FACULTY OF ENGINEERING OF THE UNIVERSITY OF PORTO

Comparative analysis of the parameters needed to define the security of supply indicator and its application in the implementation of capacity mechanisms in different European countries

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Resumo

Com o aumento da participação das energias renováveis no mix energético dos países europeus, em particular em Portugal, verifica-se uma crescente pressão sobre a viabilidade económica das centrais térmicas. Estas unidades, apesar de produzirem energia com custos variáveis mais elevados, são fundamentais para garantir a Segurança de Abastecimento, uma vez que oferecem uma resposta rápida e firme a desvios entre as previsões e os valores reais de consumo e produção. No entanto, com a elevada penetração de fontes com custo marginal nulo, a receita obtida pelas centrais térmicas no mercado diário tem vindo a diminuir significativamente, colocando em causa a sua viabilidade económica e consequente funcionamento em mercado. Neste contexto, surgem os Mecanismos de Capacidade (MC), cujo objetivo é assegurar a viabilidade económica de ativos essenciais à segurança de abastecimento do sistema, através de uma remuneração complementar.

Esta dissertação explora as várias dimensões envolvidas na justificação e conceção de Mecanismos de Capacidade, bem como uma análise comparativa das metodologias utilizadas para definir o indicador de Segurança de Abastecimento em diversos Estados-Membros europeus. O estudo iniciou-se com uma comparação detalhada dos métodos de cálculo dos parâmetros Valor da Energia Não Servida (VoLL), Custo de Nova Entrada (CoNE) e o Padrão de Fiabilidade (RS), que resulta da combinação matemática dos dois primeiros. A análise incluiu a identificação das tecnologias consideradas no cálculo do RS, incluindo produção, armazenamento e *Demand Side Response* (DSR), bem como os respetivos custos fixos e variáveis de produção de eletricidade. Foram também avaliados indicadores relacionados com o investimento, como o Custo Médio Ponderado de Capital (WACC) e os prémios de risco (hurdle rate premiums).

A consistência dos valores de RS adotados por diferentes países foi avaliada com base no mais recente *European Resource Adequacy Assessment* (ERAA), permitindo refletir sobre o grau de cumprimento dos objetivos de fiabilidade declarados.

Uma revisão bibliográfica dos mecanismos de capacidade atualmente em vigor ou em fase de desenvolvimento na União Europeia e no Reino Unido complementaram a análise realizada, com especial atenção às características estruturais e aos requisitos de participação.

Por fim, o enquadramento teórico foi validado através de simulações utilizando o modelo PS-MORA, cujo desenvolvimento foi promovido pela REN em colaboração com o INESC TEC, e com recurso a um sistema teste simplificado da IEEE. Estas simulações permitiram quantificar a capacidade a ser apoiada pelo MC e validar se o RS obtido segundo a metodologia aprovada pela ACER corresponde ao ponto ótimo económico entre o investimento, custos operacionais e o custo da energia não servida. Esta confirmação pode ser verificada nos resultados das simulações. Nas simulações realizadas, primeiro, considerando um VoLL=25 €/kWh e um CONE de uma OCGT verificou-se que o RS calculado pela fórmula da ACER (RS = 3.0 h/ano) coincide com o valor de LoLE ótimo simulado pelo PS-MORA. Segundo, num cenário de maior penetração de renováveis, cujo sistema é mais dependente de tecnologias com custo de produção nulo, confirma-se igualmente a validação, ou seja, para VoLL=20 €/kWh e o mesmo CONE (pela fórmula, RS = 3.74 h/ano), o LoLE com menor custo total do sistema simulado foi cerca de 3.8 h/ano.

Abstract

With the increasing share of renewable energy sources in the energy mix of European countries, particularly in Portugal, there is growing pressure on the economic viability of thermal power plants. Although these units produce electricity with higher variable costs, they remain essential for ensuring Security of Supply, as they can provide a fast and firm response to deviations between forecasted and actual consumption and generation. However, due to the high penetration of zero marginal cost sources, the revenue obtained by thermal plants in the day-ahead market has significantly decreased, threatening their economic viability and continued operation in the market. In this context, Capacity Mechanisms (CM) have emerged, aiming to ensure the economic viability of assets critical to the system's security of supply through complementary remuneration.

This dissertation explores the various dimensions involved in the justification and design of Capacity Mechanisms, as well as a comparative analysis of the methodologies used to define the Security of Supply indicator across several European Member States. The study began with a detailed comparison of methods for calculating the parameters Value of Lost Load (VoLL), Cost of New Entry (CoNE), and the Reliability Standard (RS), which mathematically combines the first two. The analysis included identifying the technologies considered in the calculation of the RS—such as generation, storage, and Demand Side Response (DSR)—along with their fixed and variable costs of electricity production. Investment-related indicators, such as the Weighted Average Cost of Capital (WACC) and hurdle rate premiums, were also assessed.

The consistency of RS values adopted by different countries was evaluated based on the latest European Resource Adequacy Assessment (ERAA), allowing reflection on the degree of compliance with the declared reliability objectives. A literature review of capacity mechanisms currently in force or under development in the European Union and the United Kingdom complemented this analysis, with special attention to structural characteristics and participation requirements.

Finally, the theoretical framework was validated through simulations using the PS-MORA model, the development of which was promoted by REN in collaboration with INESC TEC, and using a simplified IEEE test system. These simulations made it possible to quantify the capacity to be supported by the CM and to validate whether the RS obtained according to the methodology approved by ACER corresponds to the economic optimum point between investment, operating costs and the cost of energy not served. This confirmation can be seen in the results of the simulations. In the simulations carried out, firstly, considering a VoLL=25 €/kWh and a CONE of an OCGT, it was found that the RS calculated by the ACER formula (RS = 3.0 h/year) coincides with the optimum LoLE value simulated by PS-MORA. Secondly, in a scenario with greater penetration of renewables, where the system is more dependent on technologies with zero production costs, the validation is also confirmed, i.e. for VoLL=20 €/kWh and the same CONE (according to the formula, RS = 3.74 h/year), the LoLE with the lowest total cost of the simulated system was around 3.8 h/year.

Keywords: Capacity Mechanisms (CM), Electricity Markets, Security of Supply, Reliability Standard (RS), Cost of New Entry (CoNE), Value of Lost Load (VoLL)

UN Sustainable Development Goals

The United Nations Sustainable Development Goals (SDGs) set a global roadmap towards inclusive economic growth, environmental protection, and improved quality of life. This dissertation, focused on the comparative analysis of methodologies for defining the Security of Supply (SoS) indicator and designing Capacity Mechanisms (CMs), aligns closely with several SDGs, most notably SDG 7 and SDG 9.

- **SDG 7 – Affordable and Clean Energy:**
  Target 7.1: By 2030, ensure universal access to affordable, reliable and modern energy services. The core objective of Capacity Mechanisms is to guarantee the reliability of electricity supply, even as systems become increasingly dependent on variable renewable energy sources (RES). By analysing parameters such as the Value of Lost Load (VoLL), Cost of New Entry (CoNE), and the Reliability Standard (RS), this work directly supports universal access to reliable and modern energy services. Specifically, it helps ensure that necessary investments are made to avoid interruptions, supporting a stable supply for all consumers at affordable costs.

  Target 7.2: By 2030, increase substantially the share of renewable energy in the global energy mix. Capacity Mechanisms enable power systems to integrate a larger share of renewables while maintaining system reliability. By ensuring the economic viability of flexible resources (e.g., storage and demand-side response), these mechanisms reduce the risk of supply shortages in systems with high renewable penetration. The dissertation contributes to this goal by benchmarking European practices and recommending approaches that can support a secure transition to renewable-dominated systems.

- **SDG 9 – Industry, Innovation and Infrastructure**
  Target 9.1: Develop quality, reliable, sustainable, and resilient infrastructure, including regional and transborder infrastructure, to support economic development and human well-being, with a focus on affordable and equitable access for all. This dissertation addresses how Capacity Mechanisms and robust reliability standards (such as RS) help ensure adequate investment in generation and flexibility assets, which are critical components of modern energy infrastructure. By evaluating methodologies that balance cost-efficiency with resilience, the research promotes the development of sustainable and reliable electricity infrastructure, not only within Portugal but also in a coordinated European context, supporting cross-border energy integration and economic development.

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So I'm ready for the next stage, with the ambition that has always characterised me!

João Areias

"Stay hungry, stay foolish."

Steve Jobs

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List of Acronyms

ACER	Agency for the Cooperation of Energy Regulators
AFC	Annual Fixed Costs
aFRR	Automatic Frequency Restoration Reserve
AGC	Automatic Generation Control
AMT	Annual Market Test
APM	Application of Probability Methods
AS	Ancillary Services
BC	Bilateral Contracts
BE	Belgium
CAPEX	Capital Expenditure
CC	Capital Costs
CCGT	Combined Cycle Gas Turbine
CM	Capacity Mechanism
CMU	Capacity Market Unit
CONE	Cost of New Entry
CONEfixed	Fixed Component of the Cost of New Entry
CONEvar	Variable Component of the Cost of New Entry
CO2	Carbon Dioxide
CORP	Cost of Renewal/Prolongation
CRM	Capacity Remuneration Mechanism
CY	Current Year
CZ	Czech Republic
DE	Germany
DG	Distributed Grid
DGEG	Direção-Geral de Energia e Geologia
DER	Distributed Energy Resources
DSM	Demand-Side Management
DSR	Demand-Side Response
EAC	Equivalent Annual Cost
EC	European Commission
EE	Estonia
EENS	Exprected Energy Not Supplied
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ES	Spain
EU	European Union
EVA	Economic Viability Assessment

FCR	Frequency Containment Reserve
FI	Finland
FR	France
FRR	Frequency Restoration Reserve
GHG	Greenhouse Gases
GR	Greece
HRP	Hurdle Rate Premium
IE	Ireland
IEEE	Institute of Electrical and Electronics Engineers
INESCTEC	Instituto de Engenharia de Sistemas e Computadores, Tecnologia e Ciência
IPP	Independent Power Producer
ISO	Independent System Operator
IT	Italy
LIBRA IT	Platform used in TERRE project
LNG	Liquefied Natural Gas
LoLC	Loss of Load Cost
LoLE	Loss of Load Expectation
LoLF	Loss of Load Frequency
MARI	Manually Activated Reserves Initiative
MCP	Market Clearing Price
MCQ	Market Clearing Quantity
MIBEL	Mercado Ibérico de Eletricidade
MS	Member States
MTTR	Mean Time To Repair
NL	Netherlands
NPP	Nuclear Power Plant
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OMIE	Operador do Mercado Ibérico de Energia
OPEX	Operational Expenditure
OPF	Optimal Power Flow
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PL	Poland
PNEC 2030	Plano Nacional Energia e Clima 2030
PP1	Produit de Capacité de type 1
PP2	Produit de Capacité de type 2
PS-MORA	Power Systems Model for Operational Reserve Adequacy
PT	Portugal
PV	Photovoltaic
REE	Red Eléctrica de España
REN	Redes Energéticas Nacionais
RES	Renewable Energy Sources
RMSA	Relatório de Monitorização da Segurança de Abastecimento
RMSA-E	RMSA do Sistema Elétrico Nacional
RO	Reliability Options
RR	Replacement Reserve
RS	Reliability Standard

RTE	Réseau de Transport d'Électricité
RTS	Reliability Test System
SE	Sweden
SEN	Sistema Elétrico Nacional
SI	Slovenia
SMCS	Sequential Monte Carlo Simulation
SMRC	Short-Run Marginal Cost
SoS	Security of Supply
TENSA	Transmisora de Energía Nacimiento S.A.
TERRE	Trans European Replacement Reserves Exchange
TG	Transmission Grid
TSO	Transmission System Operator
TY	Target Year
UF	Utilization Factor
UK	United Kingdom
VoLL	Value of Lost Load
VOM	Variable Operation and Maintenance
W	Watt
WACC	Weighted Average Cost of Capital
WTA	Willingness to Accept
WTP	Willingness to Pay

Chapter 1

Introduction

1.1 Framework

The European energy landscape is amid a major transformation, with a stronger focus on the security of supply, enhancing energy sovereignty, building resilience against new challenges, and increasing the use of renewable primary energy sources as a way to reduce greenhouse gas (GHG) emissions. The onset of the war in Ukraine disrupted Russian gas exports to Europe, leading to a significant increase in gas prices. This was largely due to Europe needing to import liquefied natural gas (LNG) from alternative suppliers, such as the United States. The urgency to secure a stable and sustainable energy supply has driven the European Union to advance frameworks like the Electricity Market Design Revision Package, which aims to address the complexities of a diversified energy mix and strengthen reliability.

Within this shifting landscape and to ensure the security of electricity supply in Europe, Capacity Mechanisms (CM) are no longer temporary instruments but are evolving into core market structures, especially after the adoption of the Regulation (EU) 2019/943 [1], which establishes the rules for the internal electricity market in the European Union, aiming to foster market integration, competitiveness, and the transition to clean energy while ensuring security of supply and protecting consumers. This regulatory framework was further reinforced by Regulation (EU) 2024/1747 [2], which amended the 2019 text to improve the design of the Union's electricity market. The primary function of CM, ensuring sufficient capacity to meet fluctuating demand, plays a critical role in sustaining energy security, a crucial aspect as Europe navigates its path toward decarbonization and renewable integration. The variability of renewable sources, such as wind and solar, introduces significant challenges for ensuring security of supply. Energy systems must address this variability while ensuring a reliable and stable energy supply, especially as the continent accelerates its transition toward a renewable-dominated energy mix.

1.2 Motivation

1.2.1 Portugal Energy's mix

Renewable sources increasingly dominate Portugal's energy mix. During 2024, the total electricity production in mainland Portugal reached 45,6 TWh, of which 80.4% originated from renewable sources [3]. When considering the country's total electricity consumption, which amounted to 51.4 TWh [79], domestic renewable generation accounted for approximately 70% of the demand [4]. Figure 1.1 illustrates the detailed distribution of energy production.

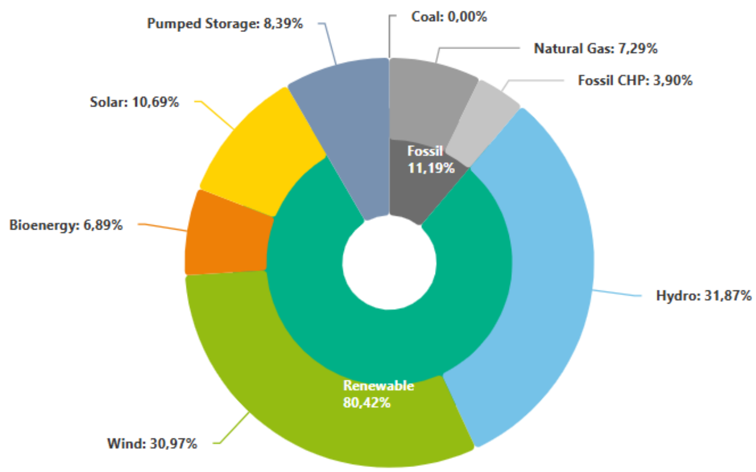

Figure 1.1: Electricity Generation by Energy Sources in Mainland Portugal in 2024[3]

As part of the Iberian Electricity Market (MIBEL), a joint market with Spain, Portugal is constantly trading energy with the neighbouring country. In 2023 and 2024, the electricity import balance corresponded to 20% of total consumption, indicating that the net difference between imported and exported electricity was positive for Portugal [5]. It should also be noted that the Figure 1.1 refers exclusively to electricity production. However, electricity consumption only accounts for around 24% of the country's total energy consumption, the rest being distributed among other forms of energy, such as oil, natural gas, and biomass.

1.2.2 Presentation of the REN and the relevance of the proposed MSc Thesis

Redes Energéticas Nacionais (REN) plays a central role in the management of the Portuguese energy system, being responsible for operating the National Electricity System (SEN) and National Gas System and ensuring the security of electricity and gas supply. As the transmission system operator, REN ensures the real-time management of the very high-voltage electricity network (400, 220 and 150 kV), guaranteeing the continuous balance between energy production and consumption. In addition, REN is responsible for the strategic planning of the expansion and modernization of electricity infrastructures, including the assessment of future capacity needs. These responsibilities are fundamental to maintaining grid stability, minimizing outages, and promoting the efficient integration of electricity markets, namely through the Iberian Electricity Market (MIBEL).

REN is also the operator of the Portuguese National Gas System, covering mainland Portugal and including key infrastructure such as the interconnections with the Spanish network, the Liquefied Natural Gas (LNG) Terminal in Sines, and the underground storage facilities. It plays a growing role in the transportation and integration of renewable gases into the national network, aligned with the country's decarbonization strategy. REN has also expanded its presence in the gas distribution sector, following its acquisition of Portgás, one of Portugal's main natural gas distribution companies.

Internationally, REN has made strategic investments to diversify its portfolio and reinforce its position in electricity transmission. In 2019, the company acquired Transemel in Chile, and more recently, in 2025, REN expanded its footprint in the Chilean market by acquiring Transmisora de Energía Nacimiento S.A. (TENSA).

The proposal for this MsC dissertation arose directly from the collaboration of the author with REN, reflecting the strategic importance of adapting the mechanisms of the Portuguese electricity sector to European requirements. To guarantee the security of supply at the long term in the context of energy transition, Portugal faces the challenge of adjusting the technical and economic indicators that support the capacity mechanisms. These indicators, such as the Value of Lost Load (VoLL), the Cost of New Entry (CoNE), and the Reliability Standard (RS), are essential to comply with the European regulatory framework, namely the provisions established by Regulation (EU) 2019/943. This regulation requires member states to align their security of supply standards and calculation methodologies with the guidelines defined by the Agency for the Cooperation of Energy Regulators (ACER).

The suitability of these indicators is particularly relevant in a country like Portugal, where the dependence on renewable energy sources, such as wind and solar, creates significant challenges of variability and the need for flexibility in the electricity system. The proposal of this work therefore aims to benchmark the practices of other Member States in applying these indicators and identifying opportunities to improve the efficiency and resilience of the SEN. In addition, this study allows to assess the feasibility of solutions that ensure a stable energy supply while promoting economic and environmental sustainability, in line with national and European decarbonization objectives.

1.2.3 The importance of capacity mechanisms for SEN

Monitoring security of supply is a responsibility of the Member State, more precisely the Energy Government Sector, which plays a central role in analysing and implementing measures related to the adequacy of the SEN. In this context, the importance of the Security of Supply Monitoring Report (RMSA) stands out, as it is an essential tool for assessing the system's operating conditions, reliability, and the long-term guarantee of supply. Although this Energy Government Sector holds the responsibility for such assessments, the Transmission System Operator, plays a key supporting role by contributing technical expertise and data to the preparation of adequacy studies such as the RMSA. Directly associated with the RMSA, the Reliability Standard (RS) is an indicator that defines the minimum objectives of security and reliability in the supply of electricity. In turn, the RMSA-E (Security of Supply Monitoring Report of the National Electricity System) checks that the resources available in the system - including generation, storage, and demand-side response - are sufficient to fulfil the objectives set by the RS. Thus, while the RS establishes the regulatory framework, the RMSA-E ensures, through detailed analyses, that the available resources remain adequate over time to maintain the security of supply. The specific indicators of the RS will be discussed later in this document. Based on the above framework and the provisions of Regulation (EU) 2019/943 and Decree-Law no. 15/2022, it can be concluded that the Reliability Standard (RS), to be calculated by each Member State, is essential to justify the implementation of capacity mechanisms (CM), thus highlighting the relevance of CM for the SEN.

1.3 Objectives

The main aim of this dissertation is to develop a comparative analysis of the parameters needed to define the security of supply indicator and its application in the implementation of Capacity Mechanisms in the different Member States of the European Union. This work aims to contribute to aligning the practices of the Portuguese electricity sector with European regulatory requirements, namely in the calculation of technical and economic parameters, such as the Value of Lost Load (VoLL), the Cost of New Entry (CoNE), and the Reliability Standard (RS). The aim is also to assess the technologies considered, the costs involved, and the safety standards defined, especially focusing on their impact on Portugal.

The general objectives of the work are organized into seven sequential tasks:

1. Framing the problem and general objectives: Contextualise security of supply in Europe and Portugal, detailing the current challenges and the relevance of capacity mechanisms.

2. Review: Analyse and understand the fundamental concepts, legislative framework, methodologies, and existing studies on security of supply at the National and European level.

3. Data collection and processing: Identify and analyse information on the studies carried out by the different member states, including:

   a. Technologies evaluated (production, storage, demand-side response).

   b. Fixed and variable costs, financing costs, and risk premiums.

   c. Technical parameters, sectorial VoLLs, and security of supply standards.

4. Setting up the comparison grid and drawing conclusions: Draw up a comparison matrix to identify good practices and possible gaps in the indicators applied by the member states.

5. Simulations of the electricity generation system with REN's probabilistic model, PS-MORA: Use an IEEE test network to validate the calculations of the security of supply standards, considering the VoLL and CoNE parameters.

6. Validating the results and drawing conclusions: Focus on the impact of the proposed methodologies for Portugal, assessing the feasibility and benefits of the solutions in the national context.

7. Writing the dissertation document: Structuring and writing the final report, consolidating the analyses and conclusions reached throughout the work.

These objectives, both in the preparatory phase and the main phase, are fundamental to achieving a robust methodological approach and a practical contribution to the Portuguese electricity sector.

1.4 Document Structure

In addition to Chapter 1, the Introduction, this dissertation consists of five further chapters.

Chapter 2 describes the restructuring of the electricity sector and the organization of electricity markets in Portugal, with particular focus on the integration into MIBEL, the functioning of day-ahead and intraday markets, and the challenges posed by the evolution of the energy mix.

Chapter 3 presents a comparative analysis of the methodologies used across EU Member States to calculate the Value of Lost Load (VoLL), the Cost of New Entry (CoNE), and the Reliability Standard (RS). It also examines investment-related indicators, such as the Weighted Average Cost of Capital (WACC) and Hurdle Rate Premium (HRP), and compares reported values among different countries.

Chapter 4 analyses the main capacity mechanisms implemented or under development in Europe. It discusses regulatory frameworks, structural features, and participation requirements, while also identifying possible barriers to implementing a Capacity Mechanism in Portugal.

Chapter 5 details the simulation methodology used to validate the theoretical framework, including the use of the PS-MORA probabilistic model and the configuration of scenarios with different renewable penetration levels. It also presents the results of these simulations and their interpretation.

Finally, Chapter 6 summarises the main conclusions drawn from this work and suggests possible directions for future work, especially in the context of improving security of supply indicators and adapting them to the Portuguese context.

Chapter 2

Restructuring the Electricity Sector and Electricity Markets

This chapter introduces the restructuring of the electricity sector and the organization of electricity markets. It details the transition from vertically integrated companies to a decentralized structure, where production and retailing activities operate in competitive markets. At the same time, the transmission and distribution networks remain regulated under exclusive concessions.

The chapter also reviews the current organization of the electricity sector in Portugal, providing a detailed explanation of the daily electricity market and the mechanisms through which prices are determined. Particular attention is given to specific challenges that complicate the ongoing energy transition.

Lastly, the final section of this chapter describes the evolution of the Portuguese electricity generation mix, the ambitious targets outlined in the National Energy and Climate Plan 2030 (PNEC 2030), and the inherent dynamics of the daily electricity market. These factors have collectively led to a remuneration challenge for certain generation technologies, a problem that this dissertation aims to address and provide potential solutions for.

2.1 Restructuring the Electricity Sector

The electricity sector in Europe, including Portugal, has undergone profound transformations in recent decades, evolving from a vertically integrated model (as shown in Figure 2.1) to a liberalized market structure illustrated in Figure 2.2. Historically, the electricity supply chain operated as a unified system in which a single entity controlled all activities, including generation, transmission, distribution, and retailing. This model allowed for centralized planning and reliable delivery of electricity but often resulted in inefficiencies, lack of innovation, and limited competitiveness due to the monopolistic nature of the system.

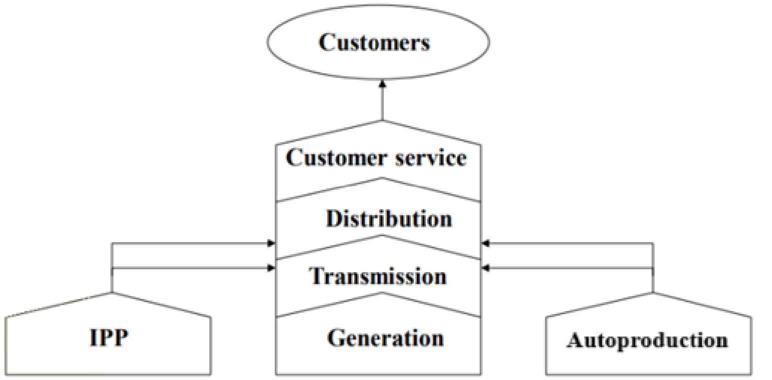

Figure 2.1: Vertically Integrated Structure of the Portuguese Electricity Sector[6]

Because of this organizational structure, there was no competition amongst the several companies that were present in the market. Every company operated in a specific concessioned geographical area and was designated a certain group of clients who could only be served by the supplier in their region. This kind of organization presented several difficulties, especially concerning industry regulation. In addition to the lack of instruments to induce cost reductions, such as competition in certain value chain activities, there was a very thin boundary between the regulatory institution and the entity being regulated. [7]

The need to reform this model was largely driven by the intention to increase the sector's competitiveness and efficiency, reduce costs for consumers, and allow for the integration of renewable energy sources. Although some EU countries started the reform before, the liberalization process was driven by the adoption of EU Directive 96/92/EC, which established a framework for the progressive opening of electricity markets. This directive required the unbundling of generation and retailing activities, allowing them to operate on a competitive basis in the market, while transmission and distribution network activities remained regulated under exclusive concessions. These measures were crucial to fostering competition between electricity producers and suppliers, stimulating investment, and offering greater choice to consumers.

