COMILLAS
UNIVERSIDAD PONTIFICIA

ICAI

MASTER’S IN INDUSTRIAL ENGINEERING

Unit Commitment Dispatch to Improve Stability in the face of Frequency Variations

Autor: Laura Abarca Carralero

Director: Fco. Alberto Campos Fernández

Co-Director: Javier Reneses Guillén

Madrid

Julio de 2026

Declaration of originality

I declare under my responsibility that the Project presented with the title **Unit Commitment Dispatch to Improve Stability in the face of Frequency Variations** at the ICAI School of Engineering of the Comillas Pontifical University in the academic year 2025/2026 is of my authorship and has not been presented previously for other purposes. The Project is not plagiarised from any other, either totally or partially, and the information that has been taken from other documents is duly referenced.

Use of Artificial Intelligence[1]

I declare under my responsibility that (indicate the correct option):

☐ I have not used Artificial Intelligence in the preparation of this document.

X I have used Artificial Intelligence in the preparation of this document and/or Annex B under the conditions allowed by Comillas Pontifical University, i.e. applying Level 2 of the Perkins et al. (2024) Assessment Scale: "AI can be used for pre-task activities such as brainstorming, description and initial research. This level focuses on the use of AI for planning, synthesising and generating ideas, but assessments should emphasise the ability to develop and refine these ideas independently". Specifically, Artificial Intelligence has been used to:

- To provide initial guidance on the overall structure of the project and the organisation of its main sections.
- Assistance in the initial understanding of technical concepts related to the project.
- To translate and refine technical explanations from Spanish into formal academic English.

Signature (student): Laura Abarca Carralero

Date: 12/07/26

[1] This declaration refers to the use of generative Artificial Intelligence to carry out the Project documents (Annex B and Memory). It does not apply to Projects where, by their nature, artificial intelligence must be used as part of them (application of machine learning techniques, neural networks, data analysis...).

Authorisation for Project delivery

Thesis supervisor	Thesis deputy supervisor (if any)
Fecha: 2026.07.12 18:27:27 +02'00'	
Signature: Fco. Alberto Campos Fernández	Signature:
Date:12/07/26	Date:

MASTER'S IN INDUSTRIAL ENGINEERING

Unit Commitment Dispatch to Improve Stability in the face of Frequency Variations

Autor: Laura Abarca Carralero

Director: Fco. Alberto Campos Fernández

Co-Director: Javier Reneses Guillén

Madrid

Julio de 2026

DESPACHO DE UNIT COMMITMENT PARA MEJORAR LA ESTABILIDAD FRENTE A VARIACIONES DE FRECUENCIA

Autor: Abarca Carralero, Laura

Director: Campos Fernández, Fco. Alberto y Reneses Guillén, Javier.

Entidad Colaboradora: ICAI – Universidad Pontificia Comillas

RESUMEN DEL PROYECTO

Este trabajo de fin de máster desarrolla y analiza un modelo de UC incorporando restricciones de seguridad de frecuencia basadas en el RoCoF. Los resultados obtenidos muestran que la necesidad de mantener suficiente inercia síncrona aumenta el coste de operación y el número de grupos síncronos acoplados y limita la integración renovable, evidenciando el compromiso existente entre seguridad de frecuencia y eficiencia económica.

Palabras clave: Unit Commitment (UC), Rate of Change of Frequency (RoCoF), inercia síncrona, seguridad de frecuencia.

1. Introducción

La transición energética está provocando un aumento progresivo de la penetración de energías renovables en los sistemas eléctricos. Este proceso resulta esencial para avanzar en la descarbonización del modelo de generación, pero también introduce nuevos retos operativos. A diferencia de los grupos síncronos convencionales, muchas tecnologías renovables no aportan inercia de forma natural al sistema. Como consecuencia, se ve reducida la capacidad del sistema para responder de forma inmediata ante desequilibrios entre generación y demanda [1].

Uno de los indicadores más relevantes para analizar esta respuesta inicial es el RoCoF, que representa la velocidad con la que varía la frecuencia inmediatamente después de una perturbación [2]. La siguiente ilustración muestra la respuesta típica de un sistema eléctrico ante una pérdida de generación.

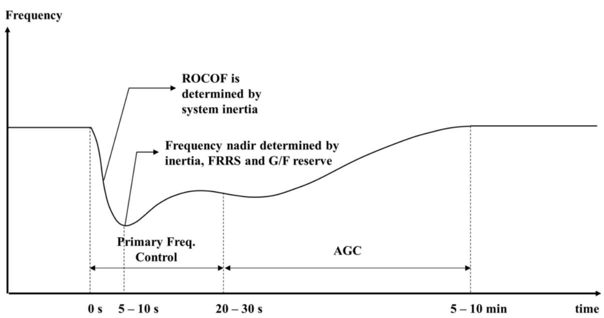

Ilustración 1. Evolución de la frecuencia ante una pérdida de generación [3]

Cuando se produce la pérdida repentina de un grupo generador, los generadores con masas rotantes acopladas comienzan a aportar su energía cinética al sistema para mantener el equilibrio entre generación y demanda, provocando que la frecuencia disminuya. Cuanto menor sea la inercia disponible en el sistema, más rápida será esta caída y mayor será el valor absoluto del RoCoF.

En este contexto, los modelos clásicos de UC deben adaptarse para reflejar no solo criterios económicos, sino también requisitos técnicos asociados a la estabilidad de frecuencia. Tradicionalmente, el problema de UC determina qué grupos deben estar acoplados y cuánto debe producir cada uno para satisfacer la demanda al menor coste posible, teniendo en cuenta restricciones técnicas como límites de potencia, rampas, arranques y paradas. Sin embargo, en sistemas con alta penetración renovable, una solución puramente económica puede no garantizar suficiente inercia para mantener la frecuencia dentro de límites admisibles tras una contingencia.

El presente trabajo propone un modelo de UC que incorpora explícitamente una restricción de RoCoF, con el objetivo de evaluar el impacto económico y operativo de exigir seguridad de frecuencia en el despacho. Además, se estudian distintas formas de introducir esta restricción de manera estricta, completamente relajada y mediante desviaciones penalizadas en la función objetivo.

2. Definición del proyecto

Se formula un modelo determinista de UC aplicado a un caso de estudio del sistema ibérico, representando de forma diferenciada España y Portugal.

El trabajo no pretende realizar una simulación dinámica detallada de la frecuencia, sino incorporar una condición simplificada pero representativa de la necesidad de mantener inercia suficiente. De esta forma, se puede estudiar de manera clara cómo la restricción de RoCoF afecta a las decisiones de acoplamiento y despacho de los grupos generadores.

El análisis se estructura a partir de varios casos de estudio. En el primero, la restricción de RoCoF se impone de forma estricta, de manera que el sistema debe cumplir el valor límite establecido en todas las horas y para todas las contingencias consideradas. En el segundo, la restricción se relaja completamente, permitiendo obtener el despacho puramente económico y utilizarlo como referencia para medir el impacto de la seguridad de frecuencia. A continuación, se analizan dos formulaciones intermedias en las que se permite cierta desviación respecto al valor de referencia del RoCoF, que se penaliza en la función objetivo.

Este planteamiento permite responder a tres preguntas principales. En primer lugar, cuánto aumenta el coste de operación al exigir el cumplimiento estricto del RoCoF. En segundo lugar, qué mecanismos operativos utiliza el sistema para cumplir dicha restricción. Por último, si es posible introducir formulaciones más flexibles que reduzcan parte del coste adicional considerando el riesgo asociado a la seguridad de frecuencia.

3. Descripción del modelo/sistema/herramienta

El modelo desarrollado corresponde a una formulación de UC en la que se minimiza el coste total de operación del sistema. La función objetivo incluye los costes de generación térmica, los costes de arranque, los costes de operación y mantenimiento, los costes asociados a emisiones de CO_2, el coste de la energía no suministrada, los costes o ingresos derivados de intercambios con áreas externas y, en los casos correspondientes, una penalización por desviaciones respecto a la restricción de RoCoF.

El sistema se representa mediante dos áreas modeladas en nodo único, España y Portugal, conectadas entre sí, además España cuenta con la posibilidad de intercambio con Francia. El parque de generación incluye tecnologías térmicas, generación renovable, generación hidráulica gestionable y bombeo. Además, algunas tecnologías se representan como generación no gestionable agregada.

Las unidades térmicas convencionales y nucleares se representan mediante variables de acoplamiento, producción, arranque y parada. También se incluyen restricciones de potencia máxima y mínima, rampas y disponibilidad. En el caso de la generación renovable, se considera una disponibilidad horaria máxima y se permite el vertido renovable. La hidráulica de embalse se modela mediante restricciones de potencia y una limitación de energía disponible en el horizonte considerado. El bombeo incorpora las variables de generación, consumo en modo bombeo y energía almacenada.

La restricción de RoCoF se incorpora considerando la pérdida de un grupo generador como contingencia. El RoCoF depende de la potencia perdida y de la inercia síncrona disponible en el sistema tras la perturbación. Para cada hora, área y contingencia considerada, el modelo exige que el RoCoF no supere en valor absoluto el límite admisible.

La inercia disponible se calcula a partir de los grupos síncronos acoplados. Por tanto, la restricción de RoCoF vincula directamente las decisiones de acoplamiento con la seguridad de frecuencia. Si el despacho económico no proporciona suficiente inercia, el modelo debe acoplar unidades síncronas adicionales o modificar el despacho de tecnologías capaces de aportar inercia.

Para analizar distintas formas de incorporar la seguridad de frecuencia, se definen cuatro casos. El caso con RoCoF estrictamente restringido no permite desviaciones. El caso sin RoCoF efectivo relaja completamente la restricción y representa el despacho económico base. El caso con desviación lineal permite desviaciones penalizadas con un coste marginal constante. Por último, el caso con desviación cuadrática penaliza más intensamente las desviaciones grandes, de modo que se permite cierta flexibilidad alrededor del valor de referencia, pero se desincentivan los incumplimientos severos.

4. Resultados

- La restricción de RoCoF aumenta el coste de operación. Este aumento se produce por la necesidad de mantener inercia síncrona suficiente.
- En el caso de despacho puramente económico, las violaciones se concentran en horas críticas asociadas a baja inercia o alta renovable.
- Para cumplir la restricción del RoCoF, el modelo realiza un ajuste del despacho y un mayor acoplamiento de unidades síncronas.
- El modelo modifica parcialmente el funcionamiento de la hidráulica para ofrecer inercia en horas críticas.
- Al aumentar la producción con tecnologías síncronas se produce el desplazamiento de la producción renovable, incrementando los vertidos renovables.

- Como consecuencia, se produce el aumento de la inercia y la reducción de la desviación del RoCoF del valor de referencia, como se puede apreciar en la siguiente ilustración donde se representa la energía cinética del sistema y el RoCoF para el caso de España.

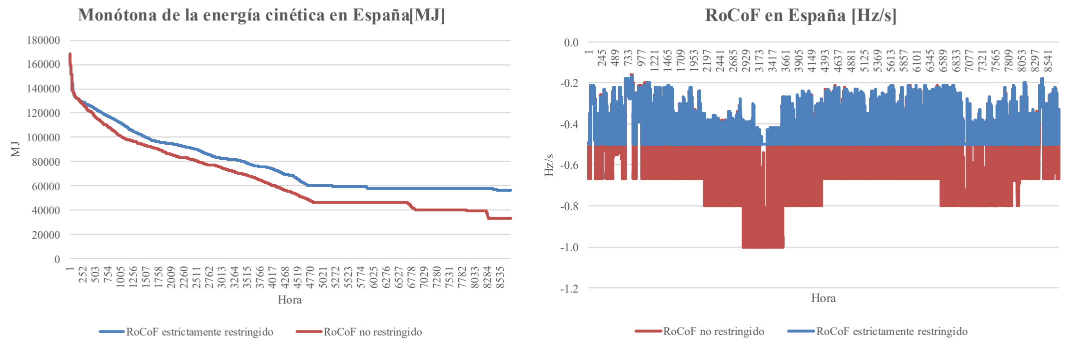

Ilustración 2. Energía cinética y RoCoF del sistema español

5. Conclusiones

El modelo desarrollado permite incorporar de forma efectiva restricciones de seguridad de frecuencia en el problema de UC, evidenciando que su consideración tiene un impacto directo en el coste y en la operación del sistema.

Los resultados muestran que existe un compromiso claro entre eficiencia económica y seguridad de frecuencia, siendo necesario asumir un mayor coste para garantizar niveles adecuados de inercia en determinadas condiciones del sistema.

Asimismo, se concluye que las formulaciones con desviaciones penalizadas ofrecen una alternativa intermedia, permitiendo equilibrar ambos objetivos. En particular, la penalización cuadrática proporciona una solución más adecuada al limitar desviaciones significativas sin eliminar completamente la flexibilidad del modelo.

6. Referencias

[1] N. Nguyen and J. Mitra, ‘An Analysis of the Effects and Dependency of Wind Power Penetration on System Frequency Regulation’, *IEEE Transactions on Sustainable Energy*, vol. 7, no. 1, pp. 354–363, Jan. 2016, doi: 10.1109/TSTE.2015.2496970.

[2] F. Pérez-Illanes, E. Álvarez-Miranda, C. Rahmann, and C. Campos-Valdés, ‘Robust Unit Commitment Including Frequency Stability Constraints’, *Energies*, vol. 9, no. 11, p. 957, Nov. 2016, doi: 10.3390/en9110957.

[3] Y. Son, Y. Ha, and G. Jang, ‘Frequency Nadir Estimation Using the Linear Characteristics of Frequency Control in Power Systems’, *Energies*, vol. 17, no. 5, p. 1061, Jan. 2024, doi: 10.3390/en17051061.

UNIT COMMITMENT DISPATCH TO IMPROVE STABILITY IN THE FACE OF FREQUENCY VARIATIONS

Autor: Abarca Carralero, Laura

Supervisor: Campos Fernández, Fco. Alberto y Reneses Guillén, Javier.

Collaborating company: ICAI – Universidad Pontificia Comillas

ABSTRACT

This master's thesis develops and analyses a UC model incorporating frequency-security constraints based on the RoCoF. The results obtained show that the need to maintain sufficient synchronous inertia increases operating costs and the number of committed synchronous units, while limiting renewable integration. This highlights the trade-off between frequency security and economic efficiency.

Key words: Unit Commitment (UC), Rate of Change of Frequency (RoCoF), synchronous inertia, frequency-security.

1. Introduction

The energy transition is leading to a progressive increase in the penetration of renewable energy sources in power systems. This process is essential for advancing the decarbonisation of the generation mix, but it also introduces new operational challenges. Unlike conventional synchronous generation units, many renewable technologies do not naturally provide inertia to the system. As a result, the system's ability to respond immediately to imbalances between generation and demand is reduced [1].

One of the most relevant indicators for analysing this initial response is the RoCoF, which represents the rate at which frequency changes immediately after a disturbance [2]. The following illustration shows the typical response of a power system following a generation loss.

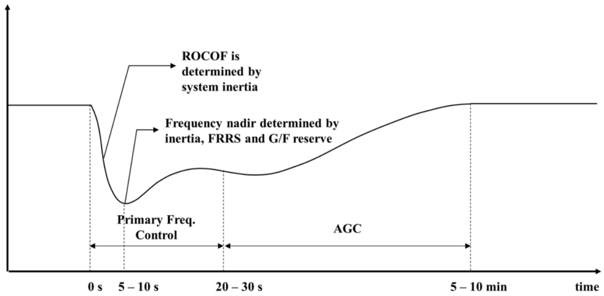

Illustration 1. Frequency evolution after the loss of a generation unit [3]

When a sudden loss of a generating unit occurs, generators with coupled rotating masses begin to release their kinetic energy into the system in order to maintain the balance between generation and demand, causing the frequency to decrease. The lower the inertia available in the system, the faster this frequency decline will be and the higher the absolute value of the RoCoF.

In this context, classical UC models must be adapted to reflect not only economic criteria, but also technical requirements associated with frequency stability. Traditionally, the UC problem determines which generating units should be committed and how much each unit should produce to meet demand at the lowest possible cost, while considering technical constraints such as power limits, ramping constraints, startups and shutdowns. However, in systems with high renewable penetration, a purely economic solution may not guarantee sufficient inertia to keep frequency within admissible limits following a contingency.

This thesis proposes a UC model that explicitly incorporates a RoCoF constraint, with the aim of assessing the economic and operational impact of enforcing frequency security in the dispatch. In addition, different ways of introducing this constraint are analysed, including a strict formulation, a fully relaxed formulation, and formulations with penalised deviations in the objective function.

2. Project definition

A deterministic UC model is formulated and applied to a case study of the Iberian power system, with Spain and Portugal represented separately.

The aim of this thesis is not to perform a detailed dynamic simulation of frequency, but rather to incorporate a simplified yet representative condition reflecting the need to maintain sufficient inertia. In this way, it is possible to clearly assess how the RoCoF constraint affects the commitment and dispatch decisions of generating units.

The analysis is structured around several case studies. In the first case, the RoCoF constraint is imposed strictly, so that the system must comply with the established limit value in every hour and for all the contingencies considered. In the second case, the constraint is fully relaxed, allowing the purely economic dispatch to be obtained and used as a reference to measure the impact of frequency security. Subsequently, two intermediate formulations are analysed, in which a certain deviation from the RoCoF reference value is allowed and penalised in the objective function.

This approach makes it possible to address three main questions. First, how much operating costs increase when strict compliance with the RoCoF limit is required. Second, which operational mechanisms the system uses to satisfy this constraint. Finally, whether more flexible formulations can be introduced to reduce part of the additional cost while accounting for the risk associated with frequency security.

3. Model description

The developed model corresponds to a UC formulation in which the total operating cost of the system is minimised. The objective function includes thermal generation costs, start-up costs, operation and maintenance costs, costs associated with CO_2 emissions, the cost of energy not supplied, the costs or revenues derived from exchanges with external areas and, in the corresponding cases, a penalty for deviations from the RoCoF constraint.

The system is represented by two single-node modelled areas, Spain and Portugal, which are interconnected, while Spain also has the possibility of exchanging power with France. The generation mix includes thermal technologies, renewable generation, dispatchable hydropower generation and pumped storage. In addition, some technologies are represented as aggregated non-dispatchable generation.

Conventional thermal and nuclear units are represented through commitment, production, start-up and shut-down variables. Maximum and minimum power limits, ramping constraints and availability constraints are also included. For renewable generation, a maximum hourly availability is considered and renewable curtailment is allowed. Reservoir hydropower is modelled through power constraints and a limitation on the available energy over the considered time horizon. Pumped storage includes variables for generation, consumption in pumping mode and stored energy.

The RoCoF constraint is incorporated by considering the loss of a generating unit as the contingency. The RoCoF depends on the lost power and on the synchronous inertia available in the system after the disturbance. For each hour, area and contingency considered, the model requires the RoCoF not to exceed the admissible limit in absolute value.

The available inertia is calculated from the committed synchronous units. Therefore, the RoCoF constraint directly links commitment decisions to frequency security. If the economic dispatch does not provide sufficient inertia, the model must commit additional synchronous units or modify the dispatch of technologies capable of providing inertia.

To analyse different ways of incorporating frequency security, four cases are defined. The strictly constrained RoCoF case does not allow deviations. The case without an effective RoCoF constraint fully relaxes the constraint and represents the baseline economic dispatch. The linear-deviation case allows deviations penalised with a constant marginal cost. Finally, the quadratic-deviation case penalises large deviations more heavily, so that some flexibility around the reference value is allowed while severe violations are discouraged.

4. Results

- The RoCoF constraint increases operating costs. This increase is caused by the need to maintain sufficient synchronous inertia.
- In the purely economic dispatch case, violations are concentrated in critical hours associated with low inertia or high renewable generation.
- To comply with the RoCoF constraint, the model adjusts the dispatch and increases the commitment of synchronous units.
- The model partially modifies the operation of hydropower generation to provide inertia during critical hours.
- The increase in generation from synchronous technologies displaces renewable generation, thereby increasing renewable curtailment.

- As a result, inertia increases and the RoCoF deviation from the reference value is reduced, as shown in the following illustration, which represents the system kinetic energy and the RoCoF for the Spanish system.

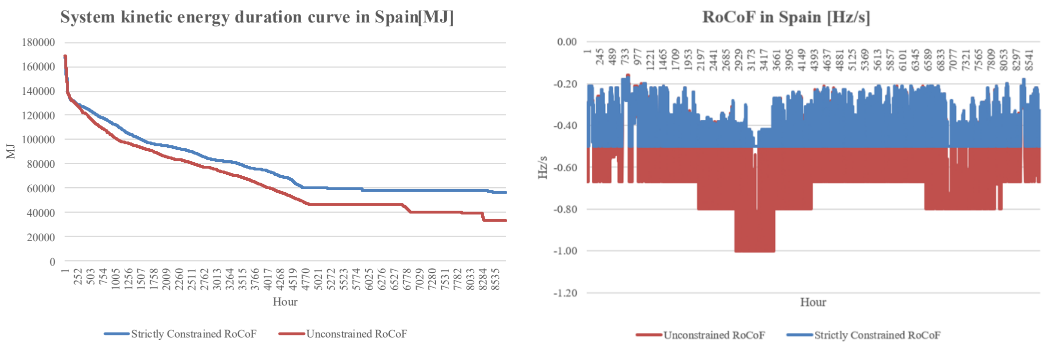

Illustration 2. System kinetic energy and RoCoF of the Spanish system

5. Conclusions

The developed model allows frequency-security constraints to be effectively incorporated into the UC problem, showing that their consideration has a direct impact on both system cost and operation.

The results show that there is a clear trade-off between economic efficiency and frequency security, making it necessary to assume higher costs in order to guarantee adequate inertia levels under certain system conditions.

It is also concluded that formulations with penalised deviations offer an intermediate alternative, allowing both objectives to be balanced. In particular, the quadratic penalty provides a more suitable solution by limiting significant deviations without completely eliminating the flexibility of the model.

6. References

[1] N. Nguyen and J. Mitra, ‘An Analysis of the Effects and Dependency of Wind Power Penetration on System Frequency Regulation’, *IEEE Transactions on Sustainable Energy*, vol. 7, no. 1, pp. 354–363, Jan. 2016, doi: 10.1109/TSTE.2015.2496970.

[2] F. Pérez-Illanes, E. Álvarez-Miranda, C. Rahmann, and C. Campos-Valdés, ‘Robust Unit Commitment Including Frequency Stability Constraints’, *Energies*, vol. 9, no. 11, p. 957, Nov. 2016, doi: 10.3390/en9110957.

[3] Y. Son, Y. Ha, and G. Jang, ‘Frequency Nadir Estimation Using the Linear Characteristics of Frequency Control in Power Systems’, *Energies*, vol. 17, no. 5, p. 1061, Jan. 2024, doi: 10.3390/en17051061.

