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INDUSTRIALES

TRABAJO FIN DE GRADO

**MARKET EQUILIBRIUM ANALYSIS OF SELF-
CONSUMPTION AND DECENTRALISED
GENERATION IN THE IBERIAN ELECTRICITY
MARKET UNDER THE NECPS 2030**

Autor: Isabel López Gómez

Director: Salvador Doménech Martínez

Co-Director: Francisco Alberto Campos Fernández

Co-Director: José Villar Collado

Madrid

Julio de 2026

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Co-Director: Francisco Alberto Campos Fernández

Co-Director: José Villar Collado

Madrid

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ANÁLISIS DEL EQUILIBRIO DE MERCADO DEL AUTOCONSUMO Y LA GENERACIÓN DESCENTRALIZADA EN EL MERCADO ELÉCTRICO IBÉRICO BAJO LOS PNIEC 2030

Autor: López Gómez, Isabel.

Director: Doménech Martínez, Salvador; Campos Fernández, Francisco Alberto; Villar Collado, José.

Entidad Colaboradora: Instituto de Investigación Tecnológica (IIT), Universidad Pontificia Comillas; Instituto de Engenharia de Sistemas e Computadores, Tecnologia e Ciência (INESC TEC).

RESUMEN DEL PROYECTO

Este trabajo aplica un modelo de equilibrio de Nash con variaciones conjeturales (VCs) al mercado eléctrico ibérico (MIBEL) en 2030 para cuantificar, de forma separada, el efecto del poder de mercado de los generadores y de los prosumidores con generación descentralizada sobre los precios de mercado, las compras a la red y el precio de captura, bajo los objetivos de autoconsumo de los Planes Nacionales Integrados de Energía y Clima (PNIECs) de España y Portugal.

Palabras clave: Autoconsumo, generación descentralizada, prosumidores, equilibrio de Nash, variaciones conjeturales, MIBEL, poder de mercado, PNIEC.

1. Introducción

La expansión del autoconsumo y la generación descentralizada (GDe) está transformando la estructura de los sistemas eléctricos modernos, en línea con los PNIECs de España y Portugal, que para 2030 establecen objetivos de 19 GW [1] y 4,3 GW [2] de potencia instalada de autoconsumo respectivamente. A medida que crece el número de prosumidores, estos dejan de comportarse como consumidores pasivos y pasan a decidir activamente cuánta energía generar, almacenar, autoconsumir o verter a la red, lo que introduce un comportamiento estratégico que diversos trabajos recientes han comenzado a modelizar [3], aunque su efecto bajo los condicionantes específicos del mercado ibérico y los objetivos de los PNIEC 2030 no está suficientemente caracterizado en la literatura existente.

Este Trabajo Fin de Grado aplica el marco de equilibrio de Nash con variaciones conjeturales (VCs) propuesto en [4] al mercado eléctrico ibérico (MIBEL) para el año 2030, con el objetivo de cuantificar de forma separada el efecto del poder de mercado de los generadores centralizados y el de los prosumidores con GDe sobre los precios de mercado, las compras a la red y el precio de captura.

2. Definición del Proyecto

Este proyecto persigue diseñar un conjunto de escenarios capaz de aislar de manera independiente el efecto del poder de mercado ejercido por los generadores centralizados del efecto del poder de mercado ejercido por los prosumidores, y de evaluar dicho efecto sobre los precios de mercado, las compras horarias a la red y el precio de captura de doce segmentos de consumo diferenciados, contrastando finalmente los resultados obtenidos con los objetivos de generación renovable establecidos por ambos PNIEC.

3. Descripción del modelo

La Figura 1 resume el esquema seguido en este trabajo, desde los objetivos de los PNIEC 2030 hasta los resultados obtenidos. El modelo aplicado, propuesto en [4], formula un Problema de Equilibrio de Nash Generalizado (GNEP) en el que generadores y prosumidores poseen variaciones conjeturales propias (VCs), que representa la pendiente de la curva de demanda u oferta residual percibida por cada agente. Este problema se reformula como un problema cuadrático de minimización de coste de resolución única, resuelto mediante la herramienta CEVESA (IIT-Comillas e INESC TEC).

El caso de estudio extiende el modelo, originalmente aplicado solo a España, al sistema conjunto España-Portugal (MIBEL), desagregando la demanda en doce segmentos de consumo. Se diseñan tres escenarios para 2030: un escenario de referencia (CGCONJ) con conjeturas activas para la generación centralizada (GC) y exportaciones de prosumidores libres; y dos escenarios con exportaciones de prosumidores fijadas a cero para aislar el efecto de las conjeturas del consumidor, con conjeturas nulas (NOCONJ) o no nulas para los segmentos industriales y comerciales (CUSCONJ).

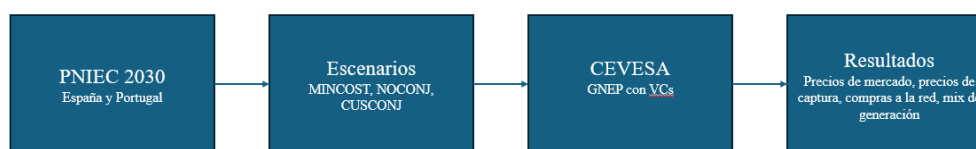


Figura 1: Esquema general del trabajo, desde los objetivos de los PNIEC hasta los resultados obtenidos

4. Resultados

Los resultados muestran una clara diferencia entre el efecto de las conjeturas de los generadores convencionales y el de las conjeturas de los prosumidores. Cuando los generadores ejercen poder de mercado (CGCONJ), el precio medio de mercado aumenta de forma sistemática y uniforme a lo largo de toda la distribución horaria, situándose entre 23 y 24 €/MWh por encima de los escenarios sin conjeturas de los generadores convencionales, y afectando por igual a la media y a los valores extremos (mínimo y máximo) de la distribución horaria de precios.

Por el contrario, las conjeturas de los prosumidores tienen un efecto muy limitado sobre el precio de mercado: el precio medio disminuye únicamente entre 0,41 y 0,52 €/MWh al pasar de NOCONJ a CUSCONJ. Esto se debe a que, al estar la capacidad de las baterías fijada exógenamente y las exportaciones a la red fijadas a cero, los prosumidores no pueden reducir sus compras anuales totales de energía y solo pueden redistribuirlas entre horas para disminuir su coste energético. Además, esta capacidad de redistribución se concentra en los segmentos industriales por la propia construcción del escenario CUSCONJ: a los segmentos industriales se les asigna el mayor valor de variación conjetural (0,003 €/MWh/MW), frente a 0,001 €/MWh/MW para los segmentos comerciales y cero para los segmentos residenciales, que permanecen como agentes precio-aceptantes tanto en NOCONJ como en CUSCONJ y, por tanto, no muestran ninguna respuesta de redistribución.

Sin embargo, este efecto de redistribución sí resulta relevante a nivel de cada segmento individual: el precio de captura anual de los doce segmentos de consumo disminuye de forma sistemática entre NOCONJ y CUSCONJ, con una magnitud que sigue el orden de las conjeturas asignadas a cada grupo, como se muestra en la Figura 2 para el caso español. Los segmentos industriales obtienen la mayor reducción relativa, alcanzando hasta un 0,93% en la industria minera, seguidos por los segmentos comerciales, mientras que los segmentos residenciales, que no ejercen poder de mercado en ningún escenario, presentan la menor reducción. Además, la comparación entre el mayor prosumidor industrial y un prosumidor residencial representativo confirma que una mayor capacidad de batería en relación con el

consumo permite desacoplar en mayor medida el perfil de compras a la red respecto al perfil de demanda, llegando incluso a reducir las compras a la red a cero durante un número significativo de horas, especialmente en Portugal.

Por último, el mix de generación anual obtenido en el escenario de referencia es coherente con los objetivos renovables de los PNIEC: la cuota renovable, excluyendo la generación nuclear y los vertidos, alcanza el 79,7% en España, frente a un objetivo del 81%, y el 89,4% en Portugal, frente a un objetivo del 90%. Esto valida el diseño de los escenarios en relación con el contexto de política energética que motiva este trabajo.

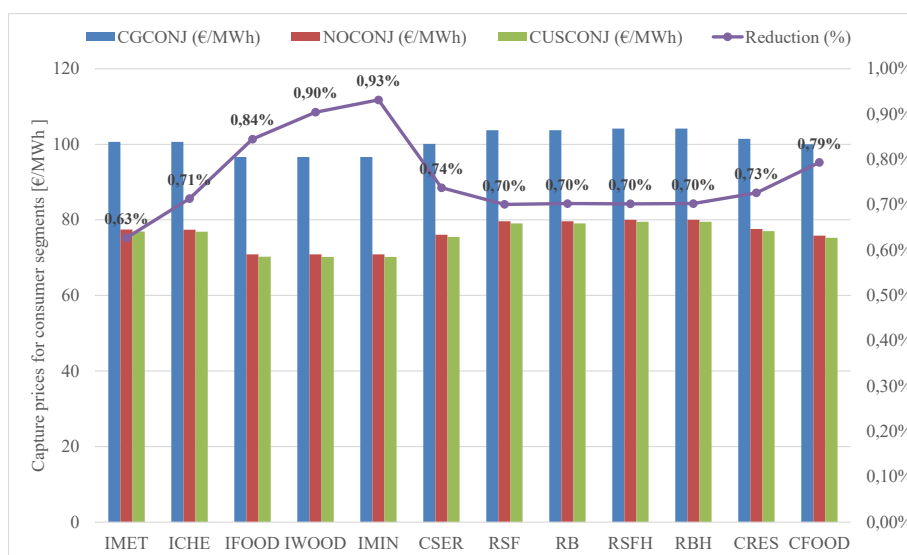


Figura 2: Precio de captura por segmento en los tres escenarios, con reducción % de NOCONJ a CUSCONJ (España, 2030)

5. Conclusiones

Este trabajo confirma que, bajo los supuestos actuales del modelo: inversión en baterías fija y demanda inelástica, el poder de mercado del prosumidor se manifiesta principalmente a través de la redistribución horaria de las compras a la red y de una reducción del coste efectivo soportado por cada segmento, más que a través de un efecto apreciable sobre el precio de mercado agregado. Para que las conjeturas del prosumidor lleguen a influir de forma significativa en el precio de mercado, sería necesario que la inversión en autoconsumo fuera endógena al modelo o que la demanda fuera elásticamente sensible al precio, dos extensiones que se identifican como las líneas de trabajo futuro más prioritarias.

6. Referencias

- [1] ‘Plan Nacional Integrado de Energía y Clima (PNIEC 2023-2030)’, Ministerio para la Transición Ecológica y el Reto Demográfico. [En línea]. Disponible en: <https://www.miteco.gob.es/es/energia/estrategia-normativa/pniec-23-30.html>
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- [4] S. Doménech Martínez, Fco. A. Campos, J. Villar, and M. Rivier, ‘An equilibrium approach for modeling centralised and behind-the-meter distributed generation expansion’, Electr. Power Syst. Res., vol. 184, p. 106337, Jul. 2020, doi: 10.1016/j.epr.2020.106337.

MARKET EQUILIBRIUM ANALYSIS OF SELF-CONSUMPTION AND DECENTRALISED GENERATION IN THE IBERIAN ELECTRICITY MARKET UNDER THE NECPS 2030

Author: López Gómez, Isabel.

Supervisor: Doménech Martínez, Salvador; Campos Fernández, Francisco Alberto; Villar Collado, José.

Collaborating Entity: Instituto de Investigación Tecnológica (IIT), Universidad Pontificia Comillas; Instituto de Engenharia de Sistemas e Computadores, Tecnologia e Ciência (INESC TEC).

ABSTRACT

This thesis applies a Nash equilibrium model with conjectural variations (CVs) to the Iberian electricity market (MIBEL) in 2030 to assess the impact of the market power exercised by generators and by prosumers with decentralised generation on market prices, grid purchases and capture prices, under the self-consumption targets of the National Energy and Climate Plans (NECPs) of Spain and Portugal.

Keywords: Self-consumption, decentralised generation, prosumers, Nash equilibrium, conjectural variations, MIBEL, market power, NECP.

1. Introduction

The expansion of self-consumption and decentralised generation (DeG) is transforming the structure of modern electricity systems, in line with the NECPs of Spain and Portugal, which set self-consumption installed capacity targets for 2030 of 19 GW [1] and 4.3 GW [2], respectively. As the number of prosumers increases, they no longer behave as passive consumers but instead actively decide how much energy to generate, store, self-consume or inject into the grid. This introduces strategic behaviour that several recent studies have begun to model [3], although its effect under the specific conditions of the Iberian market and the 2030 NECP targets has not yet been sufficiently analysed in the existing literature.

This bachelor's Thesis applies the Nash equilibrium framework with conjectural variations (CVs) proposed in [4] to the Iberian electricity market (MIBEL) for the year 2030, with the aim of assessing the effect of market power exercised by centralised generators and by prosumers with DG on market prices, grid purchases and capture prices.

2. Project Definition

This thesis aims to design a set of scenarios capable of independently isolating the effect of market power exercised by centralised generators from the effect of market power exercised by prosumers, and to assess this effect on market prices, hourly grid purchases and the capture prices of twelve differentiated consumption segments. Finally, the results obtained are compared with the renewable generation targets established by both NECPs.

3. Model Description

Figure 1 summarises the methodology followed in this thesis, from the 2030 NECP targets to the results obtained. The applied model, proposed in [4], formulates a Generalised Nash Equilibrium Problem (GNEP) in which generators and prosumers have their own conjectural variations (CVs), representing the slope of the residual demand or supply curve

perceived by each agent. This problem is reformulated as a quadratic cost-minimisation problem with a unique solution, solved using the CEVESA tool developed by IIT-Comillas and INESC TEC.

The case study extends the model, originally applied only to Spain, to the joint Spain–Portugal system (MIBEL), disaggregating demand into twelve consumption segments. Three scenarios are designed for 2030: a reference scenario (CGCONJ) with active conjectures for centralised generation (CG) and free prosumer exports; and two scenarios with prosumer exports fixed at zero in order to isolate the effect of consumer conjectures, with either zero conjectures (NOCONJ) or non-zero conjectures for industrial and commercial segments (CUSCONJ).

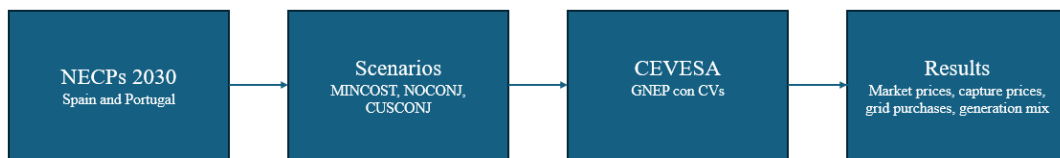


Figure 1: General structure of the thesis, from the NECP targets to the results obtained

4. Results

The results show a clear difference between the effect of CG conjectures and that of prosumer conjectures. When generators exercise market power (CGCONJ), the average market price increases systematically and uniformly across the entire hourly distribution, between 23 and 24 €/MWh above the scenarios without CG conjectures, affecting the mean and the extreme values (minimum and maximum) alike.

Prosumer conjectures, by contrast, have a very limited effect on the market price: the average price decreases by only 0.41 to 0.52 €/MWh when moving from NOCONJ to CUSCONJ. This is because, with battery capacity fixed exogenously and exports set to zero, prosumers cannot reduce their total annual energy purchases and can only redistribute them across hours to decrease their energy cost. Moreover, this redistribution capacity is concentrated in industrial segments by construction of the CUSCONJ scenario: industrial segments are assigned the highest conjectural variation value (0.003 €/MWh/MW), against 0.001 €/MWh/MW for commercial segments and zero for residential segments, which remain price-takers in both NOCONJ and CUSCONJ and therefore show no redistribution response at all. However, this redistribution effect is relevant at the level of each individual segment: the annual capture price of the twelve consumption segments consistently decreases between NOCONJ and CUSCONJ, with a magnitude that follows the order of the conjectures assigned to each group, as shown in Figure 2 for the Spanish case. Industrial segments obtain the largest relative reduction, up to 0.93% in the mining industry, followed by commercial segments, while residential segments, which do not exercise market power in any scenario, show the smallest reduction. In addition, the comparison between the largest industrial prosumer and a representative residential prosumer confirms that a higher battery capacity relative to consumption allows the grid purchase profile to be more strongly decoupled from the demand profile, even reducing grid purchases to zero during a significant number of hours, particularly in Portugal.

Finally, the annual generation mix obtained in the reference scenario is consistent with the renewable targets of the NECPs: the renewable share, excluding nuclear generation and curtailment, reaches 79.7% in Spain, compared with a target of 81%, and 89.4% in Portugal, compared with a target of 90%. This validates the design of the scenarios against the energy policy context that motivates this thesis.



Figure 2: Capture price by segment across the three scenarios, with % reduction from NOCONJ to CUSCONJ (Spain, 2030)

5. Conclusions

This thesis confirms that, under the current assumptions of the model: fixed battery investment and inelastic demand, prosumer market power is mainly expressed through the hourly redistribution of grid purchases and a reduction in the effective cost borne by each segment, rather than through a significant effect on the aggregate market price. For prosumer conjectures to have a significant influence on the market price, self-consumption investment would need to be endogenous to the model, or demand would need to be elastically responsive to price. These two extensions are identified as the highest-priority lines for future work.

6. References

- [1] ‘Plan Nacional Integrado de Energía y Clima (PNIEC 2023-2030)’, Ministerio para la Transición Ecológica y el Reto Demográfico. [En línea]. Disponible en: <https://www.miteco.gob.es/es/energia/estrategia-normativa/pniec-23-30.html>
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Chapter 1. INTRODUCTION

This chapter places the research within the broader context of the ongoing energy transition and the transformation of modern electricity systems. In recent years, the increasing deployment of self-consumption and decentralised generation (DeG) has changed the traditional role of electricity users, who are now becoming more active participants in the energy market. These changes create both opportunities and challenges for the operation and planning of power systems. In this context, the present work addresses a relevant problem linked to the integration of new distributed energy resources (DERs).

1.1 BACKGROUND

The global energy sector is undergoing a profound transformation driven by the urgent need to decarbonize the economy and mitigate the effects of climate change. The European Union (EU) has established ambitious energy and climate targets through the European Green Deal, with the goal of becoming a climate-neutral economy by 2050 [1]. Member states are required to develop National Energy and Climate Plans (NECPs) that specify binding decarbonization pathways in line with EU-level objectives [2]. For the Iberian Peninsula, the NECPs of Spain and Portugal ([3], [4]) serve as essential benchmarks for evaluating how the regional power system is expected to evolve with the growing penetration of DeG. Spain's updated NECP 2023-2030 sets out an especially ambitious roadmap: it targets a 32% reduction in greenhouse gas emissions relative to 1990 levels, a 48% share of renewables in final energy consumption, and a renewable electricity penetration of 81% by 2030, including 19 GW of self-consumption photovoltaic capacity [3]. Portugal's NECP establishes equally ambitious targets: it aims for a 55% reduction in greenhouse gas emissions relative to 2005 levels, a 47% share of renewables in final energy consumption, and a renewable electricity penetration of 90% by 2030, including 4.3 GW of self-consumption photovoltaic capacity [4].

A key pillar of this strategy is the decentralization of electricity generation, in which final consumers are empowered to produce a portion of their own energy locally using DERs. The adoption of behind-the-meter photovoltaic (PV) systems has been accelerating rapidly across Europe, driven by the sharp decline in PV module costs, approximately 90% over the past decade [5].

Complementing this cost trajectory, a succession of regulatory reforms progressively removed administrative barriers to self-consumption across Europe. In Spain, the landmark Royal Decree 244/2019 [6] established the administrative, technical and economic conditions for self-consumption, introduced simplified surplus energy compensation mechanisms, and, for the first time, recognised collective self-consumption by groups of prosumers [6].

As a result of these drivers, installed self-consumption PV capacity in Spain grew from 641 MW in 2019 to over 9.590 MW by 2025, as shown in Figure 1 [7]. Reaching the 19 GW target by 2030 would require an average annual installation rate of around 1,900 MW. This rate was exceeded in both 2022 and 2023, showing that it is technically achievable. However, the average annual rate over the last three years has remained closer to 1,500 MW, below the pace required to reach the target, so meeting it by 2030 is not guaranteed on current trends. [7].