In Portugal, this transition reflected European developments, with reforms that sought to align the country's electricity sector with EU directives. The importance of this restructuring, as shown in Figure 2.2, is undeniable. The separation of transmission and distribution activities - which remained natural monopolies under regulation - from production and retailing activities, which were opened to competition, allowed for the creation of more dynamic and competitive electricity markets. In addition, this restructuring laid the foundations for the integration of renewable sources and the advancement of the energy transition, in line with European decarbonisation objectives.

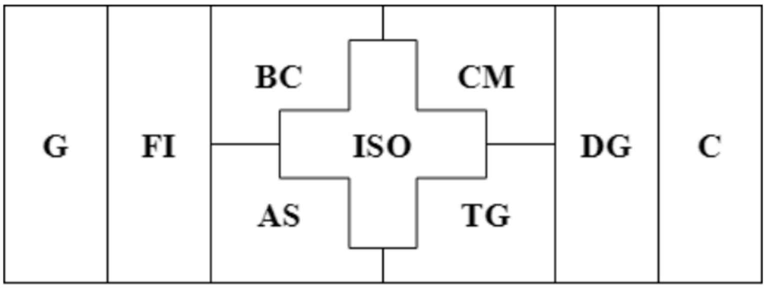

Figure 2.2: Unbundled structure of the Portuguese electricity sector [6]

There are two separate fields in this scheme. There is fierce competition on both the generation (G) and retail/commercialization (C) sides (and, by extension, the financial intermediation of generation, FI). In the former case, multiple businesses compete with one another to sell electricity, while in the latter case, they buy it on the market and resell it to end users. In a separate structure, the State grants monopoly concessions to two single businesses for the Transmission Grid (TG) and Distribution Grid (DG). Like all other levels, these services are regulated, especially regarding the quality of the service and the involved costs, revenues, and associated tariffs. The following categories apply to the tasks of the electrical sector that are carried out between generating and distribution:

- **Bilateral Contracts (BC):** Contracts of a physical or financial nature, established directly between producers and retailers or eligible customers. These contracts define the price, quantity of energy to be produced/consumed, and the contract duration.
- **Centralized Markets (CM):** An entity that receives buy and sell offers for electricity for the following day's periods. The proposals include power values and a minimum price to receive (for sell offers) or a maximum price to pay (for buy offers). The output resulting from the intersection of the aggregated curves of these two types of proposals represents the total amount of energy traded and the market price for each period.
- **Transmission Grid (TG):** Entities responsible for the construction, maintenance, and operation of the electricity transmission network, operating under a natural monopoly regime. They are remunerated through the application of the Network Usage Tariffs included in the final end user tariffs paid by consumers.
- **Ancillary Services (AS):** Entities responsible for ancillary services, such as reserve services, voltage control, and frequency control. The necessary ancillary services can be contracted in specific markets, or mandatory conditions may be defined for market participation.
- **Independent System Operator (ISO):** An entity responsible for ensuring the operation of the transmission network, considering the market dispatch and the information from established bilateral contracts. It must assess the technical feasibility of the combination of bilateral contracts and the original market dispatch for each period of the following day,

ensuring their technical viability while also being responsible for the online monitoring of the whole system.

Despite the benefits obtained, liberalization has also brought significant challenges, such as the need to ensure the economic viability of market players and to guarantee investments in network infrastructures. This context reinforces the importance of regulatory mechanisms that promote the efficiency and sustainability of the sector while ensuring its ability to respond to the demands of the energy transition [8].

2.2 The Portuguese Electricity Market and Its Integration into MIBEL

2.2.1 Introduction to the Electricity Market in Portugal

The Portuguese electricity market plays a pivotal role in the country's energy sector, ensuring that electricity is traded efficiently, transparently, and competitively. Portugal's electricity market is integrated into the Iberian Electricity Market (MIBEL), which was established to harmonize the electricity markets of Portugal and Spain, creating a single market that facilitates cross-border trading and fosters competition.

MIBEL was created as part of a broader European Union initiative to integrate electricity markets across member states and develop an energy market at the EU level. It is structured into four distinct markets, each serving specific purposes and timeframes. These markets are:

- **Day-Ahead Market:** A centralized pool market where electricity is traded for delivery on the following day.
- **Intraday Auction Market:** A same-day adjustment market, operating through scheduled auction sessions.
- **Continuous Intraday Market:** An EU level adjustment market that allows continuously trading until one hour before delivery.
- **Forward Market:** A market for short-term and long-term futures contracts, enabling market agents to hedge against price fluctuations.

While all four components play an essential role in the functioning of MIBEL, this chapter focuses primarily on the day-ahead and intraday markets, as these are the most critical for daily operations and market adjustments.

Apart from these active energy markets, the TSOs of each of the countries procure reserve services, given that FCR (Frequency Containment Reserve) is mandatory and non-paid, while aFRR (automatic Frequency Restoration Reserve) and RR (Replacement Reserve) are contracted by each TSO on the afternoon/evening of the day before operation in specific marginal-based markets. Further details on the reserve products will be provided in Section 2.2.5.

2.2.2 The Pool Market Structure: Symmetric Model

The Iberian electricity market operates under a symmetric pool model. This model centralizes the trading of electricity, where all participants (buyers and sellers) submit their bids to a central market operator. The market operator matches supply and demand through an auction process to determine the market-clearing price and the cleared quantity.

The pool is "symmetric" because buying and selling bids are treated equally. Both demand and supply bids are ranked based on the bid prices, and the market-clearing price is determined at the intersection of the aggregated supply and demand curves. This ensures that all accepted buying and selling offers are settled at the same price, as it is illustrated in Figure 2.3.

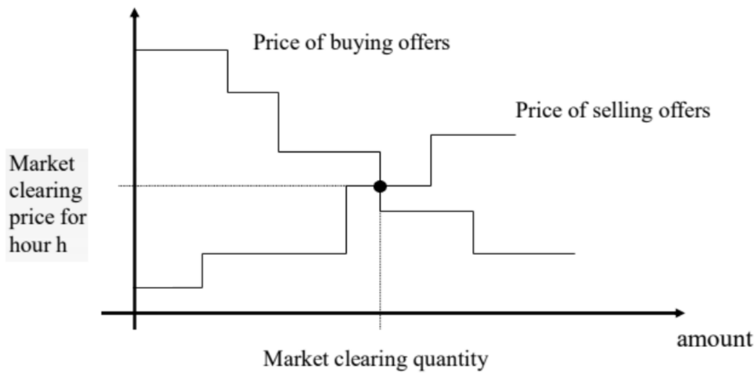

Figure 2.3: Example of the Symmetrical Pool Market [6]

The "Market Clearing Price" (MCP) for a specific hour ("h") is determined at the point where the curve of buying bids intersects with the curve of selling bids. The corresponding quantity at this point is the "Market Clearing Quantity." Only offers that meet the MCP are accepted, while others are excluded from the market.

2.2.3 The Day-Ahead Market

The day-ahead market is a key component of the Iberian electricity market, MIBEL. This market facilitates the trading of electricity for delivery on the next day. Producers and consumers submit their bids to the market operator, specifying the quantities they wish to buy or sell and the corresponding prices. These bids are submitted in hourly blocks, reflecting the hourly variations in electricity demand and supply and in the available primary resources.

The market operates as follows:

- **Submission of Offers:** Market agents (producers and consumers) submit their bids to the market operator (OMIE, the designated operator for MIBEL).
- **Price Order:** The market operator ranks all offers in ascending order of price for supply and descending order for demand.

- **Market Clearing:** The market-clearing price is determined at the intersection of the aggregated supply and demand curves, as shown in Figure 2.3. This price represents the equilibrium price for electricity for each hour of the following day.

Electricity is traded in the day-ahead market at prices expressed in euros per megawatt-hour (€/MWh). Only producers whose selling bids are accepted receive payment, while those whose bids exceed the market-clearing price do not receive any compensation. This mechanism incentivizes producers to submit competitive bids and ensures efficiency in the allocation of resources.

The daily provisional dispatch is subject to validation against the declared transmission interconnection capacity available for each hour of the next day between Portugal and Spain. If for a given hour, the available interconnection transmission capacity is exceeded, the dispatch is adjusted using the Market Splitting mechanism and different prices can then be obtained for Portugal and Spain.

2.2.4 The Intraday Markets

Complementing the day-ahead market, the intraday markets allow participants to adjust their positions closer to real-time. This market is essential for managing deviations from the initial schedule due to unforeseen changes in demand or generation capacity. For instance, renewable energy sources like wind and solar often experience variability in output, making the intraday market a vital tool for balancing the system. In this regard, it should be noted that the day ahead market is based on bids submitted in the monitoring of the day before, and its schedules are for all of the hours of the next day, that is, there is a time gap of 12 to 36 hours, between bid submission and of real time operation.

The intraday market operates through multiple trading sessions throughout the day, enabling market participants to buy or sell electricity in response to updated forecasts and system needs. This dynamic mechanism enhances flexibility and helps maintain grid stability, ensuring that supply and demand are balanced in near real time. The role of the intraday market becomes increasingly significant as the share of renewable energy in the electricity mix grows, requiring adaptive measures to address variability and unpredictability.

More recently, since 2018, the Iberian Market Operator, and so Portugal and Spain, also participated in the Continuous Intraday Market that allows transmitting buying and selling orders till 1 hour prior to delivery. This means that when a new buying/selling order is transmitted, it is included in a shared order book, and it is cleared if there is in that book a selling/buying order having a lower/higher price. It should, however, be emphasized that this matching depends on the availability of transmission interconnection capacity between the two involved bidding areas.

2.2.5 The Ancillary Services Market

Ancillary services are essential for maintaining the stability, security, and reliability of power systems. They ensure real-time balance between electricity generation and demand while managing grid constraints [9]. These services include:

2.2.5.1 Frequency Control and Active Power Reserves

To maintain system frequency at nominal levels (50 Hz in Europe), three types of reserves are used:

- Primary Reserve (FCR – Frequency Containment Reserve):
  - Mandatory and automatic, activated within 15–30 seconds to counteract sudden frequency deviations.
  - Provided by generators' speed governors, non-remunerated in most markets (e.g., Portugal and Spain).
- Secondary Reserve (aFRR – Automatic Frequency Restoration Reserve):
  - Remunerated and market-based, activated within 30 seconds to 15 minutes to restore frequency to its nominal value.
  - Managed via the Automatic Generation Control (AGC) and contracted in advance through balancing markets.
- Tertiary Reserve (RR – Replacement Reserve):
  - Activated within 15 minutes and sustained for several hours to replace secondary reserves or correct larger imbalances.
  - Procured through balancing markets, with pricing based on marginal offers.

2.2.5.2 Voltage and Reactive Power Control

Ensures stable voltage levels across the grid.

- In Portugal, it is a mandatory, non-remunerated service provided by generators and grid devices.
- In Spain, a hybrid model exists (mandatory for some, voluntary and remunerated for others), though in practice, it is mostly enforced without payment.

2.2.5.3 Resolution of Internal Technical Constraints

Addresses grid congestion by adjusting generation or demand to prevent overloads. Managed in two phases:

- Phase I: Modifies generation schedules using market offers to relieve congestion.
- Phase II: Ensures system balance if Phase I adjustments create new imbalances.

2.2.5.4 System Restoration (Black Start)

This service has the following main objectives:

- Enables rebooting the grid after a total or partial blackout.
- Remunerated and critical for resilience.
- Requires predefined restoration plans and coordination between TSOs (e.g., REN and REE in MIBEL).

These services are managed by Transmission System Operators (TSOs) under regulatory frameworks such as the European Network of Transmission System Operators for Electricity (ENTSO-E) guidelines and MIBEL procedures [9]–[11]. ENTSO-E's mission is to guarantee the reliability of the pan-European interconnected power system across all time horizons, alongside promoting the efficient operation and evolution of Europe's integrated electricity markets, while facilitating the integration of renewable energy generation and new emerging technologies.

2.2.5.5 TERRE, MARI, and PICASSO

In recent years, European system service markets have undergone significant harmonization and integration, largely driven by the Electricity Balancing Guideline [12] and several cross-border cooperation projects coordinated by ENTSO-E. These efforts aim to optimize the use of balancing resources across Member States, enhance system security, and reduce the overall cost of balancing. One of the foundational initiatives in this regard was the Trans European Replacement Reserves Exchange (TERRE) project, which facilitated the cross-border exchange of replacement reserves through the LIBRA IT platform. TERRE provided a standard product for balancing energy and operated successfully until its planned phase-out by the end of 2025 due to legal constraints [13]. Complementing TERRE, the Manually Activated Reserves Initiative (MARI) represents the European platform for the exchange of manually activated Frequency Restoration Reserves (mFRR). The MARI platform became operational in 2022 and has since expanded its membership to include TSOs across continental Europe, including the Portuguese TSO during Q4 2024 [14]. Alongside MARI, the PICASSO project—Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation—facilitates the exchange of automatically activated Frequency Restoration Reserves (aFRR), enabling more precise and automated control of system frequency deviations [15]. These platforms play a vital role in supporting the day-ahead and intraday energy markets by providing real-time flexibility, helping maintain the delicate balance between supply and demand, and enhancing the overall efficiency of the European electricity system. Their coordinated operation is a cornerstone in the evolution toward a truly integrated and resilient European electricity market.

2.2.6 The Role of MIBEL

The integration of the Portuguese electricity market into MIBEL has brought significant benefits, including:

- **Price Convergence:** Harmonization of electricity prices between Portugal and Spain, fostering economic efficiency.
- **Increased Competition:** Enhanced competition among market agents, resulting in more competitive prices for consumers.
- **Cross-Border Trading:** Facilitation of electricity trading across the Portuguese-Spanish border, improving market liquidity.
- **Market Transparency:** Implementation of transparent rules and mechanisms for market operation, ensuring fair competition and regulatory oversight.

MIBEL operates under a dual mechanism, comprising the pool market (day-ahead and intraday markets) and bilateral contracts. While the pool market provides a centralized platform for trading, bilateral contracts allow market agents to negotiate terms directly, offering flexibility and risk management options.

To conclude, the Portuguese electricity market, integrated within MIBEL, exemplifies a modern and efficient market design that promotes competition, transparency, and sustainability. The symmetric pool model and the day-ahead market are critical components that ensure the efficient allocation of resources and fair pricing for market agents. As Portugal continues to transition toward a low-carbon economy, the electricity market will play a crucial role in facilitating this transition while addressing emerging challenges and opportunities.

2.3 Evolution of the Energy Mix and Capacity Remuneration Challenges

Portugal has made significant strides in transforming its electricity mix, aligning with the targets set in the National Energy and Climate Plan (PNEC) 2030. The country aims to achieve approximately 93% of its electricity consumption from renewable sources by 2030 [16]. This ambitious goal necessitates substantial changes in the national electricity generation landscape.

In recent years, Portugal has diversified its renewable electricity portfolio, with notable increases in hydro, wind, and solar capacities. As of 2023, the total installed capacity in the National Electricity System reached 24.342 MW [17]. This expansion has led to a significant reduction in fossil fuel dependency, with fossil fuels accounting for just 10% of total electricity generation in 2024 [18].

The integration of renewable energy sources has impacted the operational dynamics of natural gas-fired power plants. These plants are now operating fewer hours and often at lower market prices due to the priority dispatch and zero marginal cost of renewables. This situation challenges the economic viability of natural gas plants, as their reduced operation hours and diminished revenue streams may not cover fixed and variable costs.

To address these remuneration challenges and ensure the security of supply, the introduction of capacity mechanisms is under study. These mechanisms provide payments to electricity generators for maintaining available capacity to meet peak demand, regardless of actual energy production. In Portugal, the DGEG oversees such capacity mechanisms, aiming to balance the market and ensure system reliability.

In summary, while Portugal's transition towards a predominantly renewable energy mix is progressing robustly, it introduces challenges related to the remuneration of conventional power plants. Implementing capacity mechanisms is essential to ensure that these plants remain financially viable and capable of contributing to the security and stability of the electricity supply.

2.3.1 Introduction to Capacity Mechanisms or Capacity Remuneration Mechanisms

2.3.1.1 Concept of Capacity Mechanisms

Capacity Remuneration Mechanisms (CRMs) or just Capacity Mechanism (CM) are tools that can be employed by the European Union member states to safeguard the reliability of electricity supply over the medium and long term. These mechanisms provide financial incentives to electricity producers, ensuring they maintain sufficient capacity to generate power during times of high demand or when the availability of other primary resources (as hydro, wind, and solar) is reduced. In practice, CRMs offer payments to power plants for their availability to produce electricity when required, complementing the revenues they earn through energy sales in the market.

Designed to address specific system adequacy issues, CRMs aim to interfere as little as possible with the normal operation of energy markets. However, their coexistence with "energy-only markets"—where producers rely solely on earnings from electricity sales—can create imbalances within the internal EU electricity market. To prevent unnecessary disruptions, the European Commission stipulates that CRMs should be used sparingly and only when strictly necessary. They must also be proportional to the severity of the adequacy problem they intend to solve, ensuring that available and planned capacity is sufficient to always meet demand without creating market distortions [19].

While the European Commission initially framed CRMs as temporary solutions, their role has evolved. Instead of being short-term interventions, CRMs now often serve as long-term instruments to maintain resource adequacy in electricity systems.

The primary goal of modern CRMs is to ensure there are enough resources in the long term, such as power generation units, storage facilities, or demand-response mechanisms, to meet the system's needs during periods of peak demand or shortage of other primary resources. By doing so, they help minimize the risk of forced electricity disconnections, like blackouts. These mechanisms frequently involve long-term contracts, typically spanning one year or more, which compensate providers for maintaining capacity rather than solely for producing energy. This transition highlights the shift from short-term, reactive measures to proactive strategies aimed at strengthening the reliability and resilience of electricity markets over the long term [20].

2.3.1.2 Main reasons for the implementation of Capacity Mechanisms

These mechanisms play a crucial role in addressing resource adequacy challenges and ensuring the stability of electricity systems, as previously referred to. Some of these benefits are listed and explained in the next paragraphs.

Enhancing Security of Supply

Capacity remuneration mechanisms (CRMs), including instruments such as reliability options (ROs), play a critical role in addressing systemic vulnerabilities related to the security of the electricity supply. By ensuring sufficient capacity is available to meet demand, CRMs help to prevent disruptions, such as blackouts, and maintain a stable electricity supply, even during periods of peak consumption or unexpected system stress [21].

One of the key contributions of CRMs is their ability to address the "missing money" problem—an inherent limitation in energy-only markets, where market revenues are often insufficient to cover the fixed costs required to maintain or invest in adequate generation capacity. By providing predictable payments for capacity availability, CRMs incentivize investments in essential infrastructure, thereby ensuring long-term reliability of supply [22].

Free electricity market or incorporate capacity mechanisms

The decision to maintain a free electricity market or to incorporate capacity mechanisms (CM) involves weighing the benefits of market liberalization against the potential for enhanced consumer participation and energy security. Proponents of market liberalization believe that the market is capable of adjusting itself, potentially leading to more efficient resource allocation and innovation [23]. In theory, this framework appears perfect, but in practice, the implementation of capacity mechanisms (CMs) provides multifaceted benefits. Not only do they enhance consumer participation by enabling active involvement in energy trading—potentially leading to greater social welfare and improved system efficiency—but they also bolster energy security and system stability. By offering financial incentives to critical producers, such as flexible gas plants, CMs ensure their economic viability even as these units operate fewer hours due to the increasing penetration of distributed energy resources (DERs). Furthermore, CMs support investments in energy storage and demand-side response technologies, maintaining grid balance and reliability. By addressing variability and covering fixed costs, these mechanisms guarantee the continued operation of essential producers, thereby fostering a more resilient and robust energy system.

2.3.1.3 Types of Capacity Mechanisms

Capacity mechanisms are characterized as "volume-based mechanisms" or "price-based mechanisms". Figure 2.4 shows the categorization of CMs based on their characteristics.

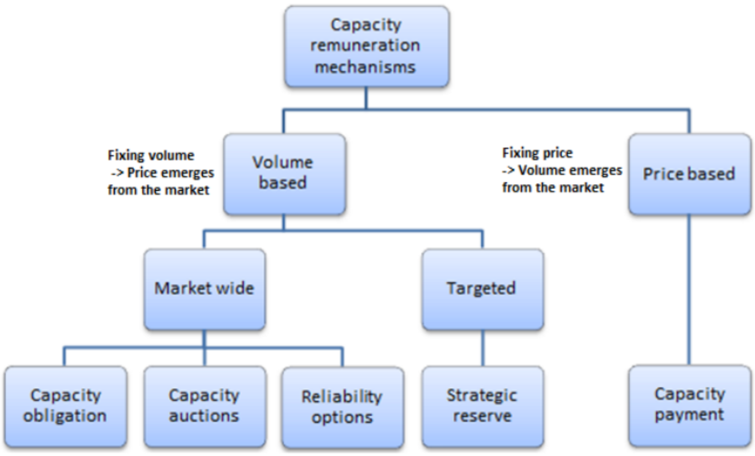

Figure 2.4: Taxonomy of capacity mechanisms [24]

In volume-based mechanisms, policymakers determine the required volume of capacity, allowing the market to establish the corresponding price. Conversely, in price-based mechanisms, policymakers set a fixed price, leaving investors to decide the level of investment they are willing to commit at that price. Targeted mechanisms focus on rewarding specific plants or technologies, while market-wide mechanisms provide incentives to all capacity providers. Additionally, capacity mechanisms can be classified based on their contracting approach: decentralized mechanisms involve bilateral agreements, as seen in capacity obligations, whereas centralized mechanisms rely on centrally managed processes, such as capacity auctions [25].

Description of the different capacity mechanisms employed in the EU [25]

- **Capacity Obligation:** Large electricity consumers or suppliers are obligated to secure a certain level of capacity, typically calculated based on their future consumption or supply estimates, along with a reserve margin. This obligation is fulfilled through contracts with capacity providers, often formalized using certificates. Financial penalties are imposed if the required capacity levels are not met.

- **Capacity Auction:** The required capacity is centrally established several years ahead and procured through auction processes. Capacity providers submit bids to receive payments that typically reflect the costs associated with new capacity construction. The newly built capacity operates within the energy-only market. However, this mechanism carries the risk that market price signals may not sufficiently drive investment decisions, potentially leading to competition between new and existing capacities.

- **Reliability Options:** Capacity providers enter an option contract with counterparties, such as transmission system operators or large consumers and suppliers. These contracts grant the counterparty the right to procure electricity at a pre-agreed strike price during periods of scarcity when spot market prices exceed the strike price. This mechanism ensures availability during critical demand periods.

- **Strategic Reserve:** A central authority, such as a transmission system operator or government agency, determines the necessary capacity several years in advance and contracts it as a strategic reserve, often through a competitive bidding process. The contracted power plants are excluded from participating in the regular electricity market and are only activated under predefined conditions to address capacity shortages.

- **Capacity Payments:** Regulators set fixed payments for capacity providers to ensure the availability of resources. These payments are typically granted irrespective of whether the plants are actively running, as long as they meet certain availability criteria. Capacity providers receiving such payments continue to participate in the energy-only market.

2.3.1.4 Current situation on the EU regarding the use of Capacity Mechanisms

Capacity mechanisms are becoming an integral tool in ensuring the security of supply across Europe, as demonstrated by their widespread implementation depicted in Figure 2.5. Various forms of CMs are currently operational or under consideration in different member states, highlighting the diverse approaches to addressing capacity adequacy challenges. The most implemented mechanisms are strategic reserves, which are operational in countries like Belgium, Germany, Poland, Sweden, and Finland.

Germany, for instance, utilizes a strategic reserve model where grid operators secure and maintain 2 GW of capacity outside the market. This reserve was initially established for the winter of 2018/2019 and aimed to operate over a set period. Similarly, Italy adopted a reliability option scheme, designed to enhance system adequacy. The Italian scheme uses competitive tenders to contract capacity through reliability options.

Among these mechanisms, Belgium's Capacity Remuneration Mechanism (CRM) stands out for its structured approach, leveraging a combination of financial incentives and regulatory measures to ensure long-term adequacy in the electricity market. Below, we explore the key features of the Belgian CRM, with a focus on its specific characteristics, such as derating factors, financial security obligations, and the role of various technologies.