Table of Contents

List of Figures

List of Tables

ABBREVIATURES

CCGT – Combined Cycle Gas Turbine

ENS – Energy Not Supplied

RES – Renewable Energy Sources

RoCoF – Rate of Change of Frequency

UC – Unit Commitment

NOMENCLATURE

Sets

H	Hours in the analysed time horizon
M	Months in the analysed time horizon
A	Areas of the system
G	Generating groups

Subsets

$H^m \subseteq H$	Hours corresponding to the month *m*
$A^{mod} \subseteq A$	Modelled areas
$A^{ext} \subseteq A$	External areas interconnected with the modelled system
$G^{th} \subseteq G$	Thermal generating groups, including CCGT, coal and nuclear groups
$G^{res} \subseteq G$	Renewable generating groups
$G^{hyd} \subseteq G$	Reservoir hydropower generating groups

Indexes

h	$h \in H$ Hour
m	$m \in M$ Month
a, a'	$a \in A$ Area
i	$i \in A^{mod}$ Modelled area
e	$e \in A^{ext}$ External area
g, g'	$g \in G$ Generating group
t	$t \in G^{th}$ Thermal generating group
r	$r \in G^{res}$ Renewable generating group
w	$w \in G^{hyd}$ Hydropower generating group

Parameters (represented starting with capital letter)

$D_{h,a}$	Demand [MW]
$RES_{h,a,g}$	Available renewable power generation [MW]
$B_{a,g}$	Binary parameter indicating the availability of generating group *g* in area *a* [-]
$\overline{P}_g$	Maximum power output of generating group [MW]
$\underline{P}_g$	Minimum power output of generating group [MW]
$\overline{RU}_g$	Ramp-up limit of generating group [MW/h]
$\overline{RD}_g$	Ramp-down limit of generating group [MW/h]
C_g^{fuel}	Fuel cost expressed in € per thermal MWh [€/MWht]
C^{CO2}	CO_2 emission cost [€/t CO_2]
C_g^{om}	Operation and maintenance cost [€/MWh]

C_g^{start}	Startup cost [€]
$C_{h,a}^{flow}$	Cost of electricity exchange with external areas [€/MWh]
C^{ens}	Cost of energy not supplied [€/MWh]
C_a^{dv1}	Linear RoCoF deviation cost coefficient [€/(MW·s^{-1})]
C_a^{dv2}	Quadratic RoCoF deviation cost coefficient [€/(MW·s^{-1})^2]
F_g^{fuel}	Net specific heat consumption [MWht/MWh]
F_g^{CO2}	CO_2 emission factor [t CO_2/MWh]
F_g^{RoCoF}	Fraction of power considered lost in the RoCoF calculation [-]
$P_{h,a}^{fix}$	Aggregated fixed power production from non-dispatchable technologies [MW]
$\overline{HYD}_{m,a}$	Maximum hydropower generation over the study period [MWh]
$\overline{STO}_a$	Maximum storage capacity of pumped-storage units [MWh]
$\underline{STO}_a$	Initial and final stored energy of pumped-storage units [MWh]
η	Round-trip efficiency of pumped-storage units [-]
$\overline{PUMP}_a$	Maximum pumping power [MW]
$\overline{TURB}_a$	Maximum turbine power [MW]
H_g	Inertia constant [s]
$ROCOF^{ref}$	RoCoF reference value [Hz/s]
$\overline{DV}_a$	Maximum allowed RoCoF deviation [MW/s]
F	Nominal system frequency [Hz]
PF_g	Power factor [-]
$\overline{FLOW}_{a,a'}$	Maximum interconnection capacity from area *a* to area *a'* [MW]

Positive Variables (represented starting with lowercase letter)

$p_{h,a,g}$	Power output of generating group [MW]
$pns_{h,a}$	Power not supplied [MW]
$turb_{h,a}$	Power generated in turbine mode [MW]
$pump_{h,a}$	Power consumed in pumping mode [MW]
$sto_{h,a}$	Energy stored in pumped-storage units [MWh]
$dv_{h,a}$	RoCoF constraint relaxation variable [MW/s]
$cur_{h,a,g}$	RES curtailment [MW]

Free variable

$flow_{h,a,a'}$	Power flow from area *a* to area *a'* [MW]

Binary variables

$u_{h,a,g}$	Commitment status of generating group [-]
$su_{h,a,g}$	Startup decision of generating group [-]
$sd_{h,a,g}$	Shutdown decision of generating group [-]

Chapter 1. INTRODUCTION

In the last years, there has been a significant increase in the penetration of renewable energy sources (RES), which are mostly intermittent and variable generation technologies, in many power systems around the world. This transition is important for decarbonization targets, but it also introduces new sources of uncertainty and operational challenges for power systems [1]. Demand patterns already involve a degree of unpredictability, but the RES increase this uncertainty as their output cannot be forecasted with complete accuracy [2].

One of the most critical consequences of the penetration of RES is the reduction in synchronous generation capacity. Synchronous generators play a fundamental role in frequency control within power systems due to their inherent rotational inertia and direct coupling between mechanical speed and electrical frequency, ensuring frequency stability by counteracting sudden imbalances between supply and demand. As rotating machines, their rotors operate at a speed synchronized with the grid frequency, allowing them to respond instantaneously to power imbalances between generation and demand. When a frequency deviation occurs, synchronous generators can adjust their rotational speed to provide primary frequency response, thereby stabilizing system frequency. This natural inertial response helps mitigate rapid frequency changes and enhances the overall stability and resilience of the electrical grid. In contrast, inverter-based renewable units lack this intrinsic property and typically operate at their maximum available output, limiting their contribution to reserves and reducing the number of synchronous generators risking the frequency control [2].

An example of the risks associated with the increasing share of RES was the incident that occurred in Spain on April 28, 2025. Severe frequency oscillations and over voltages were recorded, ultimately leading to a blackout across the Iberian Peninsula. The preliminary report [3] identified the low level of synchronous generation, following the technical constraint resolution process, as one of the main contributing factors to this event.

These circumstances place increasing significance on the development of advanced market models and optimization techniques capable of capturing both economic and technical dimensions of power system operation and managing the intrinsic uncertainty of RES. The traditional Unit Commitment (UC) problem provides a well-established framework for scheduling generation resources to minimize overall system costs while meeting forecasted demand considering technical constraints such as ramps, and economic decisions such as start-up and shut-down decisions, of thermal power plants [4]. The UC problem must also account for the effects arising from the intermittency of RES, including those related to the number of synchronous generators connected to the system.

In this context, robust optimization is increasing in importance as a method to address this uncertainty without relying on detailed probability distributions which are often unavailable or unreliable for RES [5]. By ensuring that operation constraints are satisfied under worst-case scenario, robust models enhance system security and align with the risk-averse strategies [6]. Nevertheless, the incorporation of robustness increases system costs, raising questions about the trade-off between reliability and economic efficiency.

This work develops and analyses a UC for a stylized Spanish power system that integrates frequency control constraints. The proposed framework builds upon a single node per area UC problem and complements it with frequency control constraints. The work seeks to provide meaningful insights into how market design and operational policies can balance economic efficiency with operational security. Additionally, the developed model is intended to serve as a support tool for enhancing frequency stability, by providing operational signals that can help prevent large-scale outages such as the incident previously discussed. In this sense, the framework supports the design of preventive measures to strengthen system resilience against frequency disturbances.

The remainder of this master's thesis is organized as follows. Chapter 2. reviews the literature, Chapter 3. defines the key concept of RoCoF and Chapter 4. explains the proposed model for this master's thesis. Chapter 5. presents the different case studies and their results and Chapter 6. includes the contributions, conclusions and future lines of research.

1.1 ALIGNMENT WITH ODS

The work presented in this project is closely aligned with several of the United Nations Sustainable Development Goals (SDGs).

- SDG 7: Affordable and Clean Energy. By addressing the operational challenges of integrating higher shares of renewable energy into the electricity system, the project contributes to ensuring access to reliable and sustainable energy services. The proposed model supports the secure operation of power systems under conditions of high renewable penetration, which is a key enabler for the large-scale deployment of clean energy technologies.
- SDG 9: Industry, Innovation and Infrastructure. The development of advanced market models and robust optimization techniques enhances the resilience and efficiency of energy infrastructure. By providing tools to better manage uncertainty and system security, the project fosters innovation in the design and operation of critical infrastructure.
- SDG 13: Climate Action. The project indirectly supports climate mitigation efforts by facilitating the integration of renewable energy sources, which are essential to reducing greenhouse gas emissions. By analysing the trade-offs between economic efficiency and operational security, the project contributes to identifying pathways that enable decarbonization without compromising reliability.

In sum, the project aligns with global sustainability objectives by supporting the transition to cleaner energy systems, reinforcing the resilience of infrastructure, and advancing knowledge on how to balance environmental, economic, and security goals in the context of the energy transition

Chapter 2. STATE OF THE ART

As outlined in the introduction, the main challenges associated with the integration of RES into the power system are the management of uncertainty and the frequency control. This section reviews the relevant literature addressing those issues in UC dispatches.

2.1 STATE OF THE ART OF UC UNCERTAINTY

In the first place, with regard to uncertainty management, literature has extensively addressed its treatment within UC dispatches. The most relevant contributions can be classified into two main methodological approaches. One would be stochastic optimization [7], which assumes that the probability distributions of the uncertain parameters are known. The second approach is robust optimization ([5], [6]and [8]), which considers that uncertain parameters belong to a bounded uncertainty set, without assigning probabilities to specific realizations.

Paper [7] develops a UC model with a stochastic optimization framework and concludes that this approach can reduce operation costs compared to a deterministic approach by minimizing reserve requirements, rather than overestimating them as occurs in the deterministic model. However, it also increases significantly computational cost. In contrast, papers [5], [6] and [8] and adopt robust optimization to address uncertainty in UC problem. They all incorporate the concept of uncertainty budget. This parameter controls the degree of conservativeness by specifying how many uncertain parameters can take their worst-case values at once. In particular, paper [6] integrates robust optimization with chance constraints, resulting in a model that enhances both technical and economic performance while achieving cost reductions with the appropriate uncertainty budget compared to deterministic and standard chance-constrained models. However, it is noted that these improvements could be due to the high share of hydro generation in the case study considered. Meanwhile, papers [5] and [8] propose two-stage robust formulations with an uncertainty budget, which allows the modeler to tune the level of conservativeness imposed. Their findings indicate improvements in economic efficiency with regard to reserve cost and in system security compared to traditional UC formulations.

In addition, paper [5] addresses investment in RES focusing on decision making under uncertainty due to fluctuating market prices, evolving government policies, technological developments, and unpredictable resource availability such as wind and solar generation. To model this uncertainty, it compares two optimization approaches, stochastic and robust optimization. The study concludes that decision making based on stochastic optimization may lead to lower benefits compared to robust model, as it involves more profitable but riskier choices. In contrast, robust optimization is more conservative yet more reliable, as it guarantees the maximum attainable profit in the worst-case scenario.

2.2 STATE OF THE ART OF UC WITH FREQUENCY CONTROL MODELLING

With regard to frequency control, literature has increasingly emphasized the need to adapt traditional UC formulations to ensure secure system operation in low-inertia contexts [9]. The approaches reviewed in this area generally extend the UC problem by incorporating explicit frequency-related constraints, such as limitations on the Rate of Change of Frequency (RoCoF) (see [9] and [10]) or the frequency nadir [11]. These papers represent a selection of the most relevant contributions concerning different approaches to incorporate frequency constraints to the UC problem.

Firstly, paper [12] proposes a model that introduces constraints on underfrequency load shedding. The results indicate that while the approach reduces overall system operating costs compared to standard UC, the preventive re-dispatch strategy required to avoid load shedding entails higher costs. Secondly, papers [9] and [10] focus on limiting the RoCoF. Paper [9] highlights the importance of Fast Frequency Response (FFR), particularly in highly renewable systems, and demonstrates that batteries are the most cost-efficient providers of this service. Moreover, paper [10] advances this line of research by introducing a Locational Frequency Security Constrained UC model (LF-SCUC).

A different strand of contributions addresses the frequency nadir. Papers [11] and [13] both extend UC with nadir-related constraints to enhance frequency security. Paper [11] develops a linearization method that improves the accuracy of the nadir constraint and system safety. The proposed model achieves a wider feasible operating region and lower reserve cost compared to the traditional UC problems [4]. Paper [13], in contrast, introduces a frequency security margin to ensure system stability under contingencies. The study shows that although adding such constraints increases costs and renewable curtailment, it guarantees stability. Furthermore, it demonstrates that variable renewable energy frequency support through synthetic inertia improves both security and cost-effectiveness.

Overall, these works illustrate that the incorporation of frequency-related constraints into UC models is essential to preserve system stability in high-renewable environments. At the same time, they reveal a consistent trade-off: while stricter frequency control constraints enhance security, they typically lead to higher costs, underscoring the importance of designing models that balance efficiency and reliability.

2.3 TABLEAU OF THE STATE OF THE ART

In conclusion, the literature reviewed demonstrates significant progress in adapting the UC problem to the challenges posed by renewable integration. On the one hand, uncertainty management has been advanced through stochastic and robust optimization approaches, offering different trade-offs between accuracy, conservativeness, and computational tractability. On the other hand, frequency stability has been safeguarded by incorporating novel constraints on RoCoF or frequency nadir. Altogether, these studies underline the necessity of developing market and UC models that jointly consider uncertainty and stability requirements, thereby enabling a secure and cost-effective transition toward renewable-based power systems.

Table 1 presents the reviewed literature related to the management of uncertainty, while Table 2 presents the literature related to frequency control. The description of their columns is:

- Modelling approach: describes the optimization framework or methodology adopted in each work.
- Frequency control: Describes the specific control strategy or frequency-related constraint analysed in each work.
- Main conclusions: summarizes the key findings, benefits, and limitations discussed in the studies.
- Application area: specifies the power system or operational context in which the model was applied.
- Resolution approach: refers to the algorithmic or computational techniques employed to solve the optimization framework or methodology.
- Network constraints: states whether the UC formulation considered network constraints or not.

Reference	Modelling approach	Main conclusions	Application area	Resolution approach	Network constraints
[6]	Chance Constraint and Robust Optimization with uncertainty budget	· Improves economic and technical performance vs. deterministic and standard chance-constrained OPF · Reduces ACE, ramping violations, and line overloads · Achieves cost savings with appropriate uncertainty budget · Scales to large systems and solves within seconds	Bonneville Power Administration (BPA) system (Northwestern U.S.)	Cutting plane algorithm	Yes
[8]	Robust Optimization. Two-stage model	· Proposes a robust interval optimization model for look-ahead wind power dispatch · Mitigates wind power uncertainty by scheduling intervals for wind farms and set points for conventional units · Reduces wind curtailment and frequency of turbine regulation · Improves system security compared to conventional economic dispatch · Slightly higher operating cost, but justified as the price for robustness	Bonneville Power Administration (BPA) system (Northwestern U.S.)	Transformed into a quadratic programming problem using strong duality and solved with IBM CPLEX via primal-dual interior point method	Yes
[7]	Stochastic Optimization	· Combining stochastic programming with reserve requirements gives more robust and reliable UC solutions. · This approach reduces expected costs compared to deterministic UC. · Modelling major uncertainties (generation outages, load deviations) is essential for improvements. · Computational cost is high but can be reduced with decomposition or scenario reduction.	IEEE Reliability Test System	"Brute force" approach	No
[5]	Robust Optimization with Uncertainty Budget. Two-stage model	· The adaptive robust model improves economic efficiency compared to traditional reserve methods. · It reduces cost volatility and almost eliminates penalty costs, strengthening reliability. · Performance remains stable across different probability distributions of uncertainty. · Benefits are amplified under high variability, where conventional approaches fail.	Power system operated by the ISO New England	Bender's decomposition algorithm for the outer master problem with an outer approximation technique to solve the inner bilinear subproblem	Yes

Table 1. Literature review - Uncertainty Management

Reference	Frequency control	Main conclusions	Application area	Resolution approach	Network constraints
[12]	Constraints on underfrequency load shedding	· The proposed model reduces system operating costs compared to standard UC. · Preventive re-dispatch avoids Under Frequency Load Shedding (UFLS) but increases costs	Spanish island power system	MILP with frequency dynamics and UFLS	No
[9]	Limit the RoCoF	· In highly renewable systems, FFR will be mandatory to ensure secure operation. · Batteries are the most efficient providers of FFR, while RES can also contribute but require over-investments. · Adding FFR capability does not strongly change total investment sizes, since large battery systems are already needed for energy shifting.	Chile's power system	Model transformed into LP solved with barrier algorithm from CPLEX	Yes
[11]	Limits the frequency nadir	· The proposed linearization method for the frequency nadir constraint is accurate and safe, improving frequency security. · Optimizing variable PFC droop gains reduces reserve costs and enlarges the feasible operation region. · The new SFC reserve calculation method is more appropriate than historical values, ensuring better control with lower cost. · The overall UC model achieves safer and more economical operation compared to traditional approaches	Chile's power System	MILP solved using GUROBI	Yes
[13]	Limits the frequency nadir	· The proposed frequency security margin ensures frequency stability under contingencies. · The Frequency-Constrained UC (FCUC) model maintains system security even with high variable renewable energy share. · Adding frequency constraints increases costs and renewable curtailment but guarantees stability. · Variable renewable energy frequency support (via synthetic inertia) improves both security and cost-effectiveness	Modified IEEE RTS-79 system	Linearized model in GAMS and solved by CPLEX	Yes
[10]	Limits the RoCoF	· The proposed locational frequency-constrained SCUC (LF-SCUC) ensures frequency security more effectively than system-wide approaches. · Locational constraints allow higher renewable integration without compromising security. · Compared to traditional methods, LF-SCUC avoids overly conservative schedules and reduces operating costs.	IEEE 24-bus system	GUROBI solver	Yes

Table 2. Literature review – Frequency control-

2.4 ON THE RELATIONSHIP BETWEEN FREQUENCY CONTROL AND ROBUST OPTIMIZATION

On one hand, the RoCoF measures the rate at which frequency varies immediately following an imbalance between generation and demand. RoCoF is directly related to the inertia available in the system to respond to such an imbalance. Consequently, constraining the RoCoF is equivalent to imposing a minimum total system inertia requirement. In other words, limiting the RoCoF may impose the commitment of additional synchronous units during those periods in which the constraint is binding, thereby limiting the penetration of RES.

On the other hand, robust optimization addresses the uncertainty associated with the availability of RES. Rather than relying on expected values, the model requires that the solution remains feasible under worst-case scenario. In a cost-minimization model, the worst-case scenario corresponds to the lowest renewable generation output. Reduced availability of RES consequently leads to the commitment of a greater number of synchronous units.

These two approaches are grounded in distinct perspectives, frequency security and uncertainty management, yet they operate in the same direction. Incorporating both simultaneously would therefore not yield a qualitative improvement in the formulation, on the contrary, it would produce an overlap of mechanisms and preclude the obtention of clear results regarding their individual effects. Moreover, it would be difficult to determine the relative contribution of each methodology. The RoCoF constraint directly addresses the challenge of frequency security, which constitutes the primary motivation of this work. It addresses the problem of declining system inertia arising from increased RES penetration and allows to isolate the effect of this constraint. Therefore, its impact on the cost and outcome of the economic dispatch can be rigorously analysed.

2.5 RESEARCH GAP AND CONTRIBUTION OF THIS MASTER'S THESIS

The literature reviewed shows that the integration of RES has required the extension of conventional UC formulations in two main directions: uncertainty management of renewable generation, and frequency-security modelling.

Stochastic and robust optimization methods have proven effective in addressing the variability and limited predictability of renewable generation. However, they are mainly focused on ensuring system feasibility or improving economic performance under uncertain operating conditions, rather than on isolating the effect of inertia requirements on the commitment and dispatch decisions.

In parallel, several frequency-constrained UC formulations have been proposed in the literature, incorporating frequency-security metrics such as RoCoF, frequency nadir, primary frequency response, fast frequency response, or under-frequency load shedding. These studies demonstrate that traditional reserve-based criteria may be insufficient in low-inertia systems and that frequency-related constraints can significantly affect the optimal scheduling of synchronous generation.

Nevertheless, many of these formulations rely on complex dynamic approximations, stochastic or robust frameworks, or additional frequency-support resources such as storage systems, converter-based renewables, or grid-forming technologies. As a result, the isolated operational impact of a RoCoF-based inertia constraint within a deterministic UC framework is not always clearly identifiable.

In this context, the research gap addressed in this master's thesis does not lie in the general inclusion of frequency constraints in UC, which has already been considered in previous studies, but rather in the systematic and transparent assessment of RoCoF-based constraints in a deterministic Mixed-Integer Quadratically Constrained Programming (MIQCP) UC model. In particular, the literature has devoted limited attention to comparing different ways of imposing or relaxing RoCoF requirement, as well as to evaluating how these modelling choices affect operating cost, commitment of synchronous units, renewable curtailment, unserved energy and emissions.

The contribution of this master's thesis consists in the development of a deterministic UC model that explicitly incorporates RoCoF-related constraints. The proposed framework deliberately separates the frequency-security problem from renewable uncertainty modelling, thereby enabling an independent analysis of the effects of RoCoF constraints. Moreover, several case studies are designed to compare strict RoCoF enforcement, relaxed formulations and penalty-based approaches. This methodology provides a clear basis for assessing the trade-off between frequency security and economic efficiency in a power system with high renewable penetration.

Chapter 3. ROCOF MODELLING IN POWER SYSTEMS

This chapter presents the theoretical basis of the RoCoF, which is later incorporated into the proposed UC model as a frequency-security constraint. In particular, the purpose is to explain the physical relationship between active power imbalances, synchronous inertia and system frequency variations. A more detailed discussion of the RoCoF and in general, the frequency dynamics in power systems can be found in [14].

3.1 SYSTEM DISTURBANCE, ROCOF AND FREQUENCY NADIR DEFINITIONS

In alternating current power system, generation and demand must be continuously balanced. Under normal operating conditions, synchronous generators rotate at a speed directly linked to the electrical frequency of the system. When system disturbances occur, like a sudden loss of a generation unit, the imbalance between generated and consumed active power can affect the equilibrium of these synchronous machines. In particular, in the first instants following a disturbance, synchronous generators respond by exchanging kinetic energy with the system, which modifies their rotational speed and, consequently, the system frequency. Specifically for a sudden loss of generation, the electrical power demanded by the system becomes greater than the mechanical power supplied by the remaining generators. When this occurs, the system must instantaneously compensate for the missing power. Before primary frequency control and other slower control mechanisms can react, synchronous generators provide part of the required energy by releasing kinetic energy stored in their rotating masses. As a result, their rotational speed decreases, leading to a drop in the system frequency. The same reasoning applies to a sudden increase in demand, since both situations create a power deficit. Conversely, a sudden loss of demand or an unexpected increase in generation produces a power surplus and causes the frequency to rise.

RoCoF (expressed in Hz/s) describes how fast frequency changes immediately after the disturbance. It is defined as the time derivative of system frequency $f(t)$ and therefore represents the instantaneous rate of frequency variation following a power imbalance:

E. 1
$$ROCOF = \frac{df(t)}{dt}$$

After a disturbance, in the case of a frequency drop, the frequency nadir (expressed in Hz) is the lowest value reached before recovery begins:

E. 2
$$Frecuency\ Nadir = Min\ f(t)$$

Figure 1 illustrates the typical frequency $f(t)$ evolution after a sudden generation loss. The figure shows the initial RoCoF, the frequency nadir and the subsequent recovery of the frequency as primary frequency control and slower control mechanisms are activated. This representation helps distinguish the initial inertial response, which determines the early frequency slope, from the later control actions that arrest and restore the frequency.

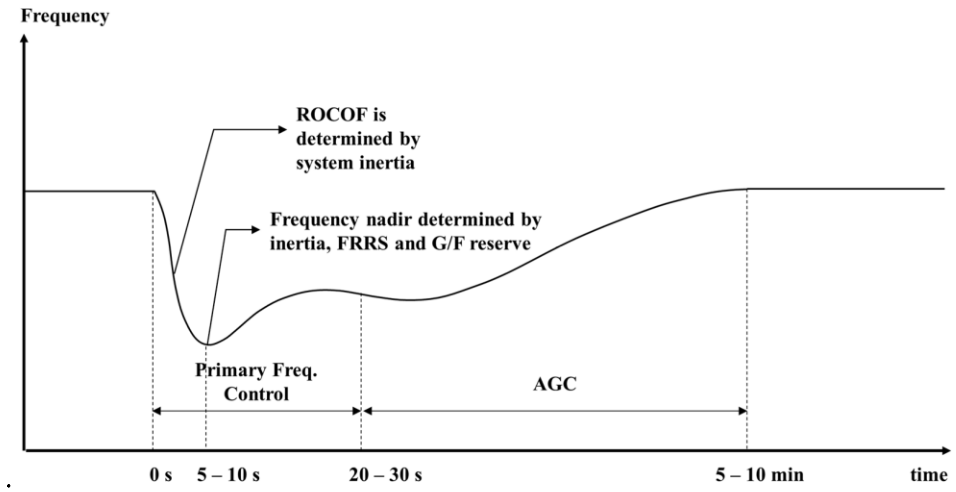

Figure 1. Frequency evolution following a sudden generation loss [15].

If the frequency nadir falls below an acceptable security threshold, it may compromise system operation and lead to the activation of protection schemes [2]. A high absolute value of RoCoF indicates that frequency is changing rapidly, reducing the time available for control mechanisms to respond. Although the frequency nadir does not depend exclusively on RoCoF, a higher initial slope can contribute to a lower nadir if sufficient corrective response is not available. Consequently, limiting RoCoF can help control the frequency nadir and is therefore relevant for maintaining frequency stability and avoiding the activation of protection schemes.

3.2 ROCOF MODELLING

The initial slope shown in Figure 1 is governed by the inertial response of synchronous generators. Therefore, the initial frequency response can be quantified from the kinetic energy stored in the rotors of the synchronous generators, which determines the system's ability to oppose rapid frequency variations immediately after a disturbance.

The kinetic energy $E_{kg}(t)$ (expressed in W·s) stored in a rotating mass of a generator g depends on its moment of inertia J_g (expressed in kg·m^2), which measures resistance to changes in rotational speed, and on the angular speed ($\omega_g(t)$), which is related to the nominal frequency of the system $f(t)$, as shown in equation E. 3.

E. 3 $$E_{kg}(t) = \frac{1}{2} \cdot J_g \cdot (\omega_g(t))^2 = \frac{1}{2} \cdot J_g \cdot (2 \cdot \pi \cdot f(t))^2$$

Power is defined as the rate at which energy changes over time. Consequently, the inertial power exchanged between the rotor and the system is given by the time derivative of the rotor's kinetic energy $E_{kg}(t)$, calculated in equation E. 4.

