow from the system to aggregator's node.

The ROM model defines a single variable for flows between two nodes as $f_{(i \leftrightarrow j)}$, which is positive if flows go in the direction node i to node j, and negative if flows stream in the contrary direction, in this case from node j to node i. However, the per MWh charge of the volumetric case shall be implemented only over the flows from the system to the aggregator's node, which represents the aggregator imports from the system, and not on the contrary direction.

Therefore, the existing variable for flows between the system and the aggregator's node needs to be decomposed in two different variables. For this purpose two additional positive variables are created: $f_{(S \to A)}$, which refers to the flows from the system to the aggregators' node, and $f_{(A \to S)}$ which refers to the flows in the contrary direction, from the aggregator's node back to the system.

Equation 3.4.12 entitles the breakdown of the flow $f_{(S \leftrightarrow A)}$ into the two new positive variables, while equations 3.4.13 and 3.4.14 provide the maximum value for the flow from the system to the aggregator's node, and from the latter to the former respectively.

$$f_{(S \leftrightarrow A)} = f_{(S \to A)} - f_{(A \to S)} \tag{3.4.12}$$

$$f_{(S \to A)} \leq \alpha \cdot PP \tag{3.4.13}$$

$$f_{(A \to A)} \leq (1 - \alpha) \cdot PN \tag{3.4.14}$$

where α is a binary variable that defines the existence of whether the flow from system to aggregator's node ($f_{(S \to A)}$) or the flow from aggregator's node to the system ($f_{(A \to S)}$), PP is a positive parameter that defines the maximum value for the flow $f_{(S \to A)}$, and PN is a positive parameter that defines the maximum value for the flow $f_{(A \to S)}$. Based on the Optimal Dispatch Case resulting maximum flows, PM was defined as 10000, and PN as 2000.

Now that an individual variable for flows from the system to the aggregator's node exists, the per MWh charge can be implemented on those flows, and the expression can be included in the system total cost objective function. Equation 3.4.15 shows the expression for total cost of the Volumetric Case, after making this inclusion.

$$TC = \sum_{p} \left[\sum_{t} (FC^t \cdot uc_p^t + VC^t \cdot g_p^t + StC^t \cdot on_p^t) \right.$$
$$\left. + NSC \cdot nse_p + (NCh^{vol} + ORCh^{vol}) \cdot f_{(S \to A)} \right] \tag{3.4.15}$$

where NCh^{vol} is the per MWh charge for network charges and $ORCh^{vol}$ is the per MWh charge for other regulated costs. These parameters were defined in a previous section, when total reference charges were assessed. Thus, the unitary charge for network costs NCh^{vol} accounts for 60.82 €/MWh, whereas the unitary charge for other regulated costs accounts for 61.77 €/MWh.

ii First Run of the Model

A first run of the model is then performed considering equation 3.4.15 as the objective function. As mentioned before, equation 3.4.15 implement the volumetric charges in the energy exchanges between the system and the aggregator's node.

The main outputs from this first run are the dispatch of back-up and PV generation for the aggregator's node, as well as the dispatch for the whole resources for the rest of nodes. In addition, an important output is a first set of references prices $MP_{p,i}^{ref}$ for every node. Finally, regulated charges are obtained for the aggregator's node:

$$NCh_A = 704 \, M€$$

$$ORCh_A = 715 \, M€$$

where NCh_A are the network charges for the aggregator's node and $ORCh_A$ stands for other regulated charges of the aggregator's node.

iii Second Run of the Model

The model second run considers the reference prices from the first run $MP_{p,i}^{ref}$ as an input. In particular, BEV and DR of the aggregator's node are implemented in this run, as they are resources that respond to prices.

On one hand, the model's second run provide a new set of marginal prices, final nodal demand, final nodal generation dispatch. By multiplying prices times demand the demand energy payment is obtained, and generation revenues are also obtained by multiplying prices time generation. The output is shown in table 3.8.

Table 3.8: Prices, demand, demand energy payment, generation, and generation revenues for the Volumetric Case

Node	Marginal Price (€/MWh)	Final Demand (MWh)	Demand Energy Payment (M€)	Generation (MWh)	Generation Energy Revenues (M€)
Node 1	45.2	12,204,331	471	146,187,680	7,101
Node 2	45.7	28,686,411	1,361	34,070,259	1,445
Node 3	42.0	12,909,859	573	20,372,016	822
Node 4.1	46.7	9,193,369	449	8,818,827	402
Node 4.2	42.9	9,422,699	418	8,735,520	372
Node 5.1	46.3	12,281,345	593	2,911,581	135
Node 5.2	47.7	20,359,859	1,016	4,501,941	215
Node 5.3	42.8	18,179,425	790	3,916,597	167
Node 5.4	43.8	20,838,876	924	4,452,616	196
Node 6.1	48.1	18,857,081	945	4,189,341	193
Node 6.2	51.1	30,659,724	1,641	4,259,398	213
Node 6.3	45.7	27,513,177	1,287	4,177,787	140
Node 6.4	45.3	15,746,431	727	2,291,973	73
Agg. Node	45.3	16,320,773	729	4,287,823	170
Total		253,173,360	11,922	253,173,360	11,645

Demand energy payments from table 3.8 are the final ones for every node. Following equation 3.4.5, demand energy payments of 11,645 M€ are used to pay generation revenues of 11,922 M€, and an ES of 277 M€ is obtained.

iv Distribution of the Economic Surplus

Now, the ES from the model is used to pay part of the regulated costs, specifically network costs. Every node is benefited in reducing its costs payment according to its final demand. The amount of surplus distribution is done by following equation 3.4.6.

After assigning the ES to every node, charges of every node are obtained (table 3.9).

v Allocation of Network Costs Shortfall

Network charges NCh_A and other regulated charges $ORCh_A$ for the aggregator's node were obtained on the model first run in step *ii*. However, when compared to data provided in table 3.7, it can be seen that there is a shortfall in both network charges and other regulated charges for the aggregator's node, as table 3.10 shows: network charges are 704 M€ when where expected to be 998 M€, for a shortfall of 294 M€; whereas the 715 M€ for other regulated charges are 299 M€ short from the 1,014 M€ of other regulated costs. This represents a total shortfall in charges of 592 M€ due to the flexible response of the aggregator node.

This shortfall in charges is distributed among the remaining non flexible nodes.

Table 3.9: Regulated charges for the Volumetric Case after economic surplus distribution

Node	Network Charges after Surplus (M€)	Other Regulated Charges (M€)	Total Regulated Charges after surplus (M€)
Node 1	93	746	839
Node 2	223	1,789	2,012
Node 3	102	815	917
Node 4.1	71	568	638
Node 4.2	73	590	663
Node 5.1	373	759	1,132
Node 5.2	619	1,258	1,876
Node 5.3	552	1,123	1,675
Node 5.4	641	1,302	1,943
Node 6.1	1,126	1,165	2,291
Node 6.2	1,831	1,894	3,725
Node 6.3	1,643	1,699	3,343
Node 6.4	946	978	1,924
Agg. Node	686	715	1,401
Total	8,979	15,400	24,379

Table 3.10: Regulated charges shortfall after Volumetric Case modeling

	Optimal Dispatch Reference (M€)	Volumetric Case Result (M€)	Shortfall (M€)
Network Charges	998	704	294
Other Regulated Charges	1,014	715	299
Total	2,012	1,419	592

The amount of 294 M€ shortfall on network costs is added to the remaining node's network costs, whereas the 299 M€ shortfall on other regulated charges are assigned similarly on remaining node's other regulated charges. This distribution is done following equations 3.4.7 and 3.4.8.

vi Remaining Regulated Costs

After assigning the shortfall in regulated costs to each node different from the aggregator's node, the resulting charges are the remaining regulated costs, which represent the costs to be charged to each node of the system. Remaining regulated costs for the Volumetric Case are shown in table 3.11.