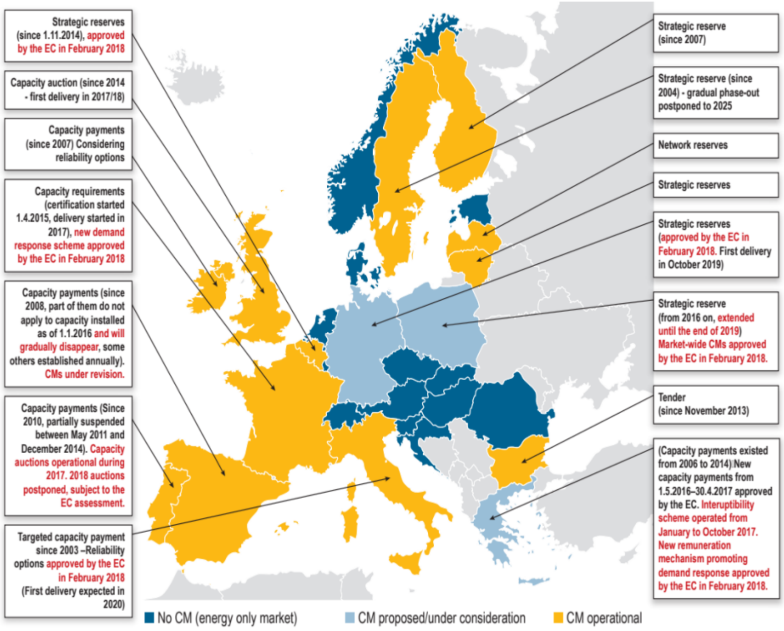

Figure 2.5: CMs implementation in Europe [25]

Chapter 3

Comparative Analysis of VoLL, CoNE, and RS Calculation Methodologies in the EU

The definition of efficient security of supply policies in the electricity sector depends on the precise quantification of three fundamental parameters: VoLL – Value of Lost Load, CoNE – Cost of New Entry, and RS – Reliability Standard, previously explained. The methodology developed by the Agency for the Cooperation of Energy Regulators (ACER) to calculate these parameters promotes more coherence between the Member States of the European Union. ACER's methodology, as defined in EU Regulation 2019/943 [1], provides strict guidelines for assessing these indicators. To ensure proper benchmarking, the ACER methodology requires Member States (MS) to apply transparent, objective, and verifiable criteria, ensuring that estimates reflect real market and consumer conditions.

3.1 VoLL calculation methodology

VoLL reflects the maximum price consumers are willing to pay to avoid an electricity interruption. Its estimation is based on surveys of consumers segmented by type and consumption profile, assessing their Willingness To Pay (WTP) to avoid supply cuts under different scenarios of duration and notice. Although the VoLL calculation aims to arrive at the value that consumers are willing to pay, ACER points out that the entities responsible for calculating the parameters can apply a triangulation of different cost estimation methods to the same category of customers if they consider that this leads to more solid estimates. The different estimation methods include the direct worth and willingness to accept (WTA) methods, in addition to the baseline WTP. The WTA method assesses the minimum compensation that consumers would require to accept supply interruptions, and Direct Worth directly estimates the financial impact of consumption failures, taking into account economic losses, mitigation costs, and operational disruptions, and is therefore easier to apply to industrial consumers. Following the WTA method, the results tend to be higher [26], and these three methods continue to show higher values when compared to the macroeconomic analyses carried out on the various sectors of each MS [27].

The methodology requires each Member State to carry out surveys, segmenting consumers according to predefined categories. It must also ensure that the parameters analysed include the duration of interruptions, the period of the day or week in which they occur, and the length of notice given to consumers. The results of these surveys are aggregated to calculate a single national VoLL, updated at least every five years or whenever there are significant changes in the market. The VoLL calculation is based on the expression 3.1:

$$VoLL_{RS} = \sum_{VoLLparams}^{cons.types} VoLL_{sect.,cons.type,VoLLparams} * Weight_{cons.type,VoLLparams} \tag{3.1}$$

In this expression:

- *cons.types* describes the consumer types;
- *VoLLparam* describes the sets of VOLL parameters (duration, period of occurrence, pre-notification period). The VOLL parameters, which best reflect the typical load-shedding events expected to take place (e.g. concerning duration and pre-notification), shall be used. These parameters may take into account the main ENS patterns observed in recent European or national resource adequacy assessments, where applicable;
- *VoLLsect.,cons.type,VoLLparams* is the best estimate of the sectoral VOLL of a given consumer type under given VOLL parameters, in €/MWh;
- *Weightcons,type,VoLLparams* is the weight for each consumer type under given VOLL parameters used to define the single VOLL for RS.

This last parameter can be calculated by the following expression 3.2:

$$Weight_{cons.type,VoLLparams} = \frac{EENS_{reduction,cons.type,VoLLparams}}{EENS_{reduction}} \tag{3.2}$$

In this expression:

- *Weightcons.type,VoLLparams* is the weight for the given consumer type and set of VOLL parameters used to define the single VOLL for RS.
- *EENSreduction,cons.type,VOLLparams* is the EENS reduction for the given consumer type and set of VOLL parameters. The EENS reduction may take into account the main ENS patterns observed in recent European or national resource adequacy assessments, where applicable;
- $EENSreduction = \sum cons.types, VOLLparamsEENSreduction, cons.type, VOLLparams$ is the total EENS reduction enabled by the additional capacity resources;

- The amount of additional capacity resources should reflect the minimum capacity need for RS.

Or by the simplified expression:

$$Weight_{cons.type,VoLLparams} = \frac{EENS_{cons.type,VoLLparams}}{EENS} \quad (3.3)$$

In this expression:

- *EENSconst.type,VOLLparams*is EENS borne by given consumer type and set of VOLL parameters. The EENS for the given consumer type may take into account the main ENS patterns observed in recent European or national resource adequacy assessments, where applicable.

- EENS = cons.types,VOLLparams EENScons.type,VOLLparams is the total EENS.

3.1.1 CoNE calculation methodology

CoNE estimates the cost required for a new generation unit to enter the market, covering both fixed and variable costs (CoNEfixed, CoNEvar, respectively). Its determination follows the structured methodology detailed in the next paragraphs:

- Selection of Reference Technologies: Identification of standard technologies that can serve as a reference for new investments, considering generation, storage and Demand Side Response (DSR).

- Definition of Technical Characteristics: Determination of technical specifications relevant to cost calculation, including fuel type, energy efficiency, de-rating factor, construction period and economic useful life.

- Cost estimate: Calculation of capital costs (CAPEX) and fixed annual costs (OPEX), based on transparent and verifiable data, adapted to the reality of each market.

- Determination of the WACC (Weighted Average Cost of Capital) for each type of technology, representing the cost of capital needed to finance new investments.

- Calculation of CONEfixed: Determination of the Fixed Cost of New Entry (CONEfixed), by converting the total costs into an annualized value adjusted by the capacity devaluation factor.

- Calculation of CONEvar: Estimation of the Variable New Entry Cost (CONEvar), including variable operating costs, fuel prices, CO2 emissions costs and other maintenance costs associated with the operation of the reference technologies.

The calculation of CoNEfixed follows expression 3.4:

$$CONE_{fixed,RT} = \frac{EAC_{RT}}{K_{d,RT}} \tag{3.4}$$

In this expression:

- *EACrt* represents the Equivalent Annualized Cost (EAC) of a given reference technology calculated according to the expression showed bellow (in local currency per MW);
- *Kd,rt* is the de-rating capacity factor of the reference technology.

The EAC (equivalent annualized cost, which is the constant annual payment over the life cycle of a project that covers the capital costs and fixed costs of a given technology) must be calculated for each of the reference technologies using the expression 3.5:

$$EAC = \left[\sum_{i=1}^{X} \frac{CC(i)}{(1+WACC)^i} + \sum_{i=X+1}^{X+Y} \frac{AFC(i)}{(1+WACC)^i}\right] * \frac{WACC * (1+WACC)^{X+Y}}{(1+WACC)^Y - 1} \tag{3.5}$$

In this expression:

- *i* represents each year over the construction period and economic lifetime;
- *X* is the construction period (in years);
- *Y* is the economic lifetime (in years);
- *CC(i)* is the best estimate of the capital costs incurred each year of the construction period (in local currency per MW);
- *AFC(i)* is the best estimate of the annual fixed costs incurred each year during the economic lifetime (in local currency per MW);
- *WACC* is the best estimate of WACC.

The costs considered for the CoNEvar calculation are as follows:

(a) fuel costs estimated based on the efficiency of the generation reference technology and the expected price of fuel during the applied timeframe;

(b) CO2 emission costs estimated based on the expected emission factor of the generation reference technology and the expected price of CO2 allowances during the applied timeframe;

(c) Other variable OPEX costs consisting of the expected cost of consumable materials (ammonia, limestone, water, etc.), by-products handling (ash, slug, etc.), etc., as well as variable operating and maintenance cost estimated based on the number of expected operating hours and/or start-stop cycles of the generation or charge-discharge cycles of storage resource;

(d) minimum activation prices for DSR resources;

(e) taxes and levies that relate to variable production.

For a given reference technology, if the entity calculating CONE expects that CONEvar will be negligible compared to the best estimate of the single VOLL for RS, the entity calculating CONE may estimate the order of magnitude of CONEvar.

3.1.2 Reliability Standard Methodology

For a new technology with a CoNEvar lower than VoLL, LoLE calculation should follow the expression 3.6:

$$LoLE_{RT} = \frac{CoNE_{fixed}}{VoLL_{RS} - CoNE_{var}} \tag{3.6}$$

In this expression:

- *LoLErt* is the LOLE threshold related to the reference new entry, in h;
- *CoNEfixed* is the best estimate of the fixed CONE, in local currency/MW;
- *VoLLrs* is the best estimate of the single VOLL for RS, in local currency/MWh;
- *CoNEvar* is the best estimate of the variable CONE, in local currency/MWh. If the CoNEvar is negligible compared to VoLLrs, CoNEvar may be neglected.

For each reference renewal/prolongation, the best estimate of LoLE shall be given by expression 3.7:

$$LoLE_{RT} = \frac{CoRP_{fixed}}{VoLL_{RS} - CoRP_{var}} \tag{3.7}$$

In this expression:

- *LoLErt* is the LOLE threshold related to the reference renewal/prolongation, in h;
- *CoRPfixed* is the best estimate of the fixed Cost of Renewal/Prolongation (CORP), in local currency/MW;
- *VoLLrs* is the best estimate of the single VOLL for RS, in local currency/MWh;
- *CoRPvar* is the best estimate of the variable CoRP, in local currency/MWh. If the CoRPvar is negligible compared to VoLLrs, CoRPvar may be neglected.

The LOLE target for RS shall be the minimum (best estimate) LOLE threshold which fulfils the minimum capacity need for RS, as shown in expression 3.8:

$$LoLE_{target for RS} = min(LoLE_{threshold}) \tag{3.8}$$

Subject to:

$$\text{capacity resource potential}(LoLE_{threshold}) \geq \text{minimum capacity need for reliability standard} \tag{3.9}$$

3.1.3 LOLE and the Optimal Trade-off Between Cost and Security of Supply

The Loss of Load Expectation (LoLE) represents the expected number of hours per year during which the electricity system is unable to meet demand due to insufficient available capacity. It is a key metric for assessing system adequacy and is directly linked to the optimal trade-off between cost and security of supply.

The optimal LoLE level is determined by balancing:

- The cost of adding new capacity to reduce ENS (Energy Not Supplied);
- The socioeconomic cost of ENS, which reflects the impact of power outages on consumers.

If LOLE is too high, frequent shortages occur, justifying new capacity investments. Conversely, if LOLE is too low, the system may be overinvested, leading to unnecessarily high electricity costs for consumers.

The optimal trade-off occurs when the marginal cost of reducing ENS does not exceed the benefit consumers derive from increased supply security. In other words, capacity expansion should only proceed if the cost of reducing LoLE is lower than the value consumers place on avoiding power shortages. The illustration of this trade-off is shown in the Figure 3.1:

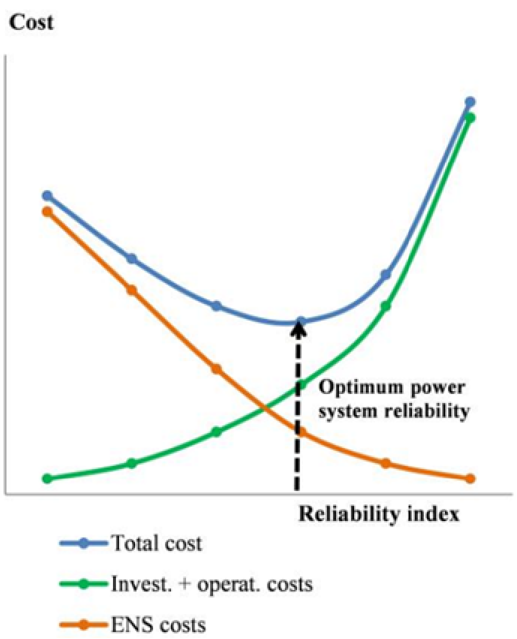

Figure 3.1: Cost vs reliability of generation power system [28]

3.2 Analysis of CoNE Calculation Across Member States: Technologies, Fixed and Variable Costs, and Methodological Approaches

Following the analysis of various official documents published by entities across different EU Member States, it was possible to compile the following graphs, which present the CoNEfixed values for different technologies in each country. Additionally, a smaller table is provided to display CoNEvar values, as the methodology proposed by ACER allows for this variable to be neglected if adequately justified. As a result, only a limited number of Member States have reported CoNEvar values, typically for well-established thermal technologies. Furthermore, this section highlights which countries have incorporated the lifetime extension of thermal power plants in their CoNE estimations and assesses the implications of these choices on the reported values.

3.2.1 OCGT, CCGT, Large-Scale NPP and Pumped Hydro Technologies

Figures 3.2 and 3.3 illustrate the CoNEfixed values across various EU Member States, highlighting the differences in the cost of new entry for different technologies. The lowest CoNE values are generally associated with Demand Side Response (DSR), which is often considered the most cost-effective solution for ensuring security of supply. Consequently, these lower CoNE values are typically used as the reference for calculating the Reliability Standard (RS) in each country.

It is important to note that while technologies such as wind turbines and photovoltaics (PVs) may not always have the lowest CoNE values, even if they did, they should not be used for RS calculations. Their inherently variable generation profiles could limit their ability to guarantee system adequacy, making them unsuitable as a benchmark for determining the required level of firm capacity. Instead, technologies with reliable and dispatchable generation characteristics, such as Hydro or Gas Power Plants, or flexible demand-side solutions, are preferred for assessing the security of supply across Member States.

Unlike variable renewables, batteries provide dispatchable capacity, making them increasingly targeted by capacity mechanisms, as seen in Italy, which has already introduced dedicated support schemes [29]. Additionally, battery storage technologies exhibit lower CoNEfixed values compared to other non-carbon-emitting options, such as solar PV and wind power, further reinforcing their economic viability as a key solution for ensuring system adequacy.

Spain also considers the Cost of New Entry (CoNE) for the lifetime extension of combined cycle gas turbines (CCGTs) and cogeneration plants as part of its capacity adequacy planning. These extensions could add 11.9 GW from CCGTs and 1.2 GW from cogeneration units. The estimated CoNE for these technologies' ranges between 27,216–41,585 €/MW for CCGT extensions and 295,276–334,497 €/MW for cogeneration plants.

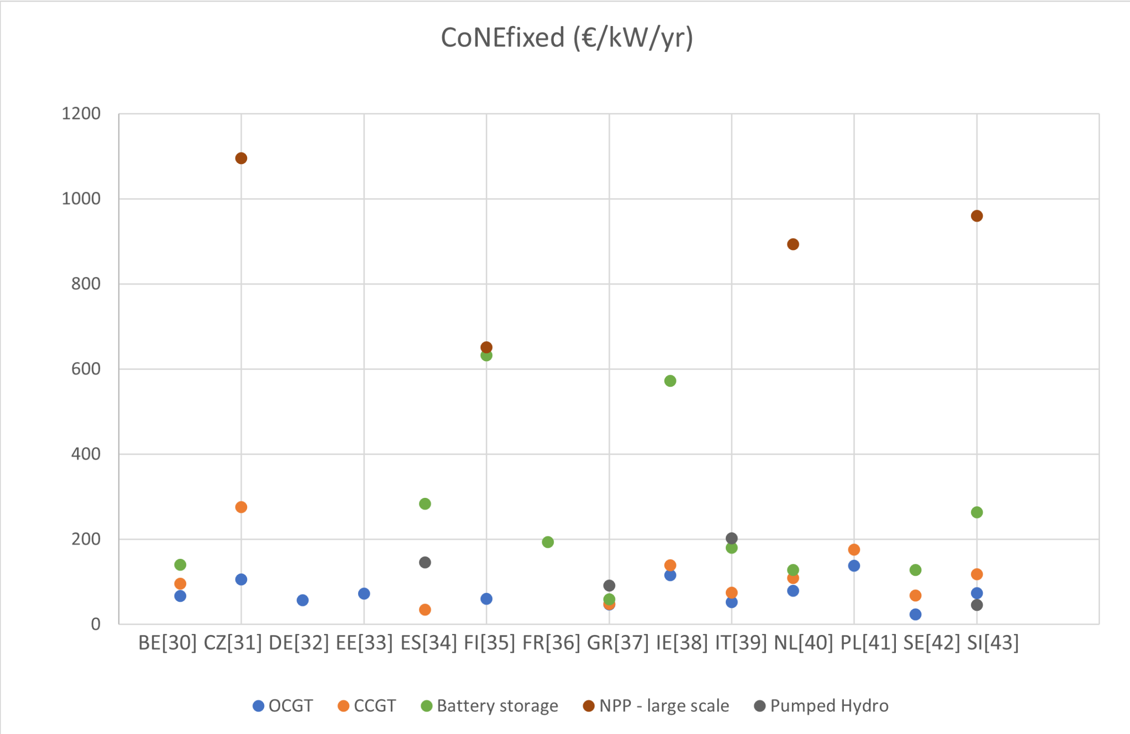

Figure 3.2: CoNEfixed Values by Member State for OCGT, CCGT, Battery Storage, Large-Scale NPP and Pumped Hydro Technologies [30]–[43]

The CoNEfixed values for Demand Side Response (DSR) technologies presented in Figure 3.3 are remarkably low in some cases, making them the reference technology for calculating the Reliability Standard (RS) in countries such as Belgium, Finland, France, Greece, and Sweden. This reinforces the economic efficiency of DSR as a viable capacity option for ensuring security of supply.

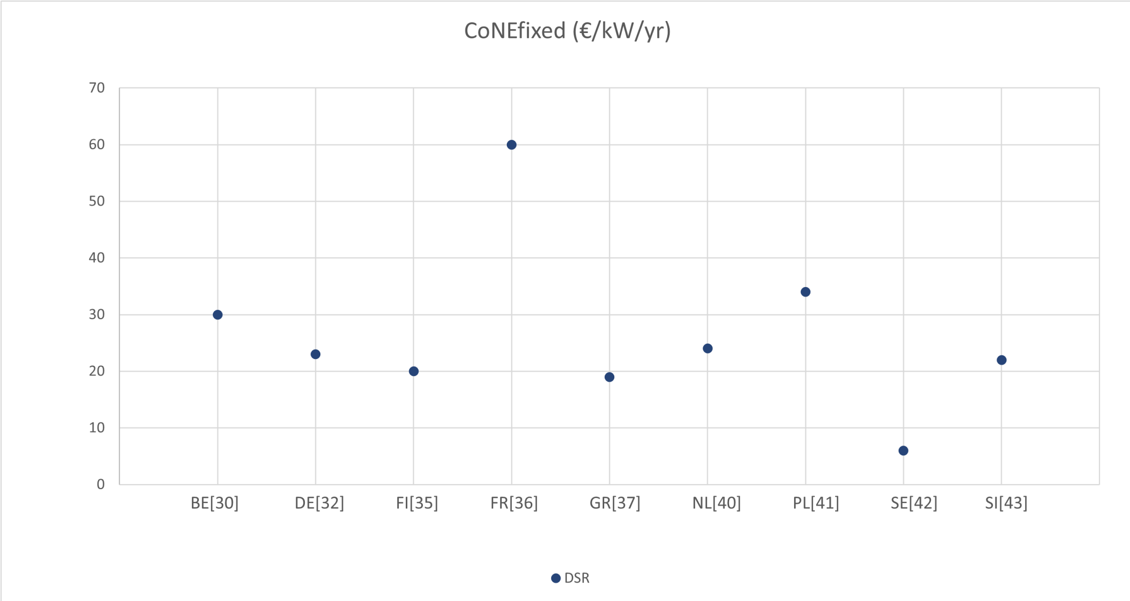

Figure 3.3: CoNEfixed Values by Member State for Demand-Side-Response Technologies [30], [32], [35]–[37], [40]–[43]

One of the objectives of this dissertation is to analyse the different technical parameters associated with DSR technologies, such as notification time before interruption, duration of the interruption, activation price of the service, and other relevant factors. However, despite the importance of these aspects, the lack of sufficient bibliographic sources and official documents prevented the identification of these key technical parameters, limiting a more detailed assessment on DSR.

3.3 Assessing Weighted Average Cost of Capital (WACC) and Hurdle Rate Premium (HRP) Across Technologies

3.3.1 Understanding WACC, Hurdle Rate, and Hurdle Rate Premium

This section introduces the concepts of Weighted Average Cost of Capital (WACC) and Hurdle Rate Premium (HRP), explaining their significance in investment decisions within the energy sector. Additionally, it clarifies the relationship between WACC, HRP, and the Hurdle Rate, which represents the minimum return required for an investment to be considered viable.

Weighted Average Cost of Capital (WACC): WACC represents the average rate of return a company is expected to pay its security holders to finance its assets. It reflects the cost of both equity and debt, weighted by their respective proportions in the company's capital structure [44].

Hurdle Rate Premium (HRP): HRP is an additional percentage added to the WACC to account for specific risks associated with a particular project or investment. This premium compensates investors for taking on higher uncertainty or potential volatility [45].

Hurdle Rate (HR): The Hurdle Rate is the minimum acceptable rate of return on an investment, calculated by summing the WACC and the HRP. It serves as a benchmark; projects with returns above this rate are considered viable, while those below are typically rejected.

3.3.2 Reported WACC and HRP Values Across Member States

This subsection presents the WACC and HRP values found for different electricity generation technologies across various EU Member States. It also discusses the findings of a study commissioned by Elia, the Belgian TSO, which specifically analysed the HRP applied to energy investments.

An analysis of the Weighted Average Cost of Capital (WACC) across various EU Member States reveals notable differences, particularly between countries that apply technology-specific WACC rates and those that adopt a unified approach. The data indicates that renewable energy technologies, such as Photovoltaic (PV) systems and Wind Power Plants (WPP), often benefit from lower WACC values, probably resulting from higher policy support and incentives, as presented in Figure 3.4.

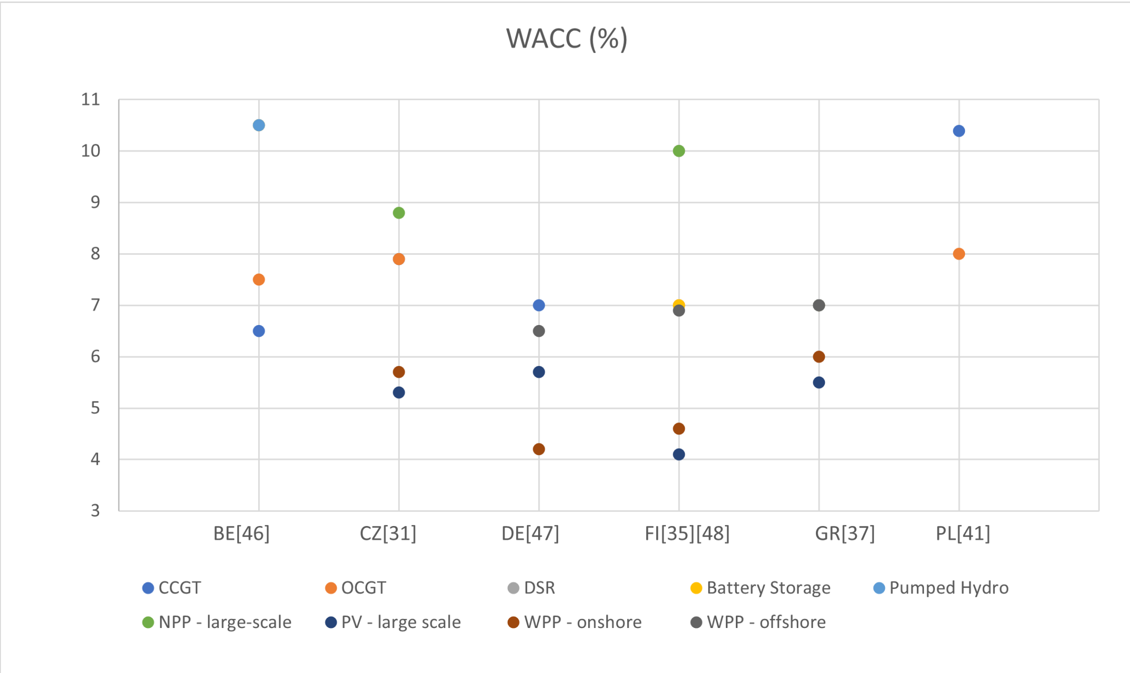

Figure 3.4: WACC Values by Member State for Every Technology [31], [35], [37], [41], [46]–[48]

3.3.3 Unified vs. Technology-Specific WACC Approaches

Some countries opt for a unified WACC across all energy technologies, while others differentiate based on specific technologies. Below are the WACC values of some of the countries that went with a unified approach:

- Ireland: 7.27% [38];

- Italy: 5.6% [39];
- Netherlands: 6.45% [49];
- Sweden: 4.39% [42].