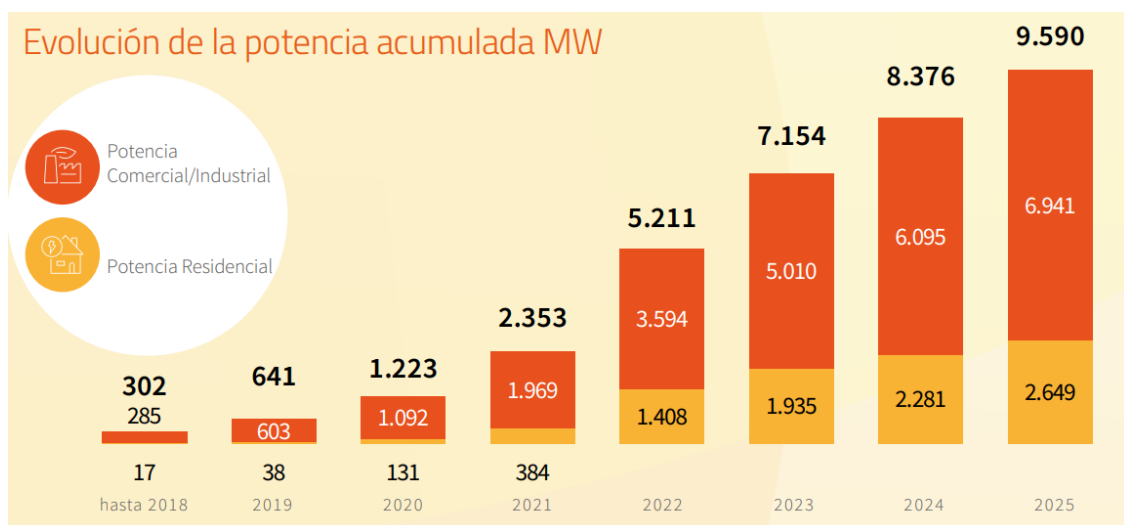


Figure 1: Evolution of cumulative installed capacity (MW) [7]

The modelling and analysis of self-consumption and DeG have therefore emerged as key research areas. In this context, one particularly relevant issue that remains insufficiently explored is the strategic behaviour of prosumers within these markets. Unlike passive consumers, prosumers actively decide how much energy to generate, store, self-consume, or sell back to the grid. When a sufficiently large number of prosumers make these decisions simultaneously, their aggregate behaviour can influence the wholesale market price itself, affecting the costs and revenues of all market participants. This ability to influence the wholesale price through their own decisions is what is understood as prosumer market power. Understanding and modelling this strategic interdependence is therefore essential for assessing how self-consumption markets work in practice. Several works have begun to address this challenge, notably [8], by applying a conjectural variations (CVs) framework to represent different degrees of strategic behaviour in electricity markets with DeG.

1.2 THE IMPACT OF SELF-CONSUMPTION AND DEG ON ELECTRICITY MARKETS

The increasing deployment of self-consumption and DeG is transforming the structure and operation of modern electricity systems. Traditionally, power systems have been organised around a centralised paradigm, where large-scale generation units supply electricity through transmission and distribution networks to passive consumers. However, the integration of DERs, particularly in the form of self-consumption, is shifting this paradigm towards a more decentralised and participatory model [8], [9].

One of the most significant impacts of DeG is the modification of power flow patterns within the network. Instead of unidirectional flows from Centralised Generation (CG) to users, power can now flow in a bidirectional manner, as consumers with local generation capabilities can inject surplus energy into the grid. As a result, new challenges arise in terms of voltage control, congestion management, and overall system stability [10].

At the same time, DeG can provide important technical benefits. Since energy is produced near the point of consumption, it can reduce transmission losses and reduce overall

usage of the grid. This may help contain the need for costly network reinforcements [11]. In addition, local generation can improve supply reliability and resilience, especially when combined with storage technologies, by reducing dependence on CG sources and long-distance transmission [11].

Another key impact concerns investment signals within the electricity market. The interaction between CG and DeG creates new dynamics that influence both types of investments. In [8], the authors demonstrate this interaction explicitly in a Spain-like system, showing that DeG investment decisions depend heavily on the design of network access tariffs and wholesale electricity prices, and on the strategic behaviour of agents with significant influence on the market. This thesis, however, focuses exclusively on the operational and market-equilibrium dimension of this interaction: investment decisions, whether for CG or DeG, are not modelled, and installed capacities are treated as exogenous inputs, as detailed in Chapter 3.

In this context, the CEVESA market model [12], shared by the *Instituto de Investigación Tecnológica* (IIT) at *Universidad Pontificia de Comillas* and INESC TEC, is a reference tool for simulating the Iberian electricity market (MIBEL). The present work aims to review the DeG model implemented in CEVESA and analyse how different levels of strategic awareness among consumers, that is, the degree to which they perceive and act upon their own influence over market prices. To this end, this work designs and analyses future scenarios inspired by the Spanish and Portuguese NECPs to assess the potential effects of different self-consumption penetration rates on market balance and the economic outcomes of the electricity system.

The CEVESA version used in this work parts from the one proposed in [8], which presents a Nash equilibrium model capable of jointly representing investment and operation decisions of CG and DeG. This approach captures the interaction between traditional market agents and new consumers with self-generation capabilities. One of the objectives of the model is to analyse the impact of the participation of these consumers in the wholesale

electricity market, assessing how their self-consumption and excess generation trading decisions may affect prices, system investments, and overall market equilibrium.

1.3 MOTIVATION

As described, the expansion of self-consumption and DeG is reshaping the structure and operation of modern power systems, challenging traditional planning approaches. In the Iberian Peninsula, this transformation is closely linked to the increasingly ambitious targets set out in the National Energy and Climate Plans (NECPs), which rely heavily on the expansion of DERs and active consumer participation. In this context, it becomes essential to assess whether these pathways remain viable under evolving consumer behaviour and ongoing technological developments.

Evaluating the interaction between CG and decentralised resources is therefore a key aspect of this analysis. The growing presence of prosumers introduces uncertainty and strategic behaviour that must be properly captured in modelling frameworks.

This project uses the CEVESA framework proposed in [8] to analyse the market equilibrium of the Iberian electricity system in 2030 under the DeG penetration targets established by the NECPs and different assumptions regarding consumer and generator CVs. The aim is to identify situations in which the planned transition may face economic or operational challenges, and to provide useful insights for improving long-term strategies and regulatory design.

1.4 OBJECTIVES

This project aims to analyse and simulate future scenarios to model the penetration of self-consumption and DeG using the CEVESA tool, developed by the IIT. To achieve this general objective, the following specific goals are established:

- Understand how the growth of self-consumption and DeG affects the Iberian electricity market, especially in terms of prices and market equilibrium outcomes.

- Apply the Nash equilibrium model proposed in [8] to the Iberian electricity market, extending its scope from Spain to the joint Spain-Portugal system (MIBEL).
- Design a set of scenarios based on the most recent versions of the Spanish and Portuguese NECPs, incorporating the 19 GW self-consumption target for Spain and 4,3 GW for Portugal as exogenous inputs to the model.
- Analyse the effect of generator CVs on market prices and dispatch outcomes, comparing a scenario in which generators exercise market power against one in which they behave as price-takers.
- Assess the effect of consumer CVs on grid purchase profiles and market prices, identifying the conditions under which consumer market power can or cannot influence market outcomes.
- Evaluate the consistency of the simulation results with the renewable generation targets established by the Iberian NECPs, in terms of technology mix and renewable share.

1.5 STRUCTURE OF THE DOCUMENT

The thesis is structured as follows. Chapter 2 presents a review of the state of the art, covering the existing literature on self-consumption modelling and equilibrium approaches for behind-the-meter DeG. Chapter 3 describes the proposed mathematical model within the CEVESA platform, including its formulation, hypotheses, and solution methodology, as presented in [8]. Chapter 4 presents the case study design and results for the scenarios simulated, followed by a comparative analysis. Chapter 5 concludes with a summary of the main findings and lines of research.

Chapter 2. STATE OF THE ART

As already mentioned in Chapter 1, self-consumption and DeG are key elements when analysing generation expansion models. The growing presence of consumers who can produce, store and sell energy, requires models that capture this new interaction between CG and DeG, as well as the impact that this has on system operation and wholesale market dynamics. The following subsections describe the main focuses found in the literature to tackle these objectives.

2.1 EQUILIBRIUM MODELS

One of the most relevant and convenient approached found in recent literature is [8], in which each agent maximises profits in the sense of Nash equilibrium while considering the CG and DeG decisions, including both investment and operational decisions. Specifically, CG agents (Generation Companies/GENCOs) maximise their market profits, while DeG customers minimise their net energy supply costs. By applying the KKT conditions to the resulting system of coupled optimisation problems, an equivalent single-level mathematical minimisation problem is solved to find Nash Equilibrium. This model, used to develop the case studies, is explained in detail in Chapter 3 and it is applied to a Spain-like single-bus system over a long-term time horizon (2019-2037).

The authors of [8] also analyse different scenarios in which access tariffs, based on either power or energy, are modified. Power-based tariffs tend to promote investment in storage and help reduce demand peaks, while energy-based tariffs tend to increase the installation of decentralised photovoltaic generation. [8] includes a simplified representation of losses, and uncertainty is partially addressed through the simulation of time periods representing different demand and generation conditions. Finally, phenomena such as load defection, where a customer reduces consumption from the grid due to self-generation capacity, or grid defection, where the customers disconnect completely from the grid, are explicitly considered.

In addition, [8] shows that the DeG investments strongly depend on the structure of network tariffs, that CG and DeG investments interact with each other in determining total system capacity, and that high penetrations of DeG may significantly alter demand profiles and wholesale prices, highlighting the importance of jointly modelling both types of generation when assessing long-term system sustainability. A key feature of [8] is the representation of customer CVs, a mathematical parameter that captures the degree to which each agent anticipates the effect of its own generation decisions on the wholesale electricity price. This allows the model to represent different degrees of market competition, from price-taking behaviour to strategic interaction among agents, making it particularly well suited for analysing different assumptions about prosumer behaviour.

Following the line of equilibrium models, [13] develops consumer centric price equilibrium models that include different market designs: peer-to-peer (P2P), Pool and Mixed, with Direct Current (DC) linear power flow approximations. For each type of market, the objective functions of the prosumer, the Transmission System Operator (TSO), the Energy Market Operator (EMO), and the Carbon Market Operator (CMO) are explicitly formulated. A single centralised equivalent problem is then proposed and solved by applying Alternating Direction Method of Multipliers (ADMM) algorithm, which enables a decentralised solution while preserving agent privacy. [13] is Part I of a two-part work, and [14] is Part II: [13] introduces the methodological framework, while [14] applied it to two case studies, a Netherlands-based 2030 scenario and a European 2050 scenario with 30 countries and HVDC interconnectors, that jointly plan generation and transmission capacities under different market design scenarios, thereby capturing the associated investment uncertainty. The network used in both parts consists of 30 buses.

The main contribution of [13] and [14] is the explicit integration of multiple market mechanism into a long-term generation and transmission planning framework. The results show how different market designs lead to different investment profiles and how the presence of prosumers with their own cost objectives modifies total system costs compared to a setting where all decisions are optimized centrally. A limitation of this approach is the exclusive use of DC power flows and the absence of a Distribution System Operator (DSO)

representation, which means that local distribution-level effects of prosumer decisions are not captured. Furthermore, the assumption of perfect competition among prosumers contrasts with the conjectural variation framework of [8], that can represent imperfect competition and is therefore more suitable for the present analysis.

Moreover, studies [15] and [16] also examine the role of prosumers in electricity markets using equilibrium models formulated as Mixed Complementarity Problems (MCPs). Although both papers rely on the same type of mathematical framework, they differ in their focus. In [15], the analysis examines prosumer behaviour in a setting where they can both consume and generate electricity. Prosumers maximise their profit by deciding the volume of power they buy or sell through bilateral contracts, the fraction of their renewable output allocated to self-consumption or curtailment, and the amount of energy they produce with their backup unit. Because the model uses nodal Locational Marginal Prices (LMPs) and DC power flows with Power Transfer Distribution Factors (PTDFs), an arbitrage agent is included to ensure that price differences between nodes are eliminated, shifting power from low-price to high-price nodes to maintain coherent and consistent prices across the network.

In contrast, [16] analyses how the increasing presence of prosumers affects transmission charges and whether this can trigger the death-spiral phenomenon, a situation where lower consumption from the grid increases network costs for the customers who remain connected, thereby encouraging even more consumers to switch to self-generation [17]. Rather than emphasizing the strategic behaviour of prosumers, [16] studies how different tariff designs, such as fixed, volumetric, or hybrid charges, affect the recovery of network costs when prosumers increasingly rely on self-generation and reduce their demand from the grid. The model extends the linear complementarity framework of Nash-Cournot competition to incorporate prosumer decisions explicitly and considers two scenarios: one in which the prosumer is a price-taker and one in which it acts as a strategic entity under imperfect competition.

Both models, [15] and [16], rely on DC power flow and use PTDFs to represent network flows without accounting for losses. In [15], the network corresponds to the IEEE 24-bus Reliability Test System (RTS), whereas [16] uses a simplified three-node system.

Although the models are deterministic, [15] and [16] introduce uncertainty by evaluating scenarios with different levels of renewable energy output. Specifically, [15] evaluates three levels of prosumer renewable output (25 MW, 50 MW, and 120 MW), while [16] considers four levels (500 MW, 1000 MW, 1500 MW, and 2000 MW).

Overall, [15] shows that when prosumers act strategically by adjusting how much energy they buy or sell to influence market prices, this does not change whether they remain net buyers or net sellers, their position in the market is determined more by their generation capacity than by their chosen strategy. Meanwhile, [16] demonstrates that the death spiral is not inevitable and largely depends on both prosumer behaviour and tariff design: transmission charges do not necessarily increase with the proportion of prosumers, but the risk of a death spiral grows when strategic prosumers with high renewable output reduce their energy purchases from the grid under imperfect competition. These findings are directly relevant to the regulatory analysis of the Iberian NECPs, where high self-consumption penetration targets raise legitimate concerns about the sustainability of network tariff frameworks.

2.2 LOCAL MARKET MODELS

It should be stated explicitly that this thesis does not model local energy markets or collective self-consumption: CEVESA represents the Iberian system at an aggregate, peninsular scale, and all DeG customer segments interact with the wholesale market individually rather than through local arrangements. This section is included to position the present work within the broader literature on decentralised energy models, not to describe a feature of the model used here.

The recent growth of DeG has spurred the emergence of Local Energy Markets (LEMs), which enable consumers to exchange energy within the local distribution grid rather than relying exclusively on the main grid. In this context, [18] models a LEM operating over an idealized distribution network, where prosumers trade power with each other and with a utility agent managed by the DSO. The study proposes a Generalized Nash Equilibrium (GNE) formulation that captures the strategic interactions among prosumers and the DSO

under shared balance constraints, ensuring that all transactions remain physically feasible within the local grid. In a standard Nash Equilibrium, each agent optimizes independently. In a GNE, all agents must additionally satisfy a shared constraint simultaneously, in this case, that the total energy produced and consumed within the local network must always be balanced. A primal-dual price update algorithm is used to iteratively solve the GNE problem in real time, enabling the framework to respond to rapid changes in renewable generation and demand without requiring a centralised coordinator. The model is designed for real-time operation and focuses on short-term market behaviour.

The authors of [18] determine that the proposed real-time GNE framework achieves three desirable properties: it reduces prosumers operating costs compared to a no-trade baseline; it ensures a unique market-clearing price, avoiding the price ambiguity that can arise in decentralised trading settings; and it allows the DSO to handle demand deviations effectively without compromising the local power balance. This shows that LEMs can improve efficiency in the local distribution grid. A notable limitation, however, is that the model does not incorporate physical power-flow constraints or storage technologies, meaning that locational effects of local trading and the temporal flexibility enabled by batteries are not captured. Furthermore, as the framework focuses exclusively on short-term operation, it does not address investment decisions or the longer-term expansion of DeG, which are the central concerns of the present thesis.

The LEM literature and the equilibrium models of Section 2.1 are therefore complementary: local market models capture the operational dynamics that emerge when prosumers trade energy within a distribution network, while equilibrium models address long-term investment and market equilibrium at the system level. While models such as [8] represent the aggregate investment and market equilibrium effects of self-consumption at the peninsular scale, local market frameworks such as [18] capture the operational dynamics and cost savings that emerge when prosumers trade energy within a distribution network. The present thesis focuses on the aggregate level by using CEVESA to simulate the Iberian system, while acknowledging the local market dynamics as an important dimension for future model development.

2.3 GAPS IN THE LITERATURE AND POSITIONING OF THE PRESENT WORK

The literature reviewed in the preceding sections covers two main streams: equilibrium models for generation expansion and local energy market frameworks. Taken together, these works provide a solid methodological foundation for understanding the role of prosumers in electricity systems. However, the review also reveals some relevant gaps that motivate the research undertaken in this thesis.

The importance of properly modelling the interaction between CG and DeG is underscored by the scale of the policy targets currently in place for the Iberian Peninsula. The Spanish NECP 2023–2030 [3] sets a target of 19 GW of self-consumption capacity by 2030, as part of a broader objective of reaching 81% renewable electricity generation and a total installed capacity of 214 GW, of which 160 GW will be renewable [3]. Self-consumption and DeG are explicitly identified in the NECPs as key pillars of citizen and business participation in the energy transition. At these penetration levels, the interaction between self-consumption, wholesale prices, and centralised generation investment can no longer be treated as a secondary effect and becomes a central factor in the planning of the electricity system. A large-scale deployment of self-consumption PV capacity modifies the demand profile seen by CG units, affects wholesale price formation, and changes investment incentives across the system [19], [8]. Properly capturing these dynamics requires a model that represents both types of agents simultaneously, making the gap identified in the literature not only a methodological concern but also a practical one in the context of the Iberian energy transition.

Despite this policy urgency, the literature that explicitly models the interaction between CG and DeG within a single equilibrium framework remains surprisingly limited. A systematic review of the literature on decentralised energy investment and operation models [20] found that operational models and local markets have been extensively studied, but that wholesale market integration and joint investment models, precisely the type of model needed to assess the NECPs targets, lack scientific attention. The main reason for this

scarcity is probably the inherent complexity of the problem: CG agents and DeG customers have opposing objectives: GENCOs seek to maximise profits while prosumers seek to minimise their energy costs, and their decisions are linked through the electricity price, which is itself a result of the equilibrium [8]. Representing this interaction requires solving a system of coupled optimisation problems simultaneously, which is mathematically demanding. As a result, most works in the literature either model CG agents alone, treating DeG as an exogenous reduction in demand, or model DeG customers in isolation, taking wholesale prices as a given input.

The local market models reviewed in Section 2.2, while methodologically rich, address a different scale of the problem. They focus on operational efficiency within distribution networks and do not capture the national-level investment dynamics that are the primary concern of long-term system planning.

The present thesis directly addresses these gaps by building on the CEVESA framework of [8]. Unlike [8], which was applied to a Spain-only system, this work extends the analysis to the full Iberian electricity market (MIBEL), jointly considering Spain and Portugal. Furthermore, the scenario design is based on the most recent versions of the Spanish and Portuguese NECPs, which set more ambitious targets than those available at the time of [8], ensuring that the analysis is aligned with current energy transition pathways. It must be stated clearly that this thesis does not model investment decisions: DeG and battery capacities are treated as exogenous inputs, taken directly from the NECP targets, and the analysis is restricted to the resulting operational dispatch and market equilibrium.

The objective of this analysis is to study the market equilibrium of the specific 2030 scenario defined by the Spanish and Portuguese NECPs. For this reason, the installed capacity of DeG is treated as exogenous input data rather than as a decision of the model, and the analysis focuses exclusively on the operational dispatch and market equilibrium outcomes that result from that predefined capacity.

A key distinguishing feature of this work with respect to the broader literature is the explicit representation of market power through CVs, applied to both CG and DeG agents

therefore including also the representation of consumers' market power. As DeG penetration grows and an increasing share of demand is covered by prosumers, the assumption that consumers are passive price-takers becomes increasingly unrealistic. Large industrial consumers or aggregated prosumer groups may be able to strategically influence wholesale prices through their self-consumption and surplus trading decisions. This thesis analyses the implications of this market power under different conjecture scenarios, a dimension that remains largely unexplored in the existing literature and that is likely to become increasingly relevant as the energy transition progresses.

To conclude this section, Table 1 summarizes the main references of the literature review, covering their model type, time scope, agents involved, objective function, research aim, main contributions, and key limitations. This taxonomy provides a structured overview of the state of the art and highlights the position of the present work relative to the existing literature.