Table 3.11: Remaining regulated costs for the Volumetric Case

Node	Network Costs (M€)	Other Regulated Costs (M€)	Total Regulated Costs (M€)
Node 1	108	761	869
Node 2	258	1,825	2,083
Node 3	118	832	949
Node 4.1	82	579	661
Node 4.2	85	602	687
Node 5.1	388	774	1,163
Node 5.2	644	1,283	1,927
Node 5.3	575	1,146	1,721
Node 5.4	667	1,328	1,995
Node 6.1	1,150	1,189	2,338
Node 6.2	1,869	1,932	3,802
Node 6.3	1,677	1,734	3,411
Node 6.4	965	998	1,963
Agg. Node	686	715	1,401
Total	9,273	15,699	24,971

3.4.3.3 The First Best Case

The First Best Case entitles the implementation of network charges in the form of 20% as a peak demand charge and the remaining 80% as fixed, whereas total other regulated charges are implemented as fixed. This implementation is done exclusively to the flexible customers of the aggregator's node, while the cost allocation for the remaining nodes of the system persists as a fixed charge. The following are the main steps followed in the First Best Case procedure:

i Modeling of Peak Demand Charges

The modeling of peak demand charges follows two steps. First, a unitary MWh charge needs to be define for network charges, so that it is applied to the peak hours' flows, to discourage aggregator's node imports from the system on those hours. Then, the charges are implemented in the model.

Following the steps described in section 3.4.1.1, the charge per MWh for network costs in the First Best Case is calculated in equation 3.4.16:

$$PkCh = \frac{20\% \cdot NCh_A^{ref}}{F^{\bar{\theta}}_{(S \to A)}} \tag{3.4.16}$$

where $PkCh$ stands for the per MWh charge to be applied over peak hours, NCh_A^{ref} is the reference network cost for the aggregator node, pk represents the peak hours where flows from system to aggregator are over the defined peak threshold, and

$F^{\overline{\theta}}_{(S\to A)}$ stands for the sum of the resulting flows (output) from the system to the aggregator's node corresponding to peak periods .

It is worth recalling that peak hours pk where defined as those whose flows from system to aggregator are over the 60$^{\text{th}}$ percentile, known as peak threshold (θ) of the flows for every hour of the year from the system to the aggregator's node on the Optimal Dispatch Case. As a reference, the peak threshold resulted to be 1,625 MW, which means that, for the First Best Case, every flow from the system to the aggregator node over 1,625 MW will be charge with the peak demand charge $PkCH$ for each imported MW above that 1,625 threshold.

Reference network charges are splitted into the part that will be charged as a peak demand charge NCh_A^{ref-pk} and the one that will be charge as fixed NCh_A^{ref-fx} (equations 3.4.17, 3.4.18 and 3.4.19).

$$NCh_A^{ref} = NCh_A^{ref-pk} + NCh_A^{ref-fx} \tag{3.4.17}$$

$$NCh_A^{ref-pk} = 20\% \cdot NCh_A^{ref} \tag{3.4.18}$$

$$NCh_A^{ref-fx} = 80\% \cdot NCh_A^{ref} \tag{3.4.19}$$

Based on results from the Optimal Dispatch case, each component is calculated as follows:

$$NCh_A^{ref} = 998\, M€$$

$$NCh_A^{ref-pk} = 200\, M€$$

$$NCh_A^{ref-fx} = 798\, M€$$

In addition, the sum of flows over the peak threshold from the system to the aggregator's node is obtained from the Optimal Dispatch Case data:

$$F^{\overline{\theta}}_{(S\to A)} = 1,138,169\, MWh$$

Finally, value for the unitary peak demand charge $PkCh$ is obtained by substituting the previous results in equation 3.4.16:

$$PkCh = 175.4\, €/MWh$$

which is the parameter to be modeled in the objective function by multiplying it times the variable for flows over the peak threshold.

Now that the unitary peak demand charge has been obtained, it can be implemented into the model. Similarly to the Volumetric Case, the First Best Case modeling implies increasing the marginal hourly price in a certain amount. However, a difference from the former is that in the latter the hourly price is increased only on those hours when flows from the system to the aggregator's node are above the peak threshold. Therefore, the peak demand charge must only multiply aggregator's imports over the peak threshold on the peak hours.

This modeling requires the creation of a new variable that specifically represents the *flows from system to aggregator's node over the peak threshold.* From the Volumetric Case a specific variable for *flows from the system to the aggregator* ($f_{S\rightarrow A}$) was created. Now, in order to define the *flows from system to aggregator's node over the peak threshold* we introduce three additional equations:

$$f_{(S\rightarrow A)} - \theta = f^{\overline{\theta}}_{(S\rightarrow A)} - f^{\underline{\theta}}_{(S\rightarrow A)} \tag{3.4.20}$$

$$f^{\overline{\theta}}_{(S\rightarrow A)} \leq \beta \cdot (PP - \theta) \tag{3.4.21}$$

$$f^{\underline{\theta}}_{(S\rightarrow A)} \leq (1 - \beta) \cdot \theta \tag{3.4.22}$$

where $f_{(S\rightarrow A)}$ represents the flows from system to aggregator's node, θ is the peak threshold, $f^{\overline{\theta}}_{(S\rightarrow A)}$ is the variable for the flows *over* the peak threshold, $f^{\underline{\theta}}_{(S\rightarrow A)}$ stands for the flows *below* the peak threshold, *beta* is a binary variable that defines the existence of whether the former or latter, and $PP - \theta$ is a positive parameter that defines the maximum value for the flows *over* the threshold ($f^{\overline{\theta}}_{(S\rightarrow A)}$). Finally, the maximum for the flows *below* the peak threshold ($f^{\underline{\theta}}_{(S\rightarrow A)}$) is defined by the peak threshold itself (θ).

As the next modeling step, the flows from the system to the aggregator's node over the peak threshold $f^{\overline{\theta}}_{(S\rightarrow A)}$ are multiplied times the peak demand charge $PkCh$, and then included in objective function of the system. Equation 3.4.23 shows the new objective function for the First Best Case:

$$\begin{aligned} TC = \sum_{p} \Bigg[& \sum_{t} (FC^{t} \cdot uc^{t}_{p} + VC^{t} \cdot g^{t}_{p} + StC^{t} \cdot on^{t}_{p}) \\ & + NSC \cdot nse_{p} + PkCh \cdot f^{\overline{\theta}}_{(S\rightarrow A)} \Bigg] \end{aligned} \tag{3.4.23}$$

From now on the remaining modeling steps follow the ones of the Volumetric Case, with small differences.

ii First Run of the Model

Now, the model is run for the first time by minimizing equation 3.4.23. Despite the generation dispatch output, we pay here a special attention to the set of references prices $MP_{p,i}^{ref}$ for each node and the regulated charges for the aggregator's node. In particular, the network charges as peak demand NCh_A^{pk} obtained for the model for the aggregator's node are:

$$NCh_A^{pk} = 102\, M€$$

It is important to remind that in this case we only obtain network charges for the aggregator's node, and not other regulated charges, as only network charges were implemented on the objective function. Other regulated charges are recovered as a fixed charge.

iii Second Run of the Model

Now we, model the reference prices $MP_{p,i}^{ref}$ from the previous step as an input in the model for running it a second time. Similarly to the Volumetric Case, BEV and DR will respond to those prices and will be dispatched. Results for this second run are shown in table 3.12.

Table 3.12: Prices, demand, demand energy payment, generation, and generation revenues for the First Best Case

Node	Marginal Price (€/MWh)	Final Demand (MWh)	Demand Energy Payment (M€)	Generation (MWh)	Generation Energy Revenues (M€)
Node 1	45.2	11,985,404	464	148,630,1639	7,236
Node 2	45.8	28,875,503	1,378	34,070,473	1,448
Node 3	46.3	13,110,199	634	20,329,727	881
Node 4.1	46.8	9,193,396	451	8,817,811	403
Node 4.2	47.3	9,508,670	467	8,725,191	408
Node 5.1	46.4	12,281,418	596	2,912,133	135
Node 5.2	47.9	20,359,793	1,021	4,500,467	216
Node 5.3	47.2	18,178,850	892	3,911,128	186
Node 5.4	48.4	20,995,581	1,057	4,449,021	219
Node 6.1	48.3	18,857,141	947	4,187,809	194
Node 6.2	51.4	30,659,656	1,648	4,261,604	214
Node 6.3	50.1	27,512,650	1,422	4,185,683	215
Node 6.4	51.2	15,803,704	823	2,243,737	120
Agg. Node	51.2	16,376,100	847	2,473,141	131
Total		253,698,064	12,644	253,698,064	11,645

After paying the corresponding generation revenues with the demand payments, an economic surplus is obtained. In this case, the surplus amounts for 637 M€.

iv Distribution of Economic Surplus

The economic surplus from the model is used to pay a small part of the network costs. The distribution of the surplus among the nodes is done following 3.4.6.