Countries employing a unified WACC typically report lower rates compared to those that differentiate by technology. This approach simplifies regulatory frameworks and reduces administrative complexities. However, it may not accurately reflect the varying risk profiles associated with different technologies, potentially leading to suboptimal investment decisions. A study published in Climatic Change highlights that uniform WACC assumptions can bias results regarding the transition of certain countries towards renewables, potentially leading to a sub-optimal use of public resources [50].

Implications for Investment

Differentiating WACC by technology allows for a more precise alignment with each energy source's specific risks and returns, encouraging investments in higher-risk technologies by appropriately compensating investors. In opposition, a unified WACC may favour established technologies, as the average rate might not sufficiently incentivize investment in newer, riskier technologies.

3.3.4 Hurdle Rate Premium

In the context of evaluating investments in new power generation technologies, the Hurdle Rate Premium (HRP) represents an additional risk margin applied to the Weighted Average Cost of Capital (WACC) to account for technology-specific uncertainties. Among the countries analysed, Spain has adopted a uniform HRP of 3% for all technologies. However, similar to a unified WACC, this approach may not accurately reflect the distinct risk profiles associated with each investment. Belgium, on the other hand, regularly commissions studies by Professor Kris Boudt to determine technology-specific HRPs, considering factors such as the risk of lower-than-expected returns and model and policy risks. These assessments have resulted in the following HRPs [51]:

- PV, Offshore/Onshore Wind, OCGT and CCGT without refurbishment: 2.94%;
- Large-Scale Batteries and DSM (4-hour activation): 3.5%;
- CCGT with refurbishment: 4.5%;
- New CCGT and old OCGT with refurbishment: 5.5%;
- New OCGT: 6.5%.

For PV and wind technologies, the risk of lower-than-expected returns is considered very low, as their revenue variability is minimal. However, these technologies are fully dependent on weather conditions and tend to benefit less from electricity price spikes. Additionally, there is moderate model and policy risk, given the possibility of regulatory changes, such as taxation of excess revenues or shifts in renewable energy support policies over their long operational lifetime [51].

For new OCGTs, the base scenario return risk is high, primarily due to their later position in the merit order, leading to greater revenue variability. Moreover, the model and policy risk is extremely high, as future regulations on fossil fuel generation could significantly impact profitability. Additionally, the long economic lifetime of an OCGT (20+ years) increases exposure to market and regulatory uncertainties over time [51].

3.4 Analysis of Value of Lost Load (VoLL): Consumer Willingness to Pay and Final Estimates

In this section, the Value of Lost Load (VoLL) will be analysed by comparing the maximum electricity prices consumers are willing to pay to avoid supply interruptions across different consumption segments. By evaluating VoLL at a sectoral level, this analysis aims to highlight how different consumer categories—such as residential, commercial, and industrial users—perceive and value the security of electricity supply.

3.4.1 VoLL Estimates and Methodological Approaches Across Member States

Figures 3.5 and 3.6 present the unique VoLL values reported in National Documents released by various EU Member States. While some countries followed the methodology proposed by ACER, the methodology itself allows for some degree of flexibility, which explains the significant differences observed in the figures. For instance, the Netherlands exhibits an exceptionally high VoLL, reflecting specific methodological choices and assumptions.

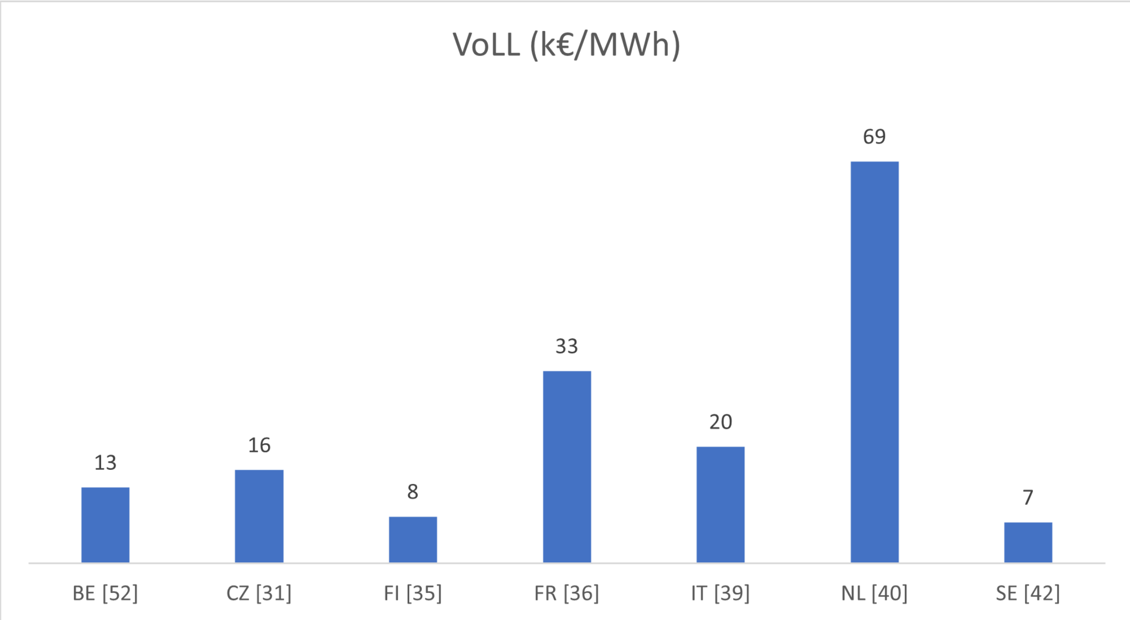

Figure 3.5: Unified VoLL Values that followed ACER's methodology by Member State [31], [35], [36], [39], [40], [42], [52]

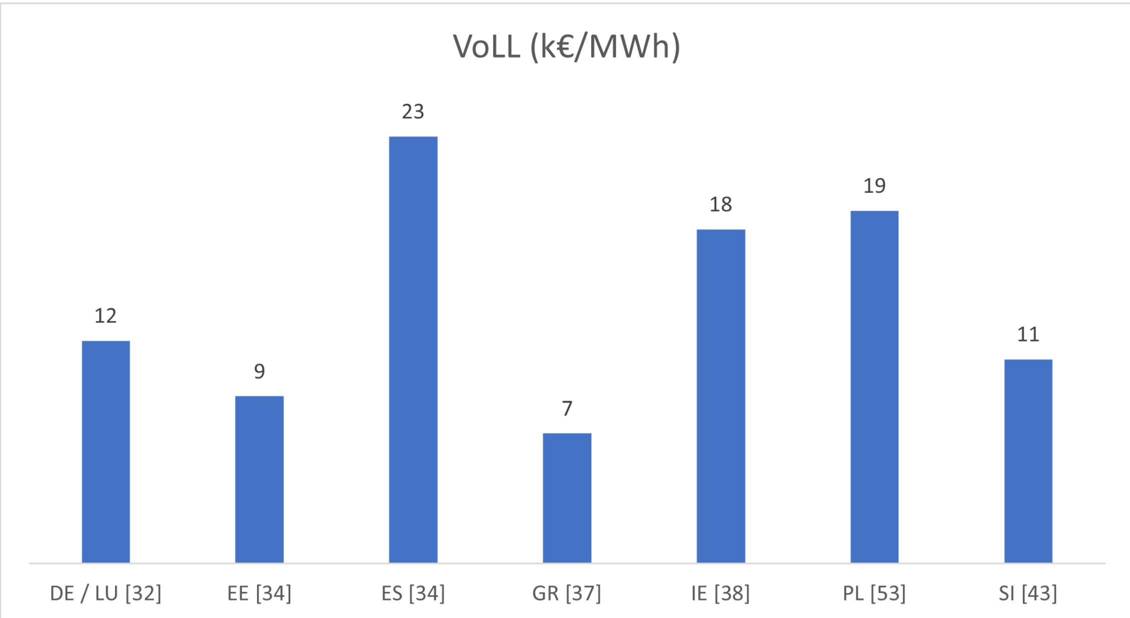

Figure 3.6: Unified VoLL Values that didn't follow ACER's methodology by Member State [32]–[34], [37], [38], [43], [53]

Regarding adherence to the methodology, it was confirmed that Belgium, the Czech Republic, Finland, France, Italy, the Netherlands, and Sweden followed ACER's guidelines. However, Germany deviated from the prescribed approach, as it was unable to obtain enough survey responses [32]. Instead, Germany/Luxembourg estimated VoLL based on public statistical data. In other cases, such as Slovenia, no evidence was found confirming or refuting the use of ACER's methodology. Furthermore, no sectoral VoLL estimates were found for Estonia, Spain, Greece, Ireland and Poland, leading to the assumption that these countries did not follow ACER's methodology, as it explicitly requires the calculation and presentation of sectoral VoLL values.

Even within the methodological flexibility allowed by ACER, Member States adopted different approaches when determining their sectoral VoLL values. One key distinction lies in how consumer segments were classified. For example, Belgium and the Czech Republic divided their consumers into B2B (business-to-business) and B2C (business-to-consumer) categories [31], [52], while Italy classified them into Residential, Tertiary, and Industrial sectors [39]. Additionally, different countries followed varied methodologies for estimating sectoral VoLL. Italy, for instance, applied a 50%-50% weighted average of WTP (Willingness to Pay) and WTA (Willingness to Accept) for the Residential and Tertiary sectors, while using 100% Direct Cost for the Industrial sector [39]. On the contrary, the Netherlands relied entirely on WTP for all sectors, demonstrating a contrast in valuation approaches across Member States [40].

3.5 Assessment of Security of Supply Standards Across Member States and Compliance in the Latest ERAA Report

This chapter presents a comparative analysis of the RS adopted by different Member States, highlighting which countries have followed the methodological approach suggested by ACER, which have not explicitly followed, and where data was unavailable. Additionally, compliance with these standards will be examined based on the latest European Resource Adequacy Assessment (ERAA), identifying whether the projected adequacy levels for each country align with their respective RS. The LoLE values reported in by ERAA in 2023 reflect the standards communicated by each Member State, rather than a centrally enforced methodology [54]. As a result, these values may not necessarily adhere to the methodological framework set by ACER. analysing the reported LoLEs in the Figures 3.7 and 3.8, it is evident that most countries have set their LoLE around 3 hours per year, except for Czechia, Estonia, and Portugal which have adopted higher thresholds of 6.7, 9 and 5 hours per year, respectively.

Despite differences in adequacy assessments, all countries followed the ACER-prescribed expression for calculating LoLE, which involves dividing the CoNEfixed by the VoLL. However, countries that did not comply with ACER's methodology for determining VoLL consequently produced LoLE values that are also considered non-compliant. Specifically, the LoLE values for Germany, Estonia, Spain, Greece, Ireland, Poland, and Portugal are classified as non-compliant, as these countries either did not adhere to the VoLL calculation methodology or failed to demonstrate compliance in their National reports.

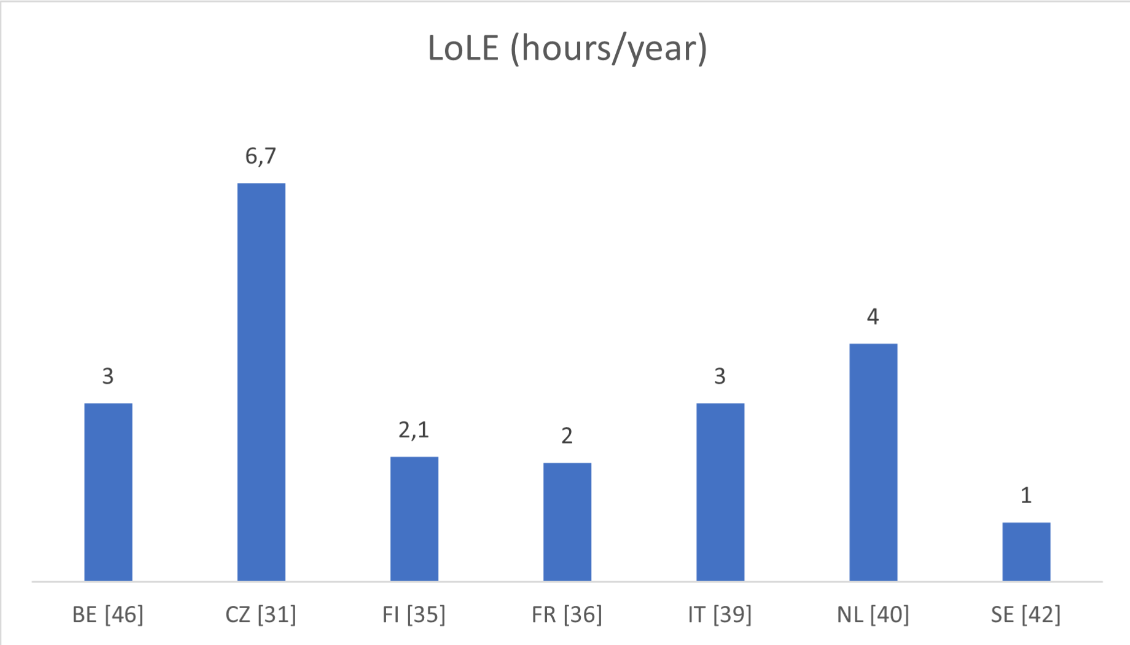

Figure 3.7: LoLE Values that followed ACER's methodology by Member State [31], [35], [36], [39], [40], [42], [46]

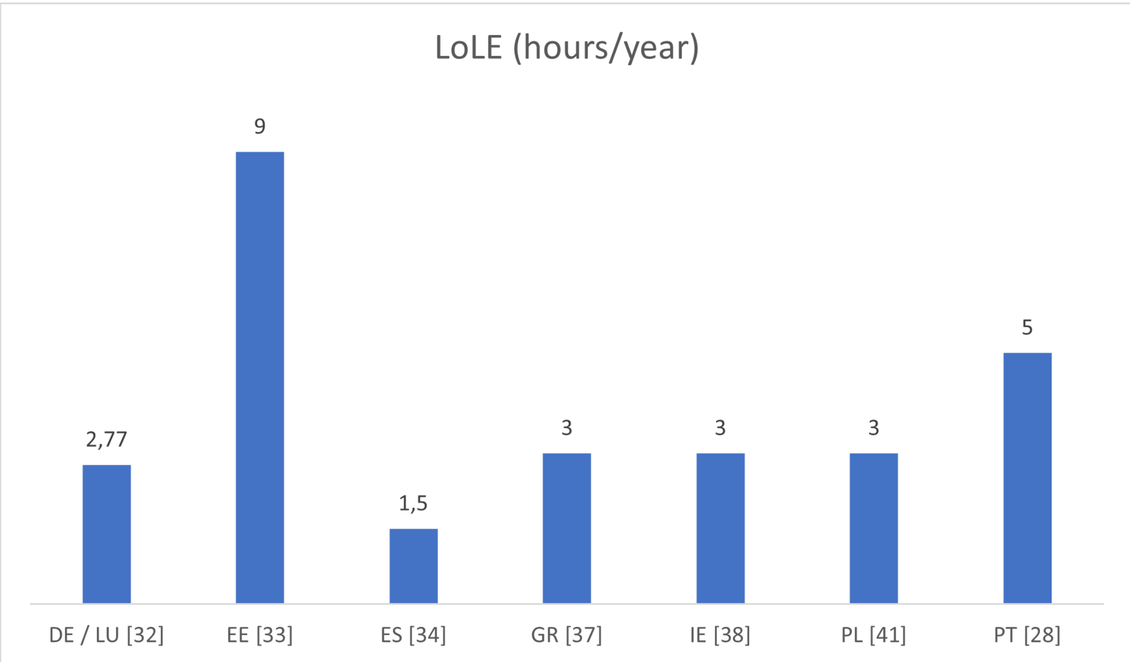

Figure 3.8: LoLE Values that didn't follow ACER's methodology by Member State [28], [32]–[34], [37], [38], [41]

3.5.1 Simulation overview

The simulation framework used in [54] is structured in two assessments. The first is the Economic Viability Assessment (EVA), which focuses exclusively on evaluating the profitability of generation assets under current and projected market conditions. Based on the outcomes of the EVA—specifically, the identification of capacities at risk of economic retirement or mothballing—a second phase, the Adequacy Assessment, is carried out. This stage incorporates the capacity retirements identified in the EVA and evaluates their impact on the system's ability to meet its reliability standard. It is within this second assessment that Loss of Load Expectation (LoLE) values are calculated. If the resulting LoLE exceeds the reliability standard (RS) defined by a given Member State, this highlights a potential adequacy gap. Such a gap reveals a misalignment between market-driven investment signals and security of supply objectives, indicating the possible need for supplementary instruments, such as capacity mechanisms, to ensure long-term system adequacy.

Once the ERAA report is published, it is up to Member States facing adequacy issues to conduct further studies to assess potential solutions. One common approach is to simulate a scenario where the generation capacities identified for decommissioning are retained and analyse how this impacts the LoLE. If maintaining these assets results in a LoLE that no longer exceeds the RS calculated using ACER's methodology, then the solution lies in providing financial incentives to make these power plants economically viable, ensuring their continued operation.

However, if retaining these capacities is not sufficient, or if sustainability policies necessitate their closure, Member States must instead simulate the entry of new capacity to determine how much additional generation is required to meet their previously calculated RS. Once the necessary volume is identified, they should proceed with capacity auctions to secure this amount, offering financial incentives for new investments. This approach fosters new capacity development, strengthens long-term system adequacy, and enhances security of supply in a market-driven yet reliability-conscious manner.

3.5.2 Scenarios Overview

In the mentioned report by ERAA [54], two different weighting approaches are used to conduct the EVA: Scenario A and Scenario B. The primary difference between these scenarios lies in how the probability of occurrence of each CY (Climatic Year) cluster is determined, influencing the way investment and decommissioning decisions are modelled [54]. These scenarios are employed to reduce the computational burden that would otherwise result from running the EVA across all 36 available CYs. Instead, representative clusters are selected and weighted accordingly in each scenario. Once the EVA is completed, its results—namely, the set of economically viable and non-viable assets—are used as inputs for the subsequent adequacy assessment, which does simulate all 36 climatic years to evaluate the overall system adequacy.

The weights of each CY in each Scenario are shown in Table 3.1. The climatic year 1985 is characterized by scarcity events, whereas 1988 and 2003 do not exhibit such conditions.

Set of CY weights	Scenario A	Scenario B
1985	0.085	0.028
1988	0.058	0.057
2003	0.858	0.915

Table 3.1: Set of CY weights for Scenarios A and B

3.5.3 Comparison of Reliability Standards with ERAA Simulated LoLE: Compliance Assessment Across Member States

In Figures 3.9 to 3.12 limit the y-axis to a maximum of 25 hours per year, as including the full range of values—particularly Ireland's Target Year (TY) 2025 LoLE, which exceeds 370 hours in both scenarios—would significantly distort the visualization, making it difficult to interpret the results for other Member States. This adjustment ensures that the differences between the reported RS values and ERAA 2023 simulated results remain clear and comparable across countries without being overshadowed by extreme outliers [55].

The comparative analysis of the reported Reliability Standards (RS) found in ERAA 2023 and the ERAA 2023 simulated LoLE values (Scenario A) highlights significant discrepancies across Member States. The results in Figures 16 and 17 show that only Czechia, Estonia, Greece, the Netherlands, and Portugal achieved a simulated LoLE lower than the RS reported in their respective National Documents included in ERAA 2023. For all other countries, the ERAA simulations suggest a higher risk of supply inadequacy than their Reliability Standard indicates. This comparison is based on RS values available in ERAA 2023, ensuring consistency with the simulated results [55], rather than using RS values reported after the publication of this document.

The fact that most countries fail to achieve their defined RS in ERAA simulations raises concerns about the real security of supply in the European power system. This suggests that current capacity levels and planned investments may not be sufficient to ensure adequacy under more stressed scenarios.

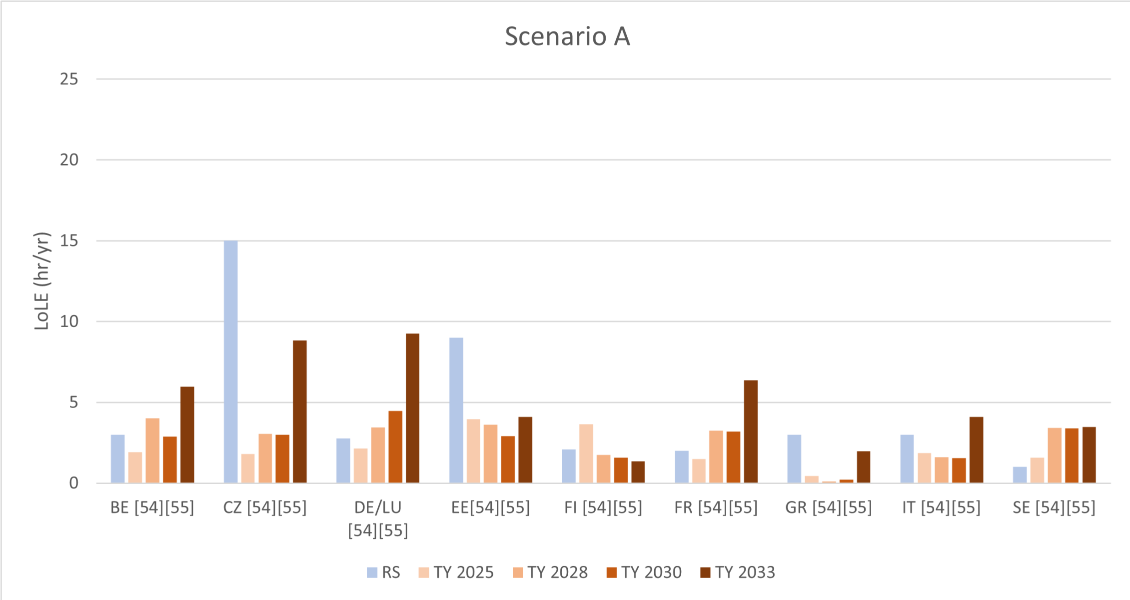

Figure 3.9: Comparison of LoLE Values: RS (reported in ERAA 2023 that followed ACER's methodology) vs ERAA 2023 Simulations (Scenario A) [54], [55]

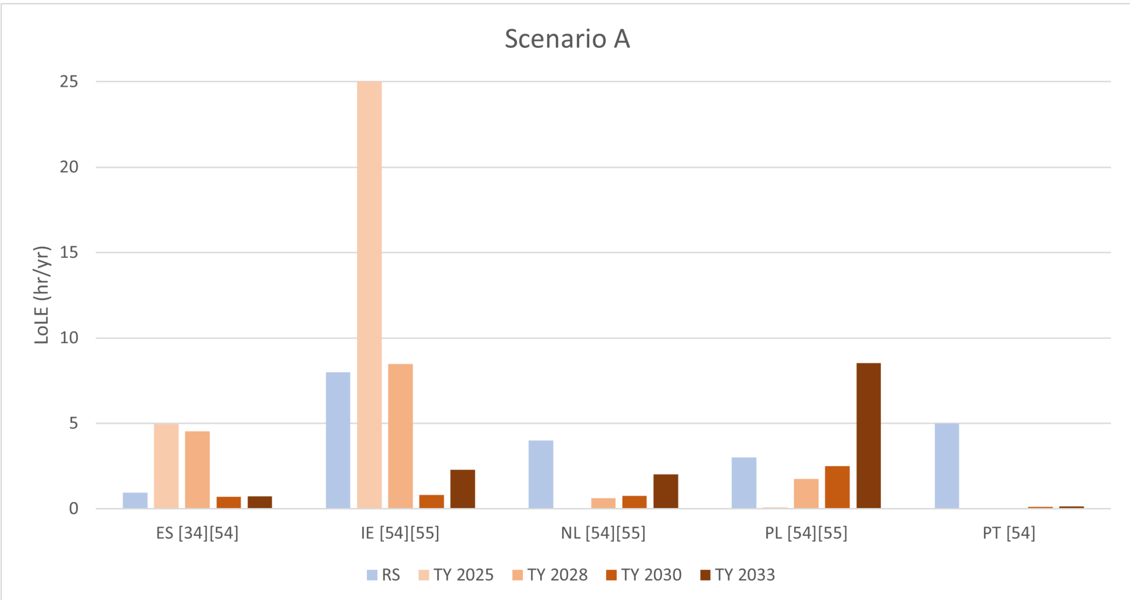

Figure 3.10: Comparison of LoLE Values: RS (reported in ERAA 2023 that didn't follow ACER's methodology) vs ERAA 2023 Simulations (Scenario A) [34], [54], [55]

The comparison between LoLE values from RS and ERAA 2023 simulations (Scenario B) in the Figures 3.11 and 3.12 highlight that only Estonia, Netherlands, and Portugal achieved simulated LoLE values below their proposed Reliability Standard and the overall increase in LoLE values. This indicates that, for these three countries, the ERAA simulations validated their adequacy targets, suggesting that their assumed VoLL and CoNEfixed values align well with the

ERAA modeling assumptions. This cements the conclusions drawn earlier regarding real security of supply in the European electricity system.