Reference	Model type	Time Scope	Agents involved	Objective function	Research aim	Contributions	Model limitations	Application
[8]	CV/Nash equilibrium, KKT single-level with UC	Long-term (2019–2037)	GENCOs, DG customers, regulator tariffs	GENCO profit maximization and consumers energy expenses minimisation	Analyse equilibrium expansion between CG and DG	Integrated CG-DG with endogenous prices, tariff effects quantified with load-defection and grid-defection	Exogenous tariffs, representative-week sampling	Spain-like single-bus, representative week per year
[13] and [14]	DC/PTDF, centralised equivalent, P2P/pool/mixed, carbon cap	Long-term (a scenario for 2030 and another for 2050)	Prosumers, TSO, EMO, CMO	Minimisation of total system, network, and carbon costs under market equilibrium conditions	Find optimal investments under different market designs and trading costs	Integrates market mechanisms into planning while preserving privacy through ADMM, endogenous prices	DC only, no DSO, perfect-competition	NL-2030 (30-node), EU-2050 (30 countries, HVDC)
[15]	Locational Marginal Prices (LMPs), PTDF network	No temporal dispatch	Strategic prosumer, producers, grid operator, consumers, arbitrageur.	Prosumer maximises benefit under power balance	Impact of strategic prosumer on LMPs, flows, and surplus	Equilibrium existence, insights on prosumer market power, endogenous prices	Static analysis with simplified network; no temporal dynamics or storage considered	IEEE 24-bus RTS, line-7 capped at 150 MW

[16]	Locational Marginal Prices (LMPs)	No temporal dispatch	Consumers, aggregated prosumers, producers, ISO/TO	Consumers/prosumers minimise cost or maximise surplus; TSO recovers fixed costs	Transmission-ch arge design vs death-spiral risk with prosumers	Evaluates prosumer-network interactions with endogenous prices	Static analysis with simplified three-node system, no storage	Stylized 3-node network, prosumer share and renewable output scenarios
[18]	GNE, primal-dual price updates	Short-term	Prosumers, Utility/DSO as market operator	Agents minimise individual costs under common balance constraints, achieving a unique market-clearing equilibrium price	Real time clearing with unique price and privacy-preserving updates	GNE design, cost reduction in case studies, endogenous prices	No power-flow constraints, no storage	Ideal power network with no representation of physical grid constraints

Table 1: State of the art of CG and DeG modelling

Chapter 3. PROPOSED NASH EQUILIBRIUM

PROBLEM

This chapter presents the mathematical model implemented in the CEVESA simulation framework to represent the expansion and operation of both DeG in the MIBEL electricity market. The model, originally developed in [8], is based on a Conjectural Nash equilibrium formulation that jointly captures the decision-making of generation companies (GENCOs) and active customers (prosumers) in the wholesale electricity market.

When a sufficiently large share of customers installs behind-the-meter generation and battery storage, their aggregate behaviour reshapes the demand profile seen by centralised generators, alters the energy balance constraint, and therefore endogenously modifies the equilibrium price. Ignoring this feedback may lead to systematic underestimation of price effects.

The Generalised Nash Equilibrium Problem (GNEP) proposed in [8] and used in this work addresses this issue by simultaneously representing two sets of agents operating in the same market: on the one hand, GENCOs that seek to maximise their profits. On the other hand, DeG customer segments minimise their total energy costs by deciding on how much energy to withdraw from or inject into the grid. Both sets of agents are linked through the energy market balance constraint, which endogenously determines the hourly electricity price as the dual variable of that constraint. This coupling is what makes the problem a Nash equilibrium, where no agent can unilaterally improve their objective by deviating from the equilibrium decisions, given the decisions of all other agents also at the equilibrium.

To represent different degrees of market power among agents, the model incorporates price-response CVs. This parameter captures the degree to which each agent anticipates that its own decisions will affect the market price. With null CVs, the equilibrium reduces to a perfectly competitive market. With non-zero CVs, agents behave strategically, consistent

with a market structure in which a number of agents can influence prices, such as an oligopoly. CEVESA can represent this market agents and conjecture, making it a particularly suitable model for the purposes of this thesis, which aims to analyse the effects of different assumptions about prosumer strategic awareness on market outcomes.

This chapter is organised as follows. Section 3.1 presents the model hypotheses. Section 3.2 formulates the objective functions of GENCOs and DeG. Section 3.3 describes the constraints that define the feasible region of each agent. Section 3.4 presents the first-order Nash equilibrium conditions, including the CVs framework and its geometric interpretation through residual demand and supply curves, together with the explicit Karush-Kuhn-Tucker (KKT) conditions incorporating the conjectures. Section 3.5 presents the Nash equilibrium formulation and its resolution methodology via an equivalent cost minimisation problem derived from the KKT optimality conditions. Finally, Section 3.6 briefly discusses the incorporation of detailed operational constraints.

3.1 MODEL HYPOTHESES

The mathematical formulation presented in this chapter is built upon a set of structural hypotheses that define the scope, limitations, and operating assumptions of the model. These hypotheses are as follows:

- **Access tariffs as exogenous inputs.** In this energy-only version of the model, grid access tariffs are treated as fixed parameters provided externally. Their effect on agent decisions is therefore captured, but the model does not adjust tariff values in response to DeG penetration. It is important to emphasise, however, that the electricity price itself is not exogenous. Customers respond to the integral tariff, which combines the fixed network access tariff with the electricity price, and this electricity price is endogenously determined by the market equilibrium, as described below. The analysis of tariff feedback and the potential emergence of the death spiral is left for an upper-level bilevel formulation.
- **Active customers with pre-installed DeG capacity.** Each customer segment is assumed to have behind-the-meter DeG technologies already installed, specifically solar

photovoltaic (PV) panels and battery storage facilities, in accordance with the 2030 targets established by the Spanish and Portuguese NECPs. Investment decisions are not endogenously optimised in this work; instead, the installed capacity of each segment is taken as an exogenous input.

- **Customer segmentation.** DeG customers are categorised into segments c according to their type (residential, industrial, or commercial) and economic activity. All customers within a segment are assumed to behave identically, so each segment is treated as a single representative agent. Each segment has an hourly base demand profile $D_{c,h,y}$ that represents the consumption they would have in the absence of any DeG installation.
- **Grid interaction scheme.** Purchases from the grid and sales of surplus electricity to the grid are both valued at the hourly market price. In addition, customers pay a regulated access tariff composed of: (i) a volumetric buying term $TV_{c,y}$ [€/MWh] applied to energy withdrawn from the grid; (ii) a volumetric selling term $TC_{c,y}$ [€/MWh] applied to energy injected into the grid; and (iii) a power-related term $TP_{c,y}$ [€/MW] (demand charge) applied annually to the customer's contracted power $cp_{c,y}$, defined as the maximum hourly net power exchange with the grid in that year. This tariff structure is a simplified version of real-world tariffs.
- **No load demand response.** Aside from the capability to invest in DeG and batteries, no additional demand response or load-shifting mechanisms are modelled for customers. Therefore, flexibility on the demand side arises exclusively from the operational dispatch of the installed batteries. The modelling of electric vehicles and hydrogen as an energy vector is outside the scope of this thesis.
- **Network losses.** Transmission and distribution losses are modelled using a simplified DC-like single-bus representation in which losses are quadratic functions of the energy flows. To keep the model computationally tractable, distribution losses are approximated using a linearised curve fitted to match the average loss rates of the Spanish system. This approach avoids the computational complexity of full network modelling while still capturing the asymmetry between self-consumption (no distribution losses) and grid exports (losses in both directions).

3.2 OBJECTIVES FUNCTIONS

The mathematical formulation presented throughout this chapter is entirely extracted from [8], to which the reader is referred for the full derivation and theoretical proofs. The model is adopted as described in [8] and applied to the Iberian system under the scenario assumptions described in Chapter 4.

3.2.1 GENERATION COMPANIES

Each GENCO g seeks to maximise its profits over the simulation horizon by choosing the hourly dispatch $q_{t,g,h,y}$ [MW] of its generation units and the annual investment in new capacity $p_{t,g,y}$ [MW]. Profits consist of revenues from selling energy at the market price $\lambda_{h,y}^E$ [€/MW], minus variable operation costs $VC_{t,g,y}$ [€/MW], and investment costs $IC_{t,g,y}$ [€/MW]. Therefore, the objective function of each GENCO g is expressed as:

$$\text{Max} \left\{ \sum_{t,h,y} (\lambda_{h,y}^E \cdot q_{t,g,h,y} - VC_{t,g,y} \cdot q_{t,g,h,y}) - \sum_{t,y} IC_{t,g,y} \cdot p_{t,g,y} \right\}, \forall g \quad (1)$$

The first summation in (1) represents the hourly net margin between energy revenues and variable costs, summed across all generation technologies t , hours h , and years y . The second term accounts for total investment costs over the planning horizon. The problem is solved for each GENCO independently, subject to the constraints described in Section 3.3.

3.2.2 DEG CUSTOMERS

Each DeG customer segment c minimises its total net energy costs over the simulation horizon. These costs include: the demand charge paid for contracted power, the investment costs for DeG capacity, and the hourly costs of purchasing energy from the grid (at the market price plus the volumetric buying tariff). Incomes arise from selling surplus generation to the grid (at the market price minus the volumetric selling tariff). The objective function of each customer segment c is:

$$\text{Min} \left\{ \sum_y TP_{c,y} \cdot cp_{c,y} + \sum_{t,y} IC_{t,c,y} \cdot p_{t,c,y} + \sum_{h,y} [(\lambda_{h,y}^E + TV_{c,y}) \cdot dq_{c,h,y} - (\lambda_{h,y}^E - TC_{c,y}) \cdot eq_{c,h,y}] \right\}, \forall c \quad (2)$$

The first term in (2) is the annual demand charge cost $TP_{c,y}$ [€/MW], associated with the customer's contracted power $cp_{c,y}$ [MW]. The second term captures total DeG investment costs over the planning horizon, computed as the sum of each technology's investment cost $IC_{t,c,y}$ [€/MW] multiplied by the installed capacity $p_{t,c,y}$ [MW], summed across all technologies and years. The third term represents the hourly cost of purchasing energy from the grid: for each unit of energy bought $dq_{c,h,y}$ [MW] the customer pays both the wholesale market price $\lambda_{h,y}^E$ [€/MW] and the volumetric buying tariff $TV_{c,y}$ [€/MW]. The fourth term represents the hourly income from selling surplus energy to the grid: for each unit injected $eq_{c,h,y}$ [MW] the customer receives the wholesale market price $\lambda_{h,y}^E$ [€/MW] but must pay the volumetric selling tariff $TC_{c,y}$, which is discounted from the revenue.

3.3 CONSTRAINTS

3.3.1 INSTALLED CAPACITY CONSTRAINT

For all generation units, whether belonging to GENCOs or to DeG customer segments, the hourly production cannot exceed the installed capacity. In its simplified form this is expressed as:

$$q_{t,s,h,y} \leq p_{t,s,y} \cdot \lambda_{t,c,h,y}^{PQ}, s \in C \cup G \quad (3)$$

where s denotes either a customer segment ($s \in C$) or a GENCO ($s \in G$), and $p_{t,s,y}$ [MW] is the installed capacity of technology t for agent s in year y . The dual variable of this constraint is $\lambda_{t,c,h,y}^{PQ}$ [€/MW], which represents the economic value of having one additional MW of

installed capacity available at that hour. That is, how much the total system cost would decrease if the capacity limit were relaxed by 1 MW.

3.3.2 CUSTOMER BALANCE CONSTRAINT

Each customer segment must satisfy its hourly electricity demand $D_{c,h,y}$ [MW] either by drawing from the grid $dq_{c,h,y}$ [MW] or by consuming its own DeG production $\sum_t q_{t,c,h,y}$ [MW]. If production exceeds demand, the surplus $eq_{c,h,y}$ [MW] is injected into the grid:

$$\sum_t q_{t,c,h,y} + dq_{c,h,y} = D_{c,h,y} + eq_{c,h,y}; \lambda_{c,h,y}^{CB} \quad (4)$$

The dual variable of (4) is $\lambda_{c,h,y}^{CB}$ [€/MW]. Note that the cost-minimisation nature of the customer problem ensures that $dq_{c,h,y}$ and $eq_{c,h,y}$ are never simultaneously positive: buying and selling at the same time would be suboptimal.

3.3.3 CONTRACTED POWER DEFINITION CONSTRAINT

The annual contracted power $cp_{c,y}$ [MW] is defined as the maximum hourly net power that the customer either withdraws from or injects into the grid during that year. This value determines the demand charge payment. The constraint is:

$$dq_{c,h,y} + eq_{c,h,y} \leq cp_{c,y}; \lambda_{c,h,y}^{CP} \quad (5)$$

The dual variable of (5) is $\lambda_{c,h,y}^{CP}$ [€/MW]. At the optimum, $cp_{c,y}$ takes the value of the largest hourly power exchange across all hours of year y , since reducing $cp_{c,y}$ below that value would violate (5) and increasing it above that value would unnecessarily increase the demand charge cost.

3.3.4 MARKET ENERGY BALANCE CONSTRAINT

All individual optimisation subproblems are coupled through the hourly market energy balance constraint. This constraint requires that total CG production plus surplus

injections from all DeG customer segments exactly covers total demand withdrawn from the grid by all customer segments:

$$\sum_{t,g} q_{t,g,h,y} + \sum_c eq_{c,h,y} = \sum_c dq_{c,h,y} : \lambda_{h,y}^E \quad (6)$$

The dual variable of (6) is the energy market price $\lambda_{h,y}^E$ [€/MW], which is endogenously determined as part of the model solution. This is the key structural feature that distinguishes the proposed model from approaches that use exogenous prices: the price is not an input but an output of the equilibrium. Constraint (6) is the game-defining linking constraint of the Nash equilibrium as it couples the decisions of all agents and makes any single agent's optimal strategy dependent on the decisions of all others.

3.4 FIRST ORDER NASH EQUILIBRIUM CONDITIONS

As demonstrated in Annex II, the first KKT optimality conditions of the above optimisation problems are:

$$\begin{aligned} \lambda_{h,y}^E &= VC_{t,g,y} - \frac{\partial \lambda_{h,y}^E}{\partial q_{t,g,h,y}} \cdot q_{t,g,h,y} + \lambda_{t,g,h,y}^{PQ} \\ \lambda_{t,c,h,y}^{PQ} + \lambda_{c,h,y}^{CB} &= 0 \\ TP_{c,y} &= \sum_h \lambda_{c,h,y}^{CP} \\ \lambda_{h,y}^E + TV_{c,y} &= \frac{\partial \lambda_{h,y}^E}{\partial dq_{c,h,y}} \cdot (eq_{c,h,y} - dq_{c,h,y}) - \lambda_{c,h,y}^{CB} - \lambda_{c,h,y}^{CP} \\ \lambda_{h,y}^E - TC_{c,y} &= -\frac{\partial \lambda_{h,y}^E}{\partial eq_{c,h,y}} \cdot (eq_{c,h,y} - dq_{c,h,y}) - \lambda_{c,h,y}^{CB} + \lambda_{c,h,y}^{CP} \\ IC_{t,s,y} &= \sum_h \lambda_{t,s,h,y}^{PQ}, s \in C \cup G \end{aligned} \quad (7)$$

$$\begin{aligned}
\lambda_{c,h,y}^{CB} \perp \sum_t q_{t,c,g,y} - eq_{c,h,y} + dq_{c,h,y} - D_{c,h,y} &= 0 \\
0 \leq \lambda_{t,s,h,y}^{PQ} \perp q_{t,s,h,y} - p_{t,s,y} &= 0 \\
0 \leq \lambda_{c,h,y}^{CP} \perp dq_{c,h,y} + eq_{c,h,y} - cp_{c,y} &\leq 0 \\
\lambda_{h,y}^E \perp \sum_{t,g} q_{t,g,h,y} + \sum_c (eq_{c,h,y} - dq_{c,h,y}) &= 0
\end{aligned} \tag{7}$$

The partial derivatives of $\lambda_{h,y}^E$ that appear in the KKT conditions in (7) represent the anticipated marginal price response of each agent to a unitary change in its own decisions. These are the so-called CVs, and they are the key parametric inputs that allow the model to transition continuously between perfectly competitive and oligopolistic equilibrium. Their specific definitions, derived from the geometry of the residual demand and supply curves, are presented in Sections 3.4.1 and 3.4.2 for generators and customers respectively, are then substituted back into (7) in Section 3.4.3 making the effect of each agent's CV explicit in the resulting optimality conditions.

3.4.1 CONJECTURAL VARIATIONS: THE GENERATOR'S PERSPECTIVE

In the electricity wholesale market, a generator submits a quantity to the market and the price is determined endogenously by the balance between total supply and total demand. The relevant concept for a strategic generator is therefore not the full market demand, but the demand it effectively faces after all competitor generators have already supplied their share, as explained in [21]. This quantity is called the residual demand, defined as:

$$RD_{g,h,y}(\lambda) = D_{g,h,y}(\lambda) - S_{-g,h,y}(\lambda) \tag{8}$$

where $D_{g,h,y}(\lambda)$ is the aggregate market demand and $S_{-g,h,y}(\lambda)$ is the aggregate supply of all generators except g . The conjectural variation (CV) $\theta_{g,h,y}^E$ is defined as the negative of the slope of the inverse of the residual demand curve $RD_{g,h,y}(\lambda)$: since this slope is itself negative, the minus sign in front of it makes $\theta_{g,h,y}^E$ non-negative, consistent with the convention adopted throughout this thesis that every conjectural variation, for generators and customers alike, is used as a non-negative parameter, i.e:

$$\theta_{g,h,y}^E = - \left. \frac{\partial RD_{g,h,y}^{-1}(\lambda)}{\partial \lambda} \right|_{\lambda=\lambda_{h,y}^E} = - \frac{\partial \lambda_{h,y}^E}{\partial (\sum_t q_{t,g,h,y})} \quad (9)$$

Because the residual demand curve, as shown in Figure 2, is downward sloping, its raw slope $\frac{\partial RD_{g,h,y}^{-1}(\lambda)}{\partial \lambda}$ is negative. The minus sign in the definition of $\theta_{g,h,y}^E$ therefore converts this negative slope into a non-negative value, so that $\theta_{g,h,y}^E$ is always greater than or equal to zero. This convention is applied consistently throughout the thesis: every conjectural variation, whether for generators or for consumers, is defined and used as a non-negative parameter in the model.

Note that (9) is only true at the equilibrium point where it is assumed that λ coincides with the electricity market price $\lambda_{h,y}^E$, and the optimal electricity generated by company g , $\sum_t q_{t,g,h,y}$ coincides, at the equilibrium, with the residual demand curve evaluated at $\lambda_{h,y}^E$.

Parameter $\theta_{g,h,y}^E$ represents the generator's estimate of how much the market price falls per additional MWh it produces. When $\theta_{g,h,y}^E = 0$, the generator believes that its production decisions have no effect on the market price, and therefore behaves as a price-taker, as in a perfectly competitive market. When $\theta_{g,h,y}^E \neq 0$, the generator anticipates a price fall and strategically reduces its output to maintain a higher price, thereby exercising market power. The magnitude of $\theta_{g,h,y}^E$ captures the degree of strategic behaviour: the higher the value, the steeper the generator perceives its residual demand curve, and the greater the price impact it anticipates from its own production decisions. Figure 2 is a schematic illustration of this construction: the curves shown are qualitative and drawn for illustrative purposes only, not computed from the model's actual numerical data. The slope of the residual demand curve at that point equals $\theta_{g,h,y}^E$: the steeper the curve, the more the price falls per additional MWh produced, and the greater the generator's market power.