Table 3.13 shows the network charges for every node after the distribution of the ES to every node.

Table 3.13: Regulated charges for the Volumetric Case after economic surplus distribution

Node	Network Charges after Surplus (M€)	Other Regulated Charges (M€)	Total Regulated Charges after surplus (M€)
Node 1	76	746	822
Node 2	181	1,789	1,970
Node 3	83	815	898
Node 4.1	58	568	625
Node 4.2	60	590	650
Node 5.1	356	759	1,114
Node 5.2	590	1,258	1,847
Node 5.3	527	1,123	1,649
Node 5.4	611	1,302	1,913
Node 6.1	1,100	1,165	2,264
Node 6.2	1,788	1,894	3,681
Node 6.3	1,604	1,699	3,304
Node 6.4	923	978	1,901
Agg. Node	859	1,014	1,873
Total	8,979	15,699	24,513

v Allocation of Network Costs Shortfall

Similarly to the Volumetric Case, the reference regulated costs of the First Best Case also correspond to the ones of the Optimal Dispatch Case, shown in table 3.7.

The main change to table 3.7 regarding the First Best Case, is the consideration of the network costs charged as peak NCh_A^{pk} for the aggregator's node obtained from the model in the point *iii* , which are 102 M€. In addition, the network costs to be charged as fixed NCh_A^{fx} are 798 M€, for a total of 900 M€ of network charges NCh_A for the aggregator's node in the First Best Case.

If the value for NCh_A for the aggregator's node is compared to the reference network charges from the Optimal Dispatch Case NCh_A^{ref}, a shortfall in network costs is obtained, as shown in table 3.14.

This shortfall of 98 M€ is distributed among the rest of nodes of the system, therefore increasing their network charges, following equations 3.4.7 and 3.4.8.

Table 3.14: Regulated charges shortfall after First Best Case modeling

	Optimal Dispatch Reference (M€)	Volumetric Case Result (M€)	Shortfall (M€)
Network Charges	998	900	98

vi Remaining Regulated Costs

After assigning the shortfall in regulated costs to each node different from the aggregator's node, the resulting charges are the remaining regulated costs, which represent the costs to be charged to each node of the system. Remaining regulated costs for the Volumetric Case are shown in table 3.15.

Table 3.15: Remaining regulated costs for the First Best Case

Node	Network Costs (M€)	Other Regulated Costs (M€)	Total Regulated Costs (M€)
Node 1	81	746	827
Node 2	193	1,789	1,982
Node 3	88	815	904
Node 4.1	61	568	629
Node 4.2	64	590	653
Node 5.1	361	759	1,119
Node 5.2	598	1,258	1,856
Node 5.3	534	1,123	1,657
Node 5.4	619	1,302	1,921
Node 6.1	1,107	1,165	2,272
Node 6.2	1,800	1,894	3,694
Node 6.3	1,616	1,699	3,315
Node 6.4	930	978	1,908
Agg. Node	859	1,014	1,873
Total	9,273	15,699	24,611

3.4.3.4 Aggregator Connected to a Different Node

Until now, every case studied implemented entitle the modeling of the aggregator as connected to the same node of the network shown in figure 3.10: node 6.4. The particular upstream network configuration of node 6.4 resembles an rural node: several voltage drops with a relative small voltage change on each of them. This configuration correspond to rural networks, where lines tend to be longer in order to reach more distant and less accessible demand centers.

On the other hand, the present case entitles modeling the aggregators' node as connected to node 6.1 of the EEN instead of at node 6.4, as shown in figure 3.10. Node 6.1 is a proxy of a urban node, given its generation and demand profile and due to its upstream network configuration with less quantity of voltage drops but a higher change in voltage in each drop.

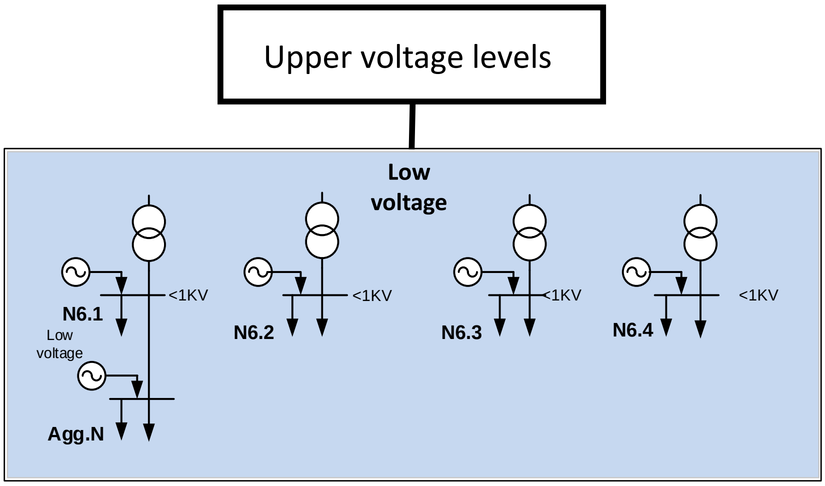

Figure 3.10: Low voltage network of the EEN when the aggregator is connected to an alternative node

In addition, this case study implies the modeling of both a reference case and a volumetric case, in order to analyze the respective changes in income redistribution. The reference case modeling and analysis is done by following the methodology described in section 3.4.3.1. On the other hand, the alternative volumetric case is implemented by following the steps shown in section 3.4.3.2. Finally, the main results for these case studies are shown in Chapter 4.

3.4.3.5 Single Node Cases

As explained before, zonal prices are considered in this case study instead of nodal pricing, replicating the pricing scheme of most European Countries and their European Price Coupling (EPC) scheme. Therefore, this case provides the same marginal price for every node of the system at each hour, by averaging the distinct node's prices.

The modeling of the Single Node CAse implies performing a reference case, corresponding to the Optimal Dispatch Case and including charges in a way where short-term signals are not distorted. This process is done following the steps from section 3.4.3.1.

On the other hand a volumetric case is run. This modeling entitles applying network and other regulated costs as volumetric charges to the energy exchanges between the aggregator's node and the rest of the system. The methodology for this case consists in the same steps as described in section 3.4.3.2.

Results for the Single Node Optimal Dispatch and Volumetric Cases are shown in Chapter 4.

Chapter 4

Results and Discussion

This chapter presents the main results obtained for the different case studies described in Chapter 3. The results section focuses on analyzing three main outputs impact of the different retail prices design on distributed locational marginal prices, total system costs, and income redistribution between consumer categories. In the first place, marginal prices for every case study are analyzed. Then, system operational costs and flexible resources dispatch are assessed, and finally, a comparison between the Volumetric Case and the First Best Case distributional effects is done. Finally, a small section is dedicated to the Single Node Cases results.

Results are shown in two groups. The first group clusters most of the study cases modeled in a system with nodal prices, namely an optimal dispatch case, where charges are implemented ex-post with no distortional effects; a volumetric case in which both network and other regulated charges are modeled in a volumetric way, the First Best Case, where network charges are implemented partly as a peak demand charge and partly as fixed. In addition, two of cases where the aggregator is modeled in a different node than before is included, in order to assess the impact on the system of allowing aggregator's to group resources of different locations, for example urban or rural.

On the other hand, the second group of results includes the modeling that assumes a single node network, which is the pricing scheme used by most European countries. For this group two study cases were modeled and analyzed: an optimal dispatch case and a volumetric case.

4.1 System with Nodal Prices

4.1.1 Distribution Locational Marginal Prices

Different retail prices designs implementation has an impact on the system energy prices. Figure 4.1 shows the resulting prices for the Optimal Dispatch, Volumetric, and First Best Cases. Prices presented are the final distribution locational marginal prices derived from that optimization iterative process. It is important to keep in mind that the prices shown are a result of an iterative process, which produces different set of prices. These prices are the result of the system and aggregator's node optimization processes.