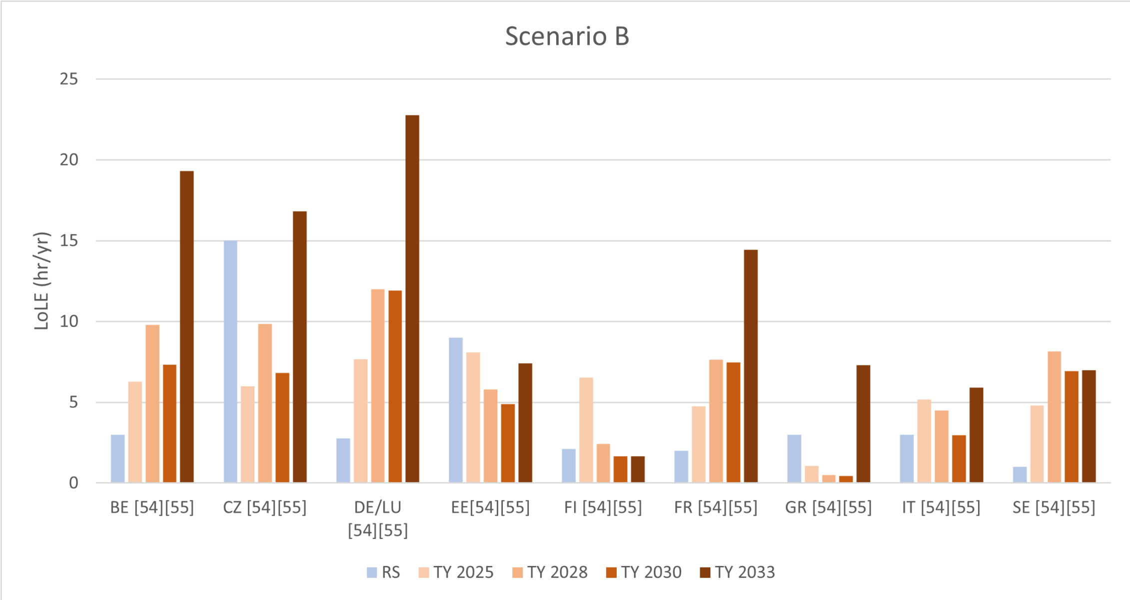

Figure 3.11: Comparison of LoLE Values: RS (reported in ERAA 2023 that followed ACER's methodology) vs ERAA 2023 Simulated (Scenario B) [54], [55]

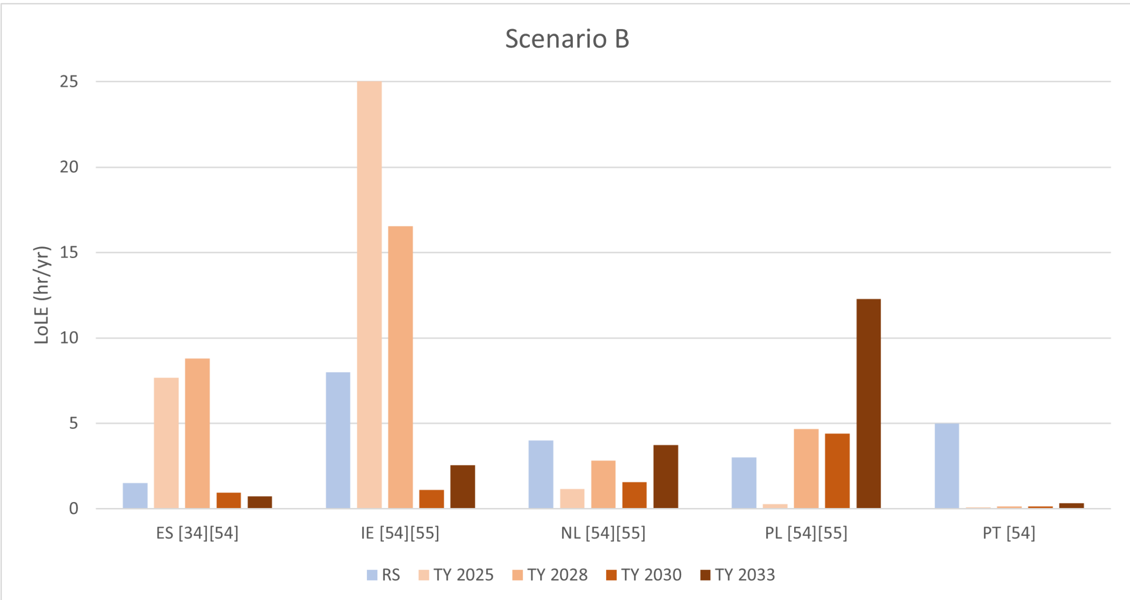

Figure 3.12: Comparison of LoLE Values: RS (reported in ERAA 2023 that didn't follow ACER's methodology) vs ERAA 2023 Simulated (Scenario B) [34], [54], [55]

3.5.4 Difference between LoLE explained (Scenario A and B)

The increase in simulated LoLE values from Scenario A to Scenario B can be attributed to the influence these scenarios have on the prior Economic Viability Assessment (EVA), which in turn impacts the results of the subsequent adequacy assessment. In Scenario A, the climatic year 1985, which is characterized by scarcity events, was assigned a higher weight (as shown in Table 3.1). This led to more frequent scarcity situations, increasing the dispatch of thermal power plants, and generating higher revenues. As a result, fewer thermal plants became economically unviable, keeping more thermal plants in the market and ensuring greater system adequacy. On the other hand, in Scenario B, the weighting was based solely on the number of climatic years per cluster, reducing the impact of scarcity-driven price spikes. This led to lower profitability for thermal plants, causing more units to be decommissioned, ultimately resulting in higher LoLE values compared to Scenario A.

3.6 Comparison of Capital Expenditure, Operational Expenditure, and CoNE Values: Member States vs. Reference Study

In this chapter, we will begin by introducing key concepts such as Capital Expenditure (CAPEX) and Operational Expenditure (OPEX), clarifying their role in power generation investments and distinguishing them from CoNEfixed and CoNEvar. Following this, a comparative analysis will be conducted, contrasting the CAPEX and OPEX values reported by various EU Member States with those obtained in a Reference Study conducted by a student in his Master Dissertation thesis [56]. Finally, we will extend this comparison to CoNEfixed values, evaluating the differences between the figures reported by Member States and those calculated using data from the Reference Study to assess potential deviations and their implications.

3.6.1 CAPEX, OPEX and CoNE

Capital Expenditure, or CAPEX, refers to investments in physical assets and infrastructure that a company acquires to maintain or expand its operations. In other words, it is the total investment needed to build a new asset, such as an Open Cycle Gas Turbine (OCGT) thermal power plant. Therefore, it is the absolute value of the initial investment in €/MW installed [57].

Operating Expenditure, or OPEX, refers to the expenses that a business incurs through its normal operations and can include costs such as rent, equipment, inventory costs, payroll, insurance, R&D funds and fuel costs. It is usually expressed by €/MW [57].

CoNEfixed, as mentioned before, is the annualised cost of a new generator, taking into account CAPEX and annual fixed costs, including a part of OPEX, such as operation staff wages and preventive maintenance.

CoNEvar, on the other hand, represents the variable costs associated with electricity production, focussing only on variable costs depending on the electricity produced, i.e. fuel, gas in the case of an OCGT and wear and tear on components, including the part of OPEX that's not included in the CoNEfixed.

3.6.2 Comparison of CAPEX and OPEX of the Reference Study and MS

Not all EU Member States provided the CAPEX and OPEX values used to calculate CoNEfixed. Therefore, the figures below include only those MS that disclosed CAPEX and OPEX values for at least one of the following technologies: OCGT, CCGT, and Battery Storage. A comparative analysis, shown in Figure 3.13, reveals that the Study [56] presents higher CAPEX values for OCGT and CCGT technologies compared to the average values reported by MS. Specifically, the average CAPEX values for these technologies across MS are approximately 480 €/kW for OCGT and 790 €/kW for CCGT, while the Study reports 645 €/kW and 1300 €/kW, respectively [56]. Conversely, for Battery Storage, the CAPEX value from the Study is lower than the MS's average. While the average reported by MS is around 780 €/kW, the Study presents a lower estimate of 730 €/kW. This indicates that, while thermal technologies in the Study appear more conservative in cost assumptions, the battery storage estimate aligns with a more optimistic cost assumption compared to other MS.

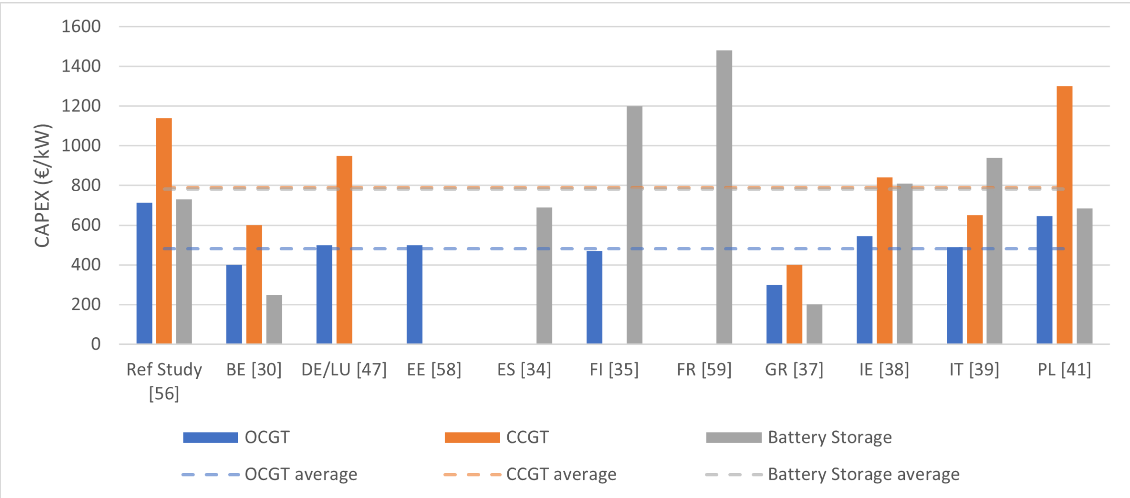

Figure 3.13: Comparison of CAPEX values presented on the Reference Study and MS, for OCGT, CCGT and Battery Storage Technologies. [30], [34], [35], [37]–[39], [41], [47], [56], [58], [59]

The comparative analysis of OPEX values between different EU Member States and the Study [56], in Figure 3.14, shows that, for all three technologies analysed (OCGT, CCGT, and Battery Storage), the values presented in the Study are consistently below the average reported by MS.

This discrepancy may be attributed to differences in cost assumptions regarding labour and rent costs across different sources. Additionally, some MS may incorporate additional fixed and variable operational expenses, which could explain the higher averages observed. These findings suggest that OPEX estimation methodologies vary significantly between sources, highlighting the need for greater harmonization in cost reporting to ensure comparability in future adequacy assessments and investment planning.

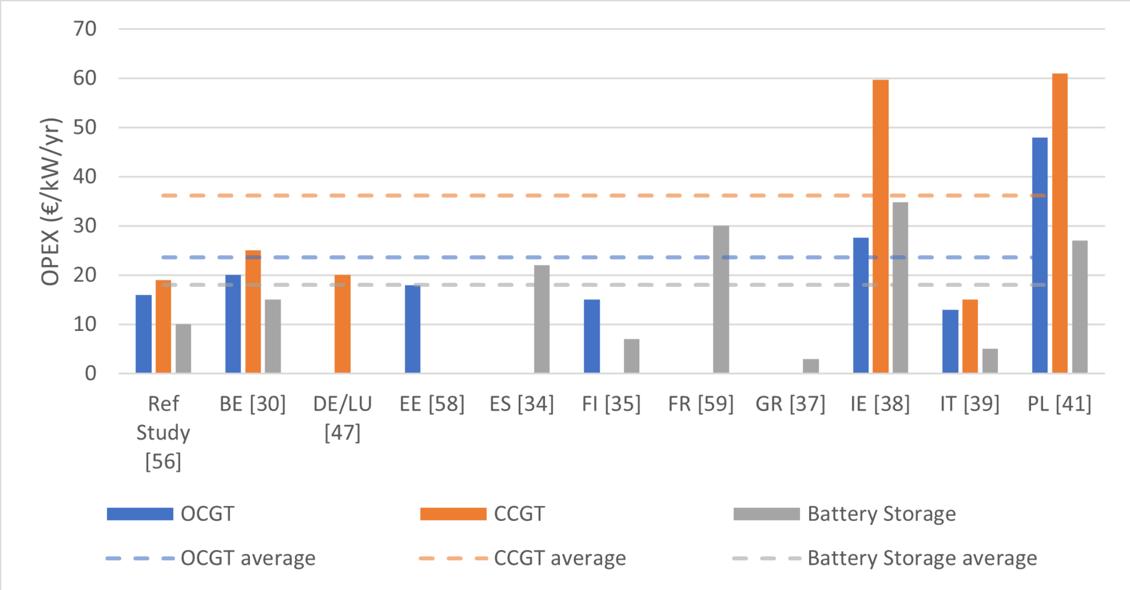

Figure 3.14: Comparison of OPEX values presented on the Reference Study and MS. [30], [34], [35], [37]–[39], [41], [47], [56], [58], [59]

3.6.3 Comparison of CoNEfixed of the Reference study and MS

To determine the CoNEfixed values using the data from the Study [56], the ACER methodology was followed, applying the expressions 3.4 and 3.5 to calculate the Equivalent Annual Cost (EAC) and CoNEfixed, respectively. In this process, the CAPEX value was used as the CC, and the OPEX value was used as the annual fixed cost (AFC). Additionally, the parameter X was set to 0, and Y was assumed as the central value of the lifespan range provided in the study. For example, in the case of CCGT, where the lifespan was given as 30-40 years, a Y value of 35 years was used for EAC calculations.

Since the study [56] did not provide WACC values, a technology-specific average of the values reported by different EU Member States was used. The derating factors applied were those presented in the study.

The CoNEfixed values obtained for OCGT and CCGT using the Study data are within the average range reported by EU Member States [56]. This outcome was expected, as the higher-than-average CAPEX values found in the Study are effectively offset by its lower-than-average OPEX values, resulting in a balanced CoNEfixed. However, for Battery Storage, the calculated CoNEfixed is significantly lower than the MS average. This discrepancy is primarily due to the 97% derating factor applied, which assumes a battery with unlimited storage capacity—an unrealistic assumption in practical applications. In the MS data, CoNEfixed values are typically provided for batteries with storage durations between 4 and 6 hours, which significantly impacts the available capacity and, consequently, the CoNEfixed. Adjusting for this factor would likely result in a higher and more realistic CoNEfixed for Battery Storage, aligning more closely with the values reported by MS. To verify it, a derating factor adjusted to the actual energy storage duration was applied. This factor was calculated as the average of all derating factors from countries that shared their large-scale battery derating factor values and was used to determine the Battery Storage (w/adjusted de-rating factor) CoNE, which is shown in yellow in Figure 3.15.

By applying these calculations, the EAC and CoNEfixed values were obtained as shown in Table 3.2.

Table 3.2: Comparison of input parameters and results for different technologies.

Technology	**Input**						**Obtained by calculations**	
	CC (€/kW)	**AFC** (€/kW/yr)	**WACC** (%)	**x** (yr)	**y** (yr)	**Derating Factor (%)**	**EAC** (€/kW/yr)	**CoNE Fixed** (€/kW/yr)
OCGT	714	16	7.5	0	35	91	80	88
CCGT	1140	19	7.8	0	25	91	115	126
Battery Storage	730	10	8.2	0	15	97	96	99
Battery Storage*	730	10	8.2	0	15	51	96	189

* With adjusted de-rating factor.

The CoNE calculated using a 51% de-rating factor is already closer to the average CoNE values reported by Member States; however, it remains distant. This discrepancy disappears when the two outlier values for Battery Storage—Finland (632 €/kW/yr) and Ireland (572 €/kW/yr) are excluded from the average calculation. Removing these outliers lowers the average CoNE for Battery Storage to 164 €/kW/yr, which is much closer to the CoNE calculated with the new de-rating factor (189 €/kW/yr).

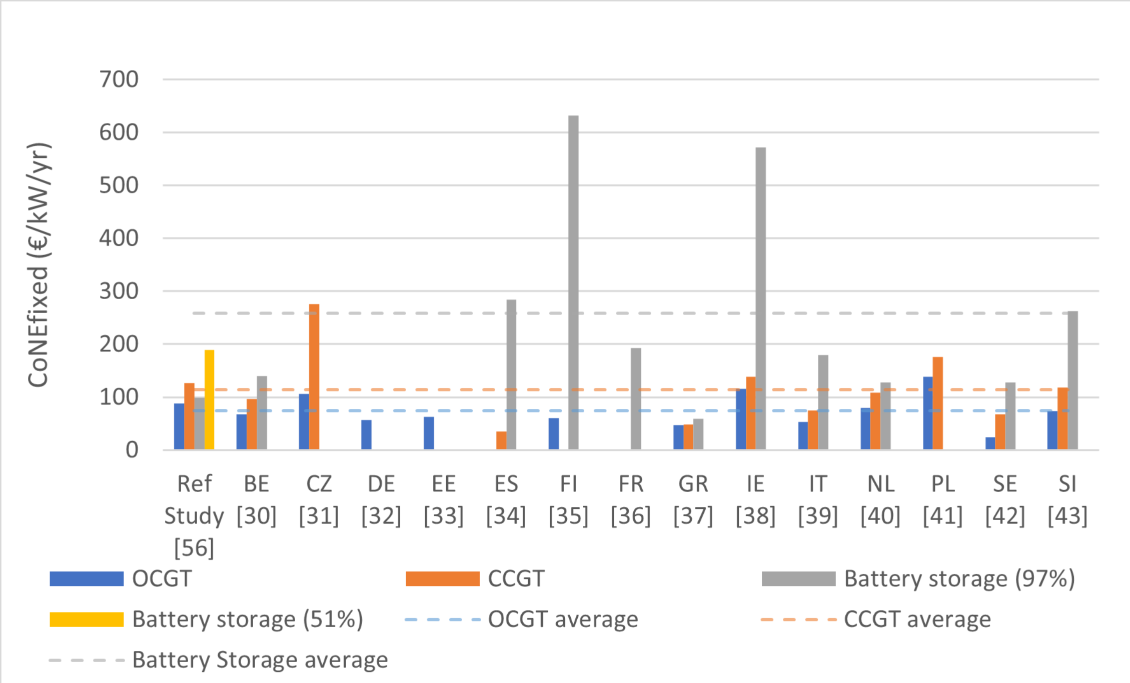

Figure 3.15: Comparison of CoNEfixed values presented on the Reference Study and MS. [30]–[43], [56]

Chapter 4

Capacity Mechanisms

4.1 Evolution of Capacity Mechanisms in EU Regulations

Capacity Mechanisms have been a key tool for ensuring electricity system adequacy in several EU Member States. The regulatory framework governing these mechanisms has evolved, with significant changes introduced in Regulation (EU) 2024/1747 [2] regarding Regulation (EU) 2019/943 [1]. This section will explore these modifications, focusing on their implications for the design and implementation of CMs across the EU. Additionally, it introduces an upcoming document aimed at simplifying the approval and implementation process of CMs, which will be further detailed later in this subchapter.

4.1.1 Capacity Mechanisms Under Regulation (EU) 2019/943

Regulation (EU) 2019/943 established strict conditions for implementing CMs, emphasizing their temporary nature and role as a last-resort solution to adress adequacy concerns. The key provision included:

Temporary Nature of CMs

- CMs were required to be approved by the European Commission (EC) for a period not exceeding ten years.
- They should be designed to solve only adequacy issues in MS and should only be used when market-based solutions proved insufficient.

Emission Limits for Supported Capacities

- From July 4th, 2019, new generation capacities emitting more than 550g CO2/kWh from fossil fuels were not eligible for CM support.
- From July 1st, 2025, existing generation capacities that began commercial operation before July 4th, 2019, emitting more than 550g CO2/kWh and averaging more than 350 kg CO2 per kW installed, were also excluded from receiving capacity payments.

4.1.2 Capacity Mechanisms Under Regulation (EU) 2024/1747

Regulation (EU) 2024/1747 brought significant modifications to the CM framework, removing their temporary status and redefining their role in ensuring system adequacy:

Permanent Recognition of Capacity Mechanisms

- CMs are no longer referred to as temporary measures, but it is still mentioned that the EC can only approve CMs for a maximum period of 10 years.
- They are no longer restricted to being a last-resort solution, reflecting a broader acceptance of their role in ensuring not only reliability but also a more flexible system in general.

Relaxation of Administrative Suppression Rules

- Under the previous regulation, if no new contracts were celebrated for three consecutive years, a CM would automatically start the phased-out process.
- The new regulation removes this administrative suppression, cementing the permanent role of the CM.

Adjustments to Emission Limits

- The 550g CO2/kWh and 350kg CO2/kW installed thresholds may, under exceptional circumstances, not apply after July 1st, 2025.
- This derogation applies to existing capacities that began commercial operation before July 4th, 2019, in cases where clear adequacy issues are identified.
- The exemption can be applied until December 31st, 2028, if specific conditions are met.

This exemption can result in high-emission Power Plants being incentivized until 2043.

4.1.3 Simplification of CM Approval and Implementation

4.1.3.1 Current Approval Process and Challenges

The approval and implementation of CM in the EU currently follows a lengthy and complex process, which includes multiple evaluations and approvals at both national and European levels. The key steps required before a CM can be implemented are:

1. **Cross-Border Consultation:** Before introducing a CM, a MS must conduct a comprehensive study on the potential effects of the mechanism on neighbouring countries. This involves consultations with at least directly interconnected MS [1];
2. **Evaluation of Strategic Reserves:** MS must first assess whether a Strategic Reserve Mechanism could resolve their adequacy concerns before considering other types of CMs [1];

3. **Adequacy Assessment Requirement:** CMs can only be implemented if the ERAA and NRAA (if conducted by the MS) identify an adequacy issue. If no resource adequacy problem is detected, a CM cannot be introduced [1];

4. **Approval of an Execution Plan:** A MS must submit a detailed execution plan to the EC, and the MS can only proceed to the CM approval after the Commission issue their opinion on the plan [1];

Due to these multiple steps, the approval process can take several years, creating challenges for MS seeking a well-timed response to adequacy concerns. The following section outlines the proposed measures to streamline and simplify this process.

4.1.3.2 Proposed Measures for Streamlining and Simplifying the Process:

A new document has been released to introduce long-discussed proposals for simplifying the CM approval and implementation process. Although this document is not yet in its final version, it lays the groundwork for expected changes [60]. The EC is expected to publish a final version in April 2025, which will formally propose measures to accelerate and simplify the CM process.

A key element of the proposal is the simplified approval pathway for MS that choose to follow standardized CM designs outlined by the EC, referred to as "pre-defined off-the-shelf models". These standardized models include two primary CM designs:

- Market-wide central buyer capacity mechanisms;
- Strategic Reserves.

While State Aid approval will still be required, the process will be significantly accelerated for MS that adopt one of these predefined structures, streamlining discussions between national authorities and the EC. Some of the proposed requirements that may be included in the final document are:

- Use of the latest ERAA report (approved by ACER) to justify the need for a CM;
- ACER provides standardized VoLL and CoNE reference values, reducing the burden on MS to establish their RS, if they decide to consider ACER's calculations;
- Early submission of implementation plans, allowing MS to make reforms while preparing for CM introduction, which previously was not an option, because MS could only advance to the approval and implementation process of CM after the EC verified that the execution plan alone would not be sufficient to solve the identified adequacy issues;
- The EC, as referred before, will provide the best practices related to CM in the final document, and the MS that decide to go with the simplified process will need to comply with these design features.

These reforms, even though they may not yet be in their final version, aim to significantly shorten the approval process, enabling MS to respond more efficiently to resource adequacy challenges.

4.2 Comparative analysis of Capacity Mechanisms in Europe

This section examines the diversity of capacity mechanisms (CMs) across Europe, this analysis deliberately excludes strategic reserves from its assessment of European capacity mechanisms. Unlike market-wide capacity markets, strategic reserves—while effective in addressing short-term adequacy—risk creating a lock-in effect by perpetuating reliance on existing conventional thermal generation [61], [62]. Such an approach would conflict with decarbonization goals, as it discourages investment in flexible, low-carbon alternatives like storage and demand-side response. Instead, this section focuses on competitive, market-based mechanisms that align with long-term sustainability objectives while ensuring system reliability.