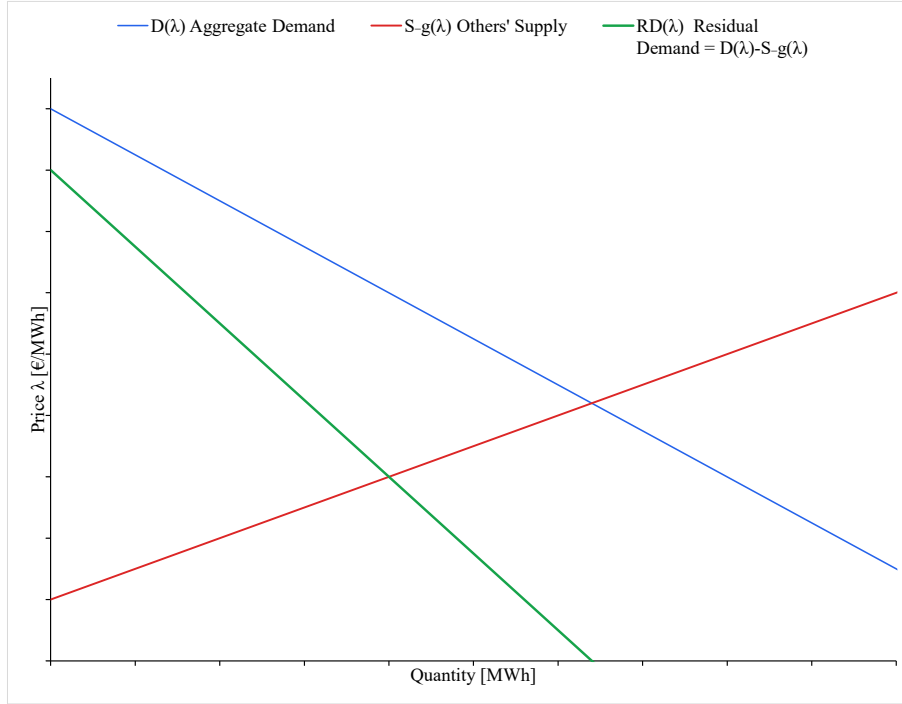


Figure 2: Construction of the residual demand curve for generator g

3.4.2 THE CONJECTURAL VARIATIONS: THE CUSTOMER'S PERSPECTIVE

From the perspective of a prosumer, the relevant concept depends on whether the customer is a net seller or a net buyer in a given hour. If the customer is a net seller, that is, its own DeG production exceeds its demand and it injects surplus energy into the grid, it faces the same market structure as a generator: additional injections put downward pressure on the price. In this case, the CV of the customer as seller coincides with the slope of the residual demand curve as described in Section 3.4.1. Therefore, if the customer is a net seller, the CV $\theta_{c,h,y}^{EQ}$ of that prosumer is none other than the conjecture described in the previous subsection and expressed in (10), that is:

$$\theta_{c,h,y}^{EQ} = -\frac{\partial \lambda_{h,y}^E}{\partial e q_{c,h,y}} \quad (10)$$

When the prosumer is instead a net buyer, withdrawing more energy from the grid than it injects, the relevant construct is the residual supply curve, defined as the aggregate

market supply minus the grid purchases of all other customers, which is mathematically expressed as:

$$RS_{c,h,y}(\lambda) = S_{h,y}(\lambda) - D_{-c,h,y}(\lambda) \quad (11)$$

where $S_{h,y}(\lambda)$ is the aggregate market supply and $D_{-c,h,y}(\lambda)$ is the aggregate demand of all customers except c . In this case, the CV $\theta_{c,h,y}^{DQ}$ coincides directly with the slope of the inverse of that curve, which is positive, that is:

$$\theta_{c,h,y}^{DQ} = \left. \frac{\partial RS_{c,h,y}^{-1}(\lambda)}{\partial \lambda} \right|_{\lambda=\lambda_{h,y}^E} = \frac{\partial \lambda_{h,y}^E}{\partial dq_{c,h,y}} \quad (12)$$

Again, this last equality is only true at the equilibrium point where variable λ coincides with the electricity market price $\lambda_{h,y}^E$, and the optimal injection to the grid $dq_{c,h,y}$ by consumer c with the residual supply curve evaluated at price $\lambda_{h,y}^E$.

Figure 3, as with Figure 2 is a schematic illustration: the curves shown are qualitative and drawn for illustrative purposes only, not computed from the model's actual numerical data. Figure 3 illustrates the construction of the residual supply curve from the customer's perspective. When a customer increases its grid purchases, it drives the market price up. The steeper the residual supply curve, the larger this price increase.

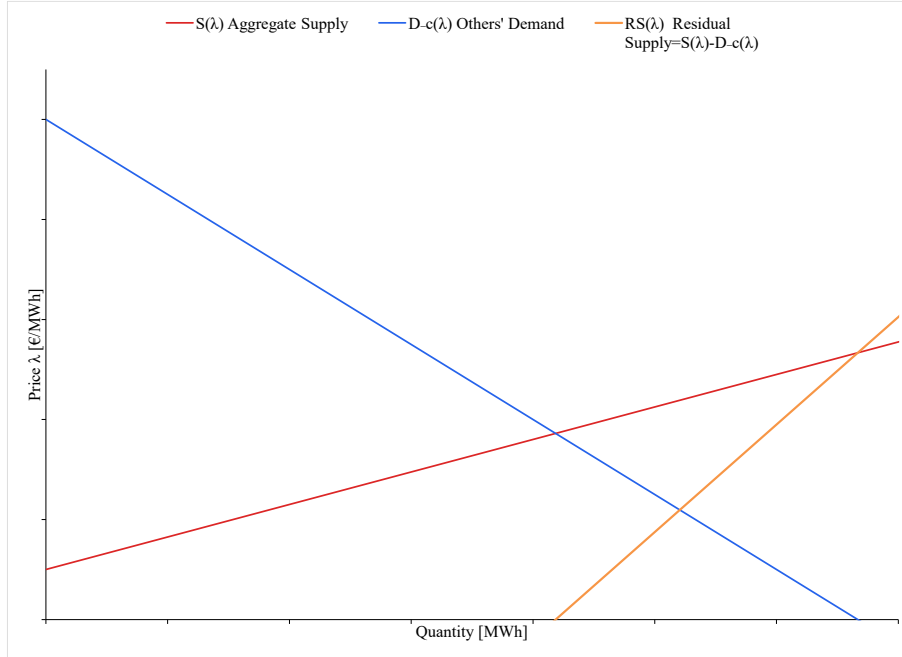


Figure 3: Construction of the residual supply curve for customer c

Following [8], the price response is assumed symmetric whether the customer acts as a buyer or as a seller, i.e:

$$\theta_{c,h,y}^{DQ} = \theta_{c,h,y}^{EQ} = \theta_{c,h,y}^E \quad (13)$$

The assumption in (13) is justified by the fact that both a unitary increase in grid injections and a unitary decrease in grid purchases have the same effect on the other market participants. Under this assumption, a single parameter $\theta_{c,h,y}^E$ captures the strategic behaviour of customer c in both directions.

3.4.3 THE KKT CONJECTURAL OPTIMALITY CONDITIONS

The CV parameters defined in the previous sections can now be substituted directly into the first-order KKT conditions of the Nash equilibrium problem. Replacing the price-partial derivatives of $\lambda_{h,y}^E$ in (7) with the CV definitions from (9) and (13), the KKT conditions become:

$$\begin{aligned}
\lambda_{h,y}^E &= VC_{t,g,y} + \theta_{g,h,y}^E \cdot q_{t,g,h,y} + \lambda_{t,g,h,y}^{PQ} \\
\lambda_{t,c,h,y}^{PQ} + \lambda_{c,h,y}^{CB} &= 0 \\
TP_{c,y} &= \sum_h \lambda_{(c,h,y)}^{CP} \\
\lambda_{h,y}^E + TV_{c,y} &= \theta_{c,h,y}^E \cdot (eq_{c,h,y} - dq_{c,h,y}) - \lambda_{c,h,y}^{CB} - \lambda_{c,h,y}^{CP} \\
\lambda_{h,y}^E - TC_{c,y} &= \theta_{c,h,y}^E \cdot (eq_{c,h,y} - dq_{c,h,y}) - \lambda_{c,h,y}^{CB} + \lambda_{c,h,y}^{CP} \\
IC_{t,s,y} &= \sum_h \lambda_{t,s,h,y}^{PQ}, s \in C \cup G \\
\lambda_{c,h,y}^{CB} \perp \sum_t q_{t,c,g,y} - eq_{c,h,y} + dq_{c,h,y} - D_{c,h,y} &= 0 \\
0 \leq \lambda_{t,s,h,y}^{PQ} \perp q_{t,s,h,y} - p_{t,s,y} &= 0 \\
0 \leq \lambda_{c,h,y}^{CP} \perp dq_{c,h,y} + eq_{c,h,y} - cp_{c,y} &\leq 0 \\
\lambda_{h,y}^E \perp \sum_{t,g} q_{t,g,h,y} + \sum_c (eq_{c,h,y} - dq_{c,h,y}) &= 0
\end{aligned} \tag{14}$$

The key interpretative insight of these conditions lies in how the conjectures modify the effective price perceived by each agent:

- For a GENCO, the term $\theta_{g,h,y}^E \cdot q_{t,g,h,y}$ inflates the effective marginal cost above its true variable cost, inducing the generator to increase prices and therefore produce less than it would under perfect competition.
- For a customer, the term $\theta_{c,h,y}^E \cdot (eq_{c,h,y} - dq_{c,h,y})$ modifies the effective net price perceived by the customer:
 - When the customer is a net buyer ($dq_{c,h,y} > 0$ and $eq_{c,h,y} = 0$), this term $-\theta_{c,h,y}^E \cdot dq_{c,h,y}$ increases the perceived buying cost $\lambda_{h,y}^E + TV_{c,y}$ by the exercise of the consumer's market power, disincentivising the purchase of energy from the grid (to decrease the buying price) and therefore incentivising greater self-consumption.
 - When it is a net seller ($eq_{c,h,y} > 0$ and $dq_{c,h,y} = 0$), the term $\theta_{c,h,y}^E \cdot eq_{c,h,y}$ decreases the perceived selling price $\lambda_{h,y}^E - TC_{c,y}$, increasing its incentive to reduce the electricity sold into the grid (to increase the selling price) and therefore disincentivising the self-consumption. It is worth noting that the sign convention

adopted in the customer conditions is consistent with the cost-minimisation objective: the term $(eq_{c,h,y} - dq_{c,h,y})$ is positive when the customer is a net seller and negative when it is a net buyer, and the CV $\theta_{c,h,y}^E$ is always non-negative.

As can be observed from the expressions above, when all CVs are zero ($\theta = 0$ for all agents), the above conditions reduce to the standard competitive equilibrium conditions, where no agent anticipates any effect on the market price.

3.5 NASH EQUILIBRIUM FORMULATION AND RESOLUTION METHODOLOGY

Directly solving the KKT conditions of the proposed GNEP may be computationally intractable. The key theoretical contribution of [8], which this work reproduces, is the proof that this GNEP can be reformulated as the following equivalent single-level quadratic minimisation problem:

$$\begin{aligned}
 \text{Min} \left(\sum_g \left\{ \sum_{h,y} \left(\sum_t VC_{t,g,y} \cdot q_{t,g,h,y} + \theta_{g,h,y}^E \cdot 0.5 \cdot \left(\sum_t q_{t,g,h,y} \right)^2 \right) \right. \right. \\
 \left. \left. + \sum_{t,y} IC_{t,g,y} \cdot p_{t,g,y} \right\} \right. \\
 \left. + \sum_c \left\{ \sum_y TP_{c,y} \cdot cp_{c,y} + \sum_{t,y} IC_{t,c,y} \cdot p_{t,c,y} \right. \right. \\
 \left. \left. + \sum_{h,y} [TV_{c,y} \cdot dq_{c,h,y} + TC_{c,y} \cdot eq_{c,h,y} + \theta_{c,h,y}^E \cdot 0.5 \right. \right. \\
 \left. \left. \cdot (eq_{c,h,y} - dq_{c,h,y})^2 \right] \right\} \Bigg) \tag{15}
 \end{aligned}$$

subject to constraints (3)-(6).

The theoretical proof of this equivalence, as well as the entire mathematical framework presented in this chapter are original contributions of [8], to which the reader is referred for the full derivation. As mentioned, the original contribution of this thesis lies in the design and analysis of the case study and scenarios applied to the Iberian electricity market under the NECPs 2030 targets, as described in Chapter 4.

3.6 OTHER CONSTRAINTS

As noted in [8], the simplified formulation presented in Sections 3.2 to 3.5 omits several detailed operational constraints that are included in the full model implemented in CEVESA. The complete mathematical formulation of these constraints is provided in [8] and is not reproduced here. The equivalence between the Nash equilibrium and the minimisation problem (15) continues to hold in the presence of these additional constraints, since they are all agent-specific and do not introduce any coupling between the strategies of CG and DeG agents. The main families of additional constraints are described below.

- Thermal unit constraints represent the unit commitment behaviour of dispatchable thermal technologies, including open-cycle and combined-cycle gas turbines, coal, and nuclear units. These constraints enforce minimum and maximum production levels per committed unit, upward and downward power ramp rates between consecutive hours, and the binary or integer logic governing start-up and shut-down decisions. The associated variable costs of start-ups, shutdowns, and ramping are incorporated into the thermal variable cost term.
- Hydro unit constraints govern the operation of hydroelectric plants, including both generating and pumping modes. Since hydro resources are managed on a weekly schedule based on historical inflow data, the key coupling constraint is a maximum weekly energy production limit that prevents over-exploitation of the stored water resource. No spatial coupling across different hydro basins is modelled, consistent with the operational, dispatch-focused scope of this thesis.
- Renewable plant constraints limit the output of solar PV and wind technologies to the product of installed capacity and an exogenous hourly utilisation factor, reflecting the

variable nature of these resources. For DeG solar PV installed behind the meter, the constraint takes the form of an inequality rather than an equality, allowing for lower energy production to represent the energy spillage when self-consumption is insufficient to absorb local generation.

- Energy storage constraints model battery technologies as a pair of charge and discharge sub-units with equal power capacity ratings. The state of charge is tracked hourly through an energy balance that accounts for round-trip efficiency losses in both the charging and discharging directions. The maximum storable energy is bounded by the product of installed power capacity and the power-to-energy ratio of the battery, which was set to two hours in accordance with [8].
- Transmission and distribution loss constraints extend the simplified energy balance (6) to account for network losses. Transmission losses are modelled as a fixed percentage of delivered energy. Distribution losses are represented as a quadratic function of the net power exchanged between each customer and the network, linearised through a piecewise outer approximation. This formulation captures the asymmetry between self-consumption (no distribution losses) and grid exports (losses incurred in both the distribution and transmission segments).
- System balance constraints extend the basic market clearing equation (6) to account for energy spillages, which may occur when renewable generation exceeds total system demand. Demand is always met in the model, as a non-served energy (NSE) variable is activated to avoid infeasibilities, penalised at the maximum regulatory price (5,000 €/MWh).

Chapter 4. CASE STUDY

This chapter presents the case study conducted using the CEVESA simulation framework for the year 2030, under the capacity targets defined by the Spanish and Portuguese NECPs. The chapter first describes the input data and the three scenarios designed to assess the role of generator and consumer CVs on market prices, grid exchanges and capture price. It then characterises the overall behaviour of the Iberian system under the NECP targets, through the analysis of the annual generation mix and the price duration curve. Unless otherwise stated, all results correspond to the simulation of the entire year 2030.

The model is run allowing energy defect and excess, with hydraulic dispatch enabled, thermal ramps, and start-up and shutdown costs. A two-step solving procedure is also applied, whereby zero-cost technologies are fixed in a second step to ensure their dispatch is correctly assigned and avoid numerical indeterminacy in the optimisation. The model is implemented in GAMS and solved within the CEVESA simulation tool, jointly developed by the *Instituto de Investigación Tecnológica* at *Universidad Pontificia Comillas* and the *Instituto de Engenharia de Sistemas e Computadores, Tecnologia e Ciência* (INESC TEC), which provides the complete implementation of the MIBEL market. The input data and scenario design are prepared using Microsoft Excel, from which all data are fed into the GAMS model. The simulations have been carried out on a virtual machine based on an AMD EPYC-Milan processor with 16 cores and 64 GB of RAM. The annual simulation of a full scenario takes approximately two hours to solve.

4.1 INPUT DATA

The following section presents the input data related to DeG, which is common to all case studies considered in this thesis. For all remaining input data, the reader is referred to [8] for a detailed description of their sources and values.

4.1.1 HOURLY DEMAND PROFILES

Hourly demand profiles by consumer type have been constructed from data published in [22] which is the only source found that provides numerical data with consumer segment disaggregation for the Spanish peninsular electricity system. The model used in the simulations distinguishes twelve consumer types: IMET (metallurgical and steel industry), ICHE (chemical industry), IFOOD (food industry), IWOOD (wood and paper industry), IMIN (extractive and mining industry), CSER (remaining industry, services, offices and retail), CRES (restaurant sector), CFOOD (food retail), RSF (households without electric heating on standard tariff), RB (households without electric heating on base tariff), RSFH (households with electric heating on standard tariff), and RBH (households with electric heating on base tariff).

However, [22] does not provide complete hourly demand curves for each consumer type. Instead, it only reports two reference values: the share of each consumer type over the aggregate daily demand profile, and its consumption at the system peak. The hourly demand profile for each consumer segment was constructed by scaling the aggregate system daily load curve from [22] by each segment's participation weight, so that the resulting per-segment profiles reproduce both the reported segment share and the peak-hour consumption. The profiles are expressed as hourly fractions of each segment's total daily demand and are stored in the model input file as dimensionless coefficients, which are subsequently multiplied by the corresponding annual energy demand to obtain absolute hourly demand values. Finally, in the absence of equivalent data for Portugal, as [22] covers exclusively the Spanish peninsular system, the same set of adapted profiles used for Spain has been applied to Portugal. The resulting hourly profiles by consumer type are shown in Figure 4.

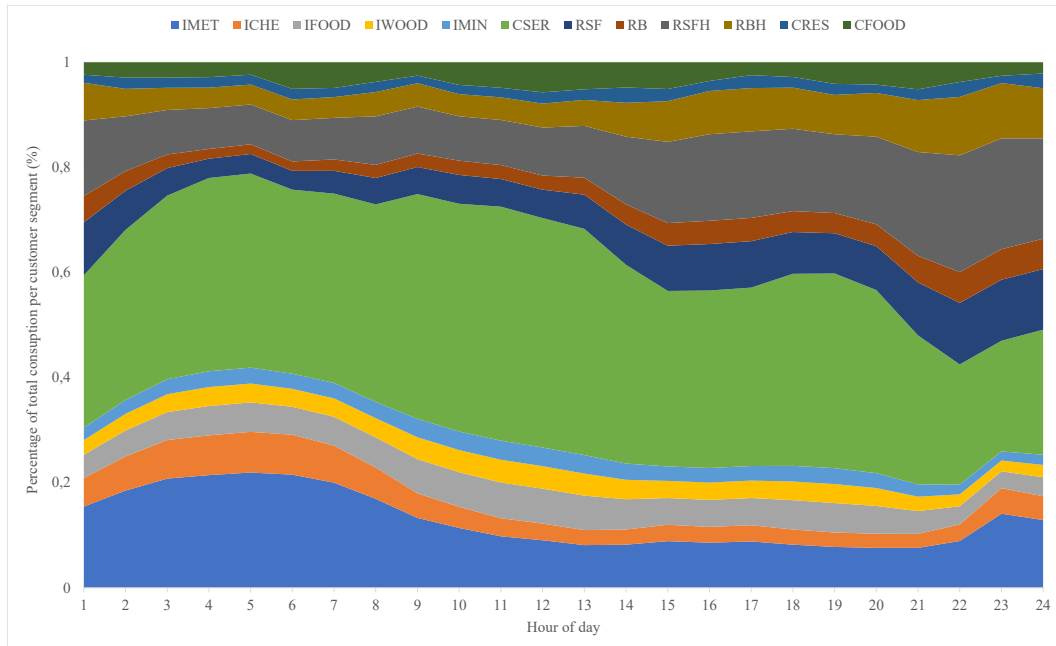


Figure 4: Percentage of total consumption per customer segment

4.1.2 INSTALLED DEG CAPACITY

Spain's NECP [3] and Portugal's NECP [4] define their self-consumption targets in terms of installed self-consumption capacity: 19 GW for Spain and 4.3 GW for Portugal by 2030. Both values refer to total installed DeG capacity of behind-the-meter self-consumption systems. This total capacity has been split equally between solar PV panels and battery storage: 9.5 GW and 2.15 GW respectively are assigned to solar PV for Spain and Portugal. The remaining 9.5 GW and 2.15 GW, corresponding to battery storage, have been distributed across consumer segments as follows: 75% has been allocated to industrial consumers (IMET, ICHE, IFOOD, IWOOD and IMIN), given that these segments are less segregated and therefore expected to exercise greater market power. The remaining 25% has been assigned to the rest of consumer segments. Within each group, capacity has been distributed proportionally to each segment's share of total daily demand, as shown in Figure 5, which has been constructed based on Figure 4. The resulting DeG capacity allocation across segments and countries is shown in Figure 6 for Spain and Figure 7 for Portugal.

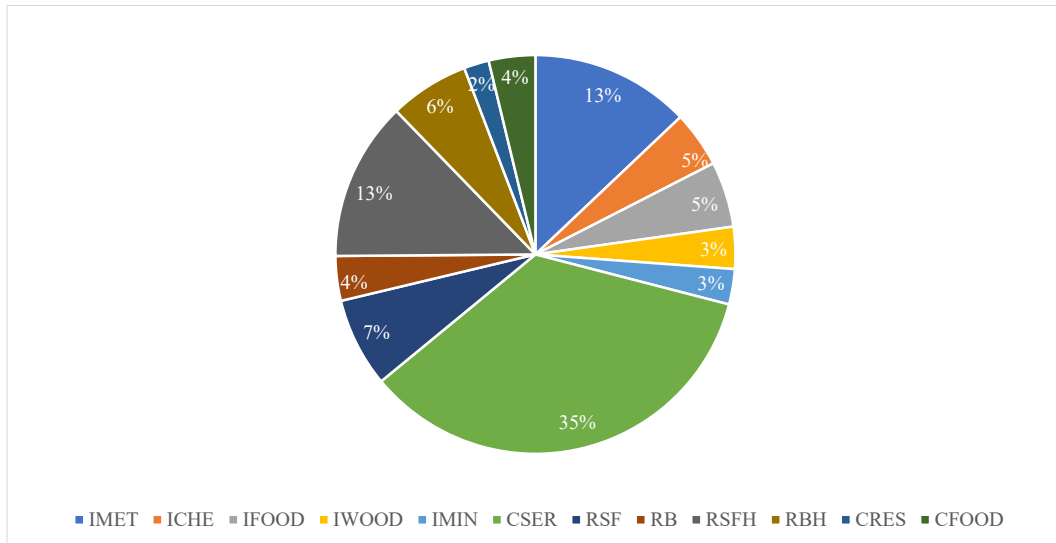


Figure 5: Share of total energy demand by consumer segment in Spain and Portugal.