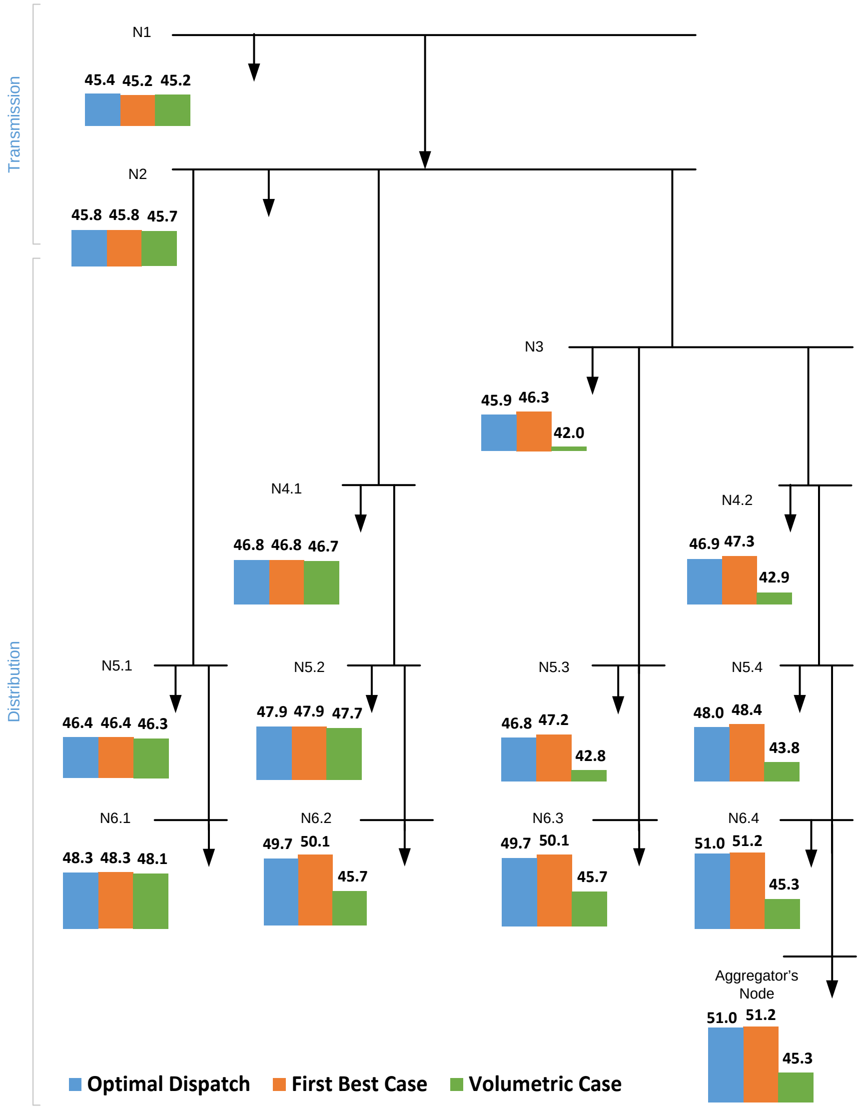

Figure 4.1: Distribution Locational Marginal Prices (DLMP) for selected nodal prices cases

In general, results show that both volumetric and peak demand charges for allocation of network costs, called *first best case*, implementation of charges move prices away from the Optimal Dispatch ones for most of the nodes. Furthermore, this effect is much higher in the Volumetric Case, which has, individually and on average, a higher distortion on prices than the First Best Case. An average decrease on prices of 4.9% for the Volumetric against an increase on prices of just 0.3% in the First Best Case prices support this finding. Notice that indeed the first best approach implies losses on efficient system operation but they are justified by reductions on network investments.

Additionally, it can be seen that the Volumetric Case has much lower prices in certain nodes than both the Optimal Dispatch and the First Base Cases. As showed in figure 4.2, the Volumetric Case has, among the distinct cases, the highest local generation on the aggregator's node. Local generation nets local demand and has an impact on decreasing losses, as generation from upper nodes is replaced and produced locally. In turn, lower losses imply a lower total demand to supply and therefore lower prices.

A closer look on figure 4.1 also shows that the nodes with highest decrease on prices are the upstream nodes of the aggregator's node (nodes 3, 4.2, 5.3, 5.4, 6.3 and 6.4). These nodes are the ones that benefit the most from high local generation on the aggregator's node, and therefore from the decrease of losses, which results in the highest decrease in prices.

4.1.2 Operational Costs and Generation Dispatch

One of the main consequences of implementing distinct retail prices is appreciated in the whole operation of the system. Figure 4.2 shows results for the total annual system operational cost and the generation dispatch for the aggregator's node for five selected case studies: Optimal Dispatch, Volumetric Charges, *Intermediate* Case, First Best, and Flat Energy Price cases.

First of all, the Optimal Dispatch Case yielded the lowest system thermal cost, 4,531 M€. This result is expected as this case entitles the optimal operational dispatch of whole system resources, whilst regulated costs are charged in this case in a way that no distortion is included in short term marginal prices (ex-post allocation).

Figure 4.2 also shows the dispatch of aggregator's resources. It can be seen that Battery Electric Vehicles (BEV) generate and inject energy to the network in every case except for the flat energy price case. Electric Vehicles (EV) energy injection to the network responds to the existence of changing marginal hourly prices in the Optimal Dispatch, Volumetric, Intermediate, and First Base cases. Different hourly prices let EV be connected to grid and charged when prices are low, and then connect and inject energy to the network when prices are high. This behavior let EV obtain a revenue from selling energy to the system at higher prices and buy at lower prices (price arbitrage).

Therefore, the absence of EV injection to the network in the Flat Energy Price Case is due to the fact that an average price during every hour eliminates the incentive for EV to sell energy to the grid: they would buy from the grid and sell energy back at the same price, which is not profitable, due to the existence of energy losses as a result of charging and discharging of EVs. Therefore, in this case EV charge only to supply

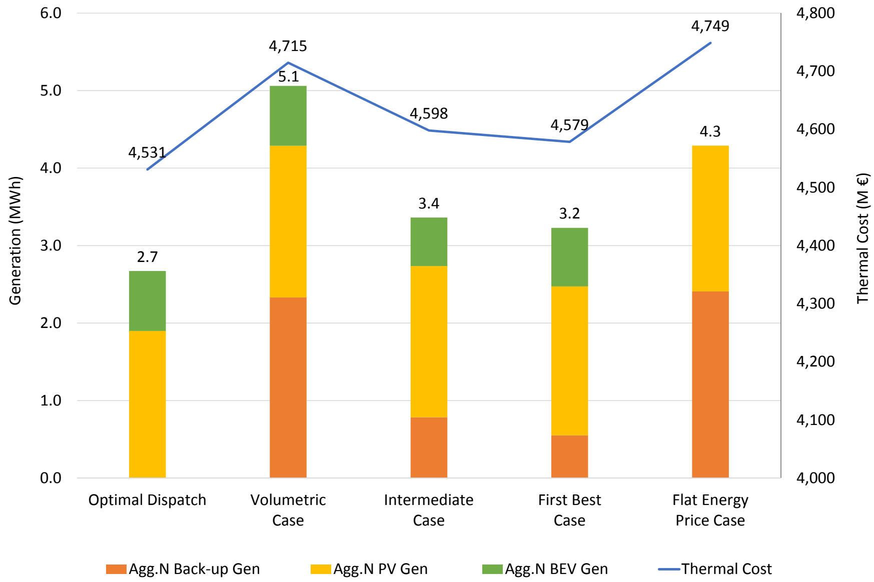

Figure 4.2: System thermal costs and generation dispatch for aggregator node

its own usage needs, and do not generate energy to supply any other part of the node's demand. Furthermore, the absence of EV injections, and given that back-up generation is dispatched at almost its maximum capacity, results in a higher thermal cost, which can be seen in figure 4.2, where the Flat Price Case has the highest system thermal cost among the selected cases, 4,749 M€.

Figure 4.2 also shows that back-up generation is not dispatched at all in the Optimal Dispatch case, mainly due to its high variable cost. In this case it is less costly to the system to supply part of the aggregator's node demand with thermal generation from upper nodes than to turn on back-up generation at this node, as the dispatch of back-up generation increases the generation costs.

On the other hand, when the Volumetric Case is modeled, thermal generation is dispatched almost at its maximum capacity. In this case, the increase in the per Megawatt hour (MWh) price of imported energy that the aggregator sees make him decide that it is cheaper to turn on its thermal generation to cover part of its own demand than to import this energy from the rest of the system.

4.1.3 Demand Payments, Economic Surplus, and Income Redistribution

Regarding demand payments, and income redistribution with respect to the Optimal Dispatch Case, three cases are analyzed: the Volumetric Case, where both network costs and other regulated costs are implemented as a volumetric charge; the First Best Case, where network costs are implemented partly as peak demand and partly as fixed charge, and other regulated charges are implemented as fixed, and the Alternative Node Case, where the aggregator's node is connected to a different node than node 6.4.