The comparison will examine key design features across different models, such as pricing methodologies, penalties in case of non-compliance, and technology eligibility criteria, before proposing adaptable solutions for future frameworks. Particular attention will be given to Spain's capacity mechanism proposal as a regional reference, given its climatic and structural parallels with Portugal.

4.2.1 Pre-qualification

The prequalification process is a fundamental stage in capacity mechanisms, serving as a gateway to ensure the technical and administrative eligibility of Capacity Market Units (CMUs) before they can participate in auctions or receive capacity certificates. Although varying in structure and scope across Europe, several commonalities and distinctive features emerge among countries.

4.2.1.1 Country Characteristics

Common Elements Across Systems

A key similarity across all analysed countries—Belgium, France, Spain, Italy, and the United Kingdom—is the enforcement of a minimum capacity threshold for eligibility. In every case, CMUs must provide at least 1 MW of capacity to be considered, which goes according to the Target Models for CM presented in the Draft Communication from the EC [63]. This threshold can often be met through the aggregation of smaller units, fostering participation from distributed energy resources and demand-side response (DSR). Additionally, all systems require the submission of detailed technical and administrative documentation, and most include the provision of a financial guarantee to deter non-serious participants or to hedge against non-compliance after auction allocation.

Country-Specific Characteristics

- Belgium implements a centralized capacity remuneration mechanism (CRM) where prequalification is mandatory for all generation assets above 1 MW, even if they do not intend to participate in the auction. A notable feature is the allowance for “unconfirmed capacity” (e.g., early-stage DSR or aggregated CMUs without finalized contracts), which is particularly useful for aggregators. Such units can still qualify for one-year contracts and are subject to higher financial guarantees (20k€/MW for virtual and newly built CMUs and 10k€/MW for existing ones) [64];

- France differs significantly due to its decentralized, market-wide obligation model. Rather than a central authority procuring capacity, the responsibility lies with electricity suppliers and large consumers who must acquire capacity certificates to meet their obligations. The prequalification process involves a bilateral agreement with RTE, the French TSO, and includes a historical performance review. Certification also considers technical availability and the contribution to security of supply. DSR providers may be required to pass activation tests. Another feature is the "Certification Tunnel", which sets a minimum and maximum percentage of effective capacity that may be certified, enhancing system reliability [65];

- Spain (proposal), Italy, and the UK utilize a centralized auction-based CM, where prequalified units must submit a financial guarantee prior to the auction that covers both participation costs and potential penalties for future non-delivery. The process aims to ensure serious commitment from all bidders [66]–[68].

There are several similarities between each country’s CM, but it is also clear that some variations exist. These variations reflect each country’s regulatory environment, system needs, and market design preferences, underlining the importance of tailoring capacity mechanisms to national contexts while maintaining a baseline of operational robustness. It is worth highlighting that the current decentralized capacity mechanism in France is scheduled to expire in 2026. The French regulatory authorities have expressed their intention to replace it with a centralized capacity mechanism, thereby aligning the country’s approach with the more conventional models implemented across other European electricity markets [69].

4.2.1.2 Derating Factor Comparison

In the context of Capacity Remuneration Mechanisms (CRMs), the de-rating factor plays a central role in the prequalification process, as it reflects the expected contribution of a resource to system adequacy during periods of scarcity. Rather than considering installed capacity alone, system operators apply technology-specific de-rating factors to estimate the effective capacity that a unit can reliably provide when most needed. As outlined in the CRM Functioning Rules document for Belgium [70], the adoption of de-rating factors ensures a consistent, technology-neutral approach to valuing capacity resources based on their reliability and availability under stress conditions. These values are often benchmarked against practices in other European countries, offering a comparative perspective for market design choices.

Table 4.1 summarizes derating factors applied in Belgium (BE), France (FR), Italy (IT), the United Kingdom (UK), and proposed in Spain (ES) for various capacity technologies:

Table 4.1: De-rating factors across countries

	De-rating Factor (%)				
Technology	**BE [17]**	**FR [70]**	**IT [50]**	**ES [43]**	**UK [77]**
OCGT	92	88	90	82 - 93	94
CCGT	94		90		92
Storage 1h	22	70	27	27 - 70	7
Storage 4h	57		70		31
Pumped Hydro	52	70	70	73 - 82	94**
PV	1	n/a	12	3 - 11	6
Wind Onshore	7	20	17	15 - 22	7
Wind Offshore	9	25		15 - 22	9
DSR	76*	n/a	n/a	n/a	79

* The DSR of 7 hours has been assumed; for DSRs with other durations, see Table A.1 in Appendix A.
** It has been assumed that the Pumped Hydro has more than 10 hours of storage.

From this comparative analysis, several insights emerge. Firstly, the consistently low de-rating factors applied by Belgium and the UK to variable renewable technologies such as solar PV and wind (both onshore and offshore) reveal a conservative stance regarding their reliability contribution to security of supply. Secondly, it is notable that the UK applies significantly lower de-rating factors for battery storage (1h and 4h durations) than other countries. For instance, while France and Italy attribute a 70% factor for 4-hour storage, the UK assigns only 31%. These international practices offer important reference points for the calibration of a future CM design for Portugal.

4.2.1.3 Capacity Auctions Design Comparisons

Capacity auctions are a fundamental component of capacity mechanisms, as they represent the primary tool through which system operators ensure that sufficient capacity will be available to meet demand during delivery year Y. These auctions play a central role in securing resource adequacy, by contracting the required capacity in advance and thereby supporting the long-term security of supply.

Typically, the auctions are held several years ahead of the delivery year. This long lead time enables new capacity to be planned, financed, and developed in time. Auctions are designed to provide a predefined share of the expected consumption in the delivery year based on demand forecasts and capacity adequacy assessments. Ideally, the final auction held in Y-1 serves mainly to correct for minor deviations between initial forecasts (from Y-4) and updated consumption projections for year Y. This layered approach allows the system operator to progressively close the capacity gap while providing market participants with flexibility and investment signals.

When comparing the auction frameworks implemented (or planned) in various European capacity mechanisms, several common features emerge. All countries under analysis besides Spain plan to conduct the first capacity auction for a given delivery year Y at least four years in advance [65]–[67], [70]. Spain stands out by scheduling its initial auction at Y-5 [65], while the other mechanisms typically begin at Y-4. After the first auction, most countries continue to hold follow-up auctions in years Y-3, Y-2, and Y-1. As the delivery year approaches, the volume of capacity to be contracted in these subsequent auctions tends to decrease as the system progressively closes the remaining adequacy gap and adjusts for updated consumption and capacity availability data.

It is also important to highlight the UK's relatively rigid framework regarding access to long-term capacity contracts. The UK capacity market sets specific conditions for multi-year contracts based on the type of Capacity Market Unit (CMU) and the investment undertaken:

- Newly built CMUs may receive contracts lasting up to 15 years if they meet defined minimum capital expenditure thresholds [68].
- Refurbishing CMUs can secure contracts of up to 3 years, depending on whether they meet a specific minimum investment level (in £/kW). Otherwise, they are eligible only for a 1-year contract [68].
- Existing CMUs and Demand Side Response (DSR) units typically receive 1-year contracts. However, unproven DSR resources may be eligible for longer durations if certain conditions are satisfied [68].

This tiered contracting structure seeks to balance investment security for new entrants with flexibility and cost control for the system while avoiding overcompensation for mature or low-risk assets.

Spain adopts a similarly stratified approach to capacity contract durations, though it differs from the UK in the criteria used to determine long-term eligibility. Rather than relying on minimum capital expenditure thresholds, the Spanish model assigns contract durations to new investments in generation and storage based on the reference technology and a value equivalent to half of its expected technical lifetime, with a maximum limit of 15 years [61]. Existing generation and storage assets, defined as those with an operating license granted before the auction announcement, are eligible only for 1-year contracts. Demand-side resources may select a service provision period between 1 and 10 years, within predefined limits, though all installations within an aggregation must share the same eligibility category, either existing or new investments [61].

4.2.2 Stress period

Once a capacity auction is completed, the awarded capacity providers enter the post-auction phase, during which they are contractually obligated to deliver the amount of firm capacity they committed to during periods of system stress. In return, these providers receive a fixed remuneration, typically monthly, expressed in €/MW of contracted capacity. This payment aims to ensure that sufficient dispatchable capacity remains available to meet peak demand or respond to unexpected supply shortages.

Beyond the fixed remuneration, capacity providers can also generate additional variable revenues by selling their energy in the electricity markets, including the day-ahead market, intraday market, and ancillary services. In practice, during system stress periods, these resources are expected to be dispatched and to benefit from the energy prices, which are often elevated due to tight system conditions. As a result, capacity providers' total income includes a fixed revenue stream from the capacity mechanism and variable revenues tied to market participation.

The definition of stress events—periods during which capacity providers must demonstrate availability—differs across countries. These periods are typically aligned with national adequacy challenges, which can vary depending on climatic conditions. For instance, colder winters in northern countries or hotter summers in southern ones result in different seasonal stress patterns. Moreover, these periods may be triggered not only by expected seasonal peaks but also by unforeseen events, such as extreme weather or unexpected outages in the transmission or generation systems.

There are different approaches to defining stress periods, the following two examples illustrate these methodologies:

Belgium – AMT Moments [70]:

- In Belgium's CRM, capacity providers are obligated to be fully available during periods known as AMT (Availability Monitoring Trigger) Moments. These are defined based on market signals—specifically, when the Belgian day-ahead electricity price exceeds a predefined AMT price threshold. AMT Moments are announced by 3:00 PM (and in specific cases by 6:00 PM) the day before the delivery. This system ensures that capacity is available when price signals indicate scarcity, making it a reactive, market-based trigger for availability obligations.

France – PP1 and PP2 Days [65]:

In contrast, France uses a forecast-driven methodology. Capacity providers must be available during pre-defined critical periods known as PP1 and PP2 days:

- PP1 Days refer to the 15 days with the highest forecasted demand in the year, selected using meteorological and statistical data. Typically, 11 days are chosen between January and March, and 4 between November and December. These are announced by RTE by 9:30 AM the day before.

- PP2 Days encompass all PP1 Days plus up to 10 additional days identified as high risk due to factors such as low generation availability, reduced interconnection capacity, or severe weather impacts. While most PP2 days are announced by 9:30 AM the previous day, those that are not PP1 can be declared up to 7:00 PM on the day before.

Although Spain will not adopt the exact same approach as France (based on PP1 and PP2 days), its methodology is also forecast-driven. However, it introduces a different constraint: the number of days identified as system stress days must lie between 5% and 10% of the year [66].

Despite the differences in how stress periods are defined, whether through market-based price triggers or forecast-driven adequacy assessments, the core objective remains the same: to ensure that contracted capacity is available precisely when the system needs it most.

4.2.3 Monitoring, Testing, and Penalties

A critical component of capacity mechanisms (CMs) across Europe is the monitoring and enforcement of delivery obligations by awarded capacity providers. Once a CMU (Capacity Market Unit) secures a contract through a capacity auction, it is required to demonstrate the availability of the committed capacity during real system stress events or scheduled testing periods. To ensure system reliability, all countries analysed implement similar frameworks of monitoring and compliance validation, yet they differ in the structure and severity of their penalty mechanisms.

4.2.3.1 Monitoring and Testing

In all the countries examined, capacity providers are subject to at least one availability test per year. These tests assess:

- The declared generation capacity of producers.
- The actual consumption reduction of demand-side response (DSR) units.
- The physical power flows through interconnectors in the case of cross-border capacity.

This uniform practice ensures that only reliable and verifiable capacity is considered when system adequacy is at risk.

4.2.3.2 Penalty Framework across Different Countries

The Spanish capacity mechanism proposes two complementary penalty approaches for producers, storage units, and DSR providers [66]. The first, represented by 4.1, applies when the average firm capacity delivered during system stress hours is below the level contractually committed, triggering a financial penalty proportional to the shortfall.

$$OPINSCAP1 = P_{inc} * Price * K1 \tag{4.1}$$

In this expression:

- P_{inc} is the undelivered capacity;
- Price is the auction award price (€/MW firm);
- K1 is the penalty coefficient for non-compliance with the availability of firm power, this coefficient is set at 1.2

The second set of penalties, represented by expressions 4.2, 4.3 and 4.4, introduces a progressive structure based on repeated underperformance. Specifically, they correspond to the penalties applied for the first, second, and third failures during a real activation or a scheduled test.

- The penalty for the 1st failure in a real or test activation is given by 4.2:

$$OPINSCAP2 = -\frac{1}{12} * P_{sub} * Price * K2 \tag{4.2}$$

In this expression:

  - P_{sub} is the firm capacity allocated in the capacity auction (MW);
  - K2 is the penalty coefficient for non-compliance with the availability of firm power, which is set at 1.2;

- The penalty for the 2nd failure in a real or test activation is given by expression 4.3:

$$OPINSCAP3 = -3 * \frac{1}{12} * P_{sub} * Price * K2 \tag{4.3}$$

- The penalty for the 3nd failure in a real or test activation is given by expression 4.4:

$$OPINSCAP4 = -P_{sub} * Price * K2 \tag{4.4}$$

Together, these mechanisms form the core of the proposed penalty framework for Spain's future capacity mechanism.

Comparison with Belgium

While Belgium applies a similar principle of penalizing capacity underperformance, the key distinction lies in the differentiation of penalty severity based on the season and whether the capacity loss was announced or unannounced [70].

For instance, ELIA (Belgium's TSO) applies the penalty factors shown in Table 4.2:

Table 4.2: Value of the Penalty Factor [70]

Type of Missing Capacity	Apr - Oct	Nov - Mar
Announced	0	0.9
Unannounced	0.5	1.4

These factors are applied within a more complex penalty expression, which calculates the unavailability penalty as a function of the CMU's weighted contract value, the amount of missing capacity, and the period over which it occurred. Expression 4.5 is used by Elia to calculate the penalties applied to the capacities.

$$\textit{Unavailability Penalty [€]} = \frac{1}{Q \cdot UP}\left[\sum_{t=1}^{T}(1+X)\cdot \textit{weighted contract value}(CMU,t)\cdot UMC(CMU,t) + \sum_{t=1}^{T}(1+X)\cdot \textit{weighted contract value}(CMU,t)\cdot AMC(CMU,t)\right] \tag{4.5}$$

In this expression:

– *T* are the Market Time Units (MTU) of the AMT Moment or quarter hours of the Availability Test;

– *Q* is the total amount of AMT MTUs of the AMT Moment or quarter hours part of the Availability Test;

– *X* is the penalty factor to be applied to the Missing Capacity for time *t* (as in Table 4.2);

– *UMC(CMU,t)* is the Unannounced Missing Capacity at time *t*;

– *AMC(CMU,t)* is the Announced Missing Capacity for time *t*;

– *UP* is the number of *AMT Moments* where ELIA expects to verify the availability, namely equal to fifteen. It is an order of magnitude and not a limitation nor a minimum number of *AMT Moments* during which ELIA effectively verifies availability;

– *weighted contract value (CMU,t)* is given by 4.6.

$$\textit{weighted contracted value (CMU,t)} = \frac{\sum_{i=1}^{N}(CapacityRemuneration_i * ContractedCapacity_i)}{\sum_{i=1}^{N} ContractedCapacity_i} \tag{4.6}$$

In this expression:

– *N* is the number of Transactions (in Primary or Secondary Market) with a Transaction Period covering time *t*, being the *AMT MTU* for Availability Monitoring or quarter hour during an Availability Test during which Missing Capacity was determined.

Belgium's model emphasizes temporal and operational granularity, with a heavier burden placed on unannounced failures during critical winter months.

Comparison with Italy

Italy also applies a tiered penalty framework. The primary difference includes the use of variable financial penalties and the classification of non-compliance into three distinct categories:

- Temporary Non-compliance: Penalized according to 4.7 [67]:

$$\text{Penalty} = CSR \cdot (RP - EP) \cdot \textit{Hours of non-compliance} \tag{4.7}$$

  In this expression:

  - CSR is the capacity subject to refund;
  - RP is the market price of energy at the time the operator should have made the contracted capacity available;
  - EP is a price limit below which the operator is not penalized for not making capacity available.

- Extended Non-Compliance is triggered when a temporary breach extends over three non-critical months (not necessarily consecutive) or any single critical month. In such cases, the capacity provider permanently forfeits the fixed remuneration ("corrispettivo fisso") corresponding to the affected months and is additionally subject to a financial penalty equal to 10% of the suspended amount [67].

- Financial non-compliance, which can be characterized as temporary or definitive, where the capacity does not pay the difference between the fixed remuneration it has received, and the variable remuneration derived from the sale of electricity on the primary and/or secondary markets if this difference is negative. This non-compliance can lead to the activation of the guarantees initially given and a termination of the contract initially settled [67].

4.2.4 Payback Obligation and CfDs

The existence of windfall profit limitation mechanisms plays an important role in some capacity markets, aiming to prevent excessive charges and ensure efficient and proportionate remuneration for the services provided by contracted capacities. The design and implementation of such mechanisms vary significantly across the countries analysed.

In Belgium, a payback obligation is in place within the CRM. This mechanism is based on the definition of a strike price, which is regularly updated. When the reference price (electricity market price) exceeds the strike price (price defined in the contracts), contracted units are required to return the difference to Elia, the Belgian transmission system operator. This prevents the accumulation of excessive profits during high price periods and helps protect consumers [70].

In France, the contracts awarded through capacity auctions take the form of Contracts for Difference (CfDs). These contracts guarantee a top-up remuneration when the reference price is below the contractual CfD price. However, when the market price exceeds the agreed CfD value, the capacity providers are similarly obliged to pay back the difference, ensuring symmetric treatment of price deviations and enhancing the predictability of revenues [65].

In Italy, a different approach is adopted through the use of bid caps in the capacity auctions. These caps impose maximum bid prices, which vary according to the type of capacity involved – for instance, existing, new, imported, and demand-side response (DSR) capacities each have distinct bid caps. This measure aims to ensure that clearing prices remain within reasonable boundaries, thereby avoiding speculative or opportunistic bidding behavior [67].

By contrast, the United Kingdom currently does not include any specific mechanism to limit windfall profits within its Capacity Market. Contracted units receive fixed capacity payments for availability, regardless of the prices observed in the energy market. A similar approach is being proposed for the future Spanish Capacity Mechanism, where no explicit provisions for windfall profit mitigation or market price restrictions are foreseen at this stage [61], [68].

A diverse range of approaches can be observed. Belgium and France have adopted payback mechanisms based on the evolution of market prices concerning a reference value. Italy applies a preventive approach using bid caps, while the UK and, likely, Spain in the future rely on unrestricted market exposure, with no mechanisms to cap earnings from high energy prices.

4.2.5 Capacity Mechanism Fee

An essential element of any capacity mechanism (CM) is the method by which its costs are recovered. In Belgium, Spain, the United Kingdom, and France, the financing structure ultimately places the financial burden on final electricity consumers [65], [66], [70], [71]. However, the way in which this cost recovery is implemented varies slightly depending on the structure of the mechanism.

In Belgium and the United Kingdom, the cost of the capacity mechanism is recovered through a variable fee applied either directly to large consumers connected to the transmission grid or to electricity suppliers. These suppliers, in turn, pass the cost down to their final customers. The fee is proportional to consumption, meaning that a consumer who uses twice as much electricity as another will also pay twice as much in CM-related fees. This straightforward, consumption-based model ensures simplicity and proportionality in cost recovery [68], [70].

By contrast, France, due to its decentralized, market-wide model, does not channel capacity mechanism costs through the transmission system operator (TSO) as the other countries do. Instead, the financial burden is embedded in the market-based transactions between producers (or DSR providers) and electricity suppliers (that later apply these fees to their customers). The TSO (RTE) recovers the cost of monitoring and auditing capacity through direct charges to capacity providers, who incorporate those costs into the price of capacity certificates. These certificates are then purchased by suppliers to meet their obligations, and the costs are ultimately passed on to final consumers [65]. As a result, while this mechanism is structurally different, the economic outcome for end users is equivalent.

Despite the consistency in cost allocation across the Member States with CM already in place, there is room for improvement in the design of these tariffs. While current schemes are proportional to energy consumption, they do not typically incorporate any price signals related to system stress periods. Incorporating such a component could provide valuable incentives for demand-side flexibility. If consumers were made aware that capacity costs increase during stress hours, they might shift part of their demand to off-peak periods, contributing to system adequacy and reducing their energy bills. Implementing time-sensitive, variable capacity tariffs could, therefore, be an effective way to encourage more responsive and flexible electricity consumption behavior in the long term.

However, Spain's proposed capacity mechanism introduces an innovative approach that already addresses this suggested improvement. Instead of applying a flat consumption-based fee, Spain plans to allocate the total cost of the mechanism dynamically across different hours based on a "coverage index". This index is calculated hourly as the ratio between total firm capacity and hourly demand, meaning that hours with lower system adequacy (i.e., lower firm capacity relative to demand) bear a higher share of the total capacity cost. The resulting cost per hour is then distributed among tariff segments according to their hourly consumption, leading to higher charges during hours of system stress [61].

This approach effectively introduces a time-sensitive price signal into the cost recovery structure, incentivizing consumers to shift their demand away from stress hours to reduce their energy bills. As such, Spain's model could serve as a reference for future implementations in Portugal, as it aligns economic efficiency with the intention to enhance system reliability through demand flexibility.

4.2.6 Cross-border Participation

According to Article 26 of Regulation (EU) 2019/943 of the European Parliament and of the Council, all capacity mechanisms (CMs) – with the exception of strategic reserves, and even those where technically feasible – must be open to direct cross-border participation by capacity providers located in other Member States. This legal obligation has led to a variety of implementations across Member States, each with its constraints and opportunities for foreign capacities. Below is a comparative overview of how different countries address cross-border participation in their respective capacity mechanisms.

Belgium

In Belgium, foreign capacity resources are permitted to participate in the capacity mechanism, but only under one-year contracts. This places an upper limit on the total remuneration that foreign participants can receive. In the Belgian CRM, longer contract durations (e.g. 8 or 15 years) are associated with higher fixed remuneration. By limiting foreign capacities to one-year contracts, the mechanism avoids granting long-term and higher incentives to external providers while still complying with European requirements [70].

France

France enables cross-border participation through two distinct regimes:

- The simplified regime applies in the absence of a bilateral agreement between RTE and the neighboring TSO. In this case, the interconnector is assigned a Certified Capacity Level, calculated based on the physical interconnection limit and its historical contribution to French adequacy. A portion of the capacity revenues is shared with the foreign TSO. This model is also used in the UK [65], [68].
- The enhanced regime is activated when a bilateral agreement exists. This allows foreign capacity providers, beyond just interconnectors, to participate directly in RTE's capacity auctions. The foreign TSO receives participation rights, which are converted into capacity certificates. Foreign providers must meet the same performance obligations as domestic ones [65].

Spain

Spain's proposed capacity mechanism closely mirrors one of the regimes of the French model. Should a bilateral agreement be reached between REE and neighboring TSOs, foreign capacity providers would be allowed to participate under identical conditions to national resources. The maximum volume of eligible foreign capacities would be determined by mutual agreement between the TSOs [66].

Italy

Italy permits cross-border participation but with notable restrictions. Foreign capacity providers must already be qualified to participate in the Italian day-ahead market and must be associated with a Virtual Foreign Zone (Area Virtual Estera) – a market representation that simplifies cross-border flow management. These units face a lower price cap in the capacity auctions compared to national providers and can only sell capacity to the Italian zone adjacent to their foreign virtual area. Additionally, Terna imposes capacity limits to prevent overreliance on external sources. Apart from these constraints, foreign units are required to meet all standard qualifications and delivery obligations applicable to domestic providers [67].

4.3 Possible barriers to the Implementation of a Capacity Mechanism in Portugal

Despite the increasing concern regarding security of supply across Europe, Portugal remains distant from implementing a capacity mechanism. One of the clearest indicators of this gap is the disparity between the adequacy results reported in the ERAA 2023 (European Resource Adequacy Assessment) [54] and those presented in Portugal's National Adequacy Report, the RMSA-E 2023 [72]. This divergence can represent a significant barrier to CM implementation approved by ACER and EU, as current European legislation requires that any proposed capacity mechanism be justified by adequacy concerns identified both in the National Adequacy Report (NRAA) and the ERAA.

Moreover, as outlined in the European Commission's proposal for streamlining the implementation process of capacity mechanisms (discussed in section 4.1.3.2 of this dissertation), simplified approval can only proceed when adequacy issues are identified within the latest ERAA report approved by ACER [60]. Alternatively, if a Member State wishes to rely on a NRAA, its assumptions, methodology, and results must first be verified by the European Commission prior to the adoption of a State aid decision [60]. Therefore, the absence of such alignment in Portugal's case poses a direct regulatory obstacle.

Table 4.3 summarizes the ERAA 2023 results for Portugal, revealing that the simulated Loss of Load Expectation (LoLE) remains significantly below the Portuguese reliability standard of 5 hours per year in all modeled target years. While ERAA does not simulate the year 2035 (which is analysed in RMSA-E), it still offers comparable insight across 2025 and 2030. In none of these years does the ERAA simulation suggest inadequacy concerns for the Portuguese system.

Table 4.3: ERAA 2023's LoLE values for Portugal [55].