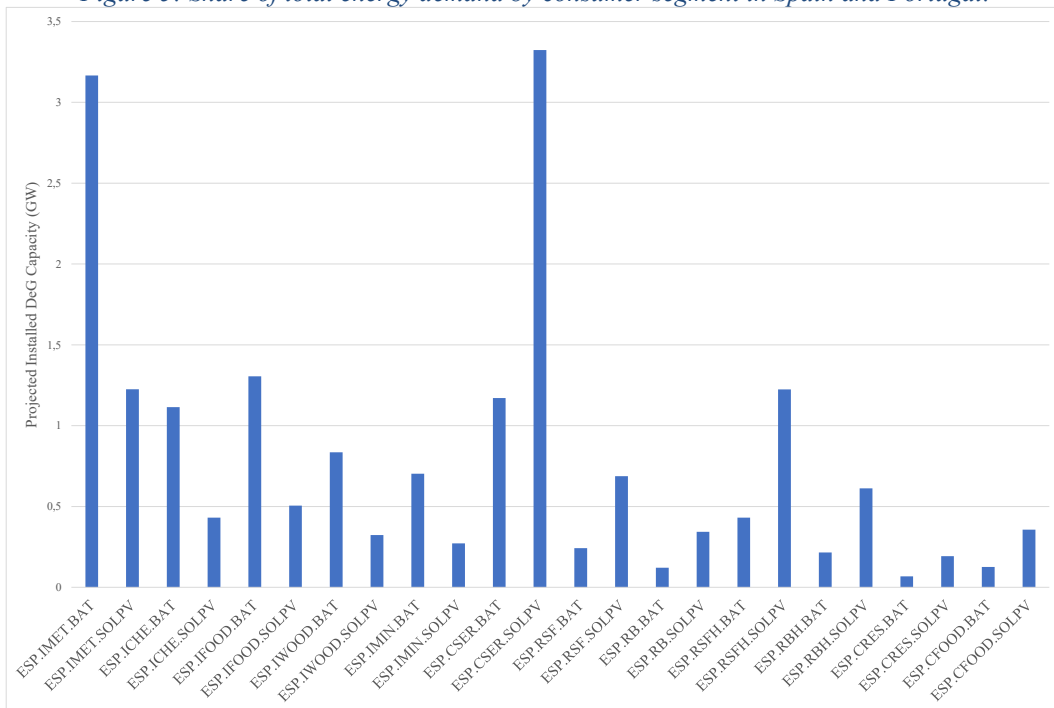


Figure 6: Estimated Installed DeG Capacity (GW) by Consumer Type in Spain (ESP) in 2030

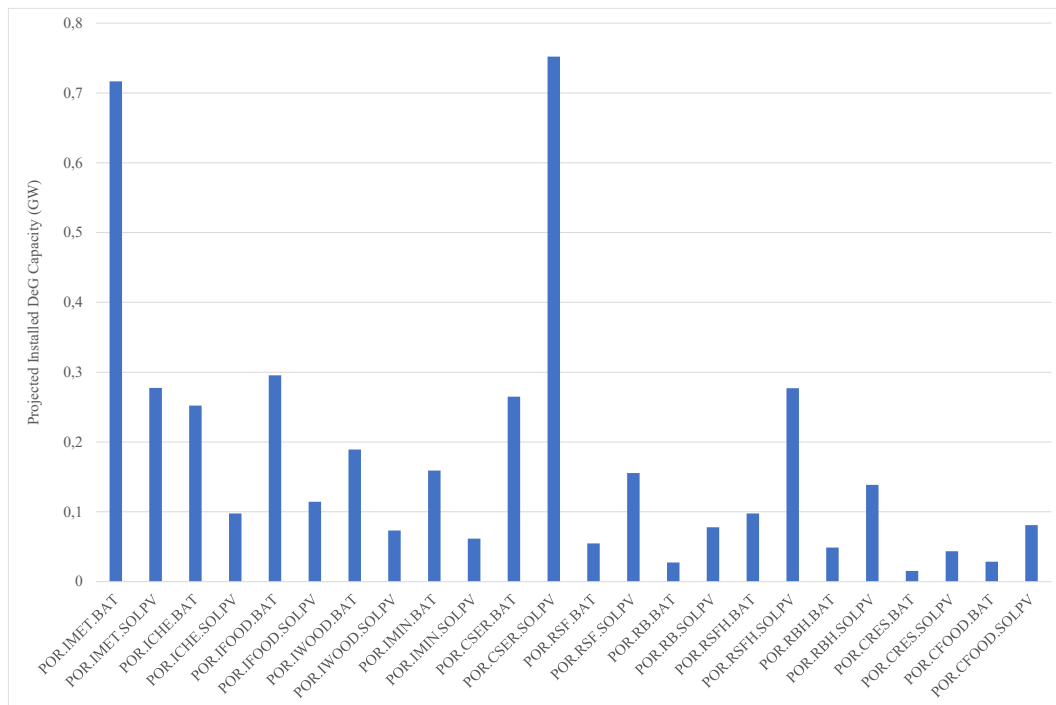


Figure 7: Estimated Installed DG Capacity (GW) by Consumer Type in Portugal (POR) in 2030

4.1.3 GRID ACCESS TARIFFS

As mentioned, the grid access tariff parameters applied to each consumer segment include a volumetric buying term TV [€/MWh], a volumetric selling term TC [€/MWh], and a demand charge term TP [€/MW]. All three terms appear directly in the customer objective function (2). The tariff values applied in this case study are taken from [8], specifically from the scenario corresponding to approximately 67% of grid-access tariff revenues recovered through the demand charge term, which was identified in [8] as broadly representative of the Spanish grid-access tariff structure at the time of that study. It should be noted that [8] was published some years before the present thesis, and no more recent equivalent calibration of the Spanish tariff structure has been used to update these values; they are kept deliberately, as a consistent basis for comparison with [8], rather than as an up-to-date representation of the current tariff structure. In [8], tariff levels were calibrated so that total tariff revenues match the regulated system costs of the Spanish electricity sector, under the assumption that no decentralised generation is installed. The values used are shown in Table 2.

	TV (€/MWh) = TC (€/MWh)	TP (€/kW/year)
IMET	14.05	50.04
ICHE	14.05	50.04
IFOOD	14.05	50.04
IWOOD	14.05	50.04
IMIN	14.05	50.04
CSER	10.53	52.07
CRES	10.53	52.07
CFOOD	10.53	52.07
RSF	28.13	48.64
RB	21.76	48.64
RSFH	28.13	56.82
RBH	21.76	48.64

Table 2: Grid Access Tariffs

Both the power and energy terms of the access tariffs are assumed to remain constant throughout the entire time horizon. The volumetric buying and selling tariff terms are assumed to be equal ($TV = TC$ (€/MWh)) for all consumer segments, following the approach adopted in [8].

4.1.4 DISTRIBUTION LOSSES

The model accounts for distribution network losses and applies an additional 3% loss factor to the transmission network.

4.1.5 CONJECTURES

The conjecture values ($\theta_{g,h,y}^E$ for GENCOs and $\theta_{c,h,y}^E$ for customers, both in €/MWh/MW) adopted in this case study were selected heuristically with the aim of capturing representative trends and behavioural patterns in the model outputs; a more rigorous

estimation of these parameters could be carried out using the methodology described in [23] which was out of the scope of this work.

Regarding GENCOs, the conjecture values $\theta_{g,h,y}^E$ (€/MWh/MW) assigned to each generation company were determined based on their relative size and market share within the Iberian electricity market. Three categories were established: large, mid-sized, and small generators. Endesa, Iberdrola, Naturgy and EDP were classified as large generators, given their dominant position in the Iberian market, and therefore, were assigned the highest conjecture values. EDP España and Galp were considered mid-sized generators, with a moderate but relevant market presence, and were assigned intermediate conjecture values. Finally, Tejo Energia, Turbogás and the group of other generators were classified as small generators with limited market power and were consequently assigned the lowest conjecture values.

It should be noted that this classification is used exclusively for modelling purposes, as an illustrative example rather than a statement about the real conduct of any of the companies named. The company names and market shares considered in this work are based on an apparently realistic representation of the Iberian electricity market, but they may not reflect the current or actual market position of these companies. Therefore, the assigned conjecture values should not be interpreted as an assessment of the real strategic behaviour or market power of any specific company.

The specific values assigned to each company are shown in Table 3.

Generation Company g	Country	Size	CG conjecture $\theta_{g,h,y}^E$ (€/MWh/MW)
Endesa	Spain	Large	0.005
Iberdrola	Spain	Large	0.005
Naturgy	Spain	Large	0.004
EDP	Portugal	Large	0.004

EDP España	Spain	Mid-sized	0.002
Galp	Portugal	Mid-sized	0.002
Tejo Energía	Portugal	Small	0.001
Turbogas	Portugal	Small	0.001
Other generators	Spain/Portugal	Small	0.001

Table 3: CG conjectures values for generation companies

Regarding consumers, two conjecture situations have been analysed, which correspond to the two consumer scenarios that will be described in detail in Section 4.2: null conjectures (scenario NOCONJ), in which all consumer segments are assumed to be price-takers, and non-null conjectures (scenario CUSCONJ), in which industrial consumer segments are assigned conjecture values consistent with those of GENCOs of comparable size. Residential consumers are assumed to have no market power in both cases, and therefore their conjecture values are always set to null. It should be noted that the same conjecture values have been considered for both Spain and Portugal. The conjecture values $\theta_{c,h,y}^E$ (€/MWh/MW) assigned to each customer segments are shown in Table 4.

	IMET	ICHE	IFOOD	IWOOD	IMIN	CSER	CRES	CFOOD
DeG conjecture $\theta_{c,h,y}^E$ (€/MWh/MW)	0.003	0.003	0.003	0.003	0.003	0.001	0.001	0.001

Table 4: Conjectures for DeG customers

4.2 SCENARIO DEFINITION

This section describes the scenarios analysed in this case study. All scenarios share the same input data described in Section 4.1 and are simulated for the year 2030. The scenarios are built around the 2030 self-consumption targets established in the NECPs of Spain and Portugal, as explained in Section 4.1.2. The scenarios differ in the degree of strategic behaviour of the agents, specifically in the conjecture values assigned to centralised

generators and consumer segments, and in whether grid exports (variable eq) are allowed or fixed to zero.

The conjecture values used for centralised generators are those described in Table 3 and remain fixed across all scenarios in which they are active. For consumer segments, two situations are considered: null conjectures, in which all consumer segments are assumed to be price-takers, and non-null conjectures, in which consumer segments are assigned the values shown in Table 4. The three scenarios analysed are the following:

- **CGCONJ:** grid exports free (i.e. not fixed to zero, unlike NOCONJ and CUSCONJ), generator conjectures are active, while consumer conjectures are set to zero. As a result, generators are able to exercise market power, meaning that the equilibrium does not correspond to a pure cost-minimisation outcome. Instead, the market price reflects the conjectural mark-up applied by each generator over its true variable cost, rather than the least-cost dispatch that would be obtained under a centralised system operator.
- **NOCONJ:** grid exports fixed to zero, generator and consumer conjectures set to zero. This scenario serves as the reference for the conjecture analysis. With all conjectures set to zero, all agents behave as price-takers, and no strategic behaviour is present. At the same time, fixing grid exports to zero constrains consumers to act as net buyers at all times, so battery use is limited to redistributing hourly purchases from the grid.
- **CUSCONJ:** grid exports fixed to zero, generator conjectures set to zero, non-null conjectures for customer segments (Table 4). By fixing grid exports to zero, consumers are constrained to act as net buyers at all times, so their strategic behaviour can only affect the hourly distribution of grid purchases rather than energy sales. The comparison between CUSCONJ and NOCONJ directly reveals the effect of consumer market power on grid purchases and market prices, since the two scenarios differ only in whether customer conjectures are active or not.

In NOCONJ and CUSCONJ, grid exports are fixed to zero ($eq = 0$) in order to isolate the effect of consumer conjectures on grid purchases. In CGCONJ, where grid exports are

allowed, consumers can act both as buyers and as sellers depending on the hour: when their DeG production exceeds their own consumption, they inject the surplus into the grid. This means they could exercise market power in two different directions: as buyers, by reducing grid purchases to push prices down, and as sellers, by reducing grid exports to push prices up, making it difficult to interpret the results cleanly. By fixing $eq = 0$, all surplus DeG production is self-consumed, and no energy is ever sold back to the grid. This ensures that any strategic effect captured by the conjectural variation term acts exclusively through the purchasing decision, allowing the impact of consumer market power on grid purchases and market prices to be interpreted without ambiguity. Therefore, the comparison that isolates the effect of consumer conjectures is NOCONJ versus CUSCONJ, since both scenarios share the same generator behaviour and the same treatment of grid exports.

The scenarios are summarised in Table 5.

Scenario	Grid exports ($eq \geq 0$ or $eq = 0$)	CG conjectures ($\theta_{g,h,y}^E$)	DeG conjectures ($\theta_{c,h,y}^E$)
CGCONJ	Free ($eq \geq 0$)	Active	Zero (price-takers)
NOCONJ	Fixed to zero ($eq = 0$)	Zero	Zero (price-takers)
CUSCONJ	Fixed to zero ($eq = 0$)	Zero	Non-null (Table 4)

Table 5: Summary of simulated scenarios

4.3 RESULTS: COMPARISON OF MARKET PRICES STATISTICS

Table 6 reports the central tendency of market prices for all three scenarios in both countries: the mean, minimum and maximum, which together provide an overall picture of the average price level and the range of the distribution. Table 7 complements this with the standard deviation, a measure of dispersion that quantifies the overall variability of hourly prices around the mean.

Measures of central tendency	Scenario	ESP	POR
Mean Market Price (€/MWh)	CGCONJ	101.42	100.89
	NOCONJ	77.73	78.14
	CUSCONJ	77.21	77.73
Minimum Market Price (€/MWh)	CGCONJ	3.54	3.54
	NOCONJ	0.00	0.00
	CUSCONJ	0.55	1.08
Maximum Market Price (€/MWh)	CGCONJ	191.01	177.56
	NOCONJ	166.06	155.41
	CUSCONJ	165.51	154.88

Table 6: Central tendency statistics of market prices by scenario and zone

Measure of dispersion	Scenario	ESP	POR
Std. dev. Of Market Price (€/MWh)	CGCONJ	36.62	35.43
	NOCONJ	46.32	45.94
	CUSCONJ	46.50	46.06

Table 7: Dispersion measure (Std. dev.) of market prices by scenario and zone

Figure 8 presents the same information reported in Table 6 and Table 7 but in a visual format. While the tables provide the numerical values in detail, the figures allow the main trends and differences between scenarios to be identified more clearly and intuitively.

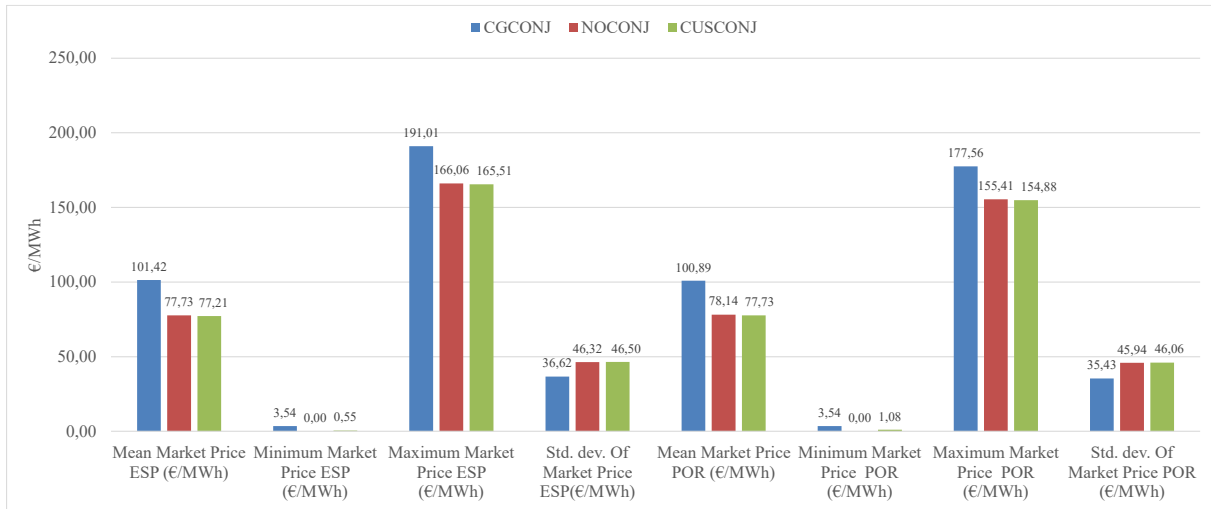


Figure 8: Bar Charts of Central Tendency Measures

Table 6 shows a systematic gap between CGCONJ and NOCONJ and CUSCONJ, which is visible across every statistic reported, not only the mean: the mean price is around 23-24 €/MWh higher in CGCONJ in both zones, and a comparable gap appears at the minimum and the maximum. This uniform shift across the whole price distribution, rather than a change concentrated in particular hours, is the expected signature of generator market power: active generator conjectures lead each GENCO to add a mark-up on top of its true cost in every hour, regardless of the demand level at that hour. Each GENCO knows that producing more would push the price down, so it holds back part of its capacity on purpose. The higher price it gets for what it still sells makes up for the energy it stops producing, which is exactly why the mark-up pays off.

Comparing NOCONJ and CUSCONJ, the mean price falls in CUSCONJ by only 0.52 €/MWh in Spain and 0.41 €/MWh in Portugal, with the minimum price actually rising slightly in CUSCONJ rather than falling. Consumer conjectures therefore have, at most, a marginal effect on the market price itself. This is consistent with the structure of the model: with battery capacity fixed exogenously and grid exports set to zero, consumers cannot reduce the total energy purchased from the grid. They can only redistribute it across hours, and this redistribution is driven by a limited share of total demand, namely the industrial segments to which the highest conjectures are assigned. The mechanism behind this limited

price response, and its effect on the hourly purchase profile, is examined in detail in the following section.

Table 7 also shows how spread out prices are: the standard deviation is around 36.62 €/MWh in Spain and 35.43 €/MWh in Portugal in CGCONJ but rises to approximately 46 €/MWh in both NOCONJ and CUSCONJ. The reason is that in CGCONJ generators hold back some of their capacity strategically, which keeps prices from falling too low even in hours when there is a lot of renewable energy available. In NOCONJ and CUSCONJ generators no longer do this, so in hours with high renewable output prices can drop to near zero, widening the overall distribution. The difference in standard deviation between NOCONJ and CUSCONJ is negligible in both zones, confirming that consumer conjectures do not affect the shape of the price distribution, only the timing of purchases within it.

4.4 COMPARISON OF GRID EXCHANGES

4.4.1 GRID EXCHANGES STATISTICS

This section quantifies the grid purchases (dq) and grid exports (eq) of DeG consumers in each scenario.

Regarding grid exports, eq is fixed to zero by construction in NOCONJ and CUSCONJ, since both scenarios are designed to isolate consumers purchasing behaviour from any selling activity. In CGCONJ, by contrast, grid exports are technically allowed. However, the hourly eq values by consumer segment are negligible throughout the whole year: considering the twelve consumer segments and the 8,760 hours, the maximum hourly value is only 1.19 kWh, while total annual exports amount to just 0.0031 GWh in Spain and 0.0034 GWh in Portugal. These values are extremely small compared with the annual dq consumption from the grid. This confirms that, although grid exports are technically allowed in CGCONJ, DeG consumers behave in practice as pure net buyers from the grid throughout the year and never become net exporters. Consequently, in the three scenarios analysed, the grid interaction of DeG consumers takes place almost entirely through dq . For this reason, the consumer-level analysis in this section focuses on dq , while eq is treated as negligible.

Table 8 reports the total annual energy purchased from the grid (dq) by all DeG consumers, aggregated by zone, for the three scenarios.