E. 4 $$\frac{dE_{kg}(t)}{dt} = J_g \cdot (2 \cdot \pi)^2 \cdot f(t) \cdot \frac{df(t)}{dt}$$

The maximum absolute RoCoF occurs immediately after the disturbance. At this instant, system frequency remains close to its nominal value, and the frequency dynamics are governed exclusively by the inertial response of the synchronous machines. Therefore, the energy exchange is evaluated at the moment of the incident. When a power imbalance occurs at time s, it is initially compensated through the exchange of kinetic energy between a synchronous generator g and the system, as shown in equation E. 5.

E. 5

$$\Delta P = \left.\frac{dE_{kg}(t)}{dt}\right|_{t=s} = J_g \cdot (2 \cdot \pi)^2 \cdot f(s) \cdot \left.\frac{df(t)}{dt}\right|_{t=s}$$

ΔP being the active power imbalance caused by a disturbance, computed as generation G minus demand D, therefore a generation loss leads to a negative imbalance (i.e. $\Delta P = G - D < 0$ and therefore RoCof=$df/dt<0$), while a demand loss leads to a positive imbalance.

Although the rotor moment of inertia J_g is physically meaningful, power system studies commonly use the inertia constant H_g (expressed in seconds). This parameter represents the time during which a generator could continue delivering its rated power using only its stored kinetic energy when operating at nominal frequency. It is defined as the ratio between the kinetic energy $E_{kg}(s)$ stored in the generator and its rated apparent power S_{Ng} (expressed in W). At the instant s, the frequency is the nominal value; therefore, the inertia constant is calculated as shown in equation E. 6.

E. 6

$$H_g = \frac{E_{kg}(s)}{S_{Ng}}$$

Then the rotor moment of inertia can be expressed as shown in the equation E. 7:

E. 7

$$J_g = \frac{2 \cdot H_g \cdot S_{Ng}}{(2 \cdot \pi \cdot f(s))^2}$$

Substituting, the expression E. 8 is obtained:

E. 8 $$\Delta P = J_g \cdot (2\pi)^2 \cdot f(s) \cdot \left.\frac{df(t)}{dt}\right|_{t=s} = \frac{2 \cdot H_g \cdot S_{Ng}}{f(s)} \cdot \left.\frac{df(t)}{dt}\right|_{t=s}$$

Equation E. 8 describes the inertial power contribution of an individual synchronous generator g. More specifically, the term $H_g{\cdot}S_{Ng}$, represents the kinetic energy stored in the rotor of generator g. However, after a disturbance, all online synchronous groups respond to the incident by providing kinetic energy. Therefore, it is necessary to consider the aggregate stored kinetic energy $E_{k,sys}$ calculated as shown in equation E. 9.

E. 9 $$E_{k,sys} = \sum_g H_g \cdot S_{Ng}$$

Extending equation E. 8 to the system level, then:

E. 10 $$\Delta P = \frac{2 \cdot \sum_g \left(H_g \cdot S_{Ng}\right)}{f(s)} \cdot \left.\frac{df(t)}{dt}\right|_{t=s}$$

As mentioned, the term *df/dt* corresponds to the RoCoF, therefore rearranging equation E. 10, the RoCoF can be expressed as:

E. 11 $$RoCoF = \frac{\Delta P \cdot f(s)}{2 \cdot \sum_g H_g \cdot S_{Ng}}$$

Which, as mentioned, must be limited for maintaining frequency stability at any time s. When a generation loss occurs $RoCoF<0$ as $\Delta P<0$, while for a demand loss $RoCoF>0$ as $\Delta P>0$.

To calculate the system kinetic energy, the apparent power $S_{N,g}$ of each generator is required. In alternating current systems, the product of the voltage and current defines the apparent power, (S = VI). However, when voltage and current are phase-shifted, not all this apparent power is converted into active power. Only the component of the current that is in phase with the voltage contributes to net active power transfer. Therefore, active power is related with apparent power through the power factor *PF*, defined as PF = $cos(\phi)$, where ϕ is the phase angle between voltage and current waveforms [16]. Figure 2 illustrates this relationship.

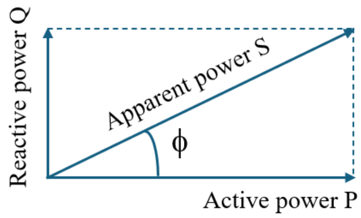

Figure 2. Relationship between active, reactive and apparent power

The PF therefore indicates the proportion of apparent power that corresponds to active power, as represented in equation E. 12.

E. 12
$$p_g = S_{N,g} \cdot cos(\phi_g) = S_{N,g} \cdot PF_g$$

Therefore, the rated apparent power S_{Ng} of each generating unit *g* is calculated by dividing its maximum active power output by the corresponding power factor, leading to:

E. 13
$$RoCoF = \frac{\Delta P \cdot f(s)}{2 \cdot \sum_g H_g \cdot \frac{p_g}{PF_g}}$$

Chapter 4. THE PROPOSED UC MODEL WITH ROCOF FREQUENCY CONTROL

This chapter presents the proposed model. The first section outlines the assumptions considered in its development, while the second describes the mathematical formulation, including the frequency control constraints based on the RoCoF.

4.1 MODEL ASSUMPTIONS

The proposed model represents an UC which includes frequency control constraints. The main assumptions considered in the formulation are the following:

- The UC is solved with hourly resolution. All variables are assumed to remain constant within each hourly time interval.
- The system consists of different interconnected areas. Each area is modelled as a single-node system, assuming the absence of internal network constraints. Consequently, generation dispatch is performed on an aggregate area level.
- Power exchanges are represented through interconnection flow variables, that account for both exchanges between modelled areas and with external areas. External areas are not explicitly dispatched; instead, they are represented through their interconnection capacities and associated electricity prices.
- Thermal generating units, including combined cycles, coal and nuclear plants, are modelled not considering minimum up-time and down-time constraints.
- Nuclear units are modelled as must-run generation over the analysed horizon. Accordingly, they are assumed to remain committed throughout the optimisation period, and start-up and shut-down decisions are not considered for this technology. This assumption is consistent with their short-term limited operational flexibility [17].

- RES are modelled with zero marginal cost, reflecting the absence of fuel costs and the negligible incremental cost of production once the generation capacity has been installed. Their output is limited by exogenous availability profiles, which reflexes the availability of a primary resource (e.g. wind or solar). Curtailment is allowed when required to satisfy operational or demand constraints.
- Hydropower generation is also modelled with zero marginal cost. In addition, an upper limit on the total energy generated over the study horizon is imposed to represent the limited availability of the water resource [7].
- Pumped-storage units are represented as aggregated elements that can either consume electricity in pumping mode or generate electricity in turbine mode. The stored energy is modelled through a state variable, which is updated according to the pumping and generation decisions. A round-trip efficiency parameter is included to reflect losses associated with the storage process.
- Non-dispatchable technologies are represented through an aggregated fixed-production parameter defined for each hour and area. Their output is not optimised by the UC model, and it is instead included directly in the power balance as exogenous generation.
- Inertia and RoCoF are evaluated at area level. The available inertia is modelled as an aggregated parameter, calculated from the inertia contributions of the committed synchronous generating units within each area.
- The model is formulated so that the RoCoF constraint can be relaxed through a deviation variable, whose penalisation is included in the objective function depending on the case study considered. This formulation allows to analyse the impact of different levels of RoCoF enforcement. Since the literature does not provide a unique reference value that guarantees secure system operation under all conditions, the selected RoCoF limit must be interpreted as a modelling assumption. More restrictive values may increase the operating cost, while less restrictive values may reduce the economic impact but imply a higher operational risk.

4.2 MATHEMATICAL FORMULATION

This section presents the mathematical formulation of the UC model proposed in this master's thesis. The objective is to determine a feasible UC schedule that minimizes the total operating cost, while satisfying all operational constraints, including the RoCof's.

4.2.1 OBJECTIVE FUNCTION

The objective function consists of minimizing the total operating cost over the analysed time horizon, as shown in equation E. 14.

E. 14
$$\min(tc^{th} + tc^{flow} + tc^{ens} + tc^{RoCoF})$$

As can be seen, the total operating cost is expressed as the sum of four cost components: the operating cost of synchronous thermal units, tc^{th}, the cost associated with power exchanges with external areas, tc^{flow}, the cost of energy not supplied, tc^{ens}, and the penalty associated with deviations from the RoCoF constraint, tc^{RoCoF}.

Equation E. 15 defines the first term tc^{th} which represents the total operating cost of the thermal generating units. This cost includes the fuel cost, CO_2 emissions cost, operation and maintenance cost, and start-up cost of the units.

E. 15
$$tc^{th} = \sum_{h,i,t}\left(\left(C_t^{fuel} \cdot F_t^{fuel} + C^{CO2} \cdot F_t^{CO2} + C_t^{om}\right) \cdot p_{h,i,t} + C_t^{start} \cdot su_{h,i,t}\right)$$

The second term tc^{flow} is calculated in equation E. 16. It accounts for the cost or income of the power exchanged with external areas.

E. 16
$$tc^{flow} = \sum_{h,i,e}\left(flow_{h,e,i} \cdot C_{h,e}^{flow}\right)$$

This term tc^{flow} is modelled by multiplying the exchanged power by the corresponding price assigned to each external interconnection. The sign convention of the power exchange determines whether the resulting contribution represents a cost, corresponding to imports, or a revenue, corresponding to exports, for the system.

The third component tc^{ens} represents the cost of energy not supplied. This term penalizes any unmet demand. It is calculated as the product of the energy not supplied and the corresponding penalty cost, as shown in equation E. 17.

E. 17
$$tc^{ens} = \sum_{h,i} C^{ens} \cdot pns_{h,i}$$

Finally, the objective function includes a penalty associated with the deviation from the RoCoF constraint explained in Section 4.2.2.7. The deviation term allows the frequency-security constraint to be relaxed, while assigning an economic cost to this relaxation. Equation E. 18 shows the formulation of the penalty as a combination of a linear and a quadratic component.

E. 18
$$tc^{RoCoF} = \sum_{h,i} C_i^{dv1} \cdot dv_{h,i} + \frac{C_i^{dv2}}{2} dv_{h,i}^2$$

The linear coefficient C_i^{dv1} represents the initial marginal cost of allowing a deviation from the RoCoF limit. It is determined based on the economic impact of the RoCoF constraint, using the average dual value of this constraint when deviations are not allowed.

The quadratic coefficient C_i^{dv2} determines how the marginal cost increases with the magnitude of the deviation. A higher value discourages the model from concentrating excessive deviations in specific hours, since larger deviations become progressively more expensive.

4.2.2 CONSTRAINTS

4.2.2.1 Power generation-demand balance

The power generation-demand balance needs to be satisfied for all hours in each area of the model. This is ensured with the constraint shown in equation E. 19.

E. 19
$$\sum_{g} p_{h,i,g} + turb_{h,i} + \sum_{\substack{a\in A \\ a\neq i}} flow_{h,a,i} + pns_{h,i} + P_{h,i}^{fix} = D_{h,i} + pump_{h,i}$$

4.2.2.2 Thermal groups (t)

Thermal groups are subject to their characteristic technical operating constraints. First, the output power is bounded, when committed, by the maximum power and the minimum operating power. These limits are defined only for the area–group combinations available in the system. This is enforced through the availability parameter ($B_{a,g}$), which is equal to zero when group g is not available in area a. These constraints are represented in equations E. 20 and E. 21.

E. 20
$$p_{h,i,t} \leq u_{h,i,t} \cdot \overline{P}_t \cdot B_{i,t}$$

E. 21
$$p_{h,i,t} \geq u_{h,i,t} \cdot \underline{P}_t \cdot B_{i,t}$$

In addition, ramping constraints are included to limit both upward and downward variations in the unit output between consecutive time periods. These constraints, represented in equations E. 22 and E. 23, are applied from the second time period onwards, being *'h0'* the first period of the time horizon.

E. 22
$$p_{h,i,t} - p_{h-1,i,t} \leq \overline{RU}_t \qquad \forall\ h \in H \setminus \{'h0'\}$$

E. 23
$$p_{h-1,i,t} - p_{h,i,t} \leq \overline{RD}_t \qquad \forall\ h \in H \setminus \{'h0'\}$$

Finally, the logical constraint governing startup, shutdown and commitment binary decisions is shown in equation E. 24. Startup and shutdown decisions in the first period are not considered, since the initial commitment condition prior to the analysed horizon is not modelled.

E. 24
$$u_{h,i,t} = u_{h-1,i,t} + su_{h,i,t} - sd_{h,i,t} \; \forall \; h \in H \setminus \{'h0'\}$$

In the specific case of nuclear units, the commitment status is fixed according to the must-run assumption described above. Therefore, startup and shutdown decisions are not optimised for this technology.

4.2.2.3 Renewable technologies (r)

The hourly power generation of each RES is limited by the estimated availability $\overline{RES}_{h,i,r}$. The difference between the available and the actual renewable power corresponds to the curtailment and is represented by the variable $cur_{h,i,g}$. The constraint for RES generation is shown in equation E. 25.

E. 25
$$p_{h,i,r} + cur_{h,i,r} = \overline{RES}_{h,i,r}$$

4.2.2.4 Hydropower (w)

Unlike other renewable technologies, hydropower availability is modelled as an aggregated energy constraint for each month, rather than as an hourly power profile. As shown in equation E. 26, this constraint limits the total hydro generation according to the available hydro energy for that month.

E. 26
$$\sum_{h \in H^m, w} p_{h,i,w} \leq \overline{HYD}_{m,i}$$

This formulation represents the operation of reservoir hydropower plants, where the reservoir is replenished by natural inflows and the available stored energy can be dispatched across the time horizon in the hours in which it is most beneficial for the system.

As well as thermal groups the output power is, when committed, bounded by the maximum power and the minimum operating power. These constraints are represented in equations E. 27 and E. 28.

E. 27 $$p_{h,i,w} \leq u_{h,i,w} \cdot \overline{P}_w \cdot B_{i,w}$$

E. 28 $$p_{h,i,w} \geq u_{h,i,w} \cdot \underline{P}_w \cdot B_{i,w}$$

4.2.2.5 Pumped-storage units

The pumping process is not fully reversible, since the energy recovered during turbine operation is lower than the energy consumed during pumping. This is represented through the pumping efficiency (η) parameter, as shown in equation E. 29.

E. 29 $$sto_{h,i} = sto_{h-1,i} - turb_{h,i} + pump_{h,i} \cdot \eta \quad \forall h \in H \setminus \{'h0'\}$$

The stored energy level ($sto_{h,i}$) is constrained by the maximum reservoir capacity, as expressed in equation E. 30. Moreover, turbine and pumping power are bounded by their respective maximum technical limits, represented in equations E. 31 and E. 32.

E. 30 $$sto_{h,i} \leq \overline{STO}_i$$

E. 31 $$pump_{h,i} \leq \overline{PUMP}_i$$

E. 32 $$turb_{h,i} \leq \overline{TURB}_i$$

In addition, the initial and final stored energy levels are fixed at the same minimum required value. This condition avoids end-of-horizon effects by preventing the model from the artificial use of the reservoir as a free source of energy at the end of the optimisation period. These constraints are enforced through equations E. 33 and E. 34.

E. 33 $$sto_{'h0',i} = \underline{STO_i}$$

E. 34 $$sto_{'hN',i} \geq \underline{STO_i}$$

Where, *'hN'* corresponds to the last period of the time horizon and as mentioned, *'h0'* to the first one.

4.2.2.6 Interconnection

The exchange between interconnected areas is represented by the free variable $flow_{h,a,a'}$. A positive value of this variable denotes a power flow from area *a* to area *a'*, while a negative value represents a flow in the opposite direction.

The power exchanged through each interconnection is limited by the corresponding transmission capacity. Since the maximum transfer capacity may depend on the direction of the exchange, the upper bound is given by the capacity from area *a* to area *a'*, shown in equation E. 35, while its lower bound is determined by the capacity from area *a'* to area *a*, shown in equation E. 36.

E. 35 $$flow_{h,a,a'} \leq \overline{FLOW}_{a,a'}$$

E. 36 $$flow_{h,a,a'} \geq -\overline{FLOW}_{a',a}$$

In addition, equation E. 37 presents an antisymmetry constraint imposed to ensure consistency in the representation of the same physical interconnection from both directions.

E. 37 $$flow_{h,a,a'} = -flow_{h,a',a}$$

This formulation guarantees that the interconnection capacity limits are respected while maintaining a unique and coherent representation of the exchanged power between areas.

4.2.2.7 Frequency constraint

As discussed in Chapter 3. the RoCoF represents the initial rate of frequency variation following an active power imbalance. Its value is mainly determined by the magnitude of the disturbance and by the inertia available in the system at the instant of the event.

The RoCoF calculation is presented in equation E. 13, to incorporate it into the model two main adjustments need to be implemented.

Firstly, ΔP denotes the active power imbalance caused by the disturbance. In this model, the RoCoF is assessed for the potential loss of generation, therefore, the power imbalance is calculated as minus the generation of the group, reflecting the potential loss of that group. For each hour, area and group, the active power imbalance associated with the considered loss is estimated as a fraction of the power produced. This fraction is defined by the parameter F_g^{RoCoF}, which determines the proportion of the group output assumed to be disconnected in the contingency used for the RoCoF assessment. This parameter allows to adjust the magnitude of the disturbance depending on the level of aggregation considered in the generation variable. For instance, when the variable corresponds to aggregated unit production, a value equal to one may be used to represent the loss of its production.

E. 38
$$\Delta P = -F_g^{RoCoF} \cdot p_{h,i,g}$$

Following equation E. 11, equation E. 39 shows the RoCoF calculation.

E. 39
$$\text{RoCoF} = -\frac{F_g^{RoCoF} \cdot p_{h,i,g} \cdot F}{2 \cdot \sum_{g' \neq g} H_{g'} \cdot \frac{\bar{P}_{g'}}{PF_{g'}} \cdot u_{h,i,g'}}$$

In this constraint the inertia term corresponds to the inertia remaining available after the loss of the synchronous generating group g, meaning that its inertia contribution is removed from the total system inertia. Moreover, in order to calculate the inertial contribution of the system it is necessary to consider only the online units. Therefore, it is necessary to multiply by the commitment binary variable $u_{h,i,g}$ in the denominator of the above equation.

In the model formulation, the RoCoF is constrained to ensure that the initial frequency variation following the disturbance remains within the admissible limit, denoted as ROCOF^{ref}, as can be seen in equation E. 40.

E. 40
$$\text{RoCoF} = -\frac{F_g^{RoCoF} \cdot p_{h,i,g} \cdot F}{2 \cdot \sum_{g' \neq g} H_{g'} \cdot \frac{\overline{P}_{g'}}{PF_{g'}} \cdot u_{h,i,g'}} \geq \text{ROCOF}^{ref}$$

Since the considered contingency corresponds to a generation outage, the resulting RoCoF is negative, as the system frequency initially decreases after the imbalance. Therefore, the reference value ROCOF^{ref} is also defined as a negative threshold, preventing excessively steep negative frequency excursions. Moreover, since the RoCoF involves the ratio between two variables ($p_{h,i,g}$ and $u_{h,i,g}$, see equation E. 40), the RoCoF is fractional nonlinear and cannot be directly included in the formulation of the proposed UC model. To address this, the constraint is reformulated by multiplying both sides of equation E. 40 by the inertia term, resulting in the equivalent linear expression shown in equation E. 41.

E. 41
$$-\frac{F_g^{RoCoF} \cdot p_{h,i,g} \cdot F}{2} \geq \text{ROCOF}^{ref} \cdot \left(\sum_{g' \neq g} H_{g'} \cdot \frac{\overline{P}_{g'}}{PF_{g'}} \cdot u_{h,i,g'} \right)$$

Finally, in equation E. 42 a deviation variable is introduced to allow a controlled relaxation of the RoCoF requirement. By including the positive deviation variable, the model is allowed to exceed the RoCoF reference limit ROCOF^{ref} when the associated economic benefit justifies it.

E. 42
$$-\frac{F_g^{RoCoF} \cdot p_{h,i,g} \cdot F}{2} + dv_{h,i} \geq \mathrm{ROCOF}^{ref} \cdot \left(\sum_{g' \neq g} H_{g'} \cdot \frac{\bar{P}_{g'}}{PF_{g'}} \cdot u_{h,i,g'} \right)$$

In theory, the RoCoF constraint is enforced for every hour, area and generating group, ensuring that all considered contingency scenarios satisfy the frequency-security requirement, committing additional thermal units when necessary. Nevertheless, the deviation variable $dv_{h,i}$ is indexed only by hour and area and is therefore shared by all group-loss cases. As a result, its value is determined by the contingency requiring the largest relaxation of the RoCoF limit. This approach ensures that deviation variable captures the worst-case frequency-security requirement among all contingencies considered in a given hour and area. Moreover, this relaxation is constrained through a global limit on the total amount of deviation allowed over the optimization horizon for each area, as shown in equation E. 43.

E. 43
$$\sum_h dv_{h,i} \leq \overline{DV_i}$$

The parameter $\overline{DV_i}$ limits the accumulated deviation permitted in each area over the optimization horizon. Therefore, the model can only make use of the relaxation in a limited way, either by allowing small deviations in several periods or larger deviations in a reduced number of hours. This prevents the model from systematically relying on RoCoF violations as an operating strategy. At the same time, this approach makes it possible to identify the periods in which the RoCoF constraint is particularly costly for the system, as well as identify the economic impact of the constraint.

As explained above, the RoCoF reference value should not be interpreted as a unique threshold that unequivocally guarantees frequency security. Rather, it constitutes a system-dependent operational criterion whose selection is subject to a certain degree of convention, as the literature does not establish a universal RoCoF limit below which the frequency nadir is necessarily maintained within acceptable bounds.

Although RoCoF is strongly related to the initial rate of frequency decline and therefore significantly influences the subsequent frequency nadir, it does not determine it independently. Consequently, allowing limited deviations from the reference RoCoF value provides a reasonable approach to assessing the trade-off between strict compliance with the selected threshold and the resulting economic and operational performance of the system.

Chapter 5. CASE STUDIES

This chapter presents the case studies designed to assess the behaviour of the proposed UC model under different levels of enforcement of the RoCoF constraint. The objective is to evaluate how frequency-security requirements affect scheduling decisions.

The analysis is based on the comparison of several operating cases in which the treatment of the RoCoF constraint is modified. This approach makes it possible to isolate and quantify the impact of the RoCoF requirement on system operation in terms of operating cost, RES curtailment, and CO_2 emissions. In this way, the case studies provide the basis for assessing the trade-off between economic efficiency and frequency-security requirements.

The chapter is structured as follows. First, the main assumptions adopted in the case studies are described. Then, the input data and parameters used in the model are presented, including demand, generation technologies, interconnection data, ENS cost and RoCoF-related parameters. Finally, the different case studies are defined, and their results are analysed and compared through two complementary time horizons: an initial analysis based on the first week of October 2030, and a subsequent annual analysis using data for the full year 2030. This set of data is based on historic profiles adjusted to reflect the expected generation and demand conditions of 2030.

5.1 ASSUMPTIONS

The main assumptions considered in the case studies are the following:

- The analysis is performed over two different time horizons. First, a week is analysed in detail, as this horizon allows hourly operating patterns to be adequately captured, including differences between weekdays and weekends. Second, a full-year simulation is performed to assess whether the conclusions obtained for the weekly analysis remain consistent. The input data are estimated to reflect the expected demand and generation conditions of the Iberian power system in 2030, as later described.

- The nominal system frequency (F) is set to 50 Hz.
- The system under study is represented by two interconnected areas, corresponding to Spain and Portugal, with limited exchange capacity between them. In addition, Spain is interconnected with France, which is represented as an external area. Portugal is assumed to be connected only to Spain, with no additional external interconnections.
- Nuclear generation is modelled with zero marginal cost. This assumption is consistent with its baseload operating behaviour and with the fact that its marginal cost is typically below the expected market price. Therefore, assigning a differentiated variable cost to nuclear generation would not provide additional relevant insights for the purpose of this study, which focuses on the impact of the RoCoF constraint.
- A design power factor of 0.9 is assumed for thermal and hydropower units. This value is taken as a common rated power factor for large synchronous generating units. This implies a relation between reactive and active power close to 0.5, that is a normal value for synchronous technologies [18].

5.2 *INPUT DATA AND PARAMETERS*

The input data presented in this section define the operating conditions considered in the case studies. These data determine the demand to be supplied, the available generation resources and the technical characteristics within which the UC model must find a feasible operating schedule. Therefore, they establish the basis for the subsequent definition and comparison of the analysed cases.