Scenario	Target Year	LoLE (h/year)
A	2025	0.04
	2028	0.00
	2030	0.10
B	2025	0.08
	2028	0.13
	2030	0.13

To complement this, Table 4.4 presents the LoLE values provided in the RMSA-E 2023 report under the "Ambição" scenario, which reflects Portugal's expected compliance with its PNEC 2030 targets [72].

Table 4.4: RMSA-E 2023's LoLE values for Ambition's scenario [72]

Target-Year	LoLE (h/year)
2025	8
2030	21
2035	23

One of the most critical sources of the observed discrepancy between RMSA-E and ERAA results lies in the treatment of interconnection capacity. While the ERAA assumes that 100% of interconnection capacity with Spain is available under all simulated hours, the RMSA-E adopts a significantly more conservative approach, assuming only a 10% contribution. The other critical source of the observed discrepancy is the simulation perimeter: while the ERAA considers a European-wide framework that models cross-border exchanges across all Member States based on their respective interconnection capacities, the RMSA-E is limited to the Iberian perimeter, applying a limited NTC on the interconnection with France and thereby excluding any potential contribution from the rest of Europe. These modelling choices lead to a substantial increase in simulated LoLE values in the RMSA-E, pushing them well above the 5h/year benchmark and showing a system that lacks adequacy—an issue not corroborated by the ERAA.

This reinforces the challenge: While Portugal's RMSA-E 2023 (under the "Ambição" scenario, which aligns with the country's NECP 2030 targets) estimates a LoLE that violates the 5h/year threshold, the ERAA results do not reflect this, effectively blocking any formal justification for a CM under EU rules. Adding to this complexity is the fact that Portugal's current 5h/year reliability standard itself does not comply with the methodology proposed by ACER [28], which further undermines the regulatory case for implementing a CM. Before considering the introduction of a capacity mechanism, Portugal must first update its Reliability Standard, specifically by calculating a new LoLE using ACER's approach.

Until these fundamental differences in assumptions and methodologies are resolved, the path toward implementing a capacity mechanism in Portugal will remain constrained both by regulatory limitations and by the lack of harmonized adequacy evidence.

Chapter 5

Methodology and Simulation Framework

5.1 PS-MORA: Functionality, Methodology, and Simulation Framework

The adequacy assessment of interconnected power systems requires advanced tools capable of representing not only the temporal and spatial variability of generation availability across multiple control zones, but also the operational rules and market mechanisms that govern cross-border exchange of energy and operational reserves. In this context, REN promoted the development of the PS-MORA (Power Systems – Model for Operational Reserve Adequacy) tool, in collaboration with INESCTEC to simulate interconnected systems with high shares of renewable energy sources (RES), adopting a probabilistic methodology grounded in Sequential Monte Carlo Simulation (SMCS).

By relying on a time-sequential probabilistic approach, PS-MORA allows for detailed simulations of system operation under uncertainty. These include stochastic representations of forced outages of system components, intermittent generation, and demand variation, enabling the estimation of reliability and economic indices such as the Loss of Load Expectation (LoLE),the Expected Energy Not Supplied (EENS) and Lost of Load Cost (LOLC), which are crucial for adequacy studies and investment planning [73]. PS-MORA is particularly suitable for complex, multi-area systems, as it supports flexibility and reliability assessments, as well as power flow analysis, under different network configurations and exchange policies between areas. It also offers a modular modelling framework, allowing the user to implement various technologies (thermal, hydro, solar, wind) using different levels of technical and economic detail [73].

The methodology applied in PS-MORA is grounded in two main traditional approaches of adequacy analysis: deterministic methods and probabilistic methods [74]. The probabilistic nature of PS-MORA enables it to better capture the uncertainty inherent to modern power systems, particularly those with high RES penetration. Among the Monte Carlo simulation techniques available, SMCS stands out by sampling system states in chronological order, which allows the model to preserve the temporal coherence of events such as wind generation fluctuations, maintenance schedules, load evolution, and the life cycle of system components. This is in contrast with non-sequential (state-space) methods, where the chronological order of events is not preserved [75].

To support its comprehensive simulation capabilities, PS-MORA is structured around three core components: Input Data, which allows defining all system parameters and assumptions; the Simulation Process, where the sequential Monte Carlo engine evaluates system behavior under uncertainty; and the Output Data, which delivers quantitative metrics that inform decision-making. This modular architecture is illustrated in Figure 5.1 and serves as the basis for the detailed exploration of key input and output datasets presented in the following subsections.

Figure 5.1: PS-MORA program basic modules [73]

5.1.1 Input Data

The Input Data module defines the characteristics of the system under study. The key input files include:

- **System -** describes the entire electric power system topology and its components. It includes both technical and economic detailed information on all generation units (thermal, hydroelectric, solar, wind), such as their forced outage ratios, transmission lines, transformers, and demand nodes (loads). Additionally, it incorporates Value of Lost Load (VoLL) values, specified in €/kWh, broken down by consumption sector (residential, commercial, industrial), with a weighting factor assigned to each of them based on its share of total demand or socioeconomic impact;

- **Load -** contains the system's percentual load curve, expressed as percentages of the annual peak load. This time series defines the load variation throughout the simulated horizon;

- **Production Costs -** includes the variable generation cost for each generator in the system, expressed in €/MWh, enabling the tool to simulate economic dispatch and assess system cost;

- **Hydro, Solar, Wind -** these files provide renewable generation profiles over time, based on historical or synthetic data, capturing the variability of resource availability;

- **Maintenance -** specifies the planned maintenance schedules for generation and transmission assets, introducing constraints on resource availability during the simulation period.

5.1.2 Simulation Process

Once all input data is loaded and processed, the simulation phase begins by generating time-sequential system states. These reflect generator and line availability, renewable resource fluctuations (e.g., wind or hydro), and hourly demand. Each sampled state is evaluated using one of three approaches: a standard linear optimal power flow (OPF) to detect load shedding, an OPF that includes an estimation of transmission losses, or a simplified optimization that minimizes load shedding, neglecting the voltage angle differences of buses. Reliability indices such as LoLE and EENS are then calculated along with their statistical variability. If the results do not meet predefined convergence criteria (typically based on the coefficient of variation, β), the simulation continues iteratively [73]. This overall workflow is illustrated in Figure 5.2, which shows the three main stages of the PS-MORA simulation process: input data handling, iterative simulation, and output processing.

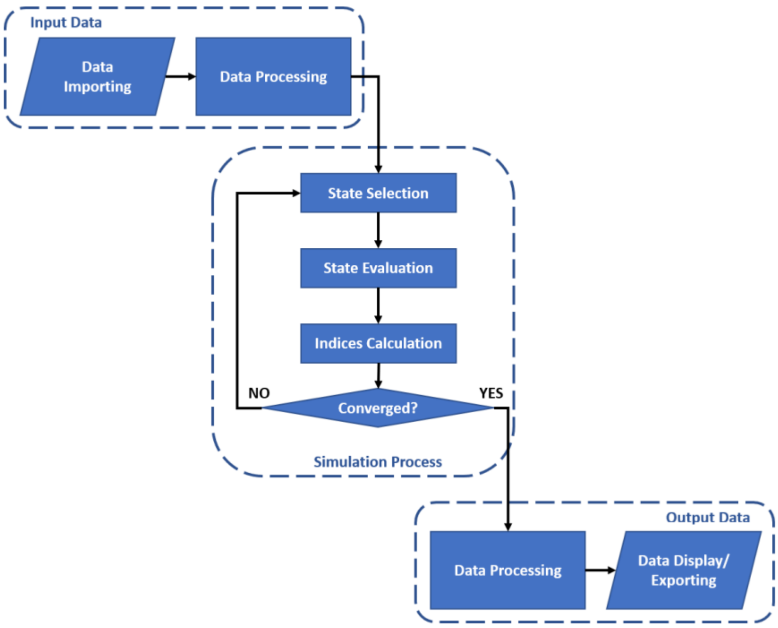

Figure 5.2: PS-MORA program simulation flow charts [73]

5.1.3 Output Data

Upon completing the simulations, the Output Data module generates a variety of indicators that support system adequacy evaluation and further analysis:

- **Final Reliability and Economic Indices -** presents key indices such as LoLE, EENS, LOLC, and Loss of Load Frequency (LoLF), disaggregated by failure type — generation failure, transmission failure, or both. These metrics form the basis for assessing whether the system meets security of supply targets;

- **Generation -** provides hourly generation and available capacity values for all power plants in the system. These can be used to visualise and analyse the evolution of the generation mix and system operation over time;
- **ENS -** presents ENS values by failure type and disaggregated by hour, week, month, and year. This breakdown allows for deeper insight into the temporal and structural causes of supply inadequacy.

5.2 Simulation Purpose and Experimental Setup

5.2.1 Objective of the Simulations

To understand the purpose of the simulations carried out using the PS-MORA tool, it is essential to recall the role of capacity mechanisms previously discussed in Chapter 4. These mechanisms are designed to ensure long-term SoS, acting as a complement to the payment obtained through the electricity markets in contexts where investments in firm capacity might otherwise fall short due to market failures or revenue insufficiency.

One of the core processes behind capacity mechanisms is the organization of capacity auctions. In such auctions, the System Operator contracts new or existing generation capacity for future delivery periods. However, for this to happen, it is first necessary to estimate the amount of capacity required to meet an acceptable reliability standard, typically expressed in terms such as LoLE (Loss of Load Expectation). Once this capacity requirement is determined, it can be auctioned competitively.

The exercise conducted in this study replicates this process using PS-MORA. Specifically, simulations are performed on a test system based on an IEEE benchmark network (described in Section 5.2.2). The starting point corresponds to a stressed scenario with a high LoLE value, signaling insufficient capacity to guarantee the desired level of reliability. In successive simulation rounds, thermal generation capacity is incrementally added in the form of OCGT units. After each addition, the system is reassessed in terms of adequacy, and key output indicators such as LoLE, EENS (Expected Energy Not Supplied), and investment costs are recorded.

The ultimate goal of this iterative process is to identify the optimal capacity level that minimizes the total system cost. This includes both the cost of new capacity and the socio-economic cost associated with unserved energy. The point at which further capacity additions result in negligible reductions in EENS, when compared to the associated investment cost, can be interpreted as the optimal capacity to be auctioned in a real-world capacity mechanism.

In addition to this objective, it is also intended to verify whether this optimal value aligns with the Reliability Standard (RS) calculated using the methodology proposed by ACER. This RS value will then be compared to the LoLE resulting from each simulation in PS-MORA, providing an additional consistency check between the optimal capacity level and regulatory benchmarks.

5.2.2 IEEE Test System

The simulations were conducted on a modified version of the IEEE Reliability Test System 1979 (RTS-79). As its name suggests, this was the first standardized test system, originally developed in 1979 by the Application of Probability Methods (APM) Subcommittee of the Power System Engineering Committee. This benchmark system started to be widely used in power system adequacy and reliability studies [76].

The version adopted in this study introduces some modifications to the original configuration in [76]. In particular, three wind power plants were added to the base system, aiming to better reflect the current generation mix and to introduce renewable variability into the system. The resulting network maintains the same basic topology and structure of the RTS-79 but expands the generation portfolio.

Table 5.1 presents the generating unit ratings and reliability data used in the simulations.

Table 5.1: Generating Units Reliability.

Technology	Unit Size (MW)	Number of Units	Failure Rate (Occ/yr)	MTTR (Hours)
Wind	2	200	7,71	80
OCGT	12	5	2,98	60
OCGT	20	4	19,47	50
Hydro	50	6	4,42	20
OCGT	76	4	4,47	40
OCGT	100	3	7,30	50
CCGT	155	4	9,13	40
CCGT	197	3	9,22	50
CCGT	350	1	7,62	100
CCGT	400	2	4,58	150

The original peak load of the RTS-79 system is 2850 MW. However, to simulate a stressed system with an initial LoLE (Loss of Load Expectation) higher than 10 hours/year, the peak load was increased by 2%, reaching 2907 MW. Regarding the generation mix, Table 5.2 provides the breakdown of total installed capacity by technology type, reflecting the system's diversity. Figure 5.3 illustrates the hourly load variation throughout the 8,760 hours of the year, expressed as a percentage of the system's peak load.

Table 5.2: The system's initial generation mix.

Tecnology	Capacity (MW)	%
OCGT	744	19,6
CCGT	2361	62,0
Wind	400	10,5
Hydro	300	7,9
Total	3805	100

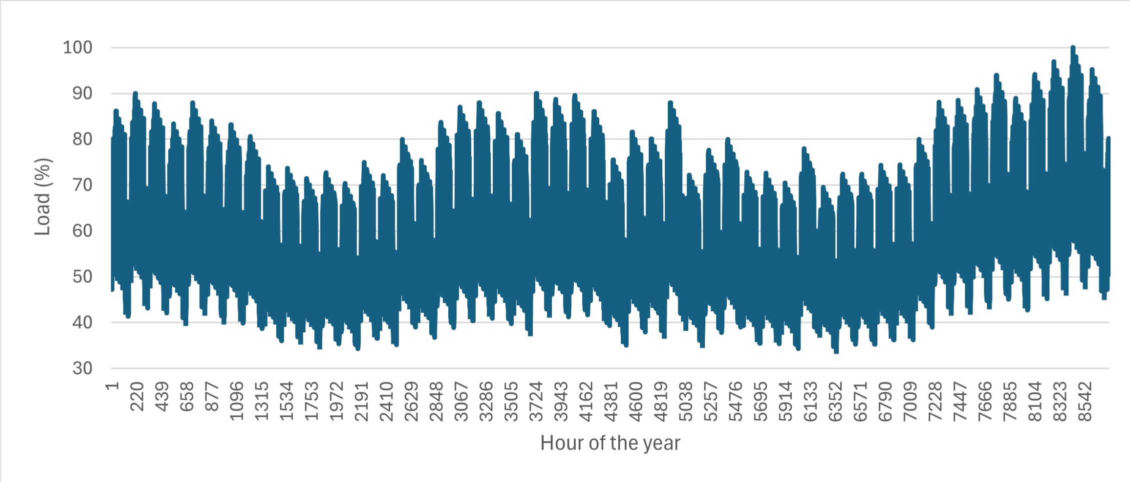

Figure 5.3: Annual hourly load profile (8760 hours), represented as a percentage of the peak system load.

Additionally, the variable generation costs for thermal units used in the initial simulation scenario (i.e., the starting point of the iterative process) are listed in Table 5.3. These costs are expressed in €/kWh and are differentiated not only by technology (e.g., CCGT, OCGT, Wind) but also by asset type (new vs. old/existing). The cost assumptions were based on the Input Data document from the ERAA 2024 [77]. The values in Table 5.3 were computed using the following cost expression 5.1 provided in the ERAA 2024 documentation:

$$SMRC = VOM + \frac{CO_2 emission factor * 3.6}{efficiency} * CO_2 price + \frac{fuel price * 3.6}{efficiency} \tag{5.1}$$

In this expression:

- SMRC is the Short-Run Marginal Cost;
- VOM is the Variable Operation and Maintenance cost in €/MWh;
- CO_2 emission factor is in tCO2/GJ;
- CO_2 price is in EUR/tCO2;
- efficiency is in %;

Table 5.3: Values used to calculate the SMRC value for 2026 [77].

	CCGT		**OCGT**		**Nuclear**
	old	**new**	**old**	**new**	
SMRC=	90,30	71,28	109,58	100,65	29,27
VOM (€/MWh)=	2,50		2,40		8
CO2 emission factor (tCO2/GJ)=	0,06		0,06		0
efficiency(%)=	0,47	0,60	0,39	0,42	0,33
CO2 price (€/tonne)=	72,68				
fuel price (€/net GJ)=	7,32				1,95

Although the network topology itself is not a key driver in the type of adequacy assessment performed in this work, a one-line diagram of the IEEE RTS-79 (with the 3 added wind farms) is shown in Figure 5.4, to provide a more realistic representation of the simulated grid.

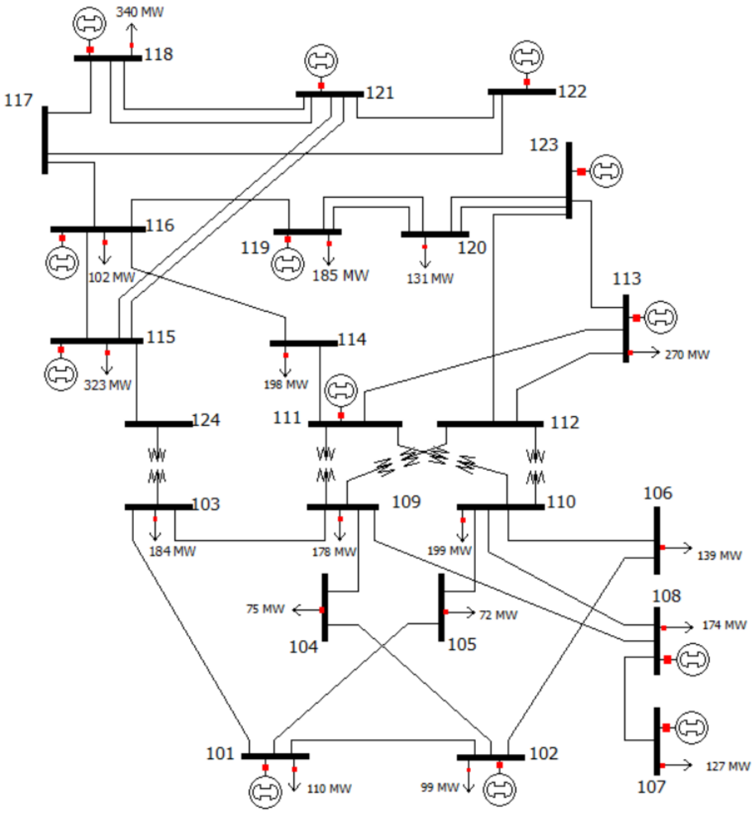

Figure 5.4: Diagram of the IEEE RTS-79 (as modified).

5.2.3 Simulation Parameters

The simulations were performed using a chronologic Monte Carlo approach with the following parameters:

- Number of Samples (Years): 10 000;
- Coefficient of Variation (β): 5%;

This means that the simulation terminates either when the coefficient of variation of all main global indices (such as LoLE and EENS) falls below 5%, or when 10,000 samples are simulated. It should be noted that setting a hard limit of 10,000 samples does not ensure quality results. This cap was only introduced to limit the computation time in some scenarios. In most cases, convergence was achieved before reaching the maximum number of samples, an indication of result quality. It was noted that as the system's capacity increased, which led to a reduction in LoLE, more samples were required to meet the 5% β threshold. This increase in the system's adequacy made failure events (e.g., load shedding) become rarer, making it harder for Monte Carlo simulations to capture them with statistical significance. Consequently, a larger number of samples is required to reach convergence criteria, especially in low-LoLE scenarios. This phenomenon is well-documented in reliability modelling literature [78], where it is emphasized that rare event estimation requires higher computational effort to ensure result stability and accuracy.

The system configuration chosen was the Main System – Single Node setup, which assumes a single aggregated system. This corresponds to a Hierarchical Level 1 adequacy study, which focuses exclusively on generation adequacy [79]. This configuration is the most adequate for the objectives of this work, as it simplifies the system by neglecting transmission constraints. Although it is technically possible to include the transmission network and still ignore transmission limits (by assigning extremely high capacities to each line), this would significantly increases the computational time by nearly a factor of 10, without improving the representativeness of the results. Hence, the simplified "single node" configuration was selected.

Within the scope of Hierarchical Level 1 studies, two types of adequacy assessments can be performed: **Static Reserve** and **Operational Reserve**.

- **Static Reserves:** These studies determine the long-term production capacity required to meet forecasted system demand while adhering to an acceptable maximum risk of load shedding. Static reserves account for uncertainties such as variability in primary energy resources, generator outages (both planned and unexpected), and demand fluctuations over time [80];

- **Operational Reserves:** These are designed to ensure that the system can respond effectively to short-term imbalances between supply and demand. Operational reserve requirements are influenced by sudden equipment failures, discrepancies between forecasted and actual renewable energy output, and demand variations. They include criteria for minimum levels of synchronized reserves, such as Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR) [80].

Assessing adequacy becomes more complex in interconnected systems due to the need to model energy exchange policies under both normal operations and emergencies. For instance, a region with insufficient production capacity may rely on neighboring areas for support, provided surplus resources and transmission capacity are available. Factors such as production capabilities, interconnection constraints, and cross-border agreements dictate the extent of this assistance.

This study focuses on static reserve adequacy, appropriate for day-ahead adequacy assessments. Operational reserve adequacy, which accounts for deviations between forecasts and real-time data (e.g., wind or solar production and demand forecasting errors), is outside the scope of this analysis [79].

5.2.4 Simulations and Results

5.2.4.1 Initial baseline simulation

To establish a baseline for the capacity expansion exercise briefly outlined in Section 5.2.1, an initial simulation was conducted using the parameters described in subsections 5.2.2 and 5.2.3. This simulation considered the generation mix shown in Table 5.2, reflecting the adapted IEEE RTS-79 system with additional wind generation capacity.

The goal of this preliminary run was to assess the reliability performance of the system before any new capacity is added. The reliability indices obtained are summarized in Table 5.4, including key indicators such as Loss of Load Expectation (LoLE) and Expected Energy Not Supplied (EENS).

Table 5.4: Relevant indices obtained with the first simulation

LoLE (h/yr)	10.0
EENS (MWh/yr)	1246.1
LoLC (M€/yr)	31.0
Operating Cost (M€)	1152.1

Figure 5.5 displays the total monthly energy production disaggregated by generation technology. This chart provides insight into the seasonal variability of RES and the role of dispatchable technologies in maintaining the supply of the demand across the year.

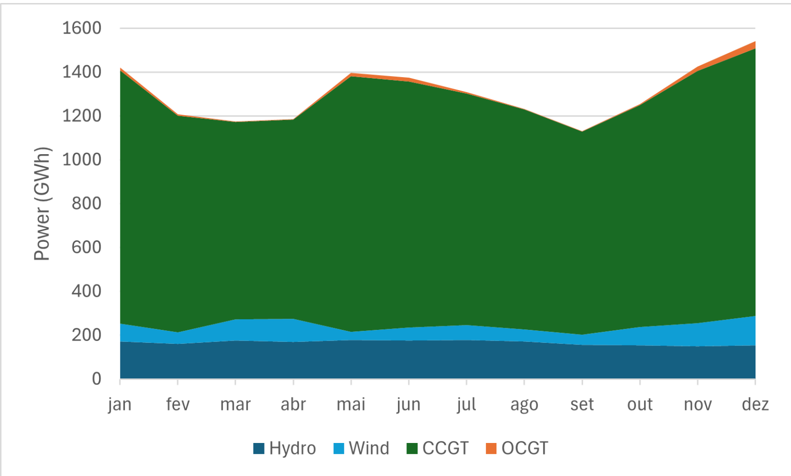

Figure 5.5: Total monthly energy production by technology

Finally, Table 5.5 shows the average capacity utilization factors (UF) for each power generation technology. These values highlight the relative usage levels of different technologies and their contribution to meeting system demand under the given operating conditions [81].

Table 5.5: Average capacity utilization factors for each power generation technology.

Hydro	OCGT	CCGT	Wind
0,76	0,02	0,73	0,26

This initial simulation serves as the baseline scenario, from which additional capacity will be progressively introduced. The impact of each capacity increment will be analysed in subsequent simulation scenarios.

5.2.4.2 Sensitivity Analysis – Validation of Simulated RS and Behaviour of LoLE and System Costs

The primary goal of this first sensitivity analysis was twofold: first, to confirm that simulated values of key parameters such as the LoLE and total system costs follow the expected trends (these will be detailed after presenting the results); and second, to verify that the LoLE corresponding to the best trade-off between investment and cost reduction aligns with the Reliability Standard calculated using the ACER methodology.

The simulations were based on the baseline case introduced in Section 5.2.4.1. In these runs, we progressively added Open-Cycle Gas Turbine (OCGT) capacity in increments of 25 MW, and focused our assessment on parameters such as:

- LoLE
- LoLC (Annual Expected Energy Not Served cost)
- Operational costs (variable costs related to electricity generation in thermal power plants)
- Investment cost (associated with the new installed capacity)

The results that were obtained are presented in Table 5.6.

Table 5.6: Results obtained for a VoLL=25 €/kWh*, CoNEfixed=75 €/kW/year** and CoNEvar=0.1 €/kWh***.