Scenario	ESP dq (GWh)	POR dq (GWh)
CGCONJ	4,358.3	961.6
NOCONJ	4,353.0	957.6
CUSCONJ	4,353.0	957.6

Table 8: Annual energy purchased from the grid (dq) by case and zone (2030)

As shown in Table 8, the total annual dq is virtually identical between NOCONJ and CUSCONJ: 4,353.0 GWh in both cases for Spain (a difference smaller than 0.01 GWh), and 957.6 GWh in both cases for Portugal. This result confirms that the conjecture term cannot reduce the total annual demand from the grid: with battery capacity fixed exogenously and grid exports fixed to zero, the only degree of freedom available to consumers is the hourly redistribution of an otherwise fixed annual purchase. The slightly higher dq of CGCONJ (4,358.3 GWh in Spain, 961.6 GWh in Portugal) is a consequence of its different scenario design (free exports and active generator conjectures).

To examine whether consumer conjectures flatten the hourly profile of dq , as theoretically expected, Table 9 (Spain) and Table 10 (Portugal) reports the main dispersion statistics of the hourly dq profile for NOCONJ and CUSCONJ, where CoV is the coefficient of variation (std. dev. / mean), P90-P10 is the difference between the 90th and 10th hourly percentiles, a dispersion measure less sensitive to outliers than the standard deviation and the Range is the difference between the maximum and the minimum. The analysis is presented both at the level of the total system, including all twelve consumer segments, and at the level of the five industrial segments (IMET, ICHE, IFOOD, IWOOD, IMIN), since these are the consumers assigned the highest conjectural variation values, as shown in Table 4.

System	Case	Std. dev. (GWh/h)	CoV	P90-P10 (GWh/h)	Range (GWh/h)
Total System	NOCONJ	4.71	0.178	12.39	30.28
	CUSCONJ	4.76	0.179	12.48	29.91
Industrial	NOCONJ	1.81	0.238	4.21	12.03
	CUSCONJ	1.70	0.224	4.16	11.94

Table 9: Hourly dq dispersion statistics by case and consumer group for Spain (2030)

System	Case	Std. dev. (GWh/h)	CoV	P90-P10 (GWh/h)	Range (GWh/h)
Total System	NOCONJ	1.00	0.182	2.60	5.28
	CUSCONJ	1.04	0.188	2.80	5.04
Industrial	NOCONJ	0.53	0.336	1.44	2.33
	CUSCONJ	0.43	0.271	1.05	2.33

Table 10: Hourly dq dispersion statistics by case and consumer group for Portugal (2030)

Figure 9 and Figure 10 present the same information reported in Table 9 and Table 10, respectively, but in a visual format.

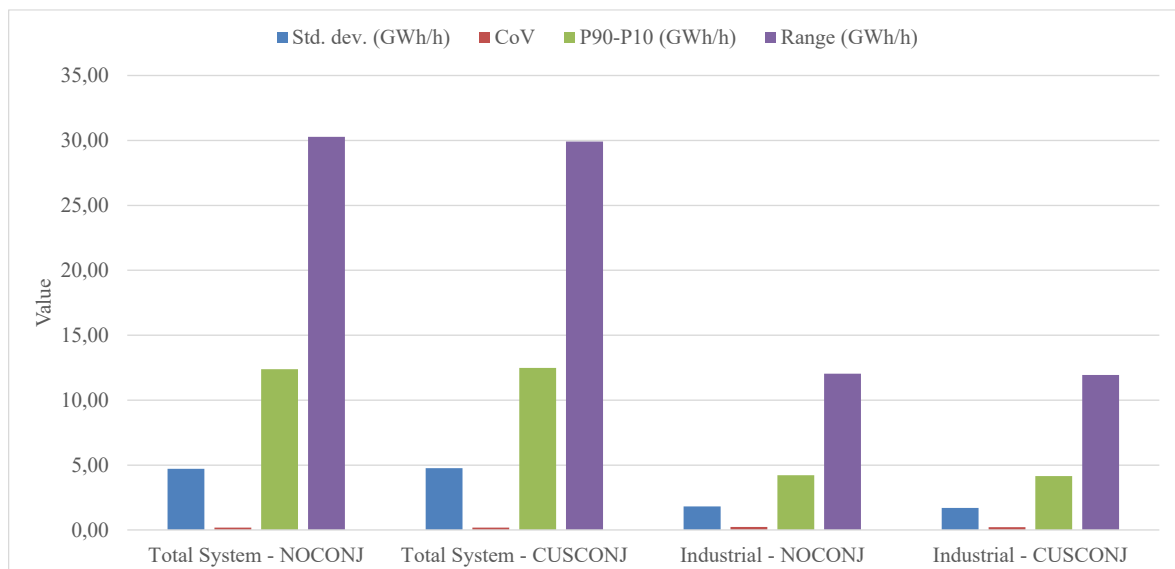


Figure 9: Bar Charts of dispersions statistics of Table 9 (Spain 2030)

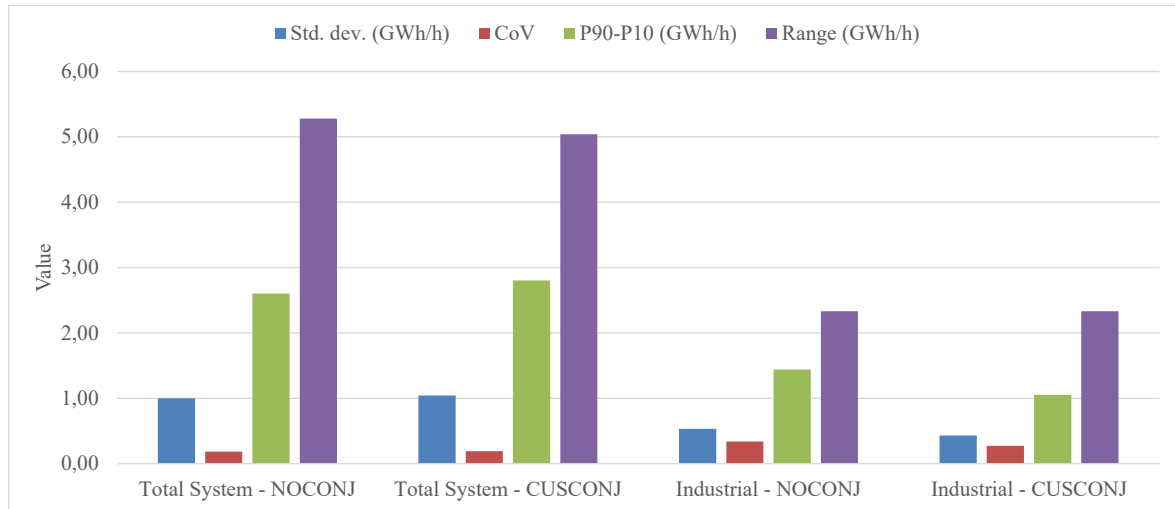


Figure 10: Bar Charts of dispersions statistics of Table 10 (Portugal 2030)

The results in Table 9 and Table 10 show a clear distinction between the effect on aggregate system-wide grid purchases (dq) and the effect observed within the industrial consumer segments. At the level of the industrial segments, the hourly dq profile flattens in CUSCONJ relative to NOCONJ: the standard deviation falls from 1.81 to 1.70 GWh/h in Spain (-6.1%) and, more markedly, from 0.53 to 0.43 GWh/h in Portugal (-19.3%); the coefficient of variation CoV falls correspondingly, from 0.238 to 0.224 in Spain and from 0.336 to 0.271 in Portugal, and the more robust P90-P10 spread decreases by 1.1% in Spain and 27.1% in Portugal. This direction is consistent with the theoretical expectation: the quadratic conjecture term in the objective function penalises large hourly net purchases, so consumers with non-null conjectures use their batteries to shave the peaks and fill the troughs of their own purchase profile.

At the level of the total system, however, this flattening is no longer visible: the standard deviation of total dq increases slightly between NOCONJ and CUSCONJ, by 0.9% in Spain and 3.2% in Portugal, and the P90-P10 spread also increases marginally in both zones (by 0.7% and 7.5% respectively). This is explained by the fact that the seven consumer segments that are not industrial (CSER, CRES, CFOOD, RSF, RB, RSFH and RBH) represent most of the system demand, accounting for 71% of the mean hourly dq in both zones, as shown in Figure 4. In NOCONJ, these segments have null conjectural variations. In CUSCONJ, residential consumers remain assigned a null conjecture, while the commercial sectors

receive only a very small conjectural variation value of 0.001 (€/MWh/MW). As a result, the smoothing effect induced by consumer conjectures is mainly concentrated in the industrial segments, where the assigned conjectural variations are higher. Once these segments are aggregated with the rest of system demand, their effect becomes diluted and is no longer visible in the total dq profile.

These results show that consumer conjectures work as expected for the consumers that have market power: they make their own hourly purchases smoother. However, this effect is too small to noticeably change the total demand profile of the system, because most demand still comes from consumers that behave as price-takers.

4.4.2 GRID EXCHANGES PROFILES

Having established that grid exports in the CGCONJ scenario are negligible, the analysis now turns to how consumers use their storage capacity under these conditions. If exports barely matter, the main question becomes whether a battery lets some consumers buy from the grid on a different pattern than their own consumption, instead of simply buying exactly what they consume, hour by hour. For this reason, the first part of this section compares the behaviour of a large industrial prosumer with that of a smaller residential prosumer in the base scenario. The second part then turns to the comparison between NOCONJ and CUSCONJ, in order to isolate the effect of consumer conjectures on the hourly dq profile and assess whether strategic consumer behaviour modifies the timing of grid purchases.

Regarding CGCONJ scenario, to analyse whether prosumers with higher storage capacity manage their consumption more autonomously and rely on the grid mainly during low-price periods, Figure 11 (Spain) and Figure 12 (Portugal) compare the hourly demand and dq profiles of two representative segments during Week 22 of the base scenario: IMET, the largest industrial segment, and RSF, a representative residential segment. This week is shown for visual clarity, since plotting the 8,760 hours of the year would make the hourly profiles difficult to interpret. However, it should be noted that the same conclusions hold throughout the entire year: the patterns observed in Week 22 are representative of all weeks

in both zones, confirming that the differences identified between IMET and RSF are not specific to the selected week.

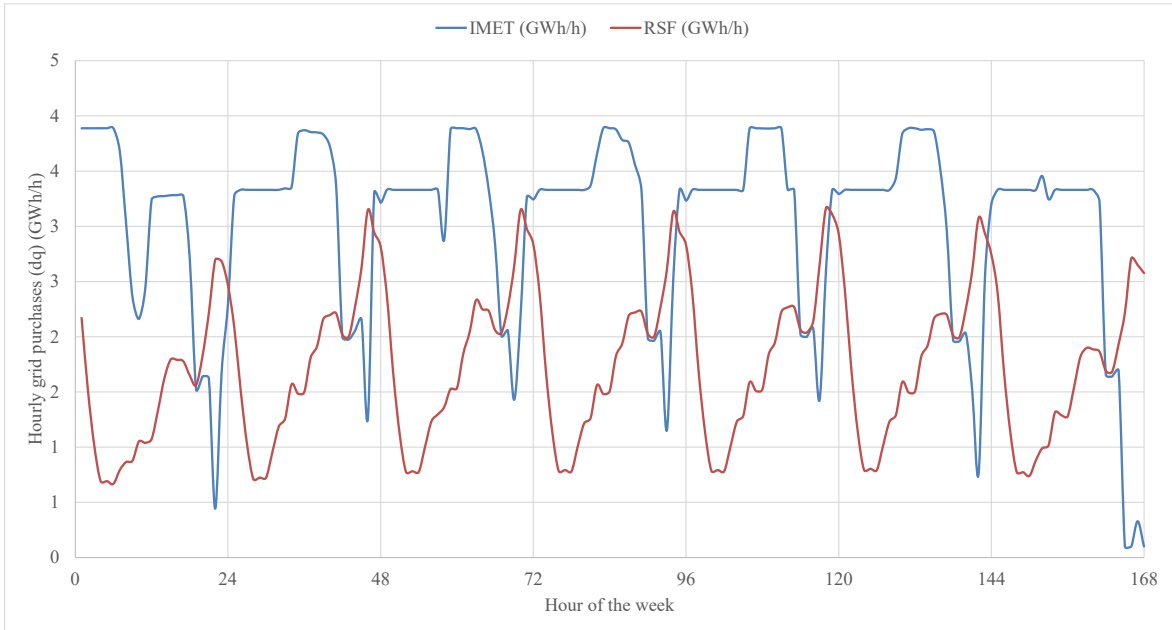


Figure 11: Hourly dq profiles of IMET and RSF during Week 22 (2030) of CGCONJ scenario in Spain

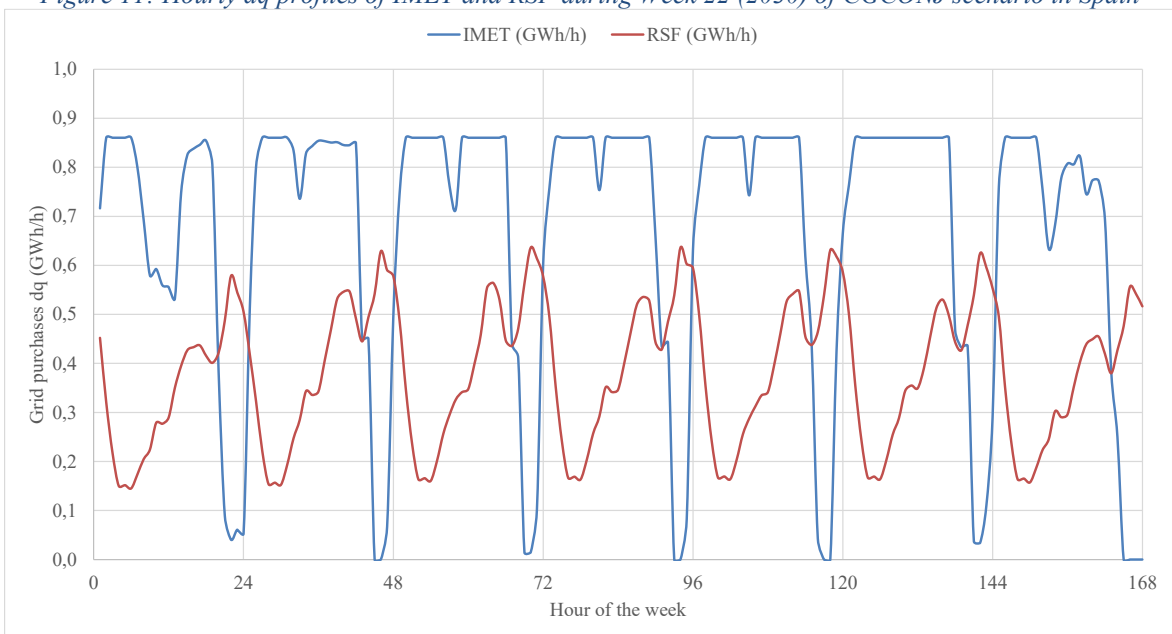


Figure 12: Hourly dq profiles of IMET and RSF during Week 22 (2030) of CGCONJ scenario in Portugal

These two segments are chosen because they have very different battery capacities relative to their consumption. Industrial segments were allocated 75% of the total installed

battery capacity, while the remaining 25% was distributed among the other segments, including residential and commercial consumers. As a result, IMET has a battery-to-consumption ratio of approximately 5.76 MW/GWh/year in Spain and 5.91 MW/GWh/year in Portugal, compared with 0.77 MW/GWh/year and 0.83 MW/GWh/year for RSF. Therefore, IMET has roughly 7.5 times more battery capacity per unit of annual consumption than RSF, which makes this comparison suitable to assess whether higher storage availability is associated with more autonomous grid-purchase behaviour.

Figure 11 and Figure 12 shows two clearly different grid-purchase patterns. IMET presents a more irregular and flexible dq profile, with several sharp reductions in grid purchases during the week. This indicates that the industrial segment is able to modify its interaction with the grid more actively, reducing its purchases in some periods instead of following a smooth consumption pattern. This behaviour is consistent with its higher storage capacity relative to annual consumption.

By contrast, RSF shows a more regular daily pattern, with grid purchases increasing progressively during the day and reaching their highest values in the evening hours. This behaviour is coherent with a residential consumption profile, where demand typically increases when household activity is higher. Since RSF has much lower storage capacity relative to consumption, its dq profile remains more closely linked to its underlying demand pattern and shows less ability to decouple purchases from consumption.

This behaviour is more pronounced in Portugal than in Spain. In Portugal, IMET reaches zero grid purchases in 331 hours of the year, equivalent to 3.8% of all hours, compared with only 27 hours in Spain, or 0.3% of the year. RSF, by contrast, does not reach zero grid purchases in either zone. This indicates that the larger industrial prosumer can cover its demand without grid purchases during a greater number of hours, especially in Portugal, where the market price profile contains more hours with very low prices.

Therefore, the comparison suggests that the main difference between the two segments is not that the larger prosumer exports more energy, but that it can manage its grid purchases more flexibly. IMET is able to reduce its purchases substantially in some hours,

whereas RSF remains more dependent on the grid throughout the week and across the year. This supports the interpretation that, in CGCONJ scenario, storage is mainly used for internal consumption management and purchase shifting rather than for significant net injection into the system.

Regarding the comparison between NOCONJ and CUSCONJ, to complement the aggregate statistics presented in Section 4.4.1, Figure 13 and Figure 14 illustrate the hourly evolution of dq in Spain and Portugal, respectively. Plotting the full 8,760 hours of the year would make it difficult to identify individual hourly patterns. For this reason, the analysis focuses on a single representative week, Week 22 of 2030. However, it should be noted that the same conclusion holds for every week of the year: in all 52 weeks and in both zones, the hourly dq profile of the industrial segments is flatter in CUSCONJ than in NOCONJ, confirming that the flattening effect documented below is not specific to the chosen representative week. Each figure presents two panels: panel (a) shows the hourly dq profile aggregated over all twelve consumer segments, and panel (b) shows the hourly dq profile aggregated only over the five industrial segments.