The input data used in the case study has been constructed to represent the expected operating conditions of the Iberian power system in 2030. Historical demand and renewable generation profiles are used as a starting point and adjusted taking into account as a reference the installed capacity, demand levels and generation projections considered in both National Energy Plans for 2030 of Spain [19] and Portugal [20]. This approach preserves the hourly variability and temporal patterns observed in historical data, while ensuring consistency with the expected evolution of the power system considered in the case study.

5.2.1 DEMAND

Demand is defined as an hourly parameter for each modelled area. Table 3 presents the mainland demand for each area in the annual horizon.

Area	*Demand [GWh]*
Spain	278,226
Portugal	59,587

Table 3. Annual demand in Spain and Portugal

These values for 2030 correspond to a 3% compound annual growth rate since 2025, excluding self-consumption. The profiles are based on the 2023 profiles of each countries, as 2023 is the most recent available year that is both non-leap and unaffected by major blackout events. Figure 3 shows the demand duration curve for Spain and Portugal.

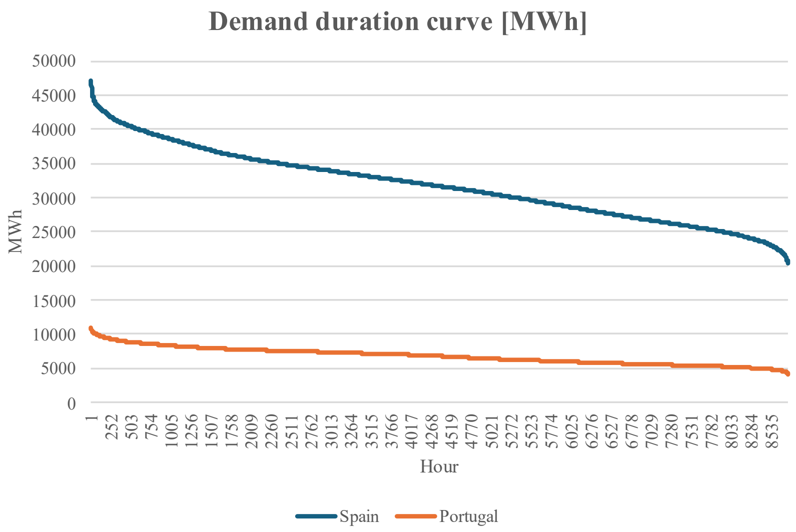

Figure 3. Demand duration curve

As can be seen, demand in Spain is significantly higher than in Portugal, reflecting the larger size of the Spanish power system.

Figure 4 illustrates the hourly demand profiles for Spain and Portugal over the analysed week, corresponding to the first week of October.

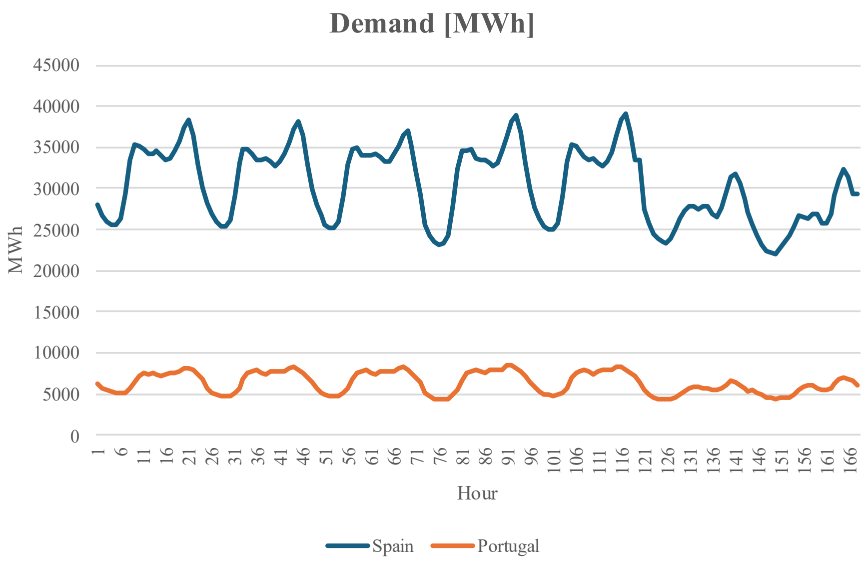

Figure 4. Demand of Spain and Portugal

In both areas, the demand profile follows a clear daily pattern, with lower values during the night and a peak in the evening hours, when residential consumption typically increases. A reduction in demand can also be observed during the central hours of the day, which is consistent with the effect of distributed solar self-consumption on the net demand seen by the system. Finally, the demand profile shows a noticeable decrease during the weekend.

5.2.2 GENERATION PORTFOLIO

Table 4 presents the installed generation capacity by technology considered in the case study for Spain and Portugal. It includes the main generation technologies represented in each area, providing an overview of the available resources used in the UC model.

	Spain [MW]	*Portugal [MW]*
Nuclear	7,117	0
CCGT	24,400	3,200
Coal	1,500	0
Hydropower	17,000	8,400
Solar Energy	56,000	8,800
Wind Power	38,000	5,700
Solar Thermal	2,300	0
Cogeneration	3,800	0
Other	1,500	700

Table 4. Installed capacity by technology

5.2.2.1 Nuclear Power Plants

Table 5 shows the main technical parameters of the nuclear units considered. All nuclear units are located in the Spanish area, while there are no nuclear plants in Portugal.

	$\bar{P}_g$ *[MW]*	$\underline{P}_g$ *[MW]*	$\overline{RU}_g / \overline{RD}_g$ *[MW/h]*	H_g *[s]*
NCL1	*1011.3*	*961.3*	*10*	*5.9*
NCL2	*1005.8*	*955.8*	*10*	*5.9*
NCL3	*995.8*	*945.8*	*10*	*5.9*
NCL4	*991.7*	*941.7*	*10*	*5.9*
NCL5	*1063.9*	*1013.9*	*10*	*5.9*
NCL6	*1003.4*	*953.4*	*10*	*5.9*
NCL7	*1045.3*	*995.3*	*10*	*5.9*

Table 5. Technical characteristics of nuclear power stations

Through the year the nuclear plants have outages periods associated with recharging fuel and maintenance. This process has an average duration of around one month and concentrated during lower demand months [21]. Taking the maintenance process into account, the following figure shows considered the number of nuclear groups available each month.

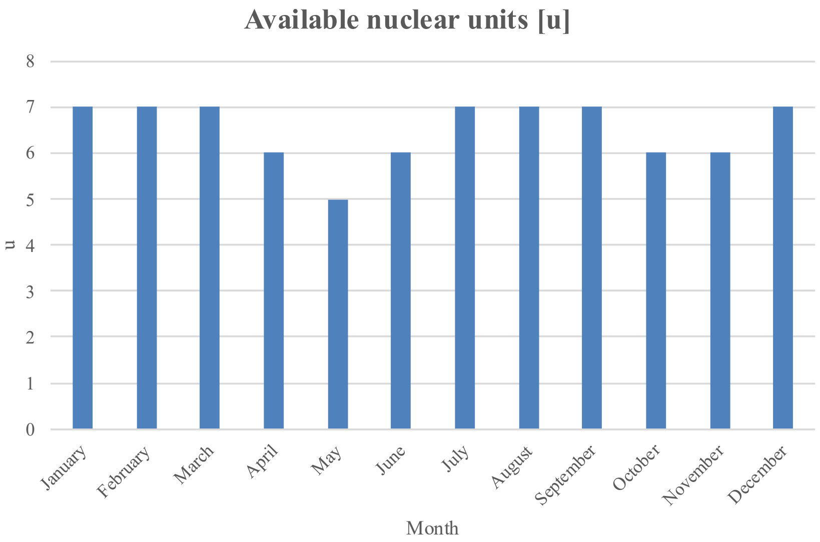

Figure 5. Available nuclear units each month in Spain

5.2.2.2 Conventional Thermal Units

This section describes the conventional thermal units considered in the case study, including CCGT units and coal power units.

Combined cycle generation is represented by 61 CCGT units in Spain and 8 in Portugal. All CCGT units are assumed to share the same technical and economic characteristics, detailed in Table 6. In addition, the Spanish area includes 3 coal units, whose characteristics are also provided in Table 6. No coal power generation is considered in Portugal.

	$\bar{P}_g$ [MW]	$\underline{P}_g$ [MW]	$\overline{RU}_g$ / $\overline{RD}_g$ [MW/h]	H_g [s]
CCGT	400	150	200	4.3
Coal	500	200	100	4.2

	C_g^{start} [€]	F_g^{fuel} [MWht/MWh]	F_g^{CO2} [t CO_2/MWh]	C_g^{om} [€/MWh]
CCGT	25,000	2	0.36	5
Coal	75,000	2.63	0.98	3.1

Table 6.Technical and economic characteristics of conventional thermal groups

The fuel and CO_2 price assumptions used to compute the thermal variable generation cost are presented in Table 7.

$C^{fuel}_{'CCGT'}$ [€/MWht]	$C^{fuel}_{'COAL'}$ [€/MWht]	C^{CO2} [€/t CO_2]
30.7	13.75	77.64

Table 7. Fuel and CO_2 cost

5.2.2.3 RES availability

Table 8 presents the total renewable availability for each area for the annual horizon.

Area	*Wind [GWh]*	*Solar [GWh]*
Spain	83,773	93,094
Portugal	13,759	14,362

Table 8. Renewable annual production

Solar availability profiles are derived from 2019 data for each country, as this year exhibits lower curtailment levels and therefore provides a more representative approximation of resource availability, rather than curtailed production. Wind availability profiles are derived from 2023 data, ensuring consistency with the reference year used for the demand, and reflecting recent wind generation patterns. Figure 6 and Figure 7 show the duration curve for RES availability in Spain and Portugal respectively.

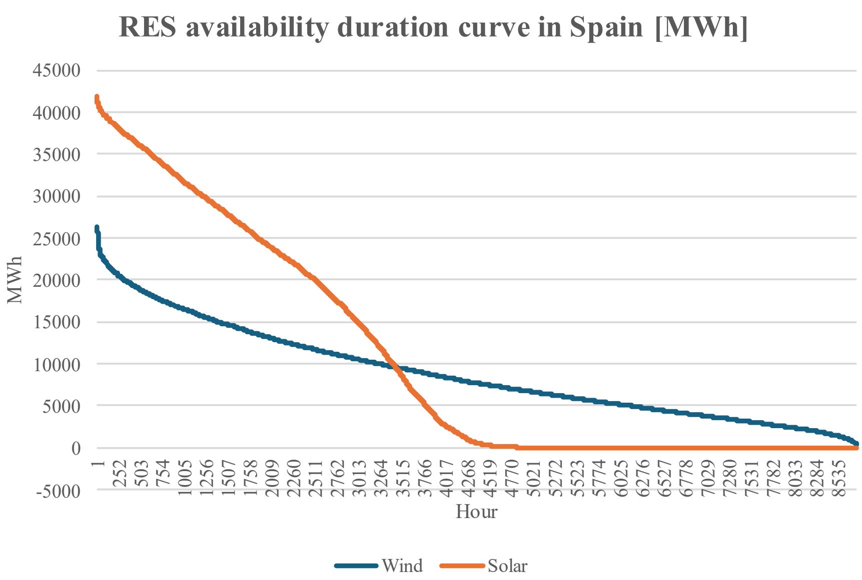

Figure 6. RES availability duration curve in Spain

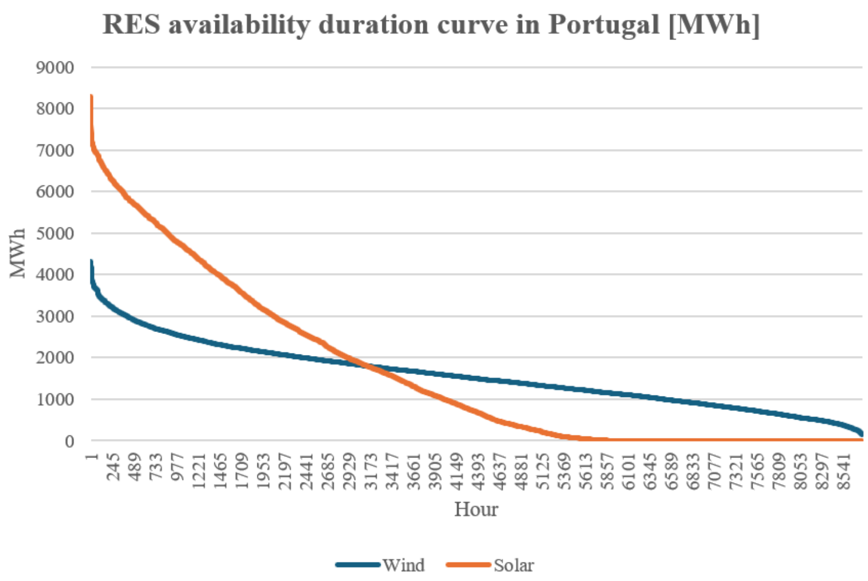

Figure 7. RES availability duration curve in Portugal

Figure 8 and Figure 9 show the RES availability profiles for Spain and Portugal respectively for the analysed week, reflecting the maximum available renewable production at each time step.

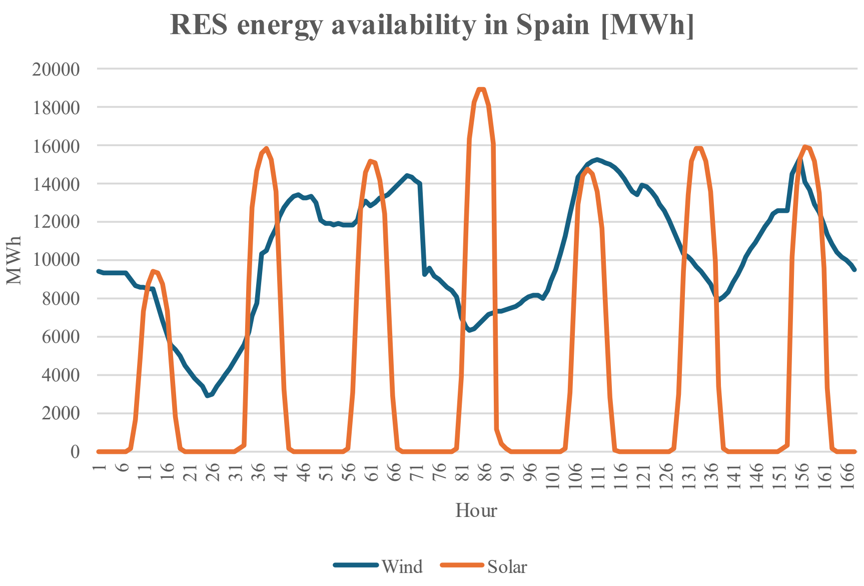

Figure 8. RES availability in Spain

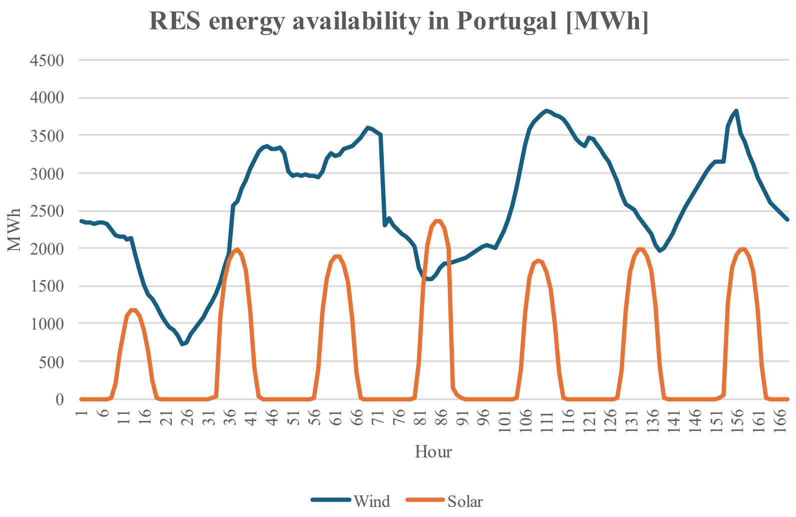

Figure 9. RES availability in Portugal

A clear insight from the figures is the high penetration of RES in both Spain and Portugal. In several hours, the combined output of solar and wind generation approaches the system demand. This highlights the growing relevance of RES in system operation and the potential challenges associated with their integration, such as curtailment or flexibility requirements.

5.2.2.4 Reservoir Hydropower

Reservoir hydropower is modelled by means of equivalent generating groups in each area. The Spanish system presents 45 hydropower groups, whereas the Portuguese system includes 30. All hydropower units are assumed to share the same technical characteristics, reported in Table 9.

	$\bar{P}_g$ *[MW]*	$\underline{P}_g$ *[MW]*	H_g *[s]*
Hydropower	200	50	3.7

Table 9. Hydropower group technical characteristics

For each area, an aggregated monthly hydro-energy availability is imposed, corresponding to the profile of the average hydro year. This limits the total energy that can be produced by the corresponding hydropower groups over each month. This monthly availability profile represents an average hydro year, constructed by calculating the arithmetic mean of the monthly hydro-energy production over the last seven years. Figure 10 shows the available energy in each month for Spain and Portugal.

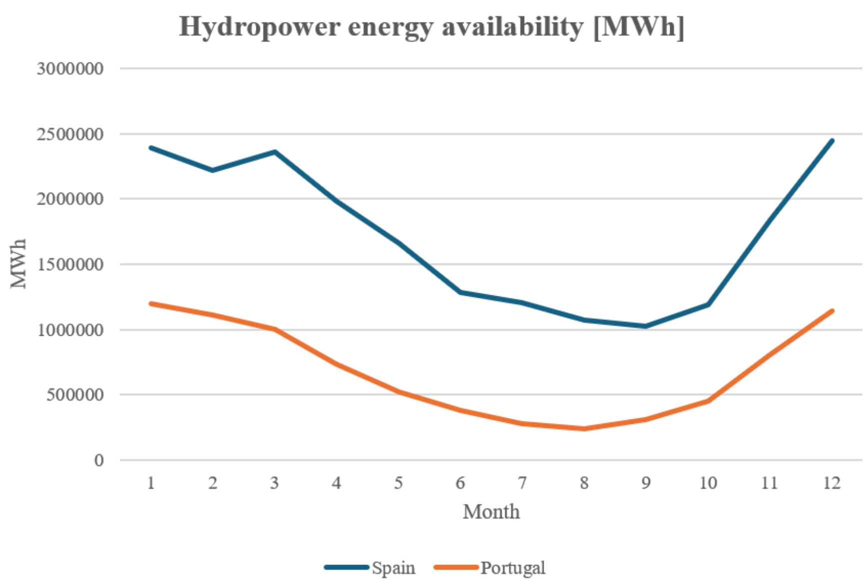

Figure 10. Monthly hydro energy

Table 10 shows the available energy for the week analysed in detail.

Area	$\overline{HYD}_a$ [MWh]
Spain	9,439
Portugal	8,608

Table 10. Hydropower energy

5.2.2.5 Pumped-Stored Units

Pumped-storage units are considered only in the Spanish area, whereas no pumped-storage capacity is considered in Portugal. The main parameters regarding their operation characteristics are shown in Table 11.

Area	$\overline{PUMP}_a$ [MW]	$\overline{TURB}_a$ [MW]	$\overline{STO}_a$ [MWh]	$\underline{STO}_a$ [MWh]
Spain	3,500	4,200	135,000	67,500
Portugal	0	0	0	0

Table 11. Pumped-stored units technical characteristics

Pumped-storage units are modelled with a round-trip efficiency η of 70% [22], accounting for energy losses during the pumping and generation cycles.

5.2.2.6 Other Technologies

In this case study, run-of-river hydropower, cogeneration, solar thermal generation and other renewable technologies are represented as non-dispatchable generation.

Table 12 presents the total non-dispatchable energy for each area for the annual horizon.

Area	*Spain [GWh]*	*Portugal [GWh]*
Cogeneration	15,000	0
Solar Thermal	5,500	0
Run-of-river	7,510	3,206
Other	8,500	3,500

Table 12. Non-dispatchable technologies annual production

Cogeneration profile is based on 2019 data, as this year provides a representative pre-crisis profile, prior to the successive disruptions that affected industrial activity. Solar thermal profile is also derived from 2019 data, following the same rationale used for solar photovoltaic, since lower curtailment levels allow the profile to better approximate resource availability rather than curtailed production. Run-of-river hydropower is represented through a monthly minimum committed power profile, calculated taking into account the corresponding monthly values over the last seven years and then extended uniformly to all hours of each month. Finally, the profile for other non-dispatchable technologies is based on 2023 data, in order to maintain consistency with the decision taken about the demand profile.

Figure 11 and Figure 12 show the duration curves of the non-dispatchable technologies for Spain and Portugal respectively (note that the actual hours represented on the horizontal axis may correspond to different real hours for each monotone).

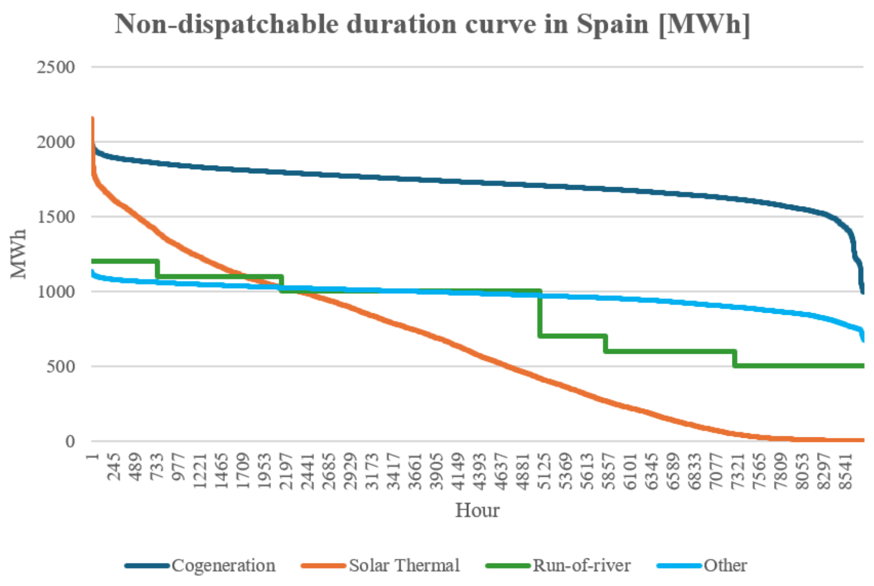

Figure 11. Non-dispatchable duration curve in Spain

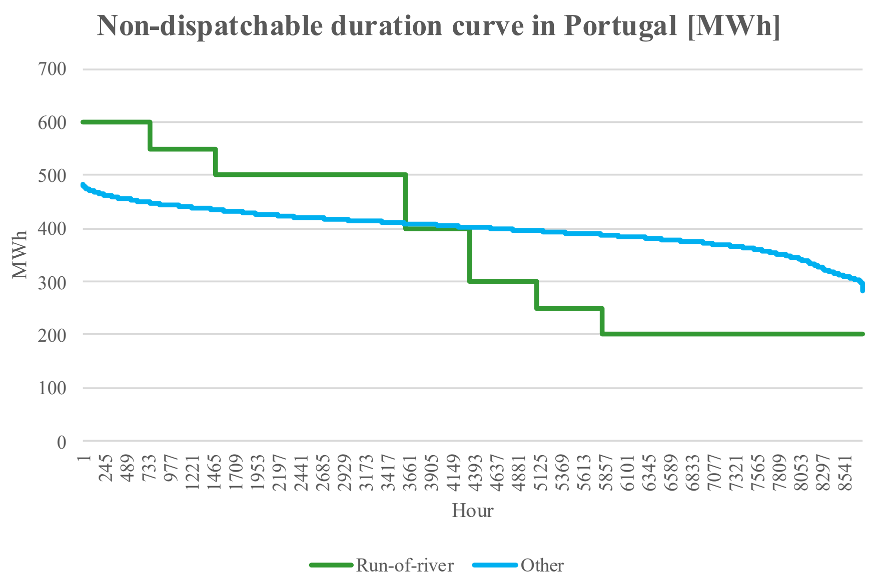

Figure 12. Non-dispatchable duration curve in Portugal

The profiles for the week analysed in detail are shown in Figure 13 and Figure 14 for Spain and Portugal, respectively.