Cap (MW)	LoLE	ENS (M€/year)	UF	Invest (M€)	Oper Cost (M€)	Total Cost (M€)
0	10,0	31,0	0,00	0,0	1152,5	1183,5
25	8,9	26,8	0,07	1,9	1152,3	1180,9
50	7,2	21,9	0,06	3,7	1151,9	1177,5
75	6,1	18,0	0,06	5,6	1152,0	1175,5
100	5,1	14,9	0,06	7,5	1152,0	1174,3
125	4,3	12,5	0,05	9,3	1152,2	1173,9
150	3,6	10,2	0,05	11,2	1152,3	1173,7
175	3,0	8,3	0,05	13,0	1152,2	1173,5
200	2,5	6,8	0,05	14,9	1152,1	1173,7
225	2,2	6,0	0,05	16,8	1152,3	1175,2
250	1,8	4,9	0,04	18,6	1152,2	1175,8
275	1,5	4,2	0,04	20,5	1152,3	1177,0
300	1,3	3,6	0,04	22,4	1152,2	1178,2

* Average VoLL of the EU countries that presented its VoLL divided by certain sectors (residencial, commercial and industrial).
** Average CoNEfixed for the OCGT technology of the EU countries.
*** Value from Table 5.3

The first key observation is that the RS obtained under the simulation conditions, calculated using the ACER methodology, is 3.01 hours/year. This value is very close to the LoLE of the scenario that presents the lowest total cost, which is highlighted in yellow in Table 5.6. This confirms that the simulation-based approach that was performed produces results that are consistent with the theoretical RS calculation.

Moreover, based on the simulation results, the graph shown in Figure 5.6 was developed, which, as expected, closely resembles Figure 3.1.

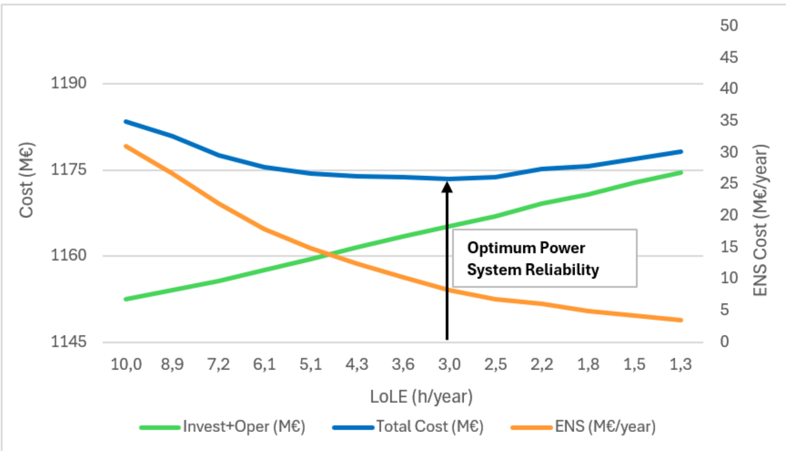

Figure 5.6: Cost vs reliability of generation power system Simulated

Following this, a similar set of simulations was carried out using alternative VoLL (Value of Lost Load) values. As before, OCGT capacity was added incrementally, and the resulting

LoLE and total cost values were recorded. The complete results are available in Table A.2 in the Appendix, while a summary of the most relevant outcomes is shown in Table 5.7 below.

Table 5.7: Summary of optimal LoLE and total cost for different VoLL values.

VoLL	Added Capacity	LoLE	RS	Total Cost
10	25	8,6	7,5	1164,9
	50	7,2		1164,4
	75	6,1		1164,8
15	75	6,1	5,0	1168,4
	100	5,1		1168,4
	125	4,3		1169,0
20	125	4,3	3,7	1171,9
	150	3,6		1171,5
	175	3,0		1171,8
25	150	3,6	3,0	1173,7
	175	3,0		1173,5
	200	2,5		1173,7
30	175	3,0	2,5	1175,2
	200	2,5		1175,1
	225	2,0		1176,4

From the information in Table 5.7, it is clear that the RS remains very close to the LoLE associated with the lowest simulated total cost, even when varying the VoLL. It is worth noting that in all these simulations, the added OCGT presented a very low utilization factor, below 7%.

An attempt was made to identify scientific papers directly relating the utilization factor of OCGTs to their economic viability, with the aim of confirming that such low capacity factors would render these plants non-viable without additional remuneration mechanisms, such as capacity mechanisms. However, no direct quantitative correlation was found in the literature. This is likely due to the large number of market-specific variables that affect OCGT viability. Nevertheless, it is widely accepted that low capacity factors increase the likelihood of a plant being financially unviable without extra capacity remuneration.

Subsequently, a similar analysis was conducted to assess the impact of changing the fixed CoNE, the investment cost per MW of installed capacity. Due to the amount of data, the results of this simulation are presented in Table A.3 in the Appendix.

It is clearly observed that decreasing the CoNE leads to a lower LoLE at the minimum total cost, and vice versa. This trend is expected since the CoNE appears in the numerator of the expression used to compute the RS (expression 3.6). These results further validate that the optimal simulated LoLE (the one that minimizes total system cost) is, in the vast majority of cases, very close to the RS.

5.2.4.3 Evaluating the Impact of New CCGT Capacity on Reliability and Costs

To assess how the methodology behaves when the new entrant is a more efficient technology than OCGT, a new set of simulations was performed, this time considering the addition of Combined

Cycle Gas Turbine capacity. Initially, a CCGT plant was added with a short-run marginal cost of 71.28 €/MWh. The results that were obtained are shown in Table 5.8.

Table 5.8: Initial simulation results with CCGT capacity additions (SRMC = 71.28 €/MWh)

Cap (MW)	LoLE	ENS (M€/year)	UF	Invest (M€)	Oper Cost (M€)	Total Cost (M€)
0	10,0	24,9	0,00	0,0	1152,5	1177,4
25	8,6	21,5	1,00	2,9	1148,1	1172,5
50	7,2	17,6	1,00	5,7	1143,7	1167,0
75	6,1	14,5	1,00	8,6	1139,6	1162,7
100	5,1	12,0	1,00	11,4	1135,6	1158,9
125	4,3	10,0	1,00	14,3	1131,6	1155,9
150	3,6	8,2	1,00	17,1	1127,7	1153,0
175	3,0	6,6	1,00	20,0	1123,5	1150,1
200	2,5	5,5	1,00	22,8	1119,3	1147,6
300	1,3	2,8	1,00	34,2	1103,4	1140,4
500	0,5	1,2	1,00	57,0	1071,0	1129,2
700	0,4	1,0	1,00	79,8	1039,0	1119,8
1500	0,4	1,0	0,87	171,0	943,1	1115,1
2250	0,4	1,0	0,65	256,5	918,8	1176,3
3000	0,4	1,0	0,48	342,0	918,5	1261,5

These results immediately revealed a key issue: the values did not converge. As more CCGT capacity was added, operational costs continued to decrease sharply, which led to a consistent reduction in the total system costs. This persistent decline is due to the fact that the added CCGT unit had the lowest variable production cost in the system (excluding renewable generation). Consequently, the plant operated as a baseload unit, maintaining a utilization factor close to 1.

This behavior exposed a limitation of the ACER methodology for calculating the Reliability Standard (RS). Under the input assumptions used in this simulation (CoNEfixed = 114 €/kW/year, VoLL = 20 €/kWh, CoNEvar = 71.28 €/MWh), the calculated RS was 5.72 hours/year, which significantly differs from the optimal simulated LoLE of 0.42 hours/year. This divergence is understandable, as the ACER approach is designed assuming that the new entrant is a peaking technology, one that is quickly dispatchable and typically has higher variable costs, thus never intended to operate as baseload as it would be the new added CCGT units.

To further explore whether there might be a relationship between the utilization factor of the new entrant and the optimal trade-off point between investment and system cost, an additional set of simulations was carried out. This time, the variable production cost of the existing thermal units with the highest capacity (one 350 MW and two 400 MW units) was modified. Previously, these units reflected CCGT-like characteristics. For the new analysis, their SRMC was replaced by that of nuclear power (see Table 5.3 for the value used), effectively turning them into baseload units with lower SRMC than the added CCGT.

It is important to note that the technological specifications of these thermal units were kept unchanged in order to maintain comparability with previous simulations. Altering their availability or forced outage parameters would have significantly changed system adequacy metrics, particularly the LoLE, and the ENS costs due to the impact of different failure patterns.

The scope of this additional analysis was solely to verify whether there exists any identifiable relationship between the utilization factor of the new entrant and the point of optimal trade-off between capacity investment and system costs.

Following this new set of simulations, the results that were obtained are presented in Table 5.9.

Table 5.9: Simulation results with modified baseload units and CCGT addition.

Cap (MW)	LoLE	ENS (M€/year)	UF	Invest (M€)	Oper Cost (M€)	Total Cost (M€)
0	10,0	25,9	0,00	0,0	623,6	649,5
25	8,6	21,5	0,78	2,9	620,3	644,7
50	7,2	17,6	0,77	5,7	616,9	640,2
75	6,1	14,5	0,76	8,6	613,9	636,9
100	5,1	12,0	0,75	11,4	610,7	634,0
200	2,5	5,5	0,72	22,8	599,6	627,9
300	1,3	2,8	0,69	34,2	589,7	626,8
400	0,8	1,7	0,65	45,6	580,9	628,2
500	0,5	1,2	0,61	57,0	573,3	631,6
600	0,5	1,1	0,58	68,4	567,0	636,5
700	0,4	1,0	0,54	79,8	561,7	642,6

From these results, no clear correlation could be identified between the utilization factor of the new entrant and the optimal trade-off point. In the first case, the UF was 0.87, while in the second, it dropped to 0.69. Therefore, the only consistent conclusion that can be drawn, not only from this section but also from Section 5.2.4.2 (Table 5.6), is that the more low-cost capacity is already available in the system, the lower the utilization factor of the new entrant will be at the trade-off point.

5.2.5 Simulation using a Higher Renewable Penetration System

To ensure the robustness of the previous findings and to align the simulated system with a more realistic context, one characterized by a higher share of zero-cost renewable production, the base case was modified. The installed renewable capacity was significantly increased, while thermal generation was reduced. Additionally, the peak load of the system was adjusted (increased). The resulting generation mix and peak demand values are presented in Table 5.10.

Table 5.10: Adjusted generation mix and peak load for the high-renewables scenario.

Tecnology	Capacity	%
OCGT	744	23,8
CCGT	1305	
Wind	2000	23,3
Hydro	3250	37,8
Solar	1300	15,1
Total	8599	100,0
Peak Load	4560	53,0*

*Proportion between the peak load and the total capacity installed in the system.

For this new configuration, the system's reliability indices were recalculated, as shown in Table 5.11.

Table 5.11: Indices for the high-renewables base case.

LoLE (h/yr)	10.5
EENS (MWh/yr)	2108.5
LoLC (M€/yr)	42.2
Operating Cost (M€)	88.8

To provide a visual overview of how energy is distributed across generation sources throughout the year, Figure 5.7 displays the monthly energy production disaggregated by generation technology.

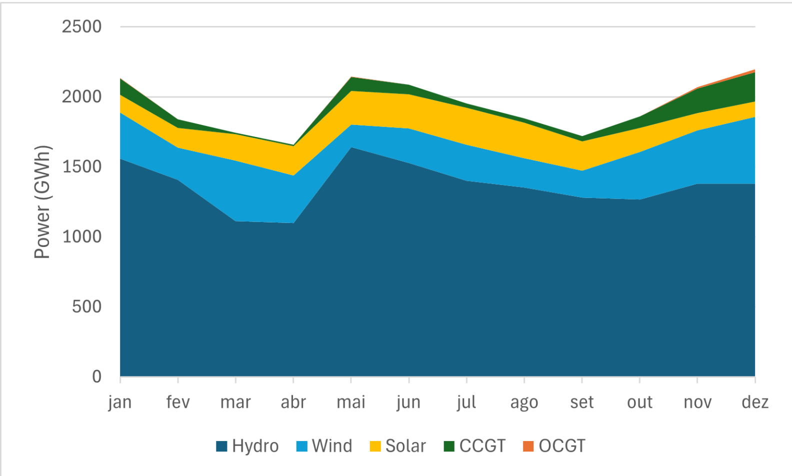

Figure 5.7: Total monthly energy production by technology in the high-renewables system.

Following the characterization of this new system, a final set of simulations was conducted. Successive additions of 25 MW of gas-fired OCGT capacity were made to the system, under the assumption of a VoLL of 20 €/kWh. This VoLL value was chosen because it is closer to the average observed across Member States, which is approximately 18.6 €/kWh. The outcomes of these simulations are presented in Table 5.12.

Table 5.12: Simulation results with successive additions of OCGT in the high-renewables system.

Cap (MW)	LoLE	ENS cost (M€/year)	UF	Invest (M€)	Oper Cost (M€)	Total Cost (M€)
0	10,5	42,2	0	0,0	88,8	131,0
25	9,3	35,2	0,016	1,9	90,6	127,6
50	8,0	30,7	0,015	3,7	90,2	124,6
75	7,4	27,7	0,014	5,6	90,0	123,3
100	6,6	24,2	0,014	7,5	90,7	122,3
125	6,1	22,5	0,013	9,3	90,6	122,4
150	5,5	19,9	0,013	11,2	90,6	121,7
175	4,9	17,4	0,013	13,0	90,1	120,6
200	4,1	14,1	0,012	14,9	89,3	118,3
225	3,6	12,4	0,011	16,8	89,1	118,3
250	3,4	12,0	0,011	18,6	90,5	121,2
275	3,0	10,4	0,011	20,5	90,3	121,2
300	2,4	8,2	0,010	22,4	88,9	119,5
325	2,3	7,5	0,010	24,2	89,8	121,6
350	2,1	6,8	0,010	26,1	89,8	122,6
375	1,7	5,5	0,009	27,9	89,5	122,9
400	1,4	4,4	0,009	29,8	89,0	123,1

Based on the results, it was also possible to obtain the graph presented in Figure 5.8. Its trend is not as linear as the ones shown in Figures 3.1 and 5.6, possibly due to the greater variability of renewable generation, which plays a more significant role in this system's operational cost.

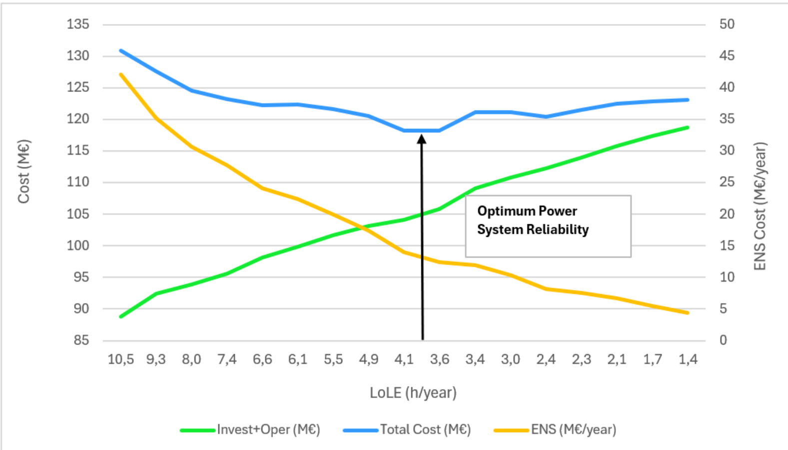

Figure 5.8: Cost vs reliability of generation in the high-renewables system.

From the results in the table 5.12, validated by the almost parallel to the X axis line connecting the total costs associated with the LoLEs of 3.59 and 4.09 in figure 5.8, it was assumed that the optimum LoLE should be 3.8 (the rounded value between the two LoLEs mentioned above).

Several noteworthy observations can be drawn from the simulation results. The first, and perhaps the most expected, is the reduction in the average anual operational cost, despite the increase in system load. This occurs because the system, previously heavily reliant on thermal production, is now primarily supported by hydro, solar, and wind resources, which have near-zero variable costs.

Moreover, once again, it is clear that the optimal trade-off point between investment and operational cost aligns closely with the RS calculated using the ACER methodology (expression 3.6). This serves as further validation of the reliability standard approach, even in a system with significantly higher renewable penetration.

It is also possible to continue verifying the conclusion reached earlier regarding the utilization factor, since for this new system, the utilization factor of the added capacity is even lower, as a result of the greater amount of capacity available at a lower cost, compared to the added OCGT.

Above all, this simulation provides strong support for the applicability of the analysis developed throughout this study to systems with a generation mix more closely resembling that of present-day in several European countries, as in Portugal and Spain, and mostly to the generation mix that will exist across Europe in 5 to 10 years time.

Chapter 6

Conclusion and Future Work

6.1 Conclusion

The implementation of a Capacity Mechanism (CM) in Portugal must be based on a robust and transparent methodological foundation, aligned with ACER's recommendations and the best practices observed in other EU Member States. Before any concrete decision regarding the mechanism's design or deployment can be made, it is essential to conduct a thorough assessment of the Value of Lost Load (VoLL), which is a central parameter in defining the Reliability Standard (RS).

This assessment should follow ACER's guidelines and ideally explore all three proposed approaches: Willingness to Accept (WTA), Willingness to Pay (WTP), and Direct Cost. If a mixed or sector-specific approach is adopted, it will be important to determine the appropriate weighting for each method when calculating a single VoLL value per consumer segment.

While the primary objective of any CM must be to ensure security of supply, reducing the final cost of electricity for consumers must also remain a key consideration during its implementation. Consumers who show flexibility in shifting their demand across time should receive financial compensation for doing so. Although this is a desirable outcome, the analysis carried out in this dissertation highlights how difficult it can be to achieve in practice without compromising the cost recovery and efficiency of the mechanism.

The simulations performed using the PS-MORA model on a simplified IEEE test system confirmed that the RS calculated using ACER's expression 3.6, generally matches the Loss of Load Expectation (LoLE) value that minimizes total system costs. The only scenario where this alignment did not hold was when the new entrant, became a baseload unit due to its low variable cost. Although this may occur in theory, it is not a realistic assumption for a new entrant, which typically is a peaking/fast-response technology. This exception reinforces the relevance of the ACER method under practical assumptions.

Additionally, in scenarios with high renewable energy penetration, the alignment between the calculated RS and the optimal simulated LoLE was maintained. This confirms the robustness of ACER's approach in today's increasingly complex and decarbonized power systems.

The main challenge ahead will be not to increase system reliability blindly, but rather to understand how much reliability consumers are truly willing to pay for. It will be essential to present clearly the trade-offs involved, showing both the benefits of additional investment in reliability and the risks of underinvestment. This is fundamental for making informed and balanced policy decisions on whether and how to implement a Capacity Mechanism in Portugal.

6.2 Future work

Several directions for future work emerge naturally from this dissertation, either to deepen the findings or to expand their applicability in a real-world context.

First, it would be highly relevant to replicate the simulations carried out in this study using a more realistic system model, rather than the IEEE electric power system employed. A model representing the entire European Electric Power system would allow for a more robust validation of the conclusions drawn from the simplified test system. Additionally, the use of alternative power system simulation software, such as Antares, Bid 3, PLEXOS, or Powersim, could help verify the consistency and reliability of the results, especially when analysing complex operational constraints and market behaviour.

Moreover, it is important to note that the simulations performed in this work did not consider the transmission network model or branch flow limits. As methodologies based on Hierarchy-Level 1 (HL1) approaches continue to mature and gain robustness, future work could benefit from transitioning to a Hierarchy-Level 2 (HL2) framework. This would make it possible to incorporate the transmission system, including inter-zonal constraints and interconnection flows, thereby improving the realism and accuracy of system adequacy assessments in interconnected markets.

Furthermore, while this dissertation focused primarily on thermal generation additions, future simulations should explore the role of energy storage technologies (such as batteries, hydro pumped storage, hydrogen storage, and others) and Demand Side Response mechanisms. Including these resources in the system adequacy analysis would provide insights into how their flexibility and cost profiles could shift the optimal reliability level or reduce the total system cost.

Another valuable area of analysis would involve monitoring the future implementation of the Capacity Mechanism in Spain, which is currently in progress. A detailed evaluation of how this mechanism affects final electricity prices, as well as overall system performance, would provide valuable insights on the real operation of such mechanism.

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Appendix A

Appendix

This appendix displays all the Tables mentioned in Chapters 4 and 5.

Table A.1: Derating Factors proposed by Elia for the 2024 Y-4 Auction with Delivery Period 2028-2029 [82]

Sub-Category	Derating Factor [%]
SLA-1h	19
SLA-2h	35
SLA-3h	48
SLA-4h	57
SLA-5h	65
SLA-6h	71
SLA-7h	76
SLA-8h	81
SLA-9h	86
SLA-10h	89
SLA-11h	93
SLA-12h	95
SLA unlimited	100

Table A.2: Results obtained for different simulated VoLLs.

VoLL	RS	Cap	LoLE	ENS (M€/year)	Oper (M€)	Inv (M€)	Total Cost (M€)
10	7,5	0	10,0	12,5	1152,5	0,0	1165,0
10	7,5	25	8,6	10,8	1152,3	1,9	1164,9
10	7,5	50	7,2	8,8	1151,9	3,7	1164,4
10	7,5	75	6,1	7,2	1152,0	5,6	1164,8
10	7,5	100	5,1	6,0	1152,0	7,5	1165,4
15	5,0	0	10,0	18,7	1152,5	0,0	1171,2
15	5,0	25	8,6	16,1	1152,3	1,9	1170,3
15	5,0	50	7,2	13,2	1151,9	3,7	1168,8
15	5,0	75	6,1	10,8	1152,0	5,6	1168,4
15	5,0	100	5,1	9,0	1152,0	7,5	1168,4
15	5,0	125	4,3	7,5	1152,2	9,3	1169,0
15	5,0	150	3,6	6,2	1152,3	11,2	1169,6
20	3,7	0	10,0	24,9	1152,5	0,0	1177,4
20	3,7	25	8,6	21,5	1152,3	1,9	1175,6
20	3,7	50	7,2	17,6	1151,9	3,7	1173,2
20	3,7	75	6,1	14,5	1152,0	5,6	1172,0
20	3,7	100	5,1	12,0	1152,6	7,5	1172,0
20	3,7	125	4,3	10,0	1152,6	9,3	1171,9
20	3,7	150	3,6	8,2	1152,2	11,2	1171,5
20	3,7	175	3,0	6,6	1152,2	13,0	1171,8
20	3,7	200	2,5	5,5	1152,1	14,9	1172,4
25	3,0	0	10,0	31,0	1152,5	0,0	1183,5
25	3,0	25	8,6	26,8	1152,3	1,9	1180,9
25	3,0	50	7,2	21,9	1151,9	3,7	1177,5
25	3,0	75	6,1	18,0	1152,0	5,6	1175,5
25	3,0	100	5,1	14,9	1152,0	7,5	1174,3
25	3,0	125	4,3	12,5	1152,2	9,3	1173,9
25	3,0	150	3,6	10,2	1152,3	11,2	1173,7
25	3,0	175	3,0	8,3	1152,2	13,0	1173,5
25	3,0	200	2,5	6,8	1152,1	14,9	1173,7
30	2,5	0	10,0	37,4	1152,5	0,0	1189,9
30	2,5	25	8,6	32,3	1152,3	1,9	1186,4
30	2,5	50	7,2	26,4	1151,9	3,7	1182,0
30	2,5	75	6,1	21,7	1152,0	5,6	1179,3
30	2,5	100	5,1	17,9	1152,0	7,5	1177,4
30	2,5	125	4,3	15,0	1152,2	9,3	1176,5
30	2,5	150	3,6	12,3	1152,2	11,2	1175,7
30	2,5	175	3,0	10,0	1152,2	13,0	1175,2
30	2,5	200	2,5	8,2	1152,1	14,9	1175,1
30	2,5	225	2,0	7,3	1152,3	16,8	1176,4

Table A.3: Comparison of total costs for the different CoNEfixed simulations.

		CoNE	0,060		0,075		0,099	
VoLL	**Added Capacity (MW)**	**RS**	3,0		3,7		5,0	
		LoLE	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**
20	75	6,1	1171,0	4,5	1172,0	5,6	1173,9	7,4
	100	5,1	1170,0	6,0	1172,0	7,5	1173,9	9,9
	125	4,3	1169,7	7,5	1171,9	9,3	1174,6	12,4
	150	3,6	1169,6	9,1	1171,5	11,2	1175,4	14,9
	175	3,0	1169,4	10,6	1171,8	13,0	1176,2	17,4
	200	2,5	1169,6	12,1	1172,4	14,9	1177,3	19,8
VoLL	**Added Capacity (MW)**	**RS**	2,4		3,0		4,0	
		LoLE	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**
25	75	6,1	1174,5	4,5	1175,5	5,6	1177,4	7,4
	100	5,1	1172,9	6,0	1174,3	7,5	1176,8	9,9
	125	4,3	1172,2	7,5	1173,9	9,3	1177,0	12,4
	150	3,6	1171,6	9,1	1173,7	11,2	1177,4	14,9
	175	3,0	1171,0	10,6	1173,5	13,0	1177,8	17,4
	200	2,5	1170,9	12,1	1173,7	14,9	1178,7	19,8
VoLL	**Added Capacity (MW)**	**RS**	2,0		2,5		3,3	
		LoLE	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**	**Total Cost (M€)**	**Invest Cost (M€)**
30	100	5,1	1176,0	6,0	1177,4	7,5	1179,9	9,9
	125	4,3	1174,7	7,5	1176,5	9,3	1179,6	12,4
	150	3,6	1173,6	9,1	1175,7	11,2	1179,4	14,9
	175	3,0	1172,7	10,6	1175,2	13,0	1179,5	17,4
	200	2,5	1172,3	12,1	1175,1	14,9	1180,1	19,8
	225	2,0	1173,2	13,6	1176,4	16,8	1182,6	22,3