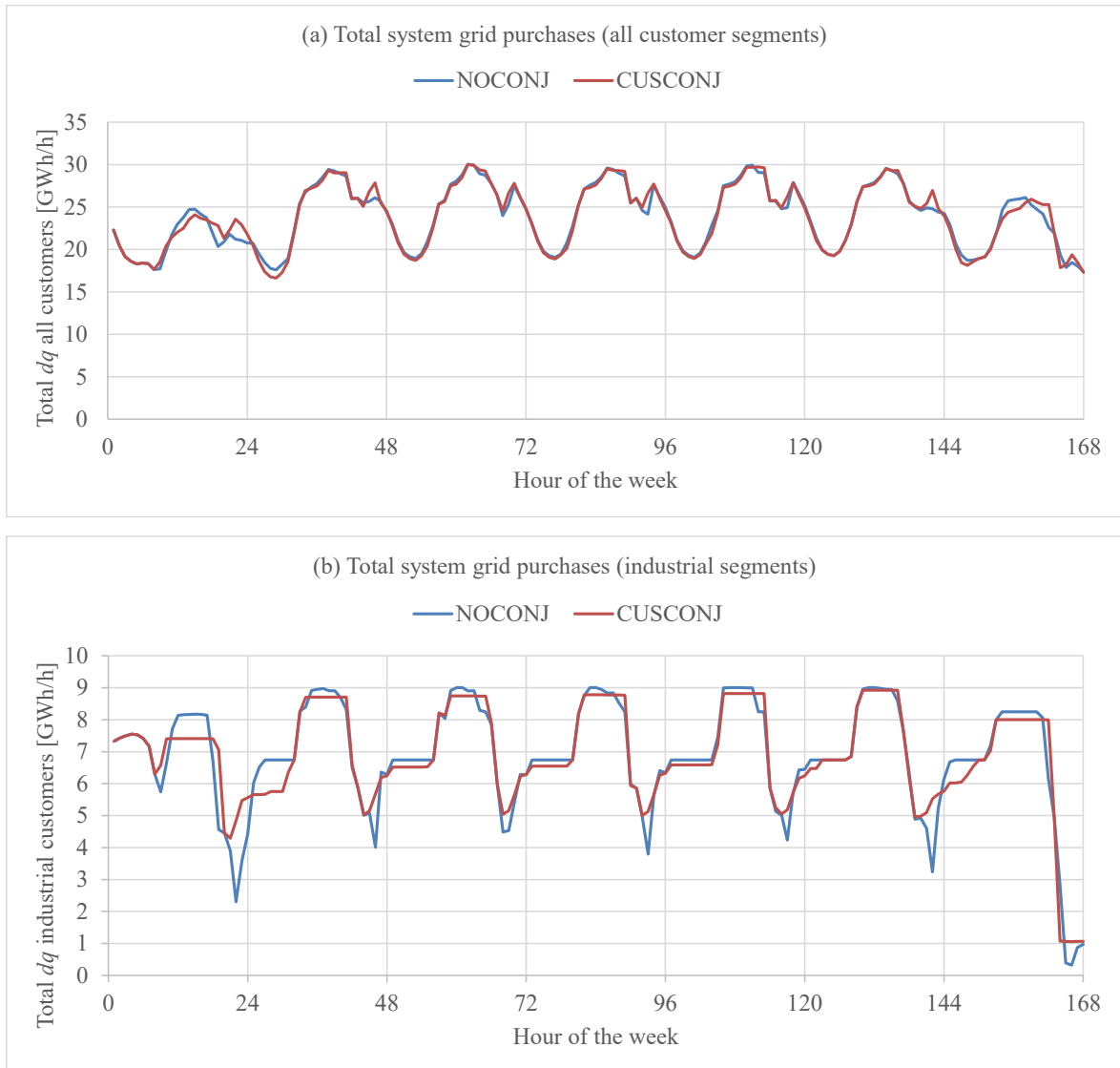


Figure 13: Hourly dq profile for Spain in week 22 of 2030

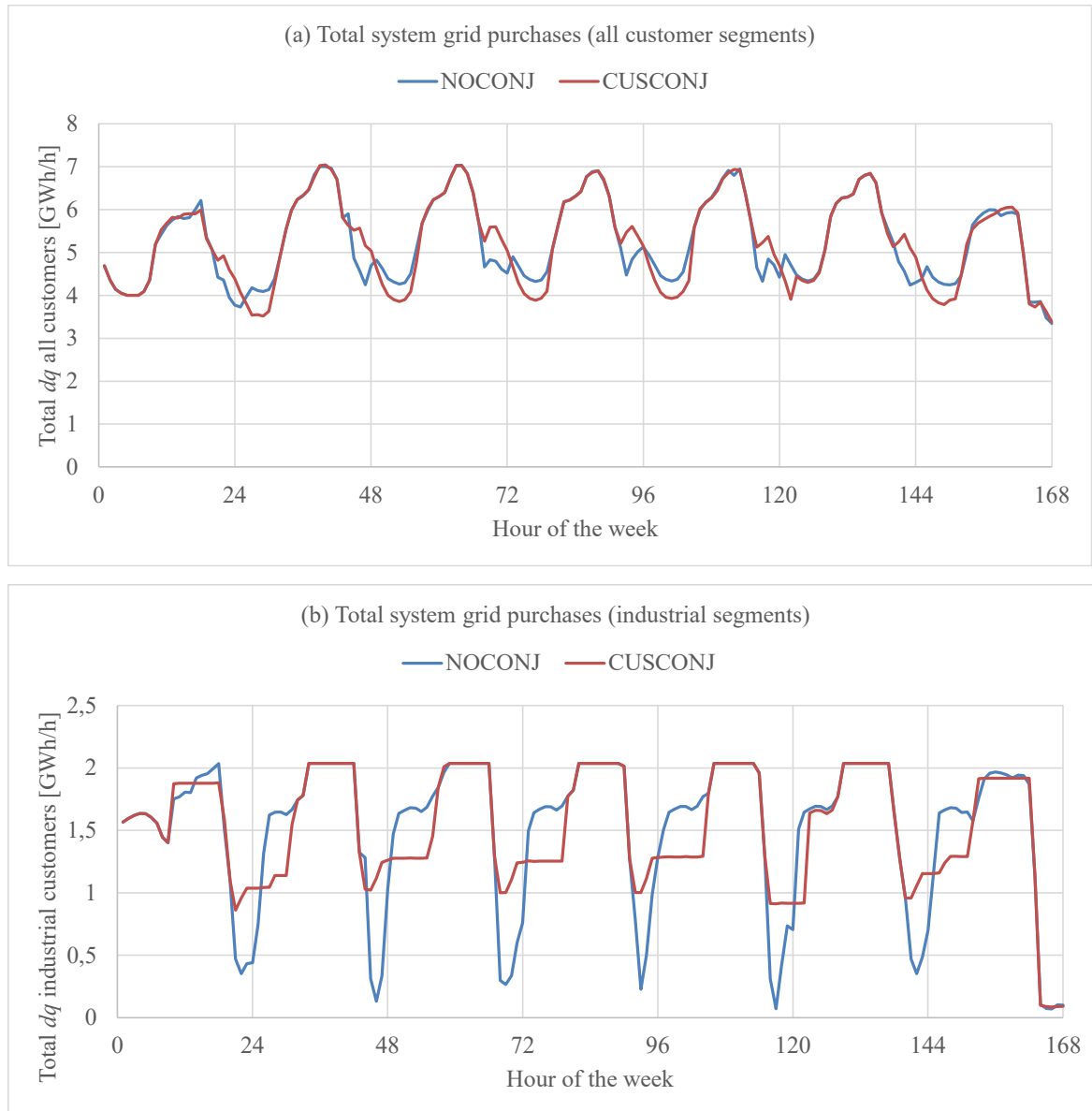


Figure 14: Hourly dq profile for Portugal in week 22 of 2030

Panel (a) in both figures confirms the result observed in Table 9: the total dq profiles in NOCONJ and CUSCONJ are almost identical throughout the representative week. Only small differences can be seen in some low-demand hours.

Panel (b) shows the effect of consumer conjectures more clearly. For the industrial segments, the dq profile in CUSCONJ is smoother than in NOCONJ. In the hours when NOCONJ reaches its lowest dq values, CUSCONJ remains noticeably higher. During peak

hours, however, both cases become very similar, because consumers are already purchasing close to their maximum required volume.

This behaviour is consistent with the role of the quadratic conjecture term in the objective function. Consumer conjectures reduce extreme variations in the hourly purchase profile, avoiding very low values as well as very high ones. As a result, the dq profile becomes flatter. This effect is stronger in Portugal than in Spain, which is also consistent with the larger reduction in the coefficient of variation reported in Table 9 for the Portuguese industrial segments.

Overall, these figures support the conclusion that consumer conjectures do affect the hourly dq profile of the segments with market power. However, this effect is mainly visible at the industrial-segment level. When these consumers are aggregated with the rest of the demand, the effect becomes diluted, so the total system dq profile remains almost unchanged.

4.5 COMPARISON ON CAPTURE PRICE BY CUSTOMER SEGMENT

This section examines the annual capture price of each consumer segment, defined as the weighted average price paid for grid purchases, that is, the ratio between the total annual cost of dq and the total annual volume of dq , as expressed in (16):

$$\lambda_{z,c,y}^{cap} = \frac{\sum_h dq_{z,c,h,y} \cdot \lambda_{h,y}^E}{\sum_h dq_{z,c,h,y}} \quad (17)$$

If consumers with market power succeed in timing their battery purchases towards cheaper hours, the theoretical expectation is that the consumer with market power should obtain a lower capture price in CUSCONJ than in NOCONJ, since its conjecture is precisely designed to represent this strategic purchasing behaviour.

Table 11 reports the annual capture price for all twelve consumer segments, in CGCONJ, NOCONJ and CUSCONJ, for both Spain and Portugal.

Segment	CGCONJ	NOCONJ	CUSCONJ	CGCONJ	NOCONJ	CUSCONJ
	ESP (€/MWh)	ESP (€/MWh)	ESP (€/MWh)	POR (€/MWh)	POR (€/MWh)	POR (€/MWh)
IMET	100.65	77.42	76.94	98.78	76.31	75.91
ICHE	100.64	77.41	76.86	98.76	76.29	75.85
IFOOD	96.63	70.87	70.27	94.58	70.34	69.85
IWOOD	96.63	70.87	70.23	94.58	70.34	69.83
IMIN	96.63	70.87	70.21	94.58	70.34	69.82
CSER	100.13	76.08	75.52	99.12	75.85	75.40
CRES	101.46	77.57	77.00	100.35	77.34	76.90
CFOOD	100.01	75.84	75.24	98.92	75.62	75.15
RSF	103.73	79.63	79.07	102.41	79.38	78.93
RB	103.73	79.63	79.07	102.40	79.37	78.92
RSFH	104.19	80.04	79.48	102.76	79.73	79.27
RBH	104.18	80.03	79.47	102.74	79.71	79.26

Table 11 : Annual capture price [€/MWh] by consumer segment, scenario and zone (2030)

Figure 15 and Figure 16 represent the same information graphically for Spain and Portugal respectively, showing the capture price for all three scenarios by consumer segment and the percentage reduction from NOCONJ scenario to CUSCONJ on a secondary axis, allowing the relative magnitude of the effect to be compared directly across segments.

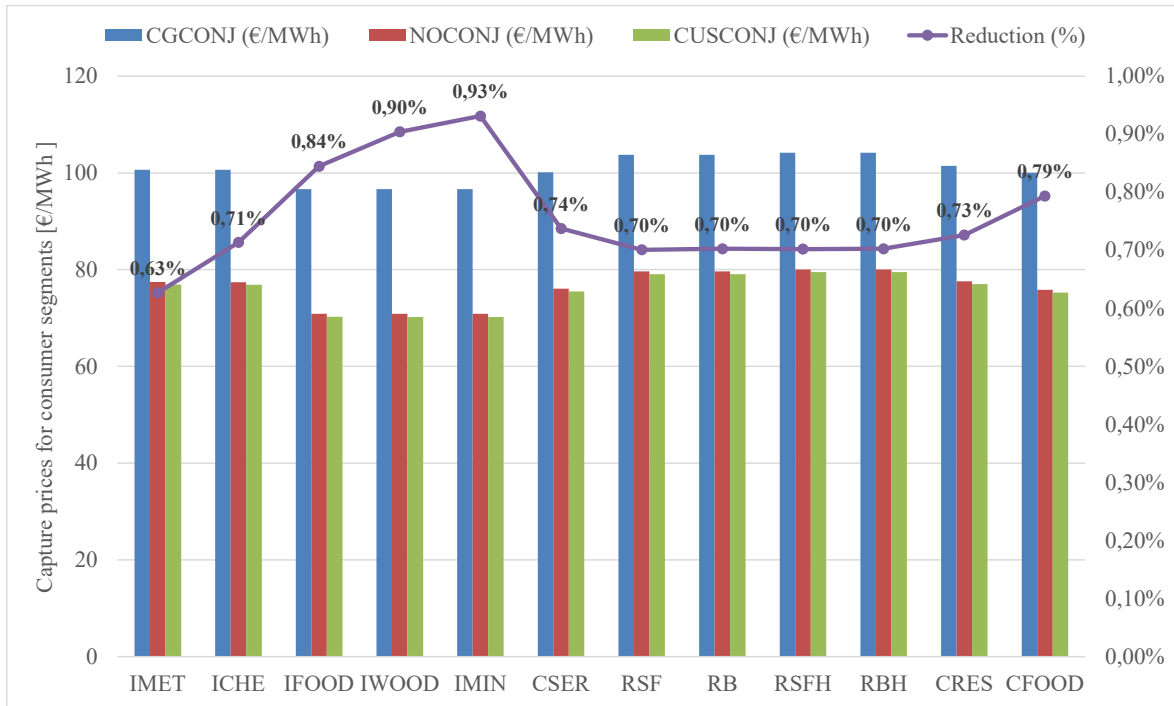


Figure 15: Capture price by consumer segment for all scenarios for Spain

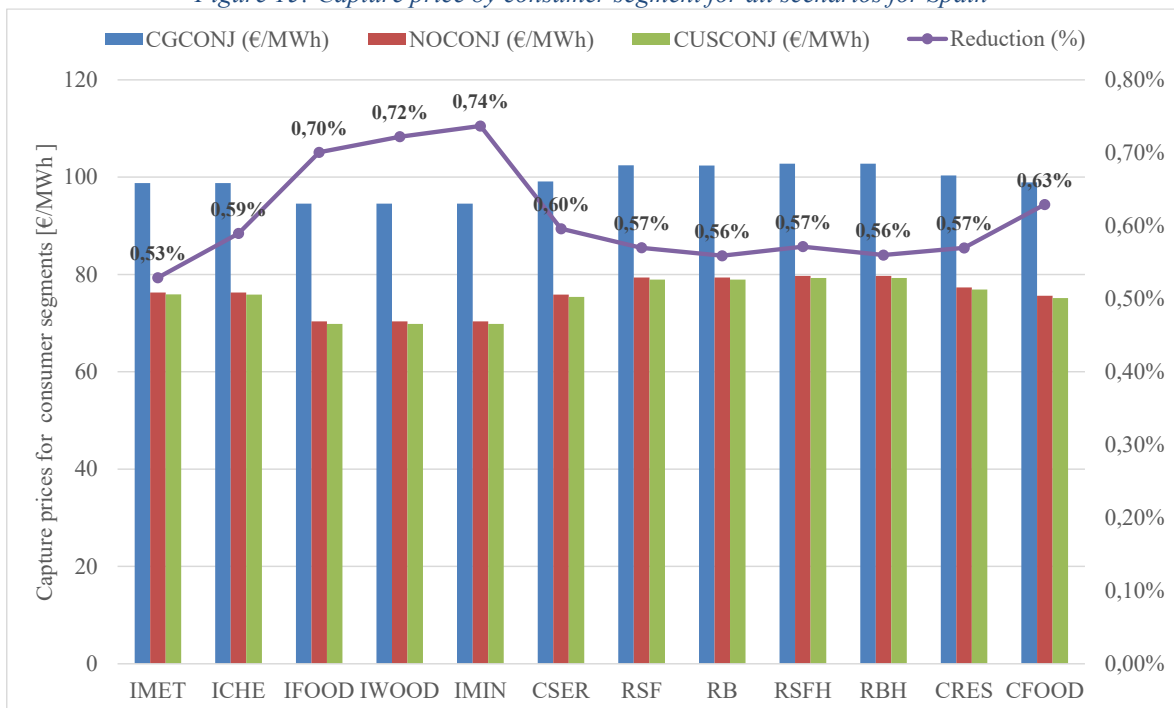


Figure 16: Capture price by consumer segment for all scenarios for Portugal

As shown in Table 11, the annual capture price decreases from NOCONJ to CUSCONJ for all consumer segments and in both zones. This result confirms that the introduction of non-null consumer conjectures in CUSCONJ reduces the effective price paid by consumers for their grid purchases. However, the most relevant result, as shown in Figure 15 and Figure 16, is the much larger reduction in capture prices observed between CGCONJ and NOCONJ and CUSCONJ. This sharper decrease is entirely due to the removal of generators' conjectures, which lowers the overall market price level and, consequently, the capture price of all consumer segments.

In NOCONJ, all consumers have null CVs. In CUSCONJ, by contrast, conjectures are introduced with different intensities depending on the type of consumer: industrial segments are assigned the highest conjectural variation value, equal to 0.003 (€/MWh/MW); commercial segments are assigned an intermediate value of 0.001 (€/MWh/MW); and residential segments remain with a null conjecture, as reported in Table 4. For this reason, the analysis focuses especially on the five industrial segments (IMET, ICHE, IFOOD, IWOOD and IMIN), since these are the consumers for which the effect of strategic behaviour is expected to be most visible.

For these industrial segments, the reduction in capture price ranges from 0.40 to 0.66 €/MWh, equivalent to a relative decrease between 0.53% and 0.93%. Within this group, IMIN shows the largest relative reduction in both zones, which can also be observed graphically in Figure 15 and Figure 16. This result is consistent with expectations, since consumers with higher conjectural variation values show a larger reduction in their effective average purchase price.

The comparison across consumer groups reinforces this interpretation. Commercial segments (CSER, CRES and CFOOD), with a lower conjectural variation value of 0.001 (€/MWh/MW), show a slightly smaller average reduction than industrial segments: -0.75% compared with -0.80% in Spain, and -0.60% compared with -0.66% in Portugal. Residential segments, which keep a null conjecture and behave as price-takers, show the smallest average reduction: -0.70% in Spain and -0.57% in Portugal.

Although the differences across groups are small in absolute terms, the observed pattern is consistent in both zones and follows the order of the conjectural variation values defined in Table 4: the largest reduction corresponds to industrial segments, the intermediate reduction to commercial segments, and the smallest reduction to residential segments. This confirms that part of the benefit obtained by industrial and commercial consumers can be attributed to their own strategic purchasing behaviour.

Nevertheless, this interpretation should be qualified. All segments, including residential consumers with null conjectures, experience a reduction in capture price. Therefore, part of the observed improvement is also explained by the slight decrease in the average market price between NOCONJ and CUSCONJ, already shown in Table 6, which benefits all consumers regardless of their own conjectural variation.

Overall, the results show that the introduction of non-null consumer conjectures produces the expected effect in the model: the annual capture price decreases for all segments, and the magnitude of this reduction increases with the conjectural variation value assigned to each group. However, the absolute size of the differences across groups remains limited. This result is consistent with the way the model is implemented in this case study. Since battery capacity is fixed, grid exports are set to zero, and the underlying demand is assumed to be inelastic, consumers have only limited flexibility to modify their grid purchases. As a result, consumer conjectures can slightly change the timing and effective cost of electricity purchases, but they cannot produce a large impact on the overall system.

4.6 ANNUAL GENERATION MIX

This section presents the results of the annual generation mix for the CGCONJ scenario. Given the high computational cost of annual runs, with each full-year simulation taking approximately two hours, this generation-mix analysis is presented only for CGCONJ. NOCONJ and CUSCONJ, which are also simulated over the full year 2030 for the consumer-conjecture analysis of the previous sections, are not repeated here since they were designed to isolate the effect of consumer conjectures rather than to characterise the overall system mix.

Figure 17 and Figure 18 show the share of each technology in the annual generation mix for Spain (Figure 17) and Portugal (Figure 18) in 2030. WIND is wind generation, SOLPV is solar PV generation, NU is nuclear generation, CCGT is combined cycle gas turbine, OTR_T is other thermal generation (coal, fuel oil, cogeneration), HCONV is conventional hydro generation, SOLTH is solar thermal generation, HTURB is turbined hydro generation, CHP is combined heat and power, and BAT is battery discharge. NU, SOLTH and HTURB appear only in the Spanish generation mix (Figure 17), while CHP appears only in the Portuguese generation mix (Figure 18), reflecting the different technology portfolios of the two zones.

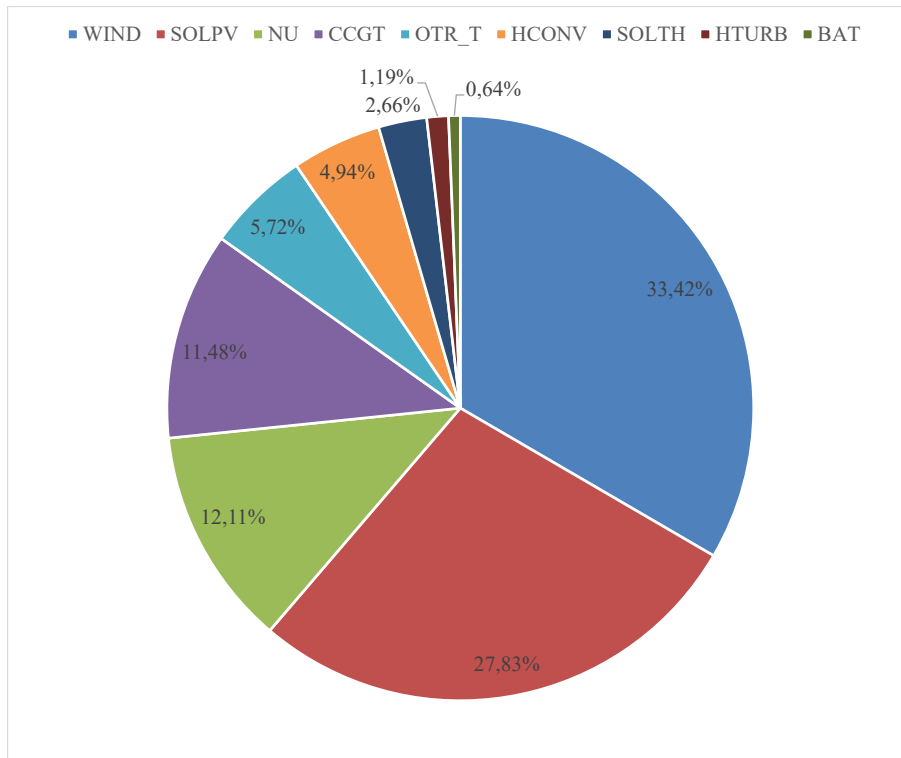


Figure 17: Annual generation mix for Spain

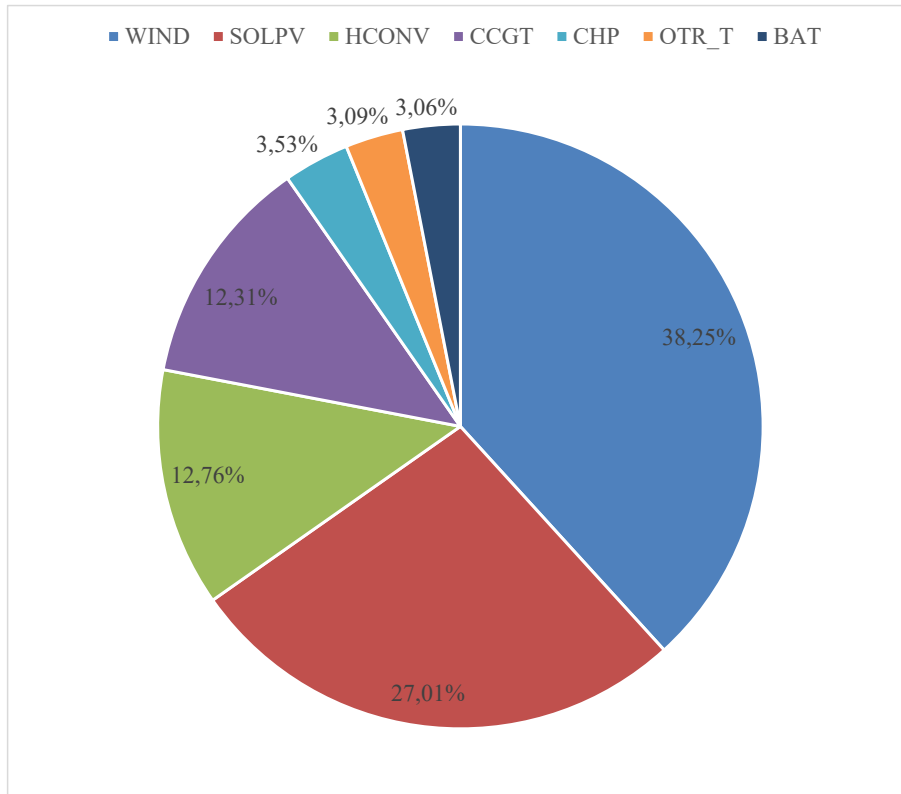


Figure 18: Annual generation mix for Portugal

The results of the simulation can be compared with the targets established by the Spanish and Portuguese NECPs [3], [4] in terms of the technology mix and the share of renewable generation in total electricity production.