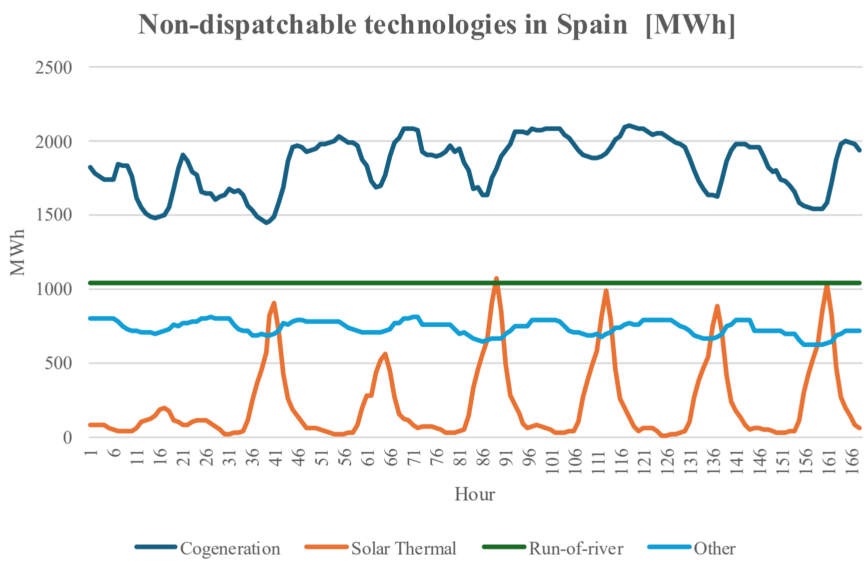

Figure 13. Non-dispatchable technologies in Spain

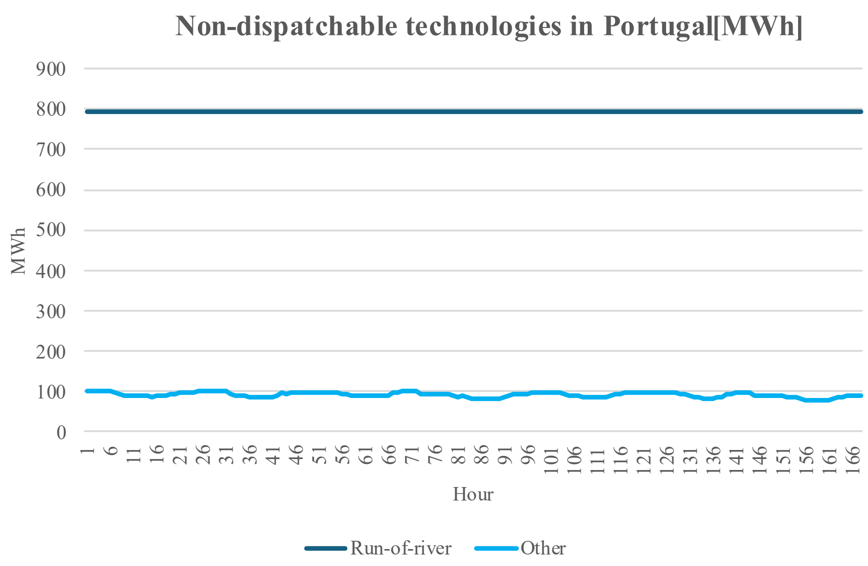

Figure 14. Non-dispatchable technologies in Portugal

5.2.3 INTERCONNECTION DATA

The interconnection between Spain (*'ES'*) and Portugal (*'PT'*) is modelled through directional exchange limits. Table 13 presents the maximum transfer capacity considered in each direction. As mentioned, these values define the upper bounds of the power that can be exchanged between the two modelled areas in each hour.

$\overline{FLOW}_{'ES','PT'}$ *[MW]*	$\overline{FLOW}_{'PT','ES'}$ *[MW]*
2,200	2,500

Table 13. Spain–Portugal interconnection capacity

Moreover, the interconnection with France (*'FR'*) is also represented by a maximum exchange capacity, presented in Table 14.

$\overline{FLOW}_{'ES','FR'}$ *[MW]*	$\overline{FLOW}_{'FR','ES'}$ *[MW]*
3,400	3,500

Table 14. Characteristics of the interconnection with France

The exchange price with France is represented by an hourly profile based on the profile of the prices of 2025, adjusted considering the forward price for 2030 [23].

Table 15 shows the average monthly price for 2030.

	Monthly average exchange price with France [€/MWh]
January	91.7
February	83.5
March	78.3
April	56.1
May	38.0
June	37.3
July	31.2
August	33.6
September	34.0
October	64.3
November	76.7
December	71.2

Table 15. Average monthly exchange price with France

Figure 15 shows the exchange price for the week analysed in detail.

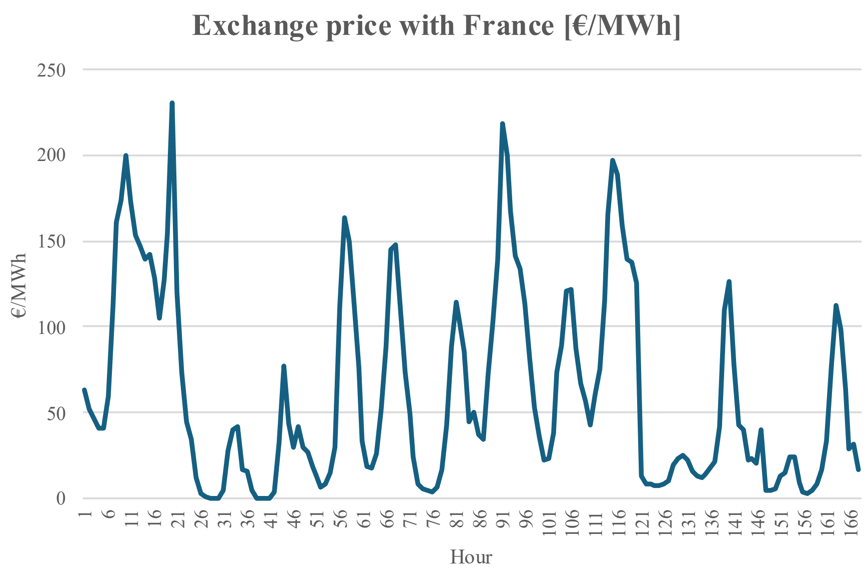

Figure 15. Exchange price with France

5.2.4 Energy Not Supplied

ENS is represented through a penalty cost applied to unmet demand in the objective function. This cost (C^{ens}) is set to 10,000 €/MWh for all areas and time periods in the case study.

This high penalty value ensures that load shedding is only used as a last resort, thereby prioritising system reliability and maintaining supply-demand balance under all operating conditions.

5.2.5 RoCoF Parameters

This section defines the RoCoF-related parameters considered in the case study. The reference RoCoF value $ROCOF^{ref}$ is set to -0.5 Hz/s [2], representing the maximum admissible frequency variation following a contingency.

In addition, the model requires the definition of a contingency size factor for each generation technology. This parameter determines the fraction of the power output of each technology that is assumed to be lost when assessing the RoCoF constraint, thereby representing the effective size of the disturbance. The values adopted in the case studies are presented in Table 16.

	F_g^{RoCoF} *[-]*
Thermal	1
RES	0.03
Hydro	1

Table 16. Contingency size factor

As can be seen, for thermal and hydropower, the factor is set equal to 1, meaning that the loss of the full output of the unit is considered. In contrast, RES generation are modelled as an aggregate power for each country. Therefore, the factor is set to 3%, representing a partial loss of the corresponding generation, representing the power loss of a renewable plant. The product between this parameter and RES power generation is intended to be representative of the total power generated by some of the largest renewable plants in Spain and Portugal, which is then considered as a contingency.

The parameters regarding the deviation of the RoCoF constraint ($\overline{DV}_a$, C_a^{dv1} and C_a^{dv2}) are defined with different values depending on the case study. They are explained in the following section.

5.3 CASE STUDIES DEFINITION

The case studies defined in this section are designed to assess the impact of the RoCoF constraint on the total system cost, security of supply, and emissions. To this end, several scenarios are analysed in which the treatment of the RoCoF constraint is modified. In particular, the cases differ in the maximum deviations allowed from the RoCoF limit and in the penalty coefficients associated with these deviations.

All cases are based on the same input data, ensuring that the differences observed in the results can be directly attributed to the implementation of the RoCoF constraint.

5.3.1 Case 1: Strictly Constrained RoCoF

In this scenario, the RoCoF constraint is strictly enforced, representing the baseline case for frequency control. No deviations are allowed, ensuring full compliance with the constraint. As a result, the penalty coefficients associated with RoCoF deviations do not affect the objective function in this case.

5.3.2 Case 2: Unconstrained RoCoF

This scenario serves to assess the impact of the RoCoF constraint, by considering its complete relaxation. To this end, a sufficiently large value is assigned to the maximum allowed RoCoF deviations, while the associated penalty cost coefficients are set to zero. Consequently, the RoCoF constraint is effectively relaxed.

5.3.3 Case 3: Linear Deviation

In this case, the RoCoF constraint remains active, but deviations from the RoCoF limit are allowed up to a predefined maximum value. Therefore, the model can relax the frequency-security requirement only within this admissible range.

These deviations are incorporated in the objective function through a linear penalty term C_a^{dv1}. This term is defined as the mean dual value of the RoCoF constraint obtained in the Strictly Constrained RoCoF (case 1), where no deviations are allowed. The quadratic penalty coefficient C_a^{dv2} is set to zero, so that deviations are penalised only according to their total magnitude, without introducing any additional cost for concentrating them in specific periods.

The maximum allowed RoCoF deviation is defined based on the results of the Unconstrained RoCoF case (case 2), in which the RoCoF constraint is effectively relaxed. In this case, the model determines the total RoCoF deviation associated with the cost-minimising dispatch when no active limitation on RoCoF deviations is imposed. The maximum admissible deviation used in the following cases is then set equal to one half of this total value. T

The linear penalty coefficient is calibrated from the dual values of the RoCoF constraints in the Strictly Constrained RoCoF (case 1). Since the RoCoF constraint is strictly enforced, these dual values provide an estimate of the marginal value of relaxing the frequency-security requirement. As the RoCoF constraint is evaluated independently for each area, the calibration is performed separately for each area. Therefore, the linear penalty coefficient is defined as the average of the dual values over the analysed time horizon.

These parameters depend on the input data; therefore, different values are obtained for the weekly and yearly analysis. They are presented in Table 17.

		$Spain$	$Portugal$
Weekly analysis	$\overline{DV}_a$ [MW/s]	129,216	1,013,780
	C_a^{dv1}[€/(MWs^{-1})]	95	52
	C_a^{dv2}[€/(MWs^{-1})^2]	0	0
Yearly analysis	$\overline{DV}_a$ [MW/s]	7,411,460	58,147,524
	C_a^{dv1}[€/(MWs^{-1})]	87	48
	C_a^{dv2}[€/(MWs^{-1})^2]	0	0

Table 17. RoCoF deviation parameters in Linear Deviation case

5.3.4 CASE 4: QUADRATIC DEVIATION

In this case, the RoCoF constraint remains active and deviations from the RoCoF limit are allowed up to the same maximum value as in the previous case (case3: linear deviation). The linear penalty coefficient C_a^{dv1} is set to zero, while the quadratic penalty term C_a^{dv1} is introduced in the objective function. As a result, the marginal cost of RoCoF deviations increases with their magnitude, discouraging large violations, thereby avoiding the concentration of frequency-security relaxations in a limited number of periods and promoting a more balanced distribution of deviations over time.

In this case study the maximum allowed RoCoF deviation is set to the same value as in the previous case. Meanwhile, the quadratic coefficient is calibrated based on a reference RoCoF deviation above which violations are considered significant from a frequency-security perspective. In this master's thesis, this reference value is set to 0.1 Hz/s. Since the deviation variable belongs to the linearised form of the RoCoF constraint it is not imposed directly in the model. Instead, it is rescaled using the average system inertia so that it is expressed consistently with the model formulation. This ensures consistency between the physical interpretation of the deviation and the mathematical formulation used in the UC model.

The quadratic penalty coefficient is then obtained from the previously defined linear penalty coefficient C^{dv1}, which provides a reference value for the marginal cost of relaxing the RoCoF requirement. Specifically, the linear coefficient is divided by the adjusted reference deviation, so that the quadratic penalty has a comparable effect around the selected reference level. This formulation assigns a relatively low marginal penalty to small deviations, while progressively increasing the marginal cost as the deviation becomes larger. As a result, moderate RoCoF deviations may still be allowed within the predefined admissible range, whereas larger deviations are more strongly discouraged due to their greater impact on frequency stability.

As stated before, the parameters depend on the input data. Table 18 shows the parameters associated with the penalisation of RoCoF deviations.

		Spain	*Portugal*
Weekly analysis	$\overline{DV}_a$ [MW/s]	129,216	1,013,780
	C_a^{dv1}[€/(MWs^{-1})]	0	0
	C_a^{dv2}[€/(MWs^{-1})^2]	0.03	0.1
Yearly analysis	$\overline{DV}_a$ [MW/s]	7,411,460	58,147,524
	C_a^{dv1}[€/(MWs^{-1})]	0	0
	C_a^{dv2}[€/(MWs^{-1})^2]	0.00005	0.0005

Table 18. RoCoF deviation parameters in Quadratic Deviation case

5.3.5 CASE STUDIES SUMMARY

The main characteristics of the case studies are summarised in Table 19. The table identifies the parameters that vary across the analysed cases and indicates whether they are included in each formulation.

RoCoF constraint		$\overline{DV}_a$	C_a^{dv1}	C_a^{dv2}
Case 1	Strictly enforced	0	Not active	Not active
Case 2	Fully relaxed	Very large	0	0
Case 3	Relaxed with total deviation limit	Limited	Active	0
Case 4	Relaxed with penalty	Limited	0	Active

Table 19. Case Studies summary

The corresponding numerical values are reported in detail in Table 17 and Table 18.

5.4 RESULTS

This section presents the results obtained from the case study analysis. The objective is to evaluate the economic impact of incorporating RoCoF-based frequency-security constraints into the UC model and to identify how these constraints influence system operation.

The analysis is structured in two stages. Firstly, the one-week time horizon is analysed in detail, secondly, a full-year time horizon is analysed to validate the conclusions obtained in the weekly analysis. Each analysis starts by comparing the Strictly Constrained RoCoF case (case 1) with the Unconstrained RoCoF case (case 2) in order to isolate the effect of enforcing the RoCoF requirement. This section continues with the analysis of the formulations with penalised RoCoF deviations to assess the cost-security trade-off between strict compliance and economic efficiency.

5.4.1 WEEKLY ANALYSIS

In this section the data corresponding to the forecasted first week of October of 2030 is analysed in detail.

5.4.1.1 Economic Impact of the RoCoF Constraint

The first performance indicator analysed is the total operating cost, which provides an aggregated measure of the economic impact of incorporating frequency-security constraints into the UC problem. To quantify this impact, the operating cost for the Strictly Constrained RoCoF (case 1) and Unconstrained RoCoF (Case 2) is compared. The difference between both cases reflects the additional operating cost associated with enforcing the RoCoF requirement.

Table 20 reports the total operating cost, expressed in €, obtained in the Strictly constrained RoCoF and Unconstrained RoCoF cases.

Area	*Strictly Constrained RoCoF (case 1)*	*Unconstrained RoCoF (case 2)*	*Difference [%]*
Spain	89,049,841	88,083,159	1.10%
Portugal	17,542,467	16,562,894	5.91%
Total	106,592,308	104,646,053	1.86%

Table 20. Operating cost of Strictly Constrained and Unconstrained RoCoF cases

The relative difference is calculated according to equation E. 44:

E. 44
$$\frac{C1 - C2}{C2}$$

where *C1* and *C2* denote the total operating cost over the whole analysed week in the Strictly Constrained RoCoF and Unconstrained RoCoF cases, respectively.

As can be seen, enforcing the RoCoF constraint increases the total operating cost by 1.10% in Spain and 5.91% in Portugal. This cost increase is mainly driven by the need to maintain sufficient synchronous inertia after the considered contingency. When the purely economic dispatch does not commit enough synchronous capacity to satisfy the RoCoF limit, the strictly constrained formulation must keep additional synchronous units online. This modifies the least-cost schedule and increases the operating cost.

The subsequent section examines which hours and areas are responsible for the observed cost increase and how the model modifies the commitment, generation dispatch, renewable curtailment and inter-area exchanges in order to satisfy the RoCoF requirement.

5.4.1.2 Impact on the RoCoF

Having quantified the aggregate cost impact, the next step is to identify when and where the RoCoF requirement becomes operationally relevant. This is done by analysing the RoCoF values obtained in the unconstrained dispatch (case 2), since they indicate the hours in which the purely economic solution would not satisfy the frequency-security criterion.

Figure 16 shows the hourly RoCoF values obtained in the Unconstrained RoCoF case for Spain.

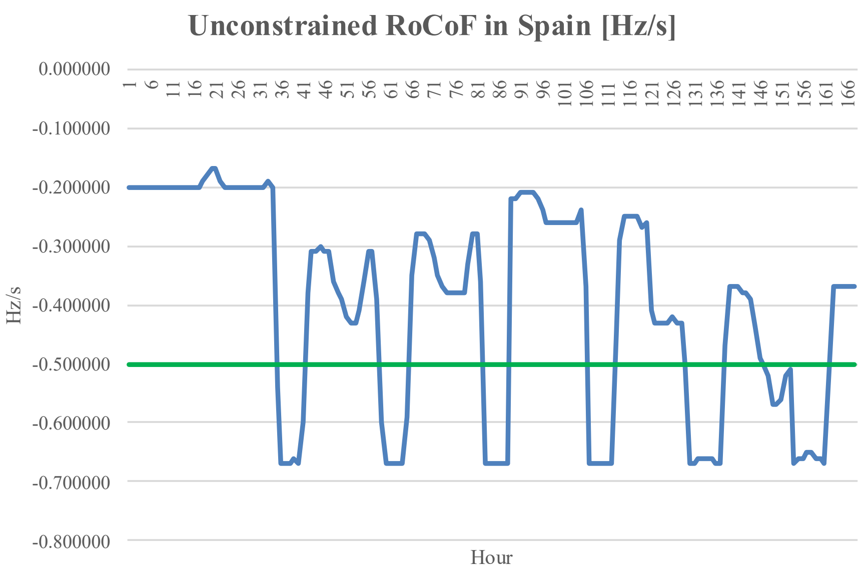

Figure 16. Unconstrained RoCoF in Spain

These values identify the hours in which the purely economic dispatch would not comply with the frequency-security criterion. In both figures, the admissible RoCoF limit of -0.5 Hz/s is included as a reference.

As can be observed, the RoCoF does not violate the RoCoF constraint throughout the whole analysed period. Instead, violations are concentrated in specific hours. Figure 17 shows the RoCoF value for the Unconstrained RoCoF case (case 2), left axis, compared with the renewable generation for each hour, right axis.

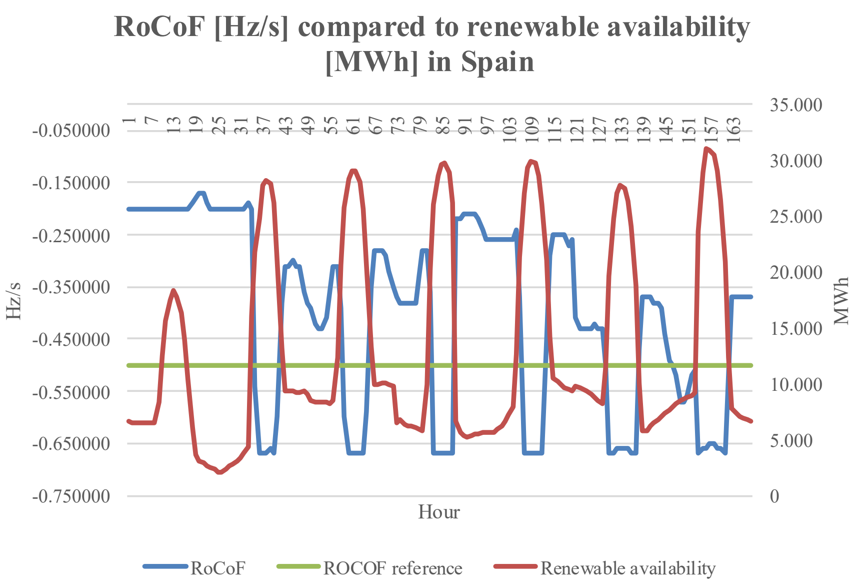

Figure 17. RoCoF compared to renewable availability

The figure shows the total dispatchable renewable generation, wind and solar power. It can be observed that the RoCoF surpasses the reference value when higher levels of renewable energy are available.

Figure 18 shows the RoCoF value in the Unconstrained RoCoF case (case 2) for Portugal.

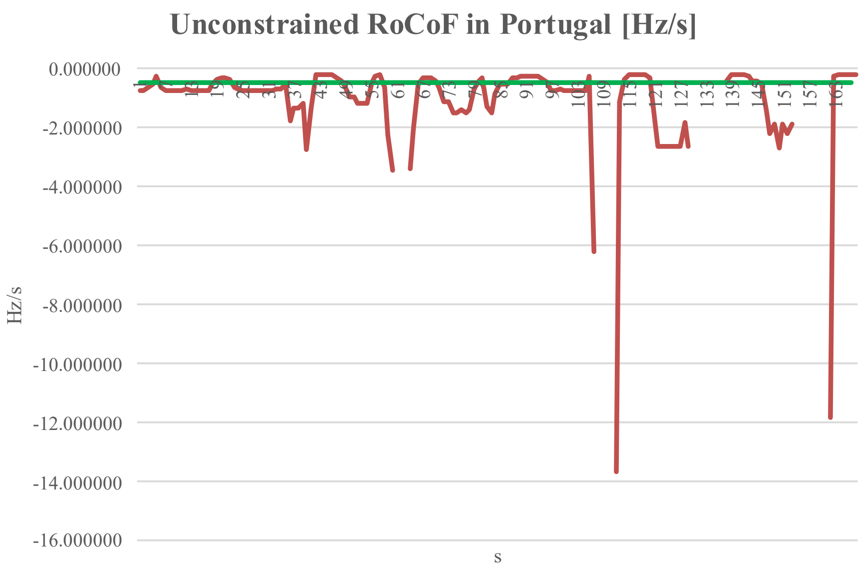

Figure 18. Unconstrained RoCoF in Portugal

The RoCoF results for Portugal exhibit some distinctive features that require further clarification. Unlike Spain, Portugal does not have nuclear generation, therefore, there is no large synchronous generation block assumed to be continuously online. As a result, during certain hours, no synchronous units are committed in Portugal, resulting in a total available inertia equal to zero. Under these operating conditions, the RoCoF cannot be physically calculated, since its formulation depends on the inverse of the available synchronous inertia.

Moreover, some RoCoF values in Portugal present very large negative values. This arises when only a small number of synchronous units are online, leading to a very low level of inertia, but greater than zero. For a given active power imbalance, a lower inertia results in a higher absolute RoCoF value. Therefore, these extreme values should not be interpreted as numerical errors but rather reflect operating conditions in which the Portuguese area is particularly vulnerable from a frequency-security perspective, in the purely economic dispatch.

To facilitate the interpretation of RoCoF results in Portugal, Figure 19 presents the RoCoF evolution using a reduced vertical-axis range. This representation improves the visibility of the constraint violations by avoiding distortions caused by extreme values.

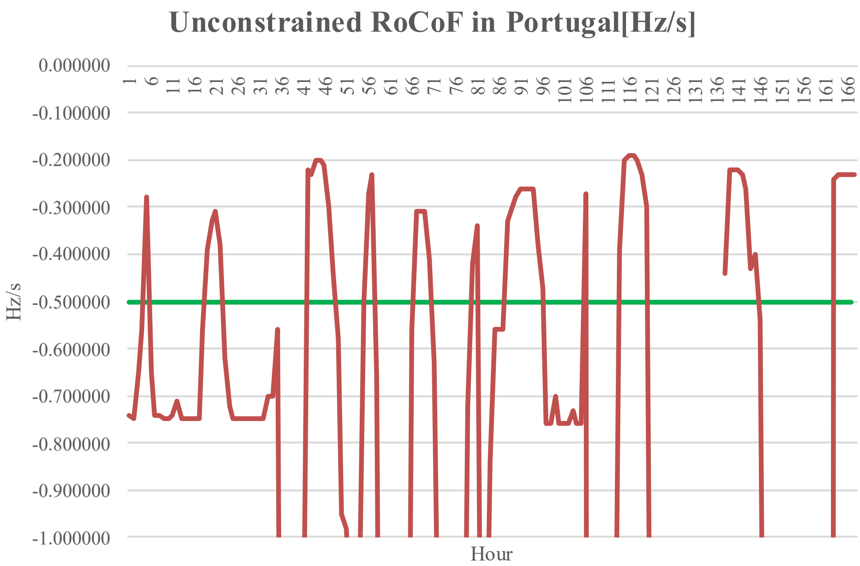

Figure 19. Unconstrained RoCoF in Portugal with reduced vertical-axis range

The results indicate that the impact of the RoCoF constraint is both temporally and geographically dependent. This means that the additional operating cost identified in the previous section should not be interpreted as the result of a uniform modification of the dispatch in all hours. Rather, it is associated with the operational changes required to correct the frequency-security limitations that arise in specific periods and areas.

These violations therefore identify the periods in which the strictly constrained formulation must modify the unconstrained dispatch. The following subsections analyse the main adjustment mechanisms: synchronous commitment and inertia, thermal dispatch, renewable curtailment and hydropower scheduling.

5.4.1.3 Impact on System Inertia

As explained, one of the main impacts of the RoCoF constraint is its effect in the inertia available, represented by the system kinetic energy, calculated as shown in equation E. 45.

E. 45
$$E_{k,sys} = \sum_{g' \neq g} H_{g'} \cdot \frac{\bar{P}_{g'}}{PF_{g'}} \cdot u_{h,m,g'}$$

Figure 20 and Figure 21 show the hourly system kinetic energy available in Spain and Portugal, respectively.

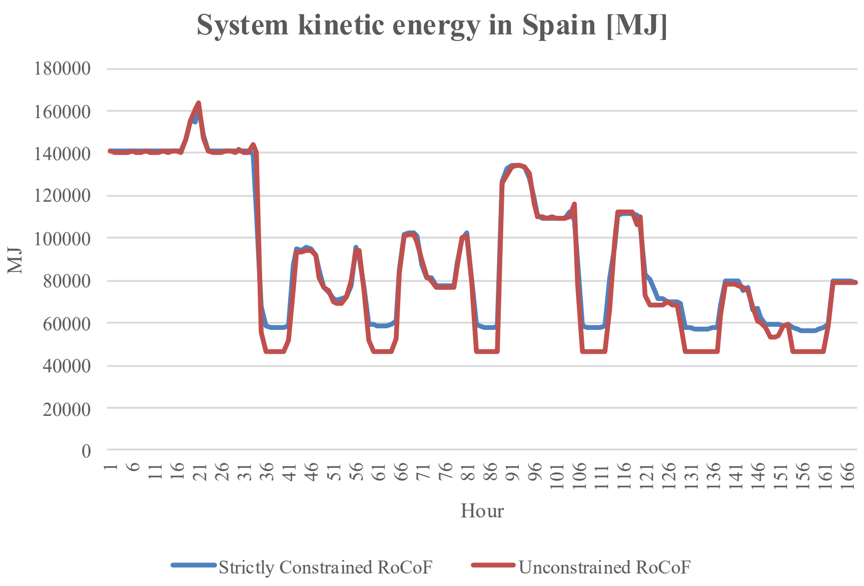

Figure 20. System kinetic energy in Spain

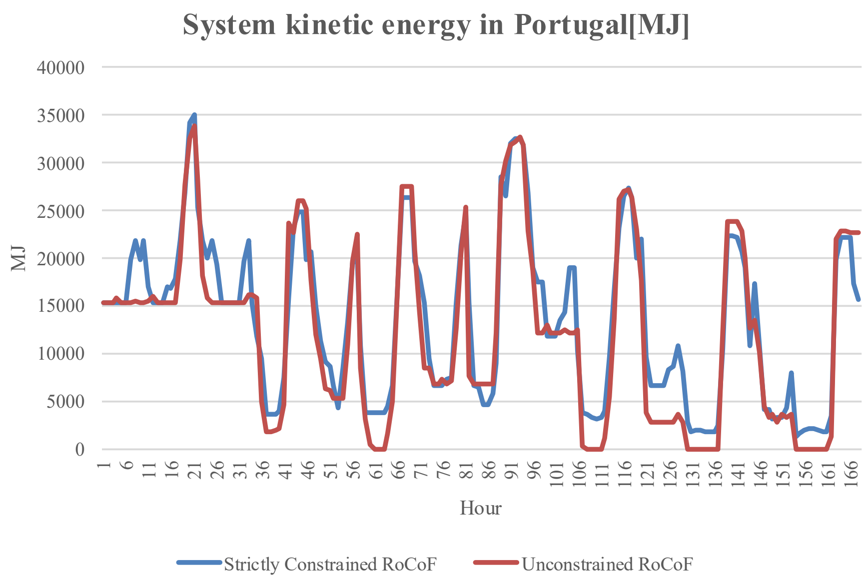

Figure 21. System kinetic energy in Portugal

As shown in the figures, the hours in which the unconstrained dispatch violates the RoCoF limit are generally associated with higher available inertia in the Strictly Constrained RoCoF case than in the Unconstrained RoCoF case. This result reflects the effect of enforcing the RoCoF constraint in the UC formulation. When the unconstrained dispatch does not provide sufficient inertial response, the model must increase the amount of synchronous inertia available in the system, mainly by committing additional synchronous generating units. This higher inertia reduces the absolute value of the RoCoF following the considered contingency and allows the system to comply with the admissible limit.

Figure 21 also confirms that, in the Unconstrained RoCoF case, Portugal presents zero available inertia in some hours. This situation disappears in the Strictly Constrained RoCoF case because the model must commit at least some synchronous capacity to satisfy the RoCoF limit.

5.4.1.4 Impact on Thermal Dispatch

The changes in synchronous commitment described above are reflected in the generation mix. Committing additional synchronous units does not only increase available inertia; it may also modify dispatch levels because committed thermal units are subject to minimum generation limits, and ramping constraints. Figure 22 and Figure 23 show the hourly thermal generation obtained when Strictly Constrained (case 1) and Unconstrained RoCoF (case 2) for Spain and Portugal respectively.

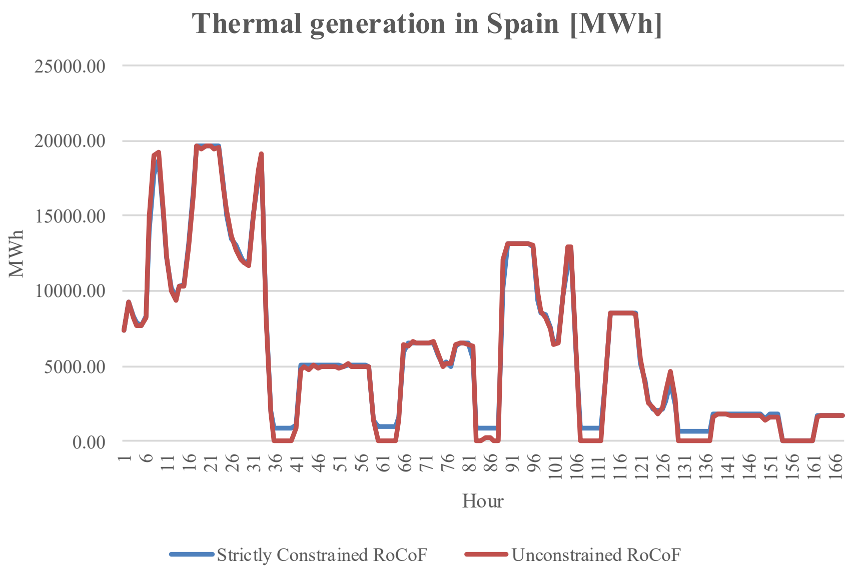

Figure 22. Thermal generation in Spain

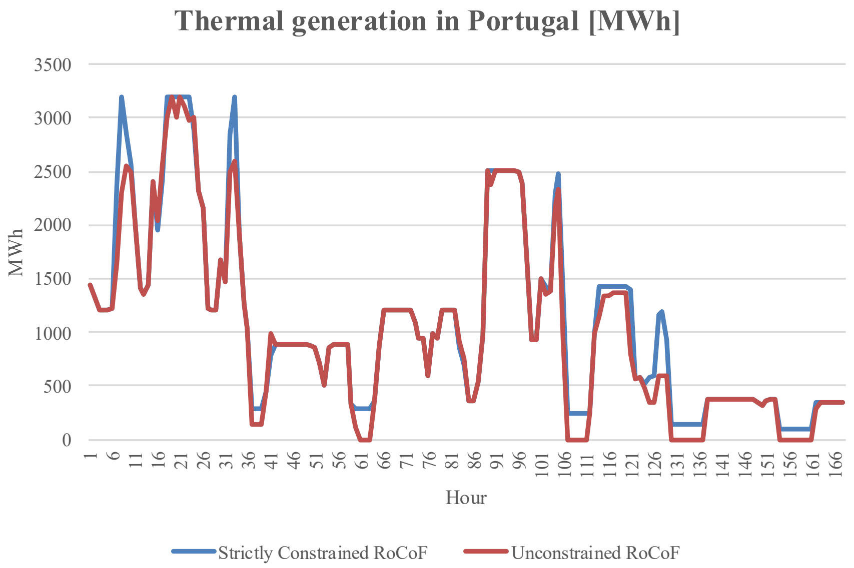

Figure 23. Thermal generation in Portugal

As discussed above, the Strictly Constrained RoCoF case may require additional synchronous units to be online. Since thermal units are subject to minimum stable generation levels, their commitment can increase thermal output even when the additional energy is not required from a purely economic perspective. This effect is especially relevant in Portugal, where the absence of nuclear generation implies that synchronous inertia depends mainly on conventional thermal and hydropower units.

5.4.1.5 Impact on CO_2 emissions

In terms of environmental impact, the increase in thermal generation observed under the Strictly Constrained RoCoF case (case 1) also implies higher CO_2 emissions. Figure 24 and Figure 25 show the CO2 emissions for when Strictly Constrained (case 1) and Unconstrained (case 2) RoCoF for Spain and Portugal, respectively.

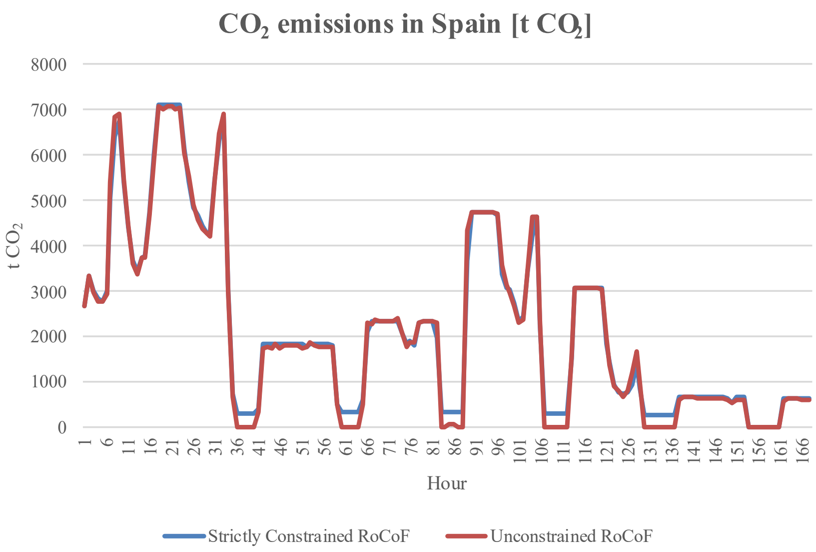

Figure 24. CO_2 emissions in Spain

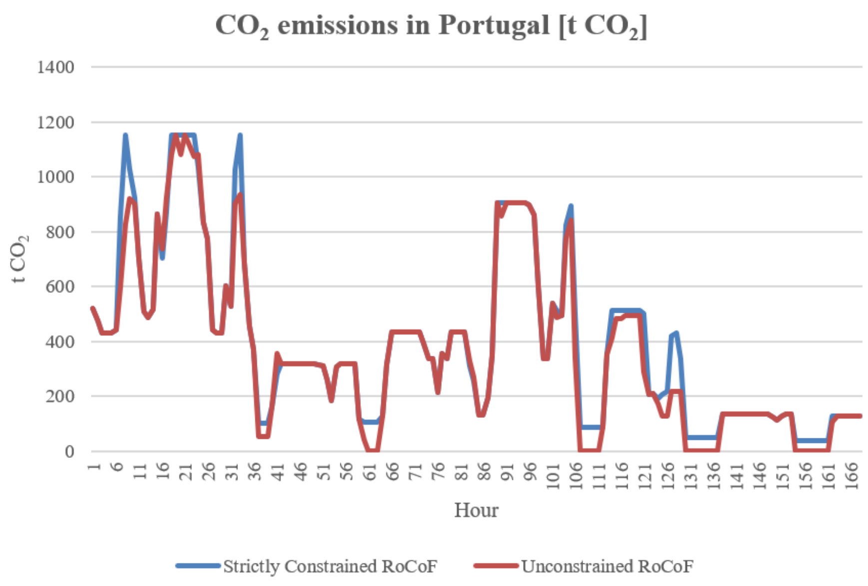

Figure 25. CO_2 emissions in Portugal

Additionally, the Table 21 presents the total amount of CO_2 emissions in each case and area.

Area	*Strictly Constrained RoCoF (case 1) [kt CO_2]*	*Unconstrained RoCoF (case 2) [kt CO_2]*	*Difference [%]*
Spain	364,2	356,4	2.2%
Portugal	66,1	61,8	6.9%

Table 21. CO2 emissions

The table and the figures show the increase in carbon emission in the Strictly Constrained RoCoF case (case 1). Since thermal technologies are associated CO_2 emission, the additional production required to satisfy the RoCoF constraint increases the carbon intensity of the generation mix. Therefore, although the enforcement of the RoCoF constraint improves frequency-security performance, it also entails an environmental trade-off.

5.4.1.6 Impact on Renewable Curtailment

An increase in synchronous generation also affects renewable integration. Since supply must match demand in every hour, a higher thermal contribution can reduce the available margin for non-synchronous renewable generation, leading to curtailment when renewable availability is high. Figure 26 and Figure 27 show the hourly difference between the renewable curtailment obtained in Strictly Constrained (case1) and Unconstrained RoCoF (case 2) for Spain and Portugal respectively.

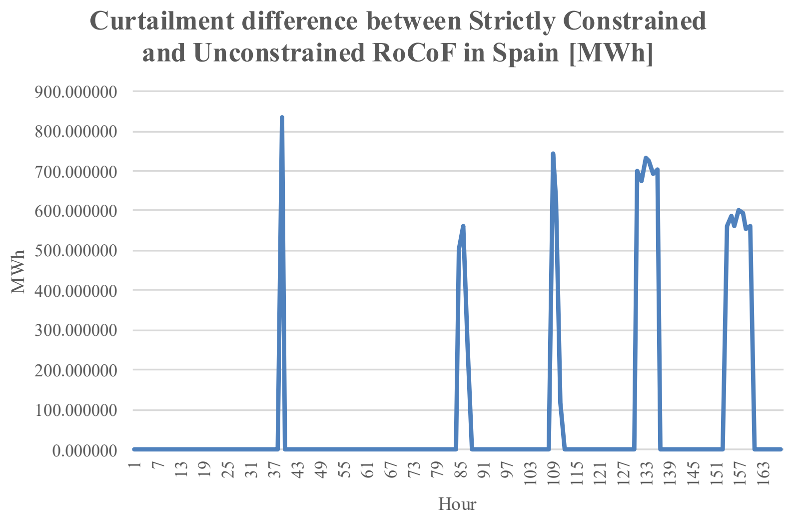

Figure 26. Difference in RES curtailment between Strictly Constrained RoCoF (case 1) and Unconstrained RoCoF (case 2) in Spain

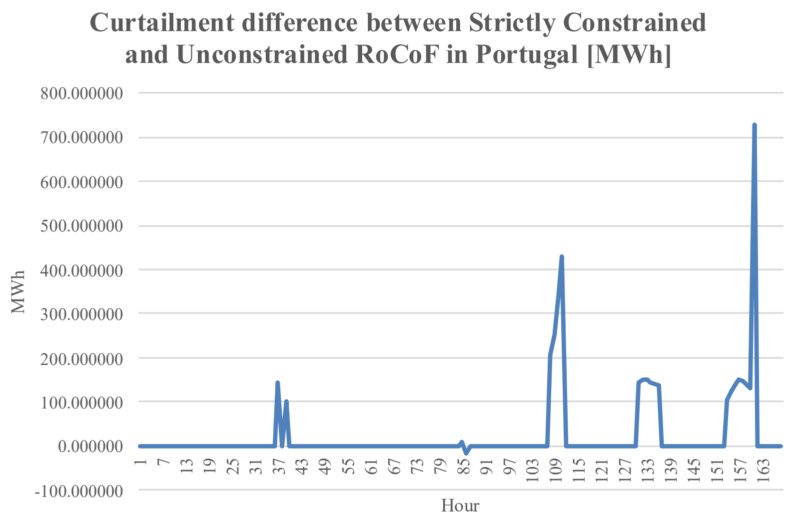

Figure 27. Difference in RES curtailment between Strictly Constrained RoCoF (case 1) and Unconstrained RoCoF (case 2) in Portugal

In these figures positive values indicate higher curtailment when the RoCoF constraint is enforced. In general, these increases can be interpreted as a consequence of the additional synchronous generation required to maintain frequency security, particularly in hours with high renewable availability or low demand.

5.4.1.7 Impact on Hydropower Dispatch

As discussed in the previous sections, the main adjustment mechanism observed in the results is the commitment of additional synchronous thermal units. However, dispatchable hydropower can also contribute to RoCoF compliance by providing synchronous inertia while allowing some flexibility in the dispatch. Figure 28 and Figure 29 show the hydropower production for Spain and Portugal, respectively for case 1 and case 2.

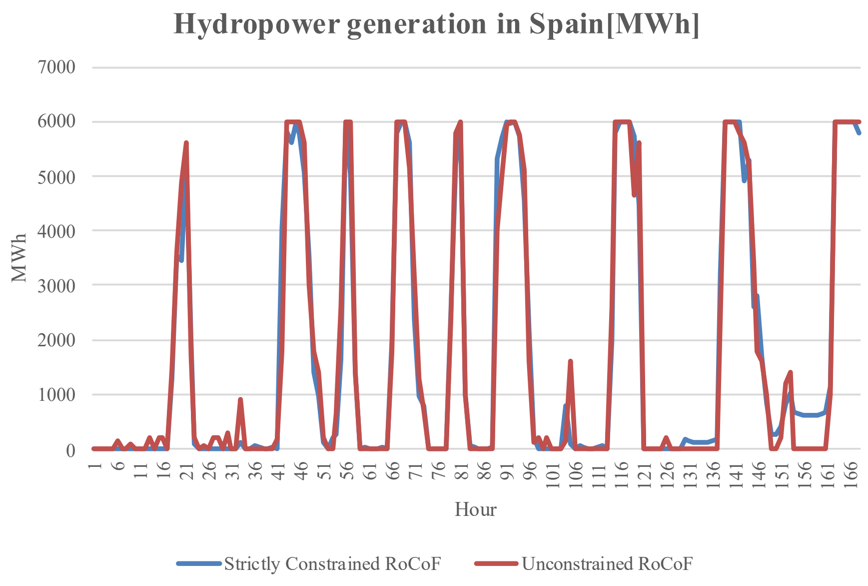

Figure 28. Hydropower generation in Spain (case 1 vs case 2)

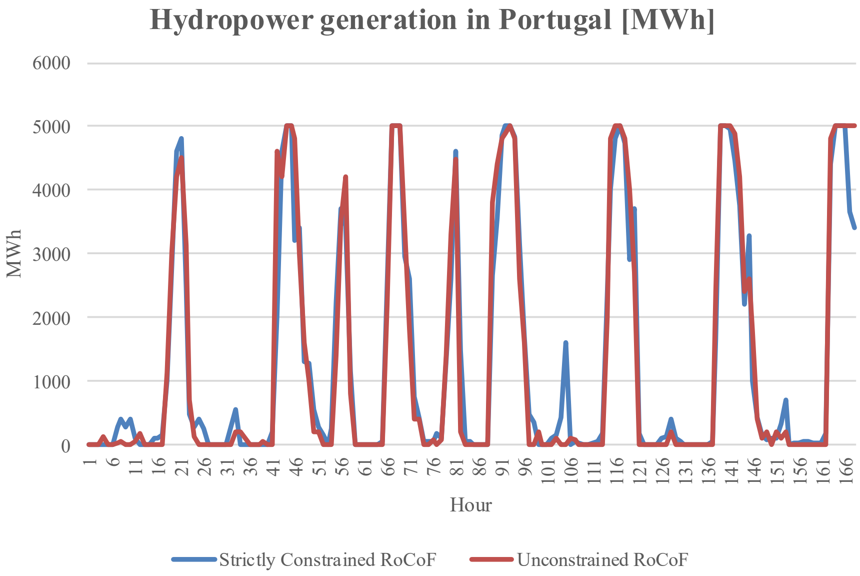

Figure 29. Hydropower generation in Portugal (case 1 vs case 2)

For most of the analysed period, hydropower generation remains very similar in both cases. This is consistent with the opportunity cost of hydropower resources: since the available hydro energy is limited over the time horizon, the model allocates it to the hours in which it provides the highest system value. Nevertheless, some periods can be identified in which hydropower production increases in the case where the RoCoF constraint is strictly enforced. This indicates that hydropower can also be modulated to contribute to RoCoF compliance while minimising the associated system cost.

5.4.1.8 Penalised RoCoF Deviations and Cost-Security Trade-off

The formulation of Strictly Constrained RoCoF (case 1) represents only one possible approach to incorporating frequency-security requirements. In practice, the reference RoCoF value should be interpreted as an admissible operational threshold rather than as an exact boundary separating secure and insecure operation. This section analyses the results obtained when RoCoF deviations are allowed but penalised in the objective function. These formulations provide intermediate solutions between the Strictly Constrained (case 1) and Unconstrained RoCoF (case 2).

Table 22 reports the operating cost, expressed in €, obtained for the four case studies.

Area	*Strictly Constrained RoCoF (case 1)*	*Unconstrained RoCoF (case 2)*	*Linear Deviation (case 3)*	*Quadratic Deviation (case 4)*
Spain	89,049,840	88,083,158	88,396,138	88,591,908
Portugal	17,542,467	16,562,893	16,356,183	16,215,143
Total	106,592,007	104,646,051	104,752,321	104,807,051

Table 22. Operational cost of all case studies one-week horizon

The cost reported in Table 22 only reflects the operating cost of the dispatch, without including the deviation penalty since it does not represent a real operating cost borne by the system.

At system level, the Strictly Constrained RoCoF case (case 1) leads to the highest operating cost, since the RoCoF requirement must be satisfied in all hours. The penalised-deviation cases reduce part of this additional cost by allowing limited violations of the reference value. However, the area-level results should be interpreted with caution. In Portugal, the Quadratic Deviation case (case 4) shows a lower operating cost than the Unconstrained RoCoF case (case 2). This does not necessarily imply that relaxing the RoCoF requirement reduces the total system cost; rather, it reflects the fact that the reported values are disaggregated by area, while the optimisation is performed at system level and may reallocate generation and exchanges between areas.

In the Linear Deviation case (case 3), the marginal cost of deviating from the reference value is constant, regardless of the size of the deviation. The model therefore evaluates each additional unit of deviation in the same way, whether the RoCoF is only slightly outside the admissible range or far from the reference value. As a result, the hours that concentrate the deviations are those in which the operating cost savings obtained by relaxing the RoCoF requirement are high enough to compensate for the corresponding penalty.

Figure 30 and Figure 31 compare the hourly RoCoF values obtained in the four case studies for Spain and Portugal, respectively. These figures illustrate how the linear and quadratic penalty formulations behave relative to the two initial cases: Strictly Constrained (case 1) and Unconstrained RoCoF (case 2).

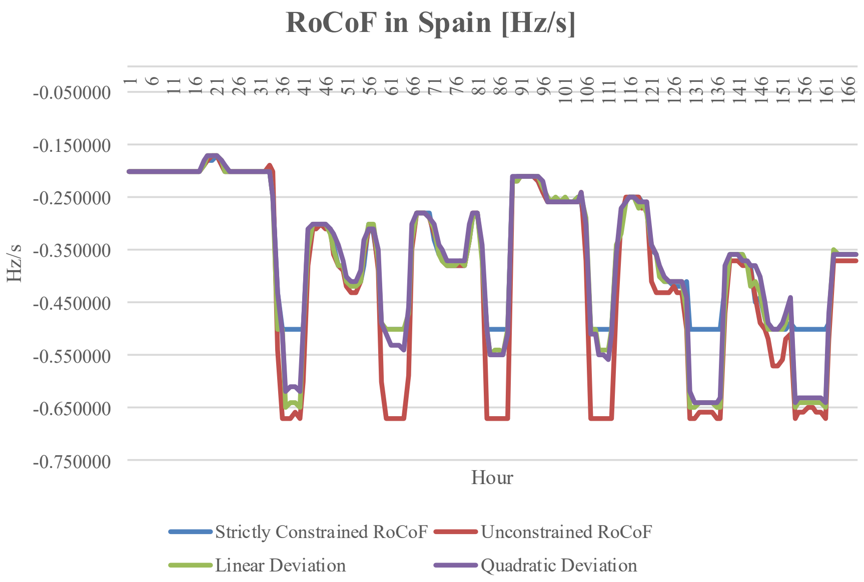

Figure 30. RoCoF values in Spain

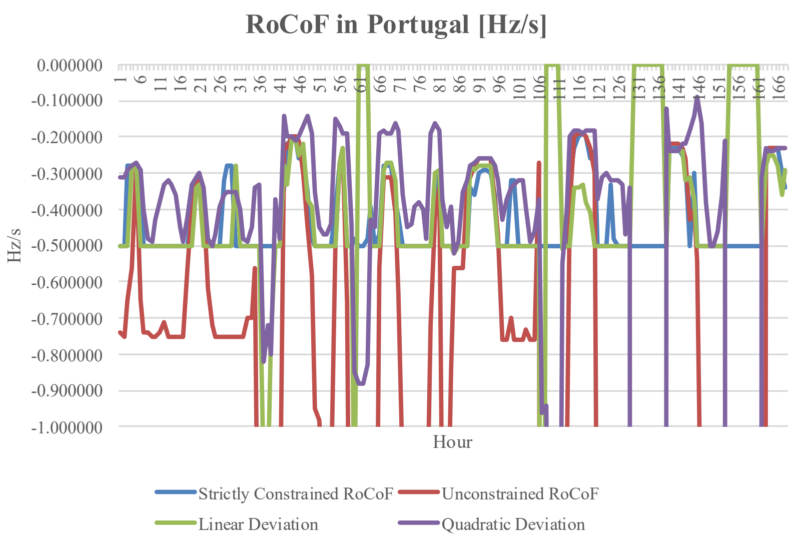

Figure 31. RoCoF values in Portugal

The figures show that there are hours in which the Unconstrained RoCoF case (case 3) violates the reference value, while the Linear Deviation case remains within the admissible limit. This occurs because, in those hours, the operating cost reduction obtained by relaxing the RoCoF requirement is smaller than the associated deviation penalty. Consequently, the model prefers to maintain the reference RoCoF value rather than accept a penalised violation. From an operational perspective, this result is relevant because it shows that there are hours in which the system can maintain the reference RoCoF value with a limited economic impact, thereby preserving a higher level of frequency security.

However, the linear penalty (case 3) has an important limitation: it introduces flexibility, but it does not adequately differentiate moderate deviations from severe ones from a risk perspective. The relevance of a RoCoF deviation is not determined only by the number of hours in which the reference value is exceeded. The magnitude of the deviation is also essential. A small deviation from the reference value may not necessarily imply a significant increase in operational risk, particularly considering that the reference RoCoF is an accepted admissible threshold rather than an exact physical limit. By contrast, larger deviations imply a steeper initial frequency decline after the contingency and, consequently, a higher risk for system security.

This motivates the formulation considered in Quadratic Deviation case (case 4), where the RoCoF deviation is penalised quadratically. Under this formulation, the penalty increases with the size of the deviation. The model can therefore accept limited deviations when strict enforcement would be excessively costly, while making large deviations increasingly unattractive. This formulation better represents the cost-security trade-off, since it allows some flexibility around the reference threshold but discourages operating points associated with a severe deterioration of frequency security.

Figure 32 shows the RoCoF for the Linear (case 3) and Quadratic (case 4) Deviation.

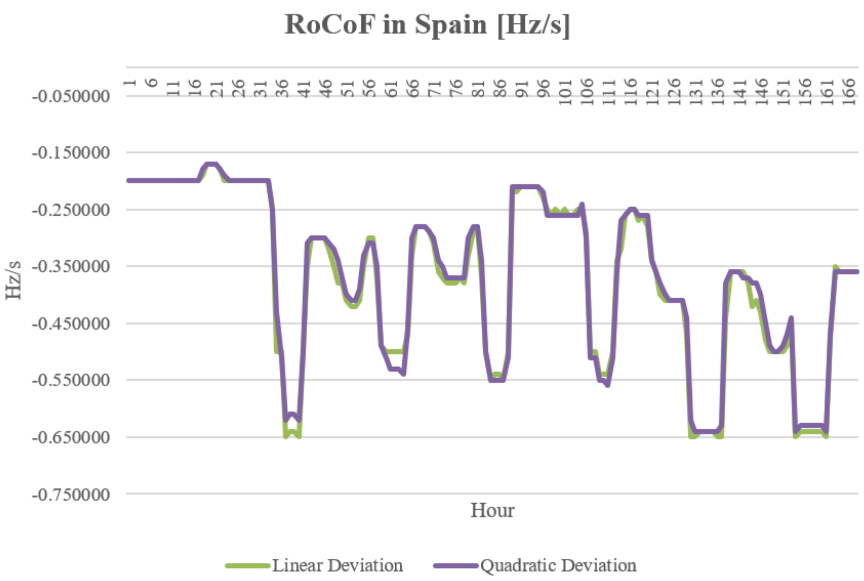

Figure 32. RoCoF for cases 3 and 4 in Spain

As observed in the figure, lower values of the RoCoF are achieved when the deviations are penalised linearly. As the total amount of deviations is limited, in the Linear Deviation case (case 3) some hours the RoCoF does not deviate from the reference value. Meanwhile, in that same period, the model is violating the RoCoF constraint in the Quadratic Deviation case (case 4) because the other periods have smaller deviations.

Overall, the penalised formulations show that part of the cost increase associated with the strictly constrained RoCoF case can be reduced by allowing controlled deviations from the reference value. Nevertheless, the comparison between the linear and quadratic penalties highlights that not only the existence of deviations matters, but also their magnitude. While the linear penalty may allow larger deviations when the associated cost savings compensate for the penalty, the quadratic formulation makes severe deviations increasingly costly. As a result, the Quadratic Deviation case offers a more balanced cost-security trade-off, since it introduces flexibility around the RoCoF threshold while discouraging operating points with a significant violation of frequency-security conditions.

5.4.2 FULL-YEAR ANALYSIS

The weekly analysis provides a detailed interpretation of the mechanisms through which the RoCoF formulations affect the operation of the system. In particular, it shows how the enforcement or penalisation of RoCoF deviations modifies the commitment of synchronous units, the available kinetic energy, renewable curtailment and the resulting operating cost. However, since the behaviour of the system may depend on the specific demand and renewable conditions of the selected week, a full-year simulation is also analysed. The objective of the annual assessment is not to reproduce the hourly discussion in the same level of detail, but to verify whether the main conclusions obtained from the weekly analysis remain valid over a broader range of operating conditions.

5.4.2.1 Economic Impact of the RoCoF Constraint

To reflect the economic impact of the RoCoF constraint, the operational cost of the Strictly Constrained RoCoF (case 1) is compared with the Unconstrained RoCoF (case 2). The operational cost for each case and area, expressed in €, is shown in Table 23.

Area	*Strictly Constrained RoCoF (case 1)*	*Unconstrained RoCoF (case 2)*	*Difference (%)*
Spain	2,494,857,554	2,257,210,549	10.5%
Portugal	760,659,086	706,704,490	7.6%
Total	3,255,516,640	2,963,915,039	9.8%

Table 23. Operation cost for the full-year horizon (case 1 vs case 2), full-year horizon

The annual cost comparison shows that strictly enforcing the RoCoF requirement leads to an increase in total operating cost with respect to the unconstrained case. This result confirms that maintaining sufficient synchronous inertia throughout the year requires the model to deviate from the purely economic dispatch in certain operating conditions. Therefore, the cost difference between both cases can be interpreted as the annual economic impact of enforcing the RoCoF security requirement

5.4.2.2 Impact on the Power Balance

To observe the difference in the generation decisions for each case, Table 24 shows the balance for both cases for the MIBEL.

	Strictly Constrained RoCoF (case 1) [GWh]	*Unconstrained RoCoF (case 2) [GWh]*	*Difference [GWh]*
Hydropower	39,549	39,549	0
RES	171,294	173,518	-2,224
Solar Thermal	5,500	5,500	0
Other	12,000	12,000	0
Renewable	228,342	230,567	-2,224
Nuclear	57,143	57,698	-555
CCGT	32,328	28,471	3,857
Carbon	0	0	0
Cogeneration	15,000	15,000	0
Thermal	104,471	101,169	3,302
Turbination	7,077	6,789	288
Pumping	-10,010	-9,598	-411
Net pumping	-2,932	-2,809	-123
Imports	18,151	18,766	-615
Exports	-10,219	-9,880	-340
Net Exchange	7,931	8,886	-955
Demand	337,812	337,812	0

Table 24. Generation demand balance for MIBEL (case 1 vs case 2), full-year horizon

The comparison of the annual generation mix provides insight into the operational mechanisms behind the cost increase. When the RoCoF constraint is strictly enforced, the model tends to increase the output of synchronous technologies to provide additional kinetic energy after the considered contingency. This modifies the least-cost dispatch obtained in the unconstrained case.

5.4.2.3 Impact on the RoCoF

Figure 33 represents the RoCoF value for Spain when Strictly Constrained RoCoF (case 1) and Unconstrained (case 2).

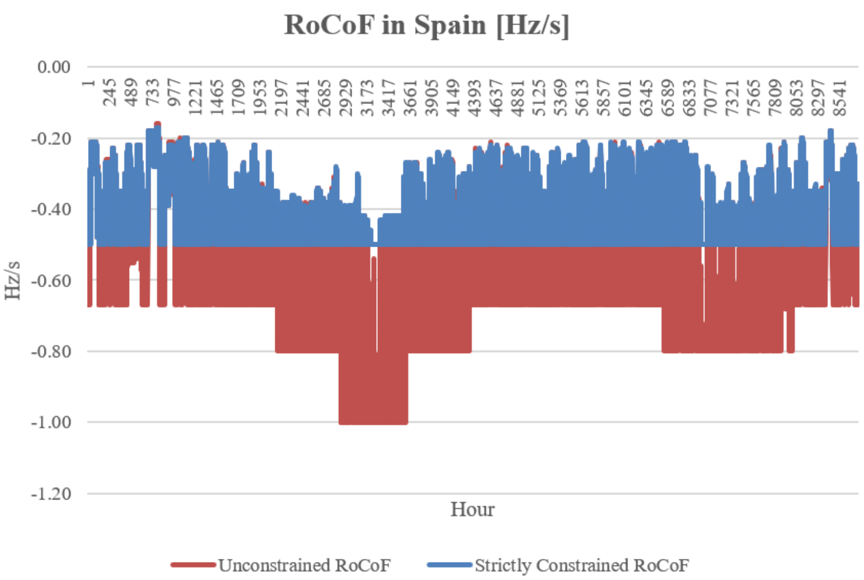

Figure 33. RoCoF in Spain (case 1 vs case 2), full-year horizon

As it can be appreciated in the figure, the RoCoF value does not go lower than -0.5 Hz/s in the Strictly Constrained RoCoF (case 1). It is also worth noting that, when unconstrained (case 2), RoCoF reaches lower values in months with lower nuclear availability.

Figure 34 shows the RoCoF value in the Unconstrained case (case 2) for Portugal.

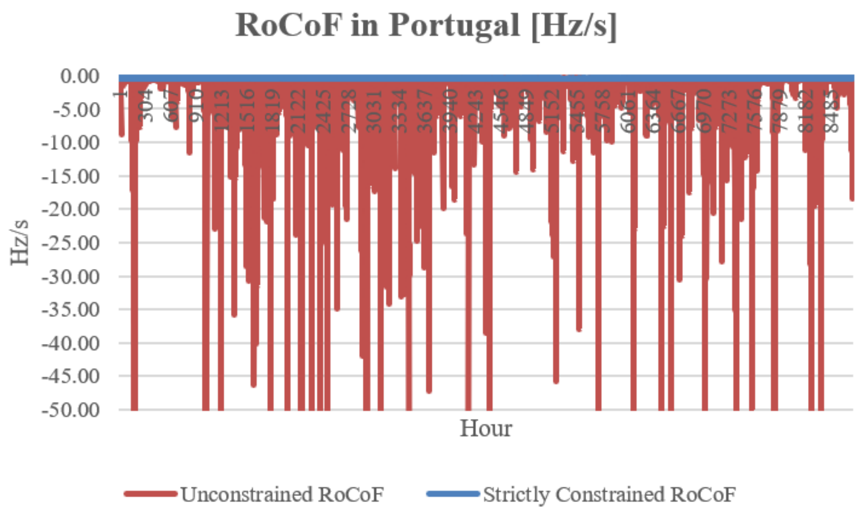

Figure 34. RoCoF in Portugal (case 1 vs case 2), full-year horizon

As explained in the weekly analysis, the RoCoF in Portugal reaches low values due to the absence of nuclear plants. It can be observed that in the Strictly Constrained RoCoF (case 1) the RoCoF constraint is met.

5.4.2.4 Impact on System Inertia

In order to meet the RoCoF restriction, the inertia of the system need to increase in those hours where the restriction is not met for the Unconstrained RoCoF case (case 2). Figure 35 and Figure 36 show the system kinetic energy, which represents system inertia, for Spain and Portugal.

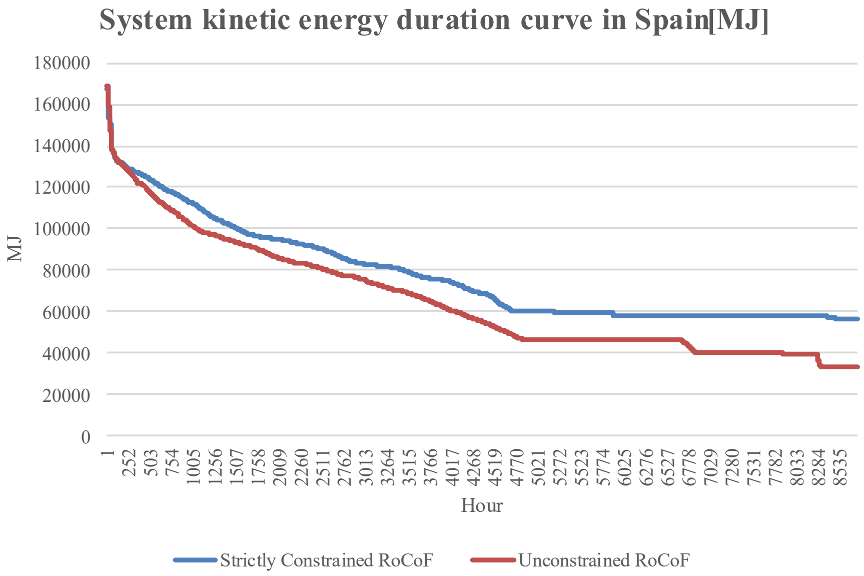

Figure 35. System kinetic duration curve energy in Spain (case 1 vs case 2), full-year horizon

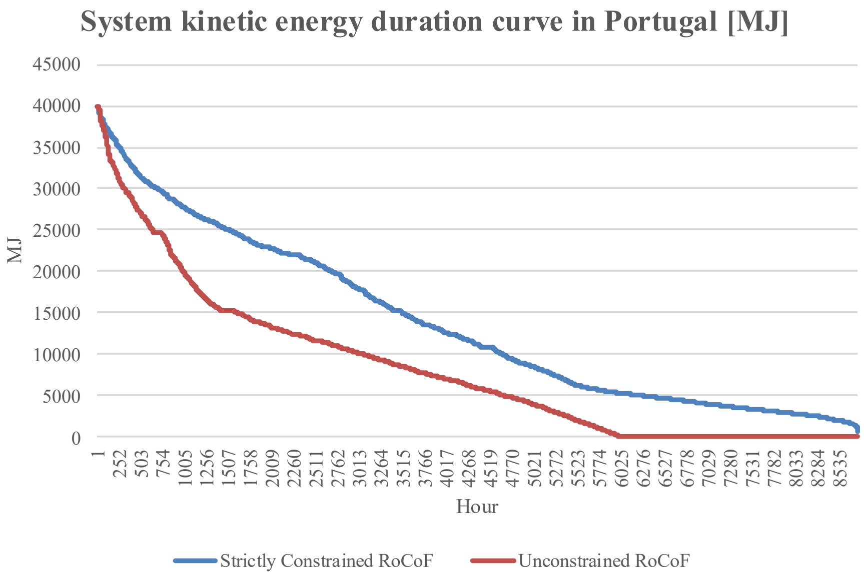

Figure 36. System kinetic duration curve energy in Portugal (case 1 vs case 2), full-year horizon

System inertia is calculated as shown in equation E. 45. It can be observed that higher levels of system kinetic energy are required when the RoCoF is strictly constrained (case 1). Particularly, in Portugal the inertia system kinetic energy in the Unconstrained RoCoF case is zero in some hours, while in the Strictly Constrained RoCoF the inertia is forced to higher values.

5.4.2.5 Impact on the number of synchronous units

To achieve the values of inertia shown in the previous figures, additional synchronous units need to be committed. Figure 37 and Figure 38 show the synchronous units (thermal and hydro) committed for Spain and Portugal respectively.

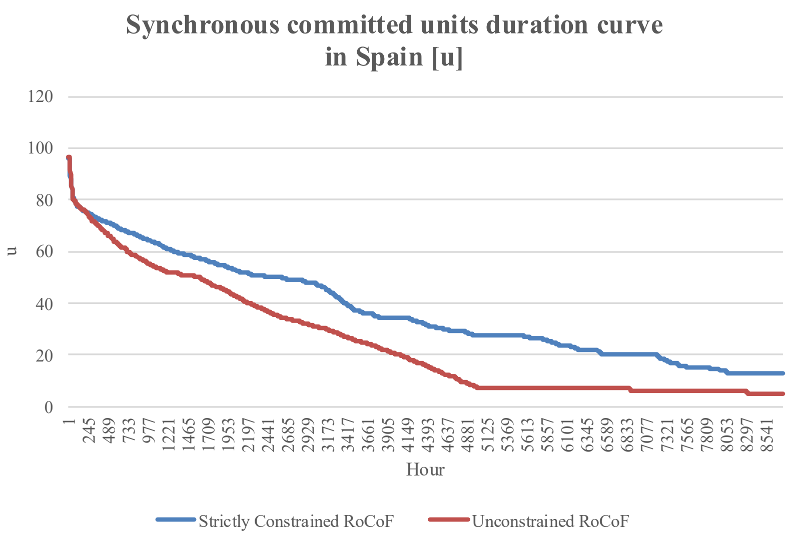

Figure 37. Synchronous committed units duration curve in Spain (case 1 vs case 2), full-year horizon

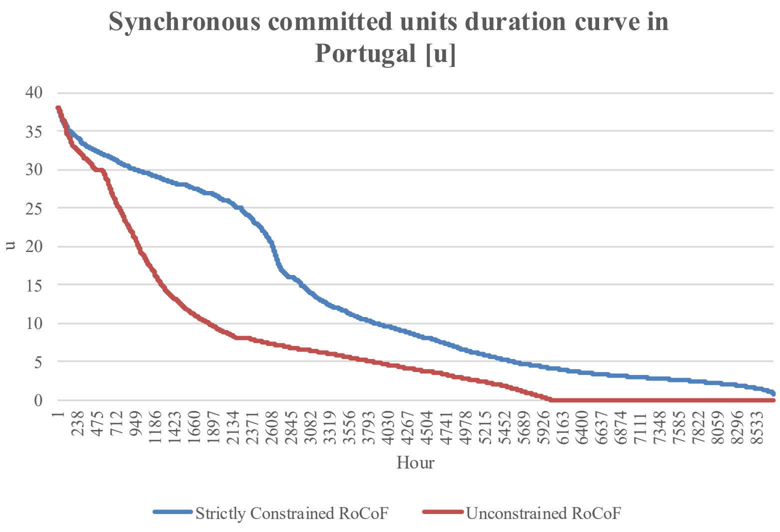

Figure 38. Synchronous committed units duration curve in Portugal (case 1 vs case 2), full-year horizon

Aligned with the analysis of the kinetic energy, the units committed are higher in the Strictly Constrained RoCoF case (case 1), for both Spain and Portugal.

5.4.2.6 Impact on Thermal Dispatch

As explained in the week-horizon analysis, the RoCoF constrain requires the commitment of synchronous units, in particular thermal units. Figure 39 and Figure 40 show the CCGT generation duration curve for Spain and Portugal respectively.

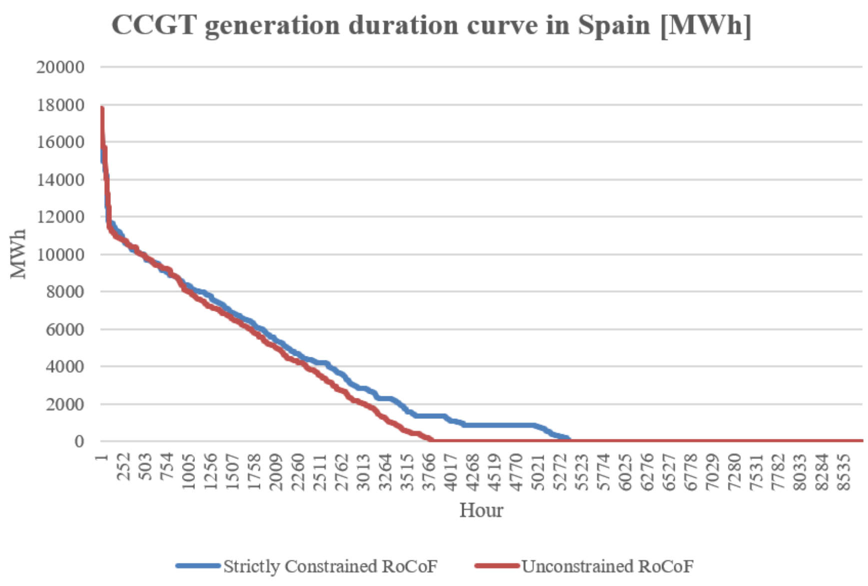

Figure 39. CCGT generation duration curve (case 1 vs case 2), full-year horizon

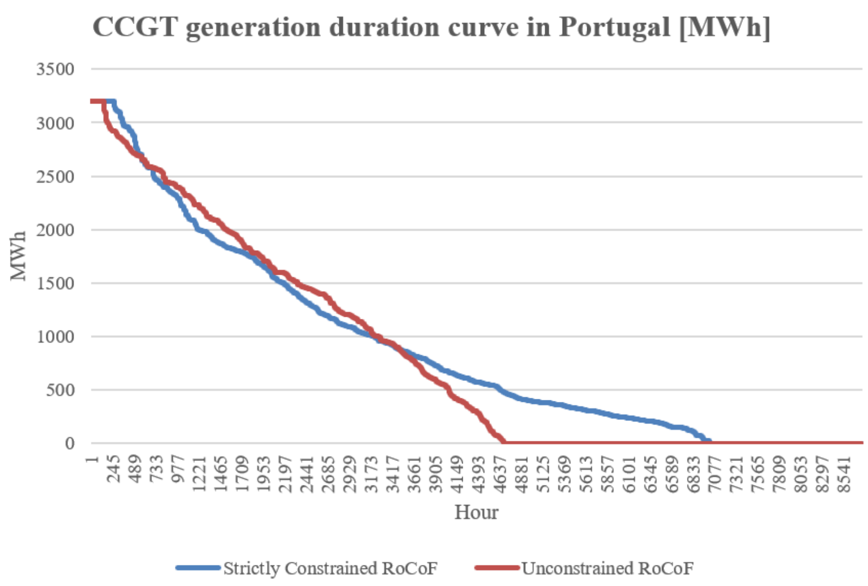

Figure 40. CCGT generation duration curve in Portugal (case 1 vs case 2), full-year horizon

As seen in the figures, the Strictly Constrained RoCoF (case 1) requires higher CCGT generation.

5.4.2.7 Impact on CO_2 emissions

In parallel with the increase in thermal generation, the CO2 emissions also increase. Table 25 shows the total carbon emission for each area comparing Strictly Constrained RoCoF (case 1) and Unconstrained RoCoF (case 2).

Area	*Strictly Constrained RoCoF (case 1) [kt CO_2]*	*Unconstrained RoCoF (case 2) [kt CO_2]*	*Difference [%]*
Spain	8,784	7,630	15.12%
Portugal	2,854	2,620	8.95%

Table 25. CO_2 emission full-year horizon (case 1 vs case 2), full-year horizon

The carbon emissions are higher for he Strictly Constrained RoCoF in both areas, which aligns with what was observed in the week time horizon.

5.4.2.8 Impact on Hydropower Dispatch

It is worth comparing the hydro energy distribution in each case. Figure 41 and Figure 42 show the hydropower duration curve for Spain and Portugal respectively.

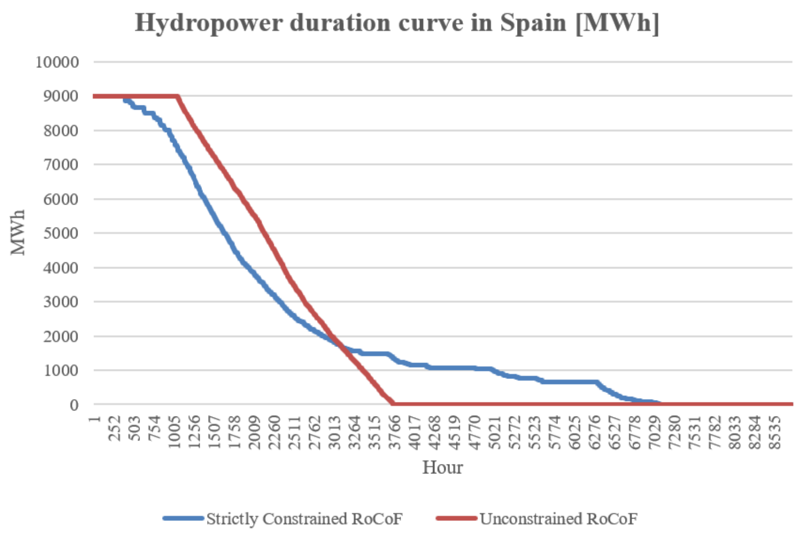

Figure 41. Hydropower duration curve in Spain (case 1 vs case 2), full-year horizon

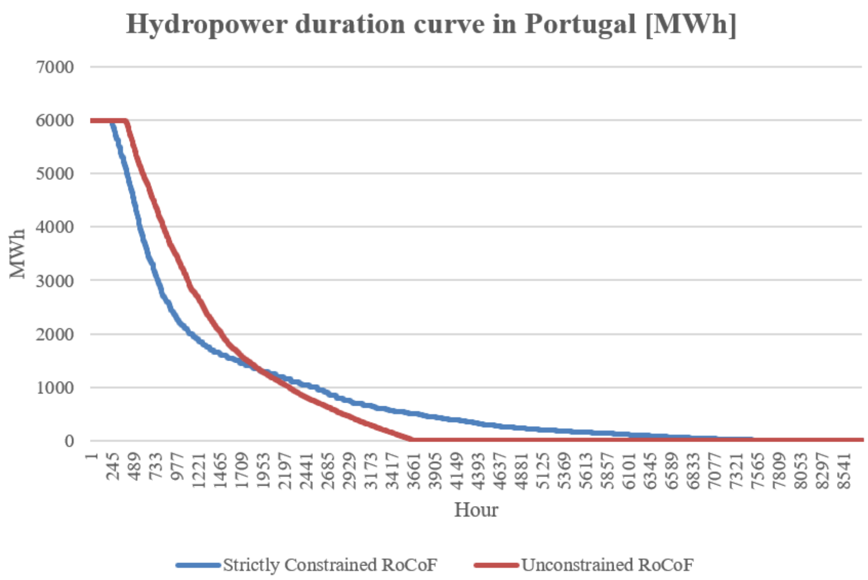

Figure 42. Hydropower duration curve in Portugal (case 1 vs case 2), full-year horizon

It can be observed that the distribution of hydropower generation changes across cases. When the RoCoF is strictly constrained (case 1) there are less hours with high hydropower output, and the energy is distributed over a larger number of hours at lower generation levels. This allows the system to use the inertia from the hydro system when necessary.

5.4.2.9 RoCoF Deviation

Figure 43 presents the RoCoF for Linear Deviation case (case 3) compared with Unconstrained RoCoF (case 2) for Spain. The reference RoCoF value is also shown in these figures to illustrate the constraint violations.

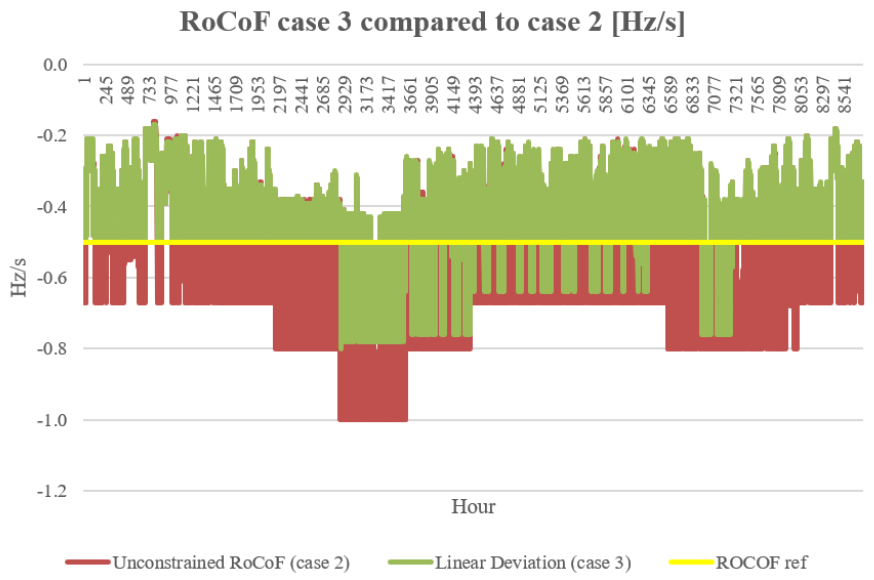

Figure 43. RoCoF case 3 compared to case 2, full-year horizon

It can be observed that the reference value is exceeded in certain hours, with large deviations concentrated in the periods in which the cost of enforcing the RoCoF constraint is higher. In addition, the RoCoF remains at the reference value during some hours, indicating that the constraint is biding in those periods.

Figure 44 shows the Quadratic Deviation case (case 4) compared to Unconstrained RoCoF (case 2).

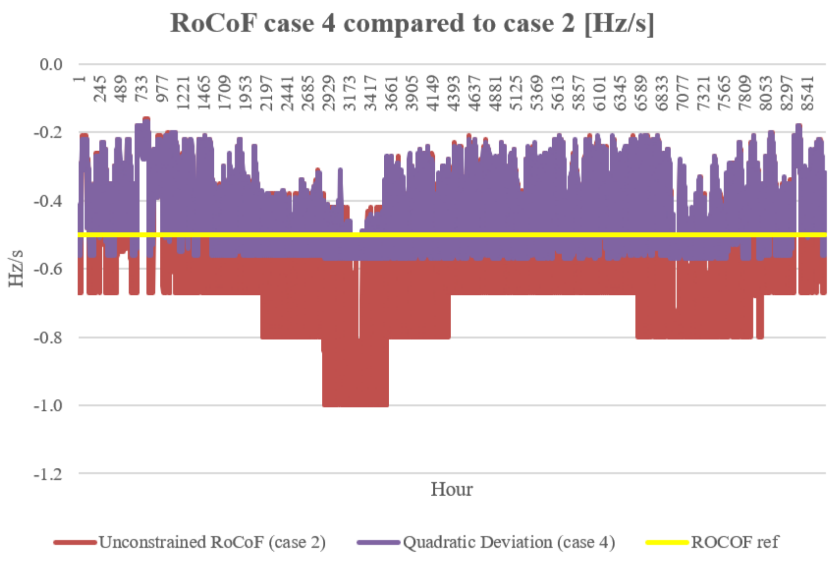

Figure 44. RoCoF case 4 compared to case 2, full-year horizon

Constraint violations are more evenly distributed throughout the year than in case 3. This effect can be more clearly seen in Figure 45, which compares both cases.

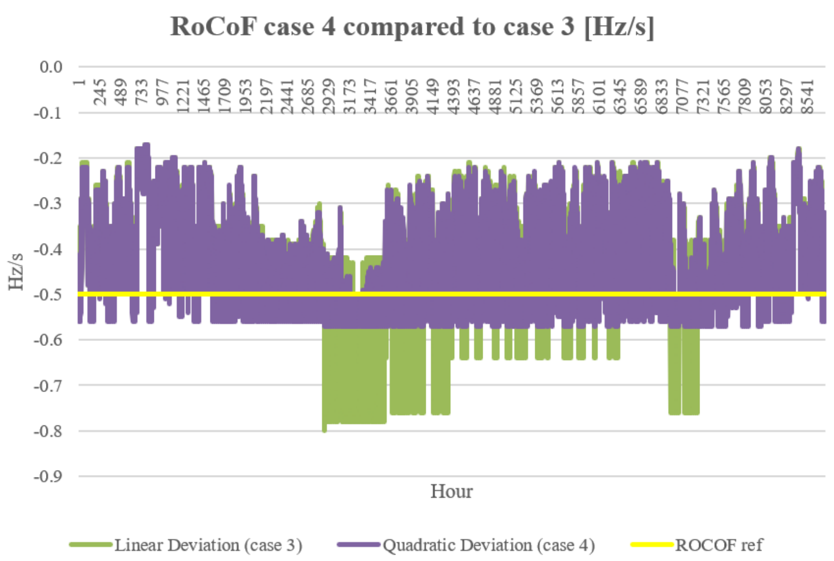

Figure 45. RoCoF case 4 compared to case 3, full-year horizon

The RoCoF reaches values further from the reference value in Linear Deviation (case 3), since case 4 applies a quadratic penalisation to the deviations, which penalises large deviations. In addition, case 4 distributes the deviations more evenly across the time horizon. Particularly, in some hours in which case 3 complies with the reference value, case 4 allows deviations, as shown in Figure 46.

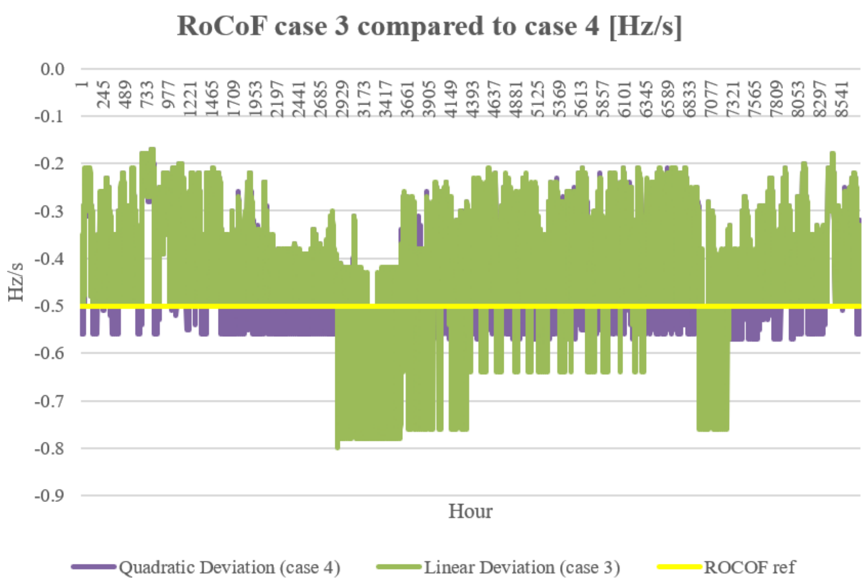

Figure 46. RoCoF case 3 compared to case 4, full-year horizon

5.4.2.10 Operational cost

The operational cost, expressed in €, is compared, shown in Table 26.

Area	*Strictly Constrained RoCoF (case 1)*	*Unconstrained RoCoF (case 2)*	*Linear Deviation (case 3)*	*Quadratic Deviation (case 4)*
Spain	2,494,857,554	2,257,210,549	2,400,716,746	2,429,758,507
Portugal	760,659,086	706,704,490	730,085,698	747,479,507
Total	3,255,516,640	2,963,915,039	3,130,802,444	3,177,238,014

Table 26. Operational cost of all case studies full-year horizon

The operating cost values are consistent with the trends observed in the weekly analysis. Allowing RoCoF deviations leads to cost savings compared with Strictly Constrained RoCoF (case 1), although these savings remain lower than the results of Unconstrained RoCoF (case 2). The Quadratic Deviation case (case 4) achieves lower savings than the case with a linear penalty (case 3).

5.4.3 COMPUTATIONAL ANALYSIS

The model was implemented in GAMS and solved using CPLEX solver. In addition, the problem is formulated as a mixed-integer quadratically constrained programming problem (MIQCP), since it includes both continuous and binary variables, as well as quadratic terms in the objective function. The computer used to solve the model is a HP Pavilion 11th Gen Intel (R) Core ™ i5-1135G7 and 16.0 GB RAM. The computer's operating system is 64-bit, x64-based processor. The models have been coded with GAMS version 47.2.0 using CPLEX as solver.

Table 27 presents the computational results for the full-year analysis.

	Strictly Constrained RoCoF (case 1)	*Unconstrained RoCoF (case 2)*	*Linear Deviation (case 3)*	*Quadratic Deviation (case 4)*
Single equations	6,219,396	4,835,316	6,219,398	6,219,398
Single variables	4,362,402	4,362,402	4,379,922	4,379,922
Non-zero elements	147,876,777	14,619,657	149,278,377	149,278,377
Discrete variables	2,733,041	2,733,041	2,733,041	2,733,041
Generation time [s]	507	467	402	450
Solver time [s]	721	401	796	2,018

Table 27. Computational comparison between case studies

An increase of 41% in execution time is observed in Case 1 compared with Case 2. This increase is mainly explained by the activation of the RoCoF constraint without allowing deviations from its limit, which makes the problem more restrictive and computationally more demanding. Moreover, the number of equations considerably increases when the

RoCoF constraint is included. Solver time needed to compute Case 3 is 2 times higher than Case 2. Lastly, Case 4 is 5 times greater, which is explained by the incorporation of the quadratic penalisation in the objective function.

Chapter 6. CONTRIBUTIONS, CONCLUSIONS AND FUTURE LINES OF RESEARCH

6.1 CONTRIBUTIONS

This master's thesis contributes to the analysis of frequency security in power systems with high RES penetration by developing a deterministic MIQCP UC model that explicitly incorporates inertia and RoCoF-related constraints. Unlike approaches focused on renewable uncertainty or detailed dynamic frequency modelling, the proposed framework isolates the operational impact of RoCoF requirements on commitment and dispatch decisions.

The main contribution lies in providing a transparent assessment of how different RoCoF formulations affect system operation. In particular, the thesis compares strict enforcement of the RoCoF constraint with relaxed and penalty-based formulations, allowing the trade-off between frequency security and economic efficiency to be evaluated in a systematic way.

The case studies quantify the impact of these modelling choices on total operating cost, synchronous generation commitment, RES curtailment, and emissions. This makes it possible to identify the operational mechanisms through which the system adapts to satisfy RoCoF requirements, as well as the conditions under which relaxing the constraint may reduce costs without fully disregarding frequency-security considerations.

Overall, the thesis provides a simplified but rigorous modelling framework that can be used to assess the role of inertia constraints in UC problems and to support the design of more flexible frequency-security formulations in systems with increasing RES integration.

6.2 CONCLUSIONS

This thesis assesses the integration of RoCoF-based frequency-security constraints into a UC formulation. The results confirm that these constraints can be incorporated into the optimisation problem and that they provide a meaningful representation of the operational requirements associated with frequency stability.

The enforcement of the RoCoF constraint leads to a measurable increase in system operating cost. This additional cost arises because the system must maintain sufficient synchronous inertia after the considered contingency, which may require changing the purely economic dispatch. In particular, when the Unconstrained RoCoF solution does not provide enough inertial response, the model commits additional synchronous units or modifies the dispatch of available synchronous technologies to satisfy the frequency-security requirement.

The operational impact of the constraint is therefore reflected mainly in the commitment and dispatch of thermal and hydro units. Additional synchronous commitment increases the kinetic energy available in the system, but it can also affect neighbouring hours through minimum output levels, ramping limits and start-up costs. Consequently, the RoCoF constraint may reduce the margin available for renewable generation and increase renewable curtailment in specific periods.

The impact of the RoCoF constraint is not uniform over time or across areas, becoming more relevant under conditions of low synchronous commitment, high renewable availability, or large contingencies relative to the available inertia. In the analysed case study, these effects are more pronounced in the area with lower availability of large synchronous generation blocks and greater dependence on renewable generation.

The analysis of penalised RoCoF deviations from the reference value shows that strict enforcement is not the only relevant formulation for frequency-security requirements. Allowing controlled deviations from the reference RoCoF value makes it possible to reduce part of the additional operating cost while explicitly representing the trade-off between economic efficiency and frequency-security risk. In this context, the form of the penalty is decisive. A linear penalty provides flexibility but may concentrate relatively large deviations in specific hours. By contrast, a quadratic penalty discourages severe deviations while still allowing limited relaxations when strict compliance would be excessively costly.

Overall, the results indicate that RoCoF-based constraints affect not only the total operating cost, but also the commitment of synchronous units, renewable integration, hydropower scheduling and the distribution of security-related costs across the time horizon. Among the formulations analysed, the quadratic penalisation of RoCoF deviations appears to provide the most balanced approach, as it introduces operational flexibility while preserving the increasing risk associated with larger deviations from the reference RoCoF value.

6.3 FUTURE LINES OF RESEARCH

One possible line of research would be to represent nuclear generation with a higher level of operational detail. In the present formulation, nuclear units are modelled with limited flexibility, which is consistent with their typical role as baseload generation. However, future work could explore a more flexible representation, considering its variable cost, and limited operational flexibility. This would make it possible to assess more accurately the contribution of nuclear units to both economic dispatch and frequency-security requirements.

Another possible line of future research would be to incorporate a probabilistic treatment of generation outages in the frequency-security assessment. Instead of considering all contingencies in the same way, future work could account for the probability of each generating unit outage and relate it to the potential impact on system operation. This would allow the expected cost of frequency-security risks to be compared with the additional operating cost associated with enforcing preventive RoCoF constraints. In this way, the model could provide a more explicit assessment of the trade-off between security requirements and their economic implications.

Finally, as a future line of development, it would be of interest to analyse the possibility of extending the current balancing framework towards a more integrated cross-border frequency support mechanism between the Spanish and Portuguese power systems. Although frequency containment and restoration services are currently organised by bidding zones, future developments could explore whether resources located in Portugal could contribute to frequency stability in Spain, and vice versa, under coordinated operational and market rules. This approach would be aligned with the broader European trend towards the harmonisation and integration of balancing services, as reflected in platforms such as PICASSO, which facilitates the exchange of automatic frequency restoration reserves across interconnected systems. Such a development could improve system flexibility, enhance the efficient use of available balancing resources, and strengthen the overall stability of the Iberian electricity system within the European balancing market framework.

References

[1] N. Nguyen and J. Mitra, 'An Analysis of the Effects and Dependency of Wind Power Penetration on System Frequency Regulation', *IEEE Transactions on Sustainable Energy*, vol. 7, no. 1, pp. 354–363, Jan. 2016, doi: 10.1109/TSTE.2015.2496970.

[2] F. Pérez-Illanes, E. Álvarez-Miranda, C. Rahmann, and C. Campos-Valdés, 'Robust Unit Commitment Including Frequency Stability Constraints', *Energies*, vol. 9, no. 11, p. 957, Nov. 2016, doi: 10.3390/en9110957.

[3] L. Rouco, E. Lobato, and F. M. Echavarren, 'Informe preliminar que analiza las causas del apagón del pasado mes de abril', COMILLAS. Accessed: Oct. 15, 2025. [Online]. Available: https://www.comillas.edu/noticias/el-iit-presenta-un-informe-preliminar-que-analiza-las-causas-del-apagon-del-pasado-mes-de-abril/

[4] L. Montero, A. Bello, and J. Reneses, 'A Review on the Unit Commitment Problem: Approaches, Techniques, and Resolution Methods'. Accessed: Oct. 15, 2025. [Online]. Available: https://www.mdpi.com/1996-1073/15/4/1296

[5] Á. García-Cerezo, A. S. Siddiqui, T. K. Boomsma, R. García-Bertrand, and L. Baringo, 'Strategic investment in electricity markets: Robust optimization versus stochastic programming', *European Journal of Operational Research*, Sep. 2025, doi: 10.1016/j.ejor.2025.08.009.

[6] M. Lubin, Y. Dvorkin, and S. Backhaus, 'A Robust Approach to Chance Constrained Optimal Power Flow With Renewable Generation', *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3840–3849, Sep. 2016, doi: 10.1109/TPWRS.2015.2499753.

[7] P. A. Ruiz, C. R. Philbrick, E. Zak, K. W. Cheung, and P. W. Sauer, 'Uncertainty Management in the Unit Commitment Problem', *IEEE Transactions on Power Systems*, vol. 24, no. 2, pp. 642–651, May 2009, doi: 10.1109/TPWRS.2008.2012180.

[8] W. Wu, J. Chen, B. Zhang, and H. Sun, 'A Robust Wind Power Optimization Method for Look-Ahead Power Dispatch', *IEEE Transactions on Sustainable Energy*, vol. 5, no. 2, pp. 507–515, Apr. 2014, doi: 10.1109/TSTE.2013.2294467.

[9] P. González-Inostroza, C. Rahmann, R. Álvarez, J. Haas, W. Nowak, and C. Rehtanz, 'The Role of Fast Frequency Response of Energy Storage Systems and Renewables for Ensuring Frequency Stability in Future Low-Inertia Power Systems'. Accessed: Oct. 15, 2025. [Online]. Available: https://www.mdpi.com/2071-1050/13/10/5656

[10] M. Tuo and X. Li, 'Security-Constrained Unit Commitment Considering Locational Frequency Stability in Low-Inertia Power Grids', *IEEE Transactions on Power Systems*, vol. 38, no. 5, pp. 4134–4147, Sep. 2023, doi: 10.1109/TPWRS.2022.3215915.

[11] L. Liu, Z. Hu, Y. Wen, and Y. Ma, 'Modeling of Frequency Security Constraints and Quantification of Frequency Control Reserve Capacities for Unit Commitment', *IEEE Transactions on Power Systems*, vol. 39, no. 1, pp. 2080–2092, Jan. 2024, doi: 10.1109/TPWRS.2023.3252502.

[12] M. Rajabdorri, A. Rouco, L. Sigrist, and E. Lobato, 'Unit Commitment With Analytical Under-Frequency Load-Shedding Constraints for Island Power Systems', *IEEE Access*, vol. 12, pp. 72337–72344, 2024, doi: 10.1109/ACCESS.2024.3401854.

[13] Z. Zhang, E. Du, F. Teng, N. Zhang, and C. Kang, 'Modeling Frequency Dynamics in Unit Commitment With a High Share of Renewable Energy', *IEEE Transactions on Power Systems*, vol. 35, no. 6, pp. 4383–4395, Nov. 2020, doi: 10.1109/TPWRS.2020.2996821.

[14] ENTSO-E, 'Inertia and Rate of Change of Frequency (RoCoF)', Dec. 2020. [Online]. Available: https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Inertia%20and%20RoCoF_v17_clean.pdf

[15] Y. Son, Y. Ha, and G. Jang, 'Frequency Nadir Estimation Using the Linear Characteristics of Frequency Control in Power Systems', *Energies*, vol. 17, no. 5, p. 1061, Jan. 2024, doi: 10.3390/en17051061.

[16] Universidad Politécnica de Madrid, 'Potencia reactiva: compensado la espuma de la cerveza – Faraday'. Accessed: Jun. 30, 2026. [Online]. Available: https://blogs.upm.es/faraday/2022/03/23/potencia-reactiva-compensado-la-espuma-de-la-cerveza/

[17] N. Jaleeli, L. S. VanSlyck, D. N. Ewart, L. H. Fink, and A. G. Hoffmann, 'Understanding automatic generation control', *IEEE Transactions on Power Systems*, vol. 7, no. 3, pp. 1106–1122, Aug. 1992, doi: 10.1109/59.207324.

[18] 'REGLAMENTO (UE) 2016/ 631 DE LA COMISIÓN - de 14 de abril de 2016 - que establece un código de red sobre requisitos de conexión de generadores a la red'.

[19] 'Plan Nacional Integrado de Energía y Clima (PNIEC 2023-2030)', Ministerio para la Transición Ecológica y el Reto Demográfico. Accessed: Jul. 01, 2026. [Online]. Available: https://www.miteco.gob.es/es/energia/estrategia-normativa/pniec-23-30.html

[20] 'Plano Nacional de Energia e Clima (PNEC) | Agência Portuguesa do Ambiente'. Accessed: Jul. 02, 2026. [Online]. Available: https://apambiente.pt/clima/plano-nacional-de-energia-e-clima-pnec

[21] 'Paradas de recarga de las centrales nucleares', Foro Nuclear. Accessed: Jul. 01, 2026. [Online]. Available: https://www.foronuclear.org/actualidad/a-fondo/paradas-de-recarga-de-las-centrales-nucleares/

[22] Enel Green Power, 'Centrales hidroeléctricas de almacenamiento'. Accessed: Jun. 21, 2026. [Online]. Available: https://www.enel.com/es/learning-hub/renovables/energia-hidroelectrica/bombas-hidroelectricas

[23] OMIP, 'France Power Future Reference Price'. Accessed: Jul. 02, 2026. [Online]. Available: https://www.omip.pt/es