Table 4.1 shows payment sources for the Optimal Dispatch, Volumetric and First Best Case, while table 4.2 shows the final use of those payments. First of all, it is important to note that, as expected from applying distribution locational marginal prices, energy payment is higher than generation revenue for the three studied cases, which results in an economic surplus. This surplus was, as addressed in the methodology section, used to pay part of the network costs.

Table 4.1: Sources of demand payments for selected case studies

Component	Unit	Optimal Dispatch Case	First Best Case	Volumetric Case
Energy Payment	M€	12,614	12,707	12,499
from which Back-up overcost	M€		63	578
Network Charges	M€	8,972	8,912	9,273
Other Regulated Charges	M€	15,699	15,699	15,699
Total	M€	37,285	37,318	37,471

Table 4.2: Final use of demand payments for selected case studies

Component	Unit	Optimal Dispatch Case	First Best Case	Volumetric Case
Network Costs	M€	9,549	9,549	9,549
Other Regulated Costs	M€	15,699	15,699	15,699
Generation Revenue	M€	12,038	12,070	12,223
Total	M€	37,285	37,318	37,471

On the other hand, it can be seen the distinct retail prices design effects on total demand payments. Both the First Best Case (37,318 M€) and the Volumetric Case (37,471 M€) result in a higher total demand payment than the Optimal Dispatch (37,285 M€), due to the fact that neither case represent an optimal dispatch of generation resources, therefore their higher cost and total demand payment. On one hand, the First Best Case introduce distortions when implementing a part of network costs on peak hours, resulting therefore in a generation dispatch different from the optimal one. On the other hand, the Volumetric Case introduces even more distortions as regulated costs are charged to every MWh of energy that the aggregator node imports. Furthermore, in line with the thermal cost of each case, the First Best Case shows the second higher demand payment while the Volumetric Case the highest. This result goes in line with the fact that the

Volumetric Case is the case that introduces more distortion to the wholesale market, and total demand payment reflects it.

Economic Surplus

The Economic Surplus (ES) comes from implementing nodal prices, therefore its utilization is worth analyzing for theses cases (table 4.3). The Optimal Dispatch Case produced an economic surplus of 577 M€, which allows the payment of 6% of total network costs. However, when volumetric charges were implemented, economic surplus decreased to 277 M€, which represent only 2.9% of the network costs. The increase in local generation in the Volumetric Case (figure 4.2) caused and important reduction in losses and therefore a decrease in marginal prices in nodes with positive net demand (4.1). Lower losses in conjunction with lower prices in nodes with positive net demand, produces an important reduction in demand energy payments, which in turn decreased the economic surplus. On the other hand, prices of the First Best Case resulted very similar to the Optimal Dispatch Case, with a slight increase in some nodes. Energy demand payments for the First Best Case was higher than the reference case, and therefore a higher economic surplus (637 M€) than the reference case. From the three analyzed cases, the surplus for the First Best Case allows the payment of the highest percentage of the network cost.

Table 4.3: Final use of demand payments for selected case studies

	Unit	Optimal Dispatch Case	Volumetric Case	First Best Case
Economic surplus (ES)	M€	577	277	637
ES as % of network costs	%	6.0%	2.9%	6.7%

Income Redistribution for the Volumetric Case

With regard to the income redistribution caused by the distortions introduced by each case, figure 4.3 shows for the Volumetric Case the change in demand payments with respect to the Optimal Dispatch Case. In this figure, demand payments are split in energy, network charges, and other regulated payments. As the whole, the aggregator's node has 116 M€ in savings with respect to the Optimal Dispatch Case, whereas the rest of nodes pay in total 301 M€ more than in the reference case.

As one of the assumptions of the model is that the aggregator manages both demand and generation of its node, the change in generation benefit is also shown in figure 4.3 for the aggregator's node. In total, generation costs for this node is 578 M€ higher than in the Optimal Dispatch Case. This is, the aggregator is losing money from dispatching its thermal generation, which is more expensive than the rest of the system.

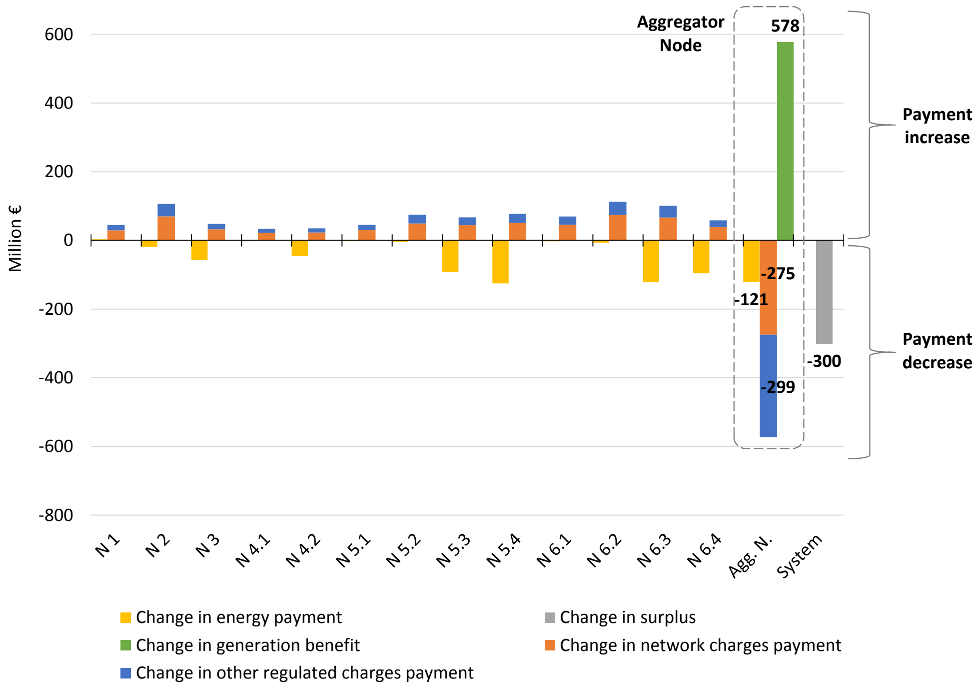

Figure 4.3: Change in demand payments with respect to the Optimal Dispatch for the Volumetric Case

This result is a consequence of the dispatch decision the aggregator must make when the volumetric charge is implemented, between importing generation and producing its own energy. In the first case, if the aggregator wants to import energy, it faces a significantly high price per imported MWh which includes both network charges and other regulated charges as volumetric. On the other hand, the aggregator sees the marginal price for its node, at which its generation would be paid. This price is lower than its generation variable cost, therefore it might lose money if dispatching its back-up generation. However, with this strategy the aggregator reduces demand for imports from the system, which decreases charges payments. The aggregator balances both alternatives and decides to dispatch its back-up generation, knowing that its generation cost will increase, but charges payment will decrease.

Furthermore, and as mentioned before, the aggregator's node experiences also a drop in its marginal price and therefore a decrease in its energy payment. Therefore, in this particular case, the aggregator losses 578 M€ by dispatching its thermal generation, saves 275 M€ in network charges and 299 M€ in other regulated charges by reducing its imports from the system, and saves 121 M€ in energy payments thanks to the prices drop, for an overall saving of 116 M€.

The aggregator's strategy described above has impacts on the remaining nodes payments as well. On one hand, the aggregator's node savings on charges must be recovered by increasing the charges to the rest of nodes. Therefore figure 4.3 shows that both network and other regulated charges payments are increased for the rest of nodes in the necessary amount to offset the aggregator's node savings. On the other hand, the aggregator's decisions also affects the rest of nodes' energy payments. Most nodes from the network pay less money for energy than in the Optimal Dispatch Case. In fact, the aggregator's node and its upstream nodes are the ones that experience the higher decrease in their energy payments. As already stated, higher local generation reduces network losses, which in turn reduces final demand and prices on those nodes. Finally, lower prices result in lower energy payments.

Income Redistribution for the First Best Case

Figure 4.4 shows the change in energy and charges payments for the First Best Case with respect to the Optimal Dispatch. It is worth noting that changes in payments or generation benefit are not as high as for the Volumetric Case(figure 4.3), i.e. the impact on payments of implementing a peak-demand charge together with a fixed charge is much more lower than of implementing a volumetric charge. For the Volumetric Case the maximum change on either component increased by 578 M€ on aggregator's node local generation, whereas the the maximum change on the First Best Case is a 102 M€ decreased in network charges for the same node.

Similarly to the volumetric case, in the First Best Case the aggregator faces two choices: on one hand, if it imports energy from the system over a certain quantity on peak hours it must pay network charges for the incremental network cost of the system; while on the other hand, it can dispatch part of its own thermal generation, even though its variable cost is over the marginal price of the aggregator's node decreasing imports on peak hours and therefore avoid paying peak demand charges. Figure 4.4 shows that the decision made by the aggregator is the latter: dispatch part of its back-up generation, which implies an increase of thermal cost in 63 M€, and consequently reduce imports from the system, which in turn let it save 102 M€ from network charges payment. These savings from charges that the aggregator's node experiences are recovered partly by increasing network charges to the rest of nodes and partly by the 60 M€ increase resulting from economic surplus.

Finally, the impact on energy payments from the application of peak-demand charges is uneven among nodes. On one hand, energy payment decreases in 3 M€ for aggregator's node, due to the drop on the node's marginal price. Energy payment also marginally decreased for four other nodes, due to reductions on their prices. However, energy payments increase in the nine remaining nodes, due to a slight increase of their prices.

This increase in prices might appear counter-intuitive, assuming that the reduction of imports from the system by aggregator's node should cause a reduction in losses and therefore a drop in prices in the rest of nodes. However, it must be considered that aggregator's strategy is not to reduce imports in every hour, but only on those peak hours

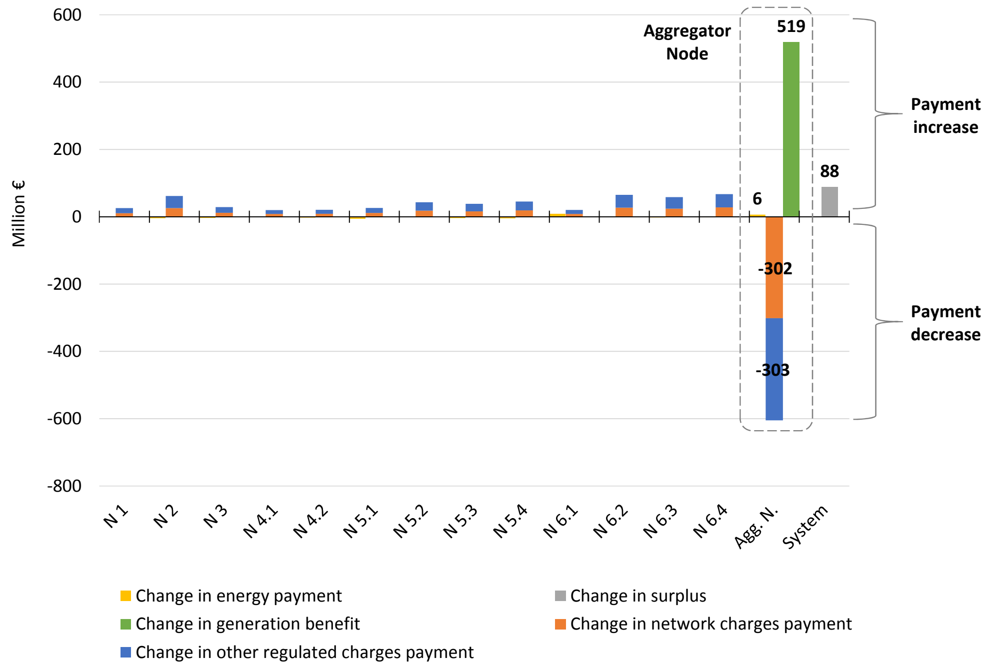

Figure 4.4: Change in demand payments with respect to the Optimal Dispatch for the First Best Case

which might imply a charge payment for the incremental network cost. In exchange, the aggregator might increase imports in other non-peak hours, when it is cheaper to import energy from the system than to produce it itself. Therefore, aggregator's decision of decreasing imports on some peak hours and increasing them on non-peak hours have drop effects on some hourly prices and incremental effects on others. This behavior resulted at last in lower annual average prices for some nodes but also higher prices for other ones, when compared to the Optimal Dispatch Case.

Finally, it is worth mentioning that income regarding other regulated charges does not change for either node, due to the fact that there was no shortfall for this charge.

4.1.4 Aggregator Connected to a Different Node

Aggregation of flexible resources in either urban or rural distribution networks could have different impacts on system operation components as losses, generation dispatch, and prices. Figure 4.5 shows the income redistribution for the Alternative Volumetric Case, where the aggregator is connected to a different node than node 6.4, specifically at node 6.1.

When results are compared to those of the Volumetric Case (figure 4.3), some similarities

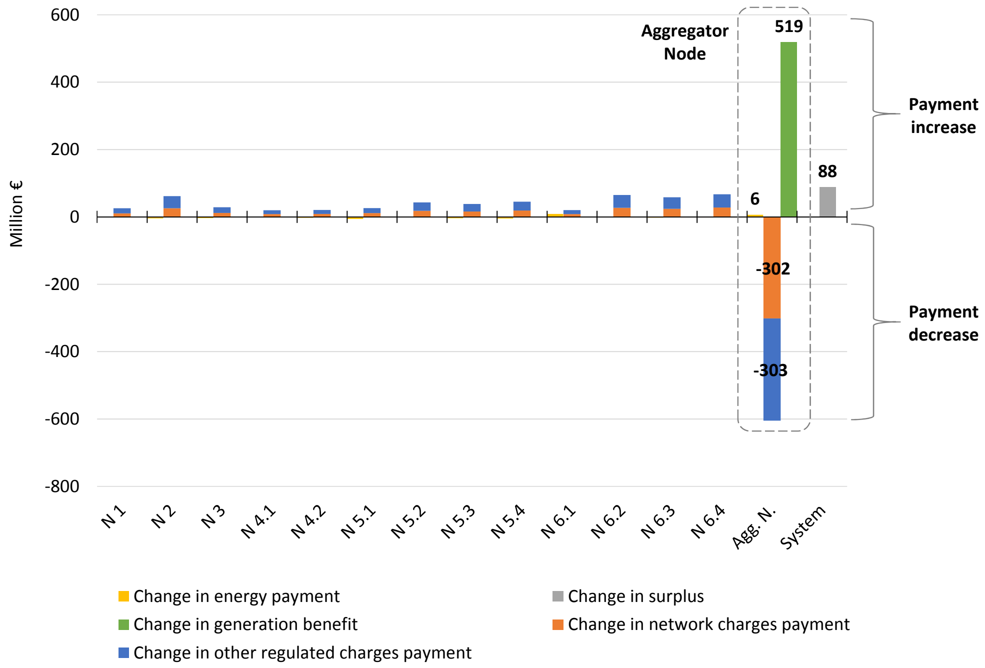

Figure 4.5: Change in demand payments with respect to the Optimal Dispatch for the Alternative Volumetric Case

can be found. First of all, in both cases the generation cost of dispatching back-up generation increased in an important amount: 578 M€ when connected to node 6.4 and 519 M€ if connected to node 6.1. In addition, aggregator's node has important savings in charges in both cases. In fact, the increase in local generation for the aggregator's node is similar on both cases: from around 1.9 Gigawatt hour (GWh) on the reference case to around 4.3 GWh in the respective volumetric case.

When results are compared to those of the Volumetric Case (figure 4.3), important differences can be found. For instance, Table 4.4 shows losses and prices for the optimal dispatch, and volumetric case both when the aggregator is connected at node 6.4 and at node 6.1.

On one hand, for the case of aggregator connected at node 6.4, system total losses change from 19.2 Gigawatt (GW) in the Optimal Dispatch to 18.0 GW in the Volumetric Case, for a decrease of 1.1 GW which represents a reduction of 6% in total losses. However, when the aggregator is connected at node 6.1, the decrease in losses is much lower, 0.3 GW which is a reduction of 1.3% on the volumetric case with respect to the reference case. This can be explained by observing the network configuration. Figure 3.3 at Chapter 3 showed that node 6.1 has less upstream nodes than node 6.4, therefore has less voltage drops and accumulates less losses than node 6.4 in the optimal dispatch

Table 4.4: System total losses for Optimal Dispatch and Volumetric Case

	Network Losses Ref. Case (GW)	Network Losses Vol. Case (GW)	Change in Network Losses (Abs)	Change in Network Losses (%)	Change in Av. Price (%)
Agg. connected at node 6.4	19.2	18.0	1.1	-6.0%	-4.9%
Agg. connected at node 6.1	19.9	19.7	0.3	-1.3%	0.1%

case. Consequently, the increase in local generation at the aggregator's node provoked by the volumetric charges has, on overall, a lower impact on upstream losses when the aggregator is connected to node 6.1 than when it is connected to node 6.4.

The small decrease in losses for the Volumetric Case when the aggregator is connected at node 6.1 resulted in almost zero changes on marginal prices, as all nodes' prices just changed 0.1% on average. The highest decrease on price happened to node 1, a node with negative net demand. This situation, along with the reduction of generation at upper nodes, caused the total system generation revenues to decreased, which in turn has consequences on the ES, as shown in table 4.5. It can be seen then, that ES increased from 864 M€ to 952 M€. This increase in the surplus, allows in turn an increase in the percentage of the network cost to be recovered, from 9% in the reference case to 10% in the Volumetric Case.

Table 4.5: Economic surplus for Optimal Dispatch and Volumetric Case

	Economic Surplus (ES) Optimal Dispatch (M€)	Economic Surplus (ES) Vol. Case (M€)	ES as % of Network Costs Optimal Dispatch (%)	ES as % of Network Costs Vol. Case (%)
Agg. connected at node 6.4	577	277	6	3
Agg. connected at node 6.1	864	952	9	10

4.2 System with Single Node

The Single Node cases ignore the location of generation and loads. This is the case of most European countries where national or zonal prices are applied, ignoring congestions and losses.

The generation dispatch and system thermal cost results are shown in figure 4.6 for the two modeled Single Node Cases: an optimal dispatch case and a volumetric case. In addition, so to facilitate the results analysis, the figure also shows the results for the reference and volumetric cases of the zonal prices scheme.

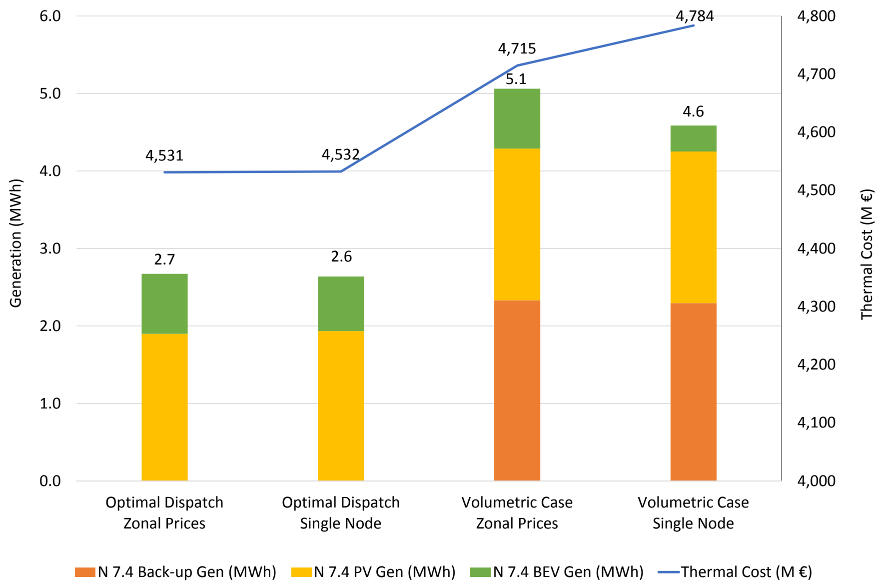

Figure 4.6: System thermal costs and aggregator's node generation dispatch for single node and zonal prices cases

First, it can be seen that the Optimal Dispatch for both zonal pricing and single node networks yields a similar dispatch for the aggregator's node resources, and also shows a difference of only 1 M€ on the system thermal cost. As no distortions are included in the reference cases

However, when distortions are implemented in the way of volumetric charges for both scenarios, some differences arises. First, a smaller quantity of energy is injected to the grid by EV in a single node network. This result is a consequence of the different prices to which EV respond in a single node network versus the ones they respond to in a nodal prices scheme. As a single node network ignores losses effects, the energy price for the aggregator node (the one to which EV respond) is lower than in the case were losses are considered (zonal pricing network). Further, as single node prices for a certain hour are an average of every node's prices, they present less variability than prices in a nodal pricing scheme. Therefore, less variability on prices of the single node case implies lower sales of generation from EV to the network.

On the other hand, system thermal cost is higher in the single node case than in the zonal prices one. This result is also related to the EV dispatch. In the single node volumetric case, as less demand is supplied locally by EV, and as price differences are reduced (considering back-up and Photovoltaic (PV) generation at their maximum capacity), the system must dispatch generation of more expensive technologies from upper nodes, in order to supply the residual demand of the aggregator node. This dispatch inevitably increases the thermal cost of the whole system.

Finally, in the single node case, the marginal cost price effect is lost. This is, the hourly price is set as the average of the distinct nodes' prices, which contrasts to a nodal pricing system where each hourly price for each node is set as the variable cost of the marginal technology. Therefore, the short term signals sent to the agents in the single node case are not optimal, and as any non-optimal scheme, the dispatching outputs and system thermal costs differ from the optimal one.

Chapter 5

Conclusions

The main objective of this thesis was to show how end-user electricity retail price designs in a context of flexible consumers can distort the efficiency of short term marginal prices that agents receive, affect agent's private benefits, and impact the overall operation of the system.

For doing so, the research considered an equivalent network representation of the Spanish power system, with annual generation and demand profile that simulates the Spanish system characteristics. In addition, consumers were considered to be whether flexible or inflexible. The former are defined by the flexible resources they are assigned, and how these resources are managed. On one hand, battery electric vehicles and demand response are assigned to the flexible consumers, so they have the ability to respond to distinct prices. On the other hand, the flexible consumers' resources are managed through an aggregator, an agent that is able to group and optimally manage different resources on behalf of its clients. Inflexible consumers are modeled without flexible resources, therefore they are unable to respond to different prices' profiles.

From the modeling point of view, the proposed way of implementing charges in an optimization and dispatching tool represents a new approach to assess the potential effects of different retail designs, both on the system operation and on consumers decisions. In this line, the study proposes the modeling of different designs for the distinct components of retail prices: energy price, network charges, and other regulated charges. Energy prices were modeled either as a nodal scheme that considers the network configuration, congestions and losses, or as a single node scheme, where congestions and losses are ignored. On the other hand, network charges were implemented as a volumetric charge, where each demanded energy unit is charged with a certain amount in €/MWh, or as a peak demand charge, where consumption over a certain threshold on peak hours is penalized. Finally, other regulated charges were considered both as volumetric and as fixed charges.

Several case studies were defined based on the combination of the different tariff designs, and divided into two main groups: nodal pricing cases and single node cases. The nodal pricing cases represent the most part of the studied cases, and entitle the modeling of: a reference optimal dispatch case, a case with volumetric charges, a case with peak demand charge together with a fixed charge, an intermediate charge with volumetric and peak demand charge, a single flat energy price case, and a case where the aggregator is modeled in a different node. Further, the single node case studies included the implementation of an optimal dispatch case and a case with volumetric charges.

Results were analyzed while assessing for flexible consumers response to the different tariff designs, and quantifying for this response impact on different system variables. Several outputs were analyzed for the aforementioned cases. First, nodes' marginal prices were assessed in order to identify those tariff design that resulted more or less efficient from the distortions of short-term signals point of view. Then, impacts on system operation was analyzed, focusing on thermal cost and generation dispatch of the aggregator's node. The former allows to identify the cheapest tariff design, while the latter provides facts to explain the changes in system costs.

The third analyzed group of outputs include the income redistribution among the different consumer groups. This analysis entitled the comparison of demand payments regarding energy and charges, in each of the cases that implied the implementation of charges in comparison to the demand payments made in the corresponding optimal dispatch case (reference).

Findings

The following are the main aspects that can be concluded from the case studies section.

i In a nodal prices scheme, it was found that volumetric charges promote the dispatch of expensive back-up generators that distort the economic dispatch, and in turn increase total generation costs. Flexible consumers with distributed resources would prefer to dispatch their expensive back-up generation in order to decrease system exports and obtain savings from charges payment.

ii A flat energy price design was found to not encourage demand response or electric vehicles' injection to the grid. Demand response objective is to move energy from high prices hours to low prices ones, in order to decrease agents and therefore system costs. The existence of a flat price on every hour eliminates demand response usefulness. On the other hand, the lack of differences on hourly prices removes the incentive for electric vehicles to charge during low prices hours and inject energy to the network during high prices hours. If electric vehicles had a 100% grid to battery and battery to grid efficiency, they could be used to inject demand to the grid, as this behavior would imply no losses for electric vehicles owners. However, electric vehicles are modeled with a 95% efficiency, which would entitle energy and monetary losses if charging from and injecting energy to the network at the same price. Therefore, electric vehicles only charge to satisfy their own usage needs.

iii The increase in local generation netting loads has been proven to reduce network losses and locational marginal prices and, as a consequence, demand market payments. The modeling of volumetric charges caused local generation to increase in low voltage nodes, which reduces their net demand. By doing so, generation requirement from upstream nodes is reduced, and therefore are network losses.

iv By reducing energy imports, flexible consumers obtain savings in regulated charges, and a shortfall in cost recovery is created. Avoided payments of regulated costs by reacting flexible consumers increase payments of inflexible consumers. Flexible consumers have the ability to respond to volumetric charges by increasing their local generation and therefore decreasing its net demand for energy imports. However, as savings in charges from flexible consumers need to be recovered, inflexible consumers are charged with the corresponding shortfall. As inflexible consumers can not respond to prices, they can not decrease their net demand to reduce regulated payments.

v Proper tariff designs promote reaction of flexible consumers that would induce system cost reductions. Network charges implemented on peak hours (proxy of incremental network charges) encourage flexible consumers to reduce their demand on those hours. By reducing the peaks, less expensive generation is required to cover peak demand, which result in lower system thermal costs. In addition, lower marginal energy prices are obtained on these hours, which ultimately benefit customers as well.

vi Under nodal prices, two alternative case studies were performed by considering flexible consumers managed by an aggregator connected at two different nodes: node 6.4 representing a rural area and node 6.1 representing an urban area. The rural and urban nodes were identified due to the upstream configuration of their network: while the rural networks usually implied long lines to supply distant demand, they are represented as nodes preceded by several voltage levels and transformations. On the other hand, the urban node is approximated by being preceded by less voltage changes than the rural one.

Aggregation of flexible resources in either urban or rural distribution networks has different impacts on systems losses, dispatch, and prices. First, it was found that if volumetric charges are implemented, either in a rural or urban node, flexible consumers can obtain important savings in charges from modifying their demand profile, whereas part of these savings are paid by non flexible consumers. On the other hand, aggregating resources in a rural low voltage area was found to has a higher impact on losses than if done on a urban area. This is due to the fact that rural nodes usually accumulate a higher amount of losses, due to the above mentioned fact that they use to require longer lines than urban areas to reach distant demand centers.

vii Under single node pricing, it was found that a lower injection of electric vehicles to the grid in comparison to nodal pricing happened. As single node models do not implement network losses in the optimization process, the resulting distribution locational marginal prices tend to be lower than in a nodal scheme, which model the network losses. Hence, electric vehicles respond to lower prices in the nodal case than in the single node one, selling less energy to the grid. In addition, in single pricing the *variable cost effect of the marginal dispatched technology* is lost, therefore results in single node schemes are non optimal. This last observation results in higher system thermal cost when modeling single pricing than when modeling nodal pricing.

Limitations and Future Work

Some limitations and future work can be considered. From the modeling point of view, an important limitation was the impossibility of including both the demand response and the electric vehicles modules in the same run of the ROM Model. When doing so, inconsistent results were obtained, therefore a work around needed to be followed. In this line, every case study required at least two runs of the model: one where electric vehicles participation was included and demand response was not, and a second one the other way around. Therefore, future work can be developed at the Institute of Research in Technology with the objective of modifying the model so that both the demand response and electric vehicles modules can interact within the same run of the model.

Time limitations prevent the execution of additional case studies. On one hand photovoltaic generation was kept fixed for all the performed case studies. In this line, additional cases can be modeled by modifying the PV installed capacity, so the impact of retail prices designs under different PV penetration scenarios can be assessed. Similarly, demand response cost was assumed to be zero during the whole study. However, this assumption can be modified in order to include the actual costs consumers face when participating in demand response programs, like the initial investments for demand response devices, and the costs related with the discomfort caused by shifting demand between hours.

Furthermore, even thought battery-electric vehicles were modeled, on site storage was left out of the study, However, recent technological innovations suggest that household storage will be an important consumers' asset in few years time. Hence, further research including local storage as a flexible resource can assess the distinct tariffs designs impacts on an power system with consumers with an even higher level of flexibility.

Finally, additional case studies can be developed by assuming that flexible resources are located in multiple nodes and with different levels of flexibility in each node. Such research can asses the impacts on system operation of having more than one aggregator, each of them looking for maximizing its clients' benefits. In addition, this case can provide insights on how consumers benefit can differ according to their different levels of flexibility.

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APPENDICES

Appendix A: Acronyms

CO^2	Carbon dioxide
ACER	Agency for the Cooperation of Energy Regulators
ADC	Advance Demand Charge
ARTF	Amsterdam Roundtable Foundation
BEV	Battery Electric Vehicles
BRP	Balancing Responsible Party
CNMC	Comisión Nacional de Mercados y Competencia
DER	Distributed Energy Resources
DLMP	Distribution Locational Marginal Prices
DR	Demand Response
EC	European Commission
EEN	Electric Equivalent Network
EPA	Environmental Protection Agency
EPC	European Price Coupling
ES	Economic Surplus
EV	Electric Vehicles
GW	Gigawatt
GWh	Gigawatt hour
HEV	Hybrid Electric Vehicles

ICE	Internal Combustion Engine
ISO	Independent System Operator
km	Kilometers
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
Mcal	Megacalorie
MIT	Massachusetts Institute of Technology
MW	Megawatt
MWh	Megawatt hour
NSE	Non-Served Energy
p.u.	Per unit
PHEV	Plug-in Hybrid Electric Vehicles
PV	Photovoltaic
PVPC	Precio Voluntario para el Pequeño Consumidor
REE	Red Eléctrica de España
RES	Renewable Energy Sources
ROM	Reliability and Operation Model for Renewable Energy Sources

Appendix B: Nomenclature

Indexes

A	Aggregator's node
S	System
i, j	Node
n	Nodes
p	Time period
pk	Peak periods
t	Thermal generation units

Parameters

θ	Threshold for peak periods
D	Input demand
DP	Demand energy payment
ES	Economic surplus
FC^t	Fixed cost
GR	Generation revenue
$MP_{p,i}$	Marginal price
NC	Network costs
NCh	Network charges
NCh^{vol}	per MWh charge for network charges
ORC	Other regulated costs
$ORCh$	Other regulated charges
$ORCh^{vol}$	per MWh charge for other regulated charges

PM	Positive parameter that sets the maximum value for the flows from the system to the aggregator ($f_{(S\rightarrow A)}$)
PN	Positive parameter that sets the maximum value for the flows from the aggregator to the system ($f_{(A\rightarrow S)}$)
$PkCh$	per MWh charge for network charges in peak hours
StC^t	Start-up cost
TC	Total thermal cost
TRC	Total regulated costs
VC^t	Variable cost

Variables

α	Binary variable that defines the existence of whether the flow from system to aggregator's node ($f_{(S\rightarrow A)}$) or the flow from aggregator's node to the system ($f_{(A\rightarrow S)}$)
β	Binary variable that defines, for the peak demand charge modeling, the existence of whether the flows over the peak threshold ($f^{\overline{\theta}}_{(S\rightarrow A)}$), or the flows below the peak threshold ($f^{\underline{\theta}}_{(S\rightarrow A)}$)
$d_{p,i}$	Final demand
$f_{(A\rightarrow S)}$	Flows from the aggregator's node to the system
$f_{(S\leftrightarrow A)}$	Flows between the system and the aggregator's node
$f_{(S\rightarrow A)}$	Flows from the system to the aggregator's node
$f^{\overline{\theta}}_{(S\rightarrow A)}$	Flows from system to aggregator's node over the peak threshold
$f^{\underline{\theta}}_{(S\rightarrow A)}$	Flows from system to aggregator's node below the peak threshold
g_p^t	Generation output
nse	Non served energy
on_p^t	Start-up decision
uc_p^t	Unit commitment decision