Regarding Spain, [3] establishes that renewable generation should account for 81% of total electricity production in 2030. In the simulation, renewable technologies (wind, solar PV, hydro and solar thermal) account for 67.7% of gross generation. However, this simulated figure includes spillage (12,593 GWh) and nuclear (44,677 GWh) in the total, which are not part of the renewable target. Excluding these two items from the total, the renewable share rises to 79.7%, which is close to the 81% target. Wind and solar PV together account for 71.1% of gross generation, consistent with the NECPs emphasis on these two technologies as the main drivers of the renewable transition. The presence of CCGT generation (11.1%) is also consistent with the NECP, which foresees 26.6 GW of combined cycle gas as a flexible back-up technology. The energy spillage of 12,593 GWh signals that at certain hours

renewable generation exceeds total system demand and available storage, underscoring the importance of the 22.5 GW storage target established by the NECP to absorb this surplus.

Regarding Portugal, [4] targets a 90% renewable share in electricity production by 2030, with wind contributing around 36% and solar around 39%. In the simulation, renewables account for 89.4% of gross generation in Portugal, which is very close to the 90% target. Wind contributes 42.1% and solar PV 29.8%, broadly consistent with the NECP projections, although solar is somewhat below the 39% target, possibly reflecting differences in the installed capacity assumptions. The absence of spillage in Portugal suggests a better balance between renewable generation, storage and demand compared to Spain.

4.7 PRICE DURATION CURVE

Figure 19 shows the price duration curves for Spain and Portugal over the full year 2030. The price duration curve represents the hourly market prices sorted in descending order, with the number of hours on the horizontal axis and the price in €/MWh on the vertical axis. It provides a comprehensive view of the distribution of market prices throughout the year.

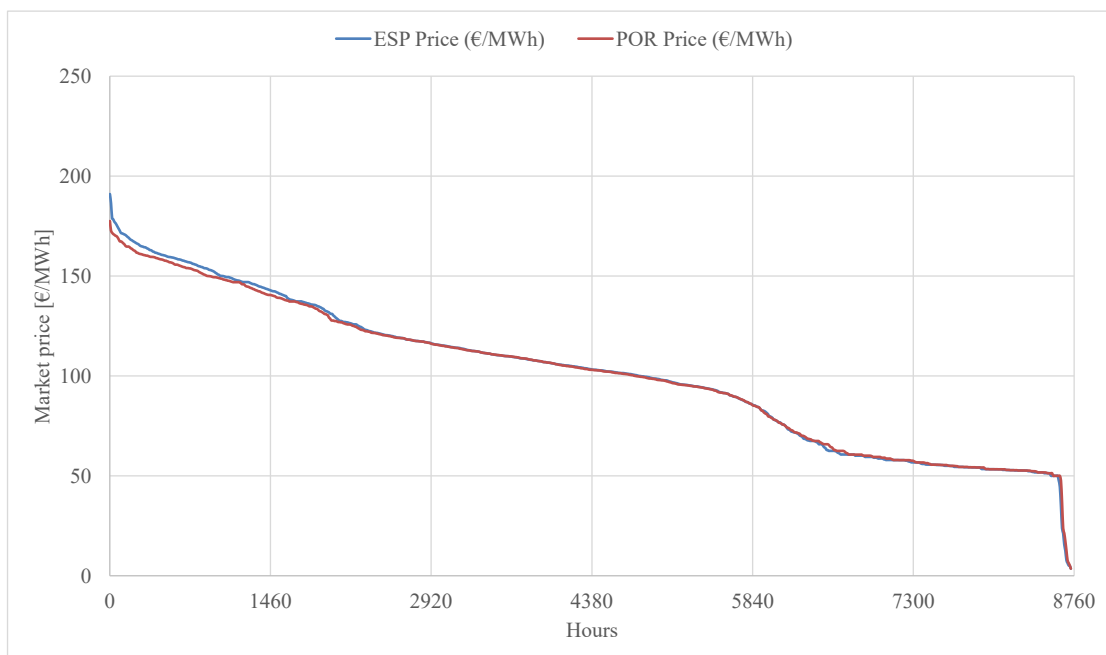


Figure 19: Price duration curve in CGCONJ scenario for Spain and Portugal

The mean annual market price is 101.42 €/MWh for Spain and 100.89 €/MWh for Portugal. The price distribution is highly asymmetric: prices above 100 €/MWh occur in 55.1% of hours in Spain (4,811 hours) and 54.6% in Portugal (4,773 hours), while prices above 150 €/MWh occur in 11.6% of hours in Spain (1,016 hours) and 10.2% in Portugal (894 hours). At the other extreme, prices fall below 10 €/MWh in only 47 hours in Spain and 37 hours in Portugal, reflecting moments of very high renewable generation coinciding with low demand. The maximum hourly price reaches 191.01 €/MWh in Spain and 177.56 €/MWh in Portugal, corresponding to peak demand hours with low renewable output.

The standard deviation of hourly prices is 36.62 €/MWh for Spain and 35.43 €/MWh for Portugal, indicating substantial price variability throughout the year. This variability is mainly driven by the large share of variable renewable generation in the system: prices tend to fall when wind and solar output is high, while thermal units set higher prices in periods of lower renewable availability. The price duration curves for Spain and Portugal are very similar in shape, reflecting the high degree of market integration within MIBEL. This is confirmed by the fact that there is no market splitting in 7,293 out of the 8,760 hours analysed, equivalent to 83.48% of the year. In these hours, the market price is identical in Spain and Portugal, meaning that the interconnection flow does not reach its capacity limit. Therefore, both zones clear at the same price most of the time, while market splitting occurs only in a limited number of hours. This result is consistent with the actual operation of MIBEL, where Spain and Portugal are usually coupled and price separation only appears when the interconnection becomes congested.

Chapter 5. CONTRIBUTIONS, CONCLUSIONS AND FUTURE DEVELOPMENTS

This chapter closes the thesis. Section 5.1 summarises the original contributions of this work with respect to the model proposed in [8]. Section 5.2 draws together the main conclusions of the case study presented in Chapter 4, regarding the effect of generator and consumer market power on prices, grid purchases and capture prices, and their implications for the modelling of consumer strategic behaviour. Finally, Section 5.3 outlines the main lines of future work that follow directly from the limitations identified throughout this analysis.

5.1 CONTRIBUTIONS

The mathematical model used throughout this thesis, including the conjectural variations framework, the equivalence between the Generalised Nash Equilibrium Problem and the quadratic minimisation problem (15), and the network loss formulation, is entirely the contribution of [8], to which the reader is referred for the full theoretical derivation. The original contribution of this thesis lies in the application and extension of that framework to a new case study and can be summarised in the following points.

- The model is extended from the Spain-only system considered in [8] to the full Iberian electricity market (MIBEL), jointly representing Spain and Portugal under a common set of conjecture assumptions.
- The scenario design is based on the most recent versions of the Spanish and Portuguese NECPs (2023-2030), which set more ambitious self-consumption and renewable targets than those available at the time of [8], in particular the 19 GW and 4.3 GW DeG capacity targets used throughout Chapter 4.

- Three scenarios are specifically designed to separate the effect of generator market power from the effect of consumer market power: a reference scenario with active generator conjectures, free grid exports and null conjectures for customers; a second scenario in which all agents behave as price-takers, with null conjectures, and grid exports are fixed to zero; and a third scenario identical to the second except that customers are assigned non-null conjectural variation values. This isolation is not addressed in [8] and that allows each effect to be quantified independently.
- The case study provides an empirical assessment of how generator and consumer conjectures propagate to market prices, grid purchases and capture prices at the level of twelve differentiated consumer segments, offering a level of disaggregation not present in the original reference.
- The results are validated against the renewable generation targets established by the Spanish and Portuguese NECPs, providing an external consistency check that links the model outputs back to the policy targets motivating this work.

5.2 CONCLUSIONS

The case study leads to a clear distinction between the effect of generator market power and the effect of consumer market power on market prices. When generators are allowed to exercise market power through non-zero conjectural variations while consumers behave as price-takers and grid exports are permitted, the market price increases systematically and uniformly across the entire hourly price distribution. This effect is present at the mean and at the extremes, confirming that generator market power operates as expected in the model.

Consumer conjectures behave differently. At the level of the market price itself, their effect is negligible: the mean price falls by less than one euro per MWh when moving from a setting in which all agents behave as price-takers and grid exports are fixed to zero to a setting in which industrial and commercial consumers are assigned non-null conjectural variation values under the same export restriction. The rest of the price distribution moves

by a similarly small amount. This is a direct consequence of the model assumptions: with battery capacity fixed exogenously and grid exports fixed to zero in both settings; consumers cannot reduce the total energy they purchase from the grid over the year but can only redistribute it across hours. Since this redistribution capability is concentrated in the industrial segments, which represent a minority of total demand and receive the highest conjectural variation values, its effect on the system-wide price is correspondingly small.

This redistribution effect is nevertheless real and consistent at the level of the individual consumer. The hourly purchase profile of the industrial segments becomes measurably flatter when consumer conjectures are introduced, and the annual capture price of every consumer segment decreases. The size of the reduction follows the ranking of the conjectural variation values assigned to each group: industrial segments obtain the largest reduction, followed by commercial segments, while residential segments remain price-takers throughout. The conjecture mechanism therefore operates in the intended direction at the level of the consumer's own effective purchase price, even though it is not strong enough to move the system-wide market price in a noticeable way.

The mechanism behind this flattening is a genuine change in how the battery is dispatched, not only in how much energy it moves. When consumers behave as price-takers, the battery is operated purely to arbitrage hourly price differences, charging in the cheapest hours and discharging in the most expensive ones. When consumer conjectures are active, the quadratic conjecture term additionally penalises large hourly net purchases in themselves, giving the consumer an incentive to avoid concentrating its grid purchases in a few extreme hours. The battery is therefore no longer used solely for price arbitrage but also to actively smooth the consumer's own hourly purchase profile, even at some cost in arbitrage efficiency. This distinction, rather than the small aggregate price effect, is arguably the most direct behavioural evidence in this thesis that a consumer conjecture, unlike a generator conjecture, changes the timing of market participation rather than its volume.

The additional comparison between the largest industrial consumer segment and a representative residential consumer segment in the setting where generators exercise market

power and grid exports are allowed reinforces this interpretation from the perspective of storage availability. The industrial segment has a much higher battery capacity relative to its annual consumption than the residential segment. This difference is reflected in their grid-purchase behaviour: the industrial segment is able to decouple its grid purchase profile from its demand profile to a greater extent, reducing its dependence on the grid in some hours and reaching zero grid purchases during a limited but relevant number of hours, especially in Portugal. The residential segment, by contrast, remains more closely linked to its underlying demand profile and never reaches zero grid purchases in either zone. This shows that higher storage availability allows larger prosumers to manage their own grid purchases more flexibly, but it does not translate into significant energy exports to the system.

This finding has an important implication for the modelling of consumer market power. In the current formulation, storage mainly affects the timing of grid purchases and the effective purchase price faced by each consumer segment, rather than the total amount of electricity exchanged with the system. For consumer conjectures to have a meaningful effect on the market price itself, rather than only on the consumer's own bill, one of the following conditions would need to hold: (i) investment decisions are endogenous, so that a higher conjecture can modify the optimal level of battery and solar PV capacity installed, or (ii) demand is price elastic, so that consumers can genuinely reduce their total consumption rather than only redistribute it across hours. Identifying which of these two extensions would have the largest impact is therefore a priority direction for future work.

Finally, the annual generation mix obtained in the setting where generators exercise market power and grid exports are allowed is consistent with the renewable targets established by the Spanish and Portuguese NECPs: the renewable share excluding nuclear and spillage reaches 79.7% in Spain against an 81% target, and 89.4% in Portugal against a 90% target. This confirms that the scenario design adopted in this thesis provides a realistic representation of the system envisaged by the NECPs for 2030.

5.3 FUTURE DEVELOPMENTS

The most direct extension of this work is the modelling of DeG investment decisions, which are taken as an exogenous input in the current model. Making battery and solar PV capacity a decision variable would allow the conjecture parameter to affect not only the timing of grid purchases but also the total amount of self-consumption capacity installed, which Section 5.2 identifies as a necessary condition for consumer market power to have a first-order effect on market prices.

A related extension concerns the conjectural variation values themselves, which in this thesis are fixed exogenous parameters assigned to each generator and consumer segment based on relative market size. A more realistic representation would treat these conjectures as endogenous, allowing them to emerge from the agents' own learning process or strategic response to market conditions rather than being imposed a priori. This would make it possible to assess whether the degree of market power exercised by a given segment changes as DeG penetration increases, instead of assuming it remains constant across scenarios, and would address one of the main simplifications of the conjectural variations approach as applied in this work.

This extension also opens the door to analysing the so-called death spiral dynamic: if DeG investment continues to be profitable as long as the avoided cost of grid purchases exceeds the investment cost, growing self-consumption would progressively erode the energy sold through the grid. Since network costs are largely fixed, a shrinking volume of grid purchases would have to be recovered through higher volumetric tariffs for the consumers that remain connected, which would in turn make self-consumption even more attractive and could accelerate further grid disconnection. Modelling this feedback loop explicitly and assessing under which tariff designs it can be contained, is identified as a relevant line of future research building directly on the model presented in this thesis.

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ANNEX I: SUSTAINABLE DEVELOPMENT GOALS

The United Nations Sustainable Development Goals (SDGs) [24] provide a global framework to promote a more sustainable and equitable future, addressing key challenges such as poverty, inequality, climate change, and environmental degradation, with the aim of achieving progress by 2030 [24].

This thesis analyses the impact of self-consumption and DeG on the operation of the electricity market. The European Union has promoted specific regulations in this field, most notably through the NECPs, which aim to accelerate the energy transition. As a result, consumers now play a more active role in the market, gaining greater control over their energy generation and consumption. This shift not only increases the share of renewable energy but also enhances the alignment between local generation and demand.

Therefore, the Sustainable Development Goals that align most closely with the development of this project are:

- SDG 7: “Ensure access to affordable, reliable, sustainable and modern energy”
- SDG 11: “Make cities inclusive, safe, resilient and sustainable”
- SDG 13: “Take urgent action to combat climate change and its impact”



Figure 20: SDGs aligned with the thesis

ANNEX II: THE FIRST ORDER KKT CONDITIONS OF THE NASH EQUILIBRIUM

The Energy-Only Equilibrium (EOE) is defined as the Nash equilibrium of the following coupled system: each GENCO g maximises (1) subject to (3) (for $s \in G$), and each customer segment c minimises (2) subject to (3)-(5) (for $s \in C$), with (6) as the market-linking constraint. This is a GNEP because the feasible region of each agent depends on the decisions of all others through the shared constraint (6).

The Lagrangian function of the GENCO problem (1) subject to (3), and of the customer problem (2) subject to (3)-(5), incorporating the linking constraint (6), are respectively:

$$\begin{aligned} \ell_g(q, p, \lambda^{PQ}, \lambda^E) &= - \sum_{t,h,y} (\lambda_{h,y}^E \cdot q_{t,g,h,y} - VC_{t,g,y} \cdot q_{t,g,h,y}) + \sum_{t,y} IC_{t,g,y} \cdot p_{t,g,y} \\ &+ \sum_{t,h,y} \lambda_{t,g,h,y}^{PQ} \cdot (q_{t,g,h,y} - p_{t,g,y}) \end{aligned}$$

$$\begin{aligned} \ell_c(q, p, cp, dq, eq, \lambda^{PQ}, \lambda^{CB}, \lambda^{CP}, \lambda^E) &= \sum_y TP_{c,y} \cdot cp_{c,y} + \sum_{t,y} IC_{t,c,y} \cdot p_{t,c,y} \\ &+ \sum_{h,y} [(\lambda_{h,y}^E + TV_{c,y}) \cdot dq_{c,h,y} - (\lambda_{h,y}^E - TC_{c,y}) \cdot eq_{c,h,y}] \\ &+ \sum_{t,h,y} \lambda_{t,c,h,y}^{PQ} \cdot (q_{t,c,h,y} - p_{t,c,y}) \\ &+ \sum_{h,y} \lambda_{c,h,y}^{CB} \cdot \left[\sum_t q_{t,c,h,y} + dq_{c,h,y} - eq_{c,h,y} - D_{c,h,y} \right] \\ &+ \sum_{h,y} \lambda_{c,h,y}^{CP} \cdot (dq_{c,h,y} + eq_{c,h,y} - cp_{c,y}) \end{aligned}$$

The first-order Karush-Kuhn-Tucker (KKT) conditions of both problems are then derived by differentiating these Lagrangians with respect to each primal variable. Setting the

partial derivatives to zero and imposing complementarity conditions yields the next KKT system:

$$\begin{aligned} \frac{\partial \ell_g}{\partial q_{t,g,h,y}} &= VC_{t,g,y} - \frac{\partial \lambda_{h,y}^E}{\partial q_{t,g,h,y}} \cdot q_{t,g,h,y} - \lambda_{h,y}^E + \lambda_{t,g,h,y}^{PQ} = 0 \\ \frac{\partial \ell_c}{\partial q_{t,c,h,y}} &= \lambda_{t,c,h,y}^{PQ} + \lambda_{c,h,y}^{CB} = 0 \\ \frac{\partial \ell_c}{\partial cp_{c,y}} &= TP_{c,y} - \sum_h \lambda_{(c,h,y)}^{CP} = 0 \\ \frac{\partial \ell_c}{\partial dq_{c,h,y}} &= -\frac{\partial \lambda_{h,y}^E}{\partial dq_{c,h,y}} \cdot (eq_{c,h,y} - dq_{c,h,y}) + (\lambda_{h,y}^E + TV_{c,y}) + \lambda_{c,h,y}^{CB} + \lambda_{c,h,y}^{CP} = 0 \\ \frac{\partial \ell_c}{\partial eq_{c,h,y}} &= -\frac{\partial \lambda_{h,y}^E}{\partial eq_{c,h,y}} \cdot (eq_{c,h,y} - dq_{c,h,y}) - (\lambda_{h,y}^E - TC_{c,y}) - \lambda_{c,h,y}^{CB} + \lambda_{c,h,y}^{CP} = 0 \\ \frac{\partial \ell_s}{\partial p_{t,s,y}} &= IC_{t,s,y} - \sum_h \lambda_{t,s,h,y}^{PQ} = 0, s \in C \cup G \end{aligned}$$

Together with the standard complementarity conditions, which ensure that the dual variable of each constraint is zero when that constraint is not active, and positive when it is:

$$\begin{aligned} \lambda_{c,h,y}^{CB} \perp \sum_t q_{t,c,g,y} - eq_{c,h,y} + dq_{c,h,y} - D_{c,h,y} &= 0 \\ 0 \leq \lambda_{t,s,h,y}^{PQ} \perp q_{t,s,h,y} - p_{t,s,y} &= 0 \\ 0 \leq \lambda_{c,h,y}^{CP} \perp dq_{c,h,y} + eq_{c,h,y} - cp_{c,y} &\leq 0 \\ \lambda_{h,y}^E \perp \sum_{t,g} q_{t,g,h,y} + \sum_c (eq_{c,h,y} - dq_{c,h,y}) &= 0 \end{aligned